International Renewable Energy Agency

ADAPTING MARKET DESIGN
TO HIGH SHARES OF VARIABLE RENEWABLE ENERGY

IRENA
International Renewable Energy Agency

978-92-9260-025-9 (PDF)

Citation: IRENA (2017), *Adapting market design to high shares of variable renewable energy.* International Renewable Energy Agency, Abu Dhabi

ABOUT IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

ACKNOWLEDGEMENTS

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DISCLAIMER

The world has embarked upon a major energy transition which is bringing about profound changes in the ways electricity is produced, distributed, and consumed.

Renewable energy is at the centre stage of this transition. Fuelled by decreasing costs and improving technologies, renewable energy deployment has grown at an unprecedented pace. Each year, renewable power capacity additions set a new record, with over 160 GW added in 2016 alone.

Still, the energy transition needs to happen faster for the world to meet key sustainable development and climate goals. The change will not happen merely with adjustments to the existing energy system, but through a paradigm shift across economies, societies and communities.

Accelerating this transition requires a rethinking of electricity markets in many aspects, a key one being the adaptation of their design and operation to support higher shares of variable renewables –solar and wind energy – as well as distributed power generation.

In this context, this report presents the latest knowledge on the different options for the adaptation of liberalised electricity markets. Building on case studies from advanced markets, it identifies policy and regulatory measures needed to accommodate variable and decentralised renewables, while ensuring high standards of efficiency, reliability and environmental stewardship.

The report highlights that regulations governing the electricity market must adapt to rapidly evolving needs and conditions in a timely manner. Enhanced flexibility for future power systems is an essential consideration. Electricity markets need to be re-designed to integrate all available resources, reward flexibility, and promote long-term investment. Modular, decentralised power generation requires new approaches to network regulation, advanced grid management methods and innovative metering technologies.

Power sector regulation and renewable energy policy must work in tandem. They must reflect each country's circumstances, ensuring reliable services at reasonable prices while sharing system costs and benefits fairly and equitably.

"Adapting Market Design to High Shares of Variable Renewable Energy" offers recommendations for the entire power supply chain, from wholesale markets and system operations to distribution networks and end users.

I am confident that this report will prove useful, particularly as policy makers and regulators strive to transform the world's power systems to achieve a sustainable energy future for all.

Adnan Z. Amin

Director-General

International Renewable Energy Agency

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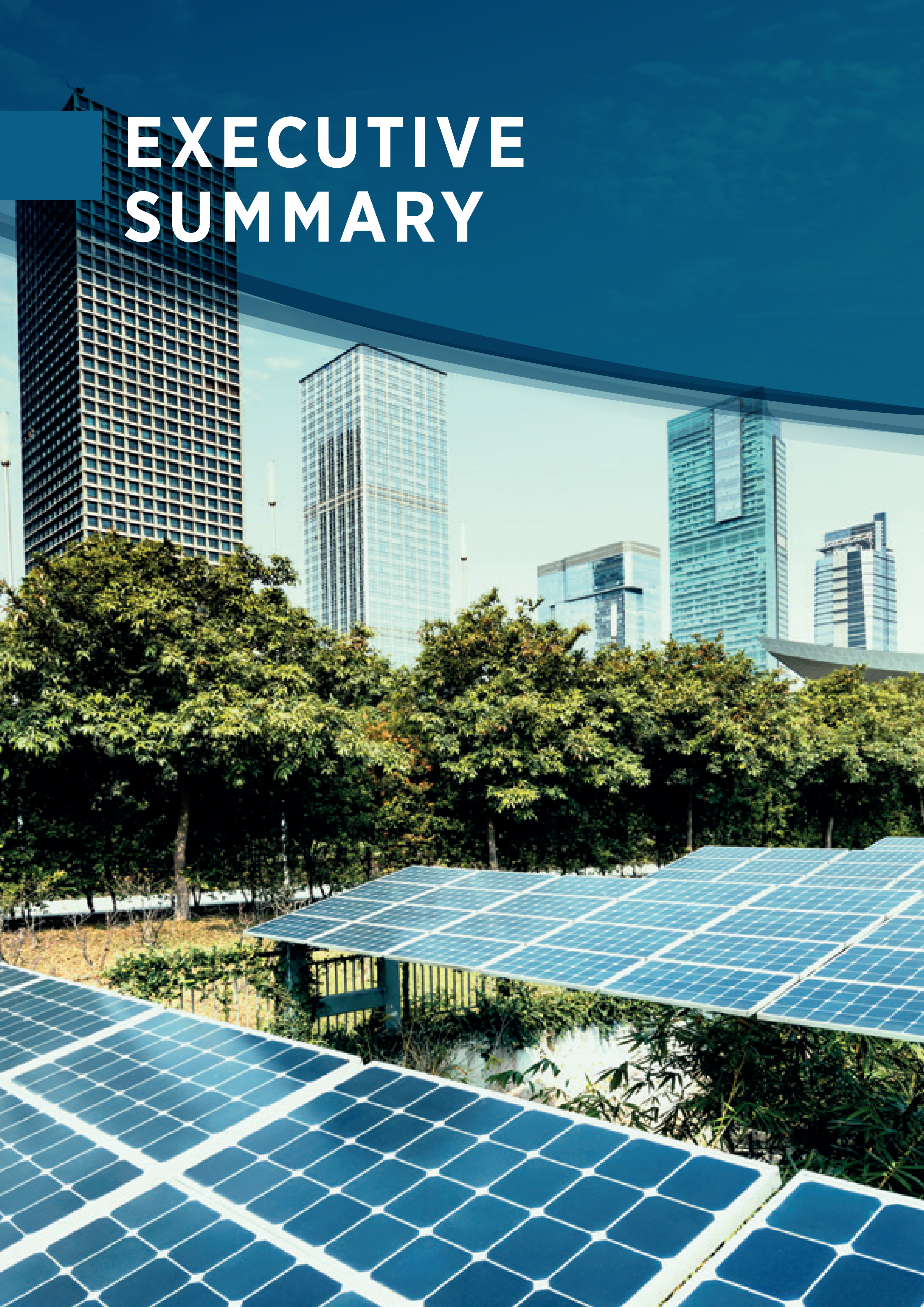
ABBREVIATIONS

AEEGSI	Autorità per l'Energia Elettrica il Gas e il Sistema Idrico
AFID	Alternative Fuels Infrastructure
AMI	Advanced metering infrastructure
ANM	Active network management
BAU	Business-as-usual
ARRA	American Recovery and Reinvestment Act
BF	Benefit factor
BRP	Balancing responsible party
CAISO	California Independent System Operator
CAPEX	Capital expenditures
CEER	Council of European Energy Regulators
CPO	Charging point operator
CPUC	California Public Utilities Commission
CRM	Capacity remuneration mechanism
DER	Distributed energy resources
DG	Distributed generation
DLMP	Distribution locational marginal price
DSIRE®	Database of State Incentives for Renewables and Efficiency®
DSO	Distribution system operator
EV	Electric vehicle
EU	European Union
FACTS	Flexible Alternating Current Transmission System
FIT	Feed-in tariffs
FRR	Frequency restoration reserve
GW	Gigawatts
ICT	Information and communication technology
IEA	International Energy Agency
ISGAN	International Smart Grid Action Network
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
KWH	Kilowatt hour
M2M	Machine-to-machine
MI	Intra-day market (Italy)
MISO	Midcontinent Independent System Operator
MV	Medium voltage
MWH	Megawatt hour
NEG	Net excess generation
NEM	Net energy metering
NYISO	New York Independent System Operator
OFGEM	Office of Gas and Electricity Markets
OMS	Outage management system
OPEX	Operational expenditures
ORDC	Operating reserves demand curve
PJM	Pennsylvania Jersey Maryland Interconnection
PLM	Peak load management
PNM	Public Service Company of New Mexico
PQM	Power quality management
PV	Photovoltaic
PX	Power exchange
RES	Renewable energy sources
REV	Reforming the energy vision
RIIO	Revenues = Incentives + Innovation + Outputs
RPI	Retail price Index
RPM	Reliability pricing model
TOTEX	Total expenditure
TOU	Time-of-use
TSO	Transmission system operator
US	United States
VIU	Vertically integrated utility
VRE	Variable renewable energy
VOLL	Value of lost load

EXECUTIVE SUMMARY



BACKGROUND AND KEY MESSAGES

The world is undergoing an accelerated energy transition, one driven by environmental, technological, social, and economic drivers. The ways in which electricity is produced, transported, and consumed are essential to this transformation, and will undergo profound changes over the next several years. These changes include the progressive adoption of low-carbon technologies, including through the increased deployment of variable renewable energy the decentralisation of generation, driven by the growing availability and reduced costs of distributed-energy resources; increases in regional inter-connection and market integration; and consumer responsiveness enabled by information and communication technologies.

High shares of variable renewable energy have been successfully integrated into the power system in several advanced markets, at rates well above 30% of the generation mix. Variable renewable energy can contribute to its own integration in the system and bring multiple benefits:

- Technological innovation allows variable renewable energy technologies to provide ancillary services, ultimately contributing to system flexibility and reliability.
- Distributed energy resources reduce energy losses, peak demand and the need for network reinforcements under certain conditions.
- Variable renewables can contribute to meet peak demand by providing capacity to the system, essentially allowing them to participate in capacity mechanisms.
- Distributed energy resources improve the resilience of the electricity system during extreme weather events and unscheduled technical failures.
- Distributed energy resources allow consumers to take on a more active role within the power system.

To realise the positive contributions of renewables regulation and electricity market design must adapt to changing conditions. The share of variable renewable energy has grown substantially in some countries and there is an ongoing process of rethinking the future design of electricity markets to make them compatible with ambitious renewable-energy targets.

To support the ongoing discourse, this report is primarily targeted at stakeholders from liberalised electricity markets with large shares of variable renewable energy, and provides a set of policy and regulatory recommendations to facilitate continued deployment. The recommendations address different activities in the power supply chain from wholesale markets and system operations to distribution networks and end users. Many different contexts and regulatory frameworks are considered, although examples are drawn mainly from North America and Europe. The recommendations are broadly appropriate for power systems with organisational models that are similar to the ones analysed here: liberalised electricity markets with high shares of renewables.

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These recommendations are based on sound regulatory principles and reflect the complex inter-relationships of activities and stakeholders across the power sector. The overarching goal is to assist policy makers and regulators to take timely action to facilitate the energy transition.

The analysis is divided into two main sections. The first part addresses the integration of variable renewable generation within wholesale electricity markets. It recommends reinforcing the design of short-term markets (day-ahead and intra-day markets), balancing markets, and long-term investment signals. Adapting short-term markets requires improving temporal and spatial granularity, increasing the details of bidding formats, and strengthening the link between energy and reserve markets. Adapting balancing markets involves redefining traded products, recognising the contribution of variable renewables to grid stability, and avoiding dual-imbalance pricing. Long-term mechanisms, which guide generation expansion according to the strategic view of government, should allow mature renewable technologies to compete with other generation technologies and to ensure that both renewable-energy support and capacity mechanisms are designed to minimise distortion in electricity markets, while taking into account the environmental externalities, and the need for further renewable energy development.

The second part of this analysis addresses the regulation of distribution networks and the design of retail tariffs to allow for smarter distribution systems and increasingly active network users. It recommends incentivising distribution companies to adopt a more active role in network planning and operation, and implementation of smart grids. The report also emphasises the importance of decoupling distribution remuneration from the volume of energy distributed, and shifting the goal of regulation solely from investment adequacy to also include a broader set of performance indicators. The report recommends promoting self-consumption through cost-reflective retail tariffs and supporting advanced metering technologies. Distribution companies should adopt new roles as market facilitators and distribution system operators, interacting more closely with other agents such as suppliers, aggregators and transmission- and independent-system operators.

1. REFORMING WHOLESALE ELECTRICITY MARKETS TO ENCOURAGE FLEXIBILITY

1.1 Adapting short-term markets

The presence of high shares of variable renewable energy increases the uncertainty in the prediction of market conditions and network constraints. Consequently, the time and locational granularity of market signals should be increased with rise in variable renewable energy levels. The design of short-term energy markets should be enhanced and refined at all levels, including timelines, bidding formats, clearing and pricing rules, and their integration with reserves and regulation markets. Some recommended reforms include:

- **Increase time granularity by making trading intervals shorter and closer to real time.** As generation variability increases, market signals should be made more time-specific and gate-closure times reduced to reveal the flexibility of resources that can respond quickly to fast-changing conditions. This can be done through continuous trading, discrete intra-day auctions or a combination of both.
- **Increase locational granularity by using zonal or nodal prices.** The increased deployment of variable renewable energy, particularly wind, may result in a constrained transmission network. Markets must reflect such network constraints. Zonal pricing is a simplified approach to address this, but it comes at the expense of market efficiency, particularly in regional markets. Zonal pricing works well when transmission congestions are structural and systematic, and when predefined price zones are easy to determine accurately. However, variable renewable energy can alter power-flow patterns significantly, thus exacerbating the limitations of zonal pricing. In this context, nodal pricing can often provide better operation and investment signals but may be harder to implement.
- **Reform wholesale-market bidding formats to incorporate increased detail in the representation of generation and demand characteristics.** With higher variability, and given the need to fully exploit flexibility from storage or demand response, it is important to rethink and reform the bidding formats used by participants in energy markets to submit their bids. These need to go beyond simple price-quantity bids and

move toward advanced schemes that allow market participants to hedge against increasingly variable short-term market conditions and to better represent the characteristics of demand response and storage.

- **Adapt existing pricing and market clearing rules**. Current pricing and clearing rules either focus on minimising the cost of economic dispatch at the expense of having uplift payments outside the market, or on providing uniform payments to all market agents at the expense of higher complexities. The right balance ought to be met according to the policy priorities in each context.
- **Strengthen the link between energy and reserves markets**. This imperative reflects an important key fact: supplying one of them implies modifying the ability of power plants to provide the other. Strengthening this link involves co-optimising energy and reserve procurement both in day-ahead and shorter-term energy markets. Where that is difficult, frequent market sessions for the procurement of reserves could be organised, aligned with the timelines of energy markets. Furthermore, system operators should abandon inflexible reserve requirements and implement new solutions to procure and price reserves according to the actual value they provide to the system.

1.2. Adapting balancing markets

Redesigning of balancing markets is essential for the effective and efficient integration of variable renewable energy. Existing rules should be reviewed to ensure that they reward flexibility and to facilitate the effective use of all resources.

- **Redefining balancing products**. To the extent possible, balancing energy should be procured from the most economic resources available in real time, even if those resources do not acquire longer-term commitments in day-ahead or other reserve markets. Furthermore, upwards and downwards reserves should be two distinct products.
- **Facilitating variable renewable energy contribution to grid stability.** To efficiently exploit all available flexibilities, including those offered by renewables, new reserve products should be explored. When service providers with different response capabilities compete to provide the same balancing product, performance-based remuneration can help avoid defining too many reserve products and markets, and can also reduce overall reserve requirements.
- **Avoiding dual-imbalance pricing.** Because dual-imbalance pricing does not exactly reflect the costs of imbalance, it distorts real-time price signals. Although portfolio aggregation can mitigate the deviation risks that renewable producers face when dual-imbalance pricing is applied, the practice still provides a competitive advantage to larger companies over small providers and distributed energy resources. Where it is applied, responsibility for balancing supply should be assigned to each generation unit to prevent competitive disadvantages.

1.3. Encouraging long-term investment

Long-term support mechanisms, including capacity or adequacy mechanisms and support schemes for renewables, are widely used to guide generation investments according to country policy priorities. When these policy interventions are deemed necessary, the following guidelines should be followed: first, as far as technically possible, mature renewable technologies should compete with other generation technologies, even in capacity markets. Second, both renewable-energy support and capacity mechanisms should be designed to minimise distortions of electricity markets.

- **Renewables should be allowed to participate in generation-adequacy mechanisms.** Renewable generation can be a valuable contributor to system adequacy, especially in power systems with a high share of conventional (*i.e.* reservoir-based) hydropower. Therefore, regulations should avoid introducing systematic technology-specific market-entry barriers, and allow renewable technologies, including variable renewables, to participate in generation-adequacy mechanisms on a level playing field, where and when it is technically possible.
- **Capacity mechanisms do not necessarily substitute for support mechanisms.** Long-term support mechanisms should be designed in a coherent way to ensure that the incentives

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provided through renewable-energy support schemes account for possible remuneration earned in the capacity market (as well as in other markets).

- **Economic support for renewables should be market compatible.** Where policy makers consider offering economic support for renewable technologies, this should be done in a way that is compatible with markets. Several designs for support schemes are available, all of them offering advantages and disadvantages. A balance must be found between optimal investment incentives and market compatibility, determined according to policy priorities. Mixed approaches may be explored to achieve a compromise solution.

2. FOSTERING SMARTER DISTRIBUTION SYSTEMS AND MORE ACTIVE NETWORK USERS

2.1. Adapting distribution systems

The efficient deployment of high levels of distributed energy resources, including distributed generation (DG), demand side management and small-scale storage, requires innovative approaches to planning and operating distribution networks. Conventional grid access and connection rules and practices should be adapted accordingly and smart-grid technologies deployed.

- **Rethinking planning for DG.** Grid connection has traditionally followed a "fit-and-forget" approach, *i.e.* reinforcing the grid as much as necessary to prevent any operational problems. This is a safe and robust strategy and requires very low levels of network monitoring. But as DG penetration levels increase such an approach can be costly, especially in areas with high concentrations of DG, and can cause long lead times for connecting new DG sources. Therefore, regulators should gradually abandon the "fit-and-forget" approach as DG penetration levels grow, and rethink network planning and grid connection.
- **Co-ordinated approach to grid connection.** Grid-connection application processes should be reviewed to speed up DG connection and to allocate grid capacity more efficiently. A first-come-first-served approach can mean higher connection costs for later applicants due to reinforcement requirements. It also results in inefficient grid development due to economies of scale. Therefore, co-ordinated approaches should be explored such as working in batches per network area.
- **Disclosure of grid condition information.** Information disclosure obligations should be levied on distribution companies such that new DG units have information on the condition of the grid for a point of connection. Publishing the available generation-hosting capacity allows DG promoters to estimate whether their application will be successful and determine which location will result in lower connection charges. Ultimately, this facilitates the integration of DG.
- **Remunerate distribution companies based on their active grid management.** Large penetrations of DG introduce complexities in distribution planning since the location of DG units can be highly uncertain. Integrating DG efficiently requires active network management as an alternative to conventional grid reinforcements, such as solving network constraints in real time, or close to it. Regulation should promote this transformation. One important way to do that is to require utilities to submit detailed business plans based on cost-benefit methodologies as part of the remuneration process.
- **Enable advanced forms of contracting between distribution companies, generators and consumers.** Active network management requires the development of smarter grids as well as closer interaction between all relevant actors. The latter can be achieved through flexible connection contracts that limit curtailment of generation or demand in exchange for some form of compensation or under specific conditions. As the presence of DER grows, more advanced forms of contracting flexibility services, such as bilateral agreements or market-based approaches, could be implemented.
- **Promote smart grids.** Technology risks, and the absence of economic incentives, prevent the development of smarter distribution grids. Policy and regulation should promote and support innovation, implementation of pilot projects, the exchange of lessons learned, and the shar-

ing of best practices. The creation of public-private collaborative networks and the definition of knowledge sharing and information disclosure obligations can facilitate information exchange.

2.2. Promoting long-term efficiency

Distribution regulation has conventionally focused on promoting adequate investment levels and short-term efficiency gains, while controlling the quality of service. This approach works well with stable and predictable grid technologies and network users. However, conventional remuneration formulas and cost-assessment methodologies are less optimal as the presence of distributed generation increases. With moderate distributed energy resource penetration levels, the potentially negative effects of distributed generation can be mitigated with a few regulatory tweaks. Nevertheless, efficiently integrating high shares of distributed energy resources requires a major regulatory overhaul.

Decoupling distribution volumes from energy volumes. Cost-assessment methods generally applied to determine allowed revenues of distribution companies are usually unable to accurately quantify the impact of distributed energy resources on network costs. To compound this situation, distribution remuneration usually depends on the volume of energy distributed, which DG (and some forms of demand side management) dminishes. As a result, distributed generation, self-consumption or energy-efficient measures may translate into a reduction in revenues without a corresponding drop in costs. To mitigate such a negative impact, distribution revenues should be independent of the volume of energy distributed. This decoupling of revenue essentially consists of adjusting network tariffs *ex post* so that distribution companies recoup exactly the allowed revenues. Moreover, if cost-assessment tools are unable to capture the impact of DG on distribution costs, economic compensation on top of conventional revenue allowances may be necessary to account for it.

Rethinking the remuneration of distribution companies. As the penetration levels of distributed energy resources increases, greater changes to current regulatory approaches are required. The regulation focus should shift from short-term cost reductions to the promotion of long-term efficiency. Distribution companies should also be encouraged to implement innovative grid planning and operation solutions (*i.e.* smarter distribution grids). This involves:

- The focus of regulation should shift from ensuring that companies invest sufficiently in networks to **assessing grid operators based on their performance**, as measured by an extended set of indicators. Those indicators could include customer satisfaction, grid-connection lead times, the carbon footprint or available distributed generation hosting capacity. When these indicators can be objectively measured and controlled by the distribution companies, incentive (and penalty) mechanisms can be implemented.
- The required novel methods of managing the network reduce the need for investment in distribution assets but increase operational expenditures. Traditional regulatory approaches discourage novel methods if distribution companies are remunerated mostly based on their capital investment. **Incentive systems should reward both operational and capital expenditures** of distribution companies.
- Regulatory benchmarking, a method of determining remuneration for distribution companies, usually relies on past information. It implicitly assumes that future developments will follow a similar trend. This assumption is questionable in a context requiring innovation. Hence, **cost-assessment methodologies should increasingly rely on forecasted data and well-justified investment plans** submitted by the regulated companies.
- Promoting efficient investment in distribution networks requires adopting a long-term perspective given the long life of the assets and the time required before innovation yields benefits. Regulators should progressively extend the length of the regulatory period to incentivise distribution companies to pursue

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long-term efficiency. Remuneration formulas should be more flexible to accommodate possible uncertainties in such a dynamic environment. This may include the introduction of profit-sharing schemes and automatic-adjustment factors.

2.3. Improving tariffs and metering

Self-consumption and the adoption of distributed storage behind the meter can yield benefits for both end-users and the power system as a whole. Therefore, regulation should actively promote self-consumption by adopting a cost-reflective design for retail tariffs and supporting the roll out of advanced metering technologies.

- High levels of self-consumption may negatively impact the financial viability of distribution utilities and the recovery of fixed power-system costs. Such issues become more prevalent in markets with high shares of renewable sources supported by net-metering policies since they implicitly value the energy injected into the grid at the retail electricity price. To keep up with these developments, regulations in many systems have limited individual or aggregate installed capacity, reduced the period of time over which energy injections can offset energy withdrawals, and changed the structure of retail tariffs and compensation rules. However, these do not provide a real long-term solution for jurisdictions with high penetration of active agents.
- The sustainable development of high levels of on-site generation in mature liberalised markets entails adoption of self-consumption schemes with hourly netting intervals, or even shorter. In addition, retail **tariffs should be cost reflective.** They should be based on the value of electricity at each time and location, the individual contribution of the network users to network costs, and a charge to recover other regulated costs so that the economic signals sent by energy and network charges are not distorted.
- **Advanced-metering infrastructure should be installed** so that adequate locational and time granularity in the tariffs can be communicated to end consumers. Electronic meters capable of recording bidirectional energy flows every few minutes are needed for the development of self-consumption and to stimulate end users' demand response, including distributed storage. Economies of scale and standardisation are important when deploying advanced meters.
- The changes that advanced power systems are experiencing are strictly interlinked with the power system digitalization. The evolving role of information and communication technologies for the efficient management of the power system calls therefore for a **close cooperation between electricity and telecommunication regulators**.

2.4. Encouraging the new roles of distribution companies

As the energy transition evolves, a growing share of the resources needed to ensure secure and flexible system operations will be connected at the distribution level. In this new environment, distribution companies must bridge the gap between flexibility providers (*i.e.*, distributed generators, responsive demand and aggregators), markets and transmission/independent system operators. To do this, they should adapt their planning and operational practices accordingly and play new roles as market facilitators and distribution system operators.

- Regulation should **allow distributed energy resources to participate in upstream energy and ancillary services**, particularly when these resources become widespread. Distribution companies should facilitate this participation and carry out activities such as *ex ante* technical validation, to ensure that no constraints arise in the distribution grid, and *ex post* verification of the provision of the services.
- To facilitate well-functioning retail markets and the participation of distributed energy resources in wholesale markets, it is critical that market agents have **transparent and non-discriminatory access to metering data.** This might be seen as a conventional task of distribution companies, but concerns arise when a metering data manager, traditionally a local distribution company, is also a market participant. In this context, alternative models for data management could be explored, such as creating a new regulated entity responsible for data manage-

ment (central hub) or opting for a decentralised approach. There is no consensus on the most appropriate model, but regulations must always ensure non-discriminatory access to data and **protect consumers' privacy**, particularly after the deployment of advanced metering.

- Distribution companies should **make use of distributed energy resource flexibilities** by actively integrating with the resources connected to their grids. *Ad hoc* regulatory mechanisms such as non-firm connection agreements, bilateral agreements or local markets may be necessary. Regulators should clearly define the responsibilities of distribution companies, especially where a distribution company belongs to a vertically-integrated company in a context of retail competition.

2.5. Facilitating the development of infrastructure for storage and electric vehicles

The development of electric mobility requires careful regulation of the contractual relationship between the various actors involved: electricity distribution operators, electricity suppliers, charging point operators, mobility service providers, and electric vehicle (EV) drivers.

Distribution companies will play a key role in the deployment and operation of new grid-edge infrastructure such as public EV charging stations, or distributed storage. The major regulatory question is whether to consider them part of the business model of distribution companies or open them to competition. The former can collide with unbundling rules and lead to a suboptimal utilisation of these technologies, while the latter may make it harder for distribution companies to benefit from their potential contribution to grid planning and operation.

- Market forces alone may not be able to foster the development of **public charging infrastructure**. Policy makers may have to kick-start the infrastructure development, for example by giving distribution companies responsibilities. However, this may be challenging. On the one hand, unbundling rules may prevent distribution companies from selling electricity to electric-vehicle users; on the other hand, treating EV charging points as part of the regulated asset base may imply that rate payers would be subsidising EV users. To avoid such problems, other policy alternatives might be adopted to provide the initial policy push.
- **Distributed storage** will be another game changer in the power sector, also for its potential to supply grid-support services. For this reason, distribution companies may seek to own and operate storage devices. However, unbundling provisions could rule this possibility out since storage operators may wish to provide other services under competition to obtain a positive business case. Thus, exemptions on the unbundling obligations may be considered in some cases. In others, distribution companies may be entitled to contract services with storage operators through auctioning.

POWER SECTOR TRANSITION

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1.1 THE ENERGY TRANSITION AND ITS IMPLICATIONS FOR THE POWER SECTOR

The global energy transition is underway, driven by ambitions to improve energy security, address environmental impacts, and achieve universal energy access. The transition will involve a fundamental rethinking of the way energy is produced, distributed and consumed which will bring changes to the way societies operate and a wide range economy-wide benefits. The political commitment to the energy transition is reflected in the adoption of the Sustainable Development Goals, and the ratification of the Paris Agreement.

The adoption of renewable energy technologies is a key pillar of the energy transition. Over the past decade, as the technologies have matured and costs decreased (Figure 1.1), their deployment has grown at a tremendous pace in the power sector. In fact, for the past five years, renewables capacity additions have exceeded additions of conventional power capacity. Looking forward, mainly because of the potential of solar and wind technologies, the power sector will play an important role in the energy transition. To achieve climate targets, part of the transportation sector has to switch to electrical mobility, and the building and industry sectors must use more electricity in their heating and cooling processes.

The increased electrification of end energy uses will take place in the midst of several other major trends that are also shaping the future of the power sector, including: 1) the integration of power systems into larger entities at regional or supranational levels, seeking more efficiency and reliability; 2) the increased interplay between the power sector and adjacent ones, such as gas, and information and communication technology; 3) the spectacular cost reduction and technology improvement in promising technologies, which could become disruptive, especially electricity storage; and 4) the increasing presence of distributed energy resources (DER), which include distributed generation, demand response, distributed storage and other devices.

Energy storage is viewed to be the next game changer in the power sector. IRENA forecasts show that the cost of energy services from battery electricity storage will continue to decline due to reductions in the installed costs and improvements in battery technology performance (Figure 1.2).

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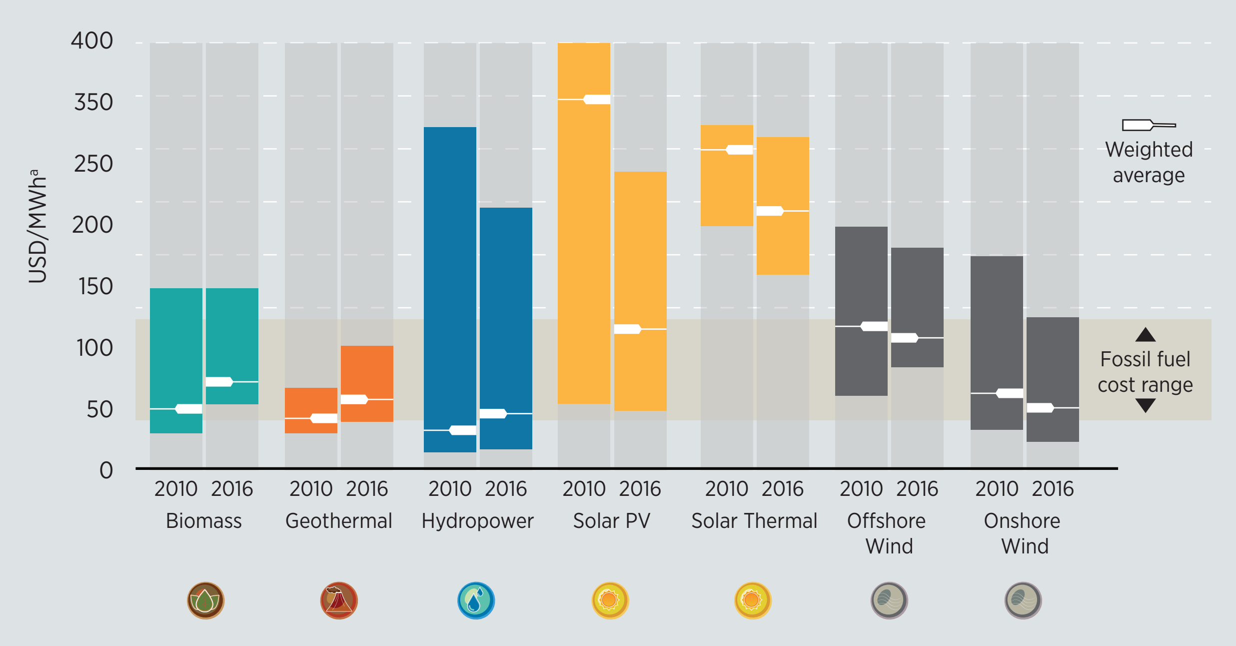
Figure 1.1 Levelised cost of electricity for utility-scale power (ranges and averages), 2010 and 2016



Note: a) MWh: megawatt-hour. b) All costs are in 2016 USD. Weighted Average Cost of Capital is 7.5% for OECD and China and 10% for Rest of World.

Source: IRENA, 2017a

According to most scenarios, future investment in power generation will be dominated by RES worldwide. Among RES investment, wind and solar technologies would represent the highest shares. In particular, the use of decentralised solar photovoltaics (PV) is expected to rise sharply, due to the significant cost reductions and the support of policies. The technology has already reached significant penetration levels in some cases. In California, for instance, around 2 GW of distributed solar PV has been installed. Figure 1.3 shows the growth of installed solar PV capacity between 2007 and 2015 under the California Solar Incentive program and the corresponding observed reduction in average installation cost during this period.

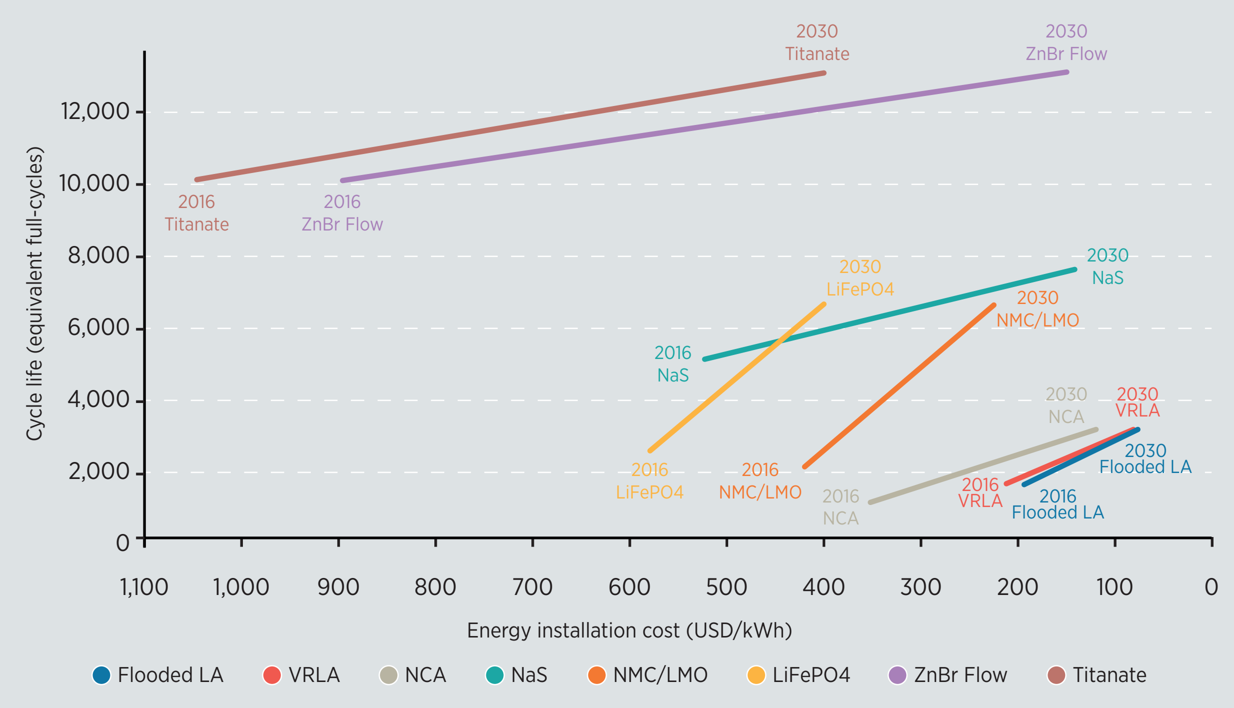
Changing role for consumers and utilities

The transition is not driven by cost reduction alone. Another relevant factor is the more active role of consumers, enabled by the possibility of generating their own electricity and by the deployment of new technologies, such as advanced meters or load automation systems. Better informed and more responsive consumers will play a crucial role in the transition to a more decentralised system, thereby shaping the electric grid of the future. For example, advanced meters can allow real-time pricing and fully automated billing. With over 12 million smart meters, California has reached close to 100% penetration, enabling consumers and utilities to access added functionalities.

The European Union also has an ambitious program for deployment of smart meters in member states before 2020. Italy pioneered a complete installation of advanced meters more than a decade ago. Of course, what matters is not the physical existence of these meters, but taking full advantage of their potential. Concerns related to the availability of abundant online information about each individual network user, such as privacy, must also be addressed.

Under this new paradigm of decentralised resources and customer engagement, new business models and commercial strategies are emerging. With the rise of distributed generation, individuals and communities have greater control on generation and consumption of energy.

Figure 1.2 Energy installation costs and cycle life of battery storage technologies, 2016 and 2030



Note: Titanate: Lithium Titanate; ZnBr Flow: Zinc-Bromine; NaS: Sodium Sulphur; NMC/LMO - Nickel Manganese Cobalt Oxide (NMC) / Lithium Manganese Oxide (LMO); LiFePO4: Lithium Iron Phosphate; NCA: Lithium Nickel Cobalt Aluminium; VRLA: Valve regulated lead-acid; Flooded LA: Flooded lead-acid

Source: IRENA, 2017b

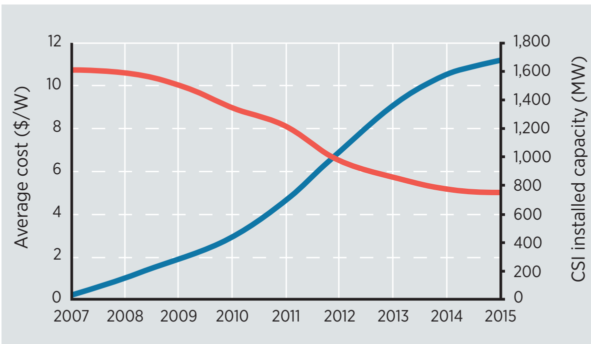
For example, 35% of Germany's RES installation is owned by citizens, whereas the aggregated share in total distributed generation capacity of the big four incumbent utilities, namely E.ON, RWE, Vattenfall and EnBW, is only 5% (BEE, 2014).

The increasing share of RES is affecting the capacity factor of fossil fuel power plants. Accordingly, several incumbent utilities changed their roles and strategies for their energy businesses. In September 2013, RWE, Germany's largest power producer, decided to depart radically from its traditional business model based on large-scale thermal power production and to become a service company, increasingly acting as project enabler, operator and system integrator of renewables. Similarly, at the end of 2014, E.ON announced that it is spinning off conventional power plants to focus on RES, distribution network and customer solutions. RWE and E.ON illustrate the strategies of traditional industry to adapt to the power sector transformation.

Power system integration

Together with the structural and ownership transformations associated with the rising presence of decentralised resources, other important drivers of change can be observed in the power sector.

Figure 1.3 Solar PV installed capacity within California Solar Incentive (CSI) program against the evolution of average cost of solar PV capacity



Source: California Solar Statistics, 2016

The integration of power systems into increasingly large markets is one. Power pools encompassing several electric utilities under traditional regulation were created in the United States during the 1970s, and they have evolved into the present regional markets, known as *regional transmission organisations* and run by independent system operators.

In the European context, electricity and gas markets form a pillar of the regional energy policy. European electricity market liberalisation, which began in the 1990s, represents one of the most extensive cross-jurisdiction reform of the electricity sector involving integration of distinct state-level or national electricity markets (CEEPR, 2005).

Today, national and regional day-ahead, intraday and balancing markets are under reform to create single platforms where all European market players can trade the different energy products, subject only to the limitations of cross-border interconnection capacities.[1]

Since the early 1990s, Latin American countries have launched diverse initiatives to increase interconnection capacities and to create integrated regional electricity markets. Mercado Eléctrico Regional, the Central American electricity market (MER), is a present reality, having formally begun operations in 2013. Another initiative is the Interconnected Andean Electricity System SINEA which is in the process of creating a sub-regional electricity market, including Colombia, Ecuador, Peru and Bolivia.

Other examples are the well-established Australian National Electricity Market, the six independently operated regional markets in China and the four power pools in Sub-Saharan Africa, which are still under establishment.

The decentralisation and growing penetration of RES are bound to transform the power sector. While some challenges remain, favorable policies and regulations can bridge the gap and avoid technology lock-ins that prevent the achievement of a suitable low carbon path. These policies include those that reduce barriers, promote investments, create a fair level playing field and ensure the long-term financial viability of the power system. Although several countries have successfully incorporated a large share of variable renewable energy (VRE), over 30% of total electricity generation, without compromising the reliability of the electricity supply, achieving the energy transition involves changes at many levels.

One of these is the adaptation of liberalized electricity markets to efficiently accommodate even higher shares of VRE.

1.2 Power sector organisation

This section briefly describes the main activities in the power supply chain and discusses the different possible organisational approaches that may be found worldwide.

Broadly speaking, the electricity supply chain can be divided into four distinct activities: generation, transmission, distribution and retailing. Until recently, power generation has usually taken place in large centralised power plants located far away from the load centers. Therefore, transmission grids are necessary to transport electricity over long distances. In the downstream segment of the power system, distribution networks supply electricity locally from the transmission substations to end consumers. The traditional role of distribution companies as network operators and suppliers of electricity to consumers is being revisited because of the need to integrate growing levels of distributed generation (DG) and to facilitate retail market competition and consumers' demand response. Lately, some countries are liberalising the retail segment with the goal of promoting efficiency.

The traditional boundaries between transmission and distribution systems were largely driven by the different functions these networks fulfilled within the power system. On the one hand, transmission grids have conventionally had a decisive impact on the system generation dispatch and its efficiency, as most generation was connected to them. On the other hand, the main role of distribution networks has traditionally been to bring the electricity to the end consumer while ensuring adequate levels of continuity of supply. However, these boundaries, both at the network (physical

1. http://www.acer.europa.eu/electricity/regional_initiatives/Pages/default.aspx asset) and system operation (their use) levels, are evolving with the progressive decentralisation of dispatchable resources (DG, demand response, distributed storage).

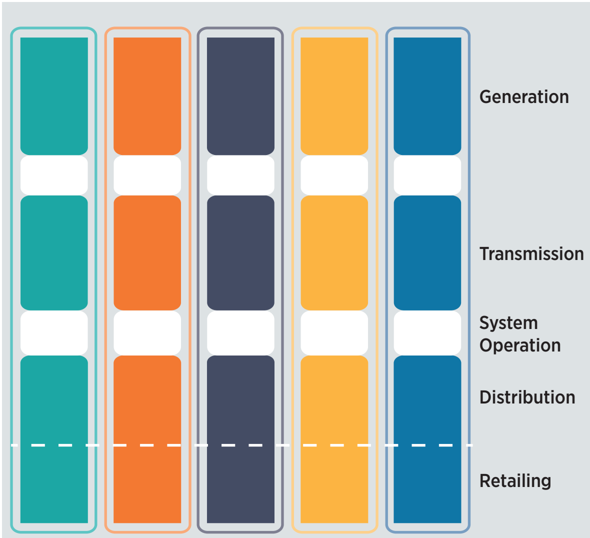
Furthermore, power systems need to be managed as a whole so that security of supply is ensured over both the short and long term. Power system planning and operation comprise a chain of sequential decisions, ranging from generation capacity expansion and transmission network planning in the long term to short-term decisions such as the dispatch of generation units and the utilisation of reserves. Besides technical constraints, these decisions must be guided by economic considerations so that social welfare is maximised, *i.e.*, this is a cost minimisation subject to prescribed reliability targets. The main differences in power system management lie in how the responsibilities of the different decisions are allocated among stakeholders.

Different power sector structures

A salient feature of the energy transition will be the integration of growing shares of RES into the power system. The policy and regulatory adaptations that are required to achieve this affect all the segments of the electricity supply chain and vary depending on the existing structure of the power sector. The essential differences among these alternatives correspond to the allocation of decision-making among stakeholders and the degree of liberalisation and restructuring introduced in the segments of the electricity chain (Batlle and Ocaña, 2013).

The traditional power sector paradigm relies on centralised decision-making by vertically integrated utilities (VIUs), owning both generation and network assets, with the obligation to supply end consumers within their territorial franchises. In this context, the state has a predominant role since VIUs are either publicly owned companies, or privately owned firms subject to some sort of cost regulation and supervision by a governmental agency. In some countries, privately and publicly owned companies coexist and are both subject to the same traditional cost-of-service regulation. Investment decisions are centrally made by the VIUs under the approval of the corresponding agency, considering both generation and transmission network expansion as a whole, whereas medium-term and short-term operational decisions are made on the basis of cost minimisation and a centralised cost-based dispatch. This power sector structure is illustrated in Figure 1.4.

Figure 1.4 Traditional power sector organisation with a vertically integrated utility in each territorial franchise



Note: Each colour represents a vertically integrated utility

Some countries have opened up their power systems to allow new entrants – known as independent power producers (IPPs) – in the generation segment. This change in paradigm may be motivated in response to the difficulties faced by publicly owned incumbents to finance new investments in generation and/or by the will to make possible the development of RES or combined heat and power facilities. The contracts signed by incumbents with IPPs, allow them to recover their generation costs (fixed and variable) and include provisions concerning their duties and obligations (*e.g.*, reliability level, ancillary services, audits, etc.).

In the markets where restructuring and liberalisation has taken place, it usually started by introducing competition into the generation sector at the wholesale level. This implies allowing new entrants to compete with the previous incumbent generation company, oftentimes a national company owning strategic resources (*e.g.*, hydropower), or splitting up the previous incumbent generation firm into a few smaller generation companies allocated to private investors through auctioning processes. These generation companies then sell their production through the intermediation of a market operator via some sort of spot-trading platform, where participation is frequently mandatory, and the resulting wholesale electricity prices are passed through to consumers by the distribution companies (see Figure 1.5). The function of operating the market can either be carried out by an entity independent of the system operator (transmission system operator plus market operator model), or by a separate market operator. In the former circumstance, the agent in charge of system and market operation is usually referred to as an Independent System Operator (ISO). Contrasting the need to centralise the operation of the system and the network expansion under a single entity, under the supervision of the regulatory authority, the transmission grid is frequently owned by one or more different agents.

Some countries that have liberalised their electricity markets have also introduced competition at the retail level. In some systems, the right to freely choose a supplier has been established for all consumers at once; while in others, it has been progressively introduced, starting from the largest consumers to the smallest residential ones. Regulated default tariffs are frequently made available for those consumers who do not wish to shop around for a supplier or who are temporarily without a contract.

Lastly, some countries have decided to go beyond the model based on a single compulsory market operator or an ISO by allowing the agents to establish bilateral contracts with one another. Thus, generators and retailers (or large consumers) may freely sign bilateral agreements, with the organised spot markets simply being another alternative. This model is depicted in Figure 1.6.

1.3 Renewable energy impact on the power sector operation

This section describes the main reasons why a large penetration of VRE imposes the need to adapt the design of power markets. While the impact that high shares of these sources have on the operation of electricity systems has already been assessed in the literature (*e.g.* NREL 2013a; Holttinen *et al.*, 2013), international experiences

Figure 1.5 Competition wholesale market and regulated distribution companies acting also as retailers

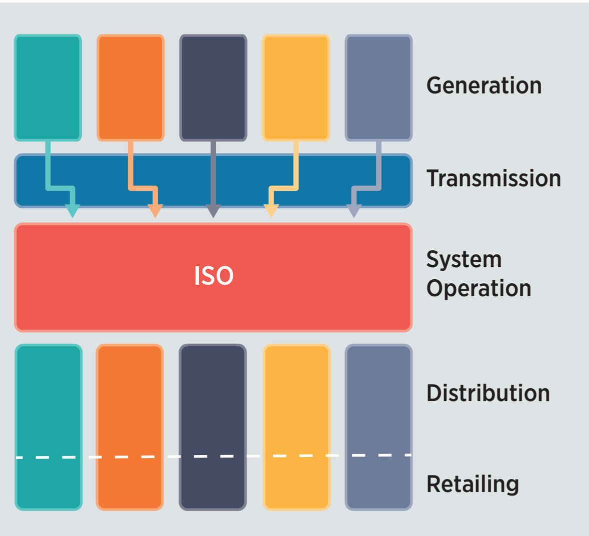
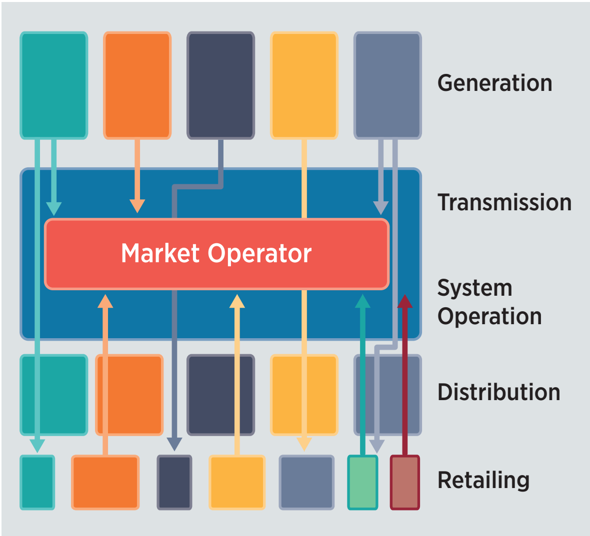


Figure 1.6 Fully liberalised power sector with competition at wholesale and retail level with bilateral contracts



can illustrate the particular operational characteristics of wind and solar, and the way they can affect both short-term operation and long-term planning in liberalised contexts.

1.3.1 System impacts of variable renewable energy

VRE technologies, in particular wind and solar, present unique characteristics that have significant impacts on the power system.

Seasonality and complementarity

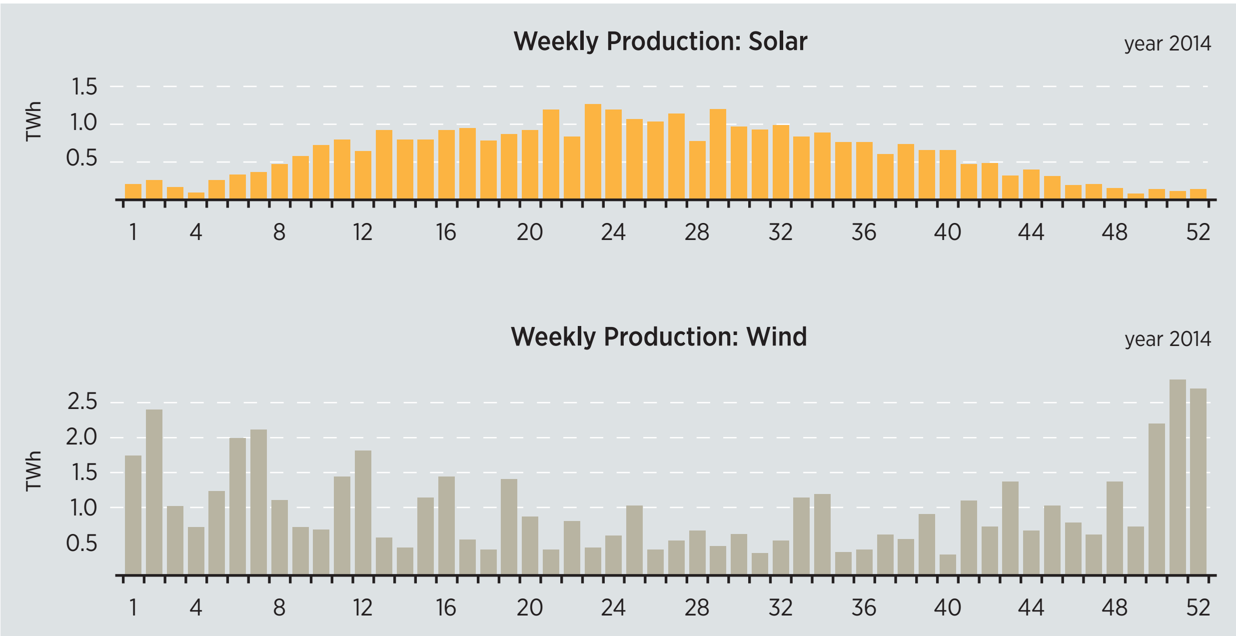
The variability patterns of wind and solar heavily depend on the climatological characteristics of each system. The assessment of the seasonality in variable energy resources production allows discovering correlations among different resources, as well as with demand. In Germany, for instance, peak demand takes place during winter, mainly due to the demand corresponding to electric space heating. Figure 1.7 depicts the annual variation of wind and solar PV production in Germany. While solar PV production is greater during summer, wind production is higher during winter. Consequently, wind production is positively correlated with demand, but there is also certain complementarity (due to inverse correlation) between wind and solar production.

We shall distinguish two different characteristics of VRE that present challenges for their integration: variability and limited resource predictability. These characteristics make solar and wind completely different resources when it comes to market integration.

Variability

The challenge associated with variable resources is the increased need for flexibility, including ramping requirements to keep the system balanced depending on resource availability. Figure 1.8. shows the hourly ramps (in GW/hour) that have to be met in the Electric Reliability Council of Texas (ERCOT) system under different solar penetration scenarios. Solar production is useful to reduce morning ramp needs since it is well correlated with the morning demand peak, however, a large amount of solar production shifts the net load peak and steep ramps to the evening. This highlights the importance of sending accurate (*i.e.* time sensitive) price signals that can drive investment to efficiently integrate high penetration levels of renewables.

Figure 1.7 Weekly wind and solar production in Germany



Source: Burger, 2014

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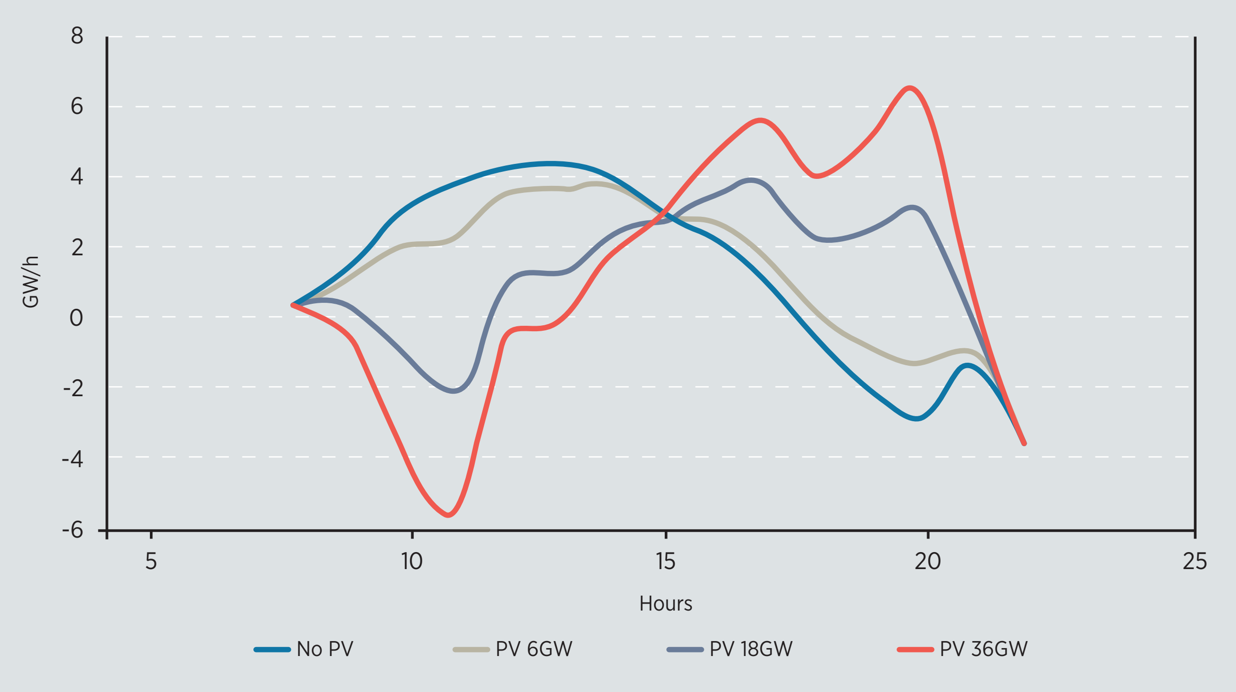
Figure 1.8 Hourly net load ramps for different penetration levels of solar PV



Source: MIT, 2015

Predictability

Another characteristic is related to resource predictability. Wind may be relatively unpredictable, as shown in Figure 1.9 which shows an example from Belgium. This example depicts the week-ahead and day-ahead forecasts versus the actual measured production. The forecast accuracy improves when it is made closer to real time. As seen in Figure 1.9 also shows that PV forecasting is more accurate than wind forecasting.

Much progress has been made in recent years on wind forecasting tools; Figure 1.10 shows the experience of the Spanish power system, for example, where the accuracy of wind forecasts has dramatically increased since 2008.

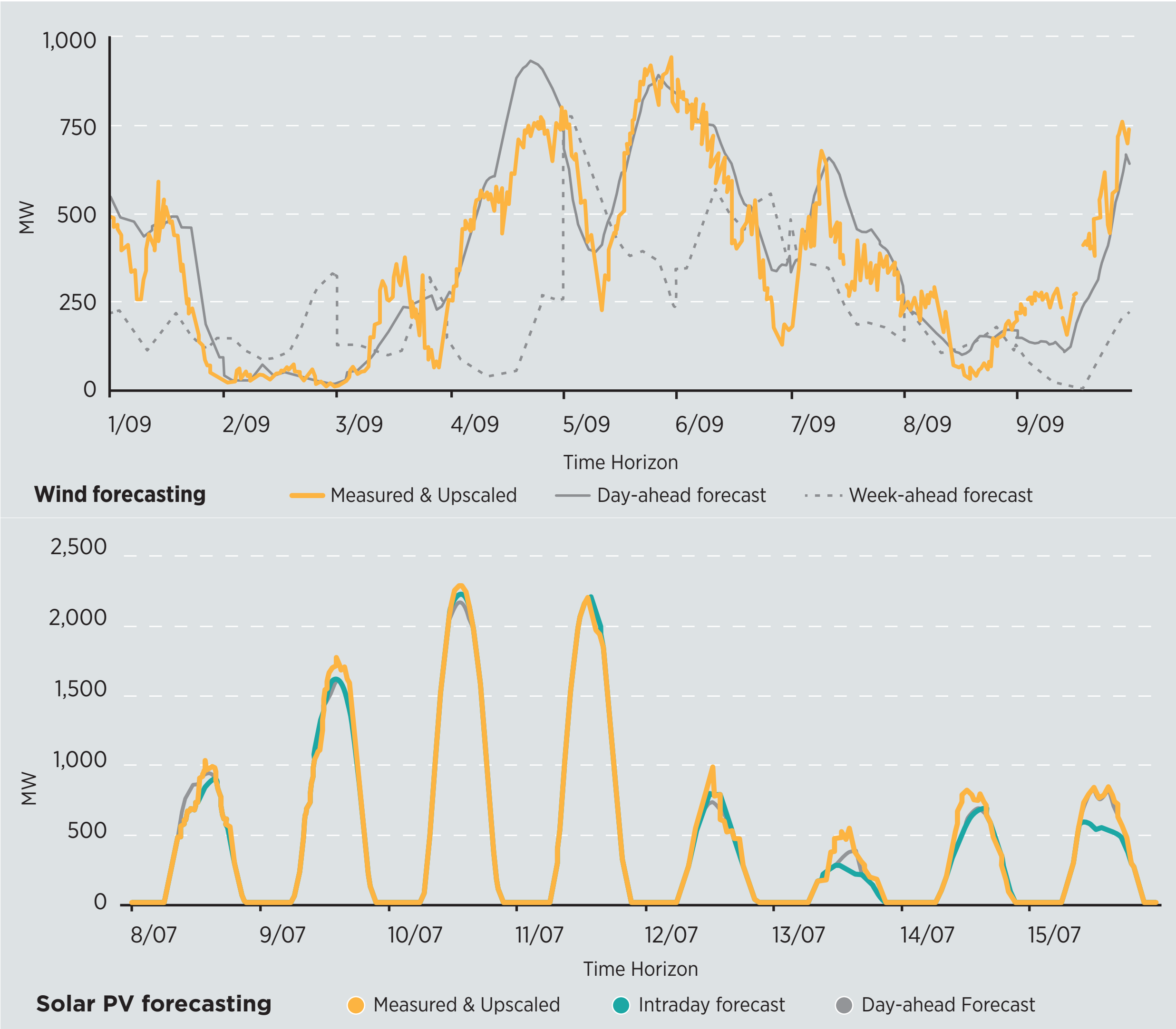
Geographical dispersion

Another relevant characteristic of RES, which makes them different from conventional thermal generation, is that the generation assets are located where abundant resources are available, sometimes leading to dispersed installations or to generation assets being relatively distant from demand centres. In specific cases and if the right regulations are in place, dispersed installations close to the demand could offset demand growth, reduce peak load and allow distribution companies to defer grid enforcements. However, RES not located near the demand could lead to the need for further investments in transmission networks and sometimes cause network congestion. This highlights the need to reinforce the grid as well as to send location-specific price signals in liberalised markets.

1.3.2 Market impacts of variable renewable energy

The impacts of a large penetration of VRE on liberalised power systems, and specifically on production costs and market prices, heavily depend on the characteristics of the generation mix. In particular whether the generation mix is energy- or capacity-constrained; and its degree of flexibility.

Figure 1.9 Wind and solar PV forecasting for Belgium



Source: ELIA, 2016

Capacity-constrained versus energy-constrained systems (system adequacy)

In capacity-constrained systems, scarcity problems arise when there is not enough installed capacity available (MW) to satisfy demand at a given moment due to, for instance, forced outage of thermal plants. These systems cannot satisfy the peak demand but could certainly have enough energy available to satisfy demand on a given day. The largest portion of the capacity mix in these systems is usually conventional thermal generation.

Energy-constrained systems, on the contrary, are characterised by a value of peak demand significantly lower than installed capacity, and only constrained when the system runs out of available energy. These are typically hydro-dominated systems with large reservoir capacity, but they also include gas-constrained systems (*e.g.*, subject to potential gas transmission constraints. These systems can meet the peak demand but the challenge in these systems is to supply the total amount of energy required (in megawatt-hour terms).

These represent the two extremes, but systems can also be both capacity- and energy-constrained at the same time.

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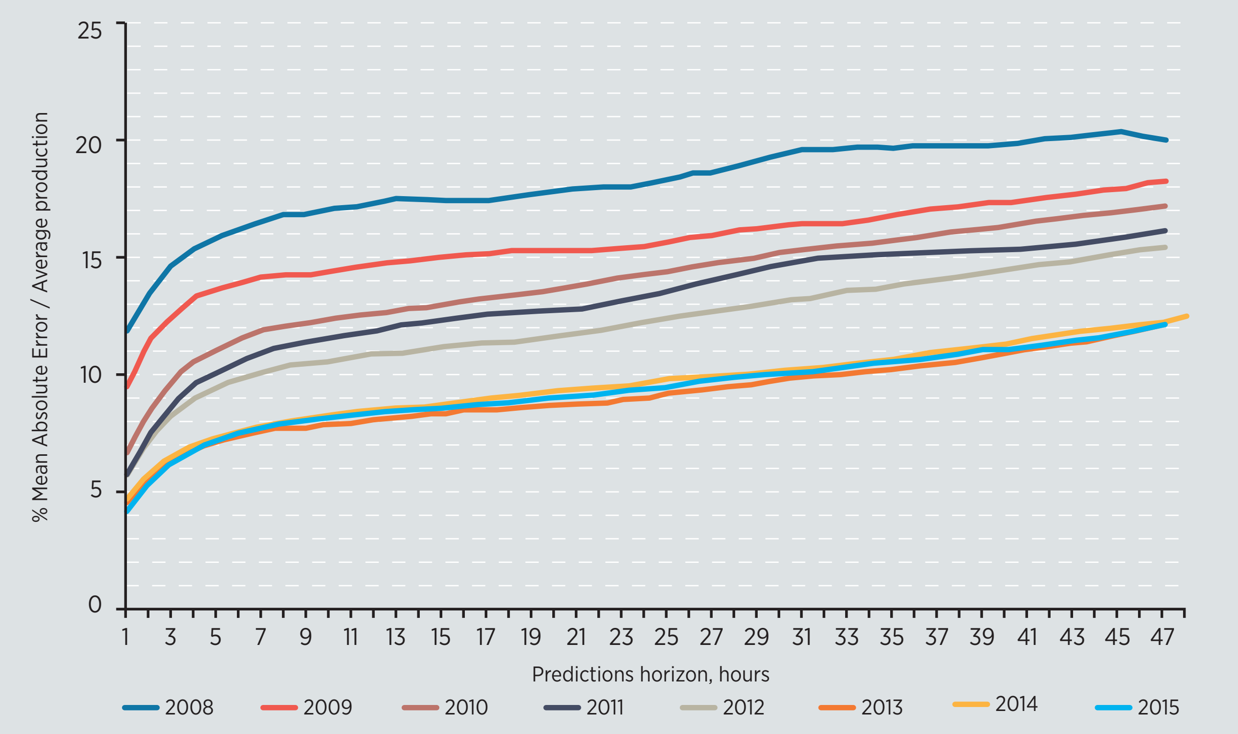
Figure 1.10 Wind forecasting error evolution in Spain



Source: REE, 2016

Flexible versus inflexible systems (system operation)

A *flexible system*, meaning a system where generation can deal both with short-term variability and limited predictability with a moderate impact on production costs, is due to the availability of different possible resources. Figure 1.11 shows a qualitative representation of the cost associated with different sources of flexibility.

An inflexible generation mix involves a significant increase in costs in the short term when generation needs to follow a variable and unpredictable net load shape (*i.e.* demand minus VRE generation). This is typically the case of systems relying on old thermal plants originally envisioned to produce base-load. Again, systems can be in-between these two 'extremes'.

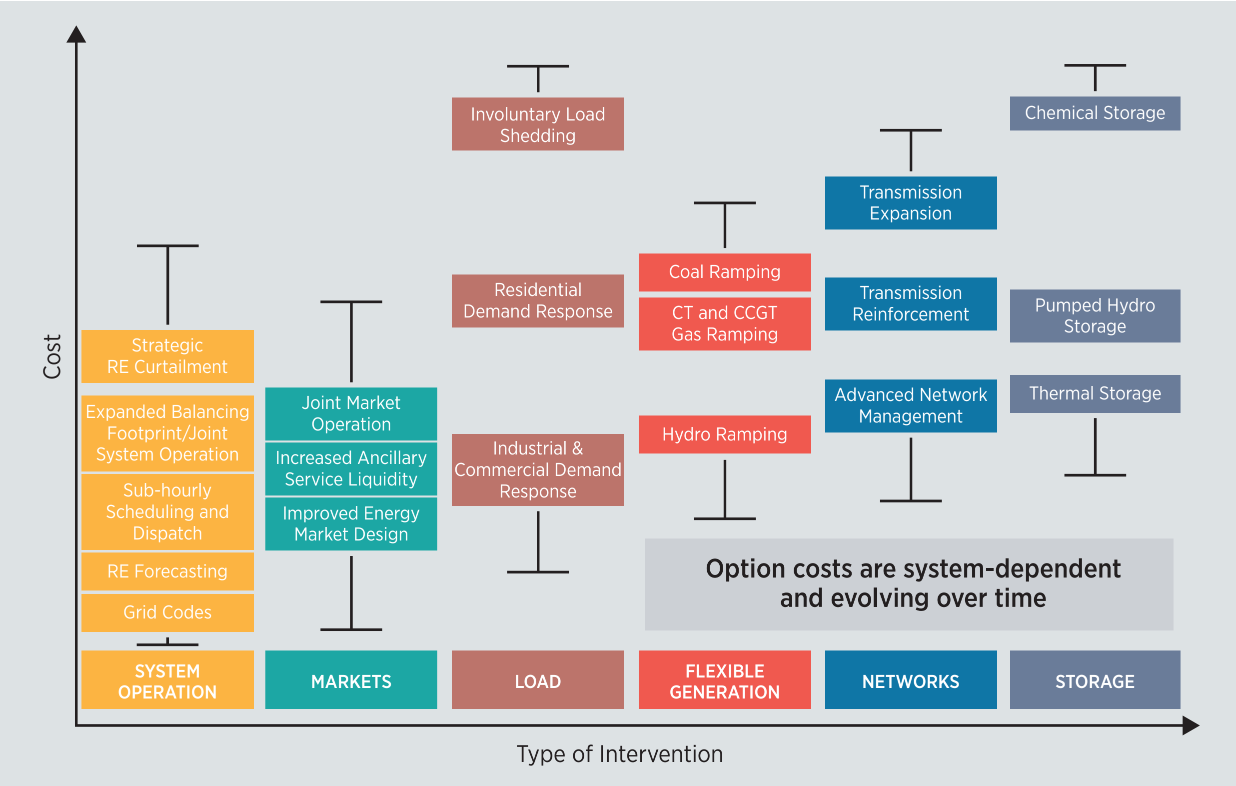
Impact on spot prices

The short-term impact of VRE on prices is larger in inflexible, thermal-dominated systems. Variable renewables that very low or even zero variable costs tend to displace the most expensive variable cost units, thus changing the marginal price of the generated power of the system. This is called the *merit order effect*, which tends to decrease wholesale prices.

In inflexible thermal-dominated systems, significant penetration of VRE (especially PV) increases the cycling requirements of conventional thermal plants. The change in the net load shape will force plants to change their output more often to meet ramps of net demand, and to start up and shut down frequently. This context is illustrated in Figure 1.12, from a simulation of different solar penetration levels in the ERCOT system. Initially solar production can reduce total short-term system costs and thermal generation costs (fuel costs), but as solar penetration increases, thermal units operation is affected by the cycling, thus increasing its cost.

Therefore, the total thermal cost will generally decrease (for its associated production decreases), but the production cost of thermal plants generating, and therefore setting the market prices in some hours, may increase. This can translate into two impacts on energy prices: the first effect leads to lower average prices; the second effect may be sharper and higher prices during a reduced number of hours because of increased cycling.

Figure 1.11 Flexibility sources and the cost involved



Source: Miller, 2015

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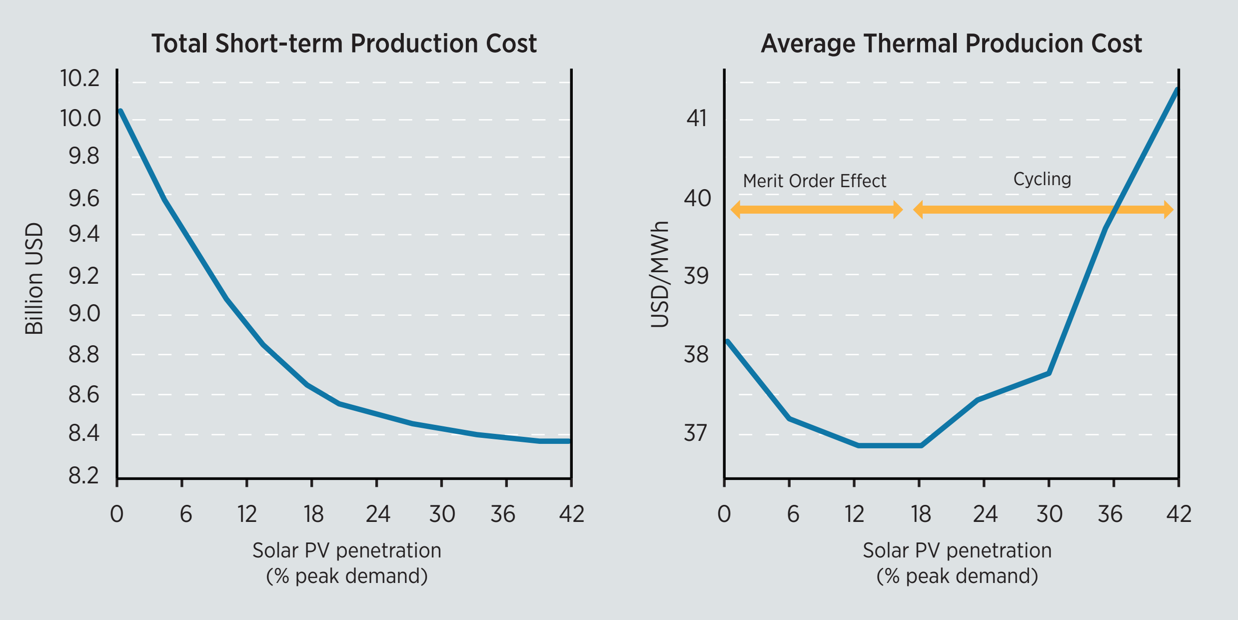
Figure 1.12 System and thermal production cost for increasing solar penetration in a thermal-dominated system



Source: MIT, 2015

The impact that increasing VRE penetration will have on short-term prices can be mitigated in flexible, energy-constrained systems. Hydropower, for instance, can easily provide the much-needed flexibility to the system and contribute to absorb the steep ramps in the net load. The same happens if there are other forms of flexibility, as discussed in the previous section.

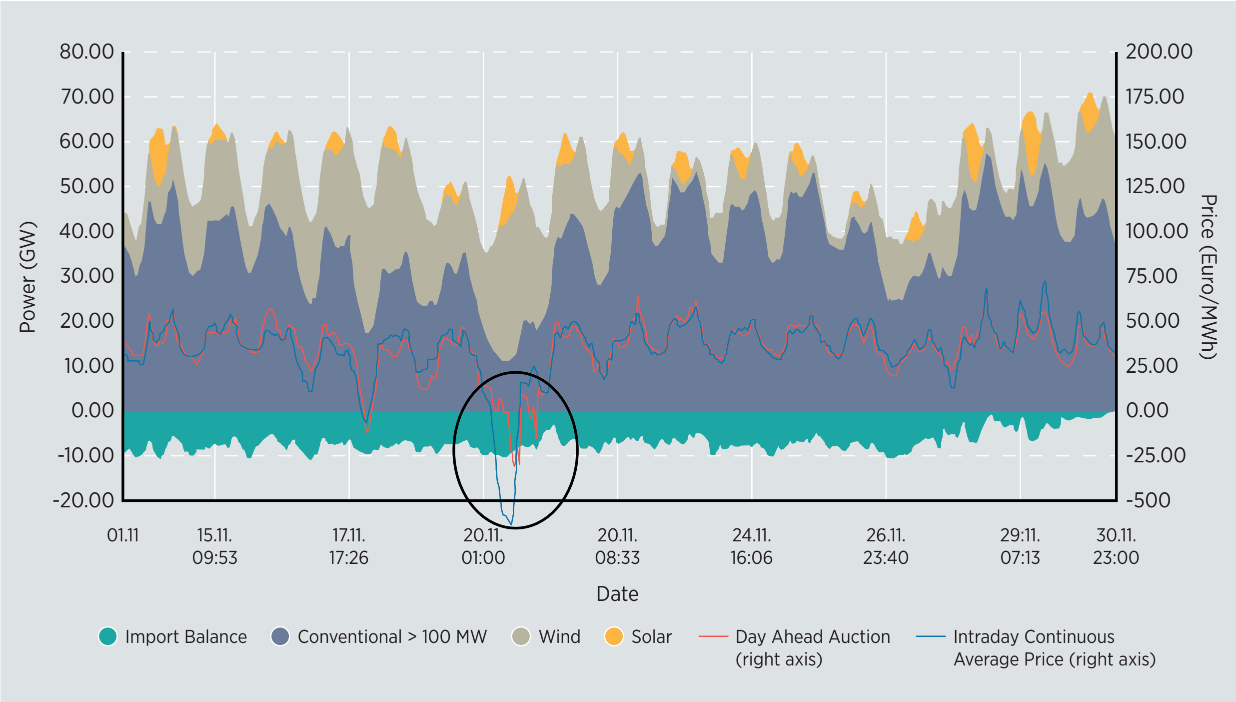
Impact on price convergence and volatility

As mentioned above, in some cases the output of VRE may be difficult to predict. Large deviations in day-ahead and intraday forecasts cause a divergence between day-ahead and intraday prices. In some cases, this price divergence can be very large, as in the example of Figure 1.13, where an unexpected increase in wind availability caused a sudden drop in electricity prices in intraday markets. Furthermore, intertemporal production constraints coupled with the inability of many thermal generators to reduce their output below a minimum technical output may cause negative prices to appear. This problem is more acute in inflexible, capacity-constrained power systems (IADB, 2014). These issues will be analysed in detail in chapter 2, which provides recommendations on how to adapt the wholesale market design for the efficient integration of high level of VRE.

1.4 Conclusions

This chapter has outlined the fundamental role renewable energy technologies will play in achieving the energy transition. The power sector is at the forefront of the transition with renewables capacity growing at a tremendous pace, outpacing those of conventional energy sources. The growing deployment of VRE technologies and rise in distributed generation are some of the factors that are driving the transition in the power sector. VRE already accounts for a large share of the electricity mix in several markets. Further accelerating the transition, while ensuring high standards of economic efficiency and technical reliability, requires supportive policy and regulatory measures.

Figure 1.13 Electricity production and spot prices, November 2016 in Germany



Source: Fraunhofer ISE, 2016

For the sustainable development and greater renewable energy deployment, adequate measures are needed to adapt the market design to address system level impacts associated with variability, resource predictability and geographical dispersion, and market level impacts that include effects on spot prices. Indeed, embracing and supporting the energy transition will bring a wide range of economy-wide benefits, in addition to positive impacts on the environment and energy security.

The remainder of this report mainly focuses on adapting policy and regulations for two elements of an advanced liberalised power system – wholesale market and distribution networks. It analyses the key impacts of variable and distributed renewables for each element and provides recommendations for policy makers and regulators in relevant markets.

WHOLESALE MARKET DESIGN

2

2.1. INTRODUCTION

The electricity market designs implemented to date, with their strengths and weaknesses, are the results of gradual adaptations to the physical characteristics of each particular power system. Although no two market designs are alike – for no two power systems are completely alike – electricity markets have been traditionally tailored to a context in which grid-connected, large-scale power plants supplied electricity in response to a relatively easy-to-forecast, passive demand. Until recently, electricity demand has been assumed to be highly inelastic and mainly dependent on temperature and expected economic activity.

■ The reconception of power systems is recasting wholesale market designs

Before the power industry reached a consensus on how to most efficiently implement electricity markets, new driving factors for change put current market designs into question. Worldwide, electricity systems are experiencing one of the most profound transformations in their history. To deepen the current transition, power systems need to integrate large amounts of variable renewable generation resources (often distributed). As a consequence, and as reviewed in Chapter 1, the original configuration and functioning of power systems worldwide is changing, and will continue to change in the near future.

All these transformations are taking place at a very fast pace. Adapting market designs to realize the maximum benefits of existing and new resources is a formidable challenge.

This chapter reviews several important issues related to the design of electricity markets, issues that need to be reconsidered in today's new setting. In doing so, it analyses three time frames: 1) long term; 2) day ahead and intraday and 3) very short term (close to real time).

2.1.1. Electricity markets, products and time frames

Electricity markets comprise all the commercial transactions involving energy as well as other complementary products related to the supply of electricity (*e.g.*, ancillary services, reliability products traded in capacity mechanisms, etc.).[1]

Procuring products aside from energy is essential to ensure that the delivery of electricity is sufficiently secure and of adequate quality. The num-

1. This general overview is based on Batlle (2013).

2

ber of these complementary products and their exact definition vary from one system to another. Notwithstanding, energy and ancillary services are jointly produced; they are not typically jointly procured, as energy procurement is left to market participants whereas the system operator is in charge of ancillary services' procurement. As we shall see later, there are alternative ways to integrate ancillary services and energy procurement.

Energy and electricity-related products can be traded in various time frames, depending on the particular market. For example:

- Energy, the most basic product traded on electricity markets, can be procured from the very long term to real time, through either physical or financial contracts.
- The system operator may acquire ancillary services (*e.g.*, operating reserves that are used to ensure a continuous match between demand and supply, even in case of contingency) in different time frames (including long-term, day-ahead and intraday, depending on the market).
- Reliability products (*i.e.*, products that assure the physical availability of an adequate quantity of resources in the system needed to run it safely without having to curtail demand) are usually procured over the long term; subsequent markets may also allow the adaptation of buying and selling positions.
- Renewable energy support mechanisms can provide long- to short-term incentives for the production of renewable energy.

It is not always easy to clearly separate the three time frames discussed here for short-, very-short- and long-term markets. All electricity markets are, to some extent, coupled. The most relevant products that are usually traded within each time frame will be discussed. The analysis will start with short-term markets, *i.e.*, day-ahead (DA) and intra-day (ID) markets because, in most power systems, the day-ahead market serves as a reference for all the others. Later, the very- short-term (balancing or real-time markets) and the long-term market design (focusing on capacity mechanisms and RES support schemes) will be discussed.

- In the day-ahead market – covered in Section 2.2 – trading takes place one day before the delivery of electricity. Market members submit their bids and offers, and a clearing algorithm determines the market price for each settlement period (*e.g.*, for each hour) of the following day and the cleared quantities. It is in this time frame where the largest fraction of operating reserves is often acquired. After the day-ahead, and before real-time delivery of electricity, there are intraday markets or other mechanisms that allow rescheduling units. The reasons for this rescheduling are diverse and depend on market design characteristics.
- The focus of Section 2.3 is on the markets related to the close-to-real-time actions of the system operator (more specifically, operations carried out by the system operator after the last market gate closure[2]). It is during this time frame when the detailed design of energy and reserves products becomes more relevant. A proper design is crucial to provide accurate price signals in the very short term, and this will play a fundamental role in unlocking all the flexibility already available in power systems while also providing efficient long-term signals.
- Finally, in Section 2.4, we focus on those mechanisms generically oriented towards directly supporting the long-term development of the power sector. Capacity mechanisms, or any other mechanism designed to guarantee the adequacy of the system, are introduced to achieve the reliability target defined by the regulator. Reliability products traded in these mechanisms may be very diverse, reflecting the diversity of scarcity conditions in different systems. Also, the procurement process varies (*e.g.*, centralised versus decentralised approaches) according to the structure of the power sector. On the other hand, RES support schemes aim at achieving a renewable penetration target. In this case, different designs are possible, each one with its pros and cons, as analysed in detail in the second part of Section 2.5.

2. The last gate closure is the moment until which market agents can modify their own programmes on the markets without the intervention of the system operator.

In the remainder of this section, we introduce the reasons why increasing penetration levels of renewables (utility scale and distributed) call for revisiting wholesale market design in liberalised power systems for all time frames.

2.1.2. Why rethink the market now

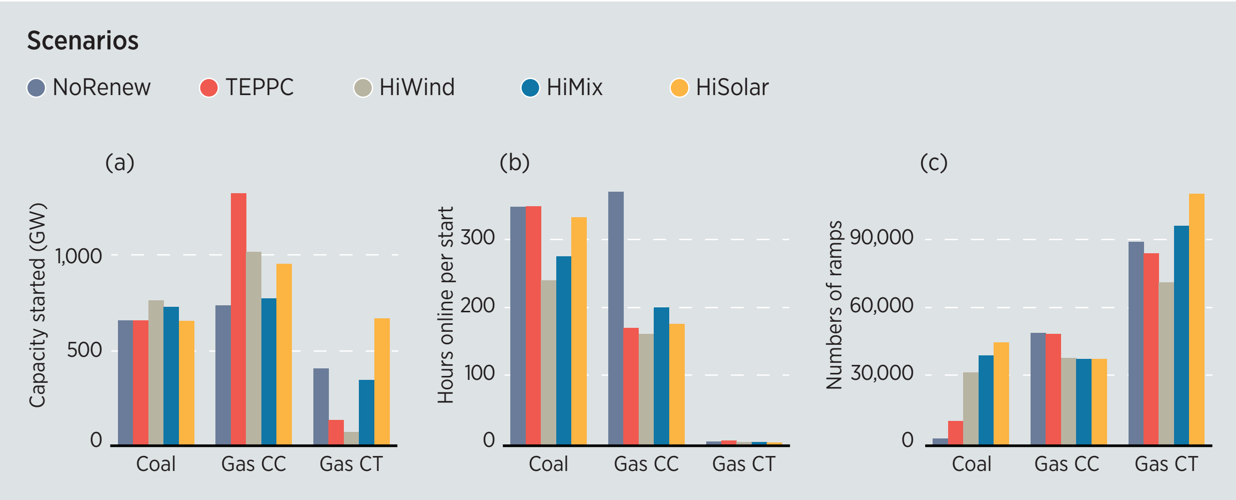
■ The need to rethink short-term and very-short-term markets today

Variable and small-scale generation and demand response solutions call for faster and more accurate short-term markets.

More than in any other kind of market, trading in power markets is largely conditioned by the laws of physics. The deployment of variable and distributed renewables may complicate the efficient management of markets if adequate adapting measures are not put in place. Designing power markets then, involves an ongoing search for the right balance between economic and engineering efficiency, between what is desirable and what is feasible.

Variable and small-scale generation on the system dispatch requires flexibility (Holttinen *et al.*, 2013; Graichen, 2015), which, among other measures, calls for a larger amount of dispatchable resources capable of dealing with changing situations, whose operation is to be based on faster and more accurate markets. Figure 2.1 illustrates the rising need for flexibility as variable generation increases across different renewable penetration scenarios in the US Western Interconnection. Three technologies are selected to represent three different types of operating regimes: coal plants (base load), combined cycles (mid-load) and gas turbines (peakers). An increasing penetration of RES technologies results in a higher "capacity started" among peaking units (Panel a), a decrease (even if not homogenous) in the number of hours that a plant is online each time it is started (Panel b) and an increase in the number of ramps required, not only from peakers, but also from base-load units (Panel c) – three effects that clearly highlight the growing need for flexibility.

Figure 2.1 VRE generation and the need for flexibility



(a) Capacity started
(b) average number of hours online per start
(c) total number of ramps for different plant types per year in different scenarios of RES penetration

Note: The scenarios simulated are: no renewables (0% wind, 0% solar); Transmission Expansion Planning Policy Committee (TEPPC 9.4% wind, 3.6% solar); High Wind (25% wind, 8% solar); High Solar (25% solar, 8% wind) and High Mix (16.5% wind, 16.5% solar). Power plant types are coal plants (base load), gas combined cycles (mid-load) and gas combustion turbines (peakers). Results depend on the technical parameters assigned to each technology and are specific to the Western Interconnection.

Source: Adapted from NREL, 2013a

2

The format of the bids in day-ahead markets implemented to date has traditionally been tailored to the prevailing generation mix in each particular context. The vast majority of relevant dispatch decisions have been one-sided (no demand response was expected except in very extreme situations) and could be mostly closed in the day-ahead horizon. Something analogous happens with the definition of reserves products and the functioning of close-to-real-time markets.

However, prevailing resources are rapidly changing. The development of renewable energy sources (RES) has fostered the proliferation of distributed generation, giving rise to a significant number of new small-scale agents and businesses that need proper accommodation in the market. In addition to this and in parallel, enabling information and communication technologies are increasingly allowing demand to receive more precise market signals and to react to them, which will empower consumers to play a major role in the energy transition. In this new context, there is growing consensus around the fact that short-term and very-short-term[3] markets need to be improved and adjusted to meet future needs.

The major refinements needed depend to a large extent on the particular type of market design in place. To simplify, there are two main ways of conceiving short-term electricity markets (Batlle, 2013): the US Independent System Operator (ISO) approach and the Target Model for the European electricity market.[4]

The short-term market design elements considered pivotal to the current transition include the time frame of markets, bidding formats, clearing and pricing rules and the integration of energy and reserve markets (see Section 2.2).

In very-short-term markets, the design elements in need of revision are the definition of balancing responsibility (for conventional and RES generation), the imbalance settlement, the definition of balancing products and the pricing of reserves (see Section 2.3).

The need to revisit long-term investment signals

Long-term regulatory mechanisms (including capacity and RES support ones) need to be designed to minimise market distortions and to encourage full integration of all resources.

According to economic theory, perfect competitive markets lead to the most efficient results, both in the short and in the long term. In real cases, however, the presence of market failures implies that this ideal outcome is often not reached.

When there is no way to fix these failures to allow the market (left to its own devices) to achieve the welfare-maximising outcome, some additional regulatory mechanisms can help the market meet this goal. These mechanisms may look to reinforce the short- and/or long-term signals that agents perceive in order to improve system security of supply or may seek to incentivise certain technologies (*e.g.*, wind or solar).

Capacity remuneration mechanisms

No consensus has been reached yet regarding instruments for the remuneration of capacity. A good number of markets, mainly on the the Americas (Batlle *et al.*, 2015) opted to implement a diverse array of explicit capacity mechanisms from the outset, while in other regions (Europe is the paradigmatic example), this was not initially the case.[5] However, several countries in Europe have now implemented, or are in the process of implementing capacity mechanisms (ACER, 2013; ACER-CEER, 2016a), as also evidenced in Figure 2.2.[6]

3 Balancing markets in the European Union and real-time markets in the United States.

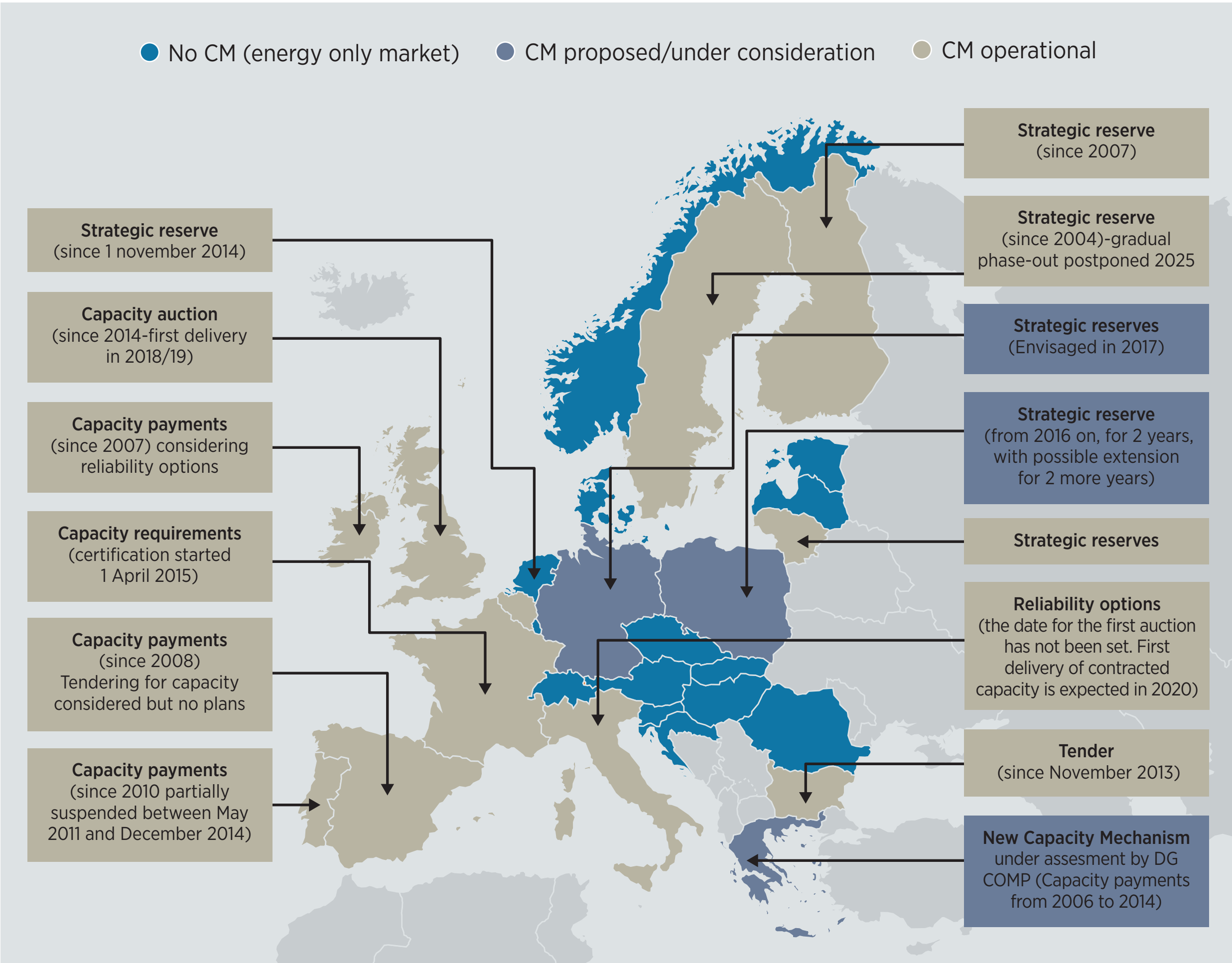
4 As defined by CACM Guideline (Commission Regulation 2015/1222) and draft Electricity Balancing Guideline.

5 Although all sorts of implicit regulatory safeguards have been applied indirectly in order to guarantee the security of supply in these energy-only markets.

6 The European Commission has highlighted the need to use a harmonised adequacy assessment methodology, in order to avoid the design of CMs at country level to be a potential threat to to the development of the internal energy market. For further details, see the Winter Package released on 30 November 2016 (https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition).

The deployment of RES has been argued by some as the new and key factor to justify the need for the implementation of capacity mechanisms. The argument more commonly raised is that high volumes of variable renewables in markets with overcapacity are driving down short-term prices and load factors of conventional generation. This makes it more difficult to forecast the frequency of scarcity events that, in a competitive "energy only" market, are the ones that allow for the recovery of the fixed costs of non-incentivised traditional plants. Indeed, in a competitive electricity market – given the standardised nature of the product – the market price is equal to the marginal cost of serving an incremental unit of demand. Therefore, as long as there is enough capacity to serve the demand, market price cannot exceed the marginal variable cost of the system. Because electricity cannot be stored economically, only when capacity is scarce with respect to demand can prices surge over variable cost, contributing to the recovery of fixed costs.[7]

Figure 2.2 European power systems with (or in the process of implementing) capacity mechanisms



Note: In Germany, there are three (envisaged) schemes: Climate Reserve, Network Reserve and a Strategic Capacity Reserve. The first is not considered to be a CM; the second could be, and the third is a CM. The Strategic Capacity Reserve is envisaged to be implemented in 2017, if the necessity is demonstrated. The envisaged CM in Poland for after 2016 includes generation units tendered by the TSO, which would definitely have been decommissioned by the end of 2015. This scheme has the characteristic of a Strategic Reserve CM.
The term "country" as used in this material also refers, as appropriate, to territories or areas.

Source: Adapted from ACER-CEER, 2016a, based on NRAs (2016) and European Commission's report on the sector inquiry into CMs (2016).

7. *"In an energy-only market, the signal for investment relies on high prices that materialize in moments of excess demand (these are called scarcity prices and moments of excess demand are scarcity scenarios): whenever there is a scarcity scenario, prices are allowed to rise so that generators start earning 'scarcity rents' that are high enough to cover their fixed costs of capital and induce new investment/new entry in the market. [...]" see European Commission, 2015a.*

2

In this context, many stakeholders have questioned whether short-term market prices alone, even if regulations allow market prices to reach very high levels in scarcity events, are a reliable enough signal to encourage adequate capacity investments. In fact, the need to reinforce long-term signals does not arise only from RES deployment itself, but also from the regulatory uncertainty (*e.g.,* around the kind of support to be provided in the future) around deployment and the effects of this uncertainty on wholesale markets.

RES support mechanisms

For many years, there has been a consensus on the need to implement long-term RES support mechanisms because of the market's inability to internalise a number of externalities. However, RES support mechanisms, and therefore RES investments, have not always benefited from stable remuneration frameworks. This lack of regulatory predictability, among other factors, affects the decisions of potential RES investors (and also the decisions of investors in conventional generation technologies).

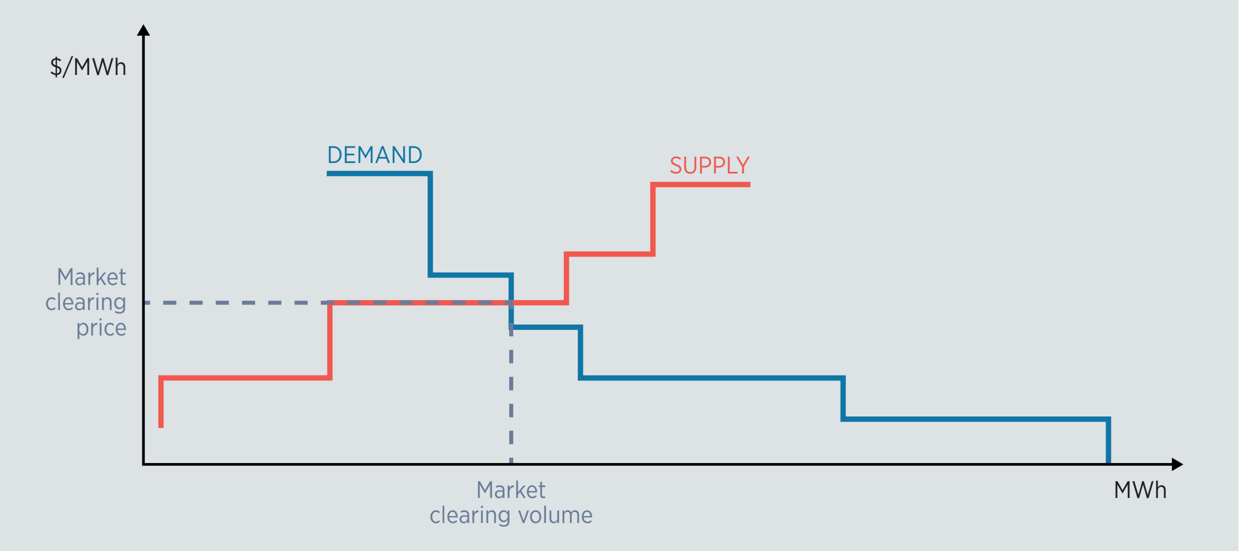
A discussion on whether the need for such mechanisms in each particular context is justified or not falls outside the scope of this study. Here, the focus is on providing recommendations about how to design these support mechanisms, both for generation adequacy and renewable development. The goals are to send proper long-term signals, to avoid interfering and distorting market functioning as much as possible, and to encourage the integration of all resources.

2.2. SHORT-TERM MARKETS

Short-term energy market design needs to be enhanced and refined at all levels, particularly timelines, locational granularity of prices, bidding formats, clearing and pricing rules and integration with reserves.

Short-term auctions are the core of electricity wholesale markets. At these auctions, bids by generators and consumers are matched with the textbook objective of determining not just who sells and who buys, but also market clearing prices (for each time interval in the auction timeline scope and for both market sides: generation and demand) – that is, as described in figure 2.3, the price at which demand equals supply, and no more demand is willing to purchase and/or supply willing to sell. These short-term electricity prices are essential since they represent the reference for the longer-term markets (which help drive the system expansion).

Figure 2.3 Market clearing price and market clearing volume setting in electricity auctions



In electricity markets, trades concern an underlying commodity which is subject to many complex physical constraints (operation, network, security, etc.). Different approaches to dealing with these physical complexities have resulted in (sometimes significantly) different market designs.

In practice, as briefly analysed in Box 2.1, there are two main approaches to accounting for all these physical constraints: the US and the European Union (EU) models. The major difference between the two is the degree of separation between the market operator and the system operator. But the two approaches are increasingly converging and promise to continue doing so.

Short-term market design elements to be reconsidered

We have pointed out that the recent proliferation of resources with new characteristics has raised concerns regarding the need to improve the current market design. Among the different design features of short-term markets, we focus here on those that we believe deserve more attention from stakeholders and policy makers:

Box 2.1 The major difference between US and EU market designs

The major difference between US and EU market designs is the degree of separation between the roles of market operator and system operator. In certain jurisdictions, the role of the system operator is less pervasive than in others, under the argument that the system operator function should be limited to ensure reliability in an attempt to maximise the range of the market. The debate on allocation of responsibilities between the market and the system operator has been central since the outset of market restructuring (see, for instance, Hogan, 1995).

The predominant models implemented in US markets and in force in the majority of EU member states – with some exceptions, including Ireland until very recently (CER, 2014) and Poland (Siewierski, 2015) – represent two different views on whether or not to carry out this separation.

- In the United States, the integration of physical constraints in the clearing process and the involvement of the independent system operator (ISO) in the markets is probably as significant as is possible. The ISO oversees both activities, market and system operation, not only from an institutional perspective, but also from the operative standpoint, as energy trades are jointly cleared with the electricity system security procedures. This is considered necessary, not only to reliably operate the system, but also to guide market agents towards the optimal dispatch (from the system operator's perspective, taking into account technical and reliability constraints). This model revolves around the concept of bid-based, security-constrained economic dispatch (SCED), where the requirements set by the ISO (*e.g.*, different types of reserves) can be co-optimised and priced along with energy.

- At the other extreme, the model currently used in most European member states, which we can call the EU power exchange (PX) approach, originally aimed at a simpler consideration of the physical reality along with a major decoupling of the system operator's responsibilities and the spot market functioning. Historically, European Power Exchanges were designed as financial platforms for agents to buy/sell energy with the supposed objective of maximising liquidity, in an attempt to isolate (as much as possible) this trading from the complexities of the network. In line with this separation between the market and the system operators, the European approach tends to allow generators to bid on a portfolio basis (aggregated bids from different facilities of the same company).[8]

- In a nutshell, as will be discussed throughout the chapter, the influence of the system operator to determine the real-time scheduling throughout the entire process is, in practice, reflected in a number of basic design elements, for example, the point in time at which the last gate closure is set (*i.e.*, the moment until which market agents can modify their own programmes without the intervention of the system operator), the integration of the physical constraints in the clearing process, the amount and diversity of reserves defined by the system operator and the mechanisms to acquire them, or even the role of the system operator as aggregator and balancing party responsible for RES.

8. Despite being the major trend in Europe, portfolio bidding is not allowed in some European systems, including, for instance, in Spain and Portugal.

2

- The time frame of markets, both for energy and reserves, which is fundamental to allow market mechanisms to respond quickly to fast-changing conditions.
- The locational granularity of prices and schedules.
- The so-called bidding formats. *i.e.*, the way generators are allowed to submit their offers in the market (not only in the day-ahead but also closer to the real-time markets).
- How markets are cleared and settled, *i.e.*, how it is determined who produces and who consumes and at what price.
- How to define and procure operational reserves, and particularly how to guarantee that the market reflects the interdependence between the energy and reserve products, especially under conditions of scarcity.

Some of these design features are relatively new (*e.g.*, the need to adjust the market timeline to fit the new flexibility requirements or the need to define new bidding formats), while other refinements (for example, the need to revisit clearing and pricing rules) target deep-rooted efficiency issues that have been acknowledged for years, but whose effect has been exacerbated by the new market conditions.

Although most of the previous design elements of short-term markets are related to some extent, for the sake of clarity, we will try to deal with them one at a time and separately.

2.2.1. Time frames of markets, dispatches and prices

As variability increases, the time specificity of produc ts traded in the markets needs to be increased. This leads to the need for better-adapted and more flexible market timelines.

One central element of the short-term market design that needs to be revisited to better accommodate RES is the time frame of the energy and reserve markets. The time frame of the system operator's actions (*i.e.*, reliability-related processes involved in the delivery of electricity) also needs reconsideration.

The design of market time frames is mainly influenced by the physical and technological characteristics of the power system. Since the outset of the electricity market liberalisation, there has been a general consensus (with some exceptions) that, in thermal-dominated systems, it is convenient to implement a day-ahead energy market and also day-ahead reserve markets. Energy and reserves can be procured: 1) within the same auction mechanisms or 2) by means of different and sequential mechanisms.

For a short-term energy market, one day is sufficient to both forecast demand consumption with reasonable certainty and to schedule thermal plants' commitments. Meanwhile, for a hydropower-dominated (energy-constrained) system, the economic dispatch and the resulting prices can be calculated over larger horizons (*e.g.*, on a weekly basis, as done in Brazil). This is evidence of the significant role that electricity systems' technological characteristics play in deciding optimal time frames.

From the day-ahead market to real time, additional markets and mechanisms are needed to allow agents to adapt their programmes to changing conditions. Increasing shares of wind and solar generation, in particular, result in increasing volumes of intraday trading necessities, and the need to adjust production schedules to the most recently updated forecasts. This requires the market time frame to adapt to fully exploit the potential of variable renewable resources.

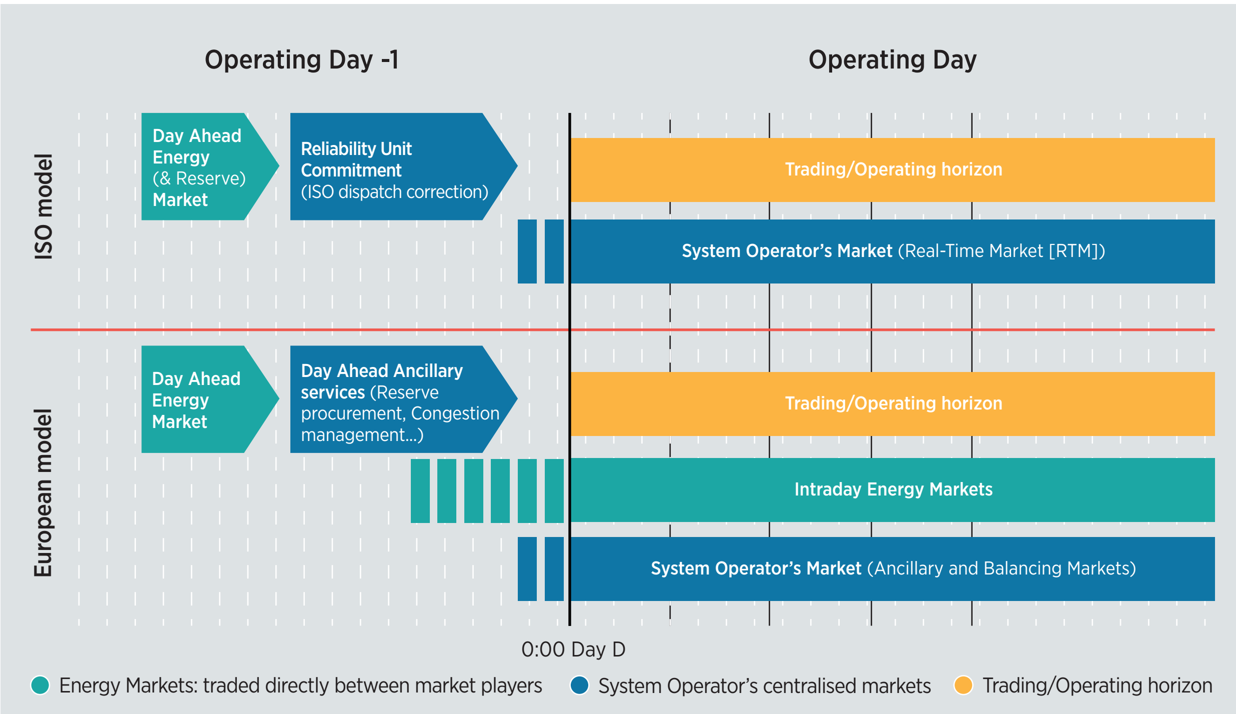
Figure 2.4 offers an overview of market time frames in the US and European contexts. This representation is simplified for clarity and mainly focuses on the most relevant differences between the two paradigms.

The figure indicates when each process takes place and the time scope covered. For example, the day-ahead market in Europe takes place in the morning of the day prior to electricity delivery (operating day – 1) and covers all 24 hours of the delivery day (operating day). Figure 2.4 also specifies whether the process is an energy market, where products are traded directly between market players, or a system operator's centralised market, where resources are purchased or sold by the system operator (which is the counterpart of all transactions). As described later, in the European model, there are intraday markets where energy products are traded directly between market players.

The first difference between both schemes in the short term lies in the way operating reserves (generation capacity readily available to the system operator for solving contingencies) are procured:

- In the case of ISO markets, reserves are usually procured simultaneously with the energy market (in the US ISO's terminology, they are often co-optimised).
- In Europe, operating reserves are organised by the system operator after[9] the energy market results are known. Therefore, the procurement is sequential in this case. (The drivers and implications of this alternative are discussed in Section 2.2.5.)

Figure 2.4 Short-term market time frames: An overview



9. Reserve resources can also be procured prior to the day-ahead energy market through longer-term agreements (e.g., through monthly tenders/auctions).

2

After the day-ahead market and the reserve procurement process(es), the system operator takes actions to ensure the reliability of the system. The timing and scope of these actions are similar in both contexts.[10] These actions are needed after the day-ahead market because this market does not account for all the physical complexities of the power system. As mentioned above, in the EU case, this lack of detail is partly the consequence of decoupling the system operator's responsibilities from the functioning of the spot market, isolating as much as possible the energy trading from the complexities of the network-constrained dispatch model. This separation comes at a cost, which is the appearance of potential infeasibilities that have to be later solved by the system operator. In the United States, although the objective is to include all the details in the energy market processes, it is still found that today, "the full alternating current representation of the transmission system cannot currently be explicitly included in the market software despite the use of state-of-the-art computational tools" (FERC, 2014c). Some operational and reliability considerations remain impossible to incorporate into the day-ahead market process. As a result, the system operator also needs to undertake some follow-up actions in US electricity markets.

Apart from the previous issues, which are analysed in subsequent sections, there are three fundamental design decisions related to the time frame of markets: 1) the definition of the time threshold within which bids have to be presented in intraday energy markets and beyond that only the system operator can take action/dispatch resources through its centralised (balancing) market (the so-called last *market gate closure* or simply the *gate closure*); 2) the timeline and format of intraday energy markets (run by the market operator in the European Union and by the ISO in the United States) and 3) the settlement period. These designs are discussed next.

Reoffering period and gate closure

Until the so-called last gate closure, market agents are allowed to balance their positions and correct their deviations without any type of intervention from the system operator. After that point in time, the final binding production schedule is determined for all participants, and only the system operator can adjust any deviation. The timing of the last gate closure represents the dividing line between markets and pure system operations.

- In Europe, the last opportunity for a market agent to change its schedule in hour h (or in a market time period x), without the system operator's intermediation, is the closure of the last intraday market session in which energy can be traded for that delivery period h (see following section on intraday settlements), see Box 2.2.
- In the United States, this dividing line between markets and purely system operations is slightly different. Once the day-ahead market closes, the ISO calculates the so-called reliability unit commitment (RUC), which corrects the schedule for the day after. The ISO first clears the day-ahead market and develops the necessary corrections. It checks either for eventual transmission constraints that could not have been fully captured by the security-constrained economic dispatch optimisation model, or seeks to adjust cleared bids to the ISO's forecast of load and RES production or as a result of the co-optimisation of both the energy and reserve markets (see Section 2.2.5). In principle, market agents are not supposed to re-adapt their bids from that point on, so to some extent this would be the gate closure. However, market agents, under certain specific and well-justified circumstances, are allowed to update their day-ahead offers. This reoffering period may end a few hours to a few minutes before real time.

The increased uncertainty on real-time operations, partially as a result of the growth of variable renewable energy, is stimulating this debate. And again, the discussion revolves around the boundaries between the market and the system operator's competencies. As discussed in the next subsection, in principle, widening the scope of the market provides market agents with

10. Although some ISOs integrate several reliability processes into the day-ahead market, as discussed in Section 2.2.5.

incentives to do their best to minimise their imbalances. This can be of utmost relevance as RES penetration rises since allowing market agents to update their offers closer to real time would improve the accuracy of their forecasts. (Miller, 2015)[11] On the other hand, forcing the transmission system operator (TSO) to operate too close to real time could require procuring reserve resources in larger amounts and/or of higher quality. Therefore, having the gate closure away from real time would be preferable to faciliate the task of the system operator and to reduce system security costs. In deciding the point in time when market participants have the last opportunity to change their schedule, benefits (from a RES producer point of view) and costs (from the system operation point of view) should be compared.

Box 2.2 Short-term electricity market timeline in Italy

Day-ahead market

In the day-ahead market, electricity is traded one day before the operating day. In a wholesale market, electricity can be traded day-ahead bilaterally (over-the-counter trading) or on the day-ahead power exchange.

In Italy, the day-ahead-market, called the MGP, is an auction market, not a continuous-trading market. Bids and offers can be submitted to the MGP beginning at 8:00 a.m. on the ninth day before the day of delivery until 12:00 p.m. on the day before the day of delivery (Day — 1), when the auction process begins. The results of the MGP aucº-tion are made known by 12.55 p.m. on the day before the day of delivery. The MGP's auction selects bids and offers based on economic merit-order criterion, taking into account transmission capacity limits between zones.

Intra-day market

The intra-day market (MI) allows market participants to modify the schedules defined in the MGP by submitting additional supply offers or demand bids. The MI takes place in seven sessions: MI1, MI2, MI3, MI4, MI5, MI6 and MI7. The schedule of each MI is as shown in the Table 2.1.

Table 2.1 Bid sessions for intraday market in Italy

MI session	Opening time	Closing Time	Result
MI 1	12.55 pm (Day -1)	3.00 pm (Day -1)	3.30 pm (Day -1)
MI 2	12.55 pm (Day -1)	4.30 pm (Day -1)	5 pm (Day -1)
MI 3	5.30 pm (Day -1)	11.45 pm (Day -1)	00.15 am
MI 4	5.30 pm (Day -1)	3.45 am	4.15 am
MI 5	5.30 pm (Day -1)	7.45 am	8.15 am
MI 6	5.30 pm (Day -1)	11.15 am	11.45 am
MI 7	5.30 pm (Day -1)	3.45 pm	4.15 pm

Source: Gestore mercati energetici, 2017.

11. But this may be relevant for thermal plants too since it would allow them to update thermal generation offers so they can represent intraday changes in gas market prices.

2

Intraday settlements

Intraday markets in Europe perform two relevant functions. First, as shown in Box 2.3, they allow generators to make incremental adjustments to their energy schedules (resulting from the day-ahead market), which improves the efficiency of the initial day-ahead programme. This can mitigate the potential inefficiency of the day-ahead dispatch due to the limitations of the European bidding formats (see Section 2.2.3). Second, they recover the balance between demand and supply if the forecasted system conditions change. For example, intraday markets are fundamental to accommodate renewable energy forecast errors, and most European intraday markets have recently been modified to improve their performance (see also Box 2.4). Intraday markets produce prices used to settle the incremental changes executed in each market.

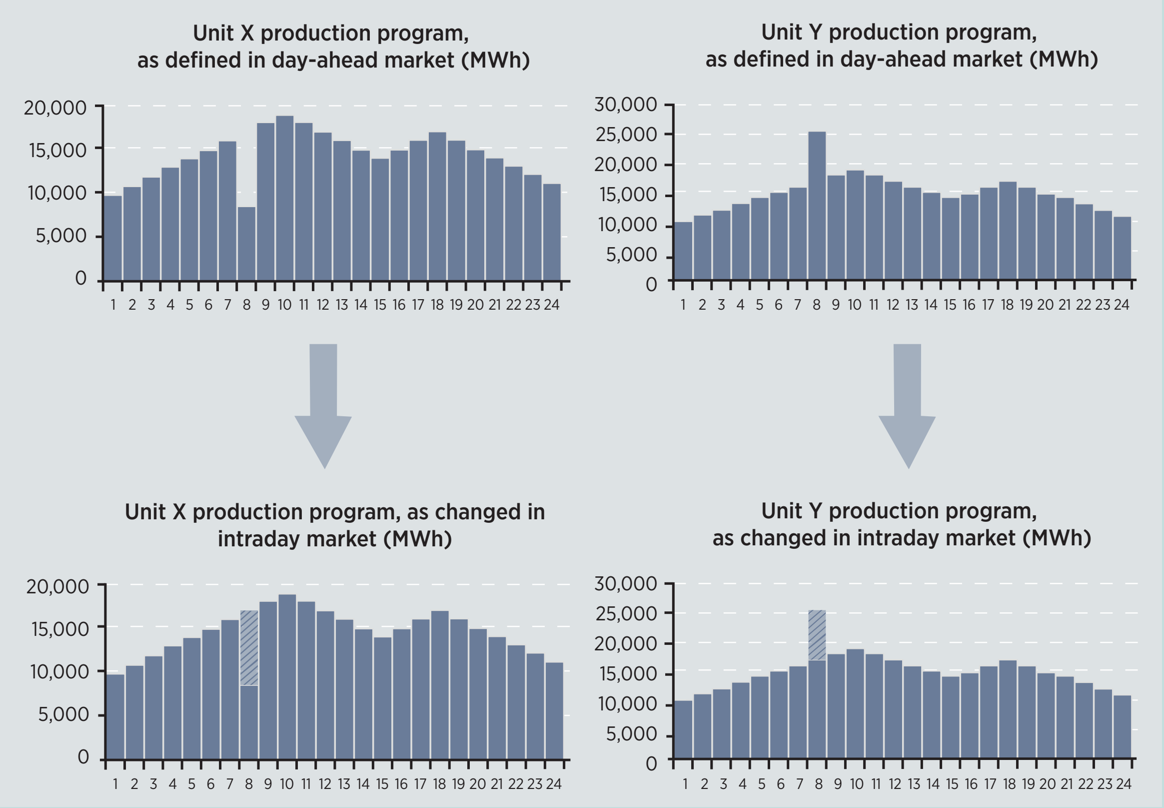
In the United States, ISOs perform intraday adjustments according to updated forecasts on the evolution of the system (mainly related to load forecasts and generation forced outages). These actions are adapting to a larger penetration of renewable energy sources. These processes are not equivalent to European intraday markets in one key aspect: generally, no intraday price signals are calculated in the United States associated with these actions. This way, the US intraday actions do not establish binding economic transactions (for they do not produce binding prices). All deviations

Box 2.3 Intraday markets and schedule adjustments

Intraday markets are useful platforms to accommodate possible forecast errors (*e.g.*, on demand or on renewable energy production) as well as to modify the production'programs of thermoelectric power plants (as shown in Figure 2.5), defined as a result of day-ahead energy markets and which, also due to the impossibility of submitting multi-bid offers, could be technically unfeasible.

The need for intraday markets is closely linked to the fact that deviations from programs (imbalances) are penalised. The intraday market therefore helps reduce the risk of imbalances.

Figure 2.5: Example of schedule adjustments in intraday market



from the day-ahead programme are settled later at the real-time price,[12] *i.e.* the price that represents the value of the electricity in real time (taking into account the actual condition of the system), calculated every five minutes through a unit-commitment-like model (similar to the one used for the day ahead but with updated information).

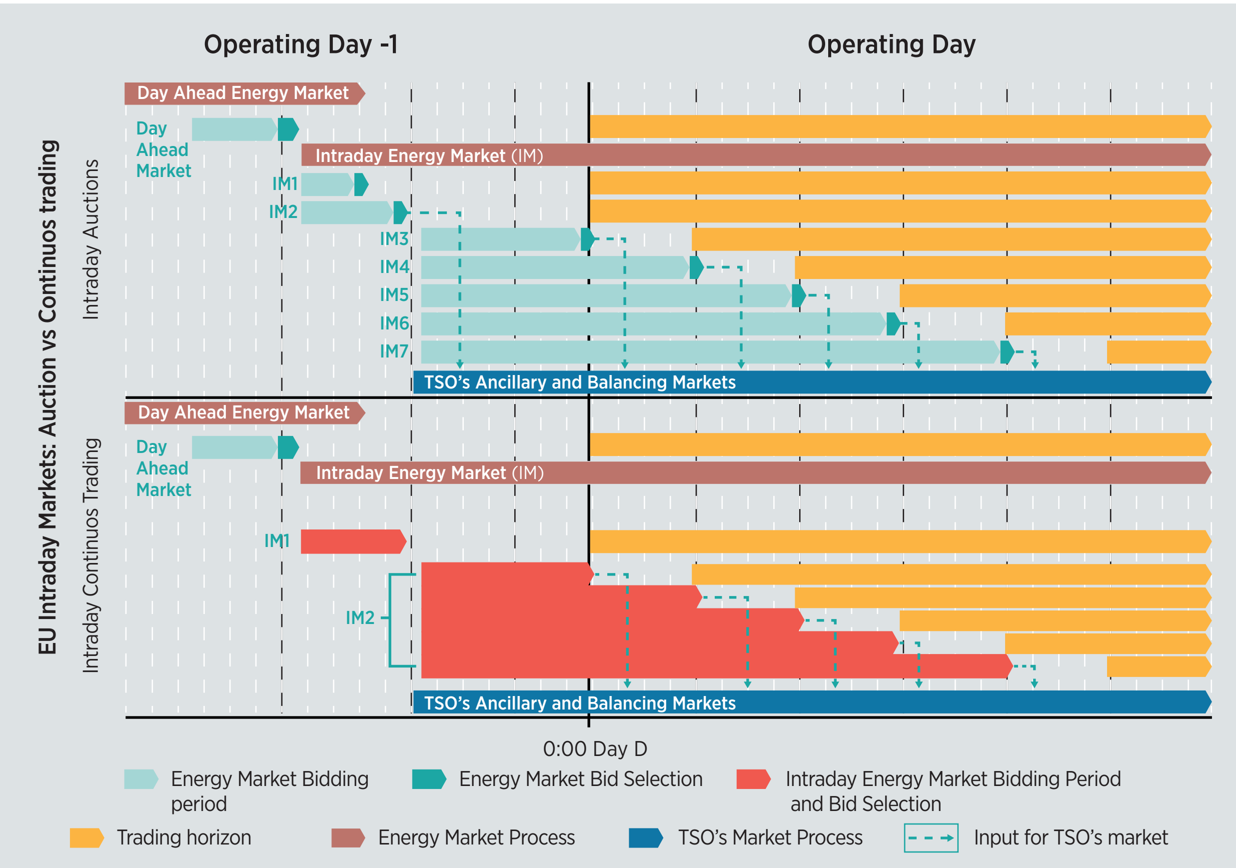
Ideally, generators deviating from the day-ahead programme should receive signals representing the cost associated with the deviations. These costs can be lower if deviations are known in advance. For example, a renewable energy source having a lower output than anticipated in the day-ahead forecast could require other resources to fill the gap. If the deviation is known only a few minutes before real time, this deviation will likely require fast-start units or expensive flexible generators, but if notified several hours in advance, the operator has enough time to adjust the output of inflexible resources more economically.

Intraday prices in Europe capture the different value in times of deviations, while the two-settlement system in ISO markets dilutes these signals since all deviations are settled at the real-time price. The important role of intraday markets and signals has also been confirmed by other analyses on market design. For example, the International Energy Agency (IEA, 2016) pointed out that *"transparent intraday prices are necessary to inform all market participants about the cost of serving the next megawatt"*, and also that *"the design in North America could be further improved by providing greater transparency of the evolution of locational prices during the intraday timeframe"*.

Continuous versus discrete intraday markets in Europe

European intraday markets, pending a unified design (XBID project), have been implemented by Member States using two methods: 1) discrete auctions, in which auctions are called at specific predefined times (Figure 2.6, upper part) and 2) continuous trading, in which bids can be submitted and matched at any time before gate closure (Figure 2.6, lower part).

Figure 2.6 Time frame of European intraday markets



12. *The day-ahead and the real-time markets make up the so-called two-settlement system.*

As shown in figure 2.6, auctions provide for different times for bid submission and selection, whereas with continuous trading, bids can always be submitted, and once submitted, they can be selected at any time. As a consequence, intraday auctions have different sections open at the same time, each collecting different bids and with its own results, even though the trading horizon can partially overlap. Intraday continuous trading, instead, is characterised as having just one session at a time, with a shortening of the trading horizon (*i.e.*, of the hourly products that can be traded) as time passes.

Figure 2.7 presents the intraday market designs implemented across different European power systems, which are based on two criteria: 1) whether these markets are continuous or auction-based and 2) which entity owns the trading platform used to carry out those transactions (*i.e.*, is the ownership based on a power exchange [PX], TSO or bilateral?).

Each of the two above-mentioned alternatives (*i.e.*, continuous and auctions) has the following characteristics, advantages and disadvantages.

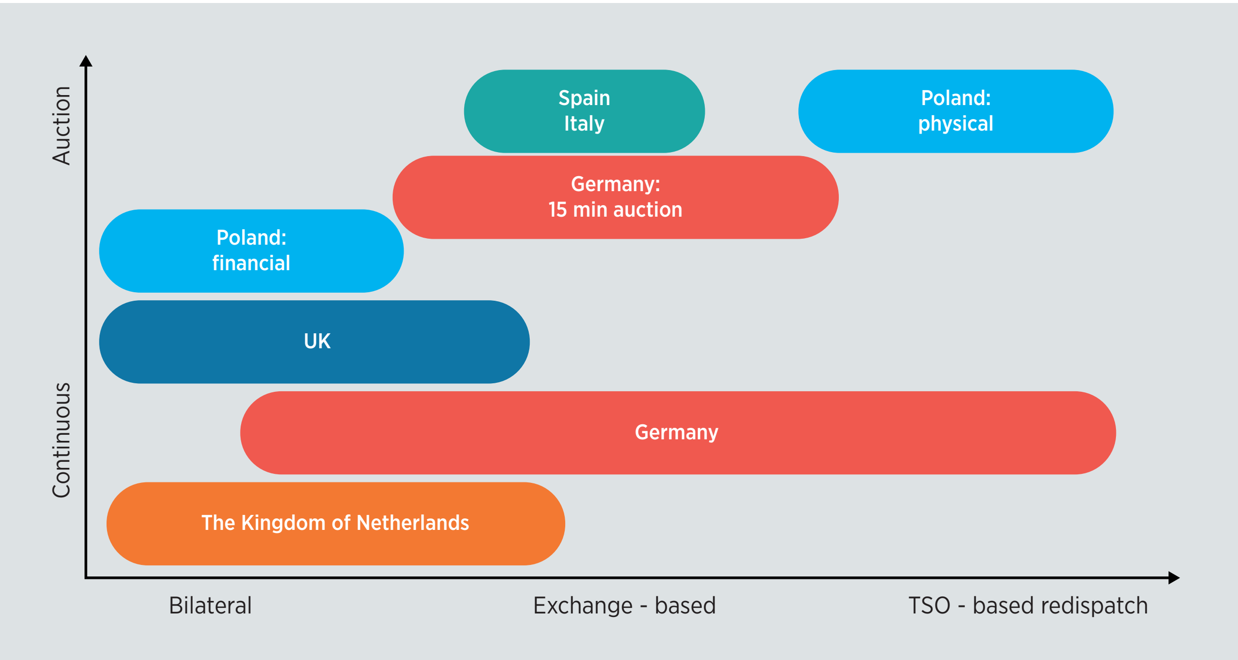
Flexibility versus liquidity

Calling auctions at specific, predefined times provides market agents with limited flexibility to change programmes since the market can only capture these changes at the subsequent auction. From a flexibility point of view, this is less of an issue if auctions are held frequently.

The potential advantage of discrete auctions is that they may provide higher liquidity since they concentrate transactions reflecting all the accumulated events since the last session. Clearly, increasing the frequency of these auctions may negatively affect their liquidity. Discrete auctions, therefore, need to be configured depending on the system characteristics, and they need to ensure sufficient liquidity.

On the other hand, continuous trading provides greater flexibility (since trading is possible at any time). However, as is the case with too frequent discrete auctions, continuous trading may result in insufficient liquidity.

Figure 2.7 Intraday trading arrangements across Europe



Source: Adapted from Neuhoff et al, 2015

Pricing cross-border capacity in continuous markets

Debate continues as to whether intraday auctions can more efficiently price the cross-border transmission capacity compared to continuous trading. The major problem is that in a continuous trading context, cross-border transmission capacity is allocated on a first-come, first-served basis; this does not allow scarcity to be properly priced in transmission. In other words, transmission capacity is allocated little by little at a zero price until it becomes congested (and at that precise moment, there is no more available spare capacity to allocate).

A potential solution: hybrid design

A hybrid design, combining a flexible continuous market with a number of discrete auctions with concentrated liquidity, may represent a suitable trade-off. The question is: to what extent can adding auctions to continuous intraday trading actually improve the performance of the market?

In Germany, the implementation of an additional local intraday auction (called at 3:00 p.m.) to complement continuous trading is assessed by Neuhoff *et al.* (2016). The analysis shows how trading volumes, liquidity and market depth[13] increased after the auction's implementation. This is in line with previous observations showing that liquidity in European power markets based on continuous intraday trading (*e.g.*, in the central western states) is lower than in markets having auction-based intraday trading (*e.g.*, Italy and Spain).

These discrete auctions can be called either at specific predefined times or upon the occurrence of particular events (*e.g.*, a forced outage of a large plant, a high forecast error, etc.).

Settlement and dispatch period

A safe and reliable system requires that energy supply always equals energy demand. As the demand, as well as the production from renewable sources, continuously fluctuates over time, the (marginal) cost of producing electricity varies almost continuously (even though small changes in the level of consumption/production from RES are managed through regulation resources). However, the product traded in energy market is standardised in the sense that it is assumed that, in order to comply with the commitment to supply/withdraw the energy sold/purchased in the market – *i.e.*, in order to be balanced – it is sufficient to do so "on average" within predefined temporal windows, named settlement periods (also referred to as trading periods) that are typically one hour long. It is the TSO's role to assure that the system is continuously balanced; to do so, all balancing resources have to divide up in sub-periods (*e.g.* 15 or five minutes) their previously assumed production commitments. Then the TSO in the balancing and ancillary services markets negotiates changes in their net production level in each of those sub-periods (or dispatch periods), and this updated program will determine the final schedule based on which unbalancing penalties are applied.

Given that for balancing resources (typically thermal power plants) it is more efficient to produce at a constant level, they will try to uniformly distribute the planned output of a settlement period through the different sub-periods. This means that the higher the demand (or the RES production) volatility within a settlement period, the more actions the TSO will have to implement to balance the system. Thus, as the RES production quota increases, it becomes more important to reduce the size of the settlement period for VRE plants as well.

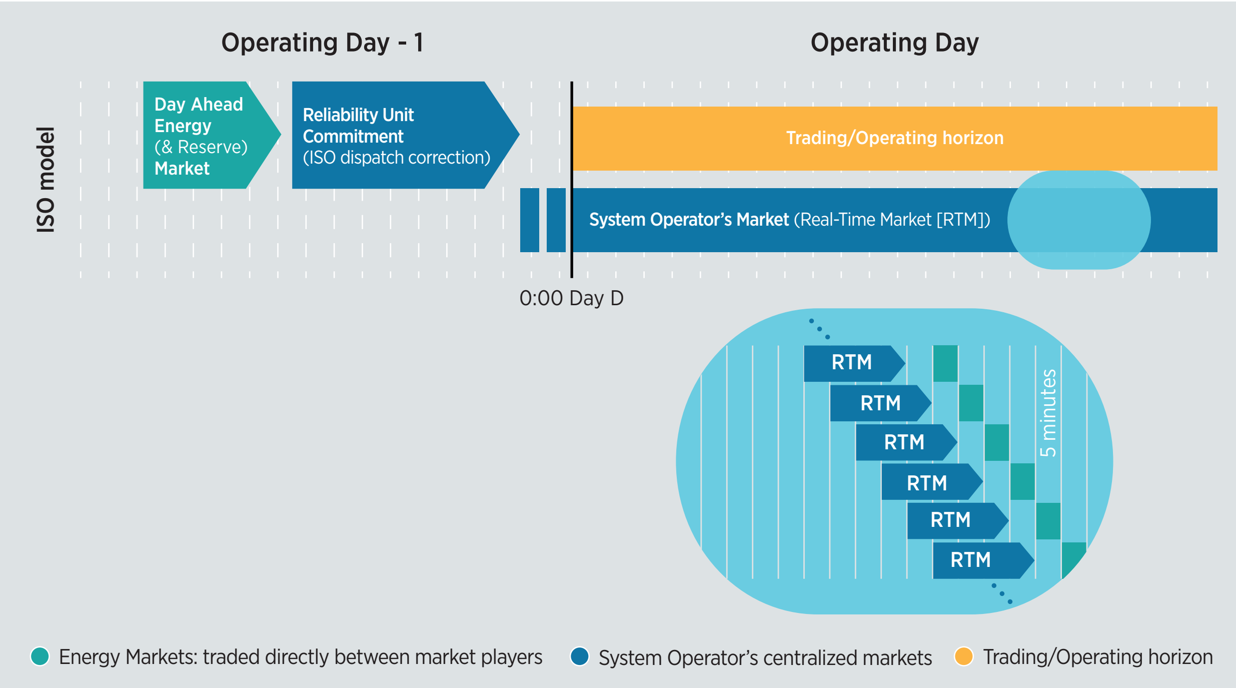
The length of the settlement period is particularly relevant for trades close to real time. This is why we first discuss the role of the settlement period in the very-short-term markets and then extend the discussion to the day-ahead market.

Settlement period in intraday and very-short-term markets

In the United States, the real time market produces five-minute dispatch instructions (Figure 2.8), and prices are also computed every five minutes. However, all ISOs, except the New York Independent System Operator (NYISO), have traditional-

13. Market depth is the market's capability to sustain large market orders without affecting the market price. It can be measured as the amount of electricity that is offered at certain prices during certain time periods.

Figure 2.8 The time frame of US real-time markets



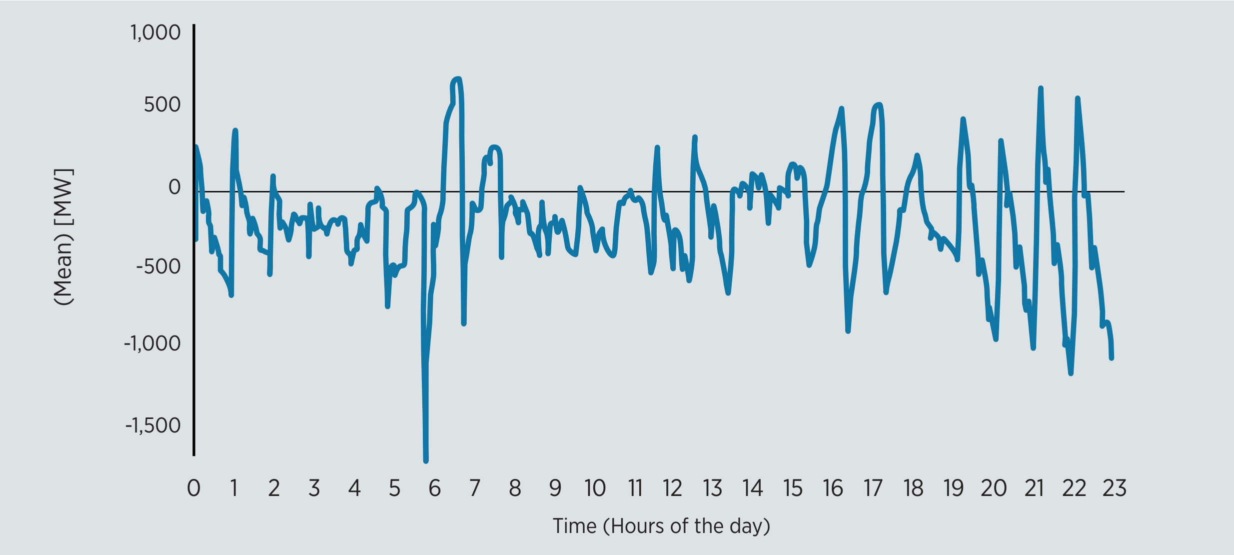
ly calculated average hourly prices to settle real-time transactions to simplify the metering and settlement process. This simplification is widely viewed as relatively inefficient, and the Federal Energy Regulatory Commission (FERC) recently issued Order 825 (FERC, 2016) requiring all ISOs to settle energy transactions in the real-time market in five-minute intervals.

Recent concerns regarding the integration of renewable generation (due to short-term variability, as discussed earlier) had already motivated sub-hourly settlements in some US ISOs – such as in the California Independent System Operator (CAISO), where 15-minute settlements are already implemented; or in the Midcontinent Independent System Operator (MISO) and the Independent System Operator New England (ISO-NE), where currently changes are being implemented. However, taking into consideration that "a movement to sub-hourly settlements may be costly and difficult to accomplish in a short period of time" (PJM, 2015b), the FERC allows additional time for full implementation of this reform.

Dispatches and prices are less granular in European systems. Using long settlement periods (*e.g.*, one hour) has relevant consequences in terms of reserve needs and use – long periods create systematic deviations as a consequence of artificially breaking a continuous and smooth demand into discrete steps. Figure 2.9 shows the system imbalance in Germany for every minute of the day during 2011. Imbalance deviations are larger around the end and the beginning of each hourly period. These leaps around full hours can also be observed in grid frequency (see Weißbach and Welfonder, 2009). As previously mentioned, this is due to the fact that, conventionally, the production/consumption programs are uniformly distributed during the settlement (or dispatch) period, whereas the actual demand and production changes continuously within each settlement period.

As a consequence of this inefficient use of reserves, Germany opted to reduce the settlement period in intraday trading down to 15 minutes, *i.e.* at time when VRE production and demand can be better predicted (see box 2.4), though some EU systems still use longer settlement periods in intraday markets. The intraday market is usually aligned with the balancing market, where TSOs charge for imbalances between supply and demand, measured in 15-minute intervals (Germany,

Figure 2.9 Average German system imbalance for every minute of the day during the year 2011



Source: Adapted from Hirth and Ziegenhagen, 2015

the Kingdom of Netherlands, and Italy for qualified units), 30-minute intervals (France, the United Kingdom) and hourly intervals Italy, Poland and Spain for non-qualified units) (Neuhoff *et al.*, 2015).

The European Commission (2016a) has recently proposed a regulation explicitly requiring market operators to allow trading energy in intervals as short as the imbalance settlement periods (*i.e.*, aligning intraday and balancing markets), which is at 15-minute intervals in all Member States. While this proposal will improve granularity in electricity markets, its projected implementation date – January 2025 – is not very ambitious.

Settlement period in the day-ahead market

A more debated topic is whether subhourly settlements should be used in day-ahead markets. CAISO (2015) sees many advantages in doing so: "Among the possible benefits of sub-hourly settlements in the day-ahead market are aligning unit commitment decisions between the day-ahead and real-time timeframes, [...] improve forward scheduling of variable energy resources and help align the CAISO ramping requirements with resource operating characteristics". However, a more granular day-ahead market could require excessive computational complexity; for example, "The NYISO has concerns that implementing sub-hourly commitment scheduling in its Day-Ahead market could significantly increase the computational time" (NYISO, 2015). Other ISOs do not see clear advantages: "ISO-NE believes that the potential benefits of sub-hourly settlements in the day-ahead market are different, and likely to be much smaller than in the real-time market." The potential drawbacks include those noted by MISO (2015): "Due to the imperfect knowledge of real-time net load or unexpected outages one day ahead, scheduling at the sub-hourly level may actually worsen the consistency and cost-efficiency than scheduling at the hourly level with some robustness".

In the European context, the above-mentioned European Commission (2016a) proposal requires the use of 15-minute intervals in both the day-ahead and intraday markets. This measure will have the positive effects of increasing granularity in wholesale markets and aligning electricity products from the day-ahead market with the balancing market (therefore preventing inefficient arbitrage opportunities). The potential drawbacks of sub-hourly settlements found in ISO markets (mainly, excessive computational complexity) should also be expected in Europe, although the use of 15-minute intervals (instead of five minutes) may alleviate the challenge.

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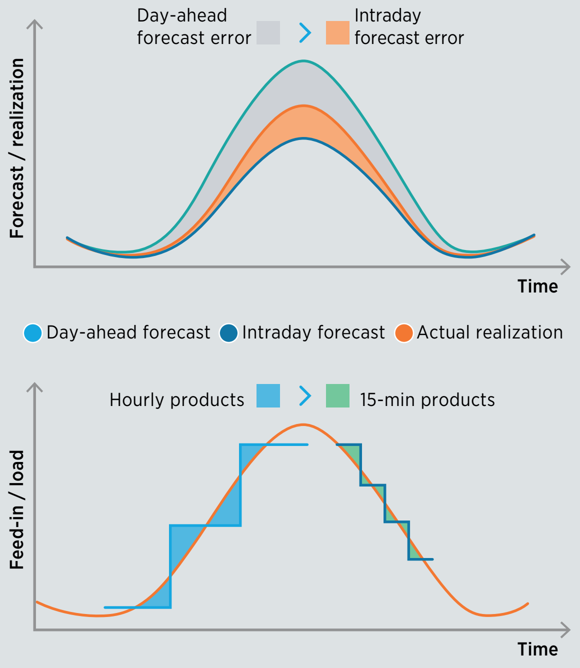
Box 2.4 **Intraday markets and forecast accuracy**

Market participants submit their offers in the day ahead market based on their assumption of the actual system conditions and on their forecasts for renewable energies. As the time of delivery approaches, the accuracy of renewable generation forecasts increases (see figure 2.10 upper part). The intraday market enables market participants to better reflect these forecasts in their positions.

Moreover, quarter-hourly products are traded in the intraday market which enable a better approximation of the real demand ramps and variable renewable energy than the hourly products at the day-ahead market. This is especially important since imbalance settlement periods are on a quarter-hourly basis. Figure 2.10 (bottom part) shows the difference between hourly and quarter-hourly products and their accuracy in representing actual feed-ins.

Figure 2.10 Approximation of realized load and forecast errors in intraday markets



Source: Adapted from TenneT, 2017

2.2.2. Locational granularity of prices and schedules

High shares of VRE deployment, particularly wind, might lead to an increasingly constrained transmission system. It is reasonable to assume that zonal pricing mechanisms may lead to higher inefficiencies with high penetration levels of VRE, both in the short and in the long run, compared to nodal pricing.

A number of regulatory options address the issue regarding the allocation of limited transmission capacity for transactions among players under normal market conditions.[14] These options fall into two main groups: pricing algorithms that involve a detailed representation of the transmission network, and those that consider a simplified one (this is true for all market segments, even if different approaches can be used for each segment):

- Nodal pricing applies security-constrained economic dispatch to derive locational marginal prices – *i.e.*, the prices paid for the energy consumed or generated at a given transmission node (a substation or any other element that creates a discontinuity in the grid). Nodal energy pricing provides an accurate description of the technical and economic effects of the grid on the cost of electricity. It implicitly includes the effect of grid losses and transmission congestion, internalising both effects in a single value (monetary unit per kilowatt hour [kWh]) that is different at each system node. Therefore, nodal prices are perfectly efficient signals for economic decisions concerning the short-term operation of generation and demand since they correctly convey the economic impact of losses and constraints at all producer and consumer locations.
- With zonal pricing, the power system is administratively divided into zones, within which little congestion is expected. Price differentials reflect only transmission congestions considered relevant by the regulator or the system operator. Different degrees of spatial resolution are possible (France and Germany feature only one price zone, while Italy has ten). Accurately

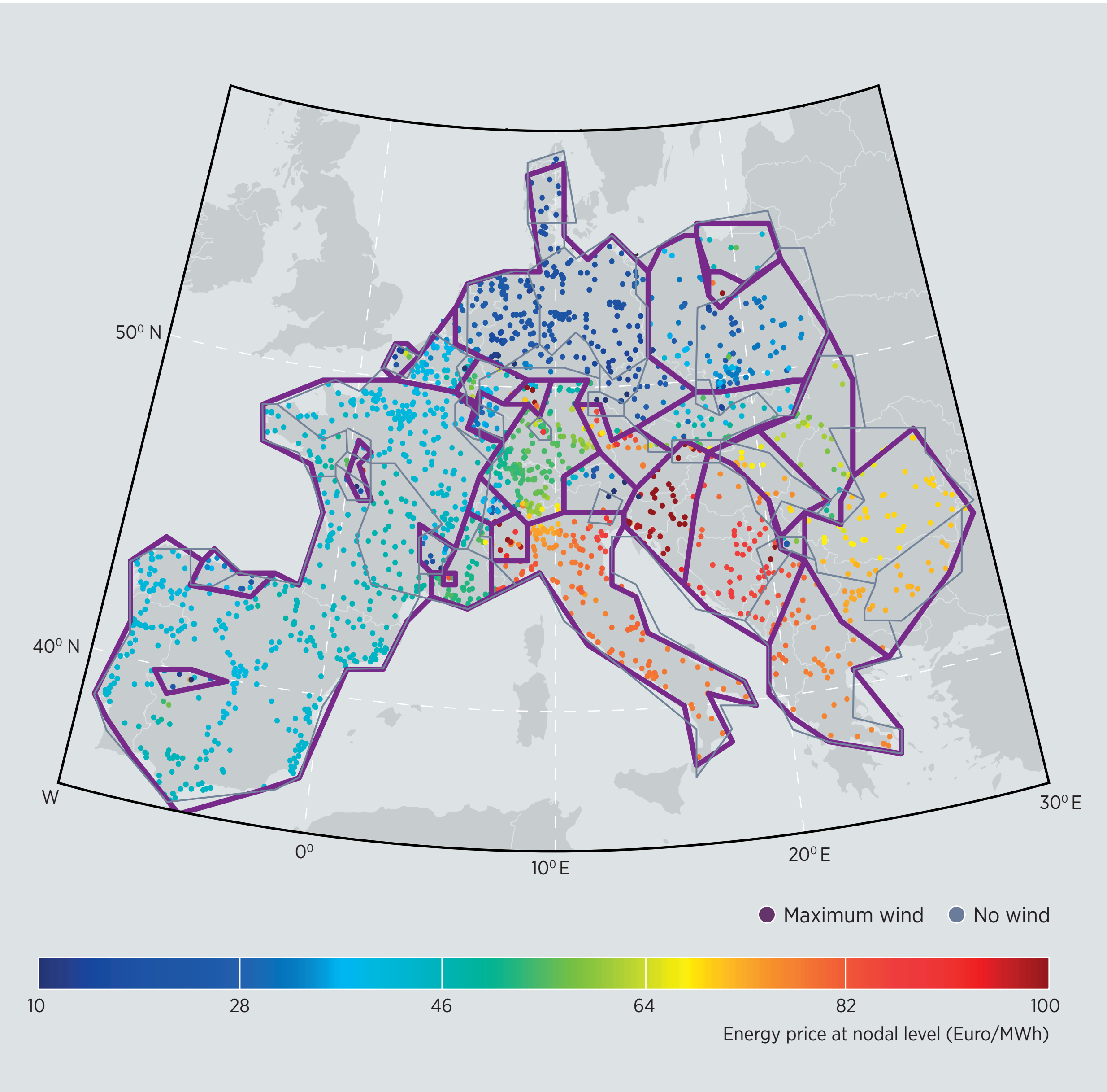
14. See, for example, Rivier et al. (2013).

defining stable zones is not a straightforward task. Zones do not match national borders and can change hour by hour alongside the changing supply/demand equilibrium. An example is provided in Figure 2.11, where the effect of wind output on zone definition is shown.

With zonal pricing (as with single-node approaches that consider an entire grid as a single node), a re-dispatch may be necessary to solve congestions (this is true for all market segments). In the (supposedly) few cases in which grid constraints are detected, the system operator re-dispatches the system, determining which players must withdraw from the system and which are to be included. Energy removed to solve a network constraint may be paid at the respective agent's bid price (if a specific bid related to the constraint-solving mechanism is in place), at the opportunity price (the energy market price less the price of the agent's bid in the energy market) or not at all. When additional energy is requested, it is normally paid at the respective agent's bid price.

The pros and cons of nodal and zonal pricing have long been debated by experts and policy makers. Several issues are to be taken into account

Figure 2.11 Simulation of suitable zones for zonal pricing in Europe (maximum wind)



Source: Adapted from Neuhoff, 2015

when estimating the benefits of these two approaches: the efficiency of the resulting price signals (both in the short and long term), the computational burden and implementation costs, the hedging complexity and the impact on the liquidity of long-term markets and geographical consumer discrimination. In usually congested electricity networks, the benefits from nodal pricing seem to outweigh the disadvantages (Neuhoff and Boyd, 2011). On the other hand, in densely meshed grids, where power flows are easily predictable and significant congestion infrequent, zonal pricing does little to affect the efficiency of the resulting price signals. At the same time, larger bidding zones are believed to increase liquidity and competition, and zonal prices represent a more stable signal for investors and tend to be less discriminatory for consumers.

Nonetheless, many arguments used to support zonal pricing are questionable. In nodal markets, financial transmission rights can provide producers the long-term hedge required to sell their productions in forward markets to operators located elsewhere in the system; at the same time, end-consumer tariffs can be calculated using any geographical granularity, *i.e.*, averaging nodal prices, if the regulator considers this necessary for the sake of equity, which prevents exposing some end users to higher local prices. Probably the most relevant obstacles to the implementation of nodal pricing arise from institutional and governance issues. In the United States, market integration is challenging because of the required co-ordination among different institutions and harmonisation among diverse regulations. The challenge is even greater when market integration must take place across different countries, as in the European Union (see Box 2.5)

Next, we briefly discuss how, in most real-world cases, a high penetration of variable generation resources may aggravate the potential inefficiency of zonal pricing.

RES and the efficiency of locational granularity

The planning process in liberalised electricity systems may be more difficult than within vertically integrated utilities because decisions about generation expansion are the result of market forces influenced by policies and regulations rather than centralised planning.

When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process, thereby potentially discouraging investment in new generation. Since, in the vast majority of cases, it takes much longer to plan, get approval for and build a high voltage transmission line than it does to plan and build a wind farm or solar generating facility, transmission reinforcements are often significantly delayed.

Furthermore, in the case of wind, for example, the best and most efficient sites to develop projects are clustered around certain geographical areas.[15] Therefore, unless (and until) transmission scales at the rate of the new RES generation build, the transmission system will be increasingly constrained around these areas, requiring more accurate network representation. In this context, a shift towards a more detailed spatial resolution in the wholesale market, and therefore the use of nodal prices, may represent a useful solution.

2.2.3. Bidding formats: fitting new necessities and resources

A large deployment of VRE requires more complex bidding formats to guarantee an efficient economic dispatch. Bids may need to include an explicit representation of technical constraints, as done, for instance, in the US ISO market model.

As illustrated in this chapter, the variability and partial unpredictability of the increasing amounts of RES that are being deployed in power systems increases complexity and uncertainty in the short-term scheduling process.

15. Relevant examples of onshore wind include Texas, where most of the wind mills are located in the west; Germany in the north and Romania in the southeastern region of the country, close to the Black Sea. Obviously the problem of geographical location is even greater in the case of offshore wind.

Box 2.5 Market integration in the European Union

Market integration is a key driver to promote overall efficiency and foster competition in the EU electricity market.

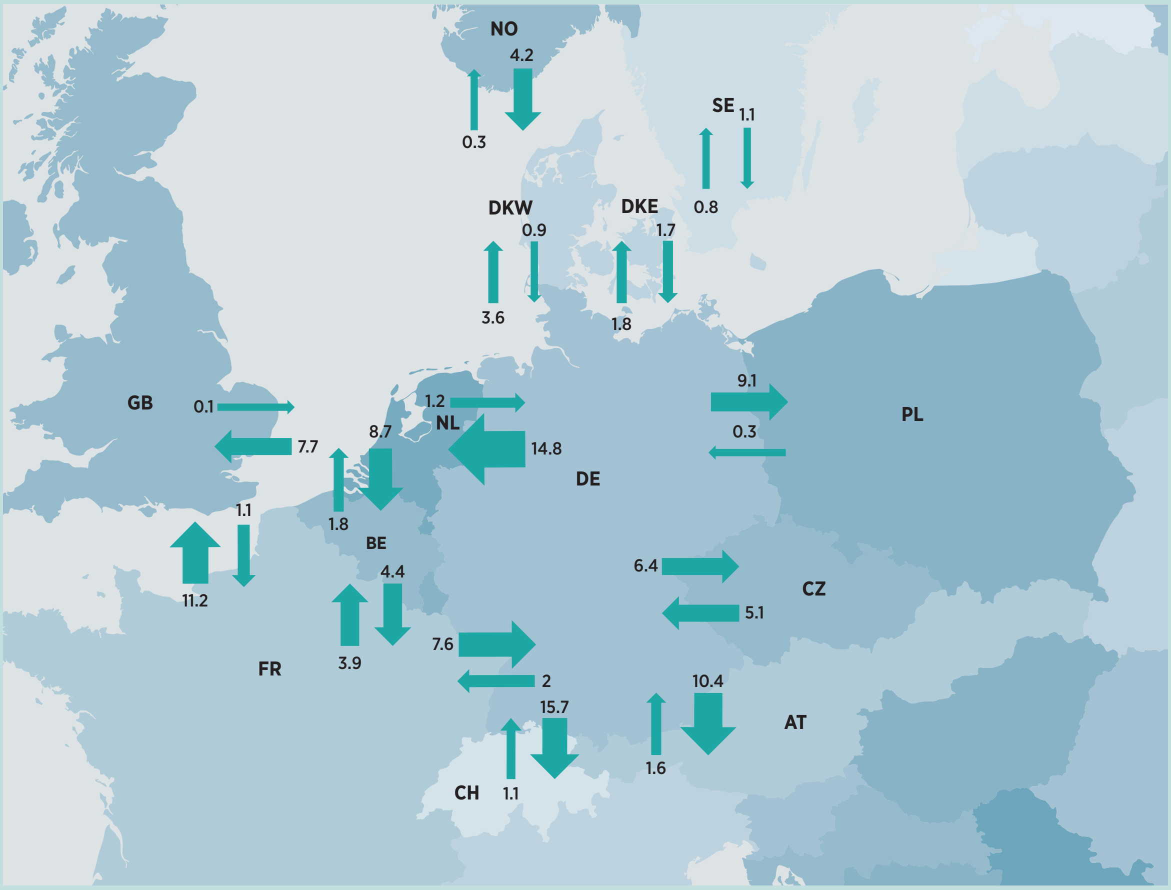
The EU electricity market consists of a number of interconnected markets. A deep coordination among them is needed to maximize the efficiency obtainable through cross border trade between market areas, given the available interconnection capacity.

Figure 2.12 shows electricity flows between EU markets in the Central Western European (CWE) region, driven by the corresponding cross-border trades, in 2016.

To promote efficient cross-border trades, seven European Power Exchanges developed an initiative (price coupling of regions, or PCR) to develop a single price coupling solution to be used to calculate electricity prices across Europe and efficiently allocate cross-border capacity on a day-ahead basis.

It must be noted that market integration is an issue not just with regard to energy markets, but also with reference to the actions TSOs have to take to maintain the system secure.

Figure 2.12 Annual total of physical cross-border flows in the CWE region and at the German borders in 2016 (in TWh)



Source: Adapted from TenneT, 2017

Figure 2.13 shows the increase in inter TSO imbalance netting – which in turn corresponds to a reduction of the balancing actions required to maintain the systems security – made possible by a deeper inter TSO cooperation. To be more precise, figure 2.13 shows the results of the International Grid Control Cooperation (IGCC) currently consisting of 11 TSOs, the largest imbalance netting cooperation in Continental Europe. On 2 February 2016, the French TSO RTE joined the IGCC. As shown in Figure 2.13, inclusion of this large Load Frequency Control Block has resulted in a significant increase of the netted volumes.

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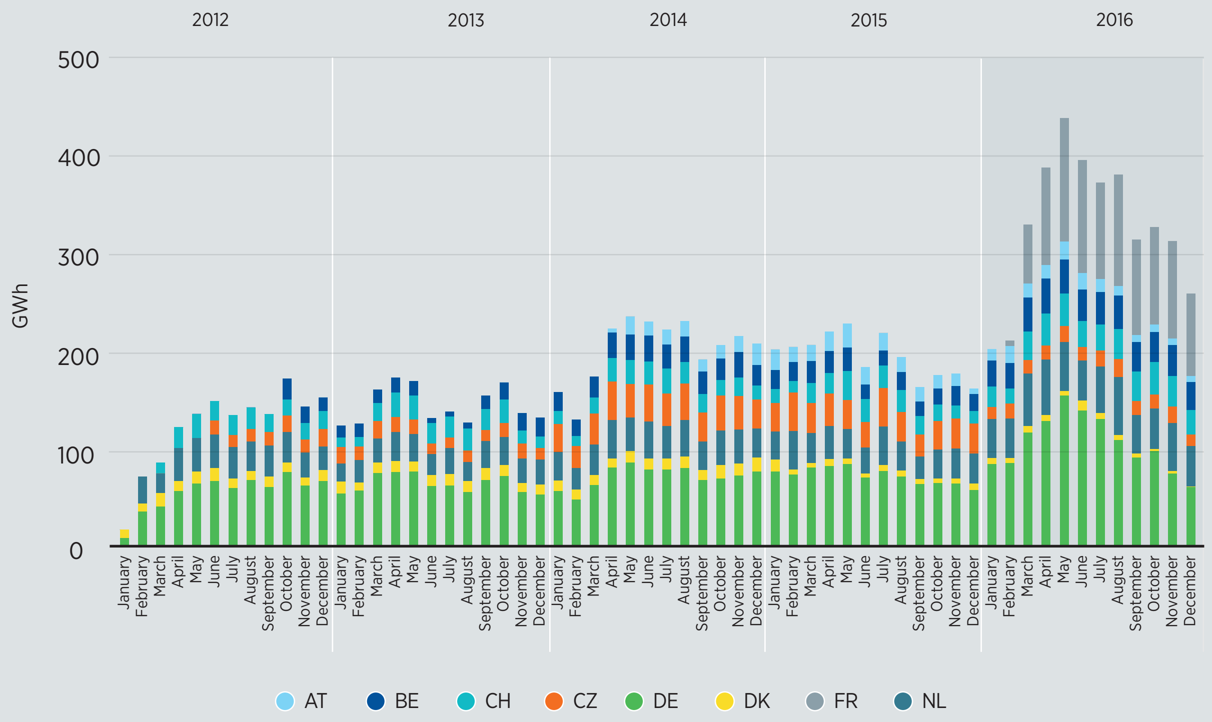
Figure 2.13 Monthly volumes of netted imbalances for all IGCC members for the imbalance netting process



Source: Adapted from TenneT, 2017

Short-term markets are nothing but tools that aim to help both market agents and system operators approach this objective in the most efficient way by optimising economic risk management for the former and achieving short-term reliability and security levels, a responsibility of the latter.

In this context, the format of the bids that market agents can use influences the ultimate market outcomes. The alternatives and the flexibility made available to market agents when building their bids is central to allowing them to reflect their true costs and the physical constraints of their generation units on the energy market. Bidding formats differ from one market to another, and they can range from a simple price-quantity hourly bid (indeed, 24 price-quantity hourly bids) to a complex declaration of technical and economic constraints.

While the optimal design of bidding formats has been an open question since the creation of electricity markets, it has recently been revealed as a critical subject that needs to be revisited. Again, we find two major approaches to the bidding format design: 1) the more complex ISO bidding format (used in the United States) (see Box 2.6), and 2) the simpler PX format (used in the European Union).

ISO bidding format and increasing penetration levels of RES

In the US, in principle, increasing the penetration of RES need not significantly impact the complexity of the format applied to existing resources since the model is already based on complex and detailed (multipart) offers. That being said, enhanced modelling software, made possible by developments in computing technology, has allowed a progressive increase in modelling detail (O'Neill *et al.*, 2011).

Where the model has to be further refined is in integrating new resources, particularly those with characteristics that differ from the status quo. This calls for a larger number of bidding formats tailored to the needs of these new resources. For example, in the relevant case of de-

Box 2.6 **Bidding formats in the US ISO market: multipart offers**

Independent system operators (ISOs) require generators to submit multipart offers aimed at representing the detailed operational (and opportunity) costs and also the technical constraints of their generating units. Table 2.2 lists several typical offer components used while modelling a conventional generator, with the aim of defining the economic dispatch in the most efficient way.

Other bidding formats have also been implemented for different types of resources, such as multistage resources (combined cycles), intermittent generation, pumped-storage hydropower units and other storage units.

Table 2.2 Typical multipart offer structure in ISO markets

Operating costs		Technical constraints	
Energy offer curve Piecewise linear or stepwise linear function with multiple MW/Price pairs	**MW, $/MW**	Economic min Economic max Ramp rate	MW MW MW/hour
No-load offer	**$/hour**	Min/max run time Min downtime	hours, min hours, min
Start-up offer Available for different types of start-ups (hot/intermediate/cold)	**$**	Notification time Cooling time Start-up time	hours, min hours, min hours, min

Note: Small storage, typically electrochemical storage, is in many cases only allowed to provide secondary frequency control reserves (regulation).

mand response, as pointed out, for example, by Liu *et al.* (2015) "the bidding system does not always provide a mechanism as an alternative to the price-quantity bid format for consumers to express their willingness to adjust consumption, particularly in response to price signals". For instance, an industrial consumer may need a certain number of consecutive hours of supply, but is willing to shift this period according to the market price. This willingness cannot be expressed as a simple quantity-price bid during each hour; it needs a complex bid format.

A similar difficulty is related to the consideration of storage technologies, as uneconomical schedules can often occur using current bidding formats. For example, they often have to define *ex ante* (before knowing the market prices) both the periods when they want to act as producers and those when they want to procure energy as regular demand. This was simpler to predict in a power sector with stable and predictable dispatches, but it becomes quite risky when the high penetration of variable technologies can unpredictably alter the price.

The main obstacle to creating more complex bidding formats is the computational complexity of the associated optimisation model. This limiting factor is not as relevant to the EU model.

The EU power exchange approach: the complexity of prioritising simplicity

As pointed out in the beginning of this chapter, most European markets were designed with the explicit aim of reducing – as much as possible – the intervention of the system operator. Concurrent aims include: releasing market agents from the need to buy and sell through a compulsory pool (a market model that centralises all

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trades and covers its costs through fees to market agents), decoupling the format of bids from plants' technical characteristics (costs and constraints), and postponing as much as possible the market gate closure.[16]

Day-ahead markets in European power exchanges were originally, and at least in theory, envisioned as simple electricity auctions, where most agents would submit price-quantity offers and bids.

The reality is not as straightforward. For simple bids to be utilised in a context where the laws of physics play such a strong role, market agents must anticipate the resulting dispatch and internalise all operational costs and constraints, a task that, to be properly fulfilled, requires that market conditions be possible to predict (the lower the size and diversity of the portfolio of plants each market agent manages, the harder this task).

The increasing penetration of RES has increased uncertainty in the dispatch, making accurate predications more difficult. This calls for bidding formats that allow for greater complexity and reduce the burden for market agents. In response, as seen in the Box 2.7, each PX has progressively incorporated so-called block orders and semi-complex orders, (rather than the multipart formats used in the US ISOs).[17]

Box 2.7 **Bidding formats in European power exchanges**

European power exchanges use the EUPHEMIA market-clearing algorithm in their day-ahead market to support the different bidding formats used by each market operator. Simple bids can be used in all bidding areas, but depending on the market operator, agents can represent some operational constraints and economic conditions using block orders or complex conditions (see Appendix: EUPHEMIA, the pan-European market clearing algorithm).

Block orders basically entail an all-or-nothing constraint, representing the willingness of an agent to sell/buy some amount of electricity at a given price, but only if this amount can be sold/bought fully. Additionally, several block orders can be combined to create more complex products.

The main goal of the new bidding formats is to allow PX participants to hedge their risk against a wrong estimation of market conditions (and thus minimise the risk of being scheduled in ways that imply additional costs), while at the same time ensuring that auctions are transparent and competitive. This allows market agents to build strategies that somehow internalise the potential impact of the physical and economic constraints of their portfolios in a more effective way than just through simple price-quantity bids.

Early on, the use and impact of these complex and block bids was rather irrelevant. A simpler approach was thought to ensure greater transparency of clearing results. Today, the uncertainty that market agents face when building their bids has significantly increased, mainly due the higher shares of variable renewable energy, and therefore the use of complex and block orders is on the rise (see Box 2.8).

It is often argued that an increase in uncertainty and a lack of more accurate bidding formats are not necessarily problems if sufficiently liquid and thus efficient intraday market sessions follow the day-ahead market auction. Certainly, as we have seen, the role of intraday sessions is relevant to allowing market agents additional resources to readapt the schedules resulting from the day-ahead market clearing, but this argument is not without challenges.

On one hand, the algorithmic complexity of the EU clearing mechanism does not handle large amounts of block bids well, the reasons for which will be reviewed in the next section. On the other hand, market agents may in the future need to combine increasing amounts of block orders in order to reliably represent their characteristics and hedge against different potential scenarios (see Appendix). This has led the current approach to be questioned since the number of block orders can become impractical. In other words, properly hedging against all potential market outcomes may require bidding on an extremely large number of block orders. For this reason, one of the root principles of EU PX is being reconsidered: the key idea is whether the algorithm performance may be improved by us-

16. These and related aims are particularly apparent since the implementation of the New Electricity Trading Agreements.

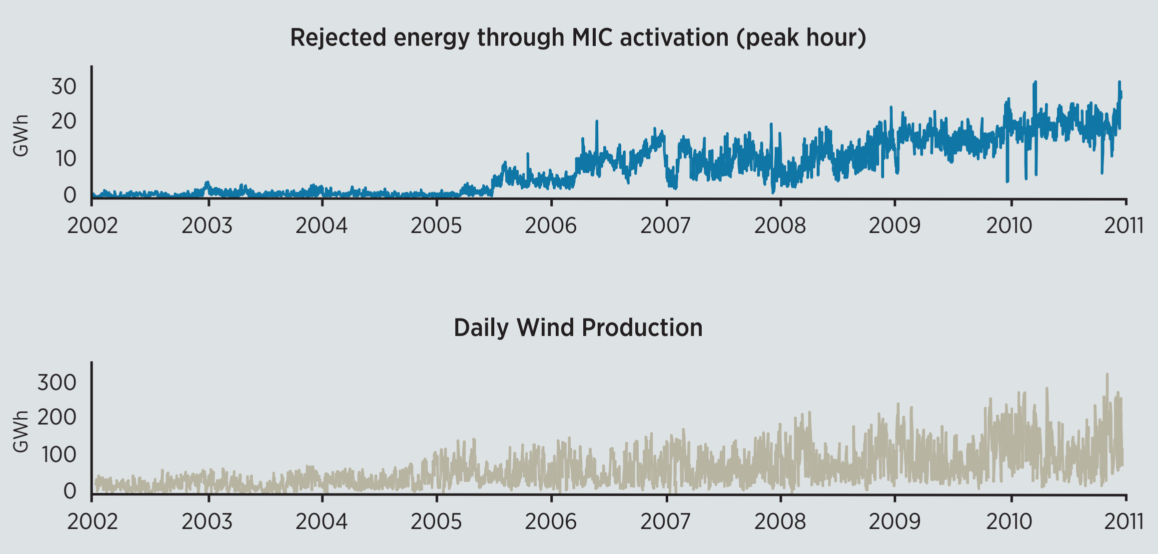
17. In some cases, the block and complex conditions were already implemented in the initial market design.

Box 2.8 Empirical evidence of the growing role of complex conditions and block bids in EU power exchanges: the case of Spain

Figure 2.14 illustrates how, even in a power market with a relatively large amount of hydropower reservoir resources, the impact of complex conditions (in this case the minimum income condition, or MIC[a]) increased alongside wind penetration (Vázquez *et al.*, 2014). The graph shows how, until 2005, the Spanish market cleared and behaved as a simple auction; the number of offers rejected during the clearing process because of the MIC condition was close to negligible. Starting from 2006, however, due to the increased penetration of wind resources and the consequent increased variability in the daily dispatch (more cycles and ramps for thermal units), the MIC conditions started being activated much more frequently. Many bids were rejected since the total income did not reach the specified minimum.

It can be argued that when the amount of offers rejected by the algorithm becomes large, the efficiency of the market results can be put into question. A market clearing based on multipart offers (as in the US ISOs) probably would not reject (all of) those bids and would minimise the overall cost of supply. Indeed, multipart offers allow producers to properly represent the technical constraints and the cost structure of the different types of plants. Conversely, block bids seek to allow for only an extremely simplified representation of those constrains, precisely with the risk of completely rejecting the offers of some plants that, if they could offer multipart offers, would have been cleared for an efficient subset of hours. In recent years, the number of complex conditions used by agents has remained relatively constant (PCR-ESC, 2015).

Figure 2.14 Evolution of the activation of the minimum income condition and wind production



Source: Adapted from Vázquez et al., 2014

a. As defined by the Spanish market operator, OMIE "sellers may include, as a condition governing the electricity sale bids they submit for each production unit, that the bid in question is only to be considered submitted for matching purposes if the seller obtains a minimum income. The minimum income required shall be expressed as a fixed amount in €, and as a variable amount expressed in €/MWh" (Omel, 2001).

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ing resource-specific bidding formats that would only require one (multipart) offer per resource, in line with the ISO approach already reviewed.

As pointed out at the beginning of this section, one alternative – recently supported in PCR-ESC (2015) – is to resort to multipart offers. This approach involves greater complexity than blocks or complex orders, but it is preferable if the multipart offer is able to replace multiple blocks. However, the EUPHEMIA provider has pointed out that including such a bid would involve a significant change in the market design and pricing and clearing rules, a design element which will be analysed in the next section.

2.2.4. Pricing and clearing rules

More complex markets require modifications to clearing and pricing models.

Of the two main approaches to pricing rules and clearing – those of the US ISO (dispatch-based pricing plus discriminatory pricing) and the EU PX (price-based dispatch) – the best option might be some point in between.

The key economic theory at the basis of electricity market designs is marginal pricing remuneration for generation. Under this principle, at each point in time, electricity is supposed to be valued at the marginal cost of producing (or not consuming) an additional unit of energy. Ideally, this has two benefits:

- First, the marginal price supports the welfare maximising solution.[18] That is to say, accepted bids are sufficiently compensated, and rejected bids are not profitable at the marginal price.
- Second, settling the transactions of all agents at the same price (uniform pricing) sends an efficient signal for bidding true costs and for optimal investment over the long term (the main argument in favour of the energy-only market approach to ensure resource adequacy).

These characteristics hold only under certain assumptions, including the absence of economies of scale in generation and the absence of "lumpy decisions" (Hogan and Ring, 2003), stemming, for instance, from "lumpy costs" (*e.g.*, start-up costs) or "lumpy constraints" (*e.g.*, all-or-nothing commitments or minimum outputs).[19] In reality, electricity markets present multiple and unavoidable lumpy decisions.

In the US ISO model, multipart offers contain both lumpy costs and lumpy constraints. In the EU contexts, simple bids do not introduce "lumpy decisions" but block bids and other complex conditions do. Thus, it is mathematically impossible to find uniform prices that support the welfare-maximising solution (Scarf, 1994).

Practical implementation of marginal pricing therefore includes modifications that accord more or less priority to the two above-mentioned objectives. Two real-world examples follow.

- Optimal-dispatch-based (marginal) prices: The volumes accepted on the market are those of the welfare-maximising solution (optimal dispatch). However, a discriminatory pricing rule must be applied to guarantee cost-recovery. Marginal prices (*e.g.*, hourly) are calculated, but some agents may have to pay/receive an additional lump sum (uplift) to avoid cleared bids that would be at a loss if only marginal prices were considered. This approach sacrifices efficient price signals for short-term operational efficiency.
- Uniform-(marginal)-price-based dispatch: A uniform pricing rule constraint is imposed; *i.e.*, all transactions in a given period (*e.g.*, an hour) are settled at the same price. The level of (uniform) market prices in the various hours of the day must therefore be such as to include – not necessarily in a perfect way – the impact of lumpy constraints and costs. This price constraint requires that the market solution deviate from the most efficient (social welfare maximising) dispatch.

18. Ventosa et al. (2013) define welfare maximisation as the "overall minimisation of system costs while respecting reliability and environmental objectives and constraints." See the same source for the economic formulation of social welfare in the power sector context.

19. More exactly, the problem is the presence of non-convexities in the optimisation problem (the maximisation of the social welfare). These non-convexities arise, for instance, from the discrete "jumps" in the cost function of thermal plants, which have a constant variable cost, but only if a fixed start-up cost is incurred at the beginning of the commitment period.

Box 2.9 Illustrating the need for uplifts

A plant submits an offer to the independent system operator (ISO), including its variable cost per megawatt hour (MWh), along with other costs such as start-up and no-load costs. Once the plant has been committed, its variable costs and the variable costs of other committed resources are the basic drivers of the marginal price and the dispatch level of the unit.

Absent other constraints (such as ramps), when the price is greater than the variable cost, the resource is dispatched at the maximum output, and when the price is less than the variable cost offer, the plant is either shut down or operated at its economic minimum (depending on whether it makes sense economically to de-commit the resource).

This setting illustrates two clear situations where the market price may not be sufficient for the unit to recover its short-term operation cost:

- If the unit is marginal, then the price is equal to its variable cost, and the unit will not recover its start-up and no-load costs.
- If the unit is committed but dispatched at the economic minimum, then the price is lower than its variable cost (since the unit is not marginal), and the variable cost is not fully recovered through the market price.

In these cases, and others, the resource needs to receive an uplift payment in order to be dispatched at the optimum level, as determined by the ISO, without losing money.

Next, we analyse the challenges involved in each particular approach and possible solutions being explored today.

Pricing and clearing in the United States: The optimal-dispatch-based pricing approach

In the United States, the ISOs first calculate the optimal dispatch and then compute prices based on the marginal cost of the system. On the basis of these prices, uplifts are calculated to compensate generators incurring costs above the revenue earned through market prices. See Box 2.9 for an illustrative example based on Bresler (2014).

Uplifts are unavoidable elements of the dispatch-based pricing system required to support the welfare-maximising dispatch. The underlying problem is the fact that not all costs incurred are embedded in uniform market prices, which alters the correct signals.[20]

The problem with energy uplifts

Resorting to uplifts not only prevents prices from reflecting the full cost of the serving load, but its associated cost has to be somewhat arbitrarily allocated to energy consumers. Currently, the uplift calculation involves only the generation side of the market, taking advantage of the fact that, because of demand-side inelasticity, it can be determined *ex post* and then socialised. In a context of active demand participation, the uplift allocation should be incorporated in the market-clearing process to be consistent with the demand side as well.

As already mentioned in the previous section, one of the effects of RES penetration in electricity markets is the increasing need for complex bidding formats, which aggravate the pricing problem. In the ISO context, this problem has recently attracted a lot of attention (see Box 2.10), and ISOs are undergoing design improvements aimed at reducing uplift. Proposed solutions attempt to internalise all costs in market prices as much as possible – in other words, to approach uniform pricing. This represents the increasing importance of short-term market signals needed for efficient generation investment and the development of demand-side resources (Hogan, 2014).

Pricing and clearing in the European Union: Uniform-price-based pricing approach

Although one of the claimed objectives of the EUPHEMIA clearing algorithm is the maximisation of social welfare, the algorithm considers two major rules to be fulfilled that condition the clearing process and thus the corresponding associated social welfare:

- The single marginal pricing rule entails that uniform market prices (without uplifts) must suffice to compensate all accepted bids.

20. This is instrumental, in theory, to leading long-term market decisions towards the optimal capacity expansion (see Herrero et al., 2015).

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Box 2.10 Uplifts: an increasingly relevant problem in some US systems

The Federal Energy Regulatory Commission (FERC) initiated a docket to improve price formation among US independent system operators (ISOs). This docket identifies uplift as a major problem (FERC, 2014a):

> *"Use of uplift payments can undermine the market's ability to send actionable price signals. Sustained patterns of specific resources receiving a large proportion of uplift payments over long periods of time raise additional concerns that those resources are providing a service that should be priced in the market or opened to competition".*

Uplifts can occur for many reasons; the three primary ones in ISO markets are: 1) the operating costs of some resources are not reflected in prices (the case reviewed in Box 2.9); 2) inflexible resources, such as the so-called block-loaded units, are committed and 3) unmodelled system constraints make necessary subsequent redispatches commanded by the ISO (FERC, 2014b).[a]

While uplift cannot be completely eliminated, it can be largely reduced with appropriate market design, as stated by Pope (2014):

> *"Uplift is a symptom rather than a cause of price formation problems, though, and efforts to improve pricing should focus on correcting the causes".*

Such causes are varied, and the solutions will affect very diverse parts of the market, but, undoubtedly, a key element is the method used to compute prices. A widely debated solution is the so-called extended locational marginal pricing, which in the literature is known as Convex-Hull pricing (Gribik *et al.*, 2007). Essentially, this method would produce hourly prices that better reflect the full cost of producing electricity (*e.g.*, internalising the start-up and no-load costs).

a. Inefficient price distortions become particularly evident for the case of block-loaded (or fixed-block) units, which are those that only operate economically at full load. Fast-start gas turbines generally lie in this category. When these units are committed, other units have to be dispatched down to accommodate the full output of block-loaded units. If block-loaded units are treated as non-dispatchable by enforcing a minimum economic output constraint, they cannot set marginal prices and, therefore, require uplift payments to recover their operational costs.

- Simple bids are given preferential treatment (over complex and block bids): if the market price is above a simple bid price, the bid always has to be fully accepted (in the terminology used by EU PXs, "simple bids cannot be paradoxically rejected").

In the presence of "lumpy decisions", these two rules make the market-clearing results deviate from those obtained in the US ISO model. Box 2.11 (based on Olmos *et al.*, 2015) offers an example of how these two rules may affect market results and divert them from those obtained in the US ISO model. The example is based on a block-loaded plant. As was noted in Box 2.10, inflexible resources are among the major reasons why uplift is needed in the United States.

The European market-clearing mechanism makes the short-term dispatch of generation units deviate from the welfare-maximising dispatch. As argued before, however, this is a matter of trade-offs, and in the European context, uniform pricing is considered an objective worth the loss in short-term cost efficiency (or, more generally, welfare maximizing). One of the advantages of uniform pricing is that demand and generation interact on the market in equal terms, and it is not necessary to define rules to allocate uplift that would inevitably send inefficient signals.

The European approach does, however, present some problems that compromise the sustainability of this model, namely: 1) the complexity of the algorithm limits the amount of complex and block orders that can be handled in practice; 2) a certain lack of transparency in the algorithm being used; and 3) the inability of some units to set the market price.

Computational complexity

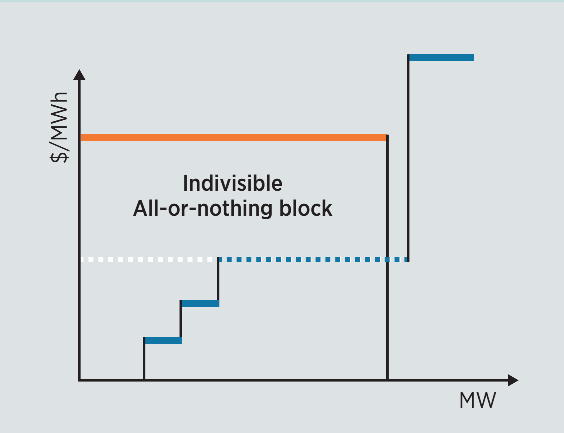
One of the major practical downsides of the EU approach is that integrating clearing and pricing in one step is inevitably a problem harder to solve

Box 2.11 Illustrating the difference between the US and EU pricing and clearing

Consider a one-hour market setting and an inflexible block type of plant. To illustrate how lumpy decisions are dealt with in the EU and US approaches, it is useful to consider the market setting represented in Figure 2.15.

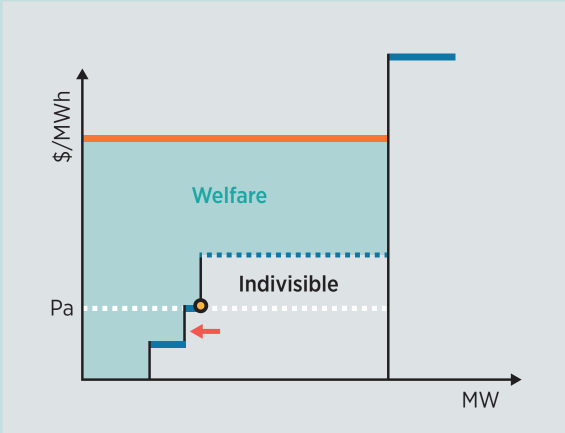
Within the generation bidding curve (in blue), we introduce a block order (dotted line). This is an all-or-nothing type of bid that is either completely matched or completely rejected. The marginal price is the cost of supplying a marginal increment in demand, and it corresponds to the variable cost of the margin unit, *i.e.*, the unit in the position of supplying such marginal increment. Because of the block-order condition, the bid represented with a dotted line will never be marginal, for it cannot "marginally" supply an additional MWh of demand due to its inflexible nature.

Figure 2.15 Pricing and clearing in the presence of lumpy bids



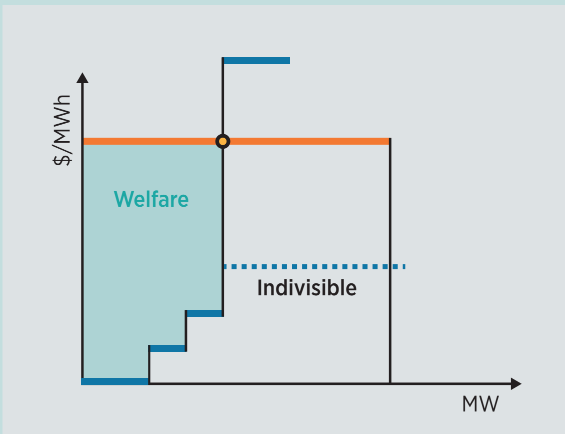
In the United States, the welfare-maximising dispatch requires reducing the production of a cheaper flexible plant to make room for the indivisible bid. Since the indivisible bid cannot be marginal, the price in the market is set by a lower-price bid (*Pa* in Figure 2.16). With such a price, the block-loaded plant would not recover its short-term productions costs. Thus, the need for an uplift. In the figure, the orange horizontal line represents the price of the demand bid (a single inflexible demand bid is considered). As explained in Ventosa *et al.* (2013), the social welfare can be represented as the area contained between the cleared demand curve and the cleared offer curve (green area in the figure 2.16).

Figure 2.16 Result with the ISO model approach



In the EU Price Coupling of Regions (PCR), EUPHEMIA also seeks to maximise the welfare, but at the same time it has to comply with the two rules previously outlined: the uniform market price (no uplifts allowed) and the full acceptance of simple bids if the bid is below the market price. Since the indivisible block needs a price equal to or above its offer to be accepted, it is not possible to partially accept any simple bid below that price. As a consequence, the algorithm rejects the block order. This leads to the dispatch depicted in Figure 2.17: the most expensive bid cannot be accepted because it exceeds the price of the demand bid. Therefore, only part of the demand will be supplied, and the price is set by the partially accepted demand bid. As can be observed by comparing Figures 2.16 and 2.17, welfare is much lower with the second clearing approach.

Figure 2.17 Result with the EU PX model approach



Source: Olmos et al., 2015

than the economic dispatch problem followed by an *ex post* price (van Vyve, 2011).

This led some PXs in the precoupling era to limit the amount of block orders that could be used. Further developments in computing and solving techniques allowed for an increase in the number of block bids that could be handled, as well as the introduction of new block bid formats. The increasing use of these formats is, however, threatening the sustainability of this approach.

Transparency

The EUPHEMIA algorithm has to deal with a difficult combinatorial problem: deciding which complex and block orders are accepted and which are rejected. How EUPHEMIA accepts and rejects the orders is reason for debate. It is difficult to justify why some orders are rejected by the EUPHEMIA algorithm when the prices would not allow them to be accepted at a loss (these are the paradoxically rejected blocks, or PRBs; for example, the indivisible block in Figure 2.17 is rejected even if the clearing price is higher than its offer). In PCR-ESC (2015), the Market Parties Platform (MPP) pointed out that: "There may exist false PRBs: rejected in-the-money blocks that could have been accepted and result in a better (higher welfare) solution. MPP asks for more transparency on optimality, to prove the absence of false PRBs".

This is linked to the computational complexity problem, which has led to a complicated clearing algorithm. The public documentation of the market-coupling algorithm (PCR PXs, 2016) is not completely detailed. The joint response of ACER and the Council of European Energy Regulators (ACER-CEER, 2015) to the European Commission's Consultation on a new Energy Market Design stated: "We would particularly like to see clearer rules and greater transparency around the market coupling algorithm (EUPHEMIA)".

Not all units can set the market price

According to the authors' best interpretation of the public description (PCR PXs, 2016), the European pricing rule also suffers one of the pricing problems we have seen in the US model: inflexible block bids cannot set the market price. This is confirmed by the thorough analysis carried out by Eirgrid *et al.* (2015), who stated:

"The effect of defining an order as a block is that the order cannot then be a full price maker. Rather, block orders may impose a bound on the range of prices possible while the price being set would still need to come from the simple order or complex order curves. This is because the decision to execute the order is an integer decision (i.e., the order is executed or not executed) and the decision on whether to accept a block occurs before the price determination sub-problem. The bound created by the last accepted block order would function to affect the price (by limiting possible values) but could not directly set this price".

"This was discussed with the PCR ALWG representative, APX, who confirmed that without the blocks setting the price, the price could only be set by other price makers, i.e., simple orders or complex orders, or the price indeterminacy rules of EUPHEMIA".

The European approach requires simple enough bids to ensure the price is representative of system costs. In a scenario where most bids are block orders, the market price will not accurately indicate the marginal cost of meeting the load.

Trends in US and EU pricing rules: towards a hybrid solution?

The problems highlighted in US and EU pricing rules share the same primary causes and could therefore benefit from similar solutions. To some extent, the novel pricing methods discussed in the US ISO context can be seen as a middle ground between the reviewed US and European approaches.

While the trend in the United States is to advance towards a hybrid solution, this possibility is generally ignored in Europe, where current efforts concentrate on improving the computational performance of EUPHEMIA in order to cope with the increasing number and complexity of the bids that are used. However, it seems that more radical solutions may be needed to decidedly solve the complexity issue. In this respect, three long-term solutions are pointed out in PCR-ESC (2015):

- Reduce the amount of block types and other complex products allowed per participant and market (bidding zones).
- Reduce the range of products treated in EUPHEMIA.
- Relax the uniform price requirement (accept that the result has more than one price per bidding zone and time period).

Among these, only the last one really tackles the root of the problem. In this regard, one of the alternatives being discussed is proposed in van Vyve (2011), whose model resembles the ISO approach in that it uses the welfare-maximising solution and compensates committed units at a loss through uplifts.

2.2.5. Rethinking reserve requirements and procurement

System operators need to implement new solutions to improve the reserves supply function in such a way that they are priced according to their real value.

At the same time, energy and reserve markets need to be properly connected in order to allow the former to reflect the actual value of the latter.

Short-term energy markets produce dispatch instructions that are very close to the actual delivery of energy. However, the final power plants' output or the demand consumption can deviate from these commitments. This calls for last adjustments during real-time operation, which can either be made automatically or by command of the system operator using different types of operating reserves (also referred to simply as reserves).

An operating reserve is defined by NERC (2015) as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection" and is typically divided under primary, secondary and tertiary frequency control.

Although operating reserve requirements are a regular requisite in electricity systems, defining these requirements for security reasons is a clear but well-accepted intervention of the central planner (the system operator in this case). The system operator (See Box 2.12) needs to ensure the availability of a certain level of operating reserves to tackle unpredictable short-term events and avoid forced curtailment or cascading failures in the system.

Two interdependent products

The values (prices) of reserves and energy are mutually dependent. The fact that generation plants can offer one or the other product links the value of reserves with the opportunity cost of providing energy, and the other way around (Stoft, 2003).

Because of this interdependence, if the objective is to provide accurate short-term price signals, it must be taken into consideration that both the requirements and the procurement mechanism (co-optimised or not) for operating reserves matter.

As discussed by Hogan (2013), in the face of efficiency, this calls for two relevant conditions in the market design:

- A proper definition of the operating reserve demand curve (ORDC) is needed. Roughly speaking, the ORDC needs to account for the real value that any amount of reserves has for the system.
- Energy markets have to reflect the opportunity cost of providing reserves and potential scarcities in the reserve product in such a way that the prices of the two products maintain a stable and transparent linkage.

We next analyse these two desirable requirements.

The operating reserves demand curve (ORDC)

System operators usually define a minimum contingency requirement for reserves. Below this minimum level of reserves, the load would be curtailed to ensure that the reserve target is met.

Usually, these quantity requirements are procured through market mechanisms. The demand

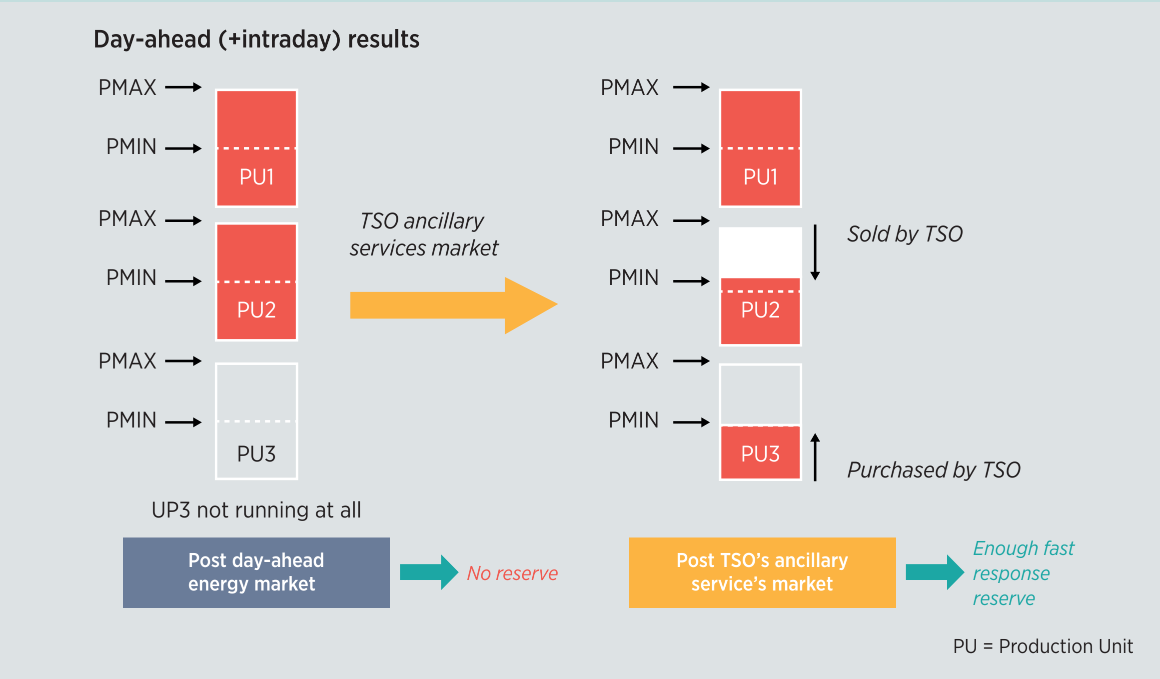
2

Box 2.12 **TSO's actions to ensure the availability of reserve resources**

One of the actions undertaken by the system operator in the ancillary services markets is to buy (sell) power from (to) specific power plants to ensure the availability in the system of sufficient spare resources capable of rapidly responding to dispatch orders in real time, so as to maintain the system balanced (see Figure 2.18 for sample).

Similar functions in US systems are carried out by the ISO through the reliability unit commitment, where the ISO adjusts the day-ahead market's schedules to take into account its load forecast and all security constraints, including the availability of adequate backup resources.

Figure 2.18 Sample of TSO's actions to ensure the availability of reserve resources



curve in such a market is completely inelastic,[21] *i.e.*, a demand bid is put for the entire quantity (equal to the contingency requirement) at a price equal to the value of lost load (VOLL). This means that the willingness to pay for each MW of reserve up to the minimum contingency level is set to the VOLL, while above this level, the marginal value of any additional MW is typically set to zero. The price for the operating reserve is then set according to supply bids from market agents. The inelastic demand bid on the reserve market reflects the priority that system operators assign to security over economic efficiency, potentially leading to over-procurement of operating reserves.

This minimum requirement and its value has been long debated in the literature. Stoft (2003), for instance, says in this respect: *"Operation reserves requirements, though based on sound principles, are rules of thumb that vary from one control area to another. Is it possible that each megawatt of operational reserve is worth U.S.$10 000 up to the requirement, but the next megawatt is worth nothing? Is it possible that there is no limit on what the system operator should pay to meet the last megawatt of the requirement?"*

Resorting to first principles, probably what is more questionable is the zero value above the minimum contingency level. As described by Ho-

21. An inelastic demand does not change its consumption behaviour depending on the price. In the reserve market, the price almost never reaches the VOLL level. Thus, in normal operations, reserves are procured up to the contingency level, no matter if their price is 10 or 1 000 USD/MWh.

gan (2014), whenever there is in real time a forced load curtailment, the value of having available additional amount of reserves (above the minimum contingency requirement) would correspond to the VOLL during that period.

At any previous time frame, such value would be probabilistic (based on the expectation of reducing the potential curtailment). In other words, the value of an increment of operating reserves would be the VOLL, but now multiplied by the probability that these additional reserves help reduce the curtailment.

This leads to an ORDC that has the shape of a loss of load probability (LOLP) function, at least above the minimum contingency level, as shown in Figure 2.19.

The effect of using such a curve would increase the price of reserves, and since the energy and reserve prices should be "connected" in properly functioning markets, the energy price would also increase. This connection is further explored next.

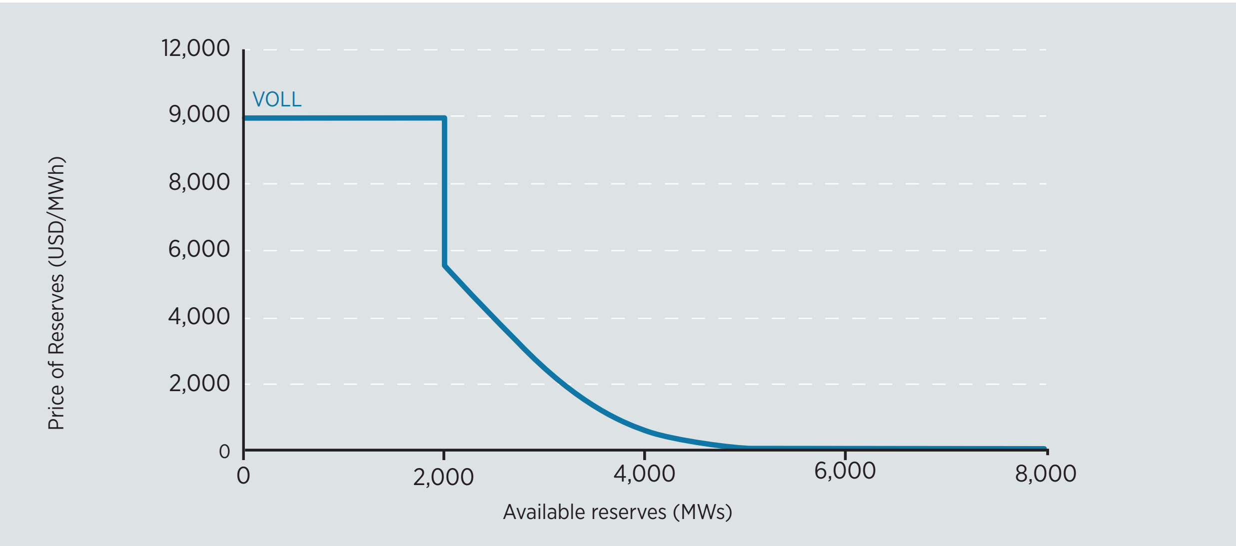
Designing the market to allow energy prices to reflect the opportunity cost of providing reserves

The co-optimisation of energy and reserves is the textbook solution that results in the appropriate valuation of energy accounting for the opportunity cost of providing reserves (and the other way around). This is the approach implemented in most US ISOs' day-ahead markets. However, the co-optimisation is not always carried out in the real-time market segment, where it is probably more important.

This is the case in ERCOT, where the market includes co-optimisation of energy and reserves to clear the day-ahead market, while the real-time market does not. This lack of co-optimisation has led to the connection between the ORDC and the energy market being implemented through the second-best approach – that of using a price adder to the energy price. This price adder aims at replicating, approximately, the outcome of co-optimisation (Hogan and ERCOT, 2013).

Figure 2.20, from ERCOT (2014), illustrates how the adder works and how it depends on the reserves available and the energy market price. On the one hand, the price of reserves depends on the quantity of reserves procured: the higher the price, the lower the quantity, with the price being USD 9,000/MWh for reserve levels below 2,000 MW. On the other hand, the adder that "connects" the price of energy with the price of reserves will depend on the gap between the prices of both products, and will therefore depend on the level of reserves and the price of energy. This way, for a reserve level below 2,000 MW and an energy price of USD 9,000/MWh, the adder would be close to zero (for the energy price is already reflecting the non-served energy price).

Figure 2.19 Operating reserves demand curve



Source: Adapted from ERCOT, 2014

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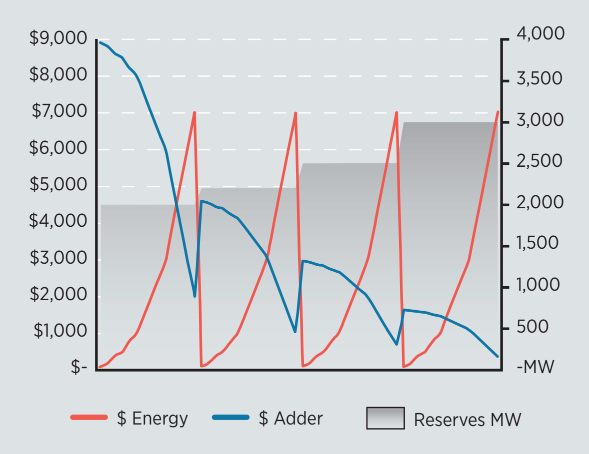
Figure 2.20 Price adder as a function of the energy price for different reserve levels



Source: Adapted from ERCOT, 2014

However, for a reserve level below 2 000 MW and an energy price of USD 2 000/MWh, the adder will be USD 7 000/MWh.

It is important to note that the value of the adder depends on the level of reserve available. Indeed, the adder's goal is to properly price the energy sold in the day-ahead market. It requires taking into account the system's scarcity, which in turn depends on the available reserve margin once expected demand is satisfied. Therefore, the value of the adder grows at the shrinking of the available reserve to reflect the higher risk of having to unintentionally disconnect the load.

Box 2.13 summarises the results of the backtesting (involving years 2011 and 2012) carried out in Texas to assess how energy prices would have changed had this operating reserve demand

Box 2.13 **Techno-economic analysis of the impact of implementing the ORDC in Texas (Backtesting for years 2011 and 2020)**

"The Public Utility Commission of Texas (PUCT) requested that ERCOT perform a back cast of an interim proposal that intended to be a more appropriate method of pricing reserves. The back cast approximated the pricing outcomes and estimated what the market impacts may have been if the solution devised had been in place for the years 2011 and 2012".

"The back cast analysis shows that the energy-weighted average energy price increases over a range of $7/MWh to $26.08/MWh in 2011 and $1.08/MWh to $4.5/MWh in 2012. This range results from different parameter settings that were used in the back cast. The back cast results for the average energy price increase with minimum contingency levels (X) of 1375 MW and 1750 MW are presented in Table 2.3. At the minimum contingency level, scarcity prices achieve the maximum allowed value".

Table 2.3 Energy-weighted average energy price adder (and online reserve price)

VOLL	Energy-weighted average price increase with X at 1375 MW (S/MWh)			Energy-weighted average price increase with X at 1750 MW (S/MWh)		
	2011	2012	2011 & 2012 combined	2011	2012	2011 & 2012 combined
$5000/MWh	7.00	1.08	4.08	12.03	2.40	7.28
$7000/MWh	11.27	1.56	6.48	19.06	3.45	11.35
$9000/MWh	15.54	2.05	8.87	26.08	4.50	15.42

Source: Hogan and ERCOT (2013).

curve been implemented with a co-optimisation of energy and reserves (Hogan and ERCOT, 2013).

In the European Union, as introduced above, there is a separation between energy markets and reserves markets. As briefly illustrated in the next section, they are sequential markets where agents can (and indeed do) withhold capacity from the energy market (though including in their bids the opportunity costs of providing reserves in the ancillary service market) to provide reserves.[22] This way, one market ideally reflects the opportunity cost of providing the other service. Unfortunately, in real life, the information is not perfect, and undesired deviations from an efficient outcome are likely.

Co-optimisation, although representing the first-based approach, would embody a major institutional challenge in the European Union today and so is not a realistic alternative.

The main problem with the EU approach is related to the timeline of the procurement of reserves. While there are frequent markets to procure and sell energy, reserve markets are not so frequent. Typically, reserves are procured in a single session, whose lead time varies from country to country (month ahead, week ahead, day ahead, etc.). This lack of frequent markets for reserves is a major drawback, preventing the effective contribution and participation of many RES and distributed energy resources (DER). Furthermore, procuring reserves exclusively in the long term may be inefficient because it does not allow for the complementarity between reserves and energy to be properly considered.

2.3. BALANCING MARKETS

Properly designing balancing markets is essential to ensure that:

1) Accurate incentives for flexibility are offered

2) All resources can effectively participate in offering their flexibility potential to system operators.

In the previous section, we discussed a multitude of issues related to day-ahead and intraday markets and introduced the concept of gate closure. After gate closure, the system operator must ensure overall system security and stability in real time, which calls for an instantaneous (in the order of seconds) matching of electricity supply and demand. Although RES obviously add complexity to this challenge, practical experiences have shown how power systems can be safely operated in real time with large levels of renewable production, provided that the system is prepared for this. The question today, however, is how to ensure this real-time security in the most efficient manner to better integrate large volumes of RES. In this respect, there is a total consensus on the key role of properly designing balancing markets and mechanisms.

Technological innovation allows variable renewable energy technologies to provide ancillary services, ultimately contributing to system flexibility and reliability (See Box 2.14). A well-designed balancing market should give incentives to all types of resources, including conventional generation, demand and RES, to offer their flexibility potential to system operators. Nonetheless, the regulation governing the provision of these services, hampers RES generators and DER from delivering them.

This section characterises the essential elements of balancing services and markets with a direct impact on the adequate integration of RES and DER resources, also highlighting best practices in their design. The section is divided into three parts: 1) the imbalance responsibility and settle-

22. *In some EU markets the sequence is the other way around – reserves are procured before the energy.*

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Box 2.14 Utility solar PV plant's ability to provide ancillary services to the grid

The technical capabilities of utility-scale PV plants to provide ancillary services have been known for a number of years. Such features have also been recently proven in commercial settings. A recent study on a 300 MW PV plant carried out by CAISO, NREL, and First Solar shows that the solar unit performance was able to meet the frequency regulation response usually provided by natural-gas-fired peaker plants. This is another demonstration of the contribution that utility-scale solar farms, equipped with advanced inverters and software controls, can offer to smooth out grid fluctuations, enhance system flexibility and reliability, and reduce needs in spinning reserves.

Source: CAISO, 2017

ment, 2) the definition of the balancing products and 3) the design of markets for procuring balancing reserves and their pricing and remuneration schemes.

2.3.1. Balancing responsibility and imbalance settlement

Dual imbalance pricing does not reflect imbalance costs and therefore distorts the real-time price signal.

How to define balancing responsible parties (BRPs) is a contentious issue when coupled with a dual imbalance pricing scheme.

When dual imbalance pricing is applied, portfolios to conform to a BRP gives a competitive advantage to large companies and introduces entry barriers to small providers.

Balancing responsibility

The imbalance responsibility and the imbalance settlement are two of the most important and controversial cornerstones of balancing mechanism design.

Imbalances are measured and settled at different aggregation levels depending on the system. In the EU context, the unit for settling the total net imbalances is known as the *balancing responsible party* (BRP). The imbalances from the programme declared at gate closure are measured and charged to these BRPs.

In the words of ENTSO-E (2014), *"in a liberalised market, the market players have an implicit responsibility to balance the system through the balance responsibility of market participants, the so called Balance Responsible Parties or BRPs. In this respect, the BRPs are financially responsible for keeping their own position (sum of their injections, withdrawals and trades) balanced or to help restore system imbalance over a given timeframe"*.

The allowed aggregation level for measuring imbalances conditions the quantities that are subject to imbalance charges (since imbalances within the BRP in opposite directions compensate each other). The criticality of the aggregation level will be explained later, as it is very much related to the adopted pricing scheme.

Imbalance settlement

The other element that completes the imbalance charges is the price to be applied. There are two major price schemes that can be applied to BRPs for their net imbalances: the single- and dual-pricing schemes.

In the single imbalance pricing scheme, imbalances are always settled at prices representing the procurement costs of the balancing services used by the system operator. This is the approach followed in the United States[23] and some EU systems (*e.g.*, Germany). With this mechanism, the price that the BRP pays when it is short and the price the BRP receives when it is long are the same for each point in time and space, and it is determined by the price of the balancing services. This way, settling imbalances results in a zero-sum operation for the system operator.

Sometimes, it is pointed out that the single imbalance pricing scheme can lead to speculative behaviour where BRPs may seek to deviate in real time to be remunerated for helping the system. System operators fear this potential behaviour

23. This is true, at least, for small imbalances. For large imbalances, depending on the system, there are additional, explicit penalties.

because, although it may help balance the system, it can also result in a situation where the TSO has to balance two imbalance origins: the original imbalance and the "speculation imbalance" if the BRP's imbalance estimation is wrong (SWECO, 2015).

The dual imbalance pricing scheme seeks to avoid the previous problem by reinforcing the incentives to prevent deviations from the gate closure programme. This scheme applies an additional penalty, on top of the price representing the balancing procurement costs, if the BRP deviation is opposite to grid needs. For example, if the BRP is short on production when there has been a negative system imbalance in real time, the BRP will not only pay the costs of the balancing services used by the system operator, but also a penalty. This pricing scheme avoids speculative behaviours, for, on average, the losses when penalised will not compensate the profits when the imbalance helps the system. This scheme also provides incentives, beyond the true short-term costs, to accurately forecast intermittent production at the gate closure.

There is a growing consensus that if the imbalance price does not exactly reflect imbalance costs, this distorts the real-time signal to agents and, therefore, may not provide correct incentives to encourage flexibility (Olmos *et al.*, 2015). That being said, if speculative behaviour is seen as a real threat, there is a second-worst alternative to dual imbalance pricing, which is not allowing parties to speculate under strict regulatory supervision. Such an approach is not recommended if it ends up artificially limiting market agents' range of action.

Defining balancing responsible parties when coupled with dual imbalance pricing

Defining BRPs is a contentious issue when coupled with a dual imbalance pricing scheme (if a single imbalance pricing is in place, the level of aggregation allowed does not interfere with market signals).

A dual imbalance pricing penalises imbalances, but a generation company can avoid imbalance charges by compensating the (positive or negative) imbalance with another plant within its BRP.[24] This gives a competitive advantage to large companies in comparison to smaller ones, and can effectively create a barrier to small DER providers and aggregators.

If dual imbalance pricing cannot be avoided, the BRP should be defined on a unit-by-unit basis, so as not to create these competitive disadvantages.

The reference market to measure imbalances

Imbalances in the real-time operation are usually measured with respect to the programme committed at the gate closure (roughly speaking, the last intraday opportunity in Europe and the real-time market in the United States).

There may be, however, additional penalties for deviating in real time from the programmes declared in previous market sessions, for example, for deviating from the day-ahead programmes. Using other markets can help allocate some system costs. Operating reserves are often procured precisely to deal with potential deviations from the day-ahead market. This is the approach of the cost allocation design implemented in some US systems, such as the Pennsylvania Jersey Maryland Interconnection (PJM). Such cost allocation provides additional incentives to provide accurate programmes in the day-ahead time frame, although it makes intermittent resources less competitive.

Balancing responsibility for RES

Traditionally, variable RES generation has been exempted from balancing responsibility in many countries. The main reason for exempting RES from this responsibility, and socialising these costs, has been to encourage RES generation by further reducing investor risk.

In the United States, the FERC issued Order 890 (FERC, 2007) that, among other things, revamped the energy imbalance provisions in Order 888. Order 890 basically provides a progressive scheme by which larger imbalances pay

24. However, depending on the mix available in the BRP, paying the imbalance charges may be more economical than self-compensating the imbalance.

2

larger imbalance charges, but also establishes softer conditions to protect RES.[25]

Reducing investor risk at the expense of distorted shortterm signals was considered an acceptable trade-off when RES volumes were small. But as volumes of variable RES generation increase, these aspects may become significantly hard to control. For this reason, there is a growing consensus on the need to make RES increasingly responsible for their imbalances. This is an important step towards the greater integration of variable RES.

Despite this global trend, there are still some countries that do not expose RES producers to balancing responsibility (See Figure 2.21 on EU countries).

Figure 2.21 RES balancing responsibility

Balancing responsibility for RES

Country	Balancing responsibility
Belgium	Yes
Denmark	Yes
Croatia	No
France	No
Germany	FIP Only
Ireland	Partly
Italy	Partly
Poland	Yes
Portugal	Yes
Spain	Yes
Sweden	Yes

Source: European Commission, 2016b

In several market designs, the calculation and pricing of imbalances may differ among conventional generation, consumption and renewable generation. Some countries, such as Italy, have opted for applying single pricing for variable RES and consumption, and dual pricing for conventional generation.

2.3.2. Balancing products

When designing balancing products, it is helpful to:

- *Define innovative products to unlock new flexible resource potential,*
- *Give different price signals to resources performing differently,*
- *Separate the procurement of, balancing energy, upward reserves and downward reserves,*
- *To the extent possible, avoid limiting participation based on size or technology*

Significant barriers to the participation of DER and RES in balancing markets can be found in the details of product definition. To properly understand this issue, it is helpful to review how balancing products are defined. Three criteria are relevant: 1) whether it is a capacity- or an energy-based product; 2) whether it involves an upward or downward balancing capacity/energy or not and 3) the time parameters involved.

Balancing capacity and balancing energy

Balancing capacity gives TSOs the possibility of activating a certain amount of balancing energy in real time. This refers only to capacity reserved in advance for its subsequent use in real time.

Balancing energy, on the other hand, refers to the actual variation of generation/consumption used in real time to fix imbalances.

Upward and downward balancing products

Upward balancing products are procured to compensate a lack of generation in real time (or an excess of consumption).

25 FERC Order 890 requires that imbalances of less than or equal to 1.5% of scheduled energy (or up to 2 MW) be netted monthly and settled at the transmission provider's incremental or decremental cost. Imbalances between 1.5% and 7.5% of scheduled energy (or between 2 MW and 10 MW, whichever is larger) are settled at 90% of decremental costs and 110% of incremental costs, respectively. Imbalances greater than 7.5% (or 10 MW, whichever is larger) would be settled at 75% of the system's decremental cost for overscheduling imbalances or 125% of the incremental cost for underscheduling imbalances. Intermittent resources, however, would be settled at 90% of decremental costs and 110% of incremental costs for imbalances greater than 7.5% or 10 MW (PJM, 2013). Apart from the previous regional applying regulation, additional RES exemptions can be implemented in each particular system. For example, under NYISO's market rules, if a variable generation resource is scheduled a day ahead, the resource must buy or sell deviations at real-time locational marginal prices. However, for up to 3 300 MW of installed wind and solar capacity, this generation is exempt from undergeneration penalties when its output differs from that scheduled in real time during unconstrained operations.

Downward balancing products are products procured to compensate an excess of generation in real time (or a lower-than-programmed consumption).

Type of response (time parameters)

In order to deal with disturbances, the system operator usually makes use of three types of balancing products in a sequential process based on successive layers of control (ENTSO-E, 2014). The names of these products vary by region:

- Primary (US) or frequency containment reserve (EU)
- Secondary (US) or frequency restoration reserve (EU)
- Tertiary (US) or replacement reserve (EU)

Box 2.15 shows some time parameters that are used to define the standard characteristics of the different products in the EU context (in the United States the parameters are similar).

Once the previous characteristics have been discussed, we focus on considerations to be taken into account in the design of balancing products to ease the integration of RES and DER (Olmos *et al.*, 2015; NREL, 2016). Subsections that follow draw recommendations for such design.

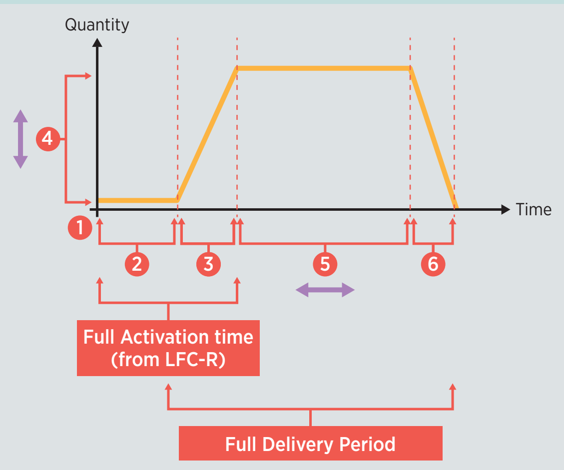
Innovative products to unlock flexible resources

The definition of new reserve products is a major discussion in the United States and in the European Union, both to unlock existing flexibility and also to allow new flexible resources to efficient-

Box 2.15 **Defining the characteristics of balancing products: The European approach**

Transmission system operators (TSOs) have to define at least the following standard parameters in accordance with the Network Codes on Electricity Balancing and Load Frequency Control and Reserves (LFC-R) to allow the exchange of balancing products (see Figure 2.22).

Figure 2.22 Standard characteristics of balancing products



Full activation time: The sum of [2] preparation period and [3] ramping period.

- [2] Preparation period: time required prior to delivery of the first megawatt (MW).
- [3] Ramping period: time when the bid is physically activated, delivers the first MW and approaches the requested power of the TSO. It is expressed in seconds if the bid is not divisible and expressed in megawatts per second (MW/s) if the bid is divisible.

Full delivery period: the sum of [3] ramping period; [5] minimum and maximum duration of delivery period and [6] deactivation period.

- [3] Ramping period: (as described above).
- [5] Minimum and maximum duration of delivery period: the time during which the balance service provider delivers the full requested power to the system.
- [6] Deactivation period: the time from the start of physical deactivation of the unit until the full instruction MW has been delivered; expressed in seconds if the bid is not divisible and MW/s if the bid is divisible.

Minimal duration between the end of deactivation period and the following activation, which allows time to recover the capacity to provide the service once again.

Other characteristics are as follows.

Divisibility: The minimum divisible unit of balancing energy expressed in MW for the divisibility of volume and expressed in seconds for the divisibility of the delivery period.

Validity period: The period defined by a beginning time (hh:mm) and an ending time (hh:mm), when the bid could be activated. The validity period is at least the full delivery period.

Mode of activation: Manual or automatic.

Source: ENTSO-E, 2014

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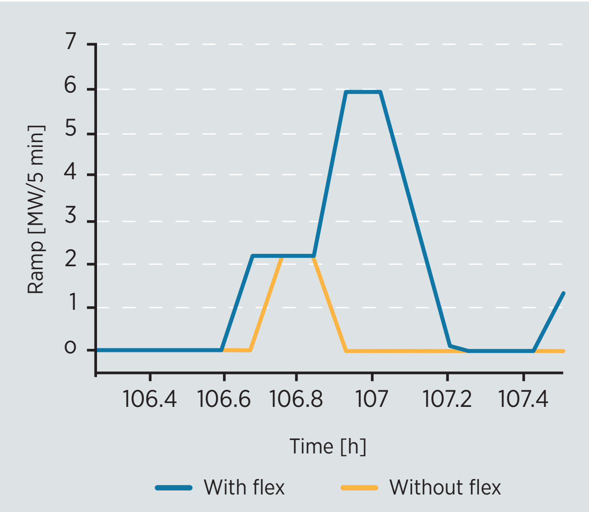
ly participate in electricity markets. The penetration of RES technologies increases the need for fast-ramping reserves, so this discussion is supposed to become more important in the future.

For example, pioneered by CAISO (Galiteva and Casey, 2015), there is a growing trend in the United States to consider introducing requirements for "flexibility reserves". As pointed out, these flexible reserves encompass a family of products that do not (yet) have a universal definition.

In CAISO and MISO, flexibility reserve products are typically designed to better prepare the system for expected and unexpected ramping, not to resolve energy or capacity shortfalls.

Some simulations (Krad *et al.*, 2015) suggest that these products will keep more resources available in advance of ramping events (see Figure 2.23, which shows how the available fast-ramping capacity increases when flexibility products are traded) and likely reduce scarcity price spikes associated with ramping shortfalls.

Figure 2.23 Available ramping capacity with and without flexibility reserve products



Source: Adapted from Krad et al., 2015

New, flexible resources may need new product definitions. This is the case, for instance, with batteries, which can offer a quick response but cannot retain the response for long periods of time. A new product designed to unlock battery potential can be compatible with current mechanisms, provide more efficient signals and result in an overall more economic system operation. The experience of defining new products for which batteries can provide fast-responding reserves has been successful in PJM (see Box 2.16).

Different price signals

In many US systems, it was usual to have different resources following regulation signals with varying performance, but all equivalently clearing on the market under the same remuneration (Benner, 2015). This was detected as a major constraint on new resources capable of providing better responses since that extra value was not acknowledged on the market. FERC Order 755 (FERC, 2011), a performance-based regulation, changed this by measuring performance with a standard metric and ranking the clearing based on performance and benefits.

The implementation of the performance-based regulation has been slightly different from one ISO to another, but in general, it has removed discrimination against flexible resources, enabled energy storage resources to profitably provide regulation services, and reduced regulation reserve costs (Xu *et al.*, 2016).

Separation of balancing capacity and balancing energy products

When balancing capacity and balancing energy products are procured jointly, only the balancing service provider having sold balancing capacity can provide balancing energy in real time to the system operator. Examples of markets with this design include the Spanish and the Danish automatic frequency restoration reserve (FRR) markets, and the German automatic and manual FRR markets.

The joint procurement of balancing capacity and balancing energy products is often inefficient because it does not reveal the benefits of the most-cost-efficient resources in real time. But what is even more important is that it limits the potential participation of renewable producers and other DER participants.

In general, the procurement of capacity products is carried out well before real time, so the system operator can ensure in advance the availability of

Box 2.16 Defining innovative products for batteries in the United States

Following FERC Order No. 755 (FERC, 2011), the Pennsylvania Jersey Maryland Interconnection (PJM) implemented a performance-based regulation. Resources providing frequency regulation are remunerated based on their performance – how fast and accurately they respond to PJM's signals. Faster and more accurate resources receive higher compensation.

PJM now has two separate signals. Conventional generation resources follow a traditional slower signal (Reg A). Faster resources, such as batteries, follow a dynamic or fast-responding signal (Reg D).

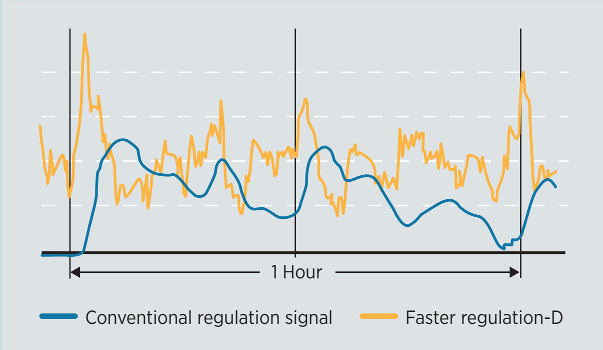
This separate fast regulation signal (Reg D) was designed to provide zero net energy required over a time period shorter than one hour (see Figure 2.24). Thus, this product is energy neutral, meaning that the accumulated signal will converge back to zero after a short time. The implementation of this new signal removes a serious obstacle to the participation of energy storage in PJM's regulation market.

This new market design uses two separate payments – one for capacity and one for performance. As of April 2015, there are several energy storage resources participating in PJM's regulation market. Regulation D was developed specifically for energy storage devices with limited storage capabilities with respect to the maximum capacity. (For example, lithium ion batteries typically operate to a 4:1 MW:MWh ratio.) That said, other technologies can also provide such services (since 2014, hydroelectricity can qualify for Regulation D).

The major challenge associated with defining different products

The major problem with this design is how to define the requirements for both types of regulation services. In practice, this calls for defining a rate of substitution between traditional Reg A resources and dynamic Reg D resources or, in other words, comparing the value of fast moving resource's regulation with that of traditional reserves.

Figure 2.24 Conventional regulation signal (blue) and the faster regulation D signal (yellow)

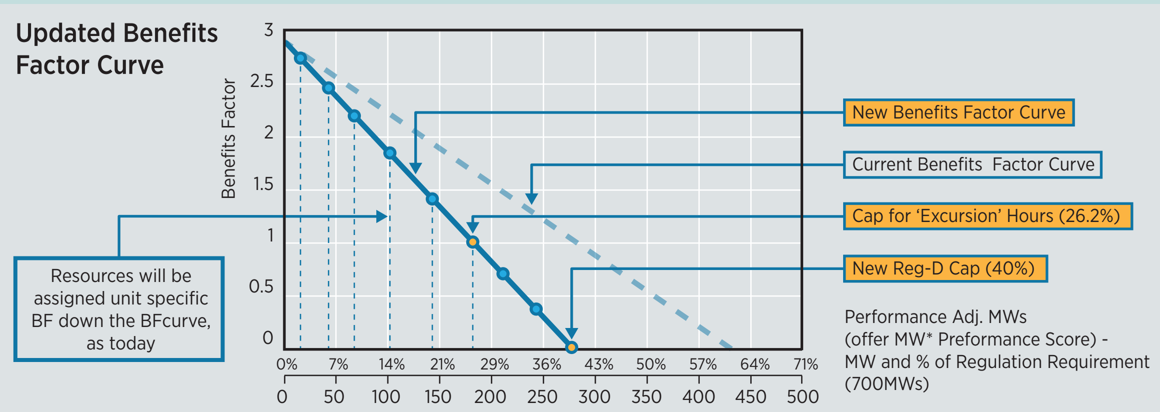


Source: PJM, 2013

This has been carried out by means of the so-called benefits factor (BF) curve (Figure 2.25). This curve expresses the equivalence of both types of reserves and depends on the amount of fast reserves procured. The x-axis represents the percentage of total reserves covered through fast-regulation reserves, while the y-axis represents the relative value of these fast reserves with respect to conventional reserves. As shown in the BF curve, the first MW of fast reserves (0% in the x-axis) is worth 3 MW of slow reserves (y-axis). However, if the amount of fast reserves increases, this equivalence lowers (even down to zero, for 40%).

As also shown in the figure 2.25, the BF curve had to be updated recently because the equivalence acknowledged during its early implementation proved to be too generous and was leading to suboptimal results.

Figure 2.25 Updated benefits factor curve to optimise operations under all system conditions



Source: Adapted from PJM, 2013

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sufficient resources to deal with real-time imbalances. For instance, in Spain, balancing capacity is procured one day before real time; in Germany and Austria, balancing capacity is guaranteed one week before real time. In the case of intermittent renewable generators, committing capacity within those time frames is a clear barrier that can hamper their participation for all intents and purposes (they cannot forecast their production accurately in such a time frame, as seen in Section 2.2 of this chapter).

A more efficient option is to decouple capacity and energy provision. It is more efficient to procure, in advance, exclusive capacity from dispatchable units (and to ensure that those balancing service providers providing capacity are obligated to offer the amount sold on the balancing energy market, perhaps by including a price threshold for them). At the same time, all resources, including those with no balancing capacity committed, may participate in the balancing energy market. This way, a variable RES unit, which cannot sell balancing capacity much before real time without incurring a high risk, would be able to sell surplus energy production (above forecasts) as balancing energy.

Examples of this design include the Belgian and the Dutch automatic and manual FRR markets and the Danish manual FRR market.

Separation of upwards and downwards reserves

In some systems, the reserve capacity product links the amount of upwards and downwards reserve capacity that has to be provided in what is sometimes called the "regulation band". The Spanish, Italian and the Danish system operators procure this band reserve product for the FRR balancing capacity.

The definition of a single product for providing upwards and downwards reserve imposes clear barriers to the participation of renewable generators since the (opportunity) costs incurred by RES for providing upwards reserves are much higher than those for providing downwards reserves.

It is also an inefficient design, given that power systems, especially those with significant RES penetration, can have very different requirements for upwards and downwards reserves in a given period.

Bid size requirements

A minimum bid size is often imposed for participation in balancing mechanisms. Such a threshold is commonly introduced for the sake of simplicity and in order to maintain the computational effort of clearing the market at an acceptable level. However, depending on the minimum size requirement, smaller resource providers may be prevented from participating. This is particularly true if, concurrently, the aggregation of individual units' offers (to comply in aggregate with minimum bid size) is not allowed. Even if a reduction of the size requirement would make the market clearing more complex, it may effectively increase the participation of RES and demand resources.

In Germany, the minimum bid size is 1 MW; in Belgium, 4 MW; and in the the Kingdom of Netherlands, 5 MW. The highest minimum bid size is that implemented in Spain, which is 10 MW.

Technology-specific products

The only prerequisites to providing a product should involve objective technical evaluations and tests. Allowing only certain technologies to provide a product, or similarly, not allowing certain technologies to offer one (as is the case for RES and DER on many markets) reduces competition and the efficiency of the overall dispatch.

By the same token, the aggregation of resources should be allowed to participate as long as compliance with the objective requirements is demonstrated.

2.3.3. Reserve markets and pricing of the products

When sufficient competition can be ensured, and when products are homogeneous, balancing services should be priced based on pay-as-cleared schemes.

If market power is a problem, relying on a market mechanism might not be enough.

As was analysed in Section 2.2.5, most European systems do not procure energy and reserves in a fully co-optimised way. In the United States, meanwhile, the procurement of these products is usually co-optimised. The efficiency of one or the other process has already been analysed.

In some cases, the provision of a service (typically primary regulation) is obligatory and not remunerated, while secondary regulation capacity and additional upward regulation capacity are procured through market mechanisms.

The pricing of balancing products can either be based on pay-as-cleared or pay-as-bid mechanisms. In many cases, the procurement is bilateral and so, by definition, these products are pay-as-bid. In other cases, pay-as-bid has been implemented (and average reserve pricing) with the objective of mitigating market power and reducing the volatility of prices. Moreover, pay-as-bid clearing rules are mandatory when the products/services procured by the TSO in a specific auction are not adequately homogeneous in terms of quality, location and time. Indeed, the adoption of a marginal pricing rule requires that the market has been segmented into homogeneous products/services and that a relation of substitutions among the different products has been established.

In general, the market price should be calculated applying the marginal pricing.[26] If it is believed that the market is prone to market power abuse, then the solution should not be to change the pricing rule but rather to fix the situation (or return to a regulated provision of the service).

Marginal prices may be more volatile, but they are the correct signals that reflect the real-time value of flexibility and give the right incentives to the resources that can respond to these price signals. Furthermore, marginal prices provide efficient long-term incentives.

2.4. LONG-TERM SUPPORT MECHANISMS

Long-term mechanisms refer to those regulatory instruments whose purpose is to guide generation expansion according to the strategic view of governments and regulators. This strategic view includes capacity (or adequacy) mechanisms and support mechanisms for RES.

In general, generation capacity mechanisms and some RES support mechanisms provide investors with an additional and/or more stable remuneration. However, there has been a major difference between them. Conventional generation technologies could be financially viable in a well-designed and fully functional energy-only market, *i.e.*, they would be able to recover their total production costs, including a suitable rate of return on investment.[27] On the other hand, in the absence of a proper internalisation of environmental externalities, until very recently, some RES have not been competitive enough to be financially viable in electricity markets, either energy only or with generation adequacy instruments. As a result, they have historically needed an additional support mechanism. Nonetheless, this does not automatically imply that they should be banned from general capacity adequacy instruments, as discussed in Section 2.4.1.

Next, we introduce the capacity (or adequacy) mechanisms and the support mechanisms for RES and later review the recommended trends in their design today.

26. When it is impossible to separate the different products in groupings of similar products (because of different qualities or times of negotiation), the use of pay-as-bid rules is justified.

27. This does not necessarily mean that in the absence of a fully active demand, the levels of reliability achieved might not reach those desired by the regulator.

2

Long-term capacity mechanisms

A combination of market and regulatory failures is often believed to threaten the long-term security of supply. If this is the case, to the extent possible, the failures should be identified and removed to allow the energy-only market to work and give proper long-term incentives. From an investment perspective, long-term markets and long-term price signals are as important as properly functioning short- and very-short-term markets (European Commission, 2015b).[28] Well-functioning long-term markets are a prerequisite for a fully functional energy market.[29] Long-term hedging products are relevant for all market participants and particularly essential for independent non-vertically integrated agents.

A liquid and efficient forward market helps provide optimal long-term price signals about future market expectations. This, in turn, promotes long-term security of supply in a market-compatible manner. Despite this essential role, well-functioning long-term markets do not happen spontaneously in electricity markets, and this represents one of the major market failures affecting the long-term security of supply.

In comparison with an energy-only framework, long-term support mechanisms can help in reducing the investment risk premium. In the absence of well-functioning long-term markets, a capacity remuneration mechanism can, in some cases, result in lower, but more stable, income for generators.

In this section, we analyse how the regulatory design of these mechanisms should evolve and adapt to the future scenario, in which high penetration levels of renewables and DER are expected. It is important to bear in mind the experience accumulated over the past two decades in the regulation of market mechanisms for generation supply and RES support instruments. Today, the major objective of regulatory design must be to improve the performance of these support mechanisms while minimising their impact on the correct market signals.

Support mechanisms for RES

Many of the most promising forms of RES once faced significant barriers to growth, ranging from their high capital cost and perceived risks to a market and regulatory structure designed to accommodate conventional fossil-based generators. Policy makers to date have recognised that in order to boost their deployment and eventually compete on the energy market, RES needed specific support policies.

Regardless of the mechanism to which RES resources finally have access, it is important that renewable technologies are exposed to market signals as much as possible in order to achieve their actual integration in power systems. They can still receive economic support if needed, but they should be increasingly required to participate in all the segments of the market, including the short and long term, and thus be responsive to all market signals.

The ideal RES support framework should allow and foster this participation in the market, and should take into consideration the revenues obtained by renewable plants in all the markets (including energy, capacity and other services), in order to calculate the incentive required to make the investment attractive and to make it available to the project developer.

There are two main aspects to consider here: 1) as far as technically possible, and taking into consideration their specific characteristics, mature RES technologies should increasingly participate in all electricity markets and be exposed to the same incentive mechanisms as any other generation technologies (including capacity markets) and 2) if RES need technology-oriented support, the corresponding long-term mechanism should be designed so that any distortion of the electricity markets is minimised.

28. We refer here to time horizons between one and 15 years.

29. This involves long-term energy markets and also long-term carbon markets (e.g., the role of a properly designed emission trading scheme is fundamental in the EU context).

2.4.1. Generation adequacy mechanisms and RES integration

RES technologies should be allowed to participate in generation adequacy mechanisms and be exposed to their market signals.

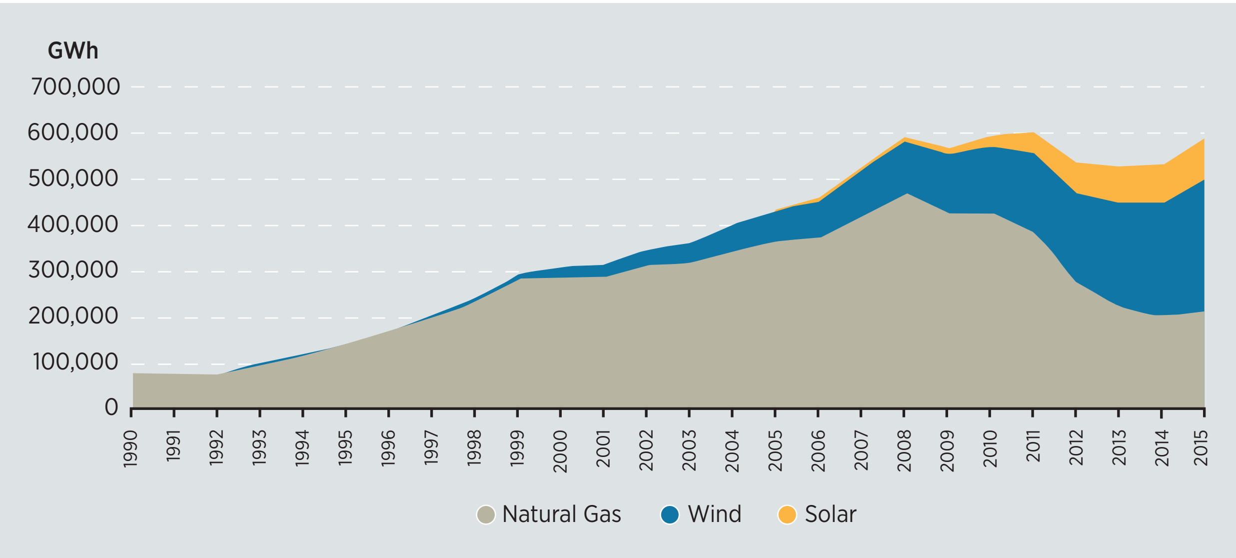
The penetration of renewable energy technologies in power systems is often argued to be one of the key reasons for the implementation of a generation adequacy mechanism. This is especially the case in Europe, where this penetration has already reached significant shares. RES, whose installation has been driven, so far, by policy support, are claimed to depress prices in the short-term electricity market (Moreno *et al.*, 2012; Reuter *et al.*, 2012). Furthermore, RES technologies have caused a significant decrease in the load factors of many conventional plants, as can be observed in Figure 2.26. These combined effects, together with their increased short-term volatility, are often claimed as major reasons behind the need for capacity mechanisms. However, this is not completely correct.

Increased price volatility in the short term, or the reduction of average prices due to the installation of variable renewable technologies (and, in some cases, generation overcapacity), hampers investments as much as uncertainty regarding the long-term deployment of these resources (due to regulatory uncertainty as regards long-term planning and to uncertainty of learning curves). This is certainly the case in those systems where RES support policies have been unpredictable because they did not stick to any consistent energy policy plan.

On the other hand, renewable technologies also represent a valuable resource for security of supply (Gouveia *et al.*, 2014):

- Regional markets can help manage fluctuations in their electricity production by increasing the geographical scope and thus reducing the probability of a concurrent lack of renewable energy. Developments in storage technologies can also reduce these fluctuations on a smaller scale for each unit or plant.
- Renewable sources may complement other energy resources, and RE technologies construction time may be significantly shorter than that of other technologies, as previously discussed (Barroso and Batlle, 2011).
- The cost of RES technologies, especially that of wind and solar PV, is swiftly decreasing, and

Figure 2.26 Annual gross aggregated electricity production from gas-fired, solar and wind electricity plants in the European Union



Source: Adapted from ACER-CEER, 2016b

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these technologies are already, or will soon be, able to compete with conventional technologies in several electricity markets.

Depending on the type of technology and the design of the mechanism, renewable technologies could also be able to participate in generation adequacy mechanisms, thus also competing with conventional technologies in the capacity market. Nonetheless, the ability of some RES technologies – like wind and solar PV – to contribute to the security of supply and to help relieve scarcity conditions is generally lower per unit of installed capacity than for conventional technologies. The RES contribution depends on the specific conditions of the power system where they are located and on the typology of scarcity conditions, as analysed next.

Variable generation in energy-constrained and capacity-constrained systems

In energy-constrained systems, *e.g.*, in hydropower-dominated countries, the coverage of the instantaneous peak load is not an issue, and scarcity conditions are more related to dry seasons that could last for months. The system could certainly satisfy peak demand, but it would be unable to supply demand during the remaining hours of the day/week. In this context, rationing takes place due to a lack of available energy, not capacity. This situation is quite common, for example, in Latin America. Brazil is the paradigmatic example, with its huge hydropower facilities and multiyear storage capability. It must be kept in mind, then, that in an energy-constrained system, the reliability product procured in a capacity mechanism is not capacity. For example, in some power systems in Latin America (as in Brazil, Chile or Peru), generation adequacy mechanisms take the form of long-term electricity auctions in which the reliability product is energy, or a call option on future energy (as in Colombia). In some cases, these auctions somehow "substitute" for the energy market (as investors are fully hedged from the fluctuations of short-term market prices); in other cases (*e.g.*, Colombia), the auctions let agents trade electricity on the short-term market, as the remuneration is thought to complement wholesale market revenues.[30]

In this context, the short-term variability of some renewables does not impede them from contributing to system reliability. Obviously, once they are installed, their non-dispatchable nature does not leave much room to manage them in the short run, but if proper incentives are implemented, the investment process can be oriented to maximise system reliability (for example, by opting for those RES technologies or those sites whose resources are positively correlated with the net needs of the system). If they are able to deliver, on average, their expected contribution in the medium term, they permit the saving of water in the reservoirs, regardless of the daily or hourly schedule of their production. Their participation in a generation adequacy mechanism can therefore be beneficial (see Box 2.17).

In capacity-constrained systems, scarcity conditions arise because there is not enough installed capacity available to meet the load at a given moment. Aggregating all the hours, the system could certainly have enough energy available to satisfy demand on a given day (more than enough prouction capacity in off-peak hours), but it lacks installed and available capacity to satisfy peak demand. This type of potential scarcity condition is found in many European and North American power systems and has prompted operators of these systems and market participants to model the very-short-term time frame in great detail. Generation adequacy mechanisms are also focused on this time frame, which can be easily observed in the reliability product design. Especially in the most recently introduced capacity remuneration mechanisms (CMs[31]) – for example, the British capacity market or the pay-for-performance reform of the Forward Capacity Market of ISO-NE) – the reliability provider is required to deliver its contribution during stress events. These may be identified by the system operator either at short notice (*e.g.*, four hours in advance in the United Kingdom) or no notice at all (the case of the so-called "shortage events" in the Forward Capacity Market).

30. See Maurer and Barroso (2011) for details.

31. Capacity remuneration mechanism is the term used in the EU context to refer to long-term security of supply mechanisms. In the US context, the term resource adequacy mechanism is used instead.

Box 2.17 **Wind penetration in Brazilian long-term auctions**

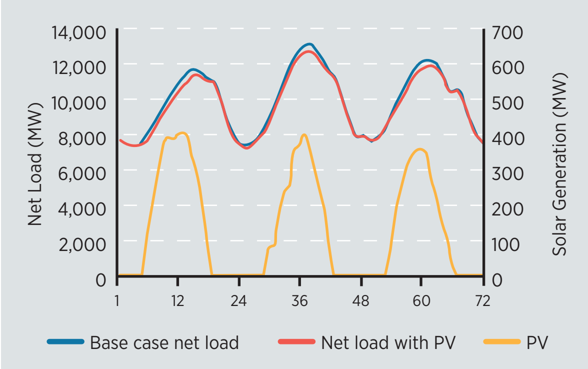
Brazil is a typical example of an energy-constrained system. Its market is organised around different kinds of long-term electricity auctions, which determine the majority of the economic flows, leaving only minor settlements to the short-term market. These tenders also represent the generation adequacy mechanism used in this country.

The outstanding participation of wind energy in the Brazilian auctions has been celebrated worldwide for the low prices offered by this technology. These prices are related to the very high capacity factors considered in the project planning, which range from 30% to 60%. This high capacity factor not only describes the amount of energy that each unit can sell in the long-term auction, but it also represents its expected contribution to generation adequacy. In fact, in the scarcity conditions foreseen in Brazil, the variability of wind power does not impede these plants' contribution to system reliability.

Also, Brazil's penalties for underperformance reflect the need for guaranteeing that enough energy is available during the year, more than that required to cover the peak load. The penalties are also for delays in the construction of plants. Once installed, a minor settlement is carried out every year, but the main penalty scheme is represented by a cumulative four-year performance assessment (IRENA, 2015), which clearly reflects the time dimension of the generation adequacy problem in Brazil.

In this context, the variability of renewable production is an issue because if the RES are not available at the very moment when the system stress occurs (*e.g.*, due to a lack of wind or solar radiation), then they cannot contribute to reducing the shortage. The contribution of variable RES to capacity mechanisms in capacity constrained systems has to be evaluated using specific, well-known and widely available methods (for solar and wind capacity values, see NREL (2013b; 2008); Figure 2.27). Statistical analyses can be used to calculate the likely production from RES during the expected scarcity periods.

Figure 2.27 Coincidence of solar energy with peak demand in Colorado



Source: Adapted from NREL, 2013b

This information can be used to define de-rating factors that constrain the amount of capacity that RES can trade in a capacity mechanism, thus limiting the remuneration they can receive from it.

A well-designed regulatory framework for RES development should be able to allow renewable participation in CMs in capacity-constrained systems, leaving to investors the definition of their risk-hedging strategy and the decision of whether to enter into CM contracts or not (see Box 2.18).

Generation adequacy and interactions with RES support mechanisms

As has been mentioned, the debate over whether or not to isolate RES from market signals (and to what extent) has been intense.[32] The inefficiencies derived from reduced wholesale market exposure were assumed to be outweighed by a reduction of investors' risks. However, as RES penetration has increased, the maturity of RES technologies has reached a level that allows these plants to be largely exposed to market mechanisms. At the same time, the impacts of a lack of market integration on the broader power system have become more difficult to ignore.[33]

In principle, CMs should allow RES of all types to participate in any kind of generation adequacy mechanisms. This is already taking place in Brazil, where generation adequacy mechanisms are a component of the income of RES. RES technol-

32. For example, in Europe the debate was around whether to use feed-in tariffs, tradable green certificates or auction-based mechanisms – see, for instance, Butler and Neuhoff (2008).

33. See Fraunhofer ISI (2015) for a discussion of the growing impact of negative prices on European wholesale power markets.

Box 2.18 Renewable participation in PJM's reliability pricing model

The Pennsylvania Jersey Maryland Interconnection (PJM) is a large interconnected (capacity-constrained) power system in the United States, whose generation mix is mainly based on conventional thermal plants. Its generation adequacy needs are covered through a capacity market called the *reliability pricing model* (RPM). RPM capacity providers, selected through centralised auctions, commit to be available whenever the system operator requires their contribution to solve scarcity conditions.

In the 2017/18 RPM base residual auction, the main procurement process of this mechanism, 803 MW wind power plants and 116 MW solar resources were cleared (PJM, 2014). On average, wind and solar units were assigned a 13% and 38% capacity factor, respectively, during the qualification phase prior to the auction. These factors, lower than those in the Brazilian case, represent the expected contribution of these units during scarcity conditions in the PJM. Since these conditions are related to short-term shortages, the likelihood of RES resources being available at the specific time when scarcity occurs is estimated to be low.

As for penalties, a capacity remuneration mechanism reform being implemented in the PJM (as well as in the ISO New England), inspired by the "pay-for-performance" principle (see Mastropietro *et al.*, 2015a, for details), introduces severe penalties for underperformance. It is not clear how this will affect renewable participation in future auctions.

ogies started being cleared in specific renewable auctions, but they also ended up being selected in conventional long-term electricity auctions for new energy. As analysed in the next subsection, this convergence is not yet complete, and some rules still need to be harmonised.

Meanwhile, in capacity-constrained systems, renewable energy technologies have so far participated in CMs to only a limited extent. In many countries, regulators decided that RES, which were already receiving some other kind of incentive (grants, feed-in tariffs [FiTs], etc.), were not eligible for the capacity mechanism remuneration. This was the case, for example, in the UK's Capacity Market (DECC, 2014). The rationale for this decision is that the capacity mechanism remuneration represents an investment incentive. Renewable technologies, for which investment is already being incentivised by some sort of RES support mechanism, are therefore not eligible since they do not need further investment support.

This argument misses the main point that we are making here – that RES technologies need to be exposed to market signals. They should be integrated into the wholesale market as much as possible. Capacity mechanisms provide not only an investment incentive, but they are supposed to provide market agents with incentives to foster the availability of committed resources during scarcity conditions, with the objective of avoiding electricity rationing. This side of the mechanism is now being reinforced through the implementation of performance incentives. If the capacity mechanism design is robust and the reliability product is technology neutral, RES participation in system reliability would be acknowledged – and RES would be exposed to an economic signal that prompts them to be available when the system most needs them. If specific renewable energy technologies/sources are technically able to compete with other resources on a level playing field, relevant renewable power plants should not be favoured, either through their exemption from penalties or through overgenerous recognition of firm energy/capacity. If RES units have to compete with conventional technologies, they should be subject to the same rules. RES support mechanisms are not incompatible with this approach. As mentioned above, the ideal RES support scheme would deduct the estimated revenues obtained by the renewable plant on all the markets, including the energy and capacity markets, from their total costs. This would be done to calculate the incentive required to make the investment attractive, and to make it available to the project developer, without spending unnecessary funds.

However, in real markets, several factors can complicate this simple theoretical discussion. According to some stakeholders, if "subsidised"

Box 2.19 **Renewable participation in ISO New England's Forward Capacity Market**

ISO-New England pursues generation adequacy through its Forward Capacity Market. This mechanism has been recently reformed to introduce stronger penalties for underperformance (FERC, 2014d).

Renewable penetration may grow significantly in the next few years (wind represents 42% of generation project proposals). According to ISO-NE (2015), state subsidies for renewable resources will put downward pressure on energy-market prices, but the capacity market will help balance the revenue needs for conventional resources. To "protect" the capacity market from excessive renewable participation, which could depress capacity prices, the regulator introduced specific offer review trigger prices for renewable technologies, which apply to all renewable bids exceeding 200 MW in each auction. These trigger prices are intended to prevent uneconomic or subsidised new entries from distorting market prices by setting a price floor below which new entrants must demonstrate their costs or withdraw from the capacity auction.

renewable technologies are allowed to take part in the capacity market, it may be difficult to guarantee that they do not depress prices in capacity auctions (as they have already done in the day-ahead market in some power systems). This concern is further described in Box 2.19, which focuses on ISO-NE's experience.

The justification for the floor described in Box 2.19 is flawed. The objective of a capacity mechanism is not to compensate all generators for their investment cost, no matter the resulting mix and reserve margin in the system. Instead, the aim is to provide investors with incentives – when needed – to ensure that a capacity level that maximises the social benefit is installed. If there is an excess of capacity due to wrong investment decisions, generators will see the prices depressed in the short and medium term. In such a context, they will most likely ask for a higher capacity remuneration to ensure total cost-recovery. But note that, in this case, the remuneration should be close to zero since no additional incentives are needed to ensure reliability.

Rules to be harmonised in capacity mechanisms

When signing a contract in the framework of a generation adequacy mechanism, power resources are committed to providing a certain reliability product, which is defined in detail in the contract provisions. The design of the reliability product represents a cornerstone for the generation adequacy mechanism. Minor changes in a specific provision can heavily impact the overall effectiveness of the scheme in achieving its objectives.[34]

If renewable and conventional technologies have to compete for the provision of generation adequacy, they have to be at the same level. When possible, no discrimination should exist in the definition of the reliability product, and the same commitment should be required from all reliability providers, regardless of technology.

Two design elements must be carefully considered in order to avoid discrimination between renewable and conventional technologies. The first is the performance incentive to which reliability providers are exposed, *i.e.*, the penalty for underperformance. The second is the methodology used to calculate the firm energy/capacity that resources are allowed to trade in the generation adequacy mechanism. Without a proper harmonisation of these contract provisions, competition between renewable and conventional technologies will be distorted. This could seriously impact the effectiveness of the generation adequacy mechanism in attracting investment and in guaranteeing reliable electricity supply.

Regional market context

The importance of exploiting the synergies between RES development and regional market integration has already been underlined. Increasing the geographical size of the market helps manage fluctuations in RES electricity production, reducing the probability of a concurrent

34. Batlle et al. (2015) identify the main design elements of the reliability product.

2

lack of renewable energy. Furthermore, regional market integration permits a co-ordinated planning of generation infrastructures that exploits the available renewable resources as efficiently as possible.[35]

A well-functioning regional market, however, should encompass all time dimensions, including generation adequacy. In this respect, differences in adequacy mechanism choices coupled with a lack of co-ordination can undermine regional market integration. International integration of national CMs is currently a major challenge (Perner, 2015).

The implementation of different national CMs to achieve a range of diverse reliability targets does not impede the optimal exploitation of regional resources but requires a minimum level of co-ordination. As mentioned by Mastropietro *et al.* (2015b), the basic requirement is to open CMs to cross-border participation. If resources are allowed to trade their reliability in all capacity mechanisms within the regional market, regardless of their point of connection (that being the only obvious constraint in the interconnection capacity), they can still locate optimally. That said, some sort of co-ordination between the neighbouring TSOs will always be necessary (for example, to avoid one plant selling the same product in different systems).

This discussion is particularly relevant to the European Union, where the regional market integration process is advanced. The EU experience is described in Box 2.20.

Box 2.20 Cross-border participation in European Capacity Remuneration Mechanisms

In the European Union, market integration efforts have focused until now on the security and the economic efficiency of short-term time frames, *i.e.*, the day-ahead and operation markets. Long-term, capacity remuneration mechanisms are being introduced with little co-ordination. Their design seems to rely almost exclusively on the domestic generation mix in the corresponding Member State, with the main objective of maintaining a reliable and self-sufficient power system. Obviously this is at odds with a regional concept of the security of generation supply.

This concern has been clearly expressed by all EU institutions, including in the recent consultation document from the European Commission (European Commission, 2015c) which claims that mechanisms to ensure generation adequacy should be open to all capacity that can effectively contribute to meeting the required reliability level, including capacity from other Member States. Nonetheless, CM designs implemented or proposed so far in the European Union (DECC, 2014; RTE, 2014; AEEG, 2011) do not allow explicit cross-border participation. Mastropietro *et al.* (2015b) highlighted that one main barrier to such participation is related to mistrust in the fulfilment of article 4.3 of the Security of Supply Directive (2005/89/EC), which states that "Member States shall not discriminate between cross-border contracts and national contracts". In order to include generation from a neighbouring system in a capacity mechanism, the transmission system operator of the country launching the CM must be sure that, during scarcity conditions, the foreign resources are able to fulfil their physical supply commitment linked to the capacity mechanism. Nonetheless, most electricity laws and national network codes in force in the Member States still contain clauses that maintain that exports to other countries will be interrupted in case of a domestic emergency of supply.

This barrier can be removed only through greater co-ordination among system operators, who should commit to fulfilling the Security of Supply Directive through the modification of national (and regional) network codes and operation procedures.

35. Obviously, this implies the existence of a regional transmission network with the adequate cross-border interconnection capacity and a regional transmission expansion strategy capable of following the evolution of the generation mix and the need for further interconnections. This relevant topic, however, exceeds the scope of this section, which is focused on electricity markets, and thus on activities open to market competition.

2.4.2. RES promotion mechanisms and wholesale market integration

RES technologies may continue to require economic support. This support should become more market compatible. Several design options exist. A balance must be found between optimal investment incentives and market compatibility.

Many of the most promising forms of RES have in the past years faced significant barriers to growth, ranging from their high capital costs and perceived risks to a market and regulatory structure designed to accommodate conventional fossil-based generators. In several countries, policy makers recognised that in order to boost RES deployment with the objective of eventually competing on the energy market, RES needed to be promoted with specific economic incentives. The cost of renewable technologies has been progressively decreasing over the past few years. Soon these units may be (and in some cases already are) able to compete with conventional technologies without the need for economic support. In some countries, however, incentives for renewables are still needed while the environmental externalities that RES mitigate are not internalised in the market prices.

This section discusses the three major RES support scheme classifications, namely capacity-based mechanisms, production-based mechanisms and support mechanisms for prosumers, and their compatibility to wholesale market integration.

Capacity-based mechanisms

In purely capacity- or investment-based support mechanisms, a remuneration is provided on a per MW installed basis (*i.e.*, there is no energy or availability contract involved). These payments are intended to cover the difference between a plant's upfront investment costs and any market revenues. While the choice of paying based on installed capacity or project cost has important consequences, depending on the policy goals, the two methods are similar in that they decouple actual production from the support price and therefore do not interfere with short-term market signals.

Capacity-based mechanisms are characterised by several key design features that affect market compatibility. Four such features are outlined below.

Design feature 1:
Support payment, amount and timing

An obviously critical initial decision in any support scheme is the overall size of the payment: how much support does a project need to earn in the various segments of the market (including energy, capacity and other services)? There is significant risk in the decision, as an overly generous payment can lead to overinvestment in renewable generation. On the other hand, too small an incentive may fail to attract sufficient investment. One of the design features that affects this issue is the timing of the support payment, which can either be calculated *ex ante* or *ex post.*

Most capacity-based support is determined *ex ante* based on the expected cost of a particular generation technology (as in Spain) or on the actual cost of the project (as in the United States with the Investment Tax Credit). Alternatively, the size of the incentive payment can be determined *ex post* based on actual costs and observed revenues from the market. For example, if energy market prices turned out to be lower than expected, an *ex post* capacity incentive could be adjusted to ensure RES plants are able to recover their fixed costs.

Providing support upfront has the advantage of a low administrative burden (it requires only a single transaction) and also rewards the best-performing projects – the windiest/sunniest sites will have an easier time covering any revenue shortfalls on the energy market and will therefore have an easier time attracting investors. On the other hand, calculating the incentive *ex post* makes it easier to guarantee a certain level of cost-recovery, regardless of external factors, such as market prices or plant location.

2

Design feature 2: Choice of reference plant

Closely related to the timing issue is selecting a reference plant for calculating the size of the capacity payment. The first decision is between using the actual cost of a project versus using a reference cost, derived from a "typical" plant. The ITC in the United States is an example of the former, while support schemes in Spain, Germany and Russia are examples of the latter (IFC, 2013).

Paying based on actual costs is straightforward and incurs a low administrative burden, but all else equal, this approach risks providing incentives for overpriced and underperforming projects. The use of a reference facility helps overcome these problems by creating a benchmark; if a developer can build a plant with a lower cost or a higher performance than the reference plant, then it will have higher profits, thus creating a natural incentive for higher-quality projects.

Developing reference plants involves estimating capital costs and production hours. However, relying on reference plants can be problematic if there are too few of them, or if the regulator fails to properly diversify them depending on the policy objectives. Spain has addressed this problem by defining some 1 276 different reference plants, diversified by technology, size, location and construction date (Barquín, 2014).

Design feature 3: Frequency of support payment

Capacity-based support can be delivered either as a one-time lump-sum payment or through a series of periodic payments. One-time payments are potentially advantageous as they can be concluded in a single interaction, reducing the administrative burden on both the developer and the government counterparty. On the other hand, periodic payments are more flexible as total compensation may be adjusted over time. This can be a useful feature for controlling policy costs and limiting windfall profits, or conversely, for keeping an underperforming project profitable.

Germany uses periodic payments to support wind generators, which are adjusted over several years depending on the performance of the project relative to a reference facility. This has the effect of distributing support costs to where they are needed: the projects in the best (windiest) locations have their incentive reduced since they are earning above-average market revenues, while projects in suboptimal locations receive a premium incentive to ensure they are able to recover their investment costs (Purkus *et al.*, 2015).

Design feature 4: Minimum performance requirements

One of the consistent criticisms of capacity-based mechanisms is that they do not motivate effective system design, efficient component selection (high-efficiency panels/turbines) or regular maintenance once the project is operational (Hoff, 2006). These risks can be mitigated by attaching minimum performance requirements to the incentive and then adjusting or even withholding part of the payment subject to conditions (which could include any sort of locational signal).

These tactics require ongoing performance monitoring, which increases administrative costs, but the upside can be substantial in terms of higher and longer-lived production from quality systems.

In addition to performance monitoring, or perhaps as an alternative, regulators can impose minimum standards for component efficiency or system design. It can be challenging, however, for regulators to maintain reasonable standards in light of rapidly evolving technology. Furthermore, there is a risk of regulatory overreach as innovative technologies and design approaches may be restricted in their development if they do not meet the administratively determined criteria.

Assessment of market compatibility

In general, capacity-based support mechanisms are highly compatible with a market-oriented power generation sector. They avoid the market distortions of production-based schemes by decoupling payment and performance. They also come with their own set of potential risks that need to be managed, such as an unstable investment environment, incentives flowing to low-quality projects and inflexibility to evolving market conditions.

Many, though not all, of these risks can be mitigated through incorporation of specific design features. The risk of under- or overpaying can be reduced by using reference plants, diversified based on key performance criteria such as plant location and size. Differentiating payments by resource quality also supports economically viable development of diverse sites and avoids inflated payments to developers in resource-rich areas. The risk of payments flowing to poor-performing projects can be reduced by attaching minimum performance requirements. Finally, paying out the incentive over time rather than in a single lump sum leaves room for program administrators to adjust the level of payment in response to changing market conditions.

■ ***Production-based mechanisms***

Production-based remuneration schemes are characterised by periodic payments based on a generator's actual production and, in some cases, the market price. By tying payment to performance these schemes create an incentive to maximise energy production, meaning developers naturally prefer the windiest/sunniest locations, the most efficient components and the best system designs.

The same cannot be said for the impact of production support on operating behaviour. While the operating decisions of wind and solar are simplified compared to their thermal counterparts due to their intermittency and zero variable cost, decisions such as shutting down in the presence of negative prices, or scheduling maintenance during off-peak times, are not driven by price signals coming from wholesale energy markets. Furthermore, linking support payments to production adds a second signal that may cause generators to change their behaviour, resulting in potentially distortive impacts across the broader market.

Production-based support mechanisms are characterised by two key design features, as follows.

Design feature 1:
Amount of production receiving support

The first key decision in the design of production-based schemes is the quantity of generation to support. Regulators can essentially decide to either remunerate any and all output, or provide support only up to a certain limit. For example, premiums for wind production could be restricted to a benchmark number of hours (*e.g.*, 2 000) after which any production receives only the market price. This has the effect of limiting windfall payments to developers in resource-rich areas, while still creating incentives to site projects in the best locations.

Design feature 2:
Type of support for production

Once quantity is established, the next key decision is the type of production support. This can generally be classified based on how the payment is determined: whether it is: 1) not tied to the energy market; 2) tied to the energy market or 3) tied to a separate market.

Production incentives that are not based on a market are administratively defined, typically either through a calculation of the levelised cost of energy or by auction. Once the incentive level is established, RES generators enter into a contract for a certain number of years and are paid on a per-kilowatt-hour basis for any production regardless of demand. FiTs are the prime example of this type of flat, out-of-market approach. They have been historically effective because they create an environment of high investor confidence due to the elimination of market price risk. However, from a pure market design perspective, they are the least compatible with markets: generators are insulated from market signals and are therefore more likely to create distortions, such as continuing to produce even when prices are negative.

Support mechanisms tied to the energy market require generators to sell their production on the wholesale market and then provide a premium on top of the market price. These schemes are broadly classified as feed-in premiums, though they have a variety of alternative names depending on the design details. These schemes are "market integrated" by nature, as generators are exposed to price signals and tune their operating decisions accordingly. However, this does not eliminate the potential for market distortions completely, as RES generators may still have an incentive to continue producing in the presence of negative prices – at least until negative pric-

2

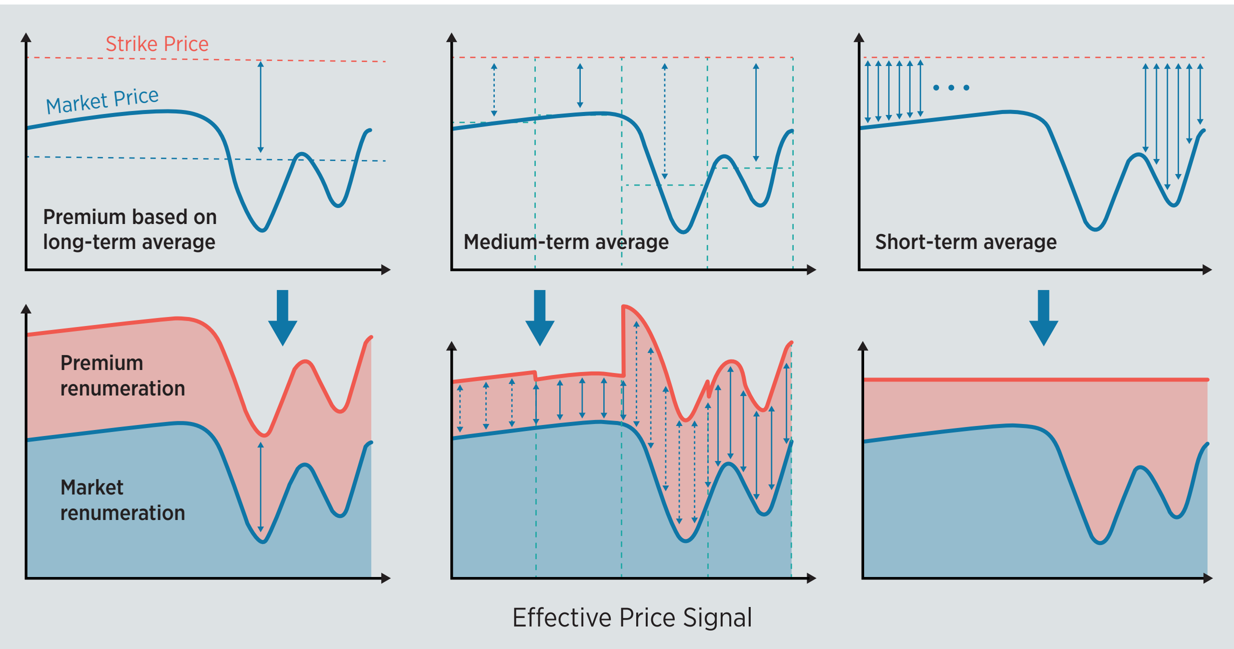
es exceed the size of the premium. The extent of these distortions critically depends on how the premium is calculated and whether it is fixed or "sliding":

- Fixed premiums are defined in advance and therefore expose generators to the same level of market volatility and price risk as any other market participant. The production tax credit in the United States, the "green bonus" in the Czech Republic and a similar scheme in Slovenia are all examples of fixed premiums (Fraunhofer ISI, 2014).
- Sliding premiums are calculated *ex post* as the difference between a strike price (which reflects the long-term price needed to recover fixed costs) and a reference price (which reflects in some way the payment received by participating through the electricity markets). By continually correcting total payment to a fixed strike price, a sliding premium provides a high level of revenue certainty while still exposing producers to market prices in real time.

The duration of the settlement period for applying the reference price is a critical factor conditioning the behaviour of generators (Huntington *et al.*, 2016). If the settlement is based on a short-term average of market prices (*e.g.*, hourly), then generators are continually "topped up" to the strike price and are thus well-insulated from market volatility. The support mechanism functions like a FIT and generators receive signals to produce until prices exceed the negative of the strike price; in fact, regardless of when they produce and of the market price at that time, their revenue is always reset to the strike price. At the other extreme, if the reference price is based on a long-term average (*e.g.*, yearly), then the premium is more stable on an hour-by-hour basis, and the mechanism sends signals equivalent to a fixed premium, exposing generators to market volatility and price risk. In this case, the generator does have a preference for producing at high-price hours. In practice, many countries choose a middle ground, balancing revenue certainty with market exposure. Germany, for example, calculates reference prices based on a monthly average while Finland uses a three-month average (RES-LEGAL, 2015). These different approaches are represented graphically in Figure 2.28.

Finally, the sliding premium may be implemented as a purely financial contract, as in the case of the United Kingdom's Contract for Differences.

Figure 2.28 Reference price settlement periods



Source: Adapted from Huntington et al., 2016

Under this arrangement, generators are still "topped up" when reference prices are below strike prices (which is most of the time), but are forced to pay back the difference when reference prices exceed strike prices (peak days). This works because generators still have an incentive to produce as prices are above their variable cost, but their revenue is effectively capped at the strike price.

A third alternative for production-based schemes is to tie premiums to an entirely separate market where the value of renewable generation is determined by the demand for it. These mechanisms are broadly categorised as "quota obligations" linked with "tradeable green certificates". While quota schemes expose producers to the efficiency of market prices, they provide less revenue certainty for investors. Price floors are commonly introduced to address this (NREL, 2011), but by guaranteeing a minimum value for the premium quota, these schemes may cause some market distortions as traditional feed-in premiums. Even a well-functioning certificate market is not immune to these problems. In a market with relatively stable prices (*e.g.*, Sweden) generators may still find it in their interest to produce when prices are zero or slightly negative, knowing that they can still sell their production in the certificate market for a profit.

Assessment of market compatibility

Fixed premiums expose generators to efficient market signals and introduce limited distortions, but they come at the price of reduced revenue certainty. Sliding premium schemes attempt to provide greater revenue certainty but create the potential for negative price distortions as generators bid up to the negative of the strike price. Certificate schemes are often perceived as the most "market compatible" since market signals and premium determination are fully decoupled, but the risk introduced by the certificate market can be significantly higher. Measures to reduce that risk, such as price floors, transform the scheme to one that functions like a traditional fixed premium.

Attempts to limit distortions through market design "fixes" may create new problems. Banning negative prices outright removes the channel through which base-load plants might continue operating, by effectively paying renewable generators to shut down. Another option is to force RES generators to shut down when prices are negative and simply pay them when they are available. However, this creates a dangerous "cliff-edge" effect where generators are highly sensitive to small changes in market prices: plants could suddenly switch between a desire to run at full output and access premium payments when prices are above zero and to turn off and be paid upon their availability when prices are below zero. These oscillations could disrupt the broader energy market and complicate system operation (DECC, 2012).

Production-based schemes will always suffer from this fundamental tension between market integration and limiting distortions because, one way or another, they alter the price signals from the energy market.

■ *Specific support mechanisms for prosumers*

Prosumers are electricity customers who both consume and produce electricity.[36] The pros and cons of support mechanisms for generators, as described in the previous section, are equally applicable to generation from prosumers. Support mechanisms for prosumers have the added dimension of interaction with the retail tariff. Depending on the metering technology and arrangement, production can net consumption and reduce consumption tariff payments. When volumetric tariffs are bundled, prosumers have the opportunity to reduce or avoid non-energy costs, such as taxes, policy costs or network charges. This aspect has a more significant impact when prosumers are allowed to "bank" production credits and apply them as negative consumption at a later date.

36. This topic is addressed here from the perspective of these mechanisms' compatibility with overall market functioning. In particular, we look at potential distortions introduced by the inappropriate design of support mechanisms. Chapter 3 will tackle these issues again from the perspective of their impact on the distribution network and the design of distribution and retail tariffs.

The metering technology plays an important role in these support mechanisms. Meters must be bi-directional, therefore providing the possibility to distinguish between consumption and production. Furthermore, smart meters with measurement intervals that are aligned with the intervals of the wholesale market allow the market value of both injected and consumed energy to be determined separately. This is especially relevant when the two profiles are not aligned – for example, with on-peak production (solar) and off-peak consumption (a night-oriented residential profile). This also helps manage imbalances and attributes imbalance costs more fairly (Eurelectric, 2015).

The remainder of this section focuses on two key design features of support schemes for prosumers: namely the parameters of the netting period, and the value of excess generation.

Design feature 1: Length and timing of netting period

The netting period refers to the window between meter readings when customers can apply generation credits to their bill, effectively "netting out" their consumption. The longer the netting period, the greater the potential subsidy since consumers have more opportunity to use generation credits to offset their consumption. Shorter netting periods, combined with a lower rate for excess generation, create incentives for prosumers to increase their rate of self-consumption.

Most states in the United States use an annual netting period, though some, like Alaska, allow credits to be carried forward indefinitely. Two utilities in California, PG&E and SDG&E, recently proposed shortening the netting period from yearly to monthly in an effort to control support costs and reduce cross-subsidisation of customers with solar production (PG&E, n.d.). Most EU countries, including Belgium and the Kingdom of Netherlands, , also use an annual netting period. Denmark uses a very short hourly netting period (European Commission, 2015c).

The timing of the netting period is another important dimension: by aligning the period with the trading interval of the wholesale market, the market can act as a basis for valuing grid injections, thus providing a more efficient long-term price signal (EURELECTRIC, 2015).

Design feature 2: Value of net excess generation

Net excess generation (NEG) refers to any production not consumed on-site and not converted to production credits to be treated as negative consumption. In net-metering schemes, NEG exists only when on-site production exceeds consumption over the course of the netting period. Schemes that do not allow banking of production credits effectively treat all grid injections as NEG.

The value of NEG influences both the operating and investment decisions of prosumers. If NEG is valued at or above the retail rate, the incentives are equivalent to net metering: customers are indifferent to their rate of self-consumption. This can also lead to the oversizing of generation assets. On the other hand, if NEG is valued below the retail rate, customers have a direct incentive to increase their rate of self-consumption and tailor the size of the generation systems accordingly.

Assessment of market compatibility

In any arrangement that allows for self-consumption, prosumers will have the opportunity to avoid paying the retail rate, and any associated network costs. Many schemes allow prosumers to carry their production credits forward and "net out" their consumption at a later time. From a pure market perspective, schemes that do not allow the "banking" of production credits, or those that minimise the netting period, lead to fewer distortions. Of course, this depends on whether the design of the network tariffs takes advantage of the pattern of injections and withdrawals of the network users.

Rather than allowing the banking of production credits, support for prosumers may be delivered by adjusting the value of NEG. As long as the value remains below the retail rate, customers will have incentives to make both efficient operating (increased self-consumption) and investment decisions (proper sizing), leading to fewer market distortions and greater overall efficiency. But the only fool-proof approach is a complete redesign of the retail tariffs, as discussed in the next chapter.

2.5. CONCLUSIONS AND RECOMMENDATIONS

In this chapter, we saw how wholesale market design will have to evolve in the near future to efficiently integrate large shares of RES and DER.

The short-term market is probably the segment that requires the most adjustment. As many characteristics of the power sector become more variable, the time granularity of market signals has to be increased. Market time frames must be adapted and become more flexible.

In terms of location, the deployment of variable technologies is likely to increase congestion on the transmission network, which may exacerbate the potential disadvantages of zonal pricing when compared with nodal pricing. Nodal pricing provides more accurate operation and investment signals, and its drawbacks in terms of long-term market liquidity and end-consumer discrimination may be reduced through financial transmission rights and a proper tariff design.

A large deployment of renewable resources also requires more complex bidding formats, if an efficient economic dispatch is to be guaranteed. Bids may need to include an explicit representation of most of the technical constraints of power resources. Also, bids may be tailored to certain products, such as those coming from demand response.

There are two key approaches to clearing bids and setting a price: that of the US ISO (dispatch-based pricing plus discriminatory pricing) and the EU PX (price-based dispatch). The best option might be some point in the middle. An optimum clearing methodology would find a balance between: 1) uniform prices that may oversimplify the problem and result in potential economic inefficiencies and 2) large uplifts that may distort the efficient price signal.

In the very-short-term, new solutions must be found to improve the reserve demand function, increasing its elasticity to price. At the same time, the linkage between energy and reserve markets has to be enhanced in order for an energy market to properly reflect the value of reserves.

Also, the balancing segment must be reformed if RES resources are to become responsible for their imbalances. Balancing products should be revised to unlock the potential of all flexible resources. Balancing capacity and balancing energy should be two separate products, procured at different stages. Resources not cleared in as balancing capacity may be allowed to provide balancing energy if they can do it efficiently. Upwards and downwards reserves should be procured separately too since some resources may be able to provide one product but not the other. Minimum-size requirements should be avoided to the largest extent possible so as not to discourage RES and DER participation.

In the long term, we saw how capacity (or, more generally, generation adequacy) mechanisms are climbing regulatory agendas in many liberalised power systems. RES technologies can represent a valuable opportunity for system adequacy. Depending on the characteristics of the power system (especially on the share of hydropower in the generation mix), the variability of some RES technologies may not be an obstacle for these resources to provide reliability products efficiently.

For this reason, RES resources should be allowed to participate in generation adequacy, and also to be exposed to the corresponding market signals, which may result in the development of technologies or strategies that maximise the availability of RES units during scarcity conditions. Harmonisation is called for in many areas, especially in the calculation of a firm's energy/capacity and in the application of penalties for underperformance.

Finally, RES participation in capacity mechanisms does not directly imply the elimination of any other form of RES support scheme. These two regulatory instruments can coexist – the only strong requisite being that the incentive provided by the support scheme account for the remuneration earned on the capacity market.

RES support mechanisms may be designed in several ways. The key question is whether to provide the incentive based on the capacity installed or the energy produced. Also in this regard, a balance must be found between optimal investment incentives and minimal market distortions.

DISTRIBUTION NETWORKS AND DISTRIBUTED ENERGY RESOURCES

3

3.1 INTRODUCTION

Over the past decade, distribution networks have experienced the connection of an increasing number of distributed energy resources (DER), most of it distributed generation (DG), but also active demand response.[1] In the near future, electric vehicles and distributed storage will have a substantial presence in several systems. The current – and anticipated – growth of DER demands new approaches to operating and planning distribution networks, and the regulation of distribution and retail activities.

What are the major challenges anticipated? For the time being, most changes will be on the DG side. A high presence of DG may increase uncertainty around distribution networks' remuneration since the methods that regulators have traditionally employed to estimate an efficient service cost may no longer be valid. The distribution system operator need to adopt advanced, innovative approaches to managing the distribution grid. The active management of networks will help solve network constraints and reduce relatively costly network reinforcements. This approach requires distribution companies to interact more closely with their network users and to deploy advanced network technologies, which will play a crucial role in future power systems. The transition towards smarter distribution networks should be initiated through policies and regulations promoting innovation and demonstration projects. Several mechanisms have been used around the world to help distribution companies efficiently integrate growing levels of DER through more active grid planning and operation. Examples of these mechanisms and of relevant demonstration projects are discussed in Section 3.2.

1. Distributed energy resources (DER) consist of small- to medium- scale resources that are connected mainly to the lower voltage levels (distribution grids) of the system or near the end users and are comprised of three main elements: distributed generation, energy storage and demand response. Demand response (DR), also known as demand-side management (DSM) or energy demand management (EDM) refers to the possibility to shift energy loads around in time. The management of small end-users must be achieved automatically at the user level, which requires online communications. In this regard, smart meters represent a key enabling technology of demand response. Distributed generation (DG) is a generating power plants serving a customer on-site, or providing support to a distribution network, and connected to the grid at distribution level voltages. For the purpose of this report, the technologies used for distributed generation are renewable energy technologies.

New regulatory approaches are needed for the remuneration of distribution networks. The method currently used by most regulators relies on some multiplicative factor – validated by experience – applied to the volume of distributed electricity. The network charges applied to the end-consumer are also, typically, volumetric, *i.e.*, proportional to the amount of consumed energy. However, with high presence of DG, revenues may fall – both the total amount determined by regulators and that collected through the application of network tariffs. This is in large part because self-generation implies a smaller amount of distributed electricity. In order to mitigate the potential financial impact of this on distribution utilities, some regulators have started to implement mechanisms that decouple the amount of allowed revenues from the volume of delivered energy. Also, some compensate companies for the incremental network costs. However, these short-term measures are not enough. More must be done to determine efficient cost levels and to incentivise the degree of innovation required to integrate high shares of DG efficiently. Profound regulatory changes are required to encourage the deployment of more active grid planning and operation. The regulatory changes to support DG integration and to promote long-term efficiency are discussed in Section 3.3.

The development of generation on consumers' premises for self-consumption presents important benefits both for end users as well as for the distribution grid. However, as a result of tariff structures that do not adequately reflect the true costs that each network user imposes on the system and outdated metering technologies, self-consumption, especially when combined with net-metering policies, may jeopardise the financial viability of the system. Acknowledging this, regulators have already started to apply mechanisms to mitigate the problem in the short term. However, the fundamental issues will not be solved until cost-reflective tariffs and advanced metering technologies are adopted. Section 3.4 discusses the negative consequences of inappropriate tariff structures in combination with self-consumption policies and discusses some measures that regulators and policy makers have implemented to tackle such challenges. Several guiding principles for a truly cost-reflective tariff design and the sustainable development of self-generation on consumers' premises are provided in this section.

Last but not least, owing to the presence of DER in their grids and the flexibility these services may provide, distribution companies will need to take on new roles as market intermediaries and system operators. This transformation means that, in the near future, distribution companies will need to interact more closely with DER, which will be at least partly dispatchable. In this new context, DER will provide services both to a distribution company itself and to upstream stakeholders and markets. Since the distribution companies will need to act as mediators in these transactions, *e.g.*, performing technical validation or verification of service delivery, the traditionally simple interactions between distribution companies and system operators – whether independent system operators (ISOs) or transmission system operators (TSOs) - ought to be revisited in order to ensure the efficient and secure operation of a largely decentralised power system. Thus, to some extent, distribution companies may become to retail markets and DER what transmission system operators are to wholesale markets and centralised generation. Moreover, as part of their newly acquired roles, distribution companies may be required to deploy new types of infrastructure – such as advanced metering infrastructure (AMI), energy storage or electric vehicle (EV) charging stations – that do not fall within their conventional core activities. Section 3.5 addresses the new roles to be adopted by distribution utilities as system operators and market facilitators, including in the deployment of infrastructure.

3.2 ADVANCED SOLUTIONS FOR DISTRIBUTION NETWORK PLANNING AND OPERATION

A growing penetration of distributed energy resources, particularly distributed generation, requires innovative approaches to distribution network planning and operation.

The presence of generation in distribution networks is beneficial, thanks to the fact that DG is located near end-consumers. It can partially offset demand growth, reduce peak load and allow distribution companies to defer grid reinforcements or reduce energy losses. However, in many cases the absence of locational network charges, as well as policy design, do not encourage efficient operating decisions regarding generation location. And even if the correct locational signals were sent, operators can make operating decisions based on many other factors. Thus, in practice, DG is not necessarily located close to the loads or operated efficiently. Moreover, its production is largely variable and may not coincide with times when local demand is highest.[2] Thus DG production does not necessarily take place where and when it is most needed from a network perspective.

Another issue to consider is that distribution companies rarely rely on DER to optimise network planning – and reap its potential benefits. Instead, they usually follow a so-called *fit-and-forget* approach to DG connection, which consists of reinforcing the grid at the time of connection in such a way that any future operational problem is prevented. This means that network capacity by itself must be sufficient to cope not only with peak demand conditions, but also with peak net generation, even if these conditions only last for a few hours per year (Eurelectric, 2013). Consequently, distribution costs can actually increase significantly due to the connection of DG.

Several studies have demonstrated that the implementation of active network management helps lower the impact of DG on distribution network costs (investment, maintenance and energy losses cost) compared to a business-as-usual approach (see, for example, Cossent *et al.*, 2011). Box 3.1 summarises the results of analyses aiming at quantifying the effect of DG deployment on network costs, the level of investments to accommodate DG integration as well as the savings that might be achieved through innovative technologies (such as storage) and more active network operation.

Policy makers all over the world acknowledge that not co-ordinating the development of DER and distribution grids is inefficient:

> *"Thus far, there has been limited incorporation of demand response and energy efficiency into distribution system planning efforts, and very little incorporation of distributed generation. [...] System planners are appropriately conservative, and inclined to consider only resources that are well known and can be relied upon [...] These challenges, however, should not preclude consideration of available, feasible, and cost-effective DER solutions as part of any distribution system planning efforts" (New York DPS, 2014: 14–15).*

> *"[R]egulatory frameworks shall enable distribution system operators to procure services from resources such as distributed generation, demand response or storage and consider energy efficiency measures, which may supplant the need to upgrade or replace electricity capacity and which support the efficient and secure operation of the distribution system"* – Proposal for a revised Electricity Directive, Art. 32.1 (European Commission, 2016b).

To achieve these goals, distribution utilities should adopt a more active role in distribution network planning and operation. Implementing advanced solutions often requires utilities to take the risks inherent in using new technologies. Pilot projects ought to be encouraged through funding mechanisms that partly hedge distribution companies against these risks. This would help ensure that suitable solutions are available when needed.

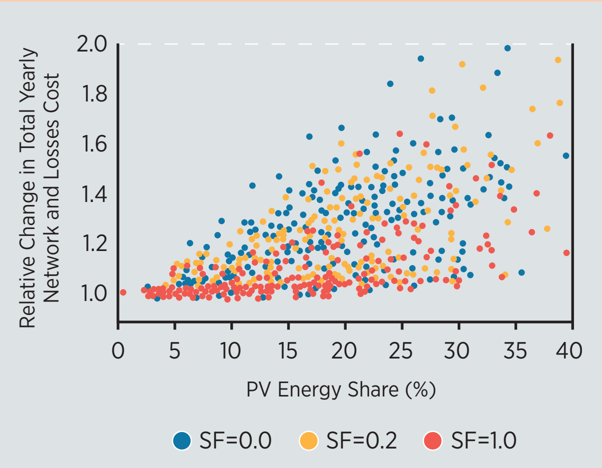
2. The coincidence in time of local generation and demand is a key factor determining the impact of DG/RES on the distribution network. For instance, solar PV production may yield significant benefits in areas dominated by commercial consumers with a significant air-conditioning demand. However, it is not possible to draw general conclusions about DG impacts since these depend on many factors, such as location, season, the year load composition, etc.

3

Box 3.1 Network investments and advanced solutions to integrate distribution generation

Figure 3.1 presents the outcome of a study assessing the influence of photovoltaics (PV) on distribution network cost and energy losses for 12 prototype networks. These networks were constructed using a distribution network planning model, called reference network model, and corresponding to different reference locations across the United States, selected based on solar radiation levels and population density. The vertical axis shows the increase in network costs driven by solar PV, relative to a scenario without DG. The horizontal axis measures PV penetration levels, defined as the share of the annual electricity demand supplied by local solar generation. In addition, the contribution of energy storage to the mitigation of PV integration costs is evaluated for different values of a storage factor. This parameter represents the reduction in DG peak injection achieved by the storage system. A value of zero means that there is no reduction in the maximum annual power injection, whereas a value of one indicates that storage fully offsets PV injections. The results show that when storage reduces the peak PV production seen by the grid, significant amounts of PV can be connected without a significant network cost increase.

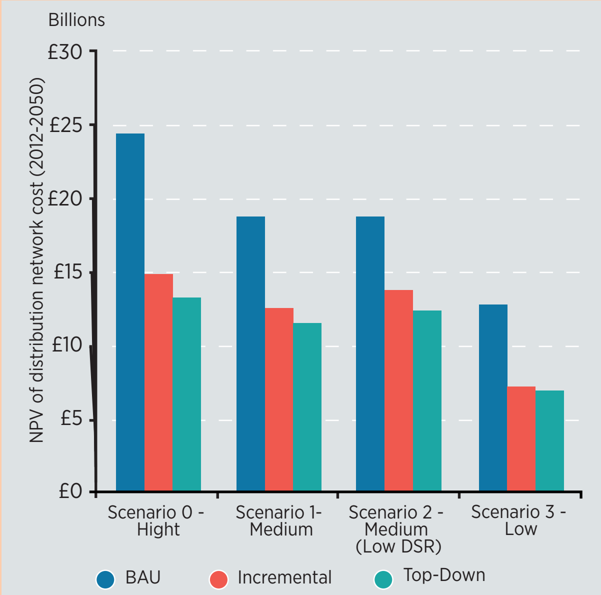
Figure 3.1 Effect of energy storage to mitigate the impact of PV penetration on distribution costs



Source: MIT, 2015
SF stands for storage factor

In 2011, the UK Department of Energy and Climate Change and the energy regulator – the Office of Gas and Electricity Markets (OFGEM) – created the so-called Smart Grids Forum for public authorities, industry representatives and stakeholders to exchange ideas about the future of their energy networks. Among other initiatives, a forum study evaluated the future investment that distribution networks need to accommodate expected DER by the year 2050 under different scenarios[a] (EA Technology, 2012). Figure 3.2 shows how, under all the scenarios, the consideration of smart grid investments (either in a top-down[b] or incremental[c] approach) yielded much lower costs than a business as usual (BAU) strategy. The vertical axis represents the net present value of expected network costs throughout the period 2012–50 quantified by means of a distribution-planning model for a set of scenarios. Each scenario displayed in Figure 3.2 corresponds to a different penetration level of low-carbon technologies (solar PV, heat pumps and electric vehicles).

Figure 3.2 Expected network investments in Great Britain to accommodate low-carbon technologies connected to the distribution network under different planning scenarios (2012-50)



Source: EA Technology, 2012

(a) Scenario 0 - high domestic decarbonisation; Scenario 1 - domestic decarbonisation to meet carbon targets; scenario 2 - domestic decarbonisation to meet carbon targets with low DSR; and scenario 3 - low domestic decarbonisation.
(b) Top down approach - A strategy where an upfront investment of enabler technologies is deployed in advance of need, followed by investment as and when networks reach their headroom limits.
(c) Incremental approach - A strategy where investment only occurs as and when networks reach their headroom limits. Enabling technologies are deployed alongside the solution variants on an incremental basis.

3.2.1 Proactive grid connection approach and long-term network planning

The management of grid connection applications should be reviewed to speed-up DG connections and allocate grid capacity more efficiently.

Information disclosure about grid hosting capacity and connection process should be promoted.

Mitigating the effect that high levels of DG can have on costs of traditional distribution networks, and making the most of the benefits provided by DER, require new approaches to grid connection and network planning. Additionally, as discussed in Section 3.2.2 more flexible grid connection and planning methodologies require distribution companies to adopt a more active grid operation.

DG units have conventionally been connected to distribution networks using a fit-and-forget approach. This means that, due to distribution companies' lack of control over DG units and DER in general, any potential operational problem, even exceptional events, had to be prevented through network reinforcements at the time of connection. This conservative strategy aims to ensure that no operational problem will arise. While this goal is a worthy one with low levels of DG, it may generate an excessive cost burden in the long run when high shares of DG are installed. This approach ought to be progressively abandoned as DG penetration levels grow to prevent undue increases in distribution costs and long lead times in DG connections.

First, grid connection processes should be revisited. Network connection requests have conventionally been managed through a first-come, first-served approach, on a case-by-case basis. As a result, the first applicants would make use of the existing connection capacity, while subsequent requests would trigger reinforcements. In case generators are obliged to bear these costs, this could make later projects unviable. Moreover, an incremental reinforcement strategy can lead to inefficient network development due to the existence of economies of scale in network components.

Therefore, to the extent possible, a co-ordinated aggregate management of connection requests should replace the first-come, first-served approach conventionally applied. Thus, the allocation of existing network capacity and cost allocation would be carried out in a much more efficient and transparent way. See, for instance, the case of Ireland, which introduced a so-called "group processing", described in Box 3.2, which has allowed the handling of a large number of wind power connection requests.[3]

Facing a similar problem related to the large number of network connection applications from promoters of generation projects, the Italian regulator implemented a specific regulatory mechanism to tackle the so-called virtual grid congestions, also described in Box 3.2. This approach is based on setting additional economic or administrative requirements before granting a certain amount of grid capacity to applicants. The main goals of the regulator were to prevent opportunistic behaviour from promoters and handle the very large volumes of grid connection requests.

New generators wishing to connect to the distribution grid typically have to submit an application to the distribution company specifying one or more potential points of connection. The generator, meanwhile, normally does not possess any prior knowledge of network conditions. As a result, applicants may find their connection being delayed or subject to high connection fees due to insufficient network hosting capacity.

3. This approach successfully addresses the problem of handling a large number of connection requests arriving at different times. As is often the case with regulations, no solution is perfect. The drawback of this approach is that it may impede the chances of better performing generators to compete with the existing ones, when their application is made later. It may also encourage the hoarding of connection permits, unless strict measures are taken to prevent this behavior.

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Box 3.2 Regulatory mechanisms to handle a large number of DG connection applications

Group processing of grid connection applications in Ireland

At the end of 2003, Ireland's energy regulator instructed network operators, both transmission and distribution companies, not to accept any new grid connections due to concerns about the secure operation of the system. Nonetheless, the number of connection requests from wind power plants kept increasing during this moratorium. Thus, the regulator decided to implement a "group processing" with the following goals:

> *"Securing early system access has become particularly valuable and important to applicants. This also mean that putting in place an orderly regime for the resumption of connection offers is essential to realizing Ireland's renewable energy obligations."* (CER, 2005)

This method consists of jointly processing connection applications from renewable generators larger than 500 kilowatts (kW) in subsequent batches or "gates". In each gate, existing applications are sorted into groups. Generators in the same group are those sharing the use of a portion of the grid. Then each group is evaluated by its corresponding network operator, both technically and economically. In case this results in a positive evaluation, applicants receive a connection offer, including their corresponding share of grid reinforcement costs, which are allocated in proportion to the capacity of each plant.

Mitigating virtual congestion in Italy

The Italian regulator published a consultation document concerning new technical and economic grid connection requirements for generators in response to the large amount of new generation capacity that had requested a grid connection (AEEGSI, 2010). By the end of 2010, projects amounting to 128 gigawatts (GW) and 22 GW had applied for connection to the transmission and distribution grid, respectively, whereas the total installed capacity and peak demand were roughly 111 GW and 57 GW, respectively[a]. Furthermore, generation projects were concentrated in areas where the grid presented less hosting capacity. Hence, important virtual grid congestions were identified, *i.e.*, potential grid constraints that would occur in case the existing DG connection requests would materialise. Two main mechanisms were devised to address this challenge for non-residential consumers/prosumers in critical network areas, *i.e.*, those facing problems of virtual congestion:

- Provide the right for network connection and access *after* additional economic guarantees had been given to the corresponding grid operator. The amount of such guarantees would be proportional to the network capacity requested. The guarantees would only be returned if the projects were realised and connected within two years from the time of application.
- Provide the right for network connection and access *only to those* projects that had already obtained construction and operation permits. Under this alternative, promoters have specific deadlines to begin the construction work of the plant before losing the right to connect, which depends on the voltage level.

The application of the first solution, initially preferred, was hampered by a litigation process. Hence, the second alternative was finally adopted. The implementation process is described in AEEGSI (2011; 2012a; 2012b). Residential consumers/prosumers were exempt from both these requirements.

a. *http://www.autorita.energia.it/it/docs/11/073-11arg.htm*

In order to achieve faster and more transparent grid connections, distribution companies should be obligated to disclose information on available. On the publication of available generation hosting capacity at potential points of connection would allow DG promoters to estimate in advance whether their application will be successful or what location would result in lower connection charges. This would, in turn, encourage generators to request their connection at the point where network conditions are most favourable. Box 3.3 provides several examples of distribution utilities that publish this type of information in different forms, sometimes subject to registration. The formats range from simple online calculators to interactive maps using geographic information system (GIS) technology.

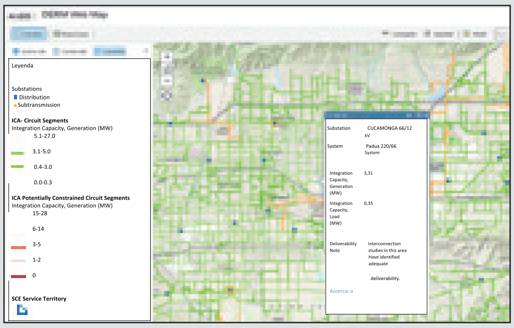
Box 3.3 Network information disclosure for new DG connections

In 2012, The United Kingdom's energy regulator, the Office of Gas and Electricity Markets (OFGEM) decided to host several discussion forums where distribution companies and generators could discuss the increasing number of generators seeking to connect to the distribution grid, the difficulties they faced when going through the connection process and the possible solutions. Today, distribution companies in the United Kingdom provide extensive and easy-to-interpret information about the connection process, as well as detailed information about the conditions of the grid. Available tools include distributed generation (DG) heat maps (SP Energy Networks), generation availability maps (Northern Power Grid) and a DG mapping tool (UK Power Networks) (see Figure 3.3).

These are interactive web-based tools that allow potential applicants to perform a preliminary assessment of grid-hosting capacity in different locations throughout the distribution grid. Figures below show two examples of map-based information provided by two distribution companies in the United Kingdom. A colour code is used to indicate the loading level of different network elements, *i.e.*, feeder circuits or substations. More detailed information (voltage level, rated capacity, existing DG capacity connected, remaining hosting capacity, etc.) is displayed by means of pop-up menus.

Likewise, distribution utilities in California were mandated to elaborate a so-called "distribution resources plan". This sought to identify optimal locations for the deployment of distributed energy resources (DER). The three main distribution utilities in the state have published the detailed information used for such analysis.[a] Figure 3.4 shows an interactive map where users may check the available capacity for generation connection in different network elements. As in the previous case, colour-coding and pop-up menus are used to display the relevant information.

Figure 3.4 DER integration map in California (Southern California Edison)

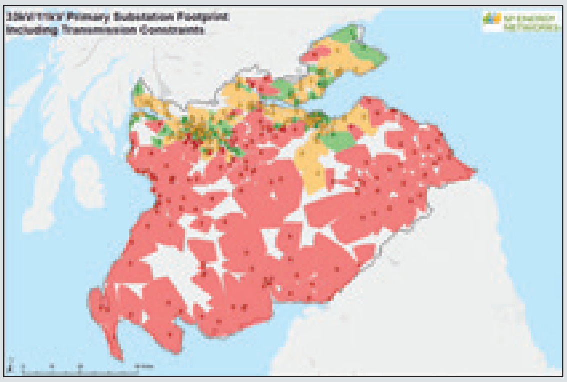


Source: Southern California Edison, 2017
a. See http://www.cpuc.ca.gov/PUC/energy/drp/index.htm.

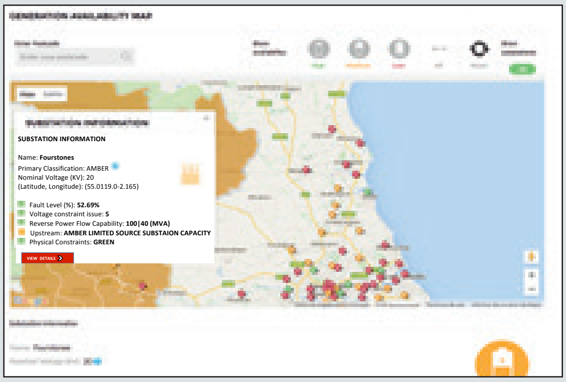
Figure 3.3 Examples of map-based information for potential DG connections in the United Kingdom

This map shows 33/11KV Primary Substations and a geographical footprint of the areas they feed. they are coloured red, amber or green depending on whether any of the following have been identified as affecting further generation connections.

- Transmission Constraint
- General Capacity Connected
- Reverse Power Flow
- 33kV Fault Level
- Percentage of 11kV Circuits Saturated



DG heat map
Source: Adapted from SP Energy Networks, 2017



Generation availability map
Source: Northern Power Grid, 2017

Over the long term, a more comprehensive, co-ordinated and forward-looking network plan ought to be undertaken (Jamasb and Marantes, 2011; Jendernalik, 2015). Conventionally, this exercise broadly consists of forecasting peak demand over the planning horizon to determine the necessary grid reinforcements. However, the times required to install a DG plant are usually shorter than those required to reinforce the grid. Distribution companies will increasingly need to foresee the connection of DG well in advance in order to prevent potential bottlenecks (Jamasb and Marantes, 2011).

The main added difficulty is that planning networks with large shares of DG, typically variable, requires knowing not only how much capacity will be connected, but also when and where DG will be using this capacity. To do this, utilities will have to move towards a probabilistic scenario-based grid planning process. More detailed geographical information, such as renewable resource availability or land-use mapping, should be employed to quantify existing DG potential. Lastly, both network reinforcements or expansions and advanced grid technologies should be considered by the distribution companies in order to determine efficient and robust investment strategies.

Regulation can promote this change in planning practices by mandating that distribution companies submit justified investment plans following common criteria. An example of such practices is that of the United Kingdom, where distribution companies have to apply a common methodology to justify their business plans based on a benefit-cost analysis, including innovative grid solutions. In this regard, the regulator states that distribution companies shall use a techno-economic model called the Transform Model[4] (or other modelling tools with comparable capabilities) and follow the long-term scenarios defined by the Department of Energy and Climate Change (OFGEM, 2013a).

3.2.2 From reinforcement-based solutions to an active network operation

Integrating DG efficiently requires the adoption of active network management as an alternative to simple conventional grid reinforcements.

Capturing the potential benefits of demand response and DG in distribution network planning necessarily involves implementing a more active network management. Thus, instead of preventing grid constraints by simply reinforcing the network or delaying the connection of DG, distribution companies may solve congestion or voltage problems during day-to-day operations.

On the one hand, distribution companies will need to adopt an enhanced use of information and communication technologies (ICT) and innovative systems to solve network constraints. These solutions comprise, among other systems, automated voltage control to mitigate the voltage rise effect caused by DG (see Box 3.4) or automatic grid reconfiguration to reduce the loading of a distribution feeder by transferring part of the DG feed-in to a neighbouring one.

In addition to deploying innovative technologies, utilities should interact more often with DER to efficiently manage network constraints. The most straightforward approach is mandating DG units to comply with certain communications requirements and dispatch signals sent by the distribution system operator (DSO), as in the existing PV curtailment system in Germany. A similar approach may be found in the United Kingdom, where distribution companies may temporarily curtail those consumers connected at the high voltage level who have agreed to be curtailed when needed in exchange for lower network charges (Box 3.5).

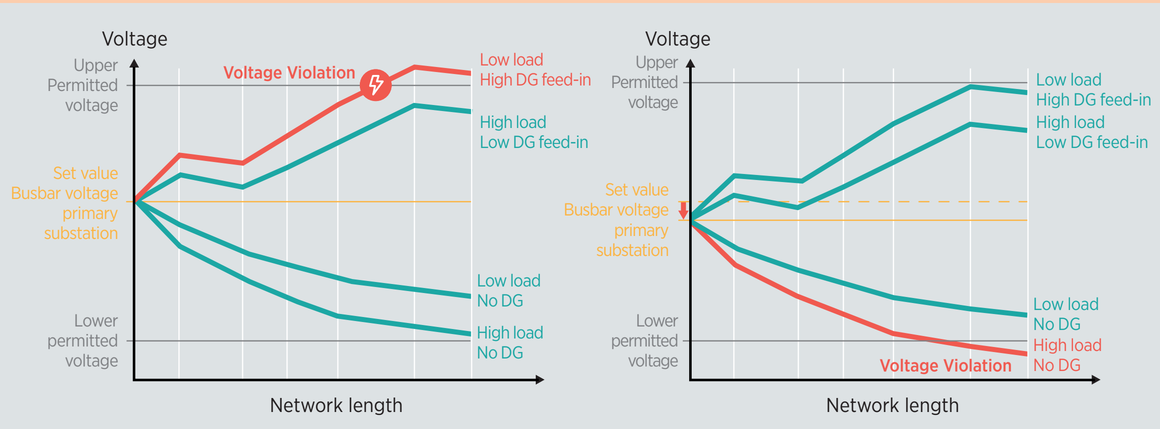
4. The Transform Model is a spreadsheet model which has been developed and is property of the consultancy firm EA Technologies. Further information can be found at http://www.eatechnology.com/products-and-services/create-smarter-grids/transform-model%C2%AE.

Box 3.4 **The need for more active network management: voltage control with DG**

In the absence of distributed generation (DG), bus voltages drop along the distribution feeders. Provided that the network is adequately designed, no voltage problems should occur. Nonetheless, the increasing connection of DG to this network could raise bus voltages up to the point where the allowable upper bound is violated. For instance, the left side of Figure 3.5 shows the voltage profile throughout a distribution feeder under different loading scenarios with and without DG. It can be seen that the presence of DG, particularly under low-load conditions, can cause an increase in voltages that at times may exceed allowable voltage limits, represented by a dashed red line, in some buses (usually those closer to the location of DG units).

The conventional solution to this kind of problem consists of permanently lowering the voltage at the substation and modifying the transformer tap position until the voltage is kept within margins. By doing this, as shown in the right-hand side of the figure, all bus voltages are shifted downwards. However, because voltages are not normally monitored in real-time, and tap positions cannot be adjusted accordingly, this could lead to an excessive voltage drop in a scenario with high load and very low DG feed-in (right part of figure). Hence, as DG penetration grows, the distribution company would increasingly need to monitor local voltage levels and dynamically adjust the substation voltage depending on actual, rather than expected, network conditions. Therefore, voltage control approaches should evolve from static passive solutions to location and time-dependent control strategies based on local measurements and grid monitoring.

Figure 3.5 Impact of DG on distribution voltage control strategies



Source: Adapted from Jendernalik, 2015

Mechanisms that allow the distributor to temporarily curtail the power injection or withdrawal of an end user for security reasons are referred to as variable or non-firm network access (Eurelectric, 2013) or smart contracts (EDSO, 2015). There is a trade-off between: 1) reducing the value of the RES due to curtailment and 2) the benefits reaped in terms of swifter DG integration. Thus, solutions should be promoted, with the aim of keeping the amount of curtailed DG production low, preventing costly grid reinforcements, increasing network hosting capacity, and allowing for a faster DG connection and access.

Existing connection requirements and planning criteria may not be flexible enough. Thus, rules obliging distribution companies to size their grids according to a worst-case scenario should be modified to allow distribution companies freedom to decide whether to reinforce the grid or offer non-firm access contracts to their users.

A limitation of these connection agreements is that the compensation for the provision of flexibility is related to the level of network charges, which does not necessarily reflect the actual value that the service has for the distribution company. Moreover, they do not generally allow different DER to compete for the provision of the service.

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Box 3.5 **Non-firm distribution network access as a means to prevent network constraints**

PV curtailment by distribution system operators in Germany

According to the German Renewable Energy Sources Act, or EEG, since January 2012, German distributors are entitled to limit remotely the injection of photovoltaic (PV) installations above 30 kilowatts (kW), subject to compensation. Plants below 30 kW may choose to permanently limit their power injection to 70% of the nameplate capacity (leaving the remainder to be curtailed or locally stored/consumed) or to install the same communication system installed on larger plants.

This mechanism should be applied only on a temporary basis in case of an emergency (congestion or overvoltage). The distribution company is still expected to eventually reinforce the grid so that no curtailment is necessary. Thus, while helpful in addressing short-term operational problems and reducing lead connection times, the mechanism does not allow distribution system operators to entirely rely on distributed generation (DG) management as an alternative to network reinforcements.

Demand-side management agreements in the United Kingdom

Distribution companies in the United Kingdom may offer non-firm network access to their network users. For instance, Scottish Power offers their extra-high-voltage consumers a demand-side-management agreement. This contract offers eligible consumers reduced charges in exchange for their agreement to reduce their maximum consumption in those periods, determined by the distribution company. Moreover, the demand charge will be reduced in proportion to the amount of capacity that is subject to such a reduction (SP Energy Networks, 2014).

Thus, more flexible and ad hoc approaches to enable the interaction of DSOs with DER have been proposed (see, for example, CEER, 2015a; CEER, 2015b; and Eurelectric, 2013). These mechanisms, as discussed in Section 3.5, may take the form of "bilateral flexibility contracts" (CEER, 2015b) or that of local markets operated by the distribution utility and participated by local DER (Trebolle *et al.*, 2010; Eurelectric, 2013; Poudineh and Jamasb, 2014). In both cases, the service provider may be the network user or an intermediary, such as a supplier or an aggregator.

3.2.3 Paving the way through demonstration and pilot projects

Policy and regulation should promote the implementation of pilot projects and the exchange of lessons-learnt and best practices.

New technology deployment should be supported through the creation of public-private collaborative networks.

More active distribution grids, largely reliant on ICTs, are necessary to ensure an efficient integration of DG. The term "smart grid" is widely used to refer to this new paradigm. Renewable integration is not the only factor driving smart grid adoption. Additional motives include improved market functioning, the development of electric mobility, a reduction in energy losses and enhanced network resiliency and reliability.

Without specific measures in place, distribution companies have little or no incentive to innovate since innovation involves increasing their risk exposure. Regulations may not allow them to use tariffs to recover the costs of innovative technologies; and the solutions adopted may not yield the expected results, leading to stranded costs. Thus, it is up to policy makers and regulators to kick-start the transformation.

Pilot projects should be promoted by means of ad hoc policy and regulation so that distribution companies are able to test innovative solutions while mitigating their risks in case of failure. Relevant regulatory instruments offer a higher rate of return on innovative investments or accelerated depreciation methods, or allow the pass-through of demonstration costs or foster direct project funding through competitive schemes (CEER, 2015b). In recent years, numerous demonstration and pilot projects have been launched to promote smart distribution grids worldwide.

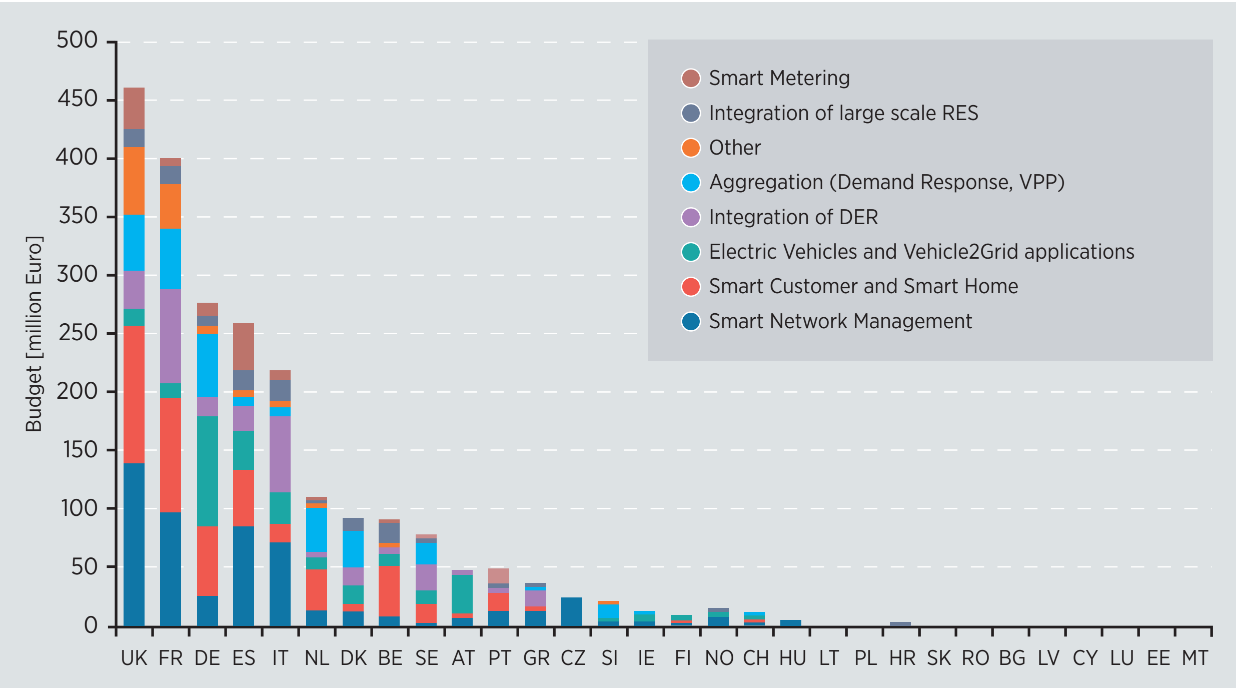
Joint public-private partnerships and fora promote the exchange of lessons learnt and identify common priorities. Examples of such collaboration networks at the regional level include the European Union (EU) Smart Grid Task Force,[5] the US GridWise Alliance[6] and the Indian Smart Grid Forum.[7] Through these networks, the European Union, the United States, and India illustrate different approaches and priorities in the transition towards smarter distribution grids. At the global level, the International Smart Grid Action Network (ISGAN),[8] includes stakeholders from 25 countries across five continents.

In the European context, smart distribution grids are considered essential to achieve more-efficient grid operation, the integration of large shares of renewable generation and a fully functional retail electricity market. The European Commission, through its Joint Research Centre, has built up a database comprising more than 450 smart grid projects (both research and development, and demonstration projects), amounting to Euro 3.15 billion in investments within the period 2002-14 (JRC, 2014). The distribution of the budget devoted to demonstration projects shown in Figure 3.6 clearly illustrates the priorities of enhancing network management, empowering consumers and integrating DER.

Furthermore, a shift in the allocation of resources from research and development to demonstration projects can be observed over the last few years (Figure 3.7). This denotes the need to implement demonstration projects to prove smart grid technologies with a view to large-scale deployment.

The American Recovery and Reinvestment Act of 2009 (US Congress, 2009), in short the Recovery Act or ARRA, represented a strong stimulus for the development of smart grids in the United States. This law allocated USD 4.5 billion to the

Figure 3.6 Distribution of budget per country and smart grid application in Europe, considering only demonstration and deployment projects



Source: Adapted from JRC, 2014

5. *http://ec.europa.eu/energy/en/topics/markets-and-consumers/smart-grids-and-meters/smart-grids-task-force.*
6. *http://www.gridwise.org/index.asp.*
7. *http://indiasmartgrid.org/.*
8. *http://iea-isgan.org/.*

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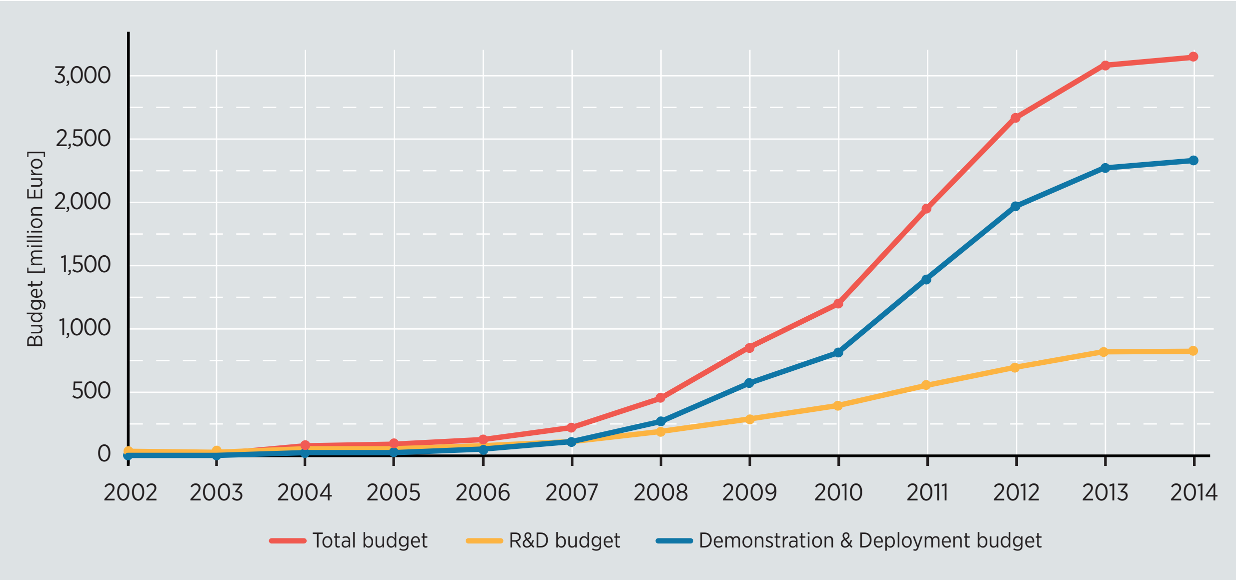
Figure 3.7 Cumulative annual budget of smart grid projects in Europe, 2002-14



Source: Adapted from JRC, 2017

United States Department of Energy (US DOE) to promote the modernisation of the US electricity system. Two major programs to foster demonstration activities in the smart grid area were created: the Smart Grid Investment Grant and the Smart Grid Demonstration Programs. These two programmes accounted for more than 93% of the ARRA funds for electric grid modernisation; over USD 3.4 billion and USD 0.68 billion, respectively. They partially funded more than 130 demonstration projects overall.[9] Figure 3.8 shows the number of demonstration projects addressing each type of functionality using data extracted from a database of smart grid demonstration projects in the United States.

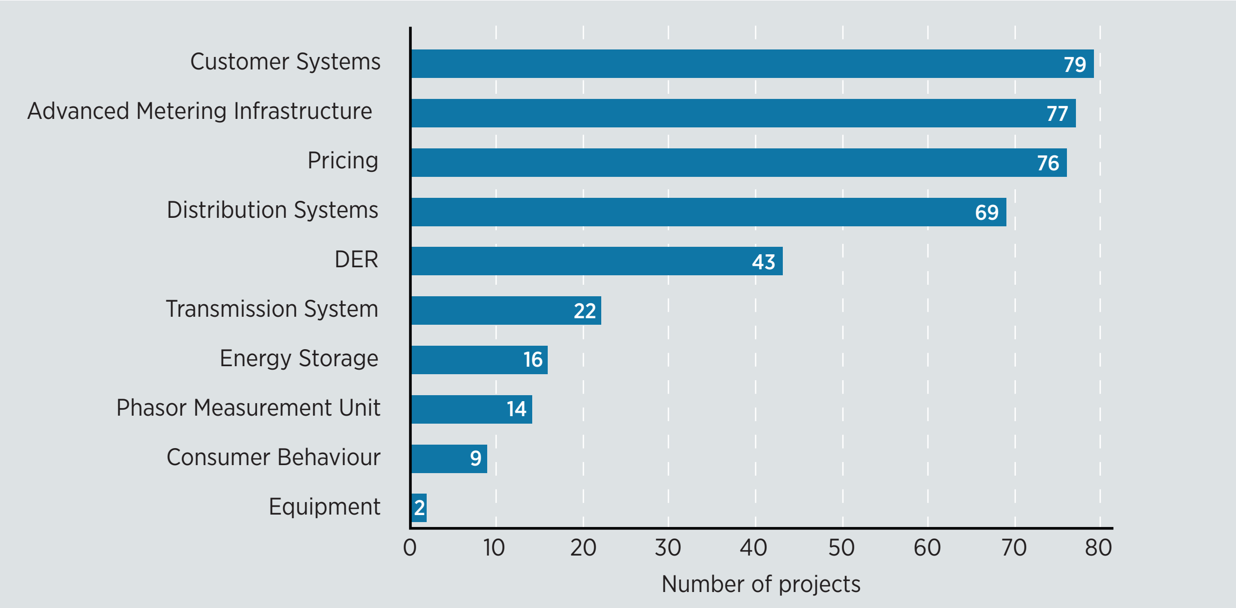
Many of these projects tested more than one functionality. For instance, projects dealing with advanced metering infrastructure (AMI) system frequently address pricing and consumer systems as well. This figure illustrates that the priorities were mainly placed on improving consumer information, demand response and network efficiency and reliability. As compared to the EU activities, the US projects focus less on retail markets than on grid resiliency and security.

In several Indian states, smart distribution grids offer a way to tackle pre-existing challenges, particularly high losses and poor reliability, and to facilitate distributed generation, especially the rooftop solar generation, by allowing movement and measurement of energy in both directions, using control systems and net metering that will help "prosumers" (NSGM, 2017). In recognition of this, the Indian Ministry of Power has selected 14 pilot projects led by different public distribution utilities (see Table 3.1). These demonstration projects mainly focus on improvements in metering systems (essential for any loss-reduction strategy), peak-load reduction and faster recovery of supply after an interruption. In 2015, the government also launched the National Smart Grid Mission (NSGM), under which four additional projects have been launched in 2016 (NSGM, 2017). Smart grid infrastructure investment is estimated to be about USD 45 billion over the period 2017-27 (T&D World, 2017).

As discussed, in order to integrate large DG levels, distribution companies will need to implement more advanced grid technologies and operational solutions. This entails a deep transformation in current practices, which should be accompanied by suitable regulations encouraging the change.

9. Full information on the projects can be found at: https://www.smartgrid.gov/ and http://energy.gov/oe/information-center/recovery-act.

Figure 3.8 Categorisation of US smart grid demonstration projects per type



Source: Based on Smartgrid, 2017

Table 3.1 Overview of smart grid pilots in India

Jurisdiction	Consumers involved	Functionalities					
		AMI Industrial	AMI Residential	PLM	OMS	PQM	DG
Telangana	11,904	X	X	X	X	X	
Assam	15,000	X	X	X	X	X	X
Karnataka	24,532	X	X	X	X	X	X
Chhattisgarh	1,900	X		X			
Puducherry	87,031	X	X				
Himachal Pradesh	650	X		X	X	X	
Jaipur	34,752	X	X	X			
Kerala	25,078	X					
Maharashtra	29,997	X	X		X		
Punjab	9,818	X		X			
Tripura	46,071	X	X	X			
Gujarat	39,422	X	X		X		
Haryana	11,000	X	X		X		
West Bengal	4,404	X	X	X			

Notes: AMI – advanced metering infrastructure, PLM – peak load management, OMS – outage management system, PQM – power quality management, DG – distributed generation.

Source: Based on NSGM, 2017

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3.2.4 Conclusions and recommendations

Management of grid connection applications should be reviewed to enable a timely and cost-effective DG connection. First, connection requests should not be processed as they arrive, but in a more co-ordinated way, *e.g.*, in batches per network area. This would result in a less discriminatory network capacity allocation and less costly network reinforcements. Second, the publication of detailed information on the capability of the existing network to host additional generation capacity enhances transparency and allows promoters to make better informed connection applications. Overall, this should result in less need for reinforcements and swifter connection processes.

Planning the distribution grid under high DG penetration levels becomes a more complex exercise. Greater uncertainty exists about DG location and future feed-in. Moreover, distribution companies will need to consider how advanced grid technologies contribute to the reduction of conventional investments on the basis of cost-benefit analyses. Regulation can push this transformation by mandating that utilities submit detailed business plans compliant with some common format or methodology as part of the revenue regulation process.

Integrating DG efficiently requires relying on a more active network operation to solve network constraints close to real-time, instead of exclusively preventing them through network reinforcements. This involves the deployment of advanced grid technologies and ICTs as well as a closer interaction between the distribution company and the existing DER. Nowadays, only a few countries allow this, mainly by means of flexible connection contracts which enable distribution companies to temporarily curtail the power of a network user in case of an emergency. Nonetheless, as the presence of DER grows, more advanced forms of contracting, such as bilateral agreements or market-based approaches, should be adopted. This should be regulated by means of newly developed distribution network codes defining the service to be provided by DER as well as some broad conditions to prevent discriminatory behaviour from the utilities.

Despite the need for smarter distribution grids, at present, distribution companies have scarce incentives to change, due to the inherent technology risks and the absence of suitable regulatory mechanisms. In the early stages, policy and regulation should promote the implementation of demonstration projects and the exchange of lessons learnt and best practices among the relevant stakeholders. Thus, both the introduction of explicit economic incentives for pilot projects and the creation of public-private collaborative networks are recommended.

3.3 ADVANCED REGULATION TO ENCOURAGE INNOVATION AND EFFICIENT DISTRIBUTED GENERATION INTEGRATION

Conventional remuneration formulas and cost assessment methodologies are ill adapted to the high presence of DER. Efficiently integrating high shares of DER requires a major regulatory overhaul.

Distribution regulation has traditionally focused on ensuring adequate investment levels and promoting short-term efficiency gains whilst preventing a deterioration in service quality. These priorities, when supported appropriately, proved successful in a context of stable technologies and predictable demand.

Under this regulatory paradigm, distribution companies require significant investments to accommodate large levels of DG under safe conditions. Moreover, since distribution remuneration is often linked to the amount of energy distributed, high levels of local self-consumption may result in a decrease in distribution companies' revenues. Consequently, utilities may see DG as a threat to their activities, and this could hamper its timely connection. Therefore, *in the absence of an in-depth regulatory reform*, regulatory measures should aim to at least neutralise the negative effects of DG on distribution revenues.

In addition, as discussed in the previous section, a business-as-usual approach to distribution grid planning and operation is not suitable to accommodate large levels of renewable and distributed generation in a cost-efficient and timely manner. Therefore, distribution companies should be encouraged to deploy innovative grid technologies and benefit from the flexibility offered by DER when this results in lower costs than conventional copper and iron reinforcements. In the early stages, pilot demonstration projects are necessary to test innovative solutions and identify the most promising ones on the basis of benefit-cost assessments.

The long-term transformation of the distribution network will be achieved only with a major regulatory overhaul. An appropriate regulatory framework should encourage distribution companies to carry out the most cost-efficient investments, including smart grids. In the process, it would ensure that remuneration is aligned with the companies' financing needs and reward them partly on the basis of their performance, rather than only on their efficiently incurred costs.

Another fundamental aspect that regulators need to take into consideration is that the changes that advanced power systems are experiencing, from the increasing VRE penetration to a more active participation of consumers, are strictly interlinked with power system digitalization. The evolving role of information and communication technologies for the efficient management of the power system calls therefore for a close cooperation between energy and telecom regulators (see Box 3.6).

Box 3.6 Digitilisation and cooperation between energy and telecom regulators

Digitalisation can be defined as the transformation of power system onto a two-layer system that combines the traditional electrotechnical technology with a new layer of information and communication technology (ICT), which provides functionality for remote monitoring, control and protection. Of course, this kind of schematisation does not mean that power system has not yet been digitalized at all. System defense tools, like automatic load shedding in case of severe frequency perturbations, were introduced decades ago; and in the first years of the second millennium, digitalisation made a further step ahead in several systems, introducing, for instance, the remote control of distribution networks. Nowadays, digitalization of power systems has much to do with deployment of smart grids and intelligent metering systems and with automation of final usages of electricity (including "domotics" in the widest context of the "Internet of Things").

The blurring edge between the electrotechnical layer and the ICT layer in digitalised power systems implies a key regulatory challenge. So far, regulation has been traditionally thought to be based on a vertical (single-sector) jurisdiction and, in most countries, organised with sectorial bodies. Only in few countries (such as Germany) the regulatory authority is a cross-sector body. In such an institutional context, cooperation between energy regulators and telecom regulators is a natural byproduct of digitilisation (BEREC, 2017).

An example of cooperation between sectorial regulators is ongoing in Italy. In 2013, the telecom regulators launched a survey on "machine-to-machine" (M2M) telecommunication services. The energy regulator (AEEGSI) contributed to the survey by collecting the experiences and lessons learnt in the energy sector for the deployment of smart grids and smart meters, both in the electricity and gas sectors. The following aspects were highlighted in that context (AEEGSI, 2014).

1) Ensuring the necessary level of interoperability (between devices built by different companies, between systems based on different technologies, between data collection and management platforms, etc.) and easy switchability among different providers (for instance through e-SIM, which can be provisioned "over-the-air");

2) Orienting regulation to encourage a level of development of "smart" applications that can minimise the cost borne by the regulated systems and, ultimately, end users, particularly the cost of communication services that sometimes account for the lion's share;

3) Ensuring that the widespread adoption of M2M applications (encouraged in part by the regulator) in the energy and water networks does not pose an obstacle to the development of multisector solutions, (for example, smart cities based on shared communications infrastructure).

Moreover, particular attention has been drawn on the *latency* parameter of M2M telecommunication services, in terms of monitoring, control and protection.

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3.3.1 Short-term measures to mitigate the impact of high levels of distributed generation on distribution revenues

Distribution revenues should be independent of the volume of energy distributed.

The combination of conventional regulation and the high penetration of DG may result in rising distribution costs and decreasing revenues for distribution companies. This impact can be counteracted in the short term through relatively simple regulatory modifications.

One of the most immediate consequences of DG, when connected behind the customer's meter, is that the amount of energy that is metered decreases. Additionally, as discussed above, network investments may even need to increase due to the impact of DG. This is because network costs typically do not directly depend on the volume of energy distributed. Moreover, network operators have little control over this factor, thus being largely exposed to volume risks. Therefore, in case of high level of DG, remuneration should be independent of the amount of energy distributed in order to prevent hurting the distribution utilities financially.[10] This separation is usually referred to as *revenue decoupling*.

The key element of a revenue-decoupled remuneration, as compared to a conventional volumetric remuneration, is that electricity rates are adjusted to ensure that the utility recovers the amount of revenues initially determined by the regulator. A study of the implementation of revenue-decoupling mechanisms in US utilities shows that, by the end of 2012, 15 states had implemented some form of revenue decoupling for at least one of their electric utilities, comprising up to 24 electric utilities (Morgan, 2013).

Revenue decoupling effectively addresses the issue of revenues being depressed by DG. Nevertheless, regulators will still need to pass the impact of DG growth on to the allowed revenues of network companies. Without knowing how to estimate this impact, revenues could be insufficient to cover distribution costs – and distribution companies may incur financial losses. Or the opposite could happen, and network users could end up paying too much. Whilst these deviations can be corrected *ex post*, retroactive actions should be avoided because they tend to create regulatory uncertainty and jeopardise the regulator's credibility. Moreover, corrections are often hard to apply in practice given existing information asymmetries, *e.g.*, regulators would need to determine *ex post* whether avoided investments in distribution are due to decreased demand or due to efficiency gains. Various ways to address these issues are discussed in Section 3.3.2.

Unfortunately, the conventional tools used by regulators to assess distribution costs are ill-adapted to the above-mentioned task. In a review of international practices, Jamasb and Pollitt (2001) find that the most common benchmarking methods rely on past information and still consider the amount of energy distributed as one of the main cost drivers. It is urgent that, as discussed in Section 3.3.2, these limitations are overcome through the adoption of new regulatory tools able to capture the effect of DG and advanced grid technologies so that regulators may compensate distribution companies for the incremental DG-driven costs and that these companies do not oppose the connection of DG:

> *"We recognise that there is significant uncertainty around the volume of DG that will connect in DPCR5, its generation type, location and voltage, all of which make it very difficult to anticipate the cost of connecting the DG to the networks. We want the DPCR5 DG incentive to ensure that there is still a strong incentive on DNOs to connect DG, and protect them from the risk of increased connection costs DG".* (OFGEM, 2009a: 22)

Acknowledging this problem, and as a transitory measure, the United Kingdom's energy regulator implemented a specific DG incentive for this purpose. This incentive was in place for two con-

10. *Similar problems may arise in the short term as a consequence of energy-efficiency measures or any other cause of falling demand. If any of these measures reduce also reduces peak load, distribution costs may indeed decrease over the long term.*

secutive regulatory periods, between 2000 and 2010, before the implementation of the RIIO reform (see Box 3.7). This incentive comprised two mechanisms which provided distribution network operators with an additional remuneration depending on the amount of DG connected.

The estimated costs incurred by distribution companies to connect DG were partially passed through to tariffs and subject to an accelerated depreciation. More specifically, companies could recoup 80% of the related investments over 15 years (the depreciation period considered for other assets was 20 years). Companies were also given an additional amount, between £1 and £2 per every kW of DG capacity connected over an additional 15 years.

Combined, these two regulatory schemes might neutralise the negative effects DG could have on DSO revenues. However, they may still be not sufficient to achieve the degree of innovation and transformation in the distribution networks which, as discussed in Section 3.2, is necessary to achieve an efficient integration of high DG.

3.3.2 Guidelines for smarter distribution regulation

Conventional, investment-focused regulation should evolve to match the new roles of distribution companies regarding DER integration.

Remuneration to distribution companies should have a long term view. Flexible remuneration schemes should be adopted.

Economic incentives to distribution companies should focus on both operational and capital cost. Forward-looking cost assessments and long-term detailed utility investment plans should be used.

Pilot projects are an essential step to testing technological solutions and disseminating knowledge gained and best practices. However, the long-term transformation of the distribution grid cannot rely exclusively on subsidised experimentation. Over the long term, regulation needs to be adapted to encourage distribution utilities to adopt innovative approaches towards grid planning and operation (CEER, 2014).

In fact, several regulatory commissions have carried out (or are carrying out) various forms of public consultation and review processes to evaluate how future regulatory frameworks should look and the main reforms needed to achieve key goals. Salient examples include those of the United Kingdom (OFGEM, 2010b), Italy (AEEGSI, 2015a) and the state of New York (New York DPS, 2014). These are described in more detail in Box 3.7.

Box 3.7 **Regulatory reforms to encourage the adoption of innovative grid technologies and solutions**

United Kingdom: The pioneering RIIO reform

Starting point: The United Kingdom was a forerunner in the application of Retail Price Index (RPI)-X regulation to the energy network industries. Over time, distribution regulation evolved towards greater separation of revenues from the amount of energy distributed, a more prominent role of comparative benchmarking across firms, stronger emphasis on the quality of service provision and equalisation of incentives to reduce both capital expenditures (CAPEX) and operational expenditures (OPEX) (OFGEM, 2009b). In fact, the regulation during the last regulatory period in which the RPI-X approach was formally applied (2010–15) already contained many of the elements that characterised the subsequent reform.

Regulatory reform: In 2009, the energy regulator – the Office of Gas and Electricity Markets (OFGEM) – launched a comprehensive review of network regulation, which was called RPI-X@20. While acknowledging that RPI-X regulation had worked well, the report asked whether new regulatory approaches were necessary for the challenges ahead (OFGEM, 2009c). This process resulted in a new regulatory model, called RIIO for "setting Revenue using Incentives to deliver Innovation and Outputs" (OFGEM, 2010b).

The major features of the RIIO reform were as follows. Regulatory periods were increased from five

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to eight years, *ex ante* total expenditure (TOTEX) revenue allowances were based on well-justified business plans and a comprehensive cost assessment toolbox, the number of incentives based on output factors (customer satisfaction, environmental impact or energy not injected by renewable energy sources due to network unavailability) was increased, and automatic revenue was adjusted within the regulatory period (menu regulation, profit-sharing and reopeners) (OFGEM, 2010a). The RIIO model is being first applied to power distribution in the period 2015–23.

Italy: Transitioning from input-based demonstration to output-based deployment

Starting point: The Italian approach to distribution regulation was based on the combination of an incentive-based revenue cap on OPEX and a more conventional rate-of-return regulation for CAPEX. In 2010, the Italian regulator AEEGSI implemented an incentive scheme to promote smart grid projects with a focus on DG integration in the medium-voltage network. Under this scheme, smart grid investments approved by the regulator were awarded an additional 2% in their allowed rate of return for a period of 12 years (9% pretax in total) (CEER, 2011).

Regulatory reform: AEEGSI has recently announced its willingness to build on the experience collected from the previous demonstration projects and move "from input-based demonstration to output-based deployment" (Lo Schiavo, 2015). A public consultation process was launched in May 2015 (AEEGSI, 2015a). The proposals made by the regulator in a resulting report offer two targets: equalising incentives to reduce OPEX and CAPEX (*i.e.*, shifting towards a TOTEX regulation) and promoting the deployment of smart grid functionalities presenting positive benefit-cost ratios through technical performance indicators. This document was followed by a second round of consultations in September 2015 (AEEGSI, 2015b) and a document that identified two main functionalities to be covered by output-based regulation in the upcoming regulatory period, *i.e.*, medium-voltage (MV) grid observability and voltage control in MV networks. Furthermore, it states that the power of the incentive mechanisms depends on the degree of their implementation and the technical capabilities of the solutions implemented.

The regulator has recently implemented provisions, including incentives for the implementation of smart grid solutions in areas with high penetration of DG, a bonus-malus scheme related to the modernisation of old urban grids, and the lengthening of regulatory periods up to eight years. Input-based innovation incentives will remain for non-tested smart grid solutions, with a particular focus on the modernisation of low-voltage networks and the development of second-generation smart metering.

New York: Proposals for Reforming the Energy Vision – REV

Starting point: The traditional utility regulation model in New York was based on the conventional cost of service or rate of return regulation. Nonetheless, rate cases progressively evolved towards multiyear reviews that implicitly provided utilities with incentives to cut costs. Therefore, earning-sharing mechanisms and performance-based schemes, mainly related to quality of service, were also introduced in order to protect both consumers and utilities from potential deviations with respect to the conditions initially considered by the regulator (New York DPS, 2014).

Regulatory reform: The review acknowledges that conventional regulation will not drive the desired evolution towards a distribution system platform provider model. The proposals released so far draw heavily from the United Kingdom's experience: longer regulatory periods, a shift towards an output-based remuneration (both for revenue adjustment and for monitoring only or scorecards), use of flexibility mechanisms such as reopeners and earning sharing schemes and the encouragement of an efficient allocation of operational and capital expenditures.

In this case, a TOTEX-based regulation to mitigate the CAPEX bias would be hindered by US accounting policies.[a] Another factor that sets the REV reform apart from its European counterparts is that, under the distribution system platform provider model, utilities are encouraged to seek additional revenue streams beyond existing rate-based earnings in the form of value-added services provided to other stakeholders (New York DPS, 2015). Obtaining these so-called market-based earnings may not be possible for European distribution companies due to existing rules on the unbundling of activities.

a. The US Generally Accepted Accounting Principles and New York regulations state that utilities are entitled to recover assets based on original cost less depreciation as opposed to a regulatory asset base determined by the regulator (and which is not necessarily based on original costs). US utilities' adoption of the TOTEX regulation under the aforementioned accounting rules could force them to write off certain assets since it is not straightforward to demonstrate that a specific asset is being recovered through the rates (New York DPS, 2015).

Despite their different scopes and approaches, several common trends and guidelines can be found among the most advanced proposals for regulatory reform. These are discussed below and summarised in Table 3.2.

Output orientation: regulation ought to shift the focus of regulatory scrutiny from investment adequacy (inputs) to how well distribution companies are providing the required services to network users (outputs). Thus, distribution companies should be increasingly assessed on the basis of a set of output indicators beyond the common ones related to supply interruptions and energy losses. These indicators can be used for monitoring, for the purposes of comparison alone or even to affect distribution revenues (depending on performance levels).

For instance, New York authorities have recently proposed to relate distribution revenues to indicators, such as peak load reduction, customer information or time taken to process connection requests. Additionally, monitoring other types of indicators has been proposed as a way to increase transparency, provide information relevant to system planning and prepare future additional incentives schemes (New York DPS, 2014). Among the indicators proposed are asset utilisation metrics, DG penetration, emissions reduction, customer satisfaction and EV adoption (New York DPS, 2015).

Efficiency incentives neutral to the actual cost structure (CAPEX versus OPEX): regulation should encourage distribution companies to realise the contribution of DER to distribution network planning and the benefits of smarter grids, which implies exploiting the trade-offs between CAPEX and OPEX, *e.g.*, investment deferral. Instead, existing regulatory approaches tend to encourage companies to resort to investment-based solutions.

In order to rectify this, the Office of Gas and Electricity Markets (OFGEM) has implemented two mechanisms in the latest application of RIIO to electricity distribution. First, cost assessments are performed following a total expenditure (TOTEX) approach, *i.e.*, the joint consideration of all com-

Table 3.2 General guidelines for a smarter distribution regulation

Shift towards an output-oriented regulation
Conventional, investment-focused regulation should evolve to match the new roles of distribution firms regarding DER connection, environmental impact, customer satisfaction and social obligations. Thus, additional output indicators should be used for performance monitoring or as utility revenue drivers.
Remuneration formulas neutral to the actual cost structure (CAPEX vs OPEX)
Cost reduction efforts tend to focus on OPEX due to an input orientation and short time intervals between price reviews. However, exploiting smart grid benefits such as investment deferral thanks to a more-active network management and DER requires equalising the incentives to cut both types of expenditures.
Forward-looking cost assessment
Due to rapid technology change and DER penetration, revenue allowances may no longer be based exclusively on past expenditures and benchmarking studies relying on historical information. Forward-looking cost assessments and long-term detailed utility investment plans should be increasingly used by regulators.
Price reviews with a long-term view
Shifting the goal of regulation from investment adequacy to long-term efficiency raises the question of extending the length of regulatory periods, with intermediate monitoring and review processes to check for excessive deviations.
More flexible remuneration formulas
Utilities are bound to face higher uncertainties driven by technology change and uncertain DER connection. This, together with potentially longer regulatory periods, strengthens the need for more flexible remuneration schemes such as profit- or earning-sharing mechanisms or index-triggered reopeners.

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panies' expenditures regardless of type (OFGEM, 2014). Second, a fixed percentage of the TOTEX is included in the regulatory asset base and subject to a recovery period of 45 years. Thus, the remuneration is independent of the actual cost structure of the companies (OFGEM, 2013b).

Forward-looking cost assessment: regulators ought to adapt their cost assessment tools and their application, as well as request distribution companies to provide them with detailed investment plans. The goal is to capture the real conditions that will be faced by the distribution companies and avoid long lags between the time costs are incurred and when they are recovered.

The application of the RIIO approach to electricity distribution in the United Kingdom provides a good example of using a forward-looking approach in cost assessments. For instance, despite applying conventional regression benchmarking models, a combination of past information and forecasted data is used as input for the models (OFGEM, 2013c). Moreover, distribution companies were mandated to submit detailed business plans. As part of this process, the companies had to apply an engineering model, called the Transform model, to justify that their investment plans captured the effects of smart grids and DG (OFGEM, 2013a).

Focus on long-term efficiency: the principle of encouraging long-term efficiency over myopic or strategic short-term cost reductions is embedded in all the aforementioned guidelines. Regulators should progressively extend the length of regulatory periods to force distribution companies to adopt this long-term viewpoint. This would allow distribution companies to spend their efforts in improving their performance rather than on time-consuming rate cases.

In this context, New York is planning to extend its multiyear rate plans from three to five years, whereas the United Kingdom has already extended the frequency of price controls from five to eight years. The flip side of this measure is that uncertainties increase. Flexibility mechanisms and automatic revisions are then usually needed.[11]

Flexible remuneration formulas: as the distribution networks evolve, technology and demand for network services will no longer be easily predictable. If the time between price reviews is lengthened, the uncertainties are worsened. Therefore, remuneration formulas should be flexible in order to react to unforeseen events and deviations. In practice, the main tools for this are the so-called *profit- or earning-sharing mechanisms* that prevent distribution companies' excessive loss or gain due to the incorrect setting of baseline revenues. When these deviations exceed a certain level, the baseline should be revised by means of reopeners. This implies that if actual costs deviate more than a certain amount from baseline revenues, the regulator is entitled to intervene.

The use of earnings-sharing mechanisms is a standard in New York. The regulator monitors the return on equity of utilities. When this exceeds a predefined threshold, the benefits are shared between the utility and the ratepayers. The innovation being proposed is to determine the sharing factor to the performance indicators (outputs) of the utilities. Thus, utilities presenting a better performance or scorecard will be allowed to retain much more of the efficiency gain as compared to poor-performing utilities. OFGEM has implemented a series of reopeners in case different types of expenses deviate significantly from the forecasts, as well as an intermediate review of the outputs delivered by distribution companies (OFGEM, 2013d).

11. Jenkins and Pérez-Arriaga (2014) present an advanced implementation proposal of this guideline. The authors build on the menu regulation with profit-sharing contracts applied in the United Kingdom by introducing an automatic ex post review based on adjustment factors computed in advance. These factors automatically correct revenue allowances for deviations in the load growth and DG penetration, thus mitigating the risks derived from forecast errors.
Automatic revisions may be hampered by acceptability issues on behalf of consumer advocates (which usually play an active role in US ratemaking), particularly when they can lead to tariff hikes. A noteworthy case is that of ComEd in Illinois in 2011. A bill was introduced enabling this utility to invest in grid modernisation and smart metering in exchange for automatic rate increases that granted the utility a return on equity of 10%. This bill was opposed by consumer advocates and the state attorney general, and it was even vetoed by the state governor. It was finally passed with a "veto-proof" majority.

3.3.3 Conclusions and recommendations

The efficient integration of DG on a large scale is not feasible without appropriate adaptation of regulatory practices. The focus so far has been placed mainly on neutralising the potential negative effect that DG may have on the revenues and investment needs of distribution companies.

On the one hand, distribution revenues should be made independent of the volume of energy distributed. Otherwise, self-consumption or energy-efficient measures may immediately translate into a reduction in revenues, whilst costs remain constant or even increase. The main component of revenue decoupling consists of an *ex post* adjustment of network tariffs so that the utility exactly recoups the revenues allowed by the regulator.

On the other hand, as long as cost-assessment regulatory tools are unable to capture the impact of DG on distribution costs, it is necessary to set economic compensations for distribution companies due to the cost increase driven by the connection of DG. These compensations should be added on top of conventional revenue allowances and be exempt from efficiency requirements.

However, none of the aforementioned regulatory measures by themselves actually encourages distribution companies to innovate grid planning and operation, which is a must for efficient DG integration. Deeper changes to current regulatory approaches are required to achieve this transformation, as has been acknowledged by some regulatory authorities. Revenue decoupling is a first step, to be followed by the implementation of new regulatory frameworks that promote long-term efficiency in the presence of large volumes of DER. A review of the ongoing regulatory reforms of this nature reveals several guidelines for future reforms of regulatory frameworks for power distribution:

- The focus of regulation ought to be shifted from ensuring that companies carry out enough network investments to assessing them on the basis of their performance, measured by an extended set of indicators.
- Distribution companies should not be incentivised to invest in conventional network assets when a less-costly alternative involving higher operation expenditures exists. Therefore, contrary to widespread practices, incentives for cost reductions should be placed on TOTEX.
- Cost-assessment methodologies should increasingly rely on forecasted data and well-justified investment plans submitted by the regulated companies.
- Promoting efficient investment in distribution networks requires adopting a long-term perspective, given the long useful life of assets. In practical terms, this has motivated some regulators to lengthen the period between price reviews.
- Remuneration formulas should be more flexible to account for this. Deviations between actual costs and revenues allowed *ex ante* may be subject to profit-sharing mechanisms and even lead to a revision of the allowances in case this deviation exceeds a certain threshold.

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3.4. SELF-CONSUMPTION: TARIFFS AND METERING

Self-consumption can yield benefits both for end users and for the power system as a whole. At the same time, it can promote demand side flexibility, including the adoption of distributed storage behind the meter. Policy and regulation should actively promote self-consumption and remove administrative barriers.

In order to attain a sustainable development of active agents with consumption, production and storage, it is important to adopt a cost-reflective design of retail tariffs and support the roll out advanced metering technologies.

Self-consumption[12] is a RES promotion policy with a relatively simple design and with high levels of consumer acceptance. Despite the benefits to consumers and overall system efficiency, in case of high DG levels, conventional tariff designs and net-metering policies[13] may jeopardise a system's cost-recovery and create cross-subsidisation among those customers who self-consume and those who do not.

It is important to highlight that end-consumers make their decisions based not on wholesale electricity prices, but on the retail tariffs they pay. In fact, the cost of generating electricity often accounts for less than half of the final electricity costs paid by the end-user. Another relevant clarification is related to the concept of grid parity, *i.e.* the point at which the LCOE of (usually) PV generation falls below the volumetric charge (USD/ kWh). The adoption of PV panels on consumer premises might be spurred once this break-even point is reached. But this may not happen when the retail tariffs do not reflect the actual value of electricity at each location and time period (IEA, 2016), thus leading to inefficient investment decisions and consumption choices.

The challenge for policy makers is twofold: 1) eliminate barriers to the adoption of self-consumption, especially for commercial and residential customers and 2) revisit tariff designs for network and other regulated charges adopting more advanced retail energy pricing mechanisms that appropriately value both the energy self-consumed and the energy exported to the grid.

Consumer empowerment and the diffusion of DG have paved the way for end-consumers who locally generate part of their electricity needs and who, during some periods, inject the surplus energy into the grid (thus becoming a producer/consumer). Local self-consumption can deliver savings both to the end-consumer and the system as a whole (although, as discussed below, these two do not necessarily go hand in hand). Box 3.8 reports two examples of commercial consumers that have managed to reduce their electricity bills to a significant extent thanks to self-consumption with solar PV.

From a system perspective, the benefits of self-consumption are realised when local generation coincides in time with the consumption behind the meter. Under these conditions, self-consumption reduces the utilisation rate of network assets, both at the transmission and distribution level. This reduces power flows through the grid, decreasing energy losses, especially in the distribution network whose losses account for most of total system energy losses, and reducing peak demand, thus potentially postponing the need for network reinforcements and upgrades in areas presenting scarcity of spare grid capacity. Note that the benefits of investment deferral may be realised when the distribution company has some certainty about the reduction of peak net demand, *e.g.*, by having the possibility

12. Self-consumption policies aim to promote the use of on-site generation for local consumption. The part of the bill that can be compensated varies per different approaches. A 'self-consumption scheme' usually refers to the mechanism of energy consumption in real-time (e.g. per 15 minutes). Schemes that allow compensating electricity injection into the grid and electricity consumption during a larger timeframe are usually called 'net-metering schemes'. Schemes that allow the calculation of the compensation on a cash-flow basis, rather than on an energy basis, are usually called 'net-billing schemes'. Hybrid schemes also exist (IEA-PVPS, 2016). See also Box 3.9.

13. See also 'Review and analysis of self-consumption policies', IEA-PVPS, 2016 to manage the injection/withdrawal of network users. This topic is discussed in further detail in Sections 3.2.2 and 3.5.1.

How to remunerate this local production is a key policy decision. Under net-metering schemes, this production is valued equal to the energy generated for self-consumption, *i.e.*, at the retail price (as discussed in Section 3.4.4). Some legislation, like that recently passed in Spain (MINETUR, 2015c), eliminates the incentive to the surplus, giving it a value of zero. Another option is to link the value of that generation to the wholesale energy price.

Several good practices have been shown to promote the adoption of self-consumption by installing DG behind the meter and to incentivise end users to not only install DG, but also to align their production with their consumption profile (by increasing the amount of self-consumed energy). Policy recommendations identified by the European Commission (European Commission, 2015c) include the following:

- Allow the installation of DG and storage behind the meter, even for small commercial and residential consumers.
- Simplify authorisation procedures for this kind of installation, allowing simple notification to the distribution grid operator.
- Promote the deployment of smart meters and allow aggregators that facilitate the participation of end users into wholesale and retail markets.
- By transmitting the right electricity prices to end users, *e.g.*, dynamic hourly prices, promote their reaction through demand-side response actions and installation of distributed storage.

3.4.1 Net-metering policies

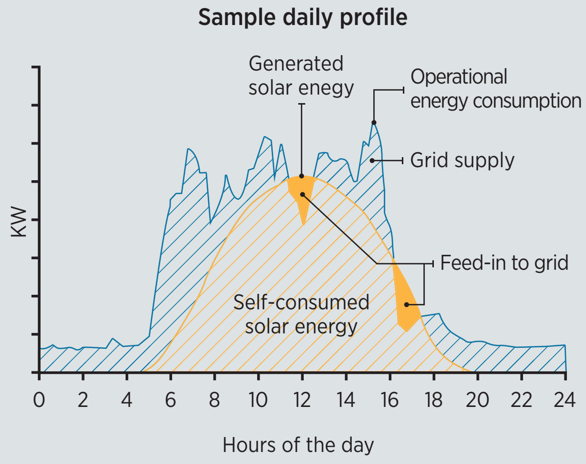
Net metering constitutes a step beyond self-consumption, and consists of allowing prosumers to use their production surplus in a given period to compensate for their consumption in a different moment. Because of this, net-metering is sometimes characterised as allowing end users to use the distribution grid as storage for their energy surplus. In fact, the implications of net-metering are much deeper. These are mainly related to the fact that, under net metering, the energy

Box 3.8 Examples of self-consumption benefits for commercial end users

The European Commission (2015c) reports the case of a commercial consumer in Germany, further described in Kraftwerk (2015), which is capable of self-consuming 87% of the annual production of its 63 kWp photovoltaic (PV) plant.[a] This is achieved because the manufacturing process runs mainly throughout the day, as shown in Figure 3.9. On an annual basis, the company is able to decrease its annual electricity bill by more than 50 000 kWh, which amounts to over 15% of its annual consumption.

Another illustrative case is an Australian winery that installed a 90 kWp solar rooftop.[b] The solar system is estimated to reduce the winery's carbon emissions by 22% and results in annual savings of up to AU$ 26 000 (approximately USD 18 900).

Figure 3.9 Sample daily load profile for a plastic manufacturing company with self-consumption from PV



Source: Kraftwerk, 2015

a. kWp measures the maximum power (in kW) instantly deliverable from a PV.
b. Detailed information on this case can be found at https://www.q-cells.com/consumer/commercial-and-industrial/references.html#references_1046894.

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injected into the grid is implicitly valued at the retail electricity price. Detailed, relevant definitions and concepts are provided in Box 3.9.

As shown in Figure 3.10, net-metering is a widespread policy in the United States, present as a mandatory rule in 41 states and several other jurisdictions. According to SEPA (2015), 99% of solar installations across the United States were under a net-metering scheme in the year 2014, representing 44% of total solar PV installed capacity in the nation. For the sake of comparison, it is worth mentioning that, by contrast, feed-in tariffs (FiTs) are present in seven states, and the Renewable Portfolio Standard (RPS) are present in 29 states.[14]

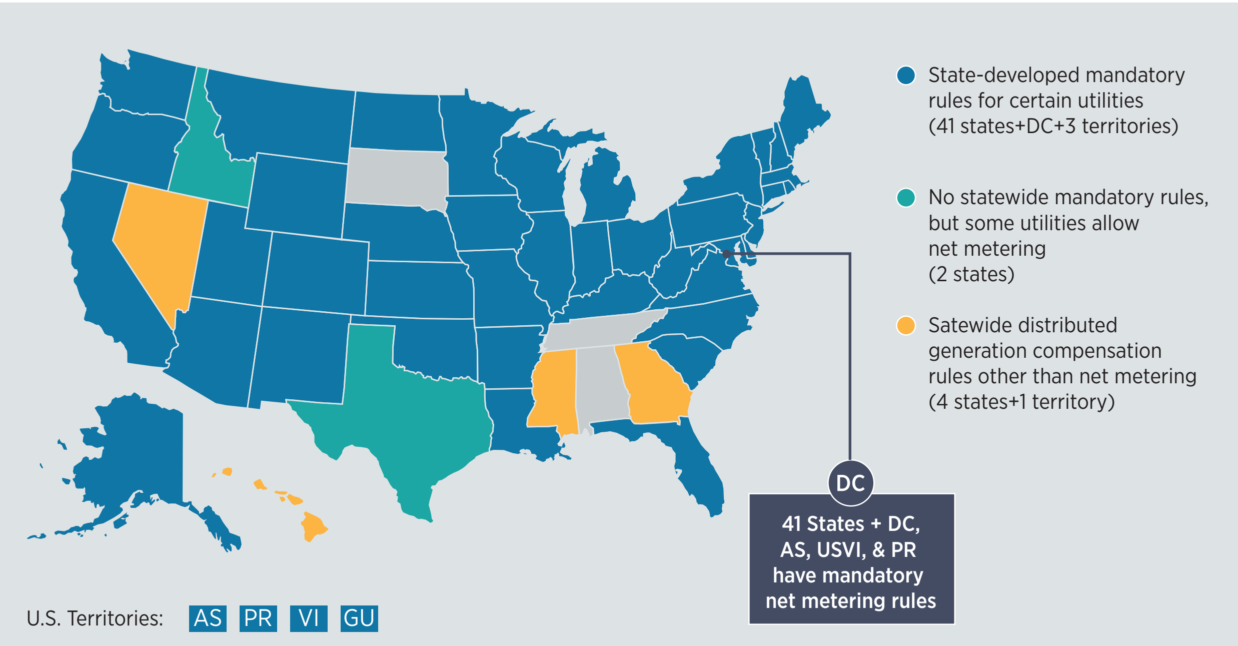
On the other hand, the deployment of renewable DG in Europe has been mainly driven by direct support schemes, such as FiTs or tradable green certificates (CEER, 2015c). Notwithstanding, net-metering, net billing, and self-consumption have been introduced in several European countries (see Figure 3.11). Such schemes are seen by policy makers as a way to keep promoting the adoption of RES, mainly solar PV, whilst progressively phasing out existing support payments. Moreover, self-consumption encourages

Box 3.9 Key terms related to self-consumption and net-metering

- *Billing period:* corresponds to how often end-consumers receive and pay their electricity bills. This period typically ranges from one to a few months.
- *Metering interval:* interval of time for which the meter records (net) consumption. In the case of modern electronic meters, this can be up to 15 minutes, whereas in the case of conventional electro-mechanical meters, this would correspond to the period in which the period meter reading is taken and, normally, also the billing period.
- *Netting period:* time interval during which prosumers are allowed to compensate energy injections and withdrawals, *i.e.*, once this time expires, the prosumer is no longer entitled to compensate net consumption with local excess production. This interval depends on the design of the net-metering scheme implemented by regulators, usually ranging from a single hour to a whole year.[a]

(a) When local production is not controllable, and once the DG installed capacity has been fixed, setting different netting periods does not affect physical power flows through the grid. In other words, if the consumption and generation profiles are set, power flows are independent of metering and billing arrangements. Nonetheless, economic transactions may differ in significant ways.

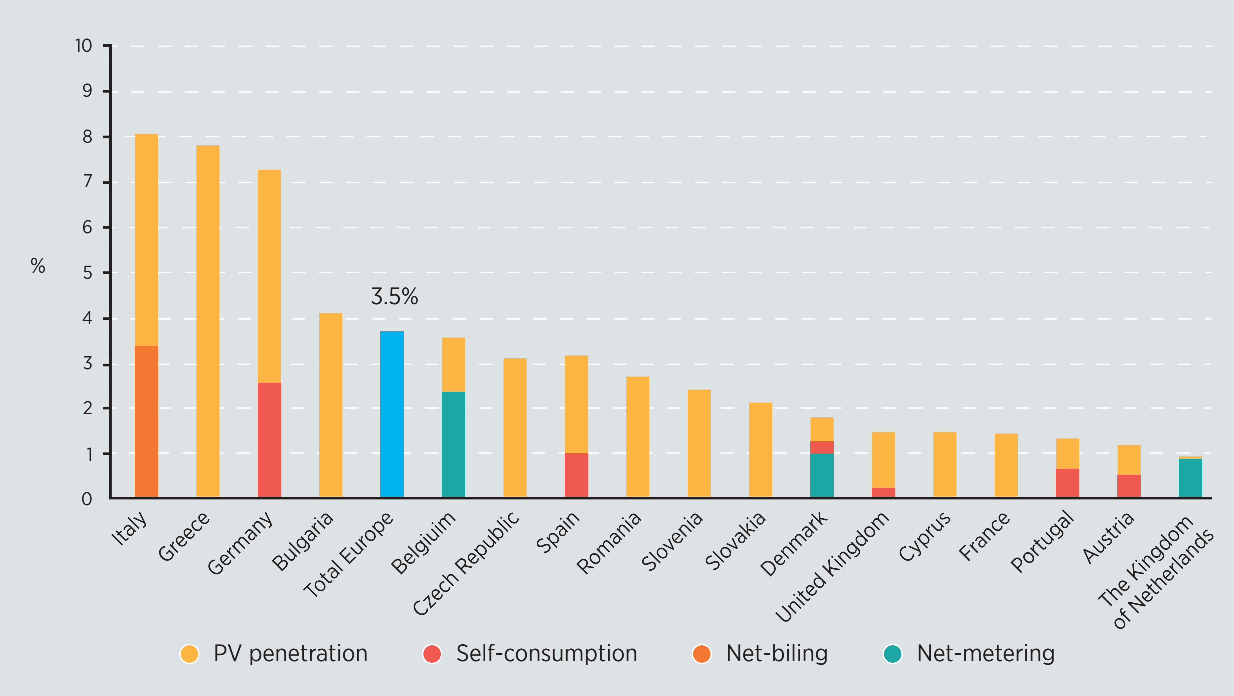
Figure 3.10 Net-metering policies across the United States in July, 2016



Source: DSIRE, 2016

14. Data extracted from the Database of State Incentives for Renewables and Efficiency (DSIRE.®). Accessible at: www.dsireusa.org

Figure 3.11 PV production in the European Union in 2014



Source: Solar Power Europe, 2015

locating DG close to where electricity is actually consumed, thus improving network utilisation.

In fact, the European Commission's initiative "Clean Energy for All Europeans" is proposing to mandate that EU Member States enable renewable self-consumption, including the right to sell excess production, and prevent "*disproportionately burdensome procedures and charges that are not cost reflective*" (European Commission, 2016b). Self-consumption has been considered so relevant that this provision has been included in two different directive proposals, *i.e.*, the electricity Directive and the RES Directive (European Commission, 2016b, 2016c).

3.4.2 Self-consumption and the missing money problem

Self-consumption mechanisms with hourly or even shorter netting intervals would contribute to the sustainable development of on-site generation.

Self-consumption involves a straightforward implementation process, high levels of customer acceptance, and low transaction costs. However, this practice can jeopardise a system's cost-recovery rates if tariffs are not cost reflective and if conventional metering technologies with very limited capabilities are used.

Under self-consumption, the value of self-consumed renewable electricity seen by end users is determined by the level of the retail tariff, more specifically the energy term (USD/kWh). However, current retail tariffs do not necessarily reflect the actual cost of electricity at a given moment. It is acknowledged that the value of electrical energy depends on the times when it is produced or consumed. Electricity markets value the energy in different time frames, ranging from hourly prices to real-time prices in periods of several minutes. Generally, this price volatility is not transmitted to retail prices. Frequently, retail prices adopt the form of flat rates or, in some cases, energy time-of-use rates.

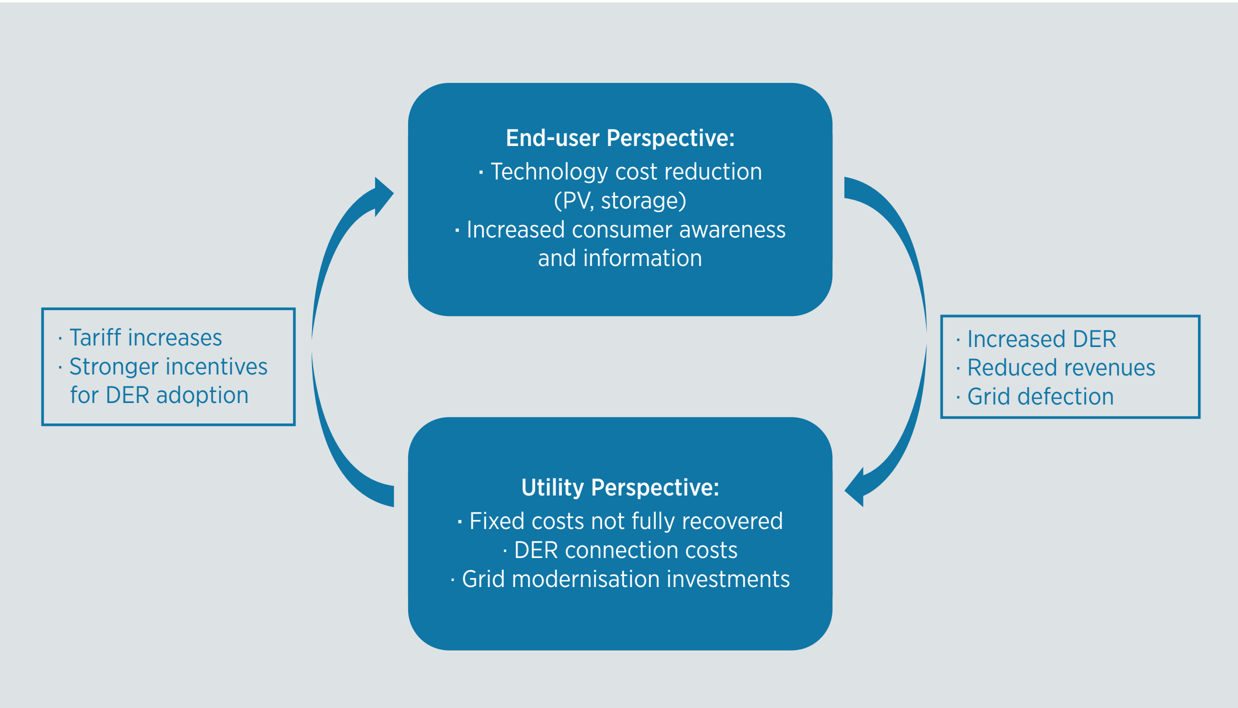
What is more, energy-based rates are often intended to recoup system costs that do not depend on the amount of energy consumed, such as network costs, system operation costs, costs of efficiency programs or support for domestic fuels or RES. Therefore, the amount of the system's fixed costs that end-users with self-consumption installations, especially those under net-metering schemes, defray can fall if tariffs do not reflect costs. Consequently, when self-consumption occurs under conventional tariff designs – with mostly a volumetric, *i.e.*, USD/kWh, component – consumers without DG are *de facto* subsidising the ones who adopt such practices. Net-metering schemes intensify this effect and reduce the sensitivity of end users to variations in electricity costs at different times, undermining efforts to promote demand-response and to promote high RE feed-in when it is critical to do so from a system-wide perspective (CEER, 2016).

It should be noted that DG can bring significant benefits to the power system: it decreases production costs and losses and defers investment of new capacity. However, net-metering may not the most suitable way to compensate DER owners. Instead, enabling self-consumption with a cost-reflective pricing system, as described in Section 3.4.4, would benefit DER users when they have a positive impact on the system. Cost-reflective tariffs would promote efficient DER investments, bringing additional value to the system as a whole as a whole.

Furthermore, regulators may be forced to raise retail tariffs to ensure cost-recovery. Higher rates also increase the economic incentive to become a self-producer, creating a vicious circle. Also, the potential large-scale adoption of distributed storage can result in prosumers disconnecting from the main grid (see figure 3.12) – a process that some have called the *utility death spiral* (EEI, 2013; Paulos, 2015).

Although grid defection is a real concern of many utilities, this possibility should not be overstated; not all users have the financial resources, willingness and space to disconnect from the main grid. Understanding how many users do would require specific and comprehensive analysis of each jurisdiction (see RMI, 2014, for an example), a process that goes beyond evaluating the economics of solar-plus-battery systems as compared to retail tariffs. EPRI (2016) suggests that the cost and reliability implications of disconnecting from the main grid are often underestimated. In any case, decreasing utility revenues and cross-subsidisation are growing concerns for policy makers and are being tackled through different policy alternatives.

Figure 3.12 Possible effects of traditional regulatory approach in the presence of high shares of DER



3.4.3 Short term solutions to tackle the missing money problem

In the absence of a well-established methodology to calculate truly cost-reflective tariffs, regulators may adopt ad hoc rules to limit the amount of missing money created through self-consumption and potentially worsened by net-metering policies when a high share of DG is installed.

To prevent prosumers from oversizing their generation units, some limitations have been set on the allowed installed capacities per metering point. Most net-metering policies in the United States also include cumulative aggregate caps. For example, PV systems in New York state may not surpass 25 kW for residential consumers, 100 kW for farms and 2 MW for non-residential users, whereas aggregate installed capacity is limited to 6% of the utility's demand for the year 2005 (including solar, farm-based biogas, fuel cells, micro-hydroelectric and residential micro-combined-heat-and-power). On the other hand, DG units in California may go up to 1 MW in capacity. An overall net-metering programme cap at the utility level was defined by the Public Utilities Commission, beyond which the investor-owned utilities (IOUs) are no longer obliged to offer net-metering to consumers. As of March 2016, approximately 79% of the capacity cap had been reached (see Table 3.3).

The volume of energy that is self-consumed and paid for can also be limited to mitigate problems of cost-recovery. Either the maximum amount of energy consumed could be limited or, indirectly, the length of the netting period could be reduced. For instance, although The Kingdom of Netherlands simplemented a yearly net-metering scheme, prosumers only receive compensation of up to 5 000 kWh/year. Similarly, Denmark recently changed the netting period from one year to one hour, making it a purely self-consumption scheme.

Table 3.3 Net-metering cap at the utility level in California (March 2016)

Utility	5% NEM Capacity [MW]	Remaining Capacity March 2016 [MW]
PG&E	2409	435.4
SCE	2240	643.7
SDG&E	607	34.1

Source: CPUC, 2016

3.4.4 Towards a new tariff design approach

Moving away from purely volumetric charges towards cost-reflective tariff structures is required.

Cost-reflective network charges should be allocated to end-users taking into consideration their location, net hourly consumption/injection and impact on asset utilisation.

The introduction of a rigorous design for network and retail tariffs that sends efficient economic signals to distribution network users is the appropriate long-term solution to enable sustainable self-consumption and encourage demand response and storage. The following are some steps taken by regulators in this direction.

Abandon purely volumetric charges

Adopting more cost-reflective tariff structures requires moving away from purely volumetric charges and introducing some kind of fixed charge (*e.g.*, USD/meter-month) or demand charge (USD/kW). As highlighted in NREL (2015b), introducing these changes in rate structures involves careful consideration of the impacts they will have on consumer bills as well as on the volumetric component. In addition to addressing the missing money problem, capacity charges encourage prosumers to reduce stress on the distribution grid. In other words, the:

> *"rate design for mass-market customers should begin to place a greater weight on the peak demand of the customer, which is closely related to the cost of the system and which can be managed by the customer"* (New York DPS, 2015:11).

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In the same line, the State of California has recently launched a proceeding which, among other goals, aims to "*ensure that the successor tariff is based on the costs and benefits of the renewable electrical generation facility*".[15] The residential rate structure was revised, after which the state's Public Utilities Commission recommended utilities to implement either minimum bills or fixed charges on residential consumers (CPUC, 2014).

Box 3.10 shows how different pricing schemes can affect end-users' investment decisions. Net-metering promotes the installation of higher PV capacities, probably above the optimal size under cost-reflective tariffs, whereas a peak demand charge encourages consumers to install storage capacity for peak shaving, thus mitigating the impact of PV penetration on the system.

Expose prosumers to time-dependent pricing

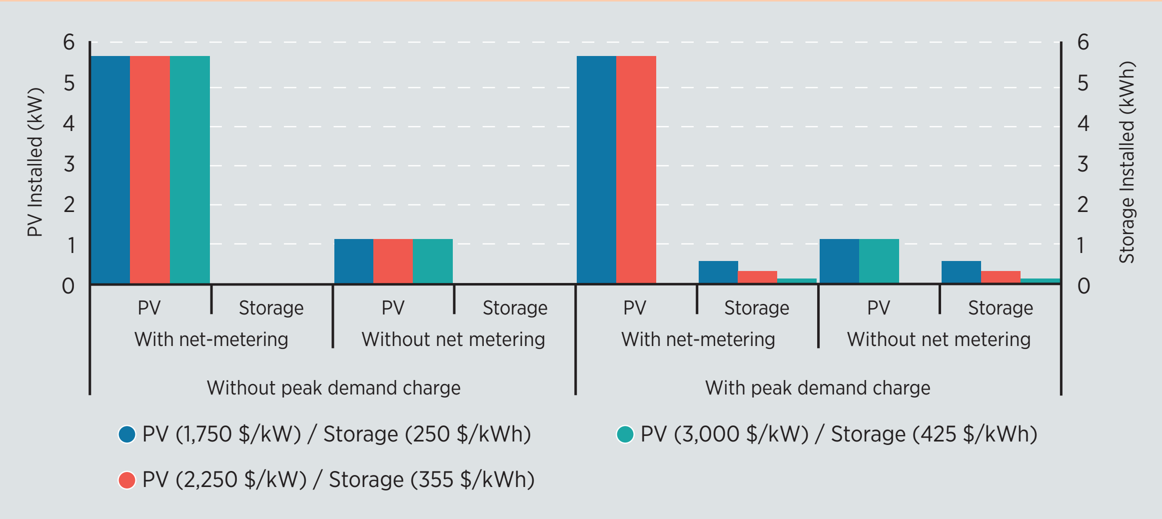
The energy component of the retail tariff determines the value of prosumers' self-consumed energy. Flat energy rates have been conventionally applied, especially to residential consumers, mostly for reasons of simplicity, limited metering capabilities and an alleged lack of demand flexibility. However, these assumptions are being increasingly challenged by the ongoing changes

Box 3.10 Simulation of investment decisions in PV and storage under different pricing schemes

Figure 3.13 shows the results of an analysis aiming to estimate the effect of net-metering together with peak demand charges on end-users' investment decisions regarding photovoltaic (PV) and storage systems under three different technology costs (Burger, 2015). The results correspond to an average New York residential house located in a suburb north of New York City with a load profile based on information available at the US Department of Energy and Energy Information Administration. Two pricing scenarios for a monthly netting period are considered: in the first, consumers are exposed to purely volumetric charges; in the second, half of the network costs are recovered through a peak demand charge.

It can be observed that net-metering significantly encourages PV investments, even in the presence of a demand charge. Nonetheless, the break-even point for PV investments is affected by this demand charge. Investments in storage, which in this case were not profitable with a purely volumetric tariff, are also encouraged to meet the evening peak demand. Storage may even be profitable for end-users in the absence of PV, thanks to its potential for reducing peak demand.

Figure 3.13 Influence of pricing signals on PV and storage investment decisions



Source: Based on Burger, 2015

15. *http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.*

in the power sector. Truly cost-reflective electricity rates should include time differentiation. The most straightforward form of time-dependent pricing would be time-of-use (ToU) tariffs, whereas the most advanced approach is based on hourly prices enabled by advanced metering infrastructure (AMI) and, in liberalised settings, by liquid and transparent wholesale markets.

The European Commission (2015c) provides recommendations on the implementation of new grid tariff designs to tackle the missing money problem and to incentivise system efficiency through self-consumption. These include:

- Future tariff designs should be based on objective and non-discriminatory criteria and reflect the impact of the consumer on the electricity grid while guaranteeing sufficient recovery of grid and system costs.
- If modifications of the current tariff structure are deemed necessary and appropriate, they should take into account the need to ensure stability for previous investments in self-consumption installations.

Decouple feed-in compensation from retail tariffs

Implicitly compensating the injection of electricity at the retail tariff level, as net-metering does, is *de facto* a support instrument to RE production that has demonstrated to be very effective to promote the deployment of decentralised RE solutions in several countries. However, this mechanism may not adequately reflect the real value of RE feed-ins at different moments. This is acknowledged by many policy makers:

> *"The current convention of crediting at the average retail rate may be either too little or too much [...]. Through the calculation of the full value of DER to the system the utility will be able to determine the total economic value of the resource [...] used as the basis of the credit"* (New York DPS, 2015: 13).

> *"Given the level of cross-subsidy that [net energy metering (NEM)] represents today, any cost-based rate design is likely to reduce the current level of support provided to NEM [...]. The goal of promoting customer-sited DG is important, but [...] subsidies should be explicit and transparent"* (CPUC, 2014: 24).

> *"Best practice include: [...] Preference for self-consumption schemes over net-metering schemes [...] Phasing in of short-term market exposure by valuing surplus electricity injected into the grid at the wholesale market price"* (European Commission, 2015c: 12).

In fact, several alternative approaches to net-metering, especially relevant in presence of high shares of DG, can compensate excess on-site DG production. In Denmark, prosumers are paid a FiT (0.08€/kWh) for their net electricity exports, whereas in the United Kingdom, PV systems smaller than 30 kilowatt peak (kWp) are given both a generation tariff for the energy that is self-consumed and a bonus for the excess electricity fed into the grid (European Commission, 2015c).

As costs go down and technology matures, self-produced electricity will increasingly compete against centralised generation rather than against a retail tariff. In a recent Portuguese regulation on self-consumption, for example, the energy injected into the grid is compensated at the average value of spot market prices (reduced by 10% to account for grid costs).

Figure 3.14 shows that different US states have implemented mechanisms that decouple the value of net excess production from retail tariffs.

Advanced tariff designs as a driver for demand response and distributed storage

For end-users' tariffs to reflect costs, tariff design methodologies should acknowledge the different added cost components of retail electricity rates. These components are: 1) the electricity price/cost in each time period and location; 2) the cost of the transmission and distribution networks and 3) other regulated costs, such as system operation or RES support.[16]

16. Note that these components strictly correspond to the costs of electricity supply. Nonetheless, taxes and levies may amount to a significant share of the final retail tariffs, even exceeding 50% of the final price in some European countries, such as Germany and Denmark (IEA, 2016).

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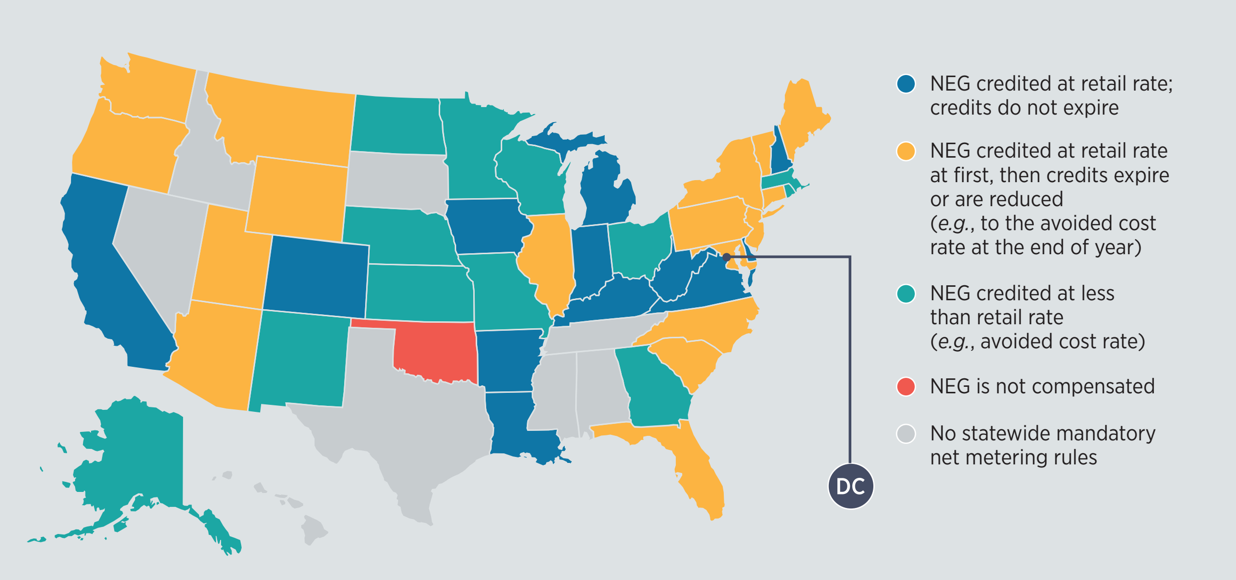
Figure 3.14 Treatment of prosumers' excess energy across the United States in July, 2016



Source: DSIRE, 2016

Exposing end-users to energy prices that vary over time and location within the grid would promote demand flexibility and distributed storage. Although this is done through ToU energy prices or hourly dynamic prices, more advanced schemes based on distribution locational marginal prices (DLMP) have been proposed (Bohn *et al.*, 1984). DLMPs essentially extend the concept of nodal prices applied at the transmission level to distribution networks. Thus, DLMPs reflect electricity's different values depending on where it is being consumed or injected in the network. This pricing methodology would therefore capture the effect of energy losses (which mostly take place at the distribution level) and grid congestion. Dynamic energy prices provide end-users with efficient short-term economic signals that promote a rational utilisation of DG, storage and demand response, either by themselves or in combination.

Network costs, both transmission and distribution, are recovered through the so-called network charges. Properly designed network charges recoup network costs and send end-users efficient long-term economic signals affecting location and investment decisions. Cost-reflective network charges should be based on the drivers for network expansion (Bharatkumar, 2015), such as location, net hourly profile (how much end users may be consuming or producing depending on the hour) and users' contribution to asset utilisation during the most critical periods of the year.

This methodological approach yields network charges that are largely independent of the volume of energy injected or consumed, but are rather based to a great extent on a fixed per-user component, which could be differentiated by voltage level or type of network user,[17] and a time-dependent capacity component (USD/kW) reflecting the impact of each end-user on the utilisation of network assets. The aforementioned capacity term would reflect the incremental network costs driven by the existence of network constraints, either current or foreseen, in the corresponding period.[18] However, in the absence

17. This term could be calculated for each network user or group of consumers according to different criteria at the choice of the regulator: Ramsey, fairness, burden sharing between small and large consumers, etc.

18. Note that, if DLMPs were in place, which is not the case in any system, part of these congestion-driven costs would be embedded into these energy prices. However, DLMPs, as it happens with nodal pricing in transmission networks, would not be enough to recoup the full network costs.

of constraints, capacity charges may produce inefficient responses from network users to reduce the loading of a grid that is not congested, *e.g.*, peak load reduction or storage installation. Thus, the remaining costs (sunk costs), which are not driven by peak consumption or generation, should be recovered through the fixed charge to prevent the distortion of previous economic signals.

It is noteworthy that network tariffs ought to be technology neutral. This means that for each time period and location the variable network charge (USD/kWh) should be the same, but with the opposite sign for consumption and injection. However, contrary to what is common today, these should not depend on the type of user that is behind the meter. Instead, for example, a power injection from a generator should be valued equal to that of a storage unit or a reduction in demand. Lastly, retail tariffs include other regulated costs related to renewable energy support policies or social policies. These costs can be very relevant in some countries and their allocation to end-users should not distort the short- and long-term economic signals provided through energy prices and network charges. In this regard, several solutions have been proposed. For example, these costs could be removed from the electricity rates, defrayed through the public budget or in the form of a tax applied to all forms of energy consumption, not only electricity. Another option could be to recover these costs through a fixed charge per consumer, acknowledging the existence of different customer categories (residential, commercial, industrial) and even subcategories (residential consumers with small, medium and large houses, for instance), but independent of their energy and capacity injections of withdrawals.

It is through the implementation of efficient short- and long-term economic signals (*e.g.*, energy prices and network charges, respectively) that distribution network users will be encouraged to provide the full value of distributed storage and demand response. Moreover, when combined with DG, both resources can maximise self-consumption and benefit the system as a whole. Aggregators may act as mediators to exploit the additional flexibilities offered by these resources.

3.4.5 The importance of metering arrangements

The flexibility of regulators to implement their desired self-consumption/net-metering scheme can be severely limited by insufficient metering capabilities. Conventional electromechanical meters allow only simple schemes with no or scarce time granularity and without compensation for net exported energy. Electromechanical bidirectional meters, or a two-meter configuration, overcome this last barrier. However, the length of netting periods would be limited by the meter-reading process. Since meters are read every one or two months, cost-recovery would hardly be mitigated by reducing the netting period.

Therefore, electronic meters capable of recording bidirectional energy flows every few minutes are a precondition for the most advanced net-metering schemes relying on time-varying tariffs and/or very frequent netting periods. Should a new meter installation or replacement be needed, regulators should assess the suitability of setting the obligation to install modern metering devices on prosumer premises. The implementation of efficient self-consumption policies is not the only driver for smart metering. Section 3.5.2 will further discuss other issues related to smart metering, such as its role in enhancing consumer awareness, retail market functioning and demand response. The section will also outline smart metering deployment policies as well as metering data management models.

3.4.6 Additional policy considerations

The implementation of the aforementioned policy measures may raise some additional considerations that are not strictly related to self-consumption and net-metering but are important to take into account.

Regulators ought to bear in mind how changes in retail tariff structure would affect all consumers, not only new prosumers. For instance, introducing a capacity charge would modify the economic signals seen by pre-existing prosumers, thus modifying the conditions in which they evaluated their investment in DG. Moreover, the introduction of fixed or capacity charges can have unintended consequences for low-consumption customers, who may see their bills suddenly increase. Therefore, gradual reforms and the progressive implementation of tariff changes are advisable (CPUC, 2014; European Commission, 2015c; New York DPS, 2015).

Burdensome administrative procedures and complex tariff options may pose a significant barrier to end-users, particularly residential consumers. Another policy priority should be to reduce transaction costs for prosumers through targeted information, simplified administrative procedures or web-based calculators (CPUC, 2014; European Commission, 2015b).

Another important issue to bear in mind is the impact that a potential massive deployment of small-scale storage, coupled with DG, can have on the power system, and distribution networks in particular. Prosumers, following price signals, could use the storage systems to store electricity and inject it back into the grid at different moments in time. Potentially, this could make it even more difficult for system operators to forecast production from DG. This is yet another argument in favour of implementing a set of cost-reflective tariff structures. Moreover, DER access to the upstream markets should be enabled. This would require, among other things, extending the conventional roles of distribution companies, strengthening co-operation between transmission and distribution grid operators and promoting the aggregation of DER. Section 3.5.1 discusses these issues in further detail. The key regulatory challenge in this regard lies in how to co-ordinate different economic signals when these enter into conflict, for example, when the provision of balancing services by a DG unit or a prosumer results in congestion at the distribution level.

3.4.7 Conclusions and recommendations

Self-consumption through the installation of DG and, in the future, storage behind the meter is a policy alternative that benefits end-users by decreasing their electricity bills and benefits the system by reducing energy losses, encouraging network investment and enhancing consumer engagement and participation. Self-consumption should therefore be supported by regulation.

Nonetheless, if not adequately designed, self-consumption measures may create a missing money problem in traditional regulatory settings, that may jeopardise the financial viability of utilities. The reason for this is usually a combination of a not adequate retail tariff design, which mainly relies on a volumetric term to recover all system costs, and old metering technologies, which are not capable of measuring bidirectional power flows with a high level of time differentiation. In some contexts, the challenge may be worsened by high volumes of net-metering policies, which implicitly value the energy injected into the grid at the retail electricity price. In response, regulators have tried to limit the allowed installed capacity or the amount of energy being compensated, or shorten the period of time over which energy injections are reduced from the amount of electricity billed and paid.

These provisions, however, do not represent a sustainable long-term solution to the missing money problem. The potential negative effects of high level of capacity supported through net metering depends on the combination of mostly volumetric (USD/kWh) tariffs and standard meters, which are applied and read monthly at the most. Therefore, it would be advisable to promote self-consumption schemes with hourly or even shorter netting intervals. In addition to this, end-users, especially those with self-consumption installations, should be exposed to well-designed retail tariffs that reflect the value of energy at each moment as well as its impact on future investments. When additional incentives compensating surplus electricity that is not instantaneously self-consumed are deemed necessary, these should be explicit.

Some policy makers and regulators have already started to implement provisions that could be considered aligned with cost-reflectivity criteria, such as introducing demand or fixed charges, ToU tariffs or decoupling the value of electricity feed-in from the level of retail prices. Truly cost-reflective tariffs would send efficient short-and long-term signals to end users, reflecting their contribution to system costs and ensuring the recovery of total system costs. Their calculation should consider the following components of system costs: 1) the price of the energy on the market, with temporal and locational differentiation; 2) the cost of the grid and 3) other regulated costs.

- Cost-reflective prices of electricity acknowledge its different value over time, and also by location, reflecting network effects (congestion and energy losses). Time-of-use or dynamic energy prices translated to end-consumers with DG and future storage installations would provide efficient economic short-term signals. These signals would in turn promote the efficient operation of those resources, including demand-response, generation dispatch and storage management.
- Network charges should provide end-users with economic signals promoting efficient location and investment decisions, which should be based on the actual contribution of each network user to the network costs. Cost-reflective network charges should be calculated attending to the various drivers of grid expansion. Thus, they should be allocated to end-users taking into consideration their location, their net hourly consumption/injection and their contribution to asset utilisation. The resulting charges would consist of a time-dependent capacity component reflecting the individual contribution to network peak utilisation (both injection and withdrawal), plus some fixed component related to the grid connection and other costs that can be somehow shared by all network users.
- The remaining regulated costs related to energy or social policies, when transferred to electricity rates, should not distort the previous short- and long-term economic signals. Several solutions have been proposed for the allocation of such costs – *e.g.*, through a fixed charge or differentiated by customer size or category. Fixed charges can also have undesired effects, such as jeopardising low-demand consumers, debasing demand response and energy-efficiency efforts or encouraging grid defection. Policy makers may decide to recoup these costs, at least in part, through alternative revenue sources such as public budgets or taxes.

Well-designed retail rates, including adequate time granularity, can only be transferred to end-consumers if an advanced metering infrastructure is available. Electronic meters capable of recording bidirectional energy flows every few minutes are a precondition for the sustainable development of self-consumption and to spur end users' demand response, including distributed storage.

3.5 FUTURE ROLE OF DISTRIBUTION COMPANIES

Distribution companies have to bridge the gap between flexibility providers, markets and system operators. Moreover, they should integrate the flexibilities offered by DER into their planning and operational practices. Thus, distribution companies should adopt new roles as market facilitators and distribution system operators.

The energy transition is undoubtedly affecting all segments of the electricity power industry. Nonetheless, it is in the lower end of the supply chain where these impacts are driving a deeper transformation. The system's decentralisation, the deployment of ICTs and enhanced consumer awareness are forcing distribution companies to reconsider their conventional roles as network owners and operators.

The agents located at the distribution level are gaining in importance and their active contribution will become essential to ensure secure system operation. In this context, distribution companies represent stakeholders essential to connecting end-users with upstream markets and system operation. Moreover, utilities should integrate the flexibilities offered by DER into their planning and operational practices by newly defined mechanisms. Performing these new roles, distribution companies will see themselves interacting more closely with other agents such as suppliers, aggregators and TSOs/ISOs.

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Moreover, regulation should define the role to be played by distribution companies in the deployment of advanced metering, as well as data collection and management. These questions are essential to unlock the flexibility potential of demand response, ensure a sustainable development of self-consumption and facilitate well-functioning retail markets.

Lastly, distribution companies may play a role in the deployment and operation of new grid-edge infrastructures, such as public EV charging stations or distributed storage. The major regulatory question is whether to consider this infrastructure as part of the business model of distribution companies or, on the contrary, open them for private initiative.

The development of EVs and its impact on the distribution activity is yet one more signal that the integration of RES should be part of a holistic approach to achieving a low-carbon energy system. The electricity system is more and more related to other sectors, such as transport and heating/cooling. This requires policy makers to consider coherent and co-ordinated intersector planning.

3.5.1 Moving from network managers to market facilitators and system operators

Regulation should grant DER access to upstream energy and ancillary services, and facilitate greater coordination with TSOs/ISOs.

Distribution companies should facilitate this participation and carry out activities such as an ex-ante technical validation and an ex-post verification of the provision of the service.

The growing presence of more flexible and diverse distribution network users forces distribution companies to reconsider their conventional roles as mere network owners and operators. As the decentralisation of the power system advances, DER will become increasingly important players in the overall functioning of power systems. Distribution-connected resources will have a stronger presence in energy markets, and their active contribution to the secure system operation will be increasingly necessary through the provision of ancillary services and network support.

In this new environment, distribution companies can enable the participation of DER in competitive markets in a transparent and non-discriminatory way. Moreover, the companies themselves are bound to become buyers of these flexibility services in order to ensure efficient distribution planning and operation. Hence, it can be said that distribution companies will need to shift their role from that of network manager to market facilitator and system operator.

It is noteworthy that, starting with similar goals (efficient DER integration, enhanced flexibility), different regions may follow significantly different strategies. This is clearly illustrated by the following two examples.

In the European context, regulators and policy makers have placed a strong emphasis on full market liberalisation. Therefore, distribution companies or DSOs are prevented from performing any activity potentially subject to competition. In those areas where this is not clearly defined – *e.g.*, energy efficiency advice, distributed storage ownership or metering data management – a strong regulatory supervision is advocated. Moreover, the enforcement of unbundling rules is seen as a key policy measure to ensure a transparent and non-discriminatory market functioning (CEER, 2015b). Meanwhile, unbundling rules make managing a significant amount of dispersed resources a complex task, as discussed below.

In a second example, the ongoing regulatory reform in the state of New York actually encourages utilities to seek what they have called market-based earnings. These are new revenue streams stemming from new activities, subject to competition or not, beyond their conventional network-related duties. Box 3.11 describes a proposal submitted by one of the state's utilities comprising four programs to yield market-based earn-

Box 3.11 Market-based earnings and new roles of utilities in New York

As part of the ongoing regulatory reform in the state of New York, utilities are requested to submit to the regulator proposals for innovative business models, consistent with the sector transformation, that can provide utilities with new revenue streams – or so-called *market-based earnings*. For example, Central Hudson Gas and Electric Corporation has presented a proposal including four of these programs (PSC, 2014).

1. A community solar program would install and operate a utility-scale solar plant and sell solar energy, in blocks of 100 kilowatt hours (kWh) and at a fixed rate, to end consumers and energy services companies willing to buy them.
2. A demand-response programme would require end-consumers or aggregators on their behalf to reduce their consumption upon request from the utility. The goal is to reduce the state-wide peak demand and defer network investments in areas selected by the utility.
3. New micro-grids, targeted at consumers or groups of consumers above 500 kilowatts (kW), would provide end-users with improved reliability in exchange for a given fee.
4. Voluntary smart meters would provide consumers with enhanced information on consumption patterns and pricing options to manage their energy bills. Subscribers would pay for the incremental cost of the smart metering system.

ings. Distribution utilities will also play a key role in facilitating the participation of other players in these services. According to this vision, utilities would become distributed system platform providers (New York DPS, 2014). It is acknowledged that greater regulatory oversight will be necessary to ensure transparency and prevent unfair practices among utilities (New York DPS, 2015).

The distribution company as a market facilitator

Despite the power sector transformation, distribution companies will inevitably remain regulated networks. Neutrality and transparency should govern any interaction between distribution companies and network users. The tasks of regulators and policy makers is to set the rules that encourage network companies to act as neutral market facilitators (CEER, 2015b). In this context, the term "market" comprises retail markets, energy markets and ancillary services markets (THINK Project, 2013).

Concerning retail markets, questions on the new role of distribution companies arise when the liberalisation process has been introduced in this segment. On the one hand, distribution companies play a key role in managing the connections (in the case of new users) and disconnections (in case of contract termination or non-payments among the suppliers' customers). This is a core function of distribution companies, which in a liberalised context requires the intermediation of suppliers who are the entities with a commercial relationship with end consumers.

The most critical role concerning a transparent and well-functioning retail market is that of managing metering data and providing data access to different stakeholders, particularly after the deployment of AMI. In a liberalised retail market, providing data access to retail companies in a transparent and non-discriminatory manner is essential to ensure competitive market functioning. Moreover, this information must be offered to end consumers so that they can actively engage and make better-informed contracting decisions. Overseeing the behaviour of distribution companies on this matter is particularly relevant where these companies belong to a vertically integrated utility undertaking active in the retail market or when distribution companies act as default suppliers. Section 3.5.2 discusses this specific topic in more depth.

Concerning energy and ancillary services markets, questions on the new role of distribution companies arise because of the participation of distribution-connected DER in these markets

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that are run by a market or system operator (see Table 3.4). This participation is to be encouraged, especially as the power system is more and more decentralised. Therefore, regulation should ensure that the role of each stakeholder involved is clearly defined, particularly that of the distribution company.

More specifically, distribution companies may act as market facilitators by technically validating the offers submitted by DER to the upstream markets, *i.e.*, by ensuring no distribution network constraints are violated. This role would be similar to what TSOs/ISOs do today with wholesale markets results. Additionally, after the service delivery, distribution companies may be required to verify the provision of the services using metering data from DER. Box 3.12. presents the case of Belgium, where distribution-connected resources are already providing flexibility services to the TSO. This case study also shows that the conventionally limited interaction between distribution companies and system operators needs to be revised.

Interactions between the distribution company and the TSO/ISO

Under liberalised electricity markets, system operators (TSOs or ISOs) and distribution network operators have been unbundled. Both are in charge of ensuring system secure operation and adequate investment planning in their respective areas of competence. Transmission and distribution networks interface in specific substations that interconnect them. Under the current practices, both operators interact periodically when they plan the need for new network assets. Within the traditional, centralised, unidirectional flow

Box 3.12 Balancing generation and demand with distributed flexibility

In Belgium, distributed energy resources (DER) are already offering their flexibility to the transmission system operator (TSO) for balancing generation and demand. The distribution company performs a preliminary assessment of those users willing to provide the balancing service in a prequalification stage and send metering data to the TSO to verify the service provisions from DER (ISGAN, 2014).

The country plans on enhancing the transparency of this mechanism by setting up a real-time balancing platform to allow the TSO to contract flexibility, substituting the current bilateral agreements. Moreover, the distribution company is to be given more visibility over the actions of DER and contracting options. Lastly, if the flexibility provision of DER keeps growing, its impact on the planned schedules of balancing responsible parties should be better considered. Otherwise, the flexibility of DER would cause a deviation in their control areas, for which they would be penalised.

Table 3.4 Major services that DER may provide to DSOs and TSOs

Service	Type of DER able to offer the service	System operator procuring such services
System balancing services	All types of DER	TSO
Frequency control	All types of DER	TSO
Voltage control	All types of DER	DSO
Blackstart	Larger-scale DS and DG	TSO and DSO
Short-term security congestion management	DG, DS, DR, (EV)	TSO and DSO

Source: THINK Project, 2013

Note: This table classifies DER into general categories, namely, DG, demand response, EVs and distributed storage. However, when the table states that a certain type of DER can offer a specific service, this does not mean that any member of that category is necessarily capable of doing so. For instance, the fact that DG, in general, could provide balancing services does not necessarily mean that any type of DG is technically capable or that it is economically reasonable for it to provide this service.

model, distribution companies provide TSOs with forecasts of the load growth at their respective network interface points.

With the change in paradigm driven by more flexible and decentralised resources connected directly to distribution networks and the more active role of distribution companies operating those resources, there is an increasing need for co-ordinating actions between TSOs and distribution companies at the operational level. The flexibility connected at the distribution level may be an efficient resource for solving network problems, not only at the distribution level but also in the transmission network.

Several models enabling this co-ordination between the distribution and wholesale levels can be envisioned. All these typically require some form of aggregation of a large number of DER, either by the distribution company itself (which may be hampered by unbundling rules) or by competitive agents such as retailers and aggregators who deliver services at both the distribution and wholesale level (IEA, 2016). In this regard, ISGAN (2014) provides country examples of interaction between TSOs and distribution companies in grid operation are identified. Table 3.5, for instance, shows the current practices and the future needs for TSO-DSO co-ordination in case of congestion in the transformer at the interface between the transmission and distribution networks when the transformer (TFO) is owned and operated by the TSO.

In this example, it is proposed that the DSO could use the flexibility provided by customers with DER (demand-side response, distributed generation, storage) to reduce the load condition of the TFO (Figure 3.15). There are other operating situations – such as line congestion, voltage support or black-start – where this co-ordination would be beneficial.

Those co-ordinated actions require DSOs to implement innovative technology solutions that are available but not yet deployed, such as grid monitoring, two-way communications with flexible customers and with the TSO, and network quasi real-time simulations.

The distribution company as a system operator

The previous example of TSO-DSO interactions represents a case where the distribution company ought to request flexibility services from its network users. Nonetheless, this would not be the only case where the distribution company should interact with DER to optimise the operation of the grid. There are situations in which this would be desirable. Regulatory mechanisms that aim to foster this interaction include non-firm connection agreements, bilateral flexibility contracts and local markets (see Section 3.2.2 and Eurelectric, 2013; CEER, 2015b).

A relevant initiative in this regard can be found in the European context. The new proposal for an Electricity Directive issued by the European Commission on November 2016, if approved as is, would mandate Member States to ensure that reg-

Table 3.5 Current and future TSO-DSO interactions

	Today	Future
TFO congestion	· Avoided in many countries by considering n-1 criteria in the network planning · Cooperation mostly during the planning phase · Emergency situations: TSO disconnects distribution feeders, possibly through a request to the DSO	· More grid monitoring and intensified data exchange would allow using flexibility on the distribution grid to reduce transformer loading when necessary · A request sent from the TSO to the DSO could translate this request to use-of-flexibility requests to flexible customers connected to the distribution grid

Source: ISGAN, 2014

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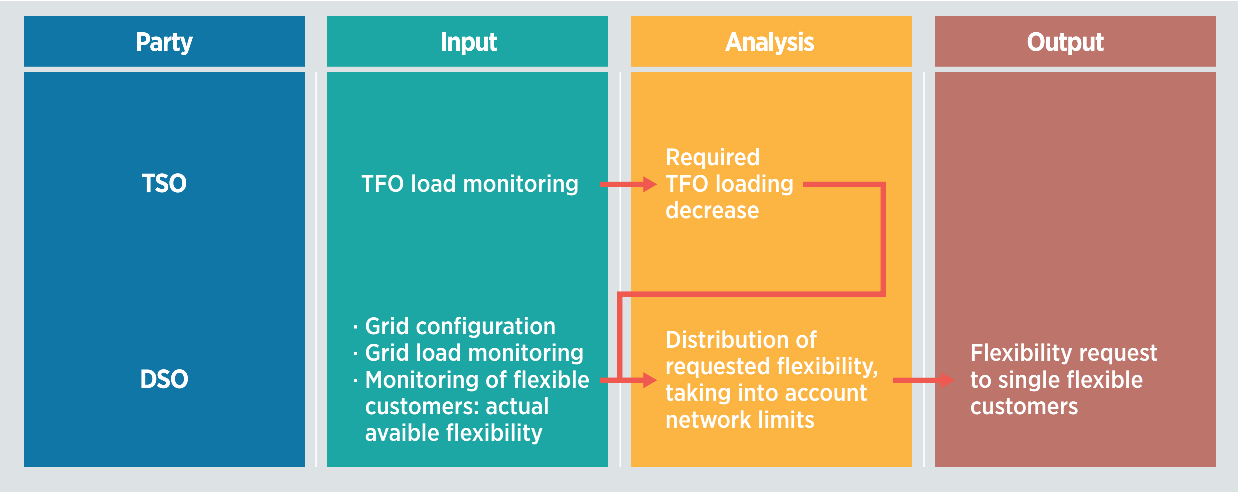
Figure 3.15 Process for avoiding TFO congestion using flexibility In the distribution grid



Source: Adapted from ISGAN, 2014

ulation enables and promotes distribution companies to procure flexibility services from network users (European Commission, 2016b). Moreover, this Directive calls for the use of "*transparent, non-discriminatory and market based procedures*" and requires distribution companies to define standardised and technology-neutral market products.

This constitutes a deep change in the conventional role of distribution companies, whose interaction with end-users has been conventionally limited to grid connection and disconnection, management of supply outages and, where the distribution company was part of a vertically integrated utility, billing. Thus, distribution companies ought to evolve from purely network managers to true distribution system operators, actively managing the resources connected to their grids, similar to what TSOs do today. Moreover, new market players, such as aggregators, may come on the scene, who combine the responses from individual customers responding to the needs of the distribution company.

In the new context concerning liberalised markets, regulation should enable the change and clearly define the roles and responsibilities of distribution companies and market players. Regulatory oversight will be needed, particularly where the distribution company belongs to a larger vertically integrated company, to avoid preferential treatment, promote competition when there are several potential suppliers for the same service and reduce the potential for market power abuse when the number of suppliers is low.

3.5.2 Advanced metering to enable demand response and competitive retail markets

Traditionally, small residential and commercial consumers have been offered very limited tariff options with scarce time differentiation. However, the integration of large shares of RES, increased interest from consumers in making better-informed decisions and the efforts to introduce competition in the retail electricity sector require a shift in paradigm. Advanced metering is a key enabling technology for the active participation of electricity end-users. Thus, smart metering is a prerequisite for demand response and well-functioning retail markets, as well as a sustainable penetration of self-consumption and an active management of EV charging and distributed storage.

There are two main policy and regulatory decisions in this domain: 1) ownership and management model for the deployment of advanced meters and 2) management of metering data and granting access to stakeholders in a transparent and non-discriminatory way.

Advanced metering roll-out

The installation and management of metering equipment have been conventionally carried out by distribution utilities, especially for small and medium consumers. Thus, metering assets have been traditionally treated as part of the monopolistic activities of distribution companies who recover the corresponding costs through network charges or a rental fee. A model where the distribution company is responsible for the deployment of advanced metering seems the most immediate solution, even in contexts where retail and distribution have been unbundled. For example, in the European Union, distribution companies are responsible for meter installation and ownership in most member states, with just a few exceptions, such as in Germany and the United Kingdom (European Commission, 2014a; 2014b).

In Germany, consumers are entitled to choose any metering operator, *i.e.*, metering is legally considered a fully competitive activity. Nonetheless, distribution companies are still the default metering operators and deliver metering services to those consumers who do not explicitly opt for a third-party metering operator. Meanwhile, electricity metering in the United Kingdom falls under the responsibility of suppliers (European Commission, 2014a).

In order to foster the penetration of advanced metering and benefit from economies of scale, policy makers may decide to opt for a large-scale rollout. This process usually stems from a policy mandate on metering operators, normally including rules governing this deployment in terms of schedule or technology capabilities. For instance, EU Directive 2009/72/EC[19] mandates European countries to install smart meters in at least 80% of consumers by 2020, provided a positive benefit-cost analysis is obtained (European Commission, 2009). Acknowledging the key role that smart metering plays in terms of consumer awareness and retail market functioning, the European Commission has proposed to provide consumers with the right to have a smart meter installed even in those countries where a negative cost-benefit analysis is obtained or where a large-scale rollout is not planned. This meter must be provided under fair conditions and comply with minimum technical standards defined in the proposal for a new Electricity Directive (European Commission, 2016b). Table 3.6 summarises the cost-benefit analysis results obtained for Germany and the United Kingdom.

According to a benchmarking study carried out by the European Commission, as of mid-2014, 16 countries had decided to implement a large-scale deployment, another three had opted for selective deployment, and just four had rejected advanced metering altogether (European Commission, 2014a). A potential drawback of a large-scale rollout is that some consumers may oppose it due to alleged health or privacy concerns. Therefore, some regulators have decided to introduce an opt-out clause in the advanced metering programs, as in the case of California (CPUC, 2012a; 2012b) and the The Kingdom of Netherlands (European Commission, 2014c).

Brazil offers a middle path between a mandated rollout and complete free customer choice. In 2012, the regulator passed a norm mandating distribution companies to offer their customers the choice of installing a smart meter. The offer highlighted the potential benefits of access to enhanced information, more tariff options and remote connection management (ANEEL, 2012).

Advanced metering data management and access

The adoption of advanced metering represents a revolution in terms of the volume of information it makes available on consumer behaviour and network utilisation. Further, smart meters may record not only consumption data, but also technical information on power quality levels, outages, meter tampering, etc. Hence, advanced metering data have immediate application to distribution network operations and planning, and distribution companies should be granted access.

The main policy and regulatory concerns around advanced metering lie on the commercial value

19. Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (Text with EEA relevance).

Table 3.6 Smart metering cost-benefit analysis (CBA) in Germany (left) and the United Kingdom (right)

CBA OUTCOME	POSITIVE (for the Roll-out Scenario Plus) NEGATIVE for the EU scenario	CBA OUTCOME	POSITIVE
Total Investment	· € mn 6,493 (by 2022) · € mn 14,466 (by 2032)	Total Investment	€ mn 9,295
Total Benefit	· € mn 5,865 (by 2022) · € mn 16,968 (by 2032)	Total Benefit	€ mn 21,749
Cost/metering point (as communicated by the Member State)	€546	Cost metering point	€161
Benefit/metering point (as communicated by the Member State)	€493	Benefit per metering point	€377
Consumers' benefit (% of total benefits)	47%	Consumers' benefit (% of total benefits)	28% (domestic sector) and 60% (non-domestic sector)
Main benefits (% of total benefits)	· Energy savings – 33% · Load shifting – 15% · Avoided investments in the distribution grid – 13%	Main benefits (% of total benefits)	Domestic sector (electricity + gas) · Supplier cost savings (54%) · Energy savings (28%) · Carbon savings (7%) Non-domestic sector (electricity + gas) · Energy savings (60%) · Carbon savings (19%) · Supplier cost savings (15%)
Main costs (% of total costs)	· Investments smart metering systems (meter, gateway, communication infrastructure) – 30% · Communication costs – 20% · IT-costs – 8%	Main costs (% of total costs)	Domestic sector (electricity + gas) · Smart meters CAPEX+OPEX (43%) · Communication costs CAPEX+OPEX (23%) · Installation costs (15%) Non-domestic sector (electricity + gas) · Smart meters CAPEX+OPEX (49%) · Communication costs CAPEX+OPEX (31%) · Installation costs (16%)
Energy savings (% of total electricity consumption)	1.2%	Energy savings (% of total electricity consumption)	2.2%; gas 1.8%
Peak load shifting (% of total electricity consumption)	· 1.3% in average between 2014 and 2022 · 2.9 in 2032	Peak load shifting (% of total electricity consumption)	· 0.5% - 1% (as a percentage of total consumption) · 1.3% - 2.9% (as a percentage of peak consumption)

Source: European Commission, 2014c

Note: The "EU Scenario" analysed in Germany corresponds to the requirement set in Directive 2009/72/EC, i.e., to install smart meters for at least 80% of all consumers by 2020. The Roll-out Scenario Plus considers the installation of smart metering systems in new and existing RES and CHP units with a contracted power above 250 watts (W), whereas it limits the installation of smart metering by 2022 to large consumers and new or renovated buildings (remaining consumers will be equipped with meters without external communications).

of this data, with respect to retail market functioning and the provision of energy services. For companies contracting with end-consumers (suppliers, energy services companies, aggregators), this information has commercial value. Consumers, meanwhile, may be able to make better-informed decisions (CEER, 2015a). Principles guiding the organisation and regulation of data access seek to ensure consumers' privacy and data transparency, accuracy, accessibility as well as the avoidance of discrimination (CEER, 2015a).

These topics are relevant in those countries where the retail market has been liberalised, especially if the regulator is concerned about insufficient unbundling or vertical integration. Note that even in those countries where a distribution company is responsible for meter deployment and operation, providing access to these data and managing that access is not necessarily the task of distribution companies (CEER, 2015b). Thus, despite the fact that distribution companies have conventionally been responsible for metering activities, they will not necessarily act as AMI data managers:

> *"CEER remains of the view that there is a need for a neutral data coordinator or data hub to manage and provide access to data, and that this role can be provided by a number of different parties as is already the case in some EU countries. [...] CEER believes that DSOs should remain as neutral market facilitators but that this does not automatically confer the status of data management coordinator to a DSO"* (CEER, 2015b: 13).

The European Smart Grid Task Force identified three main models for the management of smart metering data: centralised management operated by the distribution company, centralised management operated by an independent regulated agent and a decentralised model using a data access-point manager (Smart Grids Task Force, 2013). All of these models have pros and cons. They also involve many questions. For example, is the decision on whether to allocate the role of data manager to the distribution companies or a third party driven by the size and structure of the distribution sector? Regardless of the model chosen, regulators ought to ensure that data access is granted in non-discriminatory conditions, while the privacy of end-users is ensured.

Another issue that has attracted policy attention is the format in which these data are stored and shared. To remove market barriers and reduce administrative costs, Article 24 of the proposal for a new Electricity Directive in Europe (European Commission, 2016a) states that Member States have to define a common data format. Moreover, the European Commission could define a mandatory Europe-wide data format as well as data access procedures replacing national approaches.

3.5.3 Distributed storage and ownership models

The reduced cost of energy storage battery systems, combined with the need for enhanced flexibility in the distribution network, opens the possibility of deploying small- and medium-sized distributed storage for grid support. Interest in such applications is reflected in the large number of demonstration projects being implemented worldwide.[20] Battery systems may be installed both on the premises of end-users or directly connected to the distribution grid.

The key regulatory questions here include: 1) whether to allow the distribution utility to own and operate the storage system, given that this may collide with existing unbundling rules and 2) how to ensure that the storage is located where it is most beneficial to the distribution network when the distribution company cannot own and operate the storage system.

Energy storage systems can provide grid support services to distribution companies as well as other system services, such as balancing or price arbitrage (Eurelectric, 2012; THINK Project, 2012; US DOE, 2013). Box 3.13 offers a benefit-cost analysis of a grid-connected battery system, illustrating the challenges faced by this type of application. The benefits from distribution grid support alone may not be enough to result in a positive business

20. A comprehensive database of storage projects can be found at: http://www.energystorageexchange.org/projects/.

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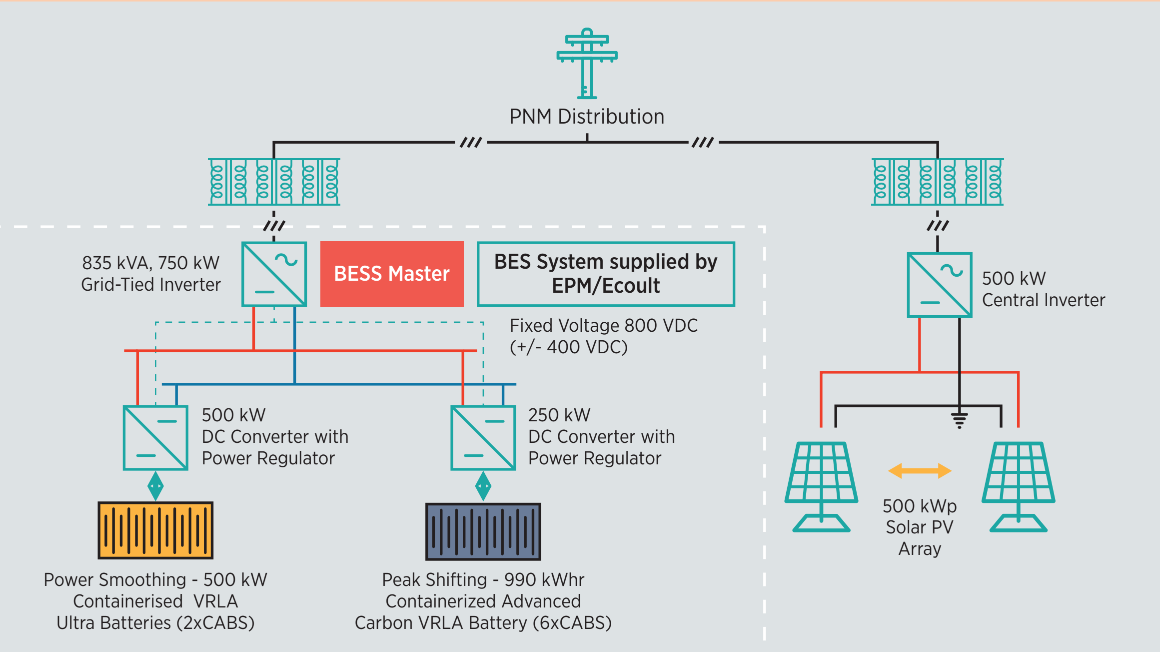
Box 3.13 The benefit-cost analysis of a grid-connected storage system

The Public Service Company of New Mexico (PNM) has carried out a demonstration project with a battery energy storage system used to smooth the impact on a photovoltaic (PV) power plant through peak shaving and voltage control in a medium-voltage (MV) utility feeder. The system schematic is shown in Figure 3.16

An evaluation of system performance in the period September 2011 until February 2014 is presented in PNM (2014). The results show that the system performed well technically. However, as shown in Table 3.7, the benefit-cost analysis yielded a negative result, even including benefits that would not normally go to the distribution utility, such as deferred generation capacity or emissions reduction. The same report states that the benefits to the distribution operator could have been much higher if the storage system had been located in a feeder with a higher PV penetration.

Figure 3.16. One-line diagram of PNM's battery storage pilot project



Source: Adapted from PNM, 2014

Table 3.7 Summarised benefit-cost analysis of PNM's battery storage pilot project

		Costs	Benefits
Base Case	Utility Revenue Requirement (Variable)	$51,576.11	-
	Utility Revenue Requirement (Fixed)	$2,929,123.43	-
	Electricity Sales	-	$114,735.61
	Distribution Investment Deferral	-	$333,987.30
	Distribution Losses Reduction	-	$15.80
	System Electric Supply Capacity	-	$177,036.26
	Emission Offset		$45,583.56
	Total	$2,980,699.54	$671,358.53

Source: PNM, 2014

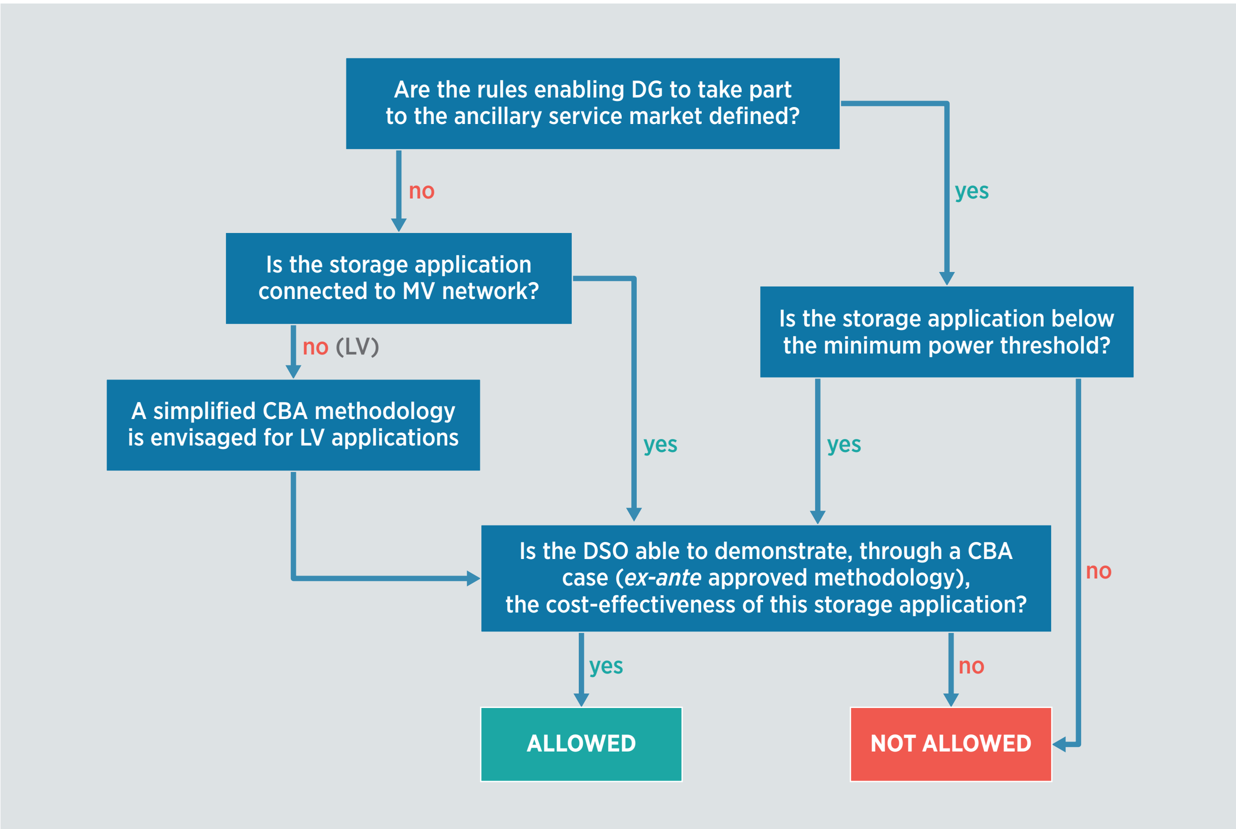
case, and the benefits to the grid largely depend on the location of the storage system.

Existing applications for grid support, usually within demonstration projects, mainly follow a structure where the distribution company directly operates the storage system. However, this may not be a viable model in regions where regulation mandates the legal unbundling of power distribution. Utilising the storage system strictly for grid support would lead to largely underutilised systems, given that network constraints in a specific area may arise only a few hours per year. On the other hand, the provision of system services subject to competition would result in distribution companies acting *de facto* as market agents.

In order to address this problem, the Italian regulator has recently proposed a framework to determine the conditions under which distribution operators may be allowed to own and operate storage assets beyond the demonstration projects (AEEGSI, 2015a). As shown in Figure 3.17, these conditions would be limited to non-competitive activities or to small-scale applications, and in all cases subject to a benefit-cost evaluation following a methodology approved by the regulator.

Meanwhile, the European Commission has stated its will to forbid distribution companies from owning, developing, operating or managing storage facilities (European Commission, 2016b). Exemptions to this rule may be implemented if the following three criteria are met: 1) other parties do not express interest in these activities in an open tendering procedure, 2) storage facilities enable distribution companies to fulfil their obligations and 3) the regulator verifies compliance with the previous two requirements and provides its approval. In order to ensure that regulation keeps up to date with technology and busi-

Figure 3.17 Framework proposed by the Italian regulator to decide upon the role of distribution companies in storage ownership



Source: Adapted from Lo Schiavo, 2015

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ness model developments, the Commission has also proposed that regulators who allow distribution companies to own storage facilities periodically (every five years) re-assess the previous conditions through a public consultation and modify regulation accordingly if needed. Another interesting initiative to encompass various phases from storage demonstration to deployment is seen in California, where authorities have set binding targets on the three largest investor-owned utilities to deploy 1 325 MW of storage capacity by 2020 (CPUC, 2013). The target is broken down per utility and type of application, distinguishing among grid-connected systems, either transmission or distribution, and customer storage (see Table 3.8).

In order to comply with this requirement, utilities shall carry out competitive solicitations every two years. Before these tendering processes, utilities are required to submit procurement plans to the regulatory commission for their evaluation, which need to justify their contribution to the following goals: grid optimisation, integration of renewable energy or a reduction of greenhouse-gas emissions. The goal of this policy decision is to spur the adoption of energy storage. Therefore, despite the fact that utilities are given a central role in the elaboration or procurement plans, they may retain the ownership of no more than 50% of the storage capacity.

An auction-based mechanism similar to the one being implemented in California could also be applied in countries like Italy, where unbundling is in place, as a means to ensure storage systems are located where they are most needed by the distribution company. The distribution company may determine the location and grid-support service required, and the winning storage operators would engage in long-term contracts with the distribution company that would contribute to their business cases.

Table 3.8 Proposed storage targets for IOUs in California (MW installed per year)

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal PG&E	**20**	**30**	**45**	**70**	**165**
Total – all 3 utilities	**200**	**270**	**235**	**490**	**1,325**

Source: CPUC, 2013

To conclude, it is useful to recall the two main regulatory questions posed at the beginning of this section: 1) whether to allow distribution companies to own and operate storage assets and 2) how to ensure an appropriate siting and sizing of storage units from the viewpoint of the distribution grid. As discussed throughout this section, enabling distribution companies to install and operate storage assets would facilitate the use of storage for network support since distributors would directly decide its location and operation. Nonetheless, this may lead to under-utilised storage assets since network constraints usually occur only on occasions. Moreover, grid-support services are not normally enough to yield a positive business case for storage devices. Therefore, storage operators would probably need to seek additional revenue streams, such as price arbitrage or balancing services, which are sometimes forbidden for distribution utilities due to unbundling or market access rules.

On the other hand, leaving the decisions on storage siting and sizing to market players would not ensure that this is located in the place and in the amount needed from the network perspective. The distribution company would need regulatory mechanisms to overcome these barriers. Thus, regulators may implement exemptions on the unbundling obligations under specific circumstances or enable distribution companies to contract services with storage operators through tendering schemes. Concerning the operational decisions over storage systems for the provision of network support (and preventing storage systems from causing grid constraints), distribution companies may purchase such services through the mechanisms discussed in Sections 3.2.2 and 3.5.1, which enable them to become true system operators.[21]

3.5.4 Business models for the deployment of electric vehicle charging infrastructure

As market forces alone may not be enough to foster public charging infrastructure at early stages, policy makers and regulators may have to step in to kick-start the EV sector.

Electric mobility has been identified as a key factor in the reduction of carbon emissions and local pollution. Hybrid vehicles, which utilise the electricity produced on-board, have been in commercial operation for quite some time. Nonetheless, the full benefits of e-mobility require the development of plug-in EVs, which recharge their batteries by connecting to the power grid.

Charging points may be located in a wide variety of places such as at homes, working places, parking lots or shopping centres. The deployment of a network of public charging points would enable the large-scale adoption of EVs. Distribution companies do not play any role concerning charging points in private areas besides granting access to the distribution grid on the same conditions as any other network user. Nevertheless, they may play a more active role in the deployment of public charging infrastructure.[22]

Public charging services can be considered a competitive activity subject to pricing alternatives such as prepayment, flat monthly rates, free charging to promote another product or service, etc. For example, in the United States, several different charging suppliers provide their services throughout the country. According to the *alternative fueling station locator*[23] from the US DOE, there are more than 11 000 EV public charging stations across the United States, of which less than 1.5% are directly operated by the utility. The

21. Note that, as discussed in Section 3.3.2, distribution companies should be encouraged by regulation to reduce overall costs, without favouring OPEX over CAPEX reductions. Otherwise, they would see little incentive to rely on storage as an alternative to network investments or, provided they are allowed to own storage, they may overinvest in storage assets to increase their regulatory asset base, benefitting from information asymmetries.

22. The deployment of (plug-in) EVs also affects the distribution grids planning and operation likewise DG, as discussed in Section 3.2. Moreover, distribution companies may resort to the flexibility potential offered by EV charging points, either when these are decentralised (e.g., in-home charging posts) or centralised (charging stations). Thus, a large-scale adoption of electromobility will stress the need for distribution companies to adopt their new role as SOs (Section 3.5.1).

23. Accessed in October 2015: http://www.afdc.energy.gov/locator/stations/.

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remaining stations are operated by private network charging suppliers or public authorities, as described in Box 3.14.

Market forces alone may not succeed in deploying this infrastructure where market size is limited (THINK Project, 2013). Policy makers may need to kick-start the EV sector in its initial stages, for example, by allocating this role to distribution companies and treating EV charging points as regulated assets. But this may be hampered by unbundling rules. For instance, the European Directive 2014/94/EU[24] on Alternative Fuels Infrastructure states that the operation of public charging points is a liberalised activity and distribution operators ought to co-operate on a non-discriminatory basis with any charging point operators (See Box 3.15). Moreover, a deployment led by the distribution company would imply that rate payers would be subsidising EV users.

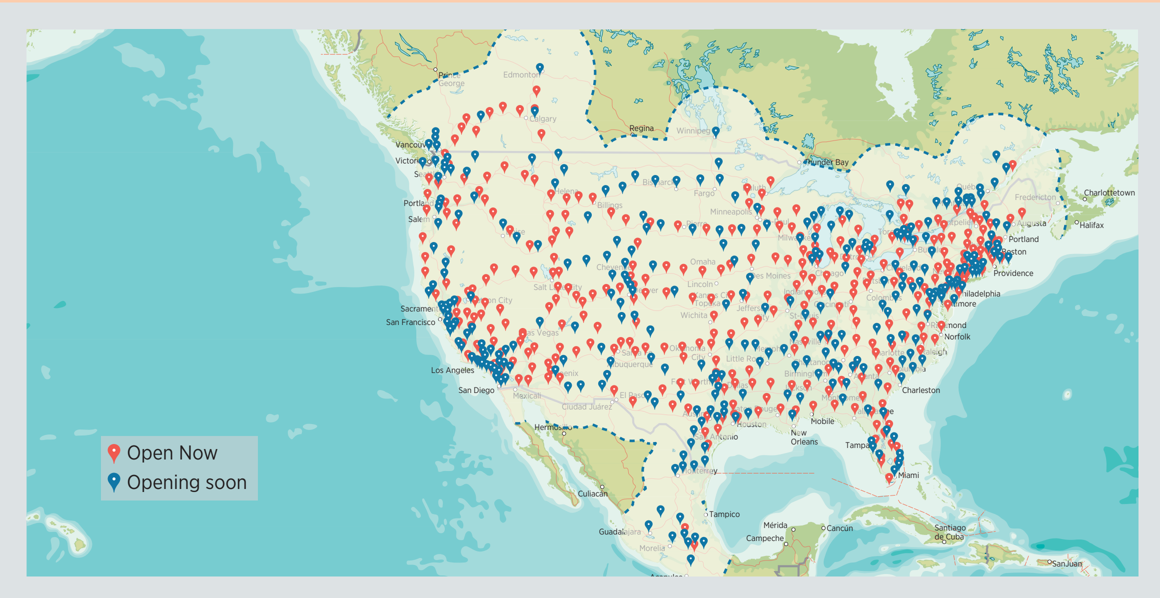
Box 3.14 **Business models and drivers for electric vehicle public charging in the United States**

Tesla Motors, a leading electric vehicle (EV) manufacturer, has deployed one of the most widespread networks of public fast charging points based on its so-called supercharger. Tesla superchargers across North America are shown in Figure 3.18.

Tesla Motors follows a strategy based on placing their superchargers along transited highways and in congested city centres, where users may charge their vehicles for free. The company's motivation, as a vehicle manufacturer, is to overcome range anxiety concerns and promote EV sales.

The remaining major network charging suppliers (SemaConnect, ChargePoint or Blink)[a] are subscription-based companies that purchase electricity from power utilities and sell it to their subscribers. These networks also sell charging points to private customers, having a range of different products for domestic users, commercial customers and others. Thus, their business model is based both on the sales of electricity and charging points.

Figure 3.18 Network of Tesla Motor's superchargers across North America



Source: Adapted from Tesla motors, 2017

a. http://www.semaconnect.com/; http://www.chargepoint.com/; http://www.blinknetwork.com/.

24. Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure Text with EEA relevance.

Box 3.15 Charging service model according to the European Directive 2014/94/EU on Alternative Fuels Infrastructure[a]

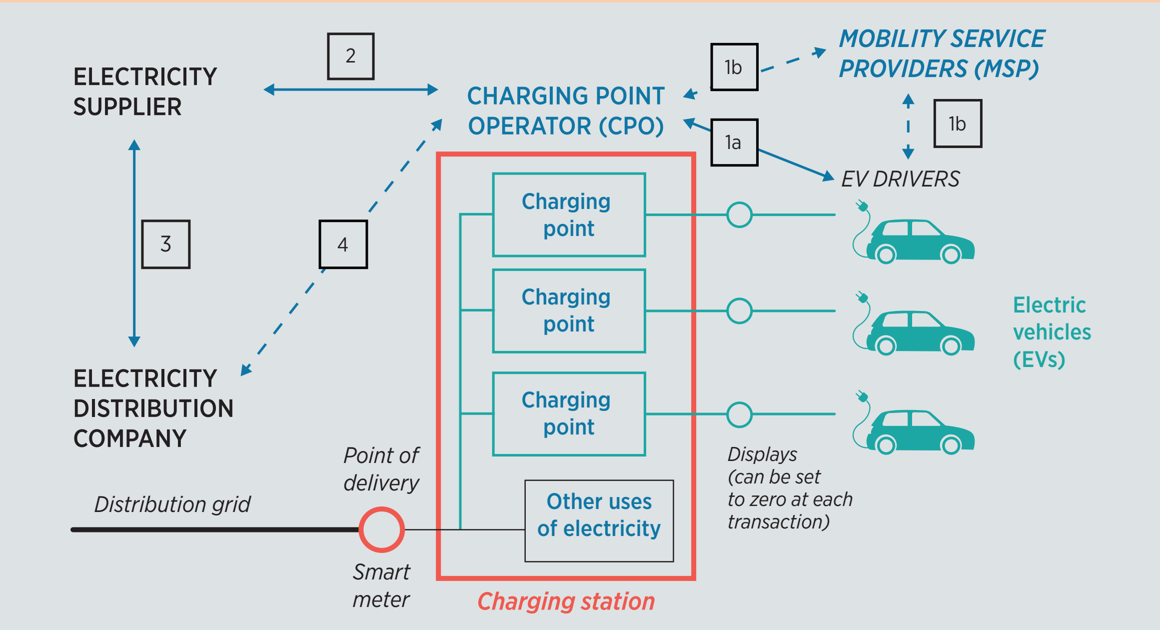
The development of electric mobility requires a careful regulation of the contractual relationship between the various subjects involved: electricity distribution operators, electricity suppliers, charging point operators, mobility service providers, mobility service providers (for instance, EV manufacturers or other specialized subjects) and EV drivers.

As shown in Figure 3.19, the European Directive 2014/94/EU on Alternative Fuels Infrastructure (AFID) sets some principles that address these contractual relationships with the aim of creating an open competitive market for recharging services. The basic assumption is that the good supplied is the bundled "recharge" product; the EV driver should not, therefore, separately purchase the charging service and the electricity needed. The final customer of the power system is the charging point operator (CPO), who has a supply contract with an electricity supplier, freely chosen in the retail market. The EV driver has no contractual relationship with the electricity supplier.

Some of the key guidelines provided by AFID are:

- The electricity distributor must operate in a nondiscriminatory way, both in providing the connection service [4] to the CPO and the electricity transport service to the electricity supplier chosen by the CPO [3]; in order to ensure the electricity distributor's impartiality and efficiency, appropriate unbundling rules should apply where the distributor belongs to a vertical integrated group that also provides (with undertakings separate from the distribution operator) the electricity supply and/or charging activity.
- The CPO shall be free to choose one or more power suppliers from any supplier in the Union [2] and must provide a charging service to EV drivers [1], providing that payment of the service can be, as chosen by EV drivers, either directly [1a], with the same modes of fuel supply, or via the intermediation [1b] of mobility service providers, typically EV manufacturers or other specialised entities.
- Further, the EV driver must be able to recharge even without having a contractual relationship with the CPO, on ad-hoc basis (single transaction settled with ordinary payment means).

Figure 3.19 Contractual relationship between actors involved in electric mobility



Legend: *1a: EV Driver –Charging Point Operator (directly); 1b: EV Driver – Charging Point Operator (intermediated by Mobility Service Provider); 2: Charging Point Operator – Electricity Supplier; 3: Electricity supplier – Electricity distribution company; 4: Electricity distribution company – Charging Point Operator (only for connection)*

a: Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure.

Source: Adapted from Lo Schiavo, 2017

Other ways to provide the policy push could be explored. For instance, local governments or other public entities may allocate the deployment and operation of charging points through a long-term contract assigned in a tendering process (THINK Project, 2013). Thus, the role of the authorities would consist of setting the conditions of such a contract (number of charging points, pricing rules, standardisation requirements, etc.) and organising the auction.

3.5.5 Conclusions and recommendations

As the energy transition evolves, a growing share of the generation capacity and the flexibility resources needed to ensure the secure system operation will be connected to the distribution networks. An increase in demand awareness and the deployment of advanced metering infrastructure is contributing to the change in the landscape seen by distribution companies. In response, distribution companies in liberalised markets need to adapt their role to ensure the efficient integration of DER.

In countries where policy makers pursue the liberalisation of the electricity sector, distributioncompanies help create well-functioning retail markets. A critical task related to the increase of DER is the need to provide market agents with access to metering data in transparent and non-discriminatory conditions. This might be seen as a conventional task of distribution companies. However, when these companies belong to a vertically integrated undertaking active in the retail market or act as default suppliers, regulators may wish to explore alternative data management models.

Different models can be found, depending on the degree of the decentralisation of data management and the involvement of distribution companies. There is no consensus on the most appropriate model. The final choice is mainly driven by the size and structure of the distribution sector in each country. In any case, regulators must ensure non-discriminatory data access and protect consumers' privacy, particularly after the deployment of advanced metering.

Distribution companies ought to facilitate the participation of DER in energy and ancillary service markets. In this regard, distribution companies may validate the technical feasibility of the offers submitted by DER to the upstream markets and verify the provision of the services *ex post* through metering data. In order to carry out these duties, the conventionally limited interaction between distribution companies and system operators needs to be revised. Co-ordinating the actions of TSOs and distribution companies at the operational level requires the implementation of innovative technology solutions.

In addition to market facilitators, distribution companies themselves should make use of DER flexibilities to ensure efficient distribution planning and operations. Thus, enhanced interaction with end-users is necessary so that distribution companies become true distribution system operators actively managing the resources connected to their grids. In this context, regulations should define clearly the responsibilities of distribution companies and oversee potential anti-competitive behaviour, especially where the distribution company belongs to a vertically integrated company in a context of retail competition.

Lastly, regulation ought to clarify the role of distribution companies in the deployment and operation of innovative infrastructures such as advanced metering, distributed storage or EV public charging infrastructure:

- Advanced metering is a key enabling technology for demand response, as well as for a sustainable penetration of self-consumption and an active management of EV charging and distributed storage. A large-scale roll-out requires a policy mandate setting the technical and economic conditions. Advanced metering deployment is normally performed by distribution companies, except in cases where competition has been introduced in metering services. Optionality clauses may be implemented as a response to opposition from end users due to privacy or health concerns.
- Distributed storage has the potential to supply grid-support services. However, this does not automatically mean that distribution compa-

nies should own and operate storage devices. In fact, unbundling provisions could rule this possibility out due to the fact that storage operators may need to provide other services under competition in order to obtain a positive business case. Thus, exemptions on the unbundling obligations may be necessary. Alternatively, distribution companies may be entitled to contract services with storage operators through tendering schemes.

- Market forces alone may not foster public charging infrastructure due to the low level of EV market development. Policy makers may kick-start the EV sector by endowing distribution companies with responsibility for its deployment. However, in some context this may not be possible. On the one hand, unbundling rules may prevent distribution companies from selling electricity to EV users. On the other hand, treating EV charging points as part of the regulated asset base would imply that rate payers would be subsidising EV users. Thus, other policy alternatives could be explored to provide the initial policy push.

LESSONS LEARNT AND POLICY RECOMMENDATIONS

4

The world is in the midst of an energy transition. Power sectors are experiencing – or will soon experience – profound changes that include low carbon technologies in the generation mix; the decentralisation of generation capacity; an increase in regional inter-connection and market integration; consumer empowerment, thanks to better information on pricing alternatives and consumption profiles; and an increase in the availability and utilisation of a diversity of distributed energy resources (DER).

In response to the challenges posed by this transformation, renewable energy policy and power sector regulation must work in co-ordination, and be adapted to the new reality, as discussed in Chapters 2 and 3.

To be effective, both regulation and policy must be designed and implemented whilst taking into account the specific characteristics of each power sector, such as the degree of its liberalisation and its institutional arrangements, market structure, grid development, electrification rate and renewables penetration.

This section summarizes the main findings of this volume and provides an overview of the major policy and regulatory recommendations offered.

4.1. WHOLESALE MARKET DESIGN

Chapter 2 focused on the upstream segments of the power sector, more specifically on generation and system operations, and in particular on the wholesale market design refinements needed to lead the system expansion towards a more efficient and sustainable future.

The discussion is divided into two major sections:

The first reviews the many important design elements that need to be fine-tuned to improve the performance of short-term market mechanisms, from the day-ahead market to the balancing market. The independent system operators of the United States and the Power Exchanges of the European Union were used as case studies. The lessons extracted from these two can be, transposed to other liberalised markets.

The second focuses on long-term mechanisms designed by electricity regulators to intervene in markets with the objective of enhancing the penetration of additional sources of capacity (including RES), *i.e.*, capacity remuneration and RES support mechanisms. The discussion follows two main perspectives. First, capacity remuneration mechanisms are reviewed from the point of view of RES. Second, the main design elements of RES support mechanisms are evaluated, seeking the best regulatory practices that minimise these mechanisms' interference in the functioning of the markets, while at the same time maximise their efficiency as a tool to promote the installation of low-carbon technologies.

4.1.1. Adapting short-term market design

Short-term energy market design needs to be enhanced and refined at all levels, particularly with respect to time frames, bidding formats, clearing and pricing rules and integration with reserves and regulation markets.

The type of refinements needed depends on the specific market design approach. Differences in the functions of the market operator (and within it, the Power Exchange) and the system operator are key. These differences are what set apart the United States and European Union market designs: the degree of separation between the roles of market operators and system operators, which is not present in the United States, and quite marked in the European Union.

Bidding formats

In liberalised power systems in the United States, independent system operators (ISOs) require generators to submit multipart offers that try to faithfully represent the detailed operational (and opportunity) costs as well as the technical constraints of their generating units. This bid format is robust against high penetration levels of renewables, because it allows generation agents to be efficiently scheduled and dispatched.

The capability of the ISO model to integrate these new resources, however, could be further improved. Resources with different characteristics could be better integrated into the market. This calls for a larger number of bidding formats tailored to specific needs. For example, regarding the relevant case of demand response, Liu *et.al.* (2015) point out that "the bidding system does not always provide a mechanism as an alternative to the price-quantity bid format for consumers to express their willingness to adjust consumption, particularly in response to price signals".

In the European Union, day-ahead markets run by power exchanges were originally envisioned as simple electricity auctions. Using simple bids involves the need for market agents to anticipate the resulting dispatch and internalise, in the bids, all operational costs and constraints – a task that, to be properly fulfilled, requires that market conditions be predictable.

The growing penetration of VRE has increased uncertainty and this has called for greater complexity in bidding formats. But instead of opting for the multipart formats used in the traditional pool or in the United States ISOs, in the European Union each power exchange has progressively incorporated the so-called block orders and semi-complex orders.

Multipart offers, while more complex than blocks or semi-complex orders, are a more "natural" way of representing the generation resources, and have advantages if a multi-part bid is able to replace multiple blocks. However, including multipart bids in the European Union power exchanges would require significant changes in the market design and pricing and clearing rules.

Continuous improvements in bidding formats are expected in both market models, with the aim of achieving a more efficient integration of intermittent renewables.

Pricing and market clearing

There are two ideal properties of pay-as-cleared (uniform) marginal pricing: first, marginal pricing is consistent with optimal dispatch and, second, settling the transactions of all agents at the same price (uniform pricing) sends an efficient signal for bidding at true costs and minimising inefficiencies.

Perfect marginal pricing can be achieved only under ideal conditions – in particular, the absence of non-linearities or "lumpiness" in the production cost functions, which are common in actual markets. The presence of VRE generation exacerbates these complex behaviors. This requires choosing between the objectives of achieving an optimal dispatch or implementing a uniform marginal pricing scheme in the clearing and pricing market rules. The United States has opted for the first objective, while the European Union has chosen the second.

In the United States, discriminatory side payments, known as uplifts, are unavoidable elements of a pricing system consistent with a strictly welfare-maximising dispatch. The underlying problem is that the uplifts are outside the uniform marginal price (or an ensemble of locational marginal prices), and this hampers the development of a correct market signal that applies to all agents. The approaches to the uplift problem reviewed in this report share something in common: an attempt (never completely fulfilled) to internalise, as much as possible, all costs in uniform prices, *i.e.*, to minimise the uplift to get as close as possible to uniform pricing.

In the European Union, giving priority to the single-pricing rule leads to a short-term dispatch that deviates from the cost-minimising one. As argued before, this is a matter of trade-offs; in the European context, supporting uniform pricing is an objective worth the loss in short-term cost efficiency. There are three major problems with the European Union day-ahead pricing and clearing design: 1) relative lack of transparency in the algorithm,2) some units are unable to set the market price and 3) the algorithm's complexity limits the number of complex and block orders that can be handled.

These three problems are all connected to the underlying complexity of clearing the market with uniform prices. Current efforts concentrate on improving the computational performance of EUPHEMIA (the algorithm used, see Appendix) to cope with the increasing number and complexity of bids.

- PCR-ESC (2015) proposes long-term solutions to solve the complexity issue, such as:
- Reduce the amount of blocks types and other complex products allowed per participant and market (bidding zones).
- Reduce the range of products treated in EUPHEMIA.
- Relax the linear pricing rule (*i.e.*, and simply adapt to the fact there will be more than one price-per-bidding zone and time period).

- As mentioned in regard to bidding formats, market clearing rules in both market models seek to efficiently integrate larger shares of variable renewables. Their development goes hand in hand: bidding formats condition market-clearing and pricing rules, and these rules in turn affect the bid formats.

Locational granularity of prices and schedules: zonal versus nodal

The increased deployment of VRE, particularly wind, may result in a more constrained transmission network. Zonal pricing is a simplified approach to reflect network constraints, but it may come at the expense of market efficiency. In this context, nodal pricing can often provide better operation and investment signals, but it may be more challenging to implement.

Rethinking reserve requirements and procurement

System operators need to implement new solutions to improve the reserves-supply function so that they are priced according to the value they provide to the system. In addition, energy and reserve markets should be properly connected to allow the former to reflect the actual conditions of the latter.

In the reserve markets, quantity requirements are typically procured through market mechanisms. The willingness to pay for each megawatt (MW) of reserve below a minimum contingency level is set to the value of lost load – although sometimes the price is artificially set below this. Above this minimum contingency level, the marginal value of any additional MW of reserves is typically set to zero – a practice that should be questioned on the basis of rigorous regulatory principles (Hogan 2014).

Time frame of markets, dispatches and prices

As variability increases, the time granularity of market signals needs to increased. Better-adapted and more flexible market timelines are needed. In the European Union case, guaranteeing full liquidity in intraday markets (through discrete sessions) is the way to go, while in the United States context the link between imbalances and pricing (cost allocation) could be improved.

4

Balancing markets and products

Properly designing balancing markets is essential to ensure that: 1) the market provides accurate incentives for flexibility and 2) all resources can effectively offer their flexibility potential to system operators.

Imbalance responsibility and imbalance settlement are the two most important – and controversial – elements of designing a balancing mechanism:

- The definition of the balancing responsible parties (BRP) is a contentious issue when coupled with a dual imbalance pricing scheme. While dual imbalance pricing is applied, allowing generation portfolios to BRP gives a competitive advantage to large companies and introduces entry barriers to small providers.
- Dual imbalance pricing does not exactly reflect imbalance costs and therefore distorts the real-time price signal.
- Today there is a growing trend to make RES increasingly responsible for their imbalances. This is important to efficiently integrating larger volumes of RES in markets.

The definition of the balancing product can introduce significant barriers to the participation of DER and RES. The following guidelines can help:

- Define innovative products to unlock the potential of new, flexible resources.
- Give different price signals to resources performing differently.
- Separate the procurement of balancing energy, upwards reserves and downwards reserves.
- To the extent possible, avoid limiting participation based on size or technology.

The pricing of balancing products can be based on either pay-as-cleared or pay-as-bid pricing. In many cases, the procurement is bilateral and therefore by definition the products are pay-as-bid. In other cases, it has been implemented as pay-as-bid (and average reserve pricing charges), with the objective of mitigating market power and providing less volatile prices. In general, marginal prices should set the market price. In case policy makers or competition authorities believe that market power is a major problem, the long-term solution is not to change the pricing rules but to address the fundamental underlying market structure that creates the market power (or to directly implement a regulated provision of the service). Marginal prices, of course, provide sharper and more volatile prices, but these are the signals needed to reflect the real-time value of flexibility and to incentivise resources that are sensitive to these price signals.

4.1.2. Improving long-term signals without ruining short-term ones

The key message of this section is rather straightforward: to the extent possible, renewable technologies should be exposed to the same market signals as conventional technologies. This is important to foster their efficient integration into the power system. While doing this, it must be guaranteed that the design of RES support mechanisms is consistent with this guideline. Thus, the economic incentives for RES should account for the costs and the benefits derived from exposing RES generators to market signals.

Long-term mechanisms, including conventional capacity mechanisms and specific renewable support schemes, are evolving due to the penetration of renewable resources and distributed generation. Generation adequacy mechanisms are at the top of the regulatory agenda in many countries. It is a fact that conventional generation suffers the increased short term price volatility and the low energy prices when renewables such as wind or solar enter the system in a short time, without giving time for the incumbent generation to adapt. However, the need for capacity remuneration is a topic mostly related to the presence of caps on market prices to regulatory uncertainty as regards to the long term planning. As discussed, the deployment of variable generation has different impacts in energy- and capacity-constrained power systems. In the former, RES technologies do not complicate the operation of the system if the transmission capacity does not create bottlenecks, and RES can substantially contribute to generation adequacy. In capacity-constrained systems, non-dispatchable power plants do affect operations, and the participation of RES technologies in capacity mechanisms is scarce and more difficult to quantify.

Capacity markets design and RES

As far as technically possible, RES technologies should be allowed and expected to participate in generation adequacy mechanisms to the extent RES agents consider feasible and acceptable in terms of risk (as is the case for any other technology). Nonetheless, when this participation is accepted, it must be guaranteed that the competition in the generation-adequacy market is efficiently designed. In this context, some design elements are pivotal in achieving fair competition, namely constraints on tradable quantities and performance incentives (penalties and credits for under- and over- performance).

Obviously, the participation of RES technologies in capacity mechanisms, as in any other market segment, should be coherent with the support being received by these technologies out of the market. It may be possible that renewable resources will still need economic incentives. However, their incentives should progressively become more market compatible in the future. From a market design perspective, support to renewable generation should provide optimal investment signals while minimising market distortions. Finally, support to prosumers and DER in general should be harmonised with end-user tariffs to guarantee cost-recovery, as discussed below.

RES support and wholesale market integration

There is a growing consensus on the need to integrate RES in electricity markets. This requires the adoption of more market-compatible support schemes. However, it must be taken into account that there is no perfect support scheme; all come with pros and cons:

- Production-based mechanisms are good at stimulating efficient investment decisions but may create short-term market distortions.
- Capacity-based mechanisms are in general more market compatible than production-based mechanisms, but they may be less successful in stimulating optimal investment decisions.

The risks inherent in capacity-based schemes can be reduced via the implementation of an appropriate design, making them generally preferable if the goal is market integration.

When RES generation is distributed and is an internal component of some network users, the same general considerations regarding support schemes hold. Specific implications for the design of support schemes and tariffs at distribution level are discussed in Section 4.2.

4.2. DISTRIBUTION NETWORKS AND DISTRIBUTED ENERGY RESOURCES

As discussed in Chapter 3, the energy transition is driving profound changes in the "downstream segments" of the power sector *i.e.*, the distribution and retail sectors. This is mainly driven by the decentralisation of generation and the empowerment of small- and medium-size consumers enabled by the diffusion of innovative technologies and increased availability of information. What follows is the summary of the recommendations for promoting the large-scale deployment and efficient integration of distributed energy resources whilst ensuring the reliability and economic viability of the power system as a whole.

4.2.1. Adapting regulation under high shares of distributed generation

Distribution networks are witnessing growing levels of DG, driven by cost reductions and policies promoting the installation of low-carbon technologies. Utilities may install DG units to supply energy to their customers. Independent promoters or end consumers may invest in DG installations, particularly in those countries where policies to promote RES favour smaller installations (*e.g.*, net metering, self-consumption or feed-in tariff policies).

The deployment of DG has positive effects for the system, for example in terms of reduction of net load (*e.g.*, in the case of photovoltaic (PV) systems production during peak demand) and transmission losses (being the generation units close to consumption points). However, in the traditional, passive approach to managing networks, the connection of high levels of DG may cause an increase in network costs. This is particularly true when the network operator, either a utility or an unbundled distribution company, has no direct control over the location and operation of the generators, freely decided by DG investors or end-users. With this in mind, regulators should encourage these companies to adopt more active strategies by establishing regulatory incentives that are well aligned with the desired transformation. Such regulatory changes become more relevant as the penetration rate of DG grows and should be progressively refined according to the experience and data gathered by the network companies managing generation in their grids.

Experience shows that in countries with low penetrations of DG, utilities or distribution companies that have scarce experience dealing with this phenomenon may see generation they do not directly own as a threat to their activities. On the one hand, the installation of on-site generation can lead to a decrease in their revenues due to lower energy distributed. On the other hand, costs may remain constant or even increase when DG increases network capacity requirements. To prevent network operators from opposing or delaying the connection of DG, regulators should focus on mitigating the negative impact DG may have distributed revenues and on network costs. Where levels of DG penetration are low, it is recommended that regulators:

- Decouple the remuneration of network activities from the amount of energy consumed. Thus, any deviation between *ex ante* allowed revenues and the money collected through the tariffs can be corrected in subsequent periods.
- Compensate utilities and distribution companies for the possible incremental costs driven by DG, which are outside their control. This may be done through revenue drivers or a pass-through of costs.

The declining costs of RES will lead to a large-scale deployment of DG. In order to support and integrate high amounts of DG efficiently, network operators should be incentivised to deploy advanced grid technologies, *i.e.*, transition towards smarter distribution grids. Since innovative solutions entail a higher risk for utilities and distribution companies than conventional "iron and copper investment", policy makers ought to promote pilot projects and facilitate the sharing of lessons learnt:

- Useful measures include the creation of and participation in, national or international public-private collaboration networks for the promotion of innovative grid projects, the diffusion of best practices and the involvement of relevant stakeholders. The goal of these initiatives is to identify local priorities and promote knowledge-sharing to accelerate the process from testing to deployment.
- Policy makers and regulators should set ad hoc financial incentives for utilities and distribution companies to invest in pilot projects in strategic areas. Best practices include allocating these funds through competitive mechanisms and introducing information disclosure obligations.

Subsequently, network operators should proceed to the deployment of proven solutions, leveraging the experience gathered through demonstration. To fully exploit the techno-economic efficiency potential of advanced grid solutions and decentralised resources providing network services and flexibility, there should be transformation in the way regulators set revenues and incentives for utilities and distribution companies.

A comprehensive reform of network regulations should be undertaken. Some of the recommended regulatory provisions are:

- Shift the regulatory focus from ensuring that distribution companies invest enough to assessing their performance through measurable indicators (*e.g.*, energy losses, customer satisfaction, carbon emissions, peak load reduction, etc.) – in other words, move from an input-oriented to an output-based regulation.
- Remove biases towards capital expenditures so that utilities and distribution companies are encouraged to solve network problems relying on the flexibility provided by DER, even if these avoid network reinforcements.
- Perform cost assessments to foresee future investment needs instead of evaluating only past information. Forecasts and justified business plans prepared by companies should become key tools for regulators.
- Lengthen the duration of regulatory periods to

allow companies to focus on delivering long-term efficiency rather than spending resources on frequent and burdensome price reviews.
- Introduce flexible remuneration formulas to acknowledge the existence of higher uncertainties, including profit-sharing schemes, menu regulation and reopeners.

4.2.2. Encouraging distribution companies to act as system operators

In response to the growing presence of new types of distribution network users, utilities and distribution companies should actively interact with DER and make the most of their contribution during the distribution network operations. This could help reduce grid reinforcement needs. This is relatively straightforward when these resources are owned and operated by a vertically integrated utility. However, in the case of unbundled utilities or distribution companies that need to manage investor-owned DG units or resort to demand response resources, the mechanisms to interact become more complex.

When this is the case, utilities and distribution companies need to become actual system operators, managing both the grid and the resources connected to it similar to the role conventionally played by TSOs/ISOs. In the case of integrated utilities, they would need to manage both their own and external resources, and regulatory measures are required to prevent discriminatory behaviour.

The need for an enhanced co-ordination with external DG promoters starts from the moment that new generators request a connection to the grid. In order to achieve a more cost-effective network capacity allocation and better-informed connection requests from promoters, the following provisions are recommended:

- Network operators should manage grid connection applications for a given area in a more aggregated manner, instead of on a simple first-come first-served basis.
- Regulators should mandate utilities and distribution companies to assess the capability of the existing network to host DG capacity and disclose this information, so that DG promoters may make better-informed applications.
- The previous recommendations can be relevant even under low or moderate levels of DG penetration. Even in these initial stages, DG capacity, albeit small in general terms, may be concentrated in specific areas, thus triggering the need to adopt some of the previous solutions for managing locally high DG penetration in these areas.

As DG levels become significant, network operators can no longer follow a *fit & forget* approach to connect new generators. For more efficient network development, they need to implement advanced solutions for managing constraints close to real time, instead of relying exclusively on grid reinforcements. In many cases, this will imply resorting to the flexibilities of DER. Also, ad hoc regulatory mechanisms will be required to enable utilities and distribution companies to benefit from the potential of third-party flexibilities.

- Under moderate penetration levels, a suitable solution would be to allow network operators to offer DER non-firm connection agreements, through which DG operators who decide to opt in would pay lower network charges in exchange for a possible limited curtailment of their production. Regulators should define the conditions under which distribution companies may resort to this measure, the rules on how to set limits to the amount of RES production to be curtailed and compensation mechanisms to DG operators.
- With larger DG penetrations and developed demand response schemes, regulators should establish more-advanced mechanisms to enable network operators to purchase services from DER such as bilateral agreements and local markets.
- Regulators should develop distribution grid codes defining the technical and economic conditions under which these services may be provided in a non-discriminatory way.

4

4.2.3. Enabling distribution companies to act as neutral market facilitators

A consequence of the increasing decentralisation of power systems is that the flexibility resources connected to the distribution grid become progressively needed to balance the systems' generation and demand. Therefore, in contexts where distributed resources are not negligible anymore, regulation and market rules should enable the participation of DER in system services through aggregation, if necessary.

Because DER are connected to the distribution grid, utilities and distribution companies have an important role to play as mediators. This role is particularly relevant in systems where a TSO/ISO is independent of the power utilities. Moreover, the existence of competitive energy and ancillary services markets represents an additional driver for the development of such business models. Otherwise, TSOs/ISOs may rely exclusively on centralised resources.

To unlock the flexibilities of DER and enable their participation in upstream system services:

Regulators should develop new grid codes that define the:

- Responsibility of utilities and distribution companies as facilitators of DER participation in upstream services and markets, which could include an ex ante technical validation and an ex post verification of the provision.
- Information exchange required between utilities or distribution companies and system/market operators.

Another factor that is driving changes in the conventional role of utilities and distribution companies is the liberalisation of retail markets. The reforms undertaken by some countries aim to promote more-efficient electricity consumption by offering a wider choice in terms of suppliers and prices. In competitive retail markets, transparent and non-discriminatory access to metering data is essential for a well-functioning market. Management of metering data is usually a task for utilities or distribution companies. However, when these companies are also active in the retail sector, either directly or through another company within the same group, regulators could be concerned about potential barriers for independent suppliers.

Alternative models for data management have therefore been adopted in some countries, sometimes with the creation of a new regulated entity responsible for data management. As these models have their advantages and disadvantages, the final choice depends upon the specific country contexts and regulatory priorities.

Regardless of the model chosen:

Regulators should clearly define the roles, rights and obligations of different stakeholders, and the conditions under which the metering data manager should provide access to retail market agents such as suppliers and aggregators:

- Consumers should be the owners of the data and have access to them to make better-informed decisions on consumption and contracting.
- Market agents should have access to metering data in transparent and non-discriminatory conditions once consumers' permission has been granted.

Finally, the deployment of innovative grid-edge technologies may be facilitated through the participation of utilities and distribution companies. These infrastructures comprises advanced metering technologies, distributed storage and electric vehicle public charging facilities. Given that the ownership and operation of these infrastructures may be subject to competition, key regulatory concerns arise in the case of unbundled distribution companies. For instance, when energy storage is used both for grid support and to perform price arbitrage. Nonetheless, regulators may decide to allow these companies to own these assets under certain conditions.

- Policy makers should promote the deployment of advanced metering technologies in those countries pursuing the sustainable development of self-consumption, demand response and distributed storage.

- Rollout strategies should be based on cost-benefit analyses, potentially leading to a mandated large-scale rollout that sets responsibilities, time frames, technical requirements and economic conditions for cost-recovery.
- Distribution companies have conventionally carried out this task and are a suitable candidate, especially for a large-scale rollout. Nonetheless, other entities may deploy these technologies; it may be more efficient, but other barriers may arise in this case, such as lack of standardisation or barriers to switching suppliers.

- Regulators should enable distribution companies to influence the location of storage units within the grid to provide efficient grid support services.
  - This may be done either by introducing exemptions on the unbundling rules, subject to size limitations or a preapproval by the regulator or by enabling distribution companies to carry out competitive tenders to purchase grid services from independently owned storage units.
- Policy makers may intervene to kick-start the deployment of public charging infrastructure to promote the use of EVs. Distribution companies may be given this role, although policy makers may consider alternative providers in case this may collide with the unbundling rules.

4.2.4. Promoting sustainable development of self-consumption and demand response

The installation of DG units behind the consumers' meters for self-consumption can facilitate the growth of RES and yield important benefits both for end users and for the power system. Therefore:

- Policy makers and regulators should enable and promote self-consumption, particularly for small commercial and residential consumers.
- Regulators should reduce to the extend possible administrative barriers to the installation of DG units for self-consumption, such as complex permission procedures, financial guarantees, costly technical connection studies, etc.

Meanwhile, traditional self-consumption and net metering practices may lead to a missing money problem that, if not properly addressed, would hamper the recovery of the power system and other energy policy costs when high shares of generation are involved.

Conventional tariff designs, *i.e.*, those that are based mostly or even exclusively on a volumetric charge (*e.g.*, USD/ kilowatt hour), coupled with conventional energy meters, unable to record consumption with a high time granularity, are at the core of this problem. Several short-term regulatory measures have already been implemented in different jurisdictions to tackle this problem, including:

- Setting limits on the size of DG units used for self-consumption, implementing an overall cap on the amount of DG eligible for self-consumption at the national/local level or limiting the annual volume of energy consumption that can be compensated with energy surplus from DG units.
- Progressively moving away from purely volumetric tariffs and recovering part of the system's fixed costs through a demand or a fixed charge, and adjusting the volumetric component accordingly. When introducing these changes in the rate structures, the impact on consumer bills should be carefully analysed. Fixed charges may jeopardise low-demand

consumers, debase demand response and energy-efficiency efforts or encourage grid defection. This highlights the importance of ensuring cost-reflective changes in the rate structure, as advocated for in this report.
- Implementing alternative schemes to compensate for the prosumers' production surplus. This requires the progressive phasing out of net-metering policies in favour of self-consumption schemes with shorter netting intervals and a decoupling of the remuneration of electricity feed-in from the retail price. This energy surplus can be valued, for instance, at the nodal energy price or the wholesale market price.

Even though the previous regulatory measures help mitigate the missing money problem, they do not provide a real long-term solution for the efficient development of prosumers. This entails developing and implementing rigorous methodologies for calculating cost-reflective tariffs that promote efficient energy consumption and grid utilisation whilst ensuring system cost-recovery. Such a retail tariff design enables the sustainable development of self-consumption and efficient decisions regarding demand response and distributed storage. Whenever support measures are deemed necessary (*e.g.*, to renewable generators or certain consumer categories), these should be explicit and transparent in order to prevent undesired effects.

Cost-reflective tariffs, enabled by the deployment of advanced metering technologies, would send efficient short- and long-term signals to end users reflecting their contribution to the system, and ensuring the recovery of total system costs. Retail tariffs should be additive, *i.e.*, calculated considering separately the different cost components: 1) the value of electricity (energy) at each time and location; 2) the cost of the transmission and distribution grid and 3) other regulated costs. Hereafter, some guidelines to calculate each of these components are provided. Note that the degree of sophistication, *i.e.*, the granularity of time and location dependent signals, can be modulated according to the penetration level of DER in a specific jurisdiction and the level of stress on the network.

- The value of energy should reflect the varying cost of producing electricity over time, as well as the variation in network effects by location. Time-of-use or dynamic energy prices would provide short-term economic signals promoting the efficient operation of DG units as well as demand-response and storage management.
- Network charges should reflect the impact of the end user on the utilisation of network assets and grid expansion. Thus, network charges should be based on the individual contribution of the network user to the transmission and distribution costs, differentiated by time period, location and whether power is being injected or withdrawn from the grid. Such charges would provide end users with long-term economic signals promoting efficient location and investment decisions. Most important, they reflect the actual contribution of network users to network stress (peaks of injection or withdrawal), thus signalling the need for new network reinforcements.
- The other regulated costs, when recouped through the electricity rates, should be allocated without distorting the economic signals sent by energy and network charges, *e.g.*, through a fixed charge per customer. This provision is particularly relevant in countries where these costs account for a significant share of total system costs, for instance, due to support for RES. Nonetheless, should policy makers wish to avoid the undesired effects of fixed charges mentioned above, these costs may be recouped, at least partially, through alternative revenue sources such as public budgets or taxes.

GLOSSARY OF TERMS

Adequacy: existence of enough resources, either installed or expected to be installed, to efficiently guarantee the match of supply and demand in the long term.

Ancillary services: services that are necessary to maintain the stability and security of power systems.

Balancing market: a market that is usually opened at gate closure, where agents submit upwards and downwards bids through which the system operator will be able to fix potential imbalances through least-cost resources; term used in the European context.

Capacity mechanism: a regulatory instrument that reinforces the economic signal provided by other electricity markets (usually short-term ones) in order to attract enough investment and ensure system adequacy in liberalised power sectors.

Commercial losses: energy losses caused by non-technical aspects of the electricity supply, such as metering or billing errors, meter tampering, illegal connections, energy theft, etc.

Continuity of supply: a component of quality of service, decided by the number and duration of supply interruptions experienced by electricity consumers.

Distributed energy resources (DER): small- to medium-scale resources that are mainly connected to the lower voltage levels (distribution grids) of the system or near the end users, and that is comprised of three main elements: distributed generation, energy storage and demand response.

Distributed generation (DG): a generating power plant serving customers on-site or providing support to a distribution network and connected to the grid at distribution-level voltages. For the purpose of this report, the technologies used for distributed generation are renewable energy technologies.

Demand-side response: also known as *demand-side management* or energy demand management, refers to the possibility to shift energy loads around in time. The management of small end-users must be automatically achieved at the user level, which requires online communications. In this regard, smart meters represent a key enabling technology of demand response.

Distribution feeder: each of the medium-voltage (MV) lines that originate from primary distribution substations and supply secondary substations or distribution transformers.

Firmness: ability of resources already installed in the system to respond to actual requirements to meet existing demand efficiently.

Firm energy and firm capacity: Energy and capacity that are expected to be available during some sort of scarcity conditions; products usually traded in the framework of adequacy mechanisms.

Gate closure time: moment at which the scheduled or forecasted production of generation units for a given period is fixed for the purpose of determining the generation schedule.

Grid code: document that specifies the technical conditions that must be met by any agent – whether a generator, consumer or grid operator – connected to the power system in order to ensure reliable, secure system operation.

Infra-marginal generation: all production units whose marginal costs fall below those of the latest unit to be dispatched in a certain time period following the cost-based merit order.

Infra-marginal rent: remuneration earned on a marginal market by infra-marginal generators.

Variable generation: electricity production units whose output is not controllable or not continuously available, usually because of their reliance on a renewable primary energy resource like wind or solar irradiation.

Levelised cost of electricity: the average cost of electricity per kilowatt hour (kWh) considering all fixed and variable costs over the lifetime of an installation.

Merit order effect: the displacement of thermal generation units from the generation economic dispatch during hours of high renewable production, driven by the much lower marginal costs of RES technologies.

Operating reserves: generation capacity readily available to the system operator for solving contingencies.

Prosumers: electricity consumers that either show some flexibility in their consumption as a response to price or volume signals (proactive consumers), or that have generation connected on their side of the meter (producer-consumers).

Real-time market: a market similar to the balancing market, implemented by U.S. system operators to fix imbalances.

Real-time pricing: retail tariff scheme in which the energy charge corresponds to the price of electricity on the wholesale market during a specific trading period, usually one hour.

Re-dispatch: process through which changes are made in the generation schedule due to changes in the supply or demand curves after a previously computed economic dispatch.

Residual demand: net electricity demand resulting from subtracting the foreseen production of intermittent RES in a given period from the total system load in that period.

Retailing (electricity): final sale of electrical energy to end consumers. Retailing constitutes the final segment of the electricity supply chain after generation, transmission, and distribution.

System operator: institution in charge of managing the transmission network and, more generally, of guaranteeing the constant match between demand and supply in liberalised power systems.

Technical losses: energy losses caused by physical phenomena and dissipated in the form of noise or heat in the electricity network.

Time-of-use pricing: a retail tariff scheme in which the energy charge varies across blocks of hours (*e.g.*, peak and off-peak hours) where the rate is pre-determined and constant over a period of, typically, several months.

Transmission system operator: an entity responsible for operating the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the electricity transmission.

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APPENDIX

EUPHEMIA, THE PAN-EUROPEAN MARKET CLEARING ALGORITHM

The Price Coupling of Regions (PCR) is the initiative of seven European Power Exchanges[1] (at this writing) to develop a single price coupling solution to be used to calculate electricity prices across Europe, and allocate cross border capacity on a day-ahead basis.

Under the PCR initiative, a common market clearing algorithm has been developed (EUPHEMIA, acronym of Pan-European Hybrid Electricity Market Integration Algorithm). This algorithm allows each Power Exhange to continue using the bidding formats previously in place in their respective market, and opens the possibility of homogenizing bidding formats across Europe in the future.

The basic bidding format in EUPHEMIA keeps on being the simple bid, though additional bidding formats that enable agents to hedge against uncertain market clearing outcomes are used, as shown in the table A.1.

Using block orders and complex conditions to avoid being matched at a loss:

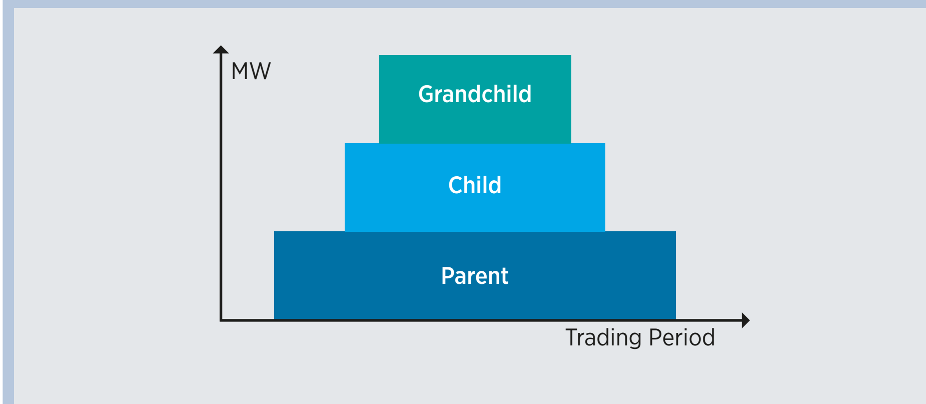
The constraints and cost structure of different resources can be bid in markets by using block bids, for example:

- A thermal unit can use a combination of linked block orders to make sure it will recover its start-up cost and it will not produce less than its minimum power output.
- A thermal plant can use the complex condition (where allowed) to ensure the recovery of the start-up cost.
- By combining block orders, storage can sell during peak hours only if its off-peak purchase order has been accepted and buy/sell combination is in the money (EPEX SPOT, 2014).
- Demand response may condition a load reduction in some periods, to an increased consumption in some others.
- Plants can use exclusive orders to bid different production profiles in order to cover a wide range of possible market outcomes.

In Box A.1 it is analyzed how, with the current bidding formats in Europe, it is quite complex to properly bid a resource that is called to play a key role in the future: storage plants.

See, for example, www.nordpoolspot.com

Table A.1 Bidding formats and description

Bid format	Description
Simple orders	
Hourly step orders	Buy or sell orders for a given volume and a limit price. It can be partially accepted if the clearing price is equal to the bid price
Hourly linear piecewise order	Buy or sell order for a given volume and a pair of prices: an initial price at which the order begins to be accepted and a final price at which the order is totally accepted
Block orders	
Regular block order	Buy or sell order for a single price and volume and a period of consecutive hours that can only be totally accepted
Profile block order	Regular block order that can be partially accepted, it includes a minimum acceptance ratio condition
Exclusive block orders	An Exclusive group is a set of block orders for which the sum of the accepted ratios cannot exceed 1. In the particular case of blocks that have a minimum acceptance ratio of 1 it means that at most one of the blocks of the exclusive group can be accepted.
Linked block orders	Set of block orders where the acceptance of some blocks (children) is conditioned to the acceptance of others (parents) **Figure A.1** Linked block orders  *Source: Miura, 2014*
Flexible hourly block order	A flexible "hourly" order is a block order with a fixed price limit, a fixed volume, and minimum acceptance ratio of 1, with duration of 1 hour. The hour is not defined by the participant but will be determined by the algorithm (hence the name "flexible")
Complex conditions	
Minimum Income	Series of hourly step orders conditioning to the recovery of a fixed quantity over the entire trading day
Ramp limit	Limits the variation between the accepted volume at a period and the accepted volume at the adjacent periods

Box A1 The complexity of bidding some resources with existing formats: the case of storage

None of the previous types of bids fits perfectly the characteristics and needs of storage, which is reducing the risk of being uneconomically committed throughout the day subject to limited energy constraints.

Linked block orders seem to be the only alternative to partially hedge such risk: by combining (linking) two block orders (one block for charging and another block for discharging), storage can sell during peak hours only if (i) its off-peak purchase order has been accepted and (ii) buy/sell combination is in the money (EPEX SPOT, 2014). However, this requires storage to anticipate the hourly periods for consuming and the hourly periods for producing in advance.

The combined use of exclusive block orders with linked block orders could help mitigating this risk. This approach allows to enter multiple candidate profiles, created in line with the principles outlined previously, each potential profile conforming an exclusive group. For example, the profile representing the limited running of the unit could be entered in various different time periods (*e.g.*, one profile during hours 10 – 13 and another profile during hours 15 – 18). Nevertheless, the amount of blocks that can be used and combined is quite limited.

Currently, the I-SEM (the Integrated Single Electricity Market, the electricity market of Ireland and Northern Ireland) is performing a number of test over the EUPHEMIA algorithm to assess the ability of the bidding protocols to perform complex optimal schedules such as those involved by storage resources. The analysis of the results will provide valuable information about the suitability of current bidding protocols. At a high level this study consists of two main phases: (i) first an initial Phase, involving trials performed by SEMO, and then (ii) the commercial phase, where trials will be performed by SEMO in conjunction with industry participants.

At the time of this writing, the first phase has been completed and the report is already available (see Eirgrid *et al.*, 2015). The results show how "the current SEM algorithm is capable of running storage units with much greater flexibility throughout a day than EUPHEMIA due to the rigid profile of the linked block orders. The SEM clearing algorithm, a unit-commitment-like algorithm, has a number of features to optimally represent units with specific characteristics (*e.g.*, pumped storage) while EUPHEMIA has products which must be adapted, for the purpose of producing commitment starting point for dispatch, for a range of technologies."

In the figure A.2 it is schematically represented the pros and cons of the different alternative methods tested so far to bid storage units in EUPHEMIA.

Figure A.2 Characteristics of pumped hydro methodologies

Method	Benefits	Disbenefits
Linked Block (original)	Accounts for reservoir levels; simplest linked block representation; units are price takers	Inflexible due to limited hours; does not restore to target level as used; requires prediction of load and price
Linked Block (extended)	Accounts for reservoir levels; allows use in multiple time periods; units are price takers	Inflexible as rejection of one hour causes rejection of all future hours; requires prediction of load and price
Simple	Allows full utilisation; allows units to be price makers; allows greatest flexibility to follow price signals; does not require prediction of load	Does not account for reservoir level limitations; would requires significant actions post DAM; requires prediction of price

Source: Eirgrid et al., 2015

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