LOYOLA DE PALACIO SERIES ON EUROPEAN ENERGY POLICY

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ELECTRICITY NETWORK REGULATION IN THE EU

The Challenges Ahead for Transmission and Distribution

EDITED BY

Leonardo Meeus
Jean-Michel Glachant

Electricity Network Regulation in the EU

THE LOYOLA DE PALACIO SERIES ON EUROPEAN ENERGY POLICY

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LOYOLA DE PALACIO SERIES ON EUROPEAN ENERGY POLICY

Cheltenham, UK • Northampton, MA, USA

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Published by
Edward Elgar Publishing Limited
The Lypiatts
15 Lansdown Road
Cheltenham
Glos GL50 2JA
UK

Edward Elgar Publishing, Inc.
William Pratt House
9 Dewey Court
Northampton
Massachusetts 01060
USA

A catalogue record for this book
is available from the British Library

Library of Congress Control Number: 2018931657

This book is available electronically in the **Elgar**online
Economics subject collection
DOI 10.4337/9781786436092

ISBN 978 1 78643 608 5 (cased)
ISBN 978 1 78643 609 2 (eBook)

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Acknowledgements

This book draws significantly upon research conducted at the Florence School of Regulation (FSR) since we joined it. Therefore, we would like to acknowledge collectively the colleagues who contributed indirectly to this book by writing a study, an article, a book chapter or a policy brief together with us. Obviously, we would like to thank especially the colleagues who contributed directly to the writing of a book chapter and we are thankful for the particular dynamism brought by Nicolò Rossetto.

Introduction

Leonardo Meeus and Jean-Michel Glachant

The European Union has the biggest open power market in the world, supported by an extended and reliable grid that has been over a century in the making. The regulation of this grid has changed significantly in recent years for several reasons. It is these changes and these reasons that inspired us to write this book, where we tell the story as we experienced it: through a European lens. The book takes stock of what we have learned along the way. It is targeted at academics and practitioners and focuses on some of the key issues that continue to be debated today.

The book consists of three parts, each of them divided into two chapters. In the first part, we treat implementation issues related to incentive regulation, that is 'aligning the interests of the grid operators with the interests of their customers'. The analysis starts by looking at Great Britain, where the innovation of power grid regulation began in the 1990s and incentive regulation was introduced to improve the cost-efficiency of the grid operators at the transmission and distribution levels. Over the following two decades, the British model evolved from 'RPI−X' towards 'RIIO' to adapt to a changing environment with more emphasis on grid innovation and renewed attention to the quality of the grid services and the challenges posed by the energy transition. In the meantime, the British-style incentive regulation also became the main reference model for the rest of Europe.

However, other EU Member States should not blindly follow the British model. In Chapter 2 we first argue that it is important to choose a model that the national regulatory authority can handle; and authorities across Europe have different skills and resources. We then explain that the business of power grid operation is essentially a set of tasks. Different tasks have different cost and regulatory characteristics, which can require a different regulatory approach. The context also matters: one country can be in the middle of an investment cycle trying to keep capital costs under control, while another is sweating the assets to make the best use of the infrastructures that are already in place. Consequently, no panacea exists for the regulation of electricity grids. On the contrary, a

workable alignment between the regulatory tools, the characteristics of the targeted network task and the regulator's capabilities must be properly identified and implemented.

The second part of the book focuses on seam issues – that is, on the fact that in the EU there is 'one market, one system, but many operators and authorities'. The long-standing goal of creating a single market for energy in Europe requires the coordination of the several private actors and public entities existing at the Member States level. An EU layer has gradually developed on top of the national regulatory frameworks through the adoption of subsequent 'energy packages'. The harmonization of rules and the institutionalization of cooperation between national regulators and system operators have been repeatedly sought by European policy-makers. Some results were achieved, as shown by the adoption of common network codes and the establishment of ENTSO-E, a body gathering all the transmission network operators in Europe. Nevertheless, as Chapter 3 discusses, EU institutions as they are today do not offer an easy and fast path to the full elimination of all the seams in the European power system.

The process of market integration is not the only reason for the emergence of seam issues. The renewable push and the progressive decentralization of the power system are increasing the number of active network users. Patterns of energy flows are changing and becoming more difficult to predict. The change is particularly transformative at the distribution level, where the traditional approach based on 'fit and forget' is no more satisfactory. Chapter 4 zooms in on this topic and addresses the coordination problems emerging between transmission system operators and the distribution system operators connected to them. In a world of more active distribution grids, new coordination mechanisms concerning congestion management, system balancing and data handling must be agreed upon and implemented in a timely fashion. This is necessary to ensure that a level playing field in energy markets is maintained and the transition to a decarbonized power sector occurs at a low cost for network users.

In the third part of the book we explore the border between the 'grid' and the 'market', which continues to be challenged and disputed more than 20 years after the decision to unbundle the first from the other potentially competitive segments of the industry. This border is not clear-cut, but there are 'grey areas' where it is not apparent whether the best choice is to allow competing companies to freely provide a service or to assign a monopoly right to a single regulated firm. Chapter 5 discusses

three of these cases: should a system operator also own the grid it operates? Is the function of market operator a competitive activity or should it be subject to monopoly regulation? Is energy storage a grid asset or a market asset that cannot be controlled by the network company? These are old questions, debated since the beginning of the electricity liberalization process, that are being revisited in the era of digitalization and innovation in storage technologies.

New grey areas have emerged as well in recent times, with European power grids moving into unknown territory. At the transmission level this is the case with grids going offshore to connect wind farms, while at the local level the case is that of distribution grids developing the infrastructure for charging electric vehicles. In many European countries, regulators have used this new territory to experiment with innovative regulatory approaches, which if found to be successful can be imported to the rest of the system. In Chapter 6, the last of the book, we investigate these two grey areas and try to understand whether the experience gained so far suggests encouraging competition from new actors or rather including these emerging businesses in the franchise of the existing regulated network companies.

PART 1

Incentive regulation: aligning the interests of the operators with the interests of their customers

1. The British reference model

Vincent Rious and Nicolò Rossetto

In the field of regulatory practice, the British regulation of the energy sector, and in particular of the electricity network, represents a crucial reference. There are five reasons for this. First, Britain was a pioneer in the concrete application of the RPI – X incentive regulation to the energy sector. Second, and because of this, it is an instructive illustration of the application of the theoretical principle of incentive regulation, and an interesting case study for the assessment of the efficiency-improving prediction of incentive regulation. From this point of view, and third, since the very beginning of its application and the liberalization process, incentive regulation has achieved great success in the electricity network sector, in terms of cost and tariff reduction, increase in quality of service for network users and investment by network companies. Fourth, this application has also shown that the very theoretical principles must be adapted in practice because theory is based on a simplified and stylized view of reality. These adaptations were designed in a pragmatic way as difficulties emerged, not necessarily through investigating the overall architecture of regulation. However, and fifth, after 20 years of application of the RPI – X regulatory principles, the British regulator, the Office of Gas and Electricity Markets (Ofgem), felt it necessary to reconsider the overall picture of its regulatory practice in order to reset the regulatory principles. Some practitioners may have interpreted this as the dawn of a real revolution in the industry, even if many of the components of the historical application of the RPI – X regulation remain.

After a short presentation of the industry landscape in Britain (Section 1.1), the chapter describes the overall evolution of the British application of incentive regulation, from the beginning of the RPI – X regulation (Section 1.2) to the renewal brought by the new RIIO (Revenue = Incentives + Innovation + Outputs) regulation (Section 1.3). It shows the difficulties in applying concretely the theoretical principle of incentive regulation, the need to complement it with safeguards and even incentives to provide specified outputs and innovation, and the interaction and inefficient interferences that can emerge as regulation results from a set

of regulatory schemes. Interesting, too, the need felt by Ofgem to reset its overall regulatory practice questions against the theory on the goal of incentive regulation. Cost-killing is not a regulatory holy grail if the network value for network users is missed. It shows, too, that theoretical work is still needed to define a cost function of electricity network activities as it could help go beyond the seminal theoretical design of incentive regulation in the power sector.

1.1 THE TSO AND DSO LANDSCAPE IN BRITAIN

Until 1989, the Central Electricity Generating Board (CEGB) had a monopoly over the generation and transmission of electricity in England and Wales. Moreover, 12 Area Boards were acting as regional electricity distribution and supply monopolies. In Scotland, two companies integrated over the whole supply chain (generation, transmission, distribution and supply) had a monopoly on their supply areas. In practice, their price was set on a cost-of-service basis.[1]

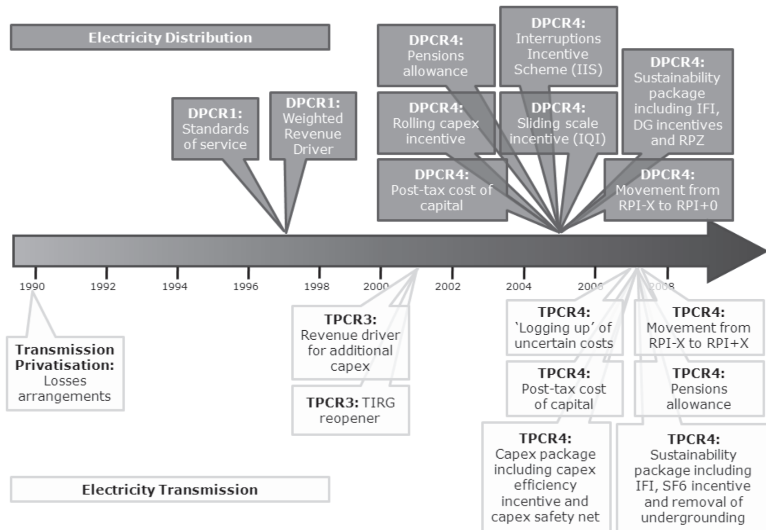
During the late 1970s and the 1980s these companies were said to be inefficient for four main reasons. First, they had a bad record of controlling capital investment costs. Second, they built uneconomic nuclear power stations. Third, they paid excessive prices for British coal under a nationalistic decision to support the domestic mining sector. Finally, in the absence of competitive information sources, the CEGB appeared to greatly underestimate the future costs of decommissioning nuclear power stations at the end of their useful life. Nevertheless, in terms of short-run operating efficiency, the CEGB's performance appears to have been reasonably good, except (as is now more apparent) for over-staffing.

Considering these inefficiencies, the British government, after several years of discussions, decided to restructure the power sector and to privatize it (Electricity Act, 1989). After numerous subsequent reforms and divestments, the industry is now organized with:

- several firms freely competing for the generation and supply of electricity to consumers
- a transmission system operator, National Grid,[2] which operates the whole British system and owns the transmission network in England and Wales[3]

- two transmission and distribution network owners in Scotland (ScottishPower Energy Networks in the south and Scottish Hydro in the north)
- 12 other electric distribution companies in England and Wales, several of which are under common ownership
- an independent regulatory authority, Ofgem, in charge of regulating the newly privatized industry.[4]

In order to improve efficiency, electricity generators and suppliers are obliged to compete in the market, whereas network companies are subject to monopoly regulation. The goal of regulation, then, is to supervise competition on the open markets of generation and supply, considering these markets are frequently oligopolistic or prone to market failures. Moreover, for network monopoly companies, the role of regulation is to mimic competition so that companies are more cost-efficient and provide better services to customers (so-called value for money). Ofgem also has the mandate to promote security of supply and sustainability for present and future generations of consumers.



Source: Ofgem (2009), p. 2.

Figure 1.1 Major milestones in the regulation of electricity transmission and distribution grids[5]

Focusing on the regulation of network monopoly companies, Ofgem has gradually scrutinized and extended its regulatory tools. Hence, a learning process took place as follows (see Figure 1.1). First, Ofgem wanted to control only some inputs and types of costs of the monopolies while ignoring the others. Network companies soon learned how to play with these partial controls, moving expenditures from one type of input to another, neglecting the increase of some inputs or even decreasing some of the outputs, such as the level of service quality provided to network users. Ofgem noticed these secondary effects and progressively improved its regulatory control to avoid this undesirable edge effect. As implied by the chronology above, over time Ofgem has expanded its regulatory control from maintenance and energy losses (as soon as transmission was privatized) to quality of service (for the transmission sector with an interruption incentive scheme in 2003 following a blackout in London, and for the distribution sector with standards of service in 1997 and an interruption incentive scheme in 2005), congestion costs (from 1993 in the transmission sector), investment (with specifically dedicated regulatory schemes for transmission in 2001 and 2007 and for distribution in 2005) and innovation (during the late 2000s). This whole movement of regulation in Britain between 1990 and 2010 was encapsulated under the term of RPI–X regulation. Even if the RPI–X regulation was at the centre of Ofgem control of the network companies during this period, in reality more and more subtle regulatory tools have been implemented in order to overcome the difficulties encountered by the sole use of RPI–X regulation.

1.2 THE RISE OF RPI–X

At the centre of the regulatory framework established for the British electricity industry in the 1990s there was an ex ante definition, provided by the regulator, of the price dynamics that network firms must respect when charging their customers. The underlying idea was to exert pressure on network firms to reduce costs and progressively share any achieved cost reduction with network users. The framework apparently worked: network firms were usually able to significantly outperform their baseline and record increased profits, especially during the first regulatory periods; meanwhile, network users benefited from an important price reduction between the subsequent regulatory periods. However, some critical positions clearly emerged over the 20 years of RPI–X regulation and some problems required pragmatic intervention by the regulator.

In this section, we start by presenting the overall principle of RPI−X regulation and the way it was pragmatically implemented by Ofgem. Then, we narrow the focus to two critical aspects of this form of incentive regulation: service quality and innovation. Finally, we provide a brief assessment of the RPI−X regulatory experience and a list of drawbacks that justified the move to a new regulatory framework around 2010.

1.2.1 RPI−X Principle

The overall principle of RPI−X regulation is that the allowed revenue of a (network) monopoly company or the price it is allowed to charge its customers are subject to a cap linked to the Retail Price Index (RPI), a common measure for price inflation, and to an efficiency factor called the *X* factor, representing the expected efficiency gains of the industry compared with those of the rest of the economy. With revenue or price dynamics set in advance, the monopoly firm is incentivized to reduce its costs below the expected efficient cost level, because it will retain as a profit any difference between the cap and its actual costs. Figure 1.2 explains this mechanism. The dark grey sloping line represents the price cap over time, as defined by the initial price level P_0, the productivity objective X set by the regulator at the beginning of the regulatory period, and price inflation as measured by the RPI. The regulated firm can charge a price up to the level defined by this line. The light grey sloping line represents the real unit costs borne by

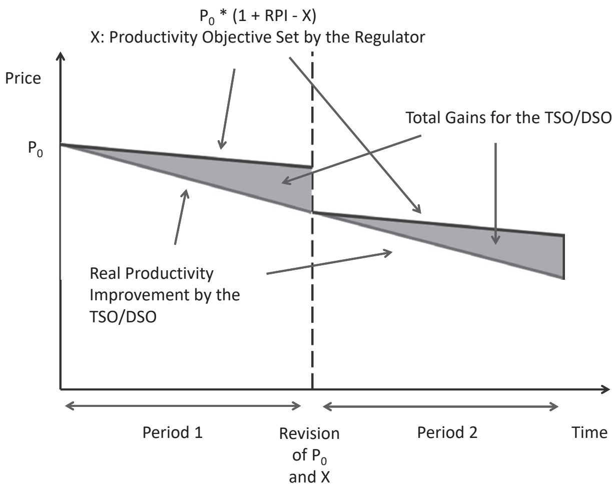


Figure 1.2 How RPI−X regulation works

the firm. The difference between the two lines, i.e. the shaded areas, is the profit the firm can earn (if the light grey line lies above, and not below, the dark grey one, then the firm records a loss and not a profit).

Ideally, the firm is incentivized to be most efficient if the price dynamics are set for a long period of time. However, in practice regulators fix the cap only for a limited number of years, usually from three to five, because the uncertainties surrounding the activity of the monopoly company grow quickly over time and unforeseen implementation issues can emerge.[6] In the early 1990s the British regulator adopted a regulatory period of four years for transmission (Transmission Price Control Review, TPCR) and of five years for distribution (Distribution Price Control Review, DPCR). Based on the experience gained in the first rounds of price controls, and as a consequence of the integration of the electricity and gas transmission grids into one single company, in the mid-2000s Ofgem decided to implement a single regulatory period for electricity and gas transmission. The length of this period was extended to five years, as in the case of distribution (see Tables 1.1 and 1.2).

Electricity distribution and transmission tariffs are determined at the beginning of each regulatory period by using a building block approach, where operating expenditure (OPEX), depreciation and the return on regulatory asset base (RAB) are estimated separately and then added together in order to define the maximal allowed revenue for the firm and the efficient and fair value for the various network tariffs. Originally, the RPI − X approach was applied only to a part of operating expenditure; its extension to capital expenditure (CAPEX) occurred later.

Table 1.1 Chronology of the regulatory periods for electricity distribution in Great Britain

<table>
<tr><th>Year</th><th>England & Wales</th><th>Scotland</th></tr>
<tr><td>April 1990–March 1995</td><td>Post-privatization price control</td><td>Post-privatization price control</td></tr>
<tr><td>April 1995–March 1996</td><td>DPCR1</td><td rowspan="2">DPCR1</td></tr>
<tr><td>April 1996–March 2000</td><td>DPCR2 after Offer reopened the price review in 1995</td></tr>
<tr><td>April 2000–March 2005</td><td colspan="2">DPCR3 after merger of the regulatory process for all British distribution companies</td></tr>
<tr><td>April 2005–March 2010</td><td colspan="2">DPCR4</td></tr>
<tr><td>April 2010–March 2015</td><td colspan="2">DPCR5</td></tr>
<tr><td>April 2015–March 2023</td><td colspan="2">RIIO-ED1</td></tr>
</table>

Source: Based on Simmonds (2002), Ofgem (2009) and Ofgem website.

Table 1.2 *Chronology of the regulatory periods for electricity transmission in Great Britain*

<table>
<tr><th>Year</th><th>England & Wales</th><th>Scotland</th></tr>
<tr><td>April 1990–March 1993</td><td>Post-privatization price control</td><td rowspan="2">Post-privatization price control</td></tr>
<tr><td>April 1993–March 1994</td><td rowspan="2">TPCR1</td></tr>
<tr><td>April 1994–March 1997</td><td rowspan="2">SCOTCO1</td></tr>
<tr><td>April 1997–March 1999</td><td rowspan="3">TPCR2</td></tr>
<tr><td>April 1999–March 2000</td><td>SCOTCO1 one-year roll-over</td></tr>
<tr><td>April 2000–March 2001</td><td rowspan="2">SCOTCO2</td></tr>
<tr><td>April 2001–March 2005</td><td rowspan="2">TPCR3</td></tr>
<tr><td>April 2005–March 2006</td><td rowspan="2">SCOTCO2 two-year roll-over</td></tr>
<tr><td>April 2006–March 2007</td><td>TPCR3 one-year extension</td></tr>
<tr><td>April 2007–March 2012</td><td colspan="2">TPCR4 after merger of the regulatory process for gas and electricity transmission companies over the whole of Great Britain</td></tr>
<tr><td>April 2012–March 2013</td><td colspan="2">TPCR4 one-year roll-over</td></tr>
<tr><td>April 2013–March 2021</td><td colspan="2">RIIO-T1</td></tr>
</table>

Source: Based on Simmonds (2002), Ofgem (2009) and Ofgem website.

Ofgem experienced six kinds of difficulties in setting the parameters of the RPI – X regulation.[7] First of all, Ofgem had difficulties in setting the perimeter of RPI – X. Initially, the cap was not applied to the overall operating expenditure because part of it was wrongly or rightly supposed to be uncontrollable by the regulated firm. Congestion costs, for instance, were not subject to an incentive scheme but were simply passed through to the network users, since they were supposed to depend not only on network constraints but also on the costs of the generators activated to relieve congestion, a variable over which the network operator did not have any control. However, during the first regulatory period, congestion costs multiplied by five in just four years (from £50 million to £250 million) because generators exerted their local market power and the transmission and system operator, National Grid, was not made financially responsible for congestions and the associated costs resulting from its maintenance activity. Indeed, as soon as a cap was applied to congestion costs, those costs began to decrease and returned to their 1990 level within four years. They further shrank by a factor of five in the following four years, reaching an overall level of £10 million. This drastic cost decrease resulted from two changes in the behaviour of

National Grid. First, the regulated scheme incentivized it to enter into a long-term contract under the scrutiny of the regulator with generators located in load pockets that were essential for network reliability and able to exert significant market power. Moreover, the regulated scheme incentivized National Grid to plan its maintenance programme in a way that would minimize network constraints and costs.

A second difficulty for Ofgem was the interference between the various incentive schemes. In the case of electricity distribution, for instance, Ofgem first set the efficiency target on OPEX. In a later distribution regulatory review, it introduced a target on CAPEX too. The problem recognized at the fifth distribution regulatory review in 2010 was that having different levels of reward to go beyond the respective OPEX and CAPEX targets prompted the network companies to choose CAPEX over OPEX. Besides, a return on investment adds up to CAPEX once integrated into the RAB, while OPEX is, at best, merely recovered without any additional revenue. These two effects taken together incentivized companies to choose CAPEX over OPEX, which is likely to be inefficient since both are needed to provide least-cost network services.

Third, Ofgem had difficulties in setting the *X* efficiency factor. This problem was particularly visible in the distribution sector. In the run-up to the 1990 privatization and before the regulator held the first distribution price control review in 1994, bundled distribution and supply tariffs were increased significantly. During the post-privatization regulatory period between April 1990 and March 1995, distribution companies were allowed to increase network charges by RPI + 1 per cent on average. At that time there was limited knowledge of distribution costs and how to assess the efficiency factor. Significant capital expenditure programmes and a limited growth in the amount of distributed electricity were also expected. In the end, actual costs were lower and excessive rent was left to the distribution companies. As a consequence, distribution firms earned remarkable profits, as confirmed by their high stock value. The British regulator then decided to revise down tariffs in 1995, between 11 per cent and 17 per cent, with further cuts in 1996 between 10 per cent and 13 per cent. An RPI – 3 per cent formula was imposed upon the companies over the following three years.

Fourth, Ofgem had difficulties in displaying transparently the methods used to set the *X* efficiency factor for regulated companies, in particular through benchmarking. The benchmarking model of distribution companies, for instance, was disclosed only from the second regulatory review onwards, despite the fact that such a model had already been used in the

first regulatory review. Statistical benchmarking methods have been applied by the regulator, especially in the distribution sector, to determine the relative efficiency of the individual firms' operating costs and service quality compared with those of their peers. The information obtained from these methods can be used as an input for setting the values of P_0 and X, in a way to incentivize the firms far from the efficiency frontier to move closer to it and to reward the most efficient firms so that they are induced to stay on the efficiency frontier (see Chapter 2, Section 2.3.1 for more information on benchmarking and yardstick competition). A range of empirical methods has been applied to identify the operating cost-efficiency frontier and to measure how far from it an individual company is positioned. Their results are obviously not identical and this has created a problem of transparency for Ofgem. Indeed, depending on the benchmarking technique chosen and the associated results, a distribution company will score closer to or further away from the efficiency frontier and hence will receive a tougher or less tough cost target for the next regulatory period. Understanding the impact of the benchmarking technique on their cost target, then, is of great importance for network companies. Although the inclusion of quality-of-service considerations has further complicated the issue, transparency has increased through the subsequent regulatory reviews, with Ofgem progressively publishing benchmarking methods, data and variables used.

However, transparency revealed a fifth difficulty for the British energy regulator: a lack of consistency and justification for changes in the benchmarking methods adopted over time. For instance, the weight applied to the different variables in the benchmarking during the second and third distribution regulatory reviews in 1999 and 2004 was different, without Ofgem giving any explanation for such change.

A last problem recognized only at the third distribution regulatory review was data gathering for benchmarking. Ofgem noticed that costs were accounted for in quite different ways across the industry. Several problems were identified. The main one was the so-called capitalization of OPEX: some distribution companies accounted part of OPEX as CAPEX; they then benefited from the return on this fictitious 'investment' and reached more easily the efficiency target on OPEX. Other problems of data collection also concerned the accounting treatment of exceptional costs, intra-company margins or expenditure required to repair the grid after major faults. Data gathering and a uniform accounting system are essential for developing sound efficiency analysis through benchmarking on an equal footing.

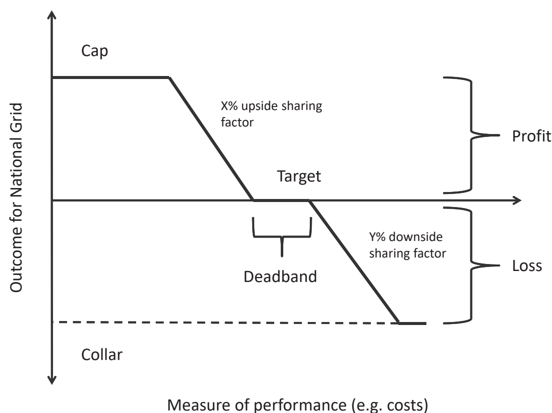
1.2.2 Output Regulation as a Safeguard for Services to Network Users

A major drawback of RPI – X regulation is that, on a stand-alone basis, it incentivizes companies to decrease the quality of the provided service. Indeed, it is far easier to cut costs by disregarding quality of service. Mechanisms providing output-related incentives hence have been developed by the energy regulator on a case-by-case basis to compensate for the failure of RPI – X regulation to ensure an adequate level of service quality for network users (see Box 1.1 and also Section 2.3.1).

BOX 1.1 FROM RPI – X REGULATION TO OUTPUT REGULATION

Output regulation generalizes the principle of RPI – X regulation to outputs instead of inputs. A target is set and the regulated company is assumed to at least reach it. Then, if it outperforms the target, it will receive a reward. Otherwise, a financial penalty will be inflicted. A deadband, where the company is neither penalized nor rewarded, can also be introduced around the target. Deadbands, rewards and penalties may be defined in a symmetrical manner or not. Rewards and penalties may be respectively subject to a cap or a floor to avoid excessive windfall profits or losses for the regulated company.

The relationship between the company's performance and the remuneration ensured by this regulation scheme balances the company's risk and its reward or penalty (see Figure 1.3). In this way, it modifies the share of profits and losses accruing to the network company and the network users.



Source: Ofgem.

Figure 1.3 Relationship between the measure of a network output and the financial outcome for the network company under output regulation

Output regulation can apply to a variety of specific activities. Basically, any output can be defined, monitored, subjected to targets and rewarded or penalized. For instance, outputs can encompass environmental policy goals (e.g. minimizing power losses from transits through modification of the network topology and of voltage control) or social policy objectives (e.g. the customer service reward scheme for rewarding actions by distribution licensees to help vulnerable customers on affordability; or, in the gas sector, gas safety and awareness of the dangers of carbon monoxide). However, the main reason output regulation has been introduced is that cost reduction prompted by RPI – X regulation could jeopardize quality of service in the longer term, with more frequent and deeper disconnections and poorer voltage quality (harmonics, voltage drops, voltage overload, etc.).

1.2.3 Three Mechanisms for One Goal: Innovation

Even with a quality safeguard, the RPI – X regulation still has a major drawback in the long run. Indeed, it incentivizes regulated companies to cut research, development and demonstration (RD&D) costs, mainly for two reasons. First, those costs can be easily cut overnight. Second, cutting those costs does not immediately endanger quality of service, thereby avoiding any immediate penalty for a network firm subject to output regulation as well. On the contrary, the firm can reach more easily its RPI – X target and earn an extra profit. However, although a cut in RD&D costs may be beneficial for the individual firm in the short run, in the long run it is detrimental from a social welfare point of view because of the public good aspect of RD&D. Thanks to spill-over effects, RD&D activities provide benefits not only to the investing company but also to other companies in the field and more generally to society as a whole. Without RD&D, little innovation can emerge, a development that is particularly negative in a period of deep technical, economic and organizational transformation for the entire energy industry.

Following the liberalization and privatization of the British electricity industry, a collapse in energy RD&D was noticed. By 2004, the amount of money British network companies were spending on RD&D was very small – less than £4 million per year, or less than 0.1 per cent of their total revenues. Thus, three regulatory schemes dedicated to innovation were designed towards the end of the RPI – X era: the Innovation Funding Incentive (IFI), the Registered Power Zones (RPZs) and the Low Carbon Network (LCN) Fund.

The IFI was the first scheme created in 2004 to allow distribution companies to invest in RD&D, even when project costs and benefits span beyond the price control's five-year horizon. IFI, extended to transmission in 2007, allowed, up to its replacement in 2015, network companies to spend up to 0.5 per cent of their yearly distribution/transmission activity revenues on eligible IFI projects. The amount of money effectively spent under the mechanism was small, in total about £25 million per year for both transmission and distribution, but still much higher than the investments recorded before its establishment. Indeed, companies could recover 80 per cent of their eligible project expenditure under the licence condition, with a 25 per cent cap on their internal costs such as salaries. Eligible projects had to meet the criteria set out in an IFI Good Practice Guide and, as a minimum, align with at least one of Ofgem's five sustainable development themes: i) managing the transition to a low-carbon economy; ii) eradicating fuel poverty and protecting vulnerable customers; iii) promoting energy saving; iv) ensuring a secure and reliable gas and electricity supply; and v) supporting improvement in all aspects of the environment.

Three RPZs were created in 2005 to encourage electricity distribution companies to develop new and more cost-effective technologies for connecting and operating renewable generation. The three zones were Skegness & Fens (Central Networks), the Orkney Isles (Scottish Hydro Electric Power Distribution) and Martham Primary (EDF Energy). Allowed revenues for the companies were then increased if renewable generation capacity connected to the respective network turned out to be higher than the baseline.[8] The RPZ incentive scheme ceased to apply to any new generation connecting onto the zones in March 2012.

Lastly, the LCN Fund was part of the electricity distribution price control arrangements that ran from 1 April 2010 to 31 March 2015 (DPCR5). The Fund allocated up to £500 million for support to projects sponsored by distribution companies to try out new technologies, and operating and commercial arrangements that would be needed to deliver smart grids capable of supporting the growth of electric vehicles or locally based generation. There were two tiers of funding under the LCN Fund. A first tier was designed to enable distribution companies to recover a proportion of expenditures incurred on small-scale projects, whereas under the second tier Ofgem promoted an annual competition for the allocation of up to £64 million to help fund a small number of flagship projects.

The combination of these three innovation mechanisms may have been enough to appreciably improve the rate of technical progress in British networks at a time when capital expenditure was increasing significantly due to the necessity of replacing old assets and preparing the system for the challenges associated with the transition to a low-carbon economy. The benefits of some of these mechanisms in terms of social welfare were assessed to be more than six times higher than the associated expenses.[9] However, one can conclude from the short overview provided above that the mechanisms were not harmonized. On the one hand, different mechanisms had the same target (electricity distribution network companies, for instance, were eligible for all the mechanisms). On the other hand, they were incomplete for two reasons. First, transmission was not fully able to participate in these mechanisms before 2007. Second, non-network players were not able to participate as well, hence preventing the (still monopolistic) network activities being opened to competition.

1.2.4 Benefits for Companies

A consumer association, Citizens Advice, blamed the RPI−X regulation and its application by Ofgem for providing excessive remuneration to the regulated companies, as proved by their ability to significantly outperform the baseline set by the regulator.[10] During the last RPI−X regulatory periods, ending respectively in 2013 for transmission and 2015 for distribution, while the allowed return on equity was set close to 6 per cent, its effective value was generally closer to 9 per cent or 10 per cent, once the rewards and penalties stemming from the various incentive regulation schemes were considered. Only once did two distribution companies get an effective return on equity below the normal rate. Indeed, a network company, by cumulating the rewards or the penalties of the different incentive regulatory schemes, had the possibility to increase its remuneration or be penalized by 400 base points over or below the allowed rate of return on equity.

Nevertheless, it is undeniable that RPI−X regulation in the electricity sector was a great success. Prices decreased over the RPI−X regulation periods by 30–50 per cent (transmission to distribution). Quality of service improved significantly, with a reduction in power cuts by more than 10 per cent in number of events and 30 per cent in duration, a drastic increase in the level of investments (almost multiplied by two compared with the pre-privatization period) and transformed use of the power networks by combined-cycle gas turbines (CCGTs) first and then renewables.

These achievements were possible because a temporary rent was left to network companies. Despite the temptation to reduce allowed revenues and regulatory rewards to better-off consumers or return efficiency gains to consumers more quickly, the theory of incentive regulation shows that doing so would destroy any incentive for companies to improve their efficiency level over time. Meanwhile, an upgrade of regulation itself is always welfare improving because it may either lower costs or provide higher value and quality of service for the network users or both simultaneously. The continued improvement of regulation in the RPI − X era was in that vein and was the real purpose of refunding it with the RIIO regulation.

1.2.5 Success and Required Improvements

For 20 years RPI − X regulation in Britain was a great success, with major price decreases and an increase in quality of service while triggering a new investment cycle and accompanying the power sector in several transformations.

The RPI − X regulation applied in practice in Britain was built with pragmatism, correcting incentive mechanisms or developing new ones when it was considered necessary. However, the RPI − X regulation had four main drawbacks. First, it resulted in a patchwork of mechanisms whose interactions were neither fully identified nor understood. Second, it had also a short-run bias with a focus on cost saving through a sweating asset regulation. Third, correction patches on outputs and innovations were introduced but they incentivized the regulated companies to focus on the regulator’s expectations rather than on investigating those of the network users. In this regard, since networks are essential for the integration of renewable energy sources and the transition to a low-carbon energy sector, a realignment of regulation with climate policy objectives is needed. Lastly, regulation became a rather intrusive process, with detailed audit and benchmarking reviews, leading to regulatory costs, possibly unaligned with network users’ expectations.

1.3 THE EVOLUTION TOWARDS RIIO

In 2009, Ofgem decided to revise the overall principle of the RPI − X regulation in order to overcome the difficulties identified since its early implementation in the 1990s. The review resulted in the so-called RIIO

regulation where RIIO stands for 'Revenue = Incentives + Innovation + Outputs', meaning that the revenues of regulated companies shall be set to deliver strong incentives, innovation and outputs for network users. The RIIO regulation is built keeping in mind that the goal of regulation is to mimic competitive pressure on monopoly firms. The activity of the regulated company thus should be consumer-oriented. Namely, it should focus on i) outputs to improve services to network users, ii) incentives for cost reduction and iii) innovation in order to provide new services and cost reduction in the long run to the benefit of network users.

Meanwhile, what was announced as a revolution, in fact became an evolution. All the elements of the RPI−X regulation are still present (the RPI−X theoretical approach, output-based regulatory schemes and innovation-promoting mechanisms). The RIIO regulation nevertheless has the advantage of overhauling the entire regulatory process with the goal of overcoming the problems identified in the RPI−X regulation. Reorienting regulation towards outputs has then shifted the focus onto network users' expectations. Besides, the objective of assessing total expenditure (TOTEX, i.e. the sum of OPEX and CAPEX) as well as OPEX and CAPEX individually was also to consider the overall service provided and not different types of costs that are of no immediate relevance for network users. The RIIO regulation also has the characteristics to allow companies to choose their incentive scheme on TOTEX from a so-called menu of contracts, with more or fewer incentives and subsequent potential risks and rewards. Lastly, innovation was fully integrated into the regulatory process and was no longer addressed through disparate mechanisms.

In this section, we start by showing how the RIIO framework is supposed to reflect better the expectations and needs of network users through the regulation of network outputs. Then, we move to consider how a menu of contracts for TOTEX can incentivize efficient behaviour by network companies. Finally, we illustrate how the promotion of innovation has been deeply embedded in the regulatory process.

1.3.1 Output Regulation Reflecting Network Users' Expectations

RIIO is a performance-based model for setting the network companies' price controls for a period of eight years. Contrary to RPI−X, the RIIO regulatory framework was built with outputs as the core element: while RPI−X regulation prescribed a set of inputs whose level had to be kept under control by the regulated company, RIIO regulation first defines a

set of outputs to be delivered to network users and only later seeks to deliver them at the cheapest cost.[11]

Six key output categories have been identified to frame the activity of network regulated companies: customer satisfaction, reliability and availability, safety, conditions for connection, environmental impact, and social obligations. Consumers and stakeholders have participated in the definition of both specific outputs for each category and the expected targets to be achieved by companies. Beside the regulator, the network company may consult them too while realizing its business plan. The company may propose additional or alternative outputs and arrangements on incentives, able to address the specific needs of the stakeholders. Considered in the overall RIIO regulatory process, this opportunity provides powerful incentives for companies to innovate and seek least-cost ways to provide network services.

Outputs were defined to enable the regulator, network companies and stakeholders to have a clear understanding of what is delivered throughout the regulatory periods. Outputs were designed in such a way as to be material, controllable, measurable, comparable, applicable, compatible with the promotion of competition and compliant with legislation.

Output categories that differ from legal requirements or do not benefit from reputational incentives are subject to an adequate incentive scheme. Basically, incentives for safety and connections mainly rely on the general enforcement of legislation. Reputational incentives apply on availability, environmental impact of losses, business carbon footprint publication and visual amenity. In contrast, incentive mechanisms apply to the other categories, namely reliability, customer satisfaction and environmental impact of SF_6, a gas with a major greenhouse effect (several thousand times higher than CO_2) that is used in transformers for electrical insulation. Output regulation also partly applies on safety for network replacement and visual amenity.

The baseline revenue estimate, including investment requirements, will be based on the assessment of efficient costs for delivering the agreed outputs. Performance on outputs subject to regulatory incentive mechanisms then impacts the return on equity earned by the regulated company and can add up or down to the allowed rate of return until 100 base points, hence a remuneration at risk close to 15 per cent of its base level (in the first RIIO regulatory period for transmission (RIIO-T1) and distribution (RIIO-ED1), the return on regulated equity without reward and penalty from incentive schemes was set at 6.7 per cent for distribution companies and close to 7 per cent for transmission companies).

Even if the first regulatory period of RIIO is ongoing, its mid-term review and the letter by Ofgem beginning the discussion on the RIIO-2 framework have shown that some questions on the definition and proper delivery of outputs remain open. One of the main issues is that key performance indicators (KPIs) are sometimes closely related to the realization of one specific investment (examples are shunts or high-voltage direct current lines). Regulatory schemes associated with these KPIs and specific investments are then extremely similar to classic RPI − X regulation, simply capping the cost of these investments. But unexpected events have occurred. For instance, the regulated companies were able to provide some expected outputs with technical solutions that were different from those planned at the beginning of the regulatory period and at a far lower cost. The regulator is hence considering decreasing the cost cap initially designed for this output/investment. Another example also stems from unplanned external factors impacting the need for new investments in order to ensure the delivery of some outputs that have materialized, which then leads to questions about the definition of the associated outputs and their associated baseline level of costs. These questions are classical ones for regulatory-like concession contracts. Regular renegotiations are then needed because of the incompleteness faced with unexpected events. Let us see how Ofgem will cope with that at the end of RIIO-1 and in the design of RIIO-2.

1.3.2 A Menu of Contracts for TOTEX Efficiency Incentives

Besides being oriented towards output regulation, the current British regulatory design is based on a periodic revenue cap mechanism (with an eight-year period rather than the five-year period under the previous RPI − X regulation). The costs budgeted by the companies for regulated activities (operation and investments) in their business plans are taken into account to define the revenue allowances for the regulatory period. The revenue cap mechanism applies to budget costs following a TOTEX design. TOTEX is defined as the sum of CAPEX (i.e. only new investments that are considered completely controllable, but not the historical asset base) and controllable OPEX.[12]

A major change from the first RIIO regulatory period is the definition of the regulated asset value (RAV).[13] In the RPI − X regulation, the RAV was classically defined as the non-depreciated network assets (namely power lines and substations). Other short-life assets such as IT facilities were included in the OPEX and so did not generate any return on

investment. Consequently, there was an incentive for the company to prefer CAPEX over OPEX since CAPEX was generating a return on investment, whereas OPEX was paid at cost only (except when specific incentive mechanisms applied). The network companies were also allowed to retain more efficiency gains on CAPEX than on OPEX, amplifying their interest in CAPEX.

To avoid this pitfall, Ofgem decided to change the way the RAV is defined (see Box 1.2). Now, the RAV is not only made up of CAPEX; a fixed part of total expenditures, whether CAPEX or OPEX, is included each year. The TOTEX capitalization rate, then, defines the part of TOTEX (so-called slow money) that is included in the RAV. A TOTEX capitalization rate of between 85 per cent and 90 per cent has been set for network companies (based on historical shares between OPEX and CAPEX). The non-capitalized part of TOTEX and non-controllable costs taken together form the so-called fast money and are funded in the year of expenditure. The RAV is then depreciated assuming that the new capitalized TOTEX is depreciated in a straight-line manner during 45 years on average.[14,15]

The revenue cap is applied on network companies' TOTEX with a menu of contracts mechanism (see Chapter 2, Section 2.3.1 for further information on the menu of contracts tool). This scheme is known as the Information Quality Incentive (IQI). The regulator targets two results with this menu of contracts. The first goal is to decrease information asymmetry as the network companies select the incentive scheme they think is more appropriate to their situation, hence revealing their target cost. Second, this incentive scheme defines the sharing factor applied to the gains or losses the network company may incur compared with the target cost. For instance, the contracts proposed by the regulator to the regulated company in the regulatory menu go from a 40 per cent to a 50 per cent sharing of efficiency gains above the target and a +/−2.5 per cent additional income reward/penalty.

The TOTEX allowances and efficiency targets are computed based on a combination of several methods (disaggregated analysis of CAPEX and OPEX, efficiency audits, consultation process, benchmarking). International benchmarking is used only to inform the overall Ofgem assessment of the companies' forecasts. No mechanical application of benchmarking as incentive scheme is implemented. Rather, it is used in the stakeholder consultation process for the regulator to assess the cost of the network companies' business plan and set the TOTEX allowances, but not to set the maximal allowed revenue itself.[16]

Incentive on TOTEX may increase or decrease the return on regulated equity by 300 base points (compared with a base level fixed at 6.7 per cent for distribution companies and around 7 per cent for transmission companies). This means that the remuneration of a network company in Great Britain can be increased by more than 40 per cent if it reaches all the efficiency and output objectives set in the RIIO regulation. The TOTEX incentive accounts for more than 75 per cent of the whole level of incentives.

BOX 1.2 ADJUSTMENT OF TOTEX, RAV AND REVENUE TO EXTERNAL FACTORS AND REVENUE FORMULA

The TOTEX and, consequently, the RAV can be adjusted because of changes in drivers of expenditures (generation or demand connections, relieving internal network constraints, etc.). A baseline for a part of TOTEX (so-called load-related expenditures) thus is defined for the whole regulatory period based on some assumptions of drivers of the network companies' activities. Changes in these drivers lead to additional TOTEX allowances. These drivers are the volume of new generation connections, new demand connections, additional transfer capability to relieve internal network constraints, integration of renewables, cost of mitigation measures to gain consent for reduction in visual amenity and funding for delivering outputs in RIIO-T2.

The RAV is also updated by inflation level. It is remunerated at the weighted average cost of capital (WACC) value. Besides, a two-year lag is introduced to make the tariff predictable enough. The authorized revenue R_N for year N is determined as follows:

$$R_N = FastMoney_{N-2} + D_N + WACC * RAV_N + A_{N-2} + I_{N-2}$$

with D_N depreciation of the RAV for year N,
A_{N-2} adjustment from the year N–2,
and I_{N-2} financial incentive from the year N–2.

1.3.3 Full Integration of Innovation in the Regulatory Process

The RIIO regulation encourages technical and commercial innovation through the core incentives of price control, innovation stimulus package and competition, with the option of giving responsibility for delivery to third parties.

The core incentives of the RIIO regulation stimulate innovation with the price control framework. First, firms are incentivized to innovate and

deliver the outputs asked by consumers and beyond through associated schemes of output regulation. Second, firms which innovate are rewarded through the normal mechanism of retaining part of the efficiency savings they achieve. Indeed, their incentive to innovate is higher in the RIIO regulation than in the RPI−X regulation because they retain efficiency gains over a longer regulatory period (eight versus five years). Lastly, companies can propose, in their business plans, the roll-out of innovative technologies, techniques or commercial strategies, which may impose higher costs in the price control period than the business-as-usual approach but that are justified by the longer-term delivery of outputs at lower cost to customers.

However, innovation also requires other mechanisms outside the price control framework. Indeed, where the commercial benefit of innovation is not clear, network companies may not have a strong motivation to pursue innovation in a timely way. It then requires the development of further specific schemes in order to encourage innovation (see Chapter 2, Section 2.3.3 for additional thoughts on the regulation of innovation).

An innovation stimulus package was then built as a starter to supplement incentives inherent to the RIIO price control framework. It provides partial financing for innovative projects intended to meet environmental objectives, not just those related to the low-carbon agenda. It relies on two processes: first, innovation allowance, and second, the network innovation competition.

Innovation allowances provide directly for small-scale innovation projects, with companies having the opportunity to self-certify against set criteria. The allowance is between 0.5 per cent and 1 per cent of total allowed revenues, depending on the quality of the supporting innovation strategy. In principle, it is similar to the previous IFI and to the First Tier funding available under the LCN Fund.

Besides, partial funding can be awarded through the Electricity Network Innovation Competition (NIC) scheme. An independent panel is appointed to evaluate the bids submitted. Ofgem then takes the final decisions on the awarding of funding based on the panel's assessment. Contrary to all the other innovation mechanisms previously mentioned (under the umbrella of the RPI−X regulation or the RIIO regulation), network and non-network parties are eligible to apply for funding to help progress projects at any stage of innovation, from early research activities to trials and pilot schemes. The amount of funding available for electricity networks was initially £95 million per year, including £30 million per year for transmission. It is now closer to £45 million per year.

Funding can reach up to 90 per cent of the project costs, with the rest to be financed through network tariffs. Non-network parties are eligible to participate and compete in the innovation stimulus package if they satisfy a set of criteria. They must hold an 'innovation licence', demonstrate that they are well placed to undertake innovation related to network services, notably showing an ability to understand network operation, have qualified specialists, have experience on relevant projects and a fully worked-up proposal for an innovative project. They should also have facilitated access to the network. Indeed, if the innovation project proposed by a non-network company involves trialling on a network, the company should seek to arrange for this access in advance of making the bid for innovation stimulus funding. If it is unable to secure agreement from a network company, the governance panel of the innovation stimulus package will decide whether to recommend that Ofgem considers taking action to require a network company to facilitate access.

1.3.4 A Major Evolution, Not a Revolution

The RIIO regulation is a major evolution of the RPI − X regulation. It allows for a less intrusive regulatory process if companies' proposed business plans are satisfactory for network users, stakeholders and the regulator. Hence, it is based on a consultation process and focuses on network users' needs. Through the definition of appropriate outputs, RIIO regulation mimics competition pressure and fosters the emergence of services needed by network users and the proposal of innovative solutions to their benefit. Besides, under RIIO, the regulatory schemes are harmonized if not merged to avoid inefficient arbitrages by the companies. Nevertheless, the RIIO regulation remains grounded on the same theoretical principle that underpinned RPI − X regulation.

1.4 CONCLUSION

The application of the RPI − X regulation in Britain has been an example if not a source of inspiration for many regulators in Europe and worldwide, showing the possibility of applying concretely the RPI − X principle, its pitfalls, the improvements needed to adapt it to real situations or unexpected and unintended observed effects. The RIIO regulation is also viewed with much interest by regulators and network operators since it

shows, on the one hand, new regulatory forms and, on the other hand, new opportunities and risks for regulated companies.

From a theoretical and practical point of view, the change from the RPI – X regulation to the RIIO regulation shows that prior to cutting costs, it is necessary to identify what users expect from the network service and the possible alternatives. Otherwise, regulation incentivizes companies to decrease outputs in order to reduce costs, at the expense of network value for users. This concretely stems from a lack of a proper mathematical definition of the network cost function. If it had been available, more modelling of regulation would have been possible, and deeper economic understanding of wanted and unwanted consequences of the different regulatory schemes applied or proposed would also have been possible. It explains, too, why it is difficult to assess efficiency factors whatever the benchmarking methods applied, because it is difficult to compare the performance of a given company over time and circumstances and with peers. With such a mathematical definition of a network cost function, it would have been possible to have more parametric econometric analyses, better grounded on the physical and organizational principles of network activity. A network cost function could also be very valuable to enrich the seminal works on incentive regulation and to help it evolve.

Despite the undeniable great improvements in regulation, there have been, since the outset, persisting difficulties with assessing efficiency factors, defining network outputs and fostering innovation in a regulated environment. There is still work for practitioners and theoreticians in this regard. The recent and dense letter by Ofgem (2017) opening the consultation on the RIIO-2 framework shows that the British energy regulator wants to keep improving the current framework in all its dimensions: better definition of outputs and associated delivery; and improvements in the process of setting incentives for cost reduction and innovation. One can expect that Great Britain will remain at the forefront of this field for some time.

NOTES

1. In this chapter we focus on Great Britain. Other parts of the UK, such as Northern Ireland, are not considered here.
2. National Grid has changed its name several times since its unbundling and privatization in 1990. For the sake of simplicity and generality, we use its most common denomination.

3. National Grid also owns and operates the high-pressure gas pipelines in the whole of Great Britain. Additionally, the company has a minority stake in some British gas distribution networks and investments in electricity and gas grids in North America.
4. Ofgem was formed in 1999 by the merger of the Office of Electricity Regulation (Offer) and the Office of Gas Supply (Ofgas). The two sector-specific regulators were initially created by the British government with the Gas Act of 1986 and the Electricity Act of 1989.
5. Under the incentive regulation framework established in the 1990s, the acronyms DPCR and TPCR denoted, respectively, a Distribution Price Control Review and a Transmission Price Control Review. For a chronology of the price control reviews see Tables 1.1 and 1.2.
6. One of the largest uncertainties concerns the level of electricity demand, which in turn affects the estimation of the efficient average cost for the network firm.
7. To be precise, the British regulator of the electricity sector was, until 2000, Offer. However, for the sake of simplicity, we refer here generically to its heir, Ofgem.
8. Defined in this way, the RPZ incentive scheme can be considered as a form of innovation output regulation. Conversely, the IFI can be seen as a form of innovation input regulation.
9. In a report for Ofgem, the consultancies Mott MacDonald and BPI (2004) estimated a net benefit for customers of £92 million due to the RPZ mechanism and of £386 million due to IFI. Costs for customers were respectively estimated at about £29 million and £57 million.
10. See Moore (2015).
11. As we have seen in Section 1.2, a focus on outputs was present also within the RPI−X regulation. Nevertheless, in that case the focus aimed merely to avoid cost reduction by network firms being realized at the expense of service quality.
12. Non-controllable OPEX is outside TOTEX and incentive regulation. It is directly passed through to the network users. It mainly includes the licence fees, the business rates (a tax on the occupation of non-domestic property in England and Wales), pensions and pensions schemes administration, and the costs related to the Inter-TSO compensation mechanism.

13. The definition of RAV is very close to that of RAB. They are sometimes used interchangeably.
14. The assets of the network companies that were already in place before the introduction of RIIO regulation will continue to depreciate over 20 years.
15. The work in progress is integrated in the TOTEX and so in the RAV, under the condition that the considered asset eventually provides the required output.
16. Ofgem's view on international benchmarking in the RIIO regulation is as follows:

> Under the RIIO regulatory framework, international benchmarking is a key element of the cost assessment toolkit, and we will continue developing our international dataset and TOTEX benchmarking methods during this price control. We will also ask the TOs to put forward more international benchmarking analysis themselves at both an aggregate and disaggregated level. However, having considered the emerging issues such as availability and maturity of the data for international comparators and stakeholders' concern on the robustness of international benchmarking, we intend to rebalance the role of TOTEX benchmarking in RIIO-T1. Although we will take the results of TOTEX benchmarking into consideration when we assess cost efficiencies of network companies, we will focus more on disaggregated cost assessment approaches.

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2. Continental incentive regulation

Vincent Rious and Nicolò Rossetto

No panacea exists for the regulation of electricity grids. A blind implementation of a 'foreign' regulatory model, even a successful one like the British model presented in the previous chapter, is not necessarily the best course of action for practitioners and policy-makers. Caution is required first because not all regulators are the same. Even in Europe they differ in administrative powers, financial endowment, staff and technical skills available. As a result, the choice of which regulatory model to follow should take into consideration what the involved regulator can actually handle. Second, network operators perform several different network tasks with their own economic and regulatory characteristics. Hence, a plurality of regulatory tools, each of them addressing a specific task, could be the wisest approach. Finally, the context is not the same everywhere. Apart from differences in the legal framework, countries can be at different points in the investment cycle: one may be building its electricity transmission network and require a swift accumulation of capital, while another may already have its grid in place and need simply to promote its efficient use; one country may be a small electricity island where the market does not have the minimum size for a workable competition, while another may have a large system that is strongly interconnected with that of neighbouring countries.

In this chapter, we first describe the landscape of energy regulators in Europe, with a specific focus on their heterogeneity and their frequently limited resources. Then, we look at the tasks network operators usually perform in the electricity industry (system operation, grid maintenance, customer relationship management and grid expansion); we look also at the new or renewed tasks network operators are called to perform in the current context of energy transition, national markets integration and digitalization. Finally, we present the main tools suggested by the academic literature and the industry practice for the regulation of network operators. They are ranked according to a scale of growing implementation complexity for the regulator. On this basis, a decision tree is proposed for aligning the abilities of the regulator, the characteristics of

a network task and the implementation complexity of a regulatory tool, so that a model of workable incentive regulation can be identified.

2.1 THE NATIONAL ENERGY REGULATORS' LANDSCAPE IN EUROPE

The establishment of an independent authority in charge of the regulatory oversight of network operators at the national level was one of the key pillars of the restructuring of the European electricity industry, which occurred between the mid-1990s and the first decade of the twenty-first century. Under the pressure set by subsequent directives and regulations, EU Member States have created national regulatory authorities (NRAs) that share similar powers and duties. Nevertheless, even though their institutional design has been somewhat harmonized, regulatory authorities are not all equal, in particular in terms of the skills and resources available to perform their legal obligations.

In this section, we start by presenting the basic features common to all EU NRAs as a result of the current European legislation on the internal market for electricity. Then, we provide an overview of the heterogeneity of powers, responsibilities and, above all, economic and technical resources characterizing the reality of the European energy regulators.

2.1.1 Some Common Basic Features

All Member States of the EU currently have one NRA dealing with the electricity industry. These 28 NRAs were established during the 1990s and early 2000s. Their institutional design, powers and responsibilities have been progressively harmonized under the pressure of European legislation, although differences remain due to national specificities and laws.

The Third Energy Package adopted in 2009 foresees the designation of a single NRA at the national level and the obligation for the Member States to guarantee its independence from any other public or private entity. Moreover, Member States must ensure that NRAs exercise their powers impartially and transparently (art. 35 of the Directive 2009/72/EC, hereafter Electricity Directive). In close cooperation with each other, the European Commission and the Agency for the Cooperation of Energy Regulators (ACER), NRAs are mandated to promote a

competitive, secure and environmentally sustainable internal market for electricity within the Community (art. 36).

In order to be truly independent and neutral vis-à-vis the interests of the industry and the wishes of the political power, NRAs must be able to take autonomous decisions; their board members are appointed for a fixed term of 5–7 years, possibly renewable but only once. Additionally, NRAs have separate annual budget allocations, which they can implement autonomously. Finally, NRAs are supposed to benefit from adequate human and financial resources to carry out their duties (art. 35).

2.1.2 Heterogeneous Conditions and Resource-bounded Regulators

Despite the above-mentioned provisions contained in EU law, the situation of the electricity regulators in Europe is far from homogeneous and does not often resemble the theoretical model of the perfectly endowed regulator described in the textbooks or assumed by academics and policy-makers.

First, EU NRAs are quite heterogeneous in terms of the tasks they perform because national situations and laws apply on top of the European common denominator. In some cases they have to regulate both the gas and the electricity industry, while in others, where natural gas is not consumed in the country, they focus only on electricity.[1] In some cases they also deal extensively with renewable support schemes or consumer protection, while in others they focus mainly on the core duties foreseen by the Electricity Directive, that is, the regulation of transmission and distribution networks and the oversight of energy markets. In some cases they watch over small, isolated electricity systems, while in others they have to cope with large grids, highly meshed with those of neighbouring countries.

Second, EU NRAs are quite heterogeneous because of the different economic resources and administrative powers they are granted. They can be funded by fees directly charged to the electricity sector or be financed out of the state budget. They can benefit from the experience gained from several years of operation or conversely have little or no institutional memory due to their recent establishment. They can rely on a large and well-paid staff of highly skilled and motivated professionals or have to perform their numerous duties with a small team and only a handful of economists and lawyers. Finally, they can have the legal power to directly fine misbehaving electricity firms or they can only propose penalties to the competent court.

A rough idea of how heterogeneous the NRAs are in terms of resources can be obtained by comparing their size expressed in terms of full-time equivalent staff (FTE).[2] Building on a survey conducted among its members, ACER provides a classification of the EU NRAs based on the number of FTE devoted to energy regulation, i.e. for both gas and electricity (see Table 2.1). NRAs are gathered in six categories. On the one hand there are micro-regulators such as those of Malta, Estonia or Cyprus with fewer than 12 equivalent employees; on the other hand there are large regulators like those of Great Britain, Germany or Romania with more than 220 equivalent employees each. The overall average is just above 117 FTE.

Table 2.1 EU NRAs in order of total human resources for energy regulation in full-time equivalent staff units

Size	**Country**	**Regulator**
Micro (less than 12 full-time employees)	Malta Estonia Cyprus Luxembourg	REWS ECA CERA ILR
Small (12–50 FTE)	Lithuania Finland Denmark Latvia Slovenia	NCC EV DERA PUC AGEN-RS
Small-mid (50–75 FTE)	Ireland Croatia Slovakia Belgium Portugal	CER HERA RONI GREG ERSE
Medium 90–140 FTE)	Greece Netherlands France Austria Sweden Bulgaria	RAE ACM CRE E-Control EI EWRC
Large-mid (170–175 FTE)	Italy Spain	AEEGSI CNMC
Large (more than 220 FTE)	Czech Republic Hungary Poland Romania Germany Great Britain	ERU HEA URE ANRE BNetzA Ofgem

Source: ACER (2016).

Undoubtedly these numbers must be interpreted with caution, as they inevitably reflect the differences in size and structure of the national markets, the duty to regulate only electricity or natural gas too, and possibly the additional tasks and powers introduced at national level. Nevertheless, given the relevance of overheads and the minimum scale required to perform certain regulatory tasks, it is clear that not all the regulators have the same capabilities and that some of them, in particular the smaller ones, face significant constraints in what they can effectively achieve.

This is all the more apparent if we look at the participation of national regulators in the activities within ACER or other international initiatives and forums. Large and medium-size regulators are able to send representatives to most of the meetings of the ACER board of regulators and the working groups, while smaller or less wealthy NRAs are not (see Table 2.2). The excessive workload and the lack of skilled employees able to work in an international context frequently represent a constraint. Sometimes, even travel and accommodation expenses can be a financial burden that is difficult to bear for these regulators.

The prolonged crisis of public finances in several EU Member States and the necessity of containing public expenditure have generally not improved the situation for NRAs. On the contrary, the introduction of new obligations, like those related to the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), and the increased speed of technological and business innovation observed in the electricity sector have further stretched regulators' capabilities to efficiently and effectively implement their legal duties.

Thus, the practice of regulation in Europe is significantly different from its theoretical frame. In the academic literature, regulators are thought to have all the desired cognitive, computational and administrative abilities to do their job. In particular, they can effortlessly identify the most efficient regulatory tool to apply to a specific case and they have all the desirable resources and skills to implement it. They may suffer from information asymmetry vis-à-vis the firms under their regulation, but they can nevertheless set adequate incentives by defining tariffs ex ante. Additionally, they are assumed to be independent of governments so that the regulatory framework they put in place is credible for both firms and investors.

The reality sketched out above does not reflect these theoretical assumptions. Many regulators are poorly endowed and are not inclined or able to apply the most complex or innovative regulatory tools to the

Table 2.2 Member States' participation in the ACER working groups between January 2013 and May 2015

	Board of Regulators	Electricity Working Group	Gas Working Group	Implementation, Monitoring and Benchmarking Working Group	Market Integrity and Transparency Working Group
No. of meetings held	22	24	25	24	20
Austria	22	24	25	19	20
Germany	22	23	25	17	19
United Kingdom	22	24	24	15	20
France	20	23	24	17	20
Belgium	22	21	25	24	11
Spain	22	19	25	19	17
Sweden	22	23	21	17	19
Portugal	22	24	25	5	16
Italy	22	20	21	11	16
Netherlands	22	24	22	6	16
Poland	21	22	25	2	16
Hungary	22	18	22	0	19
Denmark	22	21	16	6	11
Finland	22	21	15	0	16
Czech Republic	22	13	9	4	19
Ireland	22	14	14	0	12
Luxembourg	19	8	9	0	14
Slovenia	18	0	8	0	7
Croatia	15	3	5	1	4
Greece	20	1	5	0	2
Lithuania	18	1	3	0	2
Latvia	16	0	6	0	1
Malta	22	0	0	0	0
Romania	18	1	2	0	1
Estonia	18	0	0	0	0
Cyprus	14	0	0	0	0
Bulgaria	2	0	0	0	0
Slovakia	1	0	0	0	0

Source: European Court of Auditors (2015), p. 67.

network operators under their jurisdiction. Having only small teams and financial resources, they tend to be conservative with regulation in order to avoid negative judicial reviews or to enter into demanding and uncertain regulatory innovation. The identification of the best regulatory tool for a specific purpose often requires time and its proper implementation is achieved only through experience (learning by doing). The reality, in short, is that of resource-bounded regulators who must take into account their relative endowment in terms of staff, skills and administrative power when considering the more appropriate tools they should use to perform their regulatory functions.

2.2 CHARACTERISTICS OF THE MAIN TASKS PERFORMED BY NETWORK OPERATORS

The need to think in terms of the actual resources and abilities available to NRAs is not the only aspect that differentiates the practice of incentive regulation in Europe from the standard model developed by scholars. Another overly rigid assumption of such a model is that the regulator is supposed to control the costs of the network operator as a whole with a single regulatory tool. However, both transmission system operators (TSOs) and distribution system operators (DSOs) in reality perform a set of tasks with heterogeneous economic and regulatory characteristics. Hence, the regulation of an electricity network calls for the implementation of adapted and finely tuned regulatory tools, each of them addressing a distinct task and giving a consistent enough incentive to the regulated firm.

In this section, we start by presenting the traditional tasks performed by electricity network operators, together with the new or renewed tasks attributed to them more recently by developments in energy policy. Then, we introduce three criteria to characterize the various tasks from a regulatory point of view. Finally, we apply these criteria to the network operators' tasks.

2.2.1 Network Operators' Tasks

An electricity network operator usually performs four main network tasks, each of them with different characteristics and cost structures. The first three tasks deal with short-term issues, while the fourth looks more at the long term.

First, the firm operates the energy system on a daily basis, ensuring the balance between injections and withdrawals, managing congestions and contingencies (system operation). The network operator typically provides for energy losses as well and, in liberalized systems, it frequently contributes to market operation. Currently, these tasks are performed especially by the TSO. However, DSOs are also expected to play a growing role. This is because of the development of distributed energy resources (DER), which increases constraints on their networks and hence raises the necessity of making their infrastructure smarter (see Chapter 4). Second, the network operator maintains the assets of the grid in order to ensure their reliable functioning under most of the foreseeable conditions (grid maintenance). Third, the network operator manages the relationship with its customers, i.e. the network users, metering and billing energy and power, and possibly providing complementary services to them (customer relationship management). Finally, the firm plans and builds the network to connect new users, both on the supply and the demand side, and to relieve excessive congestions (grid expansion).

Depending on the specific characteristics of the system at stake, this broad classification can obviously be subject to adjustments and refinements. For instance, if system operation and transmission ownership are unbundled activities, then the transmission owner (TO) is usually in charge of maintaining and building the grid, while the system operator (SO) performs the other tasks. Similarly, a further distinction could be made between isolated and interconnected systems. As a matter of fact, the implementation of some of the tasks mentioned above could be significantly affected by the existence of interconnections with other electricity systems. An excellent example is represented by the operation of the transmission system of interconnected countries, a task that calls for specific coordination and cooperation among the involved TSOs.

Recent developments in the energy policy at the national and European levels have assigned new goals to network operators, which, in turn, have triggered new or renewed tasks alongside the four traditional ones. In particular, TSOs and DSOs have to contribute to the decarbonization of the energy sector and the completion of the internal market for electricity. On the one hand, the energy and climate targets adopted by the EU for 2020 and 2030 imply a massive deployment of renewable energy sources (RES) and a deep change in the generation mix, currently dominated by a few large and dependable nuclear or fossil-fired power plants. On the other hand, the wider and deeper integration of European electricity markets requires the creation of a seamless transmission

system on a continental level, where any generator, trader or consumer of electricity is treated in the same way, irrespective of the specific national grid to which it is connected (see Chapter 3).

In this context, network operators are called to adapt their activities to integrate new classes of assets and processes, both on the supply side (intermittent generation from wind and sun) and on the demand side (smart meters, demand response, electro-chemical storage and electric vehicles), while making sure, at the same time, that the transition to a more decentralized system does not affect the high level of reliability and security of supply necessary to the healthy functioning of modern digital societies. Moreover, TSOs and DSOs are called to involve and empower small producers and consumers of energy by facilitating their participation in energy markets, directly or through aggregators. Finally, network operators – first and foremost TSOs – are called to act as market architects in liaison with the power exchanges and to couple national markets along the lines of the EU power target model.

All these changes and new regulatory goals require a revival of the research, development and deployment activities (RD&D) of the TSOs and DSOs to better address the business and operational shifts of transmission and distribution infrastructures and services. Indeed, due to the present wave of technological innovation and digitalization, the actual work of the electricity network operators is moving beyond the pure technical network monopoly area, as it is traditionally understood in the energy sector, and is taking a first step closer to the communication sector.

2.2.2 Regulatory Characteristics of Network Operators' Tasks

The different tasks performed by network operators are heterogeneous, including in terms of uncertainty and delivery time horizons. For instance, system operation is a short-term task because the instantaneous balance between electricity injections and withdrawals must be constantly preserved, while grid expansion involves very long-term decisions due to the lengthy procedures to follow for the approval and construction of new lines, usually intended to last at least several decades. Other assignments such as grid maintenance or customer relationship management are recurrent in the medium term and present limited uncertainties. On the contrary, grid planning is highly uncertain because it is relatively difficult to foresee where generators and loads will be located 10–20 years from now. Similarly, uncertainty is high when undertaking RD&D

because the actual outcome of developing new technologies today for the network of tomorrow may be especially fuzzy.

Trying to regulate network operators as a whole with a unique regulatory tool would be rather inefficient and sometimes ineffective, given the diverse nature of the tasks they perform. A specific regulatory tool can foster the fulfilment by the network operator of a certain task, but at the same time it may undermine the implementation of another one. For instance, let us consider price cap, a regulatory scheme that induces cost containment (see Section 2.3.1 for additional information). The firm subject to regulation will be encouraged to reduce its operational expenditures (OPEX) in order to increase its profits. This tends to improve productive efficiency in the short term, at least as far as the same level of quality or the same quantity of the service concerned are provided to customers. However, price capping applied to OPEX may simultaneously damage long-term productive efficiency growth by discouraging the regulated firm from spending resources on RD&D activities that do not produce any benefit in the short term or whose outcome, even in the longer term, is rather uncertain.

In practice, the mixture of tasks performed by network operators requires a hybrid regulatory approach, consisting of the concurrent use of various regulatory tools able to deliver the various desired results. To seriously match its regulatory tools with the industry operation, the regulator has to address closely the different regulatory characteristics of the various tasks performed by the network operators. There are three key regulatory characteristics:

1. controllability;
2. predictability;
3. observability.

Controllability qualifies the network operator's ability to manage a single task and its costs or a combination of tasks and their costs so as to attain a defined level and quality of output. When a task is controllable, the regulated firm can undertake actions to reach an efficient level of operation. Hence, the firm is responsive to incentive regulatory schemes. On the contrary, when a task is barely controllable, the regulated firm can control the inputs but not the output. Therefore, any incentive scheme would probably not affect the efficiency in performing the task but rather result in regulatory costs or profit hazards for the regulated firm.

Predictability qualifies the possibility of foreseeing the influence of external factors on a network task and its costs and the relationship between a given set of costs, incurred for a task, and the level and quality of the output. Then, in the case of a predictable task, the regulator and the network operator can reasonably foresee, ex ante, the outcome for that task. In particular, they can distinguish the effect of the operator's effort on the efficiency in performing the task from the action of uncertain and uncontrollable variables such as energy demand. In this case, an incentive scheme would be effective. On the other hand, when uncertainty about the future of the system is high and it is not easy or possible to filter the impact of external variables on the operator's task, then predictability is low and it would make little sense to apply incentive regulatory tools. Risks, both for the firm and for the regulator, would be high.

Observability qualifies the possibility of verifying the influence of external factors on a network task and its costs and the relationship between a given set of costs, incurred for a task, and the level and quality of the output. Hence, in the case of an observable task, the regulator can check, ex post, the actual outcome for that task and effectively apply incentive regulation. Depending on what is observable, for instance whether inputs or outputs are observable, and the level of information asymmetry between the firm and the regulator, then it is possible to determine the specific implementable regulatory tool. However, it is important to note that observability of a task cannot be taken for granted but requires the ex ante definition of key performance indicators (KPIs) and their accurate monitoring. Besides, data manipulation by the regulated firm must be avoided by implementing KPIs in a robust manner and allowing the regulator to audit the records kept by the firm. Finally, different degrees of observability are possible: at one extreme, the regulator may have just a small historical set of data from one network operator only; at the other, a large data set spanning several years and covering several comparable network operators could be available to the regulator. Depending on the actual degree of observability, different incentive schemes are more appropriate.

2.2.3 Classification of the Tasks in terms of the Regulatory Characteristics

The three regulatory characteristics presented above can be used to classify the main tasks performed by network operators and provide a first insight into the choices that a resource-bounded regulator should make

when aiming at a workable regulation of the operators under its jurisdiction (see Section 2.3.2).

To classify the network tasks in terms of controllability, predictability and observability is not always straightforward and unambiguous, because the industry context and the regulatory framework have an impact on the tasks' characteristics. Nevertheless, a broad assessment is possible.

Let us start with system operation. It is not a fully controllable task, especially in meshed electricity grids, because cross-border energy flows can be large and dispatch choices by neighbouring network operators can heavily impact the efficient operation of the domestic system. Controllability is higher in isolated systems, where the network operator is usually able to better control the volume of energy losses and congestions by managing grid topology and optimizing the dispatch of power plants.[3] System operation is observable to a certain level, since actual energy losses and congestion costs are measurable. However, predictability of system operation is not straightforward since energy losses and congestion costs depend on the behaviour of network users, both generators and consumers, inside and outside national boundaries. Predictability of system operation will then depend on the possibility for the network operator and, a fortiori, for the regulator to distinguish the amount of losses and costs due to external factors from the amount due to actions by the network operator.

On the contrary, grid maintenance is a somewhat repetitive task over the medium to long term. The costs incurred by a network operator to perform this task are not frequently affected by uncertainty and unexpected events, except for major faults; rather, they rely on the firm's productivity potential. Hence, grid maintenance is controllable and predictable. The observability of the task depends on the regulator's evaluation of both productivity improvement and the relative cost of the practices to maintain a reliable grid. Indeed, when dealing with grid maintenance, it is important to assess the quality of the network service provided to network users because a reduction in the maintenance expenses could hide reduced reliability of the grid and, as a result, reduced quality for the users. Therefore, regulators must look at quality, a characteristic that is controllable by the network operator in the long term, through grid investment and maintenance. Moreover, quality of service is predictable, if extreme events are filtered out from quality indicators, and it is observable by the regulator, if an adequate set of KPIs is conceived and used.

The management of customer relationships is similar to grid maintenance. It is a recurrent activity for the network operator, whose costs are essentially controllable and predictable, unless strong technological or process innovation occurs (e.g. digitalization and the roll-out of smart meters). Observability is trickier, since it requires the implementation of adequate KPIs regarding the speed and quality of the responses to users' requests.

The case of grid expansion is different. Though a recurrent task for network operators, it is affected by high uncertainty due to the long lead time of network planning and building activities. Indeed, although the cost of wires, pylons, transformers and other devices is quite stable and under the control of the network operator, overall costs for the construction of a line may be less controllable and predictable due to lengthy permitting procedures and possible local opposition to infrastructure development, as well as the uncertainty over the nature of the soil (hardness, stability and so on) to set wires. Besides, the future use of long-lived physical infrastructures is intrinsically uncertain. As a consequence, the benefits of those infrastructures and the efficiency of grid expansion are difficult to calculate. For a similar reason, grid expansion is not easily observable for regulatory purposes. To build an electric line takes time, in particular an interconnection between different national systems, and the actual benefits of this activity emerge only over the years. To verify the influence of external factors on the costs and the relationship between a given set of costs and the level and quality of the output is difficult.

Finally, innovation is a controllable task in the sense that its management by the network operator influences the quantity and quality of innovation that the operator itself will produce: by spending more in RD&D, the operator will be able to innovate more and introduce new technologies or processes faster. However, although controllable, innovation is not very predictable because the outcome of any research activity and the associated trade-off between costs and benefits are by definition unknown. Innovation is not even easily observable, since it is difficult to define adequate KPIs about something that does not yet exist or whose usefulness is hard to assess. In any case, both predictability and observability increase as long as the technological and managerial maturity of an innovation grows. Indeed, innovative technologies and processes that are closer to commercialization or wide-scale deployment by the network operator suffer from less uncertainty and bring more identifiable benefits than innovations in their infancy.[4]

2.3 HOW TO ADAPT THE REGULATORY TOOLS TO THE TASKS AND THE REGULATOR'S ABILITIES

During the 1980s and 1990s, the restructuring of network industries such as electricity was coupled in Europe with the introduction of incentive regulation. Scholars and practitioners, recognizing that regulators are neither omniscient nor omnipotent, tried to cope with information asymmetry, a problem normally affecting the relationship between regulators and the firms they regulate. New regulatory tools such as price capping were developed and implemented, starting with the British telecommunication sector. Nevertheless, despite all the fanfare in the academic and public debate of the subsequent decades, incentive regulation is usually not applied to all the tasks performed by a network operator (not even in the UK – see Chapter 1 for more details). Indeed, a lack of adequate financial resources and technical expertise often drives regulators to apply less sophisticated and more traditional forms of regulation. Moreover, even if the endowment of the regulator is not an issue, there can be other arguments in favour of a limited use of incentive regulation. The controllability, predictability and observability of the costs related to some of the tasks performed by network operators are among those arguments.

In this section, we start by presenting the most common regulatory instruments developed by the practice and theory of network industry regulation; the different tools are introduced according to a scale of growing implementation complexity. Then, we provide a decision tree suggesting how the regulatory instruments can be matched with the key regulatory characteristics of the tasks performed by the network operators subject to regulation. Finally, we apply the decision tree to three network tasks as a way of illustrating its usefulness in finding a workable alignment between targeted network tasks, regulators' abilities and regulatory tools.

2.3.1 The Five Main Regulatory Tools

In the 1970s and 1980s economic theory began to recognize and take seriously the fact that regulators have limits in terms of what they know and what they can do. It was progressively acknowledged that regulated firms know better than the regulator the situation in the industry (e.g. the level of demand, customers' willingness to pay and the available technological solutions), their actual production costs and the efforts undertaken

in containing them. Benefiting from this information asymmetry, regulated firms such as electricity network operators can act strategically and exploit the regulatory process to increase their profits or to pursue other managerial goals, to the disadvantage of customers. In this sort of principal–agent relationship, two kinds of problems can arise, respectively the adverse selection problem and the moral hazard problem.[5] Essential in both cases is the information asymmetry between the principal and the agent (the principal does not know entirely the characteristics of the agent and/or cannot fully control its actions). Hence, regulatory tools are needed to address the gap suffered by regulators.

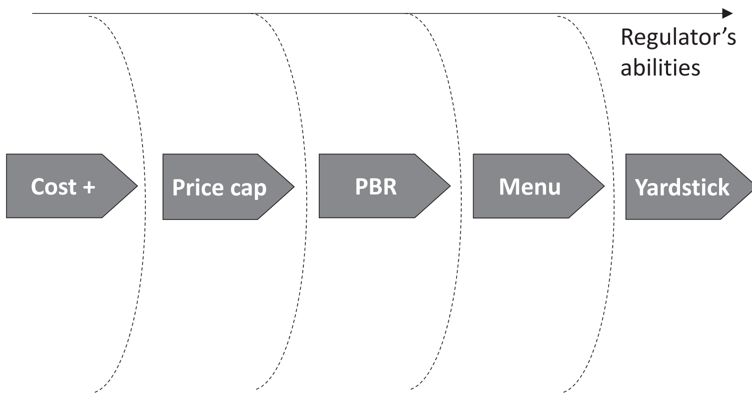
Through the application of incentive regulation, a regulatory authority is supposed to be able to alleviate the information advantage the network operator holds regarding the real costs of its activities and the effort it makes to perform them. Consequently, the firm can be incentivized to reveal its private information on the economics of its output (adverse selection problem) and to provide its services to customers in a cost-efficient way (moral hazard problem).

Reviewing the literature and the practice of regulation, it is possible to identify five main regulatory tools:

1. cost-of-service or cost-plus regulation;
2. price/revenue cap regulation;
3. output- or performance-based regulation (PBR);
4. menu of contracts;
5. yardstick competition.

The implementation of these tools by a regulatory authority requires different administrative powers, technical skills and abilities. Broadly speaking, it is possible to rank the tools according to a scale of growing implementation complexity (see Figure 2.1).

Cost-of-service or cost-plus regulation is the simplest tool for the regulation of electricity networks. It is based on the principle that the regulated firm is allowed to recover up to the costs actually incurred for service provision, including a fair rate of return on the capital invested.[6] From time to time, at the request of the regulated firm or the public, the regulator opens a rate case where it collects and audits evidence from the firm on its operating and investment costs. Based on the level of operating costs, on the used and useful investments undertaken and on the cost of capital, the regulator defines the revenue requirement or rate level for the firm. Then, it sets a tariff for the regulated service that enables the



Source: Glachant et al. (2013), p. 275.

Figure 2.1 Alignment of the regulatory tools with the regulator's abilities

firm to raise such revenue requirement. In this regulatory framework, the network operator is incentivized to declare its costs but not to avoid managerial slack and optimize its processes.[7] Indeed, although the regulator can disallow an investment that is not considered to be 'used and useful', the firm will tend to be affected by X-inefficiencies and gold-plating.[8] In this case implementation requirements for the regulator are relatively small: a good team of accountants, a few engineers and some lawyers are enough to audit the company's books, monitor and evaluate the investment programme, and eventually defend the regulatory decision in front of a judge.

A price or revenue cap is a more complex way to regulate network operators. It assumes that it is possible to induce the firm to reduce its costs by decoupling incurred costs from the earnings the firm is entitled to. When this tool is applied, the regulator unilaterally sets a maximal allowed revenue or unit price that the firm can charge for the service it provides over a regulatory period, usually lasting from three to five years. As the length of the regulatory period is relatively longer and more certain than with cost-plus regulation, the incurred costs could be lower than the earned revenue. This allows the firm to benefit from the cost reduction it is able to attain. At the same time, the firm is not incentivized to reveal its costs. In turn, this can represent a problem for the regulator when it is time to fix the revenue or the price cap for the next regulatory period. If the regulator aims to promote productive efficiency and at the

same time avoid the regulated firm being able to enjoy windfall profits or suffer from systematic losses, then it has to set the revenue/price cap close to the firm's efficient total/average costs.[9]

It is apparent that this regulatory tool requires more abilities for the regulator. Indeed, on the one hand, the burden of detailed auditing is smaller because the regulator needs information about the firm's costs only at the beginning or at the end of each regulatory period, but on the other hand, the regulator must spend highly qualified resources to correctly set the reference price and its dynamics over time, in order to avoid becoming too disconnected from the actual network performance potential. This implies the ability to forecast the trajectory of efficient costs for the whole regulatory period and it explains why in the revenue/price formula additional parameters are often introduced in order to deal with changes in the general price level and with unexpected shocks to the demand or the supply side. To prevent the worst cases, the regulator might mix revenue/price cap regulation with cost-plus regulation and share gains and losses between the consumers and the network operator. Finally, a positive remark: in the framework of revenue/price cap regulation, learning effects may have a likely positive influence on the regulator who might be able to better adjust the price formula when moving from one regulatory period to the next (see Chapter 1, Section 1.2 on the British experience with price cap regulation).

Output- or performance-based regulation is more sophisticated than revenue/price cap regulation. The focus here moves from the inputs employed by the regulated firm to the level of outputs delivered. In order to address some of the limits experienced in the application of a revenue/price cap, the regulator defines ex ante a formula linking a financial reward–penalty scheme to a firm's expected output, expressed in a pre-established set of KPIs. The firm has a significant degree of freedom in how it achieves the target set by the regulator for the given output: if it reaches the target, it will be rewarded; otherwise, it will be penalized, for example through a reduction in the maximal allowed revenue it can recover from customers (see Figure 1.3 for a graphical representation of the mechanism).

The implementation of this regulatory tool calls for an expert regulator, able to identify the relevant output and the associated performance target, to be coupled with a financial incentive to reach it.[10] Then, to optimally regulate the firm, the regulator needs to have an idea of how the firm produces the identified output and how expensive it would be to increase the level of the output delivered. The regulator should also

be able to weigh, at least approximately, the gains that any improvement in the output may have for customers and society as a whole vis-à-vis the value left to the operator in the financial incentive. Only under these conditions might the regulated firm be able to make an efficient arbitrage between the costs and the benefits that an operational effort for improving the output will generate for society. In short, since the regulator must be able to measure the benefits for society, the costs for the firm, and its performance over time, then a significant amount of expertise and adequate resources for monitoring the firm's output are required.

In a context of imperfect and asymmetric information, a regulatory authority, rather than proposing a unique input- or output-related target, can obtain better results by offering a menu of different regulatory contracts to the regulated firm. These contracts are characterized by different incentives and cost-sharing schemes: some of them provide high-powered incentives that foster an optimal managerial and cost-containment effort, while others provide low-powered incentives, ensuring the recovery of realized costs without leaving any rent to the firm. On the basis of the information it owns, the regulated firm will choose the contract most suitable to its characteristics (managers' risk aversion, estimation of its own efficiency potential, projected expenditures and so on) and to its view on future market conditions (e.g. expected demand development). Hence, a menu of contracts is a tool that promotes the improvement of productive and allocative efficiency by addressing the issues of moral hazard and adverse selection at the same time. On the one hand, it provides incentives to perform much better by giving the firm the opportunity to benefit from its own knowledge of feasible cost saving and better service. On the other hand, it ensures that information is progressively revealed to the regulator through successive regulatory reviews and that prices follow an underlying cost variation within a reasonable distance.

Sharper abilities are required for the implementation of a menu of contracts. The regulator must be aware of the existence of different types of network firms with intrinsically different efficiency improvement profiles. On this basis, the regulator must design low-powered inventive schemes, which will be chosen by firms with low potential efficiency gains or low appetite for risk/effort, and high-powered incentive schemes for firms with high potential efficiency gains or high appetite for risk/effort. Regulatory expertise is an essential condition to construct fine-tuned, appealing menus of contracts that are effective in addressing the network operators' different forms of management and shareholders.

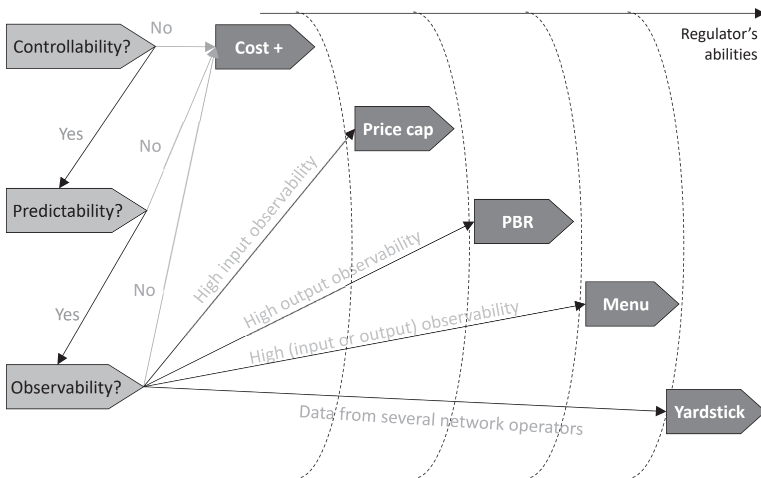
Yardstick competition is the last and most complex tool usually employed to regulate electricity network operators. In its full form, yardstick competition decouples the allowed revenues of the regulated firm from the firm's actual costs and links them to an index built on the costs and performances of other comparable network firms, to which the regulated one is benchmarked. The firm is incentivized to improve its processes and to be more efficient than the average level because in this way it can earn a profit.

Clearly, the implementation of yardstick competition rests on a number of assumptions that are not always satisfied. First, a set of several comparable network firms, performing the same tasks and operating under similar environmental conditions, must be available.[11] If this is not the case, effective benchmarking is not possible at all or would require the use of sophisticated econometric techniques, able to fictitiously create a ceteris paribus condition.[12] This leads to the second assumption: since raw data are hardly sufficient for yardstick competition, the regulator must be able to collect an important and coherent amount of information from the firms under comparison, to standardize such information and to analyze it with the help of advanced statistical instruments. Time, skills and budget are necessary. Due to the frequent lack of a sufficient number of homogeneous network firms and/or to the limited resources available to regulators, yardstick competition is usually applied only to distribution networks and rarely in its pure form. More often, regulators employ it as a starting point for the definition of the regulatory contract and as a way to estimate the productivity trend factor or the initial price in a price cap scheme. Alternatively, in the context of output-based regulation, the benchmarking process can be used to calculate the ex ante target of a task performance.

2.3.2 Decision Tree for a Workable Regulatory Alignment

In choosing the most appropriate tool for regulating a specific task of the network operator under their oversight, NRAs must find a workable alignment between the advantages and drawbacks of any regulatory tool, the regulatory characteristics of the task considered, and the skills and resources available to the NRAs themselves. A possible way to identify the appropriate match is to adopt the decision tree shown in Figure 2.2.[13]

The first criterion to look at is the controllability of the task performed by the network operator under consideration. If the operator is unable to significantly influence the cost or the outcome of a task, the economics



Source: Based on Glachant et al. (2013), p. 283.

Figure 2.2 Decision tree to align tasks, regulatory tools and regulator's abilities

of the task are mainly out of the firm's control and it will not make much sense to regulate such a task with an incentive scheme. Cost-plus regulation is the most appropriate tool in this case. Minimum accounting capabilities so as to audit the firm's uncontrollable costs and to set a tariff for their recovery are sufficient for the regulator to adequately implement the regulatory scheme.

On the contrary, if a task is controllable, then the network operator can undertake actions to reach an efficient level of operation and an incentive regulatory scheme makes sense. In practice, however, the choice of the appropriate tool depends on the predictability of the task and on the regulator's capability of managing more complex and hazardous decision processes to influence the targeted outcome. Indeed, predictability represents a second fundamental criterion: if the outcome or the costs of a task are controllable but difficult to predict by the firm or by the regulator, then a cost-plus scheme can still be applied as a satisfactory solution. Otherwise, if the degree of predictability is higher and the regulator has adequate financial resources and a skilled and experienced staff, then more complex incentive schemes can be conceived and implemented with less risk.

The third and final criterion to look at is the observability of a task and its costs. Different degrees of observability exist, ranging from a small

historical set of data from one network operator only to a large set of data from several comparable network operators. If observability is too low or the regulator thinks that its limited resources are not enough to collect the relevant information on the actual management and results for a specific task, then the effective implementation of incentive regulation is not possible and the choice of a cost-plus scheme is advisable. However, if the regulator is well resourced and benefits from relevant experience, it makes sense for it to invest in more advanced regulatory tools such as a menu of contracts, where the regulated firm is pulled into an efficiency revelation scheme. Another sophisticated way to address the observability problem is to apply some benchmarking techniques and regulate the firm by means of yardstick competition (as previously mentioned, this possibility requires that the regulator manages to gather enough pertinent information from several comparable firms and that the regulator has the cognitive and computational abilities necessary to interpret benchmarking results).

If a task's observability is high, a regulator may conveniently choose simpler regulatory tools that require less experience and resources. When only inputs are easily observable, revenue or price cap regulation represents a good choice because in this way it is possible to induce an efficient behaviour in the regulated firm without excessive regulatory involvement and costs. If the output of a task is easily observable as well, then performance-based regulation is more appropriate than a revenue or price cap because it allows control of the quality of the service provided to customers (as previously stated, performance-based schemes require that the regulator is able to properly define ex ante and measure ex post the relevant characteristics of a task's output).

To summarize, if a particular network operator's task does not satisfy any of the controllability, predictability and observability criteria, then the cost-plus scheme is the most likely regulatory tool able to ensure the recovery of costs, the protection of customers and fairly efficient productive decisions. Otherwise, if the criteria of controllability, predictability and observability are fulfilled, then the appropriateness of the different regulatory tools mainly depends on the regulator's endowment of economic and technical resources.

2.3.3 Three Illustrations

The framework proposed above can be usefully illustrated by applying it to three different tasks commonly performed by firms operating

electricity networks. They are energy losses management, grid maintenance and RD&D activities (innovation).

Energy losses management is a relevant element of system operation and a short-term task. Its regulatory characteristics and the best regulatory alignment depend first of all on whether an electricity system is isolated or highly interconnected with other systems. In the case of 'electricity islands', the volume of energy losses in the transmission and distribution of electricity is relatively controllable and partially predictable by a network operator.[14] The observability of losses and the choice of the most appropriate regulatory tool then rest with the regulator's experience and the information gap it suffers from. If the regulator has limited experience in regulating energy losses, observability is likely to be low and a cost-plus scheme will be the right regulatory tool to implement. Otherwise, the regulator can try to apply adapted incentive regulation tools. If it has a historical database of loss volumes for the firm under its regulatory oversight, output-based regulation will be tempting. With a more experienced regulator, a menu of contracts could be a suitable tool. Finally, if the regulator has information from several comparable network operators, yardstick competition will represent a viable solution.

In a highly interconnected electricity system, energy losses are no longer so controllable and predictable by the network operator. This is particularly true in the case of systems that are crossed by relevant external energy flows. Since controllability is limited, an incentive for losses minimization would not be really effective; on the contrary, it would increase the risks for the network operator. Therefore, the best regulatory alignment in this case is to implement cost-plus regulation and pass through the cost of energy losses to network users (monitoring can also be implemented to increase over time the observability of the losses and the chances to apply, in the future, incentive regulation).

Grid maintenance is a task that is particularly suited to incentive regulation because it scores quite well in terms of controllability, predictability and observability. As mentioned in Section 2.2.3, it is a rather repetitive task, whose costs are not much affected by uncertainty and unexpected events. The ability of the firm's management to efficiently organize the task and implement it is relevant. Both the firm and the regulator can evaluate the productivity improvement and the relative cost of the practices to maintain a reliable grid. As a result, a firm can be incentivized to keep the maintenance costs to the lowest level: price or revenue cap, output-based regulation or yardstick competition are all

theoretically sound possibilities. The most appropriate choice among the three depends mainly on the regulator's abilities.

However, it is important to remember that a firm can minimise grid maintenance costs by simply postponing or reducing the number of maintenance interventions. This eventually endangers the network service quality, with negative consequences for network users. For this reason, it is widely argued that service quality has to be regulated alongside maintenance costs. Output regulation with service quality indicators generally supports the regulation of maintenance costs. The regulator can implement it on a stand-alone basis, inserted in a menu of contracts or integrated in a yardstick competition scheme.

The development and deployment of innovation by network operators is a long-term task that is becoming increasingly important in the context of energy transition and the current wave of digitalization. Regulating innovation is a rather recent necessity and experience so far is quite limited.

Although innovation costs are quite controllable, it is difficult to predict (ex ante) and observe (ex post) the benefits that will follow an investment in RD&D over the long term. Uncertainty is inherently high, especially for immature technologies and solutions. In this case, it is not appropriate to put in place an incentive regulation tool because the regulated firm will probably prefer not to spend resources on such risky activities. Rather, an innovation fund, possibly financed by grid tariffs, can provide a cost-of-service regulatory framework able to trigger early innovation in accordance with the regulator's objectives. An alternative is to align certain key revenue parameters, such as the rate of return or the depreciation rate, with the risk increase resulting from more innovation in the network. The regulator can make such a decision relying on the analysis of the balance between the costs and benefits that the network firm, its customers and all the other relevant stakeholders will bear.[15] By doing so, the regulator simplifies the innovation process while letting the regulated firm undertake what it considers economically more attractive in the innovation field covered by the new rules. Regulatory help can go up to the exemption of certain basic regulatory tools such as third-party access or the use of congestion rents for financing risky interconnections.

However, when innovation maturity is growing and the innovative technology or process is integrated on a more business-as-usual basis within the network operator, both predictability and observability tend to increase. In this case, a rule of risk sharing between the operator and the grid users may be considered in order to provide the firm with stronger incentives.

2.4 CONCLUSION

National energy regulators present a manifold landscape in the EU. Although they all share a common legal framework set by European legislation, plenty of differences are detectable in terms of administrative powers and resources endowment. Heterogeneity also characterizes the transmission and distribution network operators they regulate at the national level. Besides, no network operator is a monolith but rather performs a set of different tasks, each of which has its own economic and regulatory characteristics that may change over time and space due, for instance, to technological progress, demand development and country-specific conditions.

In the past decades, the theory and practice of regulation have developed an array of tools that regulators can use to regulate network operators and manage a context of imperfect and asymmetric information. Each of these tools has its own advantages and disadvantages. In particular, each of them requires certain capabilities by the implementing regulator and will fit one network task better than another.

The limited amount of resources usually available to NRAs and the multi-faceted nature of network operators do not leave room for any single ‘silver bullet’. Sophisticated incentive schemes, for instance, are not always the best option; sometimes, they are not practically implementable at all. A hybrid, and realistic, approach to network regulation is more appropriate. Such an approach must be based on the identification of a workable regulatory alignment by the NRA, able to match the most suitable regulatory tool with the characteristics of the targeted network task and the NRA’s capabilities.

The identification of a workable regulatory alignment is not carved in stone but reflects a continuous process of trial and error by the NRAs that must constantly reassess the alignment and control its consistency with the evolution of the regulatory goals, the resources available to them and the characteristics of the tasks performed by network operators.

In the context of enduring differences among the EU Member States and the often scarce resources available, it is of the highest importance that all European regulators continue sharing their experience with the design and the implementation of the various regulatory tools, through their dedicated cooperation institutions – ACER and the Council of European Energy Regulators (CEER).[16] By doing so, NRAs can learn from each other and possibly identify or revise, more easily and quickly, the choice of the best regulatory tool for a specific network task, given their specific resources endowment.

NOTES

1. In certain countries such as Italy the energy regulator is entrusted with the regulation of other network industries as well. Typical examples are water and district heating.
2. Although information on the annual budget can be useful too, as it provides an insight into the ability to pay attractive salaries and to outsource tasks to consultants, the total number of people employed is a fundamental measure since it gives a basic understanding of how many activities and duties the regulator can effectively follow and carry out.
3. In the medium to long term, a network operator can also reduce the operating cost of managing the system by upgrading and expanding the grid.
4. In other words, a more mature innovation allows the network operator to better foresee initially, and the regulator subsequently, the usefulness and likely output of the deemed innovation, while a less mature innovation implies low predictability and observability because even the network operator can only guess the possible interaction of the innovation with the rest of the power system and, as a consequence, the associated costs and benefits.
5. Adverse selection refers to a situation in which an actor (agent) does not have any incentive to reveal the sensitive information it holds to its counterpart (principal). Moral hazard refers to a situation in which the agent does not have any incentive to undertake the maximum effort in order to perform a task assigned to it by the principal.
6. Rate of return regulation is another way to identify this traditional regulatory tool.
7. From a principal–agent perspective, it is possible to say that cost-plus regulation solves the problem of adverse selection but does not do anything to solve the problem of moral hazard.
8. X-inefficiency is the difference between the output a firm can theoretically obtain from the most efficient use of a given set of inputs and the output the same firm practically obtains from the very same set of inputs. The difference is usually attributed to a lack of clarity in the firm's goals, imperfect organization of productive processes and managerial slack. The absence of competitive pressure is usually assumed to be one of the ultimate reasons for X-inefficiency. Gold-plating refers to a tendency of regulated

firms, entitled to cost recovery, to invest in assets of an excessive and unnecessary high quality.

9. A price/revenue cap tackles the issue of moral hazard but does not solve the problem of adverse selection.
10. The relevant output and the associated performance target may be identified also with the involvement of the industry stakeholders.
11. From a theoretical point of view, it is important that the firms under comparison do not collude against the regulator as well. The number of compared firms may be important in this regard. However, there is no evidence that any case of this type of collusion has actually occurred in the electricity industry.
12. Failure to define this condition may lead to inefficient and unfair regulation of the network operator. Litigation in courts is likely to follow and the regulator's decision may be overruled by the judge.
13. It should not be forgotten that a regulator does not have an ex nihilo knowledge of the best regulatory tool for each network operator's task. On the contrary, even a well-resourced regulator may understand how the regulatory tools match with its goals and the targeted network tasks only through a trial and error process that can follow the decision tree depicted in Figure 2.2.
14. Losses can be controlled, for instance, by modifying the topology of the grid, and predicted by forecasting the future level and spatial distribution of energy injections and withdrawals within the system.
15. A good example is the extra remuneration awarded to investment in innovative grid technologies such as batteries by Italian network operators. The decision to award the companies was taken on the basis of a net present value (NPV) analysis of the proposed projects.
16. Forums that involve all the main industry stakeholders, such as the Florence Forum for electricity and the Madrid Forum for natural gas, are important platforms for knowledge exchange as well.

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PART 2

Seams issues: one market, one system, but many operators and authorities

3. TSO–TSO seams issues

Jean-Michel Glachant

The EU power transmission industry faces discontinuities within its infrastructure architecture and its decision-making process. Seen from the point of view of grid users – say, consumers, generators or intermediaries as traders – this creates 'border issues' (within the infrastructure architecture) and 'seams issues' (within the decision-making process).

Transmission power grids are sets of assets which connect consuming units ('load') and generating units ('supply') to combine their operation into an interactive power system resulting in a common power flow. But the transmission grids being connected are never 'copper plates': they are only 'grids' of lines. Power transmission grids, like railways or highways, have their own physical limits which are notably (but not only) the discontinuities designed into their infrastructure architecture. Where these grid discontinuities are significant enough, the connected units do not combine into a single high-level interactive power system but into several distinct lower-level power systems. The same situation can arise for the power market. Buyers and sellers belong to a single and unified power market as long as the products they buy or sell can easily substitute for each other. Where significant grid and system discontinuities prevent the easy substitution of products, buyers and sellers belong to different, distinct power markets. Of course, the fact that most of the EU transmission grids have been conceived and built at national level creates borders between the various grids, systems and markets at the EU level. However, one can find similar borders within countries: where islands, peninsulas or remote poorer provinces are not, or are not very well, connected with the rest of the country. Even the state of Texas in the USA is considered as a 'quasi' electrical island isolated from the rest.

The very fact that the borders of grids and systems can be internal or external to a country helps to clarify what are seams issues vis à vis borders issues. Knowing that certain grids and systems face significant enough border discontinuities, how does the decision-making process work at the junction of their discontinuous architectures? Is the decision-making process homogeneous enough to limit the border

effects to small enough consequences? Or does the process add its own seam discontinuities which amplify the concrete 'border effects' stemming from the discontinuous infrastructure architecture? Hence the content of this chapter: Section 3.1 'TSOs' seams' in the existing TSO landscape; Section 3.2 The actual EU approach; and Section 3.3 The remaining EU regulatory gaps.

3.1 'TSOs' SEAMS' IN THE EXISTING TSO LANDSCAPE

Seams are discontinuities in the practice, the rules and the decision-making processes between two or more TSOs, when items or events are not treated the same ('harmonization') or are not treated together – where they interact ('coordination') – by the related TSOs in their related control zones. To better understand the nature of the issue we first have to identify what a TSO does and then what influences its practice.

Chapters 1 and 2 introduced TSOs. TSOs perform many different tasks and have responsibility for the hardware – i.e. managing the connections of users, maintaining existing assets and investing in new assets – and for the software – i.e. balancing the system, managing congestions, running an information system and interacting with other industry stakeholders (such as market operators, distribution grids and grid user representatives). Each of these seven basic TSO tasks can have, in one or another TSO control zone, a significant exposure to seams effects.

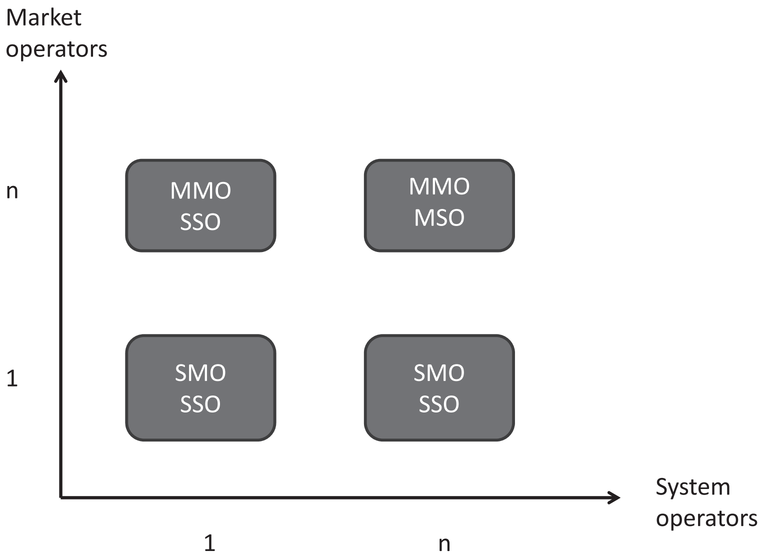
The first significant factors among the many 'objective factors' influencing how a single TSO performs its tasks are, of course, the grid architecture and the system characteristics. The grid architecture is the most crucial because the actual set of lines, devices and chosen technologies that makes up a physical grid can be rather isolated from any other transmission grid (think electrical island), or rather interconnected or very much interconnected (think Germany or France, each with six or more foreign zones connected to their domestic grids). Any grid architecture can also be structurally weak or really strong. The 'system characteristics', then, play another key role because the actual set of generators and generating technologies, consumers' needs or behaviour connected to the transmission grid will determine the general characteristics of the power system (such as the peaks, the shape and slope of the load, the available reserves, the plants' ramping rates, etc.). Therefore, in a nutshell, most of the TSOs present significant differences in their grids

and/or systems and thus should not be expected to perform the same tasks in the same way.

The next relevant factors influencing the TSOs' practice are institutional (as in institutional economics: see the works of Ronald Coase, Oliver Williamson, Douglass North and Paul Joskow). First, TSOs have different 'corporate governance'. They can be state department (Sweden) or state undertaking (Denmark); state-owned listed company (France) or purely private listed company (the UK). They can have mainly national or European owners, or significant non-EU owners (think the role now played by State Grid Corporation of China in Portugal or Italy). All these TSOs cannot behave the same regarding investments into grid assets or information technology, debt and equity, market or technology risk taking. The TSOs also have different national 'regulatory frames'.[1] Chapters 1 and 2 identified up to five alternative or complementary basic regulatory tools, put into different regulatory mix regimes by existing regulatory authorities. These authorities are themselves distinguishable by the strength of their decision rights and independence, as well as by the size or depth of their resources and experience. Parallel to their various regulatory frames, TSOs may also have differing surrounding 'market operators' and 'market designs' covering parts or all of their control zones, or of their bordering control zones. Some TSOs even own the market operators (think Nord Pool). Other key market operators are structurally independent from the TSOs (think EPEX). Others are state owned (as in Italy or Spain). Jorge Vasconcelos, in the research report published by the Florence School in April 2017,[2] showed various regimes of market operation–system operation relations at a glance (Figure 3.1).

Another significant diversification factor influencing the TSOs' practice is their zones' 'stakeholders' political economy', such as incumbent generators and new entrants, national energy resources, peripheral territories, industrial energy-intensive consumers, household preferences and 'sacred cows'. Of course, all TSOs, being regulated entities, are sensitive to hard 'political economy' pressures that parliament, government or public law courts can, at any time, materialize in a TSO political (legislative or executive) or legal defeat.

Coming back to the first factor mentioned, that is the various TSO tasks (marked as (1) in Figure 3.2), Chapters 1 and 2 have already shown that the ranking among these tasks can change substantially from one TSO to another, or from one period to another. One TSO can prioritize capacity investment to host offshore wind farms, another reducing balancing costs, a third testing or deploying new information technologies.[3]



Source: Glachant et al. (2017), p. 31.

Figure 3.1 Possible combinations of market and system operators in any interconnected system

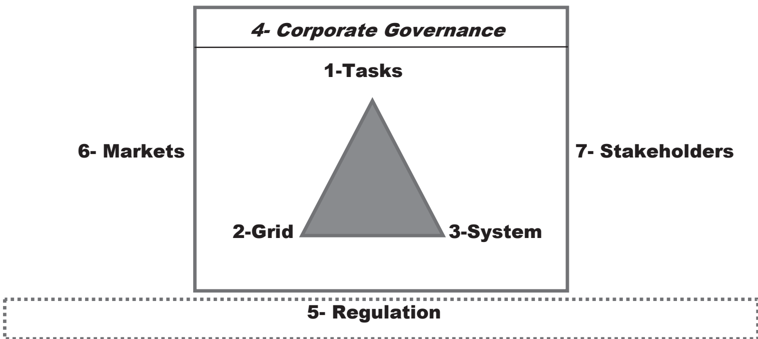


Figure 3.2 Seven factors influencing the differentiation of TSOs' practice

This leaves seven components of TSOs' practice differentiation, which is of course a high number, suggesting that bordering TSOs are rarely – if ever – fully aligned.

As a result, in this EU TSO landscape, the size and strength of seam potential are impressive, with (in 2015, before the Brexit vote) about 45 TSOs and 30 countries involved, including Norway and Switzerland, which are outside the EU but inside its market and (Norway) / or (Switzerland) its system. Thus, the erasing of seams resulting from the Europeanization of the EU grids and systems practice is neither easy nor spontaneous. It requires effort and organization. But how?

3.2 THE ACTUAL EUROPEAN APPROACH

The actual European approach to electricity TSO seams issues can be seen from its outcome (what has been put in place) or from its process (how such an issue is addressed in the EU). I will start with the process because the vast majority of us, having some understanding of one particular country case at national level (everyone has a country of reference), expect the EU, more or less, to do something similar as a whole, at a higher level, on a more general scale. The fact is that this view is wrong: the EU level, as a proper institution, does not and cannot do more or less, at a higher level or scale, than what an EU country does at country level. EU 'roof level' is not a country, or a European country. It is 'only' a very particular 'not a country' institution that the EU countries specially designed and built to put above themselves. The real and actual EU 'roof level' is not what any sensible EU country would like to do but at a higher level; it is what the many, various and heterogeneous countries can agree to put on their common roof, while keeping the maximum possible diversity and inconsistency between and inside each of these many countries.[4] Therefore, understanding how the EU can approach the TSOs' seams issues will reveal as much as, and sometimes even more than, knowing the actual details of the outcome.

3.2.1 The European Process to Address Seams Regulation

It takes a long time to understand what institutional Europe is made of. This is because it is a non-national construct. Even 'large states', such as Canada, the USA and Brazil, have a strong national core. But the EU, conversely, has no national flavour or trunk. It is instead a particular type

of construct put on top of national roofs, with the trunks and roots being the Member States. And this particular construct has been built only to be put exactly there (on the top), primarily by these Member States themselves – by these states interacting at EU level, not by ordinary citizens in their day-to-day lives. The strongest caveat is that groups of interests also act at the EU level. But they do not lead much when the EU has to define its own 'institutional design' (the key rules of the EU-level games). Lobbies play the games, but roughly within the rules set by the EU institutional design.

Two big institutional steps are coming in our reasoning.

- Step 1: the EU executive power has not been equipped with any kind of federal regulatory authority or agency. There are a few large exceptions, however: the competition authority, DG Competition, which is a department within the leading EU executive power (the Commission) and the European Central Bank (ECB), which is an independent authority outside this EU executive power.
- Step 2: the executive power of the Commission can issue detailed regulatory rules *only if* allowed by a particular EU law and controlled by other powers (Member States as co-executive; Council of the European Union and Parliament as co-legislators). This is not straightforward.

Step 1: the EU executive power has not been equipped with any kind of federal regulatory authority or agency

Usually a 'law' is a constraining public rule, expressed in terms general enough to permit its further combination with the hundreds of other already existing laws. This close combination of the many laws will be reviewed ex post by judges and courts, while the text of each new law is an ex ante general definition of the new rule produced by the legislators. Similarly, a 'regulation' is a public set of detailed practicalities, usually defined by an executive authority, permitting the implementation of a new law in the field of practice before knowing what a court (private law or public law) might later say.

Unfortunately, both references, while very usual at country level, are frequently wrong at the EU level. A typical EU law is only a 'directive'. It means that it sets only 'objectives' that each Member State will have to appropriately redefine in terms nationally relevant and precise enough to be combined with the hundreds of other national laws, to nationally reach similar objectives (within a time period set by the EU directive).

This necessary renationalization of the EU law is called 'transposition' by Member States. What the EU itself calls a 'Regulation' (with a capital 'R') is another type of EU law, supposed to be precise and effective enough to directly enter all Member States' bodies of law with no kind of 'transposition' into national laws.

What, then, is EU 'regulation' (with a small 'r')? Does EU executive authority produce its own sets of detailed practicalities to launch the implementation of the EU law into the field of practice? No, most of the time, this simply does not exist. Most of the EU laws are not federal laws implemented by federal departments and agencies (as, say, in the USA) but only 'directives' which have to be both translated and redefined in terms of each Member State's national body of law. Therefore, there simply is no straightforward track to get European-wide unified sets of detailed practicalities to start implementing the EU law with no seams between all Member States' fields of practice. Jorge Vasconcelos in two FSR research reports, published in 2015 and 2017,[5] gives a comprehensive view of the regulatory gaps in the EU electricity sector from 1996 to 2016.

Here is the difficulty. The hybrid nature of the EU (a 'federal type of confederation') has no fast and easy track to produce 'EU regulation' permitting coherent sets of detailed practicalities to implement the EU law with a guaranteed no seams effect.

Could the European Commission bypass this difficulty by enlarging and inflating 'EU Regulation' to get sufficient 'EU regulation' in it? It is not an absurd idea. But how is it possible to always include enough relevant 'executive details' in a general legislative ruling to be voted both by a council of all Member State ministers (Council of the European Union) and the EU Parliament? There is an obvious obstacle: it is too hard to expect a pan-EU legislative agreement to produce much or all EU single detailed practicalities by law in a single EU 'Regulation'. And the rigidity: once voted, the EU law is an EU law and it cannot be adapted later on in light of the hundreds of novelties popping up every year in real fields of practice.

Could DG Competition take special care of the detailed practicalities and act as a sheriff, getting Member States to converge towards a single market 'level playing field'? It is not absurd, but a competition authority can punish only the ones that are guilty, or get the guilty to agree to 'voluntary commitments'; it cannot set codes of detailed practicalities constraining all other undertakings in the same relevant market. In a free

market, marketers are free and competition authorities stay mute – and are happy to do so.

It is now obvious that 1) many factors, really objective or nationally institutional, push individual TSOs to not spontaneously converge towards no seams behaviour in most of the particular fields of practice; and 2) the EU institutional frame is not well equipped to reduce this natural TSO tendency to produce many seams. What has the EU process delivered, then?

Step 2: the executive power of the Commission can issue detailed EU regulatory rules only if allowed by a particular EU law and controlled by other powers

This window of opportunity is small and not easy to enter. To issue detailed regulatory rules conceived to sensibly frame the implementation of a given EU law, the Commission has to get ex ante a 'green light' put in this related particular EU law with the co-legislators' agreement (Council of Ministers of the European Union and Parliament). Then the Commission has to submit its proposal of detailed regulatory rules to a 'committee of experts' representing each Member State and voting with qualified majority. Even if voted by this committee, both Council and Parliament keep a final veto right because it is 'their' law to be implemented in this detailed way.

Once fully adopted by all these powers, this set of practicalities becomes a 'Commission regulation', which is as mandatory as a 'Council and Parliament Regulation' but from a lower level. An EU Regulation is a full law, defining both the general objectives and their main means. A Commission regulation is only a regulation, a set of practicalities, defining detailed practical means to implement the objectives set by the law.

While this process of combining four powers (Commission, Member States' experts, Council of the EU and Parliament) is not straightforward, other key difficulties remain at stake. 1) How could the Commission find the professional skills, the human capabilities, to produce sensible detailed practicalities to implement the general objectives of a new EU law in all 28 Member States? The fact is that the Commission has no large and resourceful federal bureaucracies getting practical knowledge and experience by interacting with the day-to-day life of the many fields of practice in the many countries of the EU. 2) Furthermore, who will guarantee a fair enough (no seams) implementation of the new common EU regulation in the very day-to-day life of the many countries' public or private areas? Not the Commission, it has no federal apparatus to do

so: all 'first-line' implementation players (business or authorities) are country based.

One of the many rational answers to these two powerful difficulties is to voluntarily feed the EU Commission regulation process with a good deal of EU-level 'self-regulation'. The Commission can build, at the EU level, particular crowds or coalitions of 'nationally interested regulatory experts and players' and link them to: a) the building of the Commission 'regulation proposals'; b) the decision-making of the 'Committee of national experts'; and c) the national processes of implementation of the new Commission's regulation. This strong 'self-regulation' logic has been seen many times in many industries (from drugs and food to trucks and cars). Could it also be built in the electricity sector? And then support the take-off of a first wave of Commission regulation, able to sensibly reduce the room for manoeuvre for country or infra-country seams?

3.2.2 The European Outcome Addressing Seams

The EU process could start addressing seam issues from the lighter EU law (Directives), the stronger EU law (Regulation), or ad hoc decisions made by the Commission (as DG Energy or DG Comp), or other novelties to be seen. One of the major novelties would be entering a proper Commission regulation process.

The First Directive on the internal market for electricity (1996) did roughly acknowledge its feebleness by doing virtually nothing about addressing country seams except abolishing the hardest countries' Chinese walls: 1) by cancelling Member States' right to close borders (via legal monopolies of imports and exports); 2) by opening all countries' national markets for big consumers; 3) by requesting the designation of a TSO in any country transmission grid, but with an imprecise definition of its statute. TSOs could stay bundled with generation and supply, with their own special accounting. Regulatory authorities themselves were not mandatory. So the third-party access to the grids could be either 'regulated' or only 'negotiated' with the vertically integrated transmission monopoly. No market design of any kind was set. And the 'single buyer' option was kept as legal: the consumer buying from a new entrant was then supposed to transfer their new supply contract to the incumbent supplier for implementation. Not surprisingly, as noted by Leigh Hancher and myself,[6] the EU at the time had as many seams as countries and sometimes more, as the UK and Germany went for alternative wholesale market regimes and several TSOs in each country.

In response, in 1998 the Commission created a voluntary pool of pioneers producing soft convergence through debates and a willingness to do more: the 'Florence Forum for Electricity' (where many future pillars of our Florence School of Regulation – created in 2004 – were involved as national regulators: Jorge Vasconcelos, Pippo Ranci and, later, Ignacio Perez-Arriaga, etc.[7]). Many European associations have also been created to act as voluntary pioneers producing soft paths of better convergence (CEER for regulators, ETSO for TSOs, etc.).

At the Second Directive, in 2003, it became mandatory to have a national regulator in every Member State (it was new for Germany). The regulators gathered in CEER became a collective advisor of the Commission under the legal 'hat' of the European Energy Regulators Group for Electricity and Gas (ERGEG). And the 'negotiated' third-party access disappeared from legality. The duties of the TSOs were better defined, while still in general and non-operational terms. However, a voluntary 'convergence of the willing' increased within ETSO. In 2006 leading volunteer TSOs created the 'Market Coupling' initiative for day-ahead wholesale trade, which was a major step towards the reduction of seams by running common 'implicit capacity auctioning' at borders for France and the Benelux. Regulators, via ERGEG, enriched the initiative, ending up hosting Germany in 2010, with another new key step in 2014 when extending to Great Britain and the Nordic and Iberian countries. Flow-base was another step ahead for capacity calculation.

Only in 2015 did the Commission take full responsibility by issuing a Commission regulation (a very special instrument, as described earlier). For the first time, 19 years after the First Directive, the EU established a comprehensive guideline on capacity calculation and allocation, congestion management, market coupling and 'market operators' (NEMOs), coordinated redispatch, allocation of costs and bidding zones. 'Until then, it was mainly a non-regulated, contractual TSO relationship' (Jorge Vasconcelos).[8] Being established as 'Guidelines', this Commission regulation has a lower direct content than a proper 'network code', as it still requires TSOs and NEMOs to develop the detailed methodologies, to be approved by the NRAs and being necessary to make the guidelines work. However, it is such a big change in the course of EU electricity regulation that it can be said to be the real Day 1 of 'EU regulation addressing TSOs seams'.[9] From the summer of 2018, all the methodologies needed for a pan-EU implementation should have been issued and this EU seam eraser should then be at work.

Another interesting, though smaller, piece of law somehow announced this EU regulatory shift. It was EU Regulation 347/2013, which transformed the EU policy of funding 'European value-adding' infrastructures, in relation to the newly created 'Connecting Europe Facility' (CEF): €24 billion for Transport, Energy and Communications in 2014–20. This EU Regulation–law created a due process to define and choose projects contributing to new pan-EU 'energy corridors' and/or increasing interconnections of regions and countries. Being a European Regulation, then a law with no transposition process, it became an opportunity to redefine the TSO obligations at the EU level notably by asking them to adopt 'common network operation tools to ensure coordination of network operation' and by giving the European network of TSOs (ENTSO-E) two years to define the necessary specifications, to be then approved by ACER and the Commission. This 2013 case, that of grid planning coordination (also called system planning), deserves more attention before coming back to the wave of Commission regulations opening up in 2015.

It was EU Regulation 714/2009, within the Third Package, that first asked ENTSO-E to produce a 'non-binding Community-wide ten-year national development plan' (TYNDP), associated with a generation adequacy outlook and to build it a) on national investment plans; b) on system user needs and investor commitments regarding cross-border interconnections; so as to be able to c) identify EU investment gaps, 'notably with cross-border capacities'. Of course, developing such a tool takes time, and TYNDP 2010 and 2012 were not yet delivering a deep analysis that worked well. TYNDP 2012 frankly acknowledged the need for more work to produce a strong 'top-down' definition of scenarios as a complementary approach to the dominant 'bottom-up' approach already in place. TYNDP 2014 performed much better for 'top-down', as well as for offering some CBA (cost–benefit analysis). Finally, for the first time in the EU, TYNDP 2016 was able to focus on common planning studies where interconnection targets were agreed, to identify investment gaps and to formally use a refined CBA methodology. It was a big step forward,[10] but with other limits still in place.

EU Regulation 347/2013 (already introduced as a companion to the CEF initiative) has been officially labelled 'Guidelines for trans-European energy infrastructure'. It kept TYNDP as a reference scenario for EU-level policy thinking and called for a more precise and accurate CBA methodology. But it did create a new governance structure to produce the EU infrastructure policy decision-making. These 2013

mandatory EU Infrastructure Guidelines detached the process of evaluating, selecting and financing the European priority grid projects from the governance created by Regulation 713/2009. Instead of building on the existing governance, with ENTSO-E as a hub of TSOs, it created a new process called 'Projects of Common Interest' (PCIs), governed by a brand new governance structure made up of 12 ad hoc regional groups, and gave, by law with no transposition, a clear supremacy to these new PCIs vis à vis the tools and processes designed by the Regulation and Directive from 2009. It seems that an opportunity for operationally combining TSOs' actual investments, national network development plans, EU policy priority and financing, and the EU network development plan, in a converging process reducing all the related seams, was missed there, in the first and proper EU 'guidelines for energy infrastructure'.

These smaller, but consequential, Hardware Guidelines (EU Regulation 347/2013) and the bigger Software Guidelines (Commission regulation 2015/1222) are not carved from the same stone. What really underpins the first wave of Commission regulations is still clearly based on the Third Package from 2009.

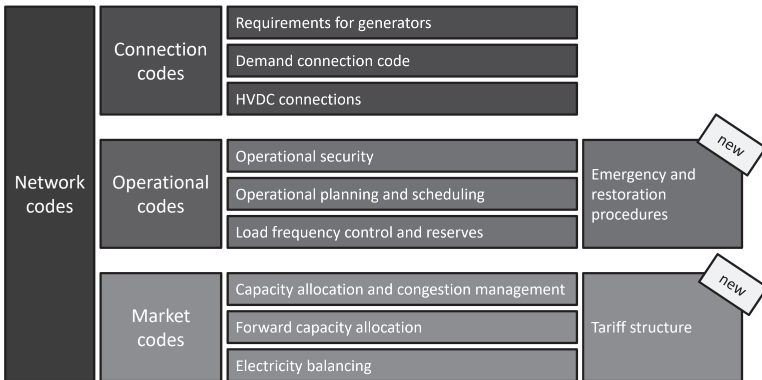
While this package pushed the definition of rights and duties of TSOs and NRAs far beyond the two older packages, it did not change the preference for staying 'general' and not addressing the operational coherence needed to erase the seams. It also did not define any 'market design model'. The core of this Third Package was twofold: 1) making mandatory by law the unbundling of the TSOs (which both Germany and France were refusing to do, in the name of their national champions); 2) mutualizing the national powers of both the TSOs and the NRAs into two new European bodies to become ENTSO-E and ACER. ENTSO-E was created as a European body by a special 'EU Regulation' (714/2009). That same Regulation, an EU law with no transposition, also gave the Commission a 'green light' for proposing further Commission regulations defining 'grid codes' and/or 'guidelines' addressing all key practical points needed for the operation of the EU electricity system and internal market and to be submitted to the 'Comitology procedure' (referred to earlier in this chapter: Committee of Member States experts, plus final veto rights to co-legislators Council and Parliament). In the same Regulation law, obligations were given to ACER (hence the mutualized NRAs) to produce 'framework guidelines' to be sent to ENTSO-E (hence the mutualized TSOs) to produce 'network codes'. After mutual checks and balances between ACER and ENTSO-E, the Commission was set free to draft the final proposal to be submitted to the Comitology

process. Thus, the mutualized NRAs were producing the framework guidelines, while the mutualized TSOs were producing the grid codes. But the Commission was retaining its final bargaining power with TSOs, NRAs, Member States, Council and Parliament.

It took a long time to make this new process, launched in 2009, work and deliver. The first big 'real size' test came in the form of the Capacity Allocation & Congestion Management (CACM) Commission Guidelines, officially issued in July 2015. But it was more than a big test, it was a revolution. A single piece of Commission regulation was simultaneously defining the reference EU 'market design' (which has never been done) and the related TSO operational guidelines (except for balancing and forward capacity allocation (FCA), being two distinct pieces in the same wave of Commission regulations).

This real EU revolution in addressing seams is summarized in Figure 3.3, from 2015, showing that 11 pieces of Commission regulation were foreseen, in three baskets: Market codes, (System) Operational codes and (Grid) Connection codes.[11] In practice, as we have already seen, the Commission redrafted its regulation proposals for CACM and FCA as 'guidelines'.

Once the Commission market guidelines (or network codes) are adopted and equipped with the relevant methodologies, who is legally responsible for their proper implementation into the fields of practice of the many EU Member States? It is the same TSOs and NRAs that have been mutualized within ENTSO-E and ACER.



Source: Glachant, Vasconcelos and Rious (2015), p. 33.

Figure 3.3 Overview in 2015 of the EU network codes to become Commission regulations

It is true that this new EU regulatory frame, conceived and launched by the Third Energy Package, is not a 'fast track'. Designed in 2009, it will start being operational only in 2018. But it exists and should work effectively. Except for the NEMOs (the market operators created by regulation 2015/1222), all the professional experts that have had a hand in defining the framework guidelines and have worked on the network codes drafts are the same entities that will have to implement them as a binding EU regulation: the TSOs and NRAs of the European Member States.

3.3 THE REMAINING EU REGULATORY GAPS

The EU is credibly engaged in a wave of Commission regulations, with enough field skills and experience in the upstream drafting (i.e. the TSOs and NRAs mutualized by ENTSO-E and ACER) and enough proven capabilities to act in the downstream implementation at individual Member State level (brought there by the very same TSOs and NRAs). Overseeing them all, the European Commission, as key EU executive power, is their general coordinator and principal. Of course, getting the full benefits of this seams-erasing wave will take some years (for example, the EU balancing code implementation had already been delayed for six years). But this whole process will inevitably and considerably reduce the room for seams in the EU. Will it be so deep and comprehensive that we can already assume that the seams in the EU electricity sector are to disappear? In a sense we need more time to find out. In another sense no time is necessary, it is already obvious. Two Florence School research reports investigated the issue (Glachant, Vasconcelos and Rious (2015), and Glachant, Rossetto and Vasconcelos (2017)). Jorge Vasconcelos, a founding father of EU electricity regulation (CEER, ERGEG, Florence Forum, etc.), is the main author of the 'regulatory gap' analysis exposed in this research. The mere fact that each Member State has a regulatory authority and at least one TSO while the European level has none – no EU regulator and no EU TSO or ISO – creates a regulatory gap that should still be consequential, even after the full implementation of the current Commission regulations wave.

3.3.1 The Missing EU Regulatory Pillars

One way of identifying the nature of this EU regulatory gap is to identify the 'missing regulatory pillars': that is, the ones that have yet to be fully and comprehensively addressed at the EU level.

The first one is 'coordination'. In a common and single market, all interconnected grids and their systems at Member State level are only parts of a pan-EU grid and system. Interactions between the decisions made by transmission managers and investors, systems operators and millions of grid users and market players have to be addressed as such, and embodied into relevant EU coordination mechanisms. As seen in Chapters 1 and 2, this is needed from grid connection to assets maintenance and investment planning; from system operation to interaction with all grid users or market players. The current wave of Commission regulations addresses many parts of that, but not all of them and not in a systematic manner (we have already seen a gap in the loop between TYNDP and PCIs). This will be substantiated much further in the next subsection – the EU roadblocks.

The second missing regulatory pillar is 'sharing the costs and the benefits'. The pan-EU grid and system are still both (for long, or forever) fragmented into many control zones and TSO companies. Then the numerous actions needed to efficiently transform the bones or muscles of the EU grid (the hardware) or to manage the blood or the brain of the EU system (the software) entail costs and benefits being unevenly distributed among the many zones and many companies. If this regulatory issue is not properly addressed, the adverse incentives rooted in the transmission zones and companies' fragmentation can block the efficient pan-EU, or even regional, and sometimes simply bilateral, outcome.

The third missing pillar is 'solidarity beyond costs and benefits'. The speed and extent to which electricity systems deteriorate in strained situations or outright crises call for 'solidarity' as the more rational behaviour (as a rescue in a car crash). The rationale is to first save the 'power systems' by keeping them on the safe side; only later might one discuss what happened, and why, and what should be changed. However, in any case, 'solidarity' has to be organized ex ante; if not, any crisis might easily end up in a 'sauve qui peut' scenario, which will increase the likelihood of major disasters or the extent of the damages to be incurred. There is a typical seam effect when a crisis born here, this side of a TSO border, is not considered there, on the other side. The UK Prime Minister Tony Blair was simply furious when the French gas TSOs refused to

promise to help Great Britain in the name of their own French 'public service' obligations. But why didn't he call for a pan-EU crisis and solidarity regulation before the emergency?

3.3.2 The Current EU Regulatory Roadblocks

The accuracy of the conceptual notion of 'regulatory missing pillars' will be easily confirmed by the list of current EU 'regulatory roadblocks' identified by the April 2017 FSR research report. There are 12 significant roadblocks identified by the Florence School (see Table 3.1) – eight are 'first-order', which means they lack a proper 'coordination mechanism' in the decision-making process; four are 'second-order', meaning that what is lacking is mainly the 'harmonization' of rules and principles.

Table 3.1 The EU regulatory roadblocks

First-order: coordination	
1.	Lack of comprehensive coordination of system planning, further to the TYNDP
2.	Lack of comprehensive coordination of cross-border investments
3.	Lack of comprehensive coordination of system operation
4.	Lack of a common redispatching approach
5.	Lack of common reserve contracting and cost allocation
6.	Lack of intraday cross-border allocation with auction
7.	Lack of load shedding coordination
8.	Lack of comprehensive coordination for solidarity
Second-order: harmonization	
9.	No harmonization of common congestion rent allocation scheme
10.	No harmonization of capacity remuneration mechanisms
11.	No harmonization of transmission tariffs across countries and TSO zones
12.	No harmonization of 'state aid' to big energy consumers (through reduced network tariffs or green levies)

Source: Glachant et al. (2017), p. 53.

This list is long and meaningful, revealing consistent regulatory gap and seams potential in the EU electricity landscape. What is striking is that half of these regulatory roadblocks involve players beyond the proper TSOs. From number (7), load shedding, to number (12), state aid, they are the regulators or, directly, the governments that are responsible or co-responsible for these EU regulatory gaps. As we have shown in Section 3.1 (TSO seams factors), many seams effects are coming from the public authorities, directly or indirectly.[12] As regulated entities, the TSOs are taking directly from public authorities many items that TSOs

see as impossible to change, or too risky, or too costly to change by themselves.

3.4 CONCLUSION

Grids, system control zones and countries have borders. It does not mean that they have to have strong seams. Borders favour seams but do not make them mandatory. Of course, there are so many factors, objective or institutional, which favour TSO seams creation that we cannot expect seams to spontaneously or easily disappear.

However, if Europeans are serious about their aim of creating a seamless internal market for electricity, a goal stemming from the EU Single Act in 1986 and being launched since the First Directive on an internal market for electricity in 1996, a consistent European approach to erasing seams is needed.[13] In fact, and unfortunately so, the EU institutions do not offer an easy path to electricity seams erasing. It is because such a policy requires many consistent regulations to be defined and implemented, while the EU has no 'federal' regulatory authority powers and no pan-European system operator or transmission company.

To tell the truth, this reality does not block the EU from going ahead. The EU has been able to create its own particular 'third best' path to seams erasing. The core of it, its spine, is mutualizing national TSOs within ENTSO-E, and national NRAs within ACER, and integrating both into the Commission regulations creation process. It is the particular but working way by which the EU became able to define and implement common regulations addressing seams. It is 'third best' only because national players (TSOs and NRAs) will not face any EU federal regulator when implementing the common European regulations. This EU wave of common regulations will be fully deployed in 2022, when the regulation of balancing is expected to be totally implemented.

Where will the EU end up? Jorge Vasconcelos is seeing a significant but still incomplete EU seams erasing. One big seams potential is even rooted in the bifurcation made by EU law between the 'Access to Networks' Regulation 714/2009 and the 'Infrastructure Guidelines' Regulation 347/2013.

Could the Fourth Legislative Package process, pushed by the European Commission since the autumn of 2016, reduce this seams potential? Say, by redefining the ways TSOs, NRAs, ENTSO-E and ACER work, so as to significantly reduce the autonomy of each national player within

its own EU body or within its national borders? Could country TSOs themselves lose a part of their independence with the creation of regional entities acting as 'light regional system operators': the ROCs (regional operational centres)? Already NRAs and TSOs are fiercely opposing any denationalization of their existing powers. Will, then, the Member States and the EU Parliament follow the new Commission proposals, or their opponents, the proud 'countries' national militias'? The Florence School has repeatedly advocated that regulatory regimes and goals have to align on the actual capability of the regulator(s).[14] Is this the long-term feed-back loop in which the Fourth Package will end or not?

Nevertheless, all the future of EU electricity seams is not there, in the institutional issues. Another, and gigantic, part is rooted in the transformation of the objective grid and system factors. Renewables, being massively 'distributed generation' and, because of that, having potential for 'self-consumption', redefine the EU relevant grid architecture and system characteristics. Distribution grids are becoming distribution systems, widening a new seam issue on the flanks of transmission operators. 'Prosumers' are themselves bypassing all grids (distribution and transmission) and systems. New devices, tools, software and processes (such as blockchain-based exchange) open new spaces of transaction, agreement and settlement to new markets, new platforms, new communities and … new seams.

The whole global industry enters a new 'industrial revolution' led by digitalization, data processing, 'peer-to-peer' or 'crowd-to-crowd' smart interactions. In a new world of electric self-driving cars, say in 2035, it would be strange to find that the centre of all electricity affairs would still be the highly centralized electricity grid and system that a long time ago, in 1996, was supposed to favour the launching of the EU internal market paradise.

NOTES

1. A strong proof is given in the FSR research report published in 2013 by Glachant et al.
2. Glachant, Rossetto and Vasconcelos (2017).
3. The reader is again invited to read the FSR research report (Glachant et al., 2013).
4. Remember this as a reference point: in October 2016 the leading party of the Wallonia region, inside Belgium, being politically

weak (it would be ousted from government a year later), blocked for weeks, in the name of 3 million inhabitants, a trade agreement with Canada agreed by the rest of the European Union (more than 510 million inhabitants).

5. See Glachant, Vasconcelos and Rious (2015), Chapter 1, and Glachant, Rossetto and Vasconcelos (2017), Chapters 1–3.
6. Glachant (2001).
7. Read the early assessment made by leading EU energy regulators after the birth of the Florence Forum: Vasconcelos, Ordonez and Ranci (1999).
8. Jorge Vasconcelos, a founding father of CEER, the Florence Forum and ERGEG in Glachant, Rossetto and Vasconcelos (2017), p. 35.
9. See it on the internet as 'Commission regulation 2015/1222' (57 pages); its nickname is 'CACM guidelines' – not to be confused with 'CACM framework guidelines', which is an earlier and smaller provisional step from ACER.
10. Glachant, Rossetto and Vasconcelos (2017), pp. 62–76.
11. The list of EU Network Codes, conceived in 2015, has changed since then. See an updated version of it in the handbook produced by the Florence School of Regulation: Meeus, L. and T. Schittekatte, 'The EU Electricity Network Codes', *Florence School of Regulation research report*, EUI, January.
12. On top of the Florence School research reports 2015 and 2017, do not miss Glachant et al. (2013), for regulatory seams between national regulators; and for regulatory seams between Member States' governments, and between… European Commission directorates, Glachant et al. (2014).
13. See Glachant and Lévêque, 2005, 2009; Glachant and Ruester, 2013.
14. See the two following working papers: Glachant et al., 2012 and Vandendriessche, Saz Carranza and Glachant (2017).

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4. DSO–TSO seams issues

Leonardo Meeus and Samson Yemane Hadush

Renewable energy sources are increasingly connected to the European power grid. This includes utility-scale wind farms connected to transmission grids, as well as millions of relatively small-scale photovoltaic installations on the rooftops of our houses that feed into the distribution grids. In Germany, more than 90 per cent of renewable energy units are connected to distribution grids, an industry trend that is picking up in the rest of Europe.

The intermittent nature of these energy sources has made the power system more complex to plan, control and balance. To cope with these added complexities and future challenges, both DSOs and TSOs are trying to unlock the flexibility resources connected to the distribution network. As a result, DSOs are becoming more important, and vertical seams issues between operators (DSO–TSO) have started to emerge.

In this chapter, we first introduce the DSO landscape in Europe. We then discuss why (and how) DSOs and TSOs will need to cooperate to balance the system and to manage congestion in their grids. We close the chapter by zooming in on the issue of data management.

4.1 THE DSO LANDSCAPE IN EUROPE

In this section, we first describe the border between transmission and distribution.[1] We then look at the concentration and unbundling of DSOs in Europe.

4.1.1 Distribution versus Transmission

The final mile in the delivery of electricity is the most significant. TSOs operate only 3 per cent of the power lines in Europe; the rest is managed by DSOs. There are 2400 DSOs that own and operate 10 million km

of power lines, which is 13 times to the moon and back. They employ 240 000 people and service 260 million customers that have a separate connection point to the distribution grid. These customers, about 90 per cent of them, are mostly residential and small businesses.

There are around 10 000 interconnection points between transmission and distribution grids in Europe. DSOs operate power lines at various low-voltage (<1 kV) and medium-voltage levels and most of them also partly operate the high-voltage (>36 kV) network in their country (up to 110 kV and even 150 kV in exceptional cases). Therefore, the border between what is referred to as the 'transmission' and the 'distribution' grid is very varied across Europe.

4.1.2 DSO Concentration

Even though there are about 2400 DSOs in total, the industry is rather concentrated. At the EU level, there are four industry associations representing the interests of DSOs: GEODE, CEDEC, EDSO and Eurelectric. The larger DSOs in Europe work together in the association EDSO for smart grids. This association has about 30 members that represent more than 70 per cent of the industry. In countries such as Ireland, Lithuania and Slovenia, there is only one DSO. In countries like France (158 DSOs) and Italy (144 DSOs), there is one dominant DSO and there are many small players sharing less than 10 per cent of the market.

There are also countries in which the concentration is significantly lower. This is the case, for instance, in Austria (138 DSOs), Belgium (24 DSOs), Norway (155 DSOs), Sweden (173 DSOs) and Germany (880 DSOs), where the three largest DSOs account for less than half of the industry.

4.1.3 DSO Unbundling

The TSO and DSO business was created at the start of the liberalization process. Before, the grid was often integrated in a company that was also active in the production and supply of electricity locally or nationally. They could limit the investment in the grid to protect the domestic market from international competition, and could also reduce access to the grid. When production and supply became a competitive activity, regulators introduced rules to make sure that the incumbents could not abuse

their unique position in the transmission and distribution grids to deter new entrants. This includes the introduction of third party access rules for grids, and stricter procedures for grid planning and investments. In addition, unbundling rules were gradually introduced that required the utilities to separate the TSOs and DSOs they owned from their other activities. This has been done by introducing a separate legal entity, accounts, company name, logo, branding, management, with ultimately a separation in terms of ownership.

The EU unbundling rules for TSOs are strict, even though they do not yet impose ownership unbundling. The EU rules are much less strict for DSOs as this was considered less important when this legislation was adopted. Legal, functional and accounting unbundling does apply to DSOs, but only if they have more than 100 000 customers, which is the case for 190 of the 2400 DSOs. The new EU legislative initiatives included in the 2016 Clean Energy Package do not include proposed changes to the unbundling rules, but it has been proposed to cross out the part of the EU Directive 2009/72/EC that said that DSO unbundling is less important (see Box 4.1).

BOX 4.1 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – RECITAL 26

(43) Non-discriminatory access to the distribution network determines downstream access to customers at retail level. ~~The scope for discrimination as regards third-party access and investment, however, is less significant at distribution level than at transmission level where congestion and the influence of generation or supply interests are generally greater than at distribution level. The rules on legal and functional unbundling currently in place can lead to effective unbundling provided they are more clearly defined, properly implemented and closely monitored.~~ To create a level playing field at retail level, the activities of distribution system operators should therefore be monitored so that they are prevented from taking advantage of their vertical integration as regards their competitive position in the market, in particular in relation to household and small non-household customers.

4.2 DSO–TSO CONGESTION MANAGEMENT

In this section, we start by underlining the importance of congestion management. We then take stock of the conventional approach to congestion management in transmission and distribution grids. We close the section by discussing the seams issues between DSOs and TSOs, and how to overcome them.

4.2.1 Importance of Congestion Management

The cheapest energy resources can be used to supply the customers, wherever they are, as long as there is enough network capacity at transmission and distribution level. When there is congestion somewhere in the European grid, the market will still clear but the location of the customer will matter, and more expensive generation units will run if they are in the right location. The market will then trade at different prices in locations that are separated by a congested power line. However, this is possible only if the market design includes several bidding zones that can clear at different prices, which is not always the case.

If the market does not take into account network constraints, they will need to be managed by the operators after the market closes. If necessary, the operators can indeed take remedial actions by re-dispatching the system in real-time. This means that some units will be compensated not to run, while others will be paid to run even though they were not cleared by the market. These interventions are out-of-the-market solutions to deal with network constraints. It is well known that this can easily be abused by traders, so it is better to include the constraints in the market design rather than resort to re-dispatching.

California learned this the hard way. The market design in California at the start of the century did not take into account network constraints, while the state had structural congestion in some locations. Traders soon discovered that if they offered the generation units in these locations at very low cost in the market, the market would clear with a solution that the operators could not allow to happen, so these generation units could receive compensations not to run. Traders could even offer expensive units cheaply in the market and be compensated. This was one of the schemes that the Enron traders used in the California market and which contributed to the Californian energy crisis (see Box 4.2).

BOX 4.2 THE EXPERIENCE OF CALIFORNIA

'The smartest guy in the room' is a documentary about Enron, one of the biggest and most controversial companies to go bankrupt in America's history. Part of the story is about the Californian power market, which was one of the first power markets in the world, and Enron played a leading role in what happened there. In what follows, we provide an abstract from that documentary, which we warmly recommend.

Enron hit California with rolling blackouts. Lights went out in the middle of the winter where only half the capacity was used during the summer. There was demand for only 30 GW while total generation capacity was 45 GW. A Californian energy regulator stated: 'I knew there was illegality going on. I could feel it, I could sense it. There was no other explanation. […] It was never about lack of supply.'

Enron chose California to experiment with its new concept of 'deregulated electricity'. In 1996 a bill was passed by Governor Pete Wilson, 'under pressure from energy companies', allowing the deregulation of electricity. The rules were complicated and hard to follow.

Enron looked for loopholes to exploit. The names of the strategies it devised included 'Wheel out', 'Fat boy', 'Shorty', 'Death Star' and 'Ricochet'. For example, the 'Ricochet' strategy was to first export and then wait for prices to rise to import back in, overbook the transmission rights and then tell California utilities: 'If you want to use the line, pay us.'

When confronted with these strategies in a public hearing, the CEO of Enron said: 'The only thing that I was aware of, was a difference of opinion about the rules, the ISO was just set up and the rules were not quite clear.'

A commodity that usually traded in the 30s, with high prices somewhere in the 50s, was sometimes at a thousand dollars. This eventually also led to rolling blackouts in California in the summer of 2002. The crisis cost the state of California $30 billion.

What happened had been the consequence of inadequate market design and supervision. For some observers, it was used as the proof that power markets cannot work. The Californian energy regulator stated: 'There is one fundamental lesson we must learn from this experience: electricity is really different from everything else. It cannot be stored, it cannot be seen, and we cannot do without it, which makes opportunities to take advantage of a deregulated market endless. It is a public good that must be protected from private abuse.'

This experience not only slowed down the liberalization process in California, it also contributed to the US patchwork of states with power markets and states in which the power system is still a fully regulated vertically integrated monopoly business.

4.2.2 Conventional Congestion Management Approach for Transmission

In Europe, the conventional congestion management approach for transmission is to internalize the borders between TSOs in the market design and to remedy congestion within a TSO control zone after market closure. TSOs have harmonized the way they calculate the cross-border capacity that can be made available to the market, and the market operator uses these capacities as constraints in the market clearing algorithm.[2] With the introduction of flow-based market coupling, the interactions between available capacities on the borders are now also (partly) taken into account. This is a work in progress that is included in the target model for the internal electricity market in Europe (see Chapter 3).

Up until recently, congestion mainly occurred between countries, or between TSO control zones. This is no longer the case. In many countries, transmission investments have not been able to keep up with the rapid integration of renewable energy sources, which has resulted in structural congestion within countries. Re-dispatching actions by TSOs have consequently been increasingly significant, especially in Germany. The solution is to split the country into several bidding zones, which has been done in the Nordic countries. This then allows TSOs to limit the available transmission capacity between the bidding zones and allows the market operator to constrain the trade between these zones to the available capacity and clear the market with zonal prices in case of congestion.

There is a lot of resistance to this solution. The case of Sweden, however, sets an interesting precedent. In 2009, Denmark introduced an anti-trust case against Sweden in front of the European Commission, and won (see Box 4.3). Sweden then had to split the market into several bidding zones. It had been resisting doing this despite the structural congestion between the production in the north and the consumption centres in the south of the country. To reduce the congestion from the north to the south, the Swedish TSO reduced the international flow from Norway to Denmark, which partly transits via Sweden, by artificially reducing the available capacities on the borders. These actions were considered anti-competitive because they discriminated against international trade.

The Swedish case triggered a discussion on optimal bidding zones in Europe, so it is likely that more countries will (be forced to) follow the Nordic example. In the USA, some states have reduced the size of the bidding zones to the size of the nodes in the transmission grid, which is referred to as nodal pricing. In Europe, we are still far from nodal

pricing, but we have implemented zonal pricing on a geographical scale that is unprecedented.

BOX 4.3 COMMISSION DECISION OF 14.4.2010 RELATING TO A PROCEEDING UNDER ARTICLE 102 OF THE TREATY ON THE FUNCTIONING OF THE EUROPEAN UNION AND ARTICLE 54 OF THE EEA AGREEMENT (CASE 39351 – SWEDISH INTERCONNECTORS)

Below we have selected a few abstracts of this landmark decision targeted at Svenska kraftnät (SvK), the Swedish TSO.

(44) The Commission's preliminary assessment was that by curtailing interconnector capacity because of internal congestion, SvK treated domestic transmission services and transmission services to an interconnector intended for exporting electricity differently. Demand for domestic transmission services was satisfied where transmission capacity was available, whereas in a significant number of hours and to a significant extent demand for transmission services to/over interconnectors was refused despite transmission capacity being available.

Domestic transmission services excluding the Swedish interconnectors and transmission services using an interconnector with a view to exporting electricity are equivalent transactions within the meaning of the case law of the Court of Justice. They take place on the same market, that is, the Swedish transmission market. The preliminary assessment of the Commission was that SvK curtailed interconnector capacity because of internal congestion which has led indirectly to a different treatment of customers depending on their residence. Ultimately, SvK has contributed to a segmentation of markets between Member States and contracting parties to the EEA Agreement impeding customers and producers from reaping the benefits of the internal market contrary to the fundamental aims of the Union.

(45) According to the Commission's preliminary assessment, SvK did not provide the evidence necessary to demonstrate that the suspected conduct is objectively justified.

…

(47) According to the commitments offered by SvK on 4 September 2009 to meet the Commission's competition concerns SvK will subdivide the Swedish transmission system into two or more bidding zones and operate the Swedish transmission system on that basis by 1 July 2011 at the latest. The configuration of the bidding zones will be flexible enough so that it can be modified to adapt to foreseen and unforeseen changes in the future flow patterns on the Swedish transmission system. From the date the bidding zones are operative, SvK will manage congestion in the Swedish transmission system without limiting trading capacity on interconnectors.

(48) There will be one exception to this principle of management of internal congestion: congestion in the West-Coast-Corridor. SvK has argued that congestion in the West-Coast-Corridor cannot be managed in an efficient manner by bidding zones as this area would not contain sufficient suitable generation resources to be able to set a market price by itself. SvK commits to reinforce the West-Coast-Corridor section by building and operating a new 400 kV transmission line between Stenkullen and Strömma-Lindome by 30 November 2011.

4.2.3 Conventional Congestion Management Approach for Distribution

The conventional approach in Europe for distribution is to 'fit and forget'. This means that these grids were typically oversized to handle almost all circumstances. TSOs also try to avoid network constraints in their control zone by investing in the transmission grid, but if they do have congestion, they can re-dispatch the customers connected to their grids. Up until recently, DSOs did not actively manage their grids.

In some countries, DSOs have already been faced with massive connection requests. In Ireland and Scotland, this has been the case for wind farms, for instance. In Germany and Italy, this has been the case for photovoltaic systems. The conventional response would be to limit the connections either by creating a connection queue or by resorting to non-firm connections that allow the DSO to curtail customers connected to their grid. Curtailing of customers with a non-firm connection is one option to manage congestions at the distribution level. Some DSOs have already started considering a second option, which is to procure flexibility services to re-dispatch the system at the level of distribution grids.

The experience of the Orkney Isles, off the northeastern coast of Scotland, presents an interesting case. The Isles are well known for their attractive wind power potential. Around 2005, the submarine cables between the distribution grid on the island and the transmission grid on the mainland became a barrier for the development of wind power on the island. The cables had been designed to be able to import the island's maximum consumption from the mainland to the island. When consumption on the island is low, the same cables are now used to export the production on the island to the mainland. Production could not increase above the maximum consumption, otherwise the island could risk having too much production which could overload the distribution grid and lead it to collapse.

The traditional solution would have been to increase the capacity of the submarine cables between the island and the mainland, but this can be expensive, with long lead times due to permitting and other regulatory requirements. Moreover, the additional grid capacity would be used only in the limited hours of the year that strong wind conditions are combined with low consumption on the island so that the renewable energy needs to be evacuated to the mainland.

The alternative solution is to curtail the wind power plants during the few hours of the year that this is necessary to remedy congestion in the distribution grid. To be able to do this, the distribution grid company in the Orkney Isles (Scottish and Southern Energy Power Distribution) became one of the first to implement an active distribution grid management system. The system, which came into operation in around 2009, increased the renewable energy hosting capacity of the local distribution grid by almost 50 per cent (i.e. from 47 MW to about 68 MW) and avoided a network upgrade and reinforcement that would have cost around £30 million, while the total cost of developing and delivering the system was around £500 000.

Note that curtailing is one way of re-dispatching a distribution grid. Alternatively, a market can be organized to trade flexibility services in which DSOs could procure ancillary services to re-dispatch their distribution grids in case of congestion. In most countries, there are no rules in place that allow DSOs to do that, but this will soon change. The new EU legislative initiatives included in the EU Clean Energy Package include clear provisions that will enable DSOs to do so (see Box 4.4).

BOX 4.4 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 32 TASKS OF DISTRIBUTION SYSTEM OPERATORS IN THE USE OF FLEXIBILITY

Article 32 Tasks of Distribution System Operators in the use of Flexibility

1. Member States shall provide the necessary regulatory framework to allow and incentivise distribution system operators to procure services in order to improve efficiencies in the operation and development of the distribution system, including local congestion management. In particular, regulatory 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. Distribution system operators shall procure these services according to transparent, non-discriminatory and market-based procedures.

Distribution system operators shall define standardised market products for the services procured ensuring effective participation of all market participants including renewable energy sources, demand response and aggregators. Distribution system operators shall exchange all necessary information and coordinate with transmission system operators in order to ensure the optimal utilisation of resources, ensure the secure and efficient operation of the system and facilitate market development.

Distribution system operators shall be adequately remunerated for the procurement of such services in order to recover at least the corresponding expenses, including the necessary information and communication technologies expenses, including expenses which correspond to the necessary information and communication infrastructure.

2. The development of a distribution system shall be based on a transparent network development plan that distribution system operators shall submit every two years to the regulatory authority. The network development plan shall contain the planned investments for the next five to ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads including re-charging points for electric vehicles. The network development plan shall also demonstrate the use of demand response, energy efficiency, energy storage facilities or other resources that distribution system operator is using as an alternative to system expansion.

The regulatory authority shall consult all current or potential system users on the network development plan. The regulatory authority shall publish the result of the consultation process on the proposed investments.

Member States may decide not to apply this obligation to integrated undertakings serving less than 100 000 connected consumers, or serving isolated systems.

4.2.4 Solving the DSO–TSO Seams Issues for Congestion Management

Congestion management used to be about dealing with transmission constraints, basically ignoring distribution constraints. As some countries have already experienced, in the future managing distribution network constraints will be more important. This means that DSOs and TSOs will

need to cooperate for congestion management. As discussed for TSOs, there are basically two options. Applying these options to distribution grids, however, is more challenging than for transmission grids.

The first option is to let the market clear without anticipating the distribution constraints and to take out-of-the-market actions in case congestion occurs. This is what TSOs do when congestion occurs within a bidding zone, and this is what DSOs could do in their networks. Here, one question is, who will do what exactly? Will the DSO only signal the congestion or also do the re-dispatching to remedy this congestion? In any case, there will be a competing demand for flexibility from the distribution as well as the transmission level, so it is important that both levels coordinate the procurement as well as the activation of that flexibility. In this regard, some DSOs have proposed a traffic light system to coordinate with TSOs (see Box 4.5).

BOX 4.5 TRAFFIC LIGHT SYSTEM

This is an abstract from the ANNEX of EG3 Report on EU SMART GRID TASK FORCE (2015).

The use of flexibility for mitigating constraints in distribution networks will, in fact, represent a new approach, next to traditional grid expansion, and as such may lead to more optimal grid expenditure. It is important, however, that the interaction between DSOs and markets on how and when to procure flexibility for this purpose, is well defined, so as to enable efficient and transparent market competition.

Network congestion problems should be addressed with non-discriminatory market-based solutions which give efficient economic signals to the market participants and distribution system operators involved.

Definition of system states in the distribution networks is thus key to providing transparency about grid constraints to the market and the creation of flexibility products.

In this respect, the Traffic Light Concept could be a promising starting point, which could be further developed and experimented in Europe.

It is defined as a concept in which three grid states are identified (green/amber/red) and forms the basis for the definition and implementation of grid state-dependent market rules, which are required for a transparent communication between the smart grid and smart markets in case of grid constraints in distribution networks.

The development of this approach should enable flexible national solutions. However, to make it a more universal approach throughout Europe, stronger efforts and guidance are needed to define interactions between markets and grids – especially in the ‘amber phase’; in this way it contributes to the further development of the Internal European Energy Market.

…

The definition of the DSO–market interaction, related to the use of flexibility, is in its early stages.

In the process of further development of designing solutions to use flexibilities for mitigating grid constraints in distribution networks, the following steps should be considered. The grid–market interaction rules, corresponding to the green, amber and red system state, should be defined (for example, 'green' means the market is fully operating, no grid–market interaction; 'amber' signals to the market the request for flexibility to mitigate existing or predicted grid constraints; 'red' means there is an imminent grid stability/security of supply issue, which requires DSO intervention overriding market functioning). The objective of actions to be taken in the amber state would be to return as fast as possible to the green state and to reduce the number of anomalies in the red state, which are currently increasing as a result of further integration of renewables (as today the amber state does not exist).

These amber states should be made public in advance and must be clear for all market players; this is meant to avoid interference with market interests and market price developments. That is, the question of how to find a balance between transparency and consumer data privacy objectives must be addressed.

Define the relevant granularity of the grid network segments, for which grid status signals should be communicated to the market and how these status signals are communicated to the market (website, data, protocols, etc.).

DSOs should examine the possible use of flexibility for mitigating grid constraints, following technical and economic criteria, and NRAs should allow the DSO to contract with flexibility providers/aggregators for this purpose.

DSOs and TSOs define a non-discriminatory framework agreement for contracting flexibility from the market, including processes related to requesting, bidding, accepting, activation payment and settlement of flexibility.

Define the measurement methodology, as a basis for the payment and settlement process between the DSO and the flexibility provider/aggregator, as much as possible in line with existing procedures for balancing to avoid distortions.

Examine how gaming in the day-ahead market and other markets (requiring DSO to procure flexibility for non-existing loads) can be avoided.

Investigate how the coordination of TSOs and DSOs should be arranged when accessing the same flexibility products for different purposes. This requires the definition of clear principles and well-aligned processes to minimise costs.

Another question is how the costs will be allocated. TSO re-dispatching costs are shared among all its customers, while the origin of the congestion might well be in another control zone. The same is already happening with DSOs; they will be expected to share the costs among their customers, even if the origin of the congestion is at the TSO level.

The experience at TSO level is also that traders can easily exploit such a system with re-dispatching (see Box 4.2 about the experience in California). As market power at local level is going to be even more significant than at national level, this is also likely to be an issue for DSOs, which argues in favour of the second option.

The second option is to let the market split into price zones when congestion occurs. This is what TSOs do on the border between countries and also increasingly within countries that already have several bidding zones. In total, at the time of writing there are about 50 bidding zones in Europe, but there are 10 000 interconnection points between transmission and distribution grids. If every DSO connection point would become a price zone, this would imply a significant increase in the number of bidding zones. Still, it would be a first step towards a market solution for congestion in distribution grids. At the extreme, one could even consider nodal pricing for distribution grids, which is already a subject of academic papers but far from being considered in practice.

4.3 DSO–TSO SYSTEM BALANCING

In this section, we start by underlining the importance of system balancing. We then take stock of the conventional approach to balancing management in transmission and distribution grids. We close the section by discussing the seams issues between DSOs and TSOs and how to overcome them.

4.3.1 Importance of System Balancing

As it is too expensive to store electricity, the power system has been designed to balance consumption and production instantly. Customers have a supply contract that stipulates a price, but there is no floor or cap on the volume. They can therefore consume whatever they want at whatever time; the power system has been designed to be able to follow the demand. Generation units were typically large-scale power plants that were highly reliable. Except for annual maintenance, and the occasional unannounced outage, power plants were either running or on standby to start running when consumption increased. However, with the integration into the power system of variable renewable energy sources such as wind and solar, the balancing paradigm has changed. The power system is becoming increasingly distributed, unpredictable and inflexible, with more and more bi-directional power flows. As a result, demand will increasingly

follow supply instead of the opposite, and the need for flexibility will increase as the overall system becomes more sensitive to weather patterns.

Wholesale markets are used by suppliers to procure what they think their customers will want to consume, and by producers that offer what they think they can produce. Many market parties have their own customers and production assets and use wholesale markets to fine-tune their portfolio. Traders create additional liquidity by trading between locations and time zones to level out arbitrage opportunities. However, when we move closer to real-time, the TSO takes over and makes sure that the system remains balanced, even if market parties deviate from their wholesale market commitments.

Typically, many market parties will be unbalanced in real-time – some imbalances will be positive, some will be negative, and depending on the direction of the system imbalance, they cause or help solve the system imbalance. The TSO reserves balancing services ahead of real-time and also pays for activating them in real-time. The reservation costs are typically shared among all market parties; the activation costs are typically allocated to the market parties that cause the system imbalance. TSOs need services that can respond instantly, as well as services that can endure; there is often a trade-off between these characteristics.

4.3.2 Conventional Balancing Approach for Transmission

There are several synchronous zones in Europe, including Ireland, Great Britain, Scandinavia and the European continent.[3] Synchronous zones operate as a single system, with a single frequency. The TSOs in the same synchronous zone have to collaborate to balance the system; if not, the imbalance caused by one of them could black out the whole system. In 2006, this almost happened after a problem that started in Germany led to a cascading of power lines that disconnected because they were overloaded and power plants that disconnected from the system to protect themselves against large frequency deviations. Note that some incidents can be avoided by improved collaboration, while others cannot as the system will never be 100 per cent secured. It is also important to mention that the collaboration between TSOs had already been institutionalized before the liberalization process started. They already collaborated for technical reasons; with the introduction of markets, the scope of collaboration increased significantly.

The conventional approach among TSOs on the continent is that when something happens, the initial response (i.e. frequency containment) is

a joint response. TSOs contribute to this joint response in proportion to the size of their control zone. By pooling their efforts, each TSO has to buy fewer services than they would otherwise have to buy to insure themselves against the loss of a large power unit. The size of the insurance has been determined based on the largest power plant in the system, which is a nuclear unit in France. For the initial response TSOs have to reserve expensive fast-response services, which are then replaced by other services that are used to restore the system balance (i.e. frequency restoration). The restoration of the balance is the responsibility of the TSO where the problem started.

TSOs mainly procure balancing services domestically. There is typically no coordination beyond the initial response to a system frequency deviation. As a result, it often happens that one TSO is activating services to solve a negative imbalance, while the neighbouring TSO at the same time is doing the same for a positive imbalance. If they were to coordinate, they would only need to balance the difference between the two. In addition, they could procure the necessary services together so they could share flexibility resources across borders. The Nordic TSOs have been the first to organize a cross-border balancing market in 2002, and this is now also high on the EU agenda.

Most TSOs are now involved in pilot projects to explore the costs and benefits of cross-border balancing cooperation. The third EU liberalization package has also foreseen the development of network codes for balancing, which was adopted on 23 November 2017. It envisages the development of European platforms for the exchange of balancing energy for replacement reserves, frequency restoration reserves with manual activation, frequency restoration reserves with automatic activation, and imbalance netting (see Box 4.6).

BOX 4.6 COMMISSION REGULATION (EU) 2017/2195 ON ESTABLISHING A GUIDELINE FOR ELECTRICITY BALANCING – CHAPTER 2 EUROPEAN PLATFORMS FOR THE EXCHANGE OF BALANCING ENERGY

Article 19 European platform for the exchange of balancing energy from replacement reserves

1. By six months after entry into force of this Regulation, all TSOs performing the replacement reserve process pursuant to Part IV of Commission Regulation (EU) 2017/1485 shall develop a proposal for the implementation framework for a European platform for the exchange of balancing energy from replacement reserves.

…

Article 20 European platform for the exchange of balancing energy from frequency restoration reserves with manual activation

1. By one year after entry into force of this Regulation, all TSOs shall develop a proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation.

…

Article 21 European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation

1. By one year after entry into force of this Regulation, all TSOs shall develop a proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation.

…

Article 22 European platform for imbalance netting process

1. By six month after entry into force of this Regulation, all TSOs shall develop a proposal for the implementation framework for a European platform for the imbalance netting process.

4.3.3 Conventional Balancing Approach for Distribution

TSOs procured balancing services among only the customers connected to transmission grids, typically large power plants and large industrial customers with flexibility. Flexibility providers connected to distribution grids were often not able to participate in these markets, or only in principle but not in practice because of the service requirements. A typical example is that service providers had to provide several MWs to be allowed to participate in balancing markets, while flexibility at distribution level is typically more small-scale, even after aggregating the resources of several customers.

With the integration of renewable energy sources into the power system, the balancing paradigm is changing. The idea is that demand will increasingly follow supply instead of the opposite, and the need for flexibility will increase as the overall system becomes more sensitive to weather patterns. Moreover, the system is decentralizing, so not involving the distributed energy resources in the balancing of the system is not an option, and TSOs have already taken steps to open balancing markets to flexibility providers connected to distribution grids. Note that this is especially important to allow demand-response solutions to compete on an equal footing with the traditional supply-side solutions. The EU Clean Energy Package includes an EU Directive with provisions to make sure

that TSOs and DSOs open up to demand response solutions (see Box 4.7). This is a positive evolution, but it creates additional seams issues between DSOs and TSOs which they will have to deal with over time.

BOX 4.7 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 17 DEMAND RESPONSE

1. Member States shall ensure that national regulatory authorities encourage final customers, including those offering demand response through aggregators, to participate alongside generators in a non-discriminatory manner in all organised markets.
2. Member States shall ensure that transmission system operators and distribution system operators when procuring ancillary services, treat demand response providers, including independent aggregators, in a non-discriminatory manner, on the basis of their technical capabilities.
3. Member States shall ensure that their regulatory framework encourages the participation of aggregators in the retail market and that it contains at least the following elements:
   (a) the right for each aggregator to enter the market without consent from other market participants;
   (b) transparent rules clearly assigning roles and responsibilities to all market participants;
   (c) transparent rules and procedures for data exchange between market participants that ensure easy access to data on equal and non-discriminatory terms while fully protecting commercial data;
   (d) aggregators shall not be required to pay compensation to suppliers or generators;
   (e) a conflict resolution mechanism between market participants.
4. In order to ensure that balancing costs and benefits induced by aggregators are fairly assigned to market participants, Member States may exceptionally allow compensation payments between aggregators and balancing responsible parties. Such compensation payments must be limited to situations where one market participant induces imbalances to another market participant resulting in a financial cost.

   Such exceptional compensation payments shall be subject to approval by the national regulatory authorities and monitored by the Agency.
5. Member States shall ensure access to and foster participation of demand response, including through independent aggregators in all organised markets. Member States shall ensure that national regulatory

> authorities or, where their national legal system so requires, transmission system operators and distribution system operators in close cooperation with demand service providers and final customers define technical modalities for participation of demand response in these markets on the basis of the technical requirements of these markets and the capabilities of demand response. Such specifications shall include the participation of aggregators.

4.3.4 Solving the DSO–TSO Seams Issues for System Balancing

We have already discussed system balancing among TSOs, but what if DSOs get involved? Their involvement has become unavoidable as TSOs start to procure flexibility connected to distribution grids. There are basically two options for involving DSOs in system balancing, which we discuss below.

The first option is that balancing responsibility stays with TSOs. Even if this is the case, DSOs will need to be involved in the prequalification of flexibility connected to their grid. If DSOs also start to re-dispatch the system to manage the congestion in their grids, they will sometimes overrule the balancing actions of TSOs, which means that they are de facto also balancing the system together with TSOs. The alternative is that DSOs only signal congestion in their distribution grids and that the TSOs are then responsible for doing the re-dispatching.

The second option is that DSOs and TSOs share the balancing responsibility of a control zone. At the extreme, DSOs could become fully responsible for balancing. The risk is that we lose economies of scale, but the possible advantage is that we place the responsibility where the problems that arise will need to be solved anyway. This would be the case if in the future network constraints at distribution level become more prominent than at transmission level. Just like TSOs do today when the network allows, DSOs could also organize joint balancing markets with other DSOs and TSOs to capture economies of scale. In such a market, it would be up to the TSOs to signal to DSOs congestion in the transmission grid. For many practitioners, this is a theoretical option that only interests academics.

The Balancing network code approved in 2017 foresees cooperation between TSOs and DSOs (see Box 4.8). Yet neither the Third Package nor the proposal of the EU Clean Energy Package have foreseen the procurement of frequency ancillary services by DSOs.

BOX 4.8 COMMISSION REGULATION (EU) 2017/2195 ON ESTABLISHING A GUIDELINE FOR ELECTRICITY BALANCING – ARTICLE 15 COOPERATION WITH DSOs

TITLE II ELECTRICITY BALANCING MARKET

CHAPTER 1 FUNCTIONS AND RESPONSIBILITIES

Article 15 Cooperation with DSOs

1. DSOs, TSOs, balancing service providers and balance responsible parties shall cooperate to ensure efficient and effective balancing.
2. Each DSO shall provide, in due time, all necessary information to perform the imbalance settlement to the connecting TSO in accordance with the terms and conditions related to balancing pursuant to Article 18.
3. Each TSO may, together with the reserve connecting DSOs within the TSO's control area, jointly elaborate a methodology for allocating costs resulting from actions of DSOs pursuant to paragraphs 4 and 5 of Article 182 of Regulation (EU) 2017/1485.The methodology shall provide for a fair allocation of costs taking into account the responsibilities of the parties involved.
4. DSOs shall report to the connecting TSO any limits defined pursuant to paragraphs 4 and 5 of Article 182 of Regulation (EU) 2017/1485 that could affect the requirements set out in this Regulation.

4.4 DSO–TSO DATA MANAGEMENT

In this section, we start by underlining the importance of data management. We then take stock of the conventional approach to data management in transmission and distribution grids. We close the section by discussing the seams issues between DSOs and TSOs, and how to overcome them.

4.4.1 Importance of Data Management

As discussed in the previous section, the power system operators manage to keep the balance between supply and consumption with very limited storage. This requires highly advanced systems for congestion management and system balancing. To ensure cost-efficient, sustainable and reliable system operation, both TSOs and DSOs should rely not only

on sophisticated tools but also on a robust data management system. As we are heading towards a more digital energy system future, data management and exchange have become indispensable for the proper functioning of the power system.

4.4.2 Conventional Data Management Approach for Transmission

TSOs have always carefully monitored and metered the customers connected to their grids with advanced technology. Besides monitoring what happens in real-time, TSOs collect market data ahead of real-time to be able to anticipate what will happen and take action. Market parties are typically obliged to share (commercially sensitive) information with the operators so that they can perform these tasks. As part of their transmission grid planning responsibility, the operators are also tasked with studying possible scenarios for the future and to derive the need for grid investments from these scenarios.

Since 2015, the ENTSO-E Transparency Platform has been established to comply with the EU Transparency Regulation (see Box 4.9). The platform includes information about the load of the system, generation, prices in each of the bidding zones, balancing prices, balancing positions of control zones, availability of transmission capacity, etc.

BOX 4.9 COMMISSION REGULATION (EU) NO 543/2013 OF 14 JUNE 2013 ON SUBMISSION AND PUBLICATION OF DATA IN ELECTRICITY MARKETS – ARTICLE 3 ESTABLISHMENT OF A CENTRAL INFORMATION TRANSPARENCY PLATFORM

1. A central information transparency platform shall be established and operated in an efficient and cost-effective manner within the European Network of Transmission System Operators for Electricity (the 'ENTSO for Electricity'). The ENTSO for Electricity shall publish on the central information transparency platform all data which TSOs are required to submit to the ENTSO for Electricity in accordance with this Regulation.

   The central information transparency platform shall be available to the public free of charge through the internet and shall be available at least in English.

   The data shall be up to date, easily accessible, downloadable and available for at least five years. Data updates shall be time-stamped, archived and made available to the public.

2. The ENTSO for Electricity shall submit a proposal concerning the operation of the central information transparency platform and the associated costs to the Agency for the Cooperation of Energy Regulators (the Agency) four months after entry into force of this Regulation. The Agency shall provide its opinion within three months from the date of submission of the proposal.
3. The ENTSO for Electricity shall ensure that the central information transparency platform is operational 18 months after the entry into force of this Regulation.

4.4.3 Conventional Data Management Approach for Distribution

Distribution grids used to be developed in line with a 'fit and forget' philosophy. DSOs therefore only recently started to carefully monitor and meter the customers connected to their grids. This was also encouraged by the EU target to equip 80 per cent of its citizens with smart meters by 2020, which corresponds to 200 million smart meters. The target is not binding, but countries are expected to do a smart meter roll-out unless they can demonstrate with a cost–benefit analysis that this is not opportune for them.

In most countries, DSOs are responsible for this roll-out. In addition to smart meters, distribution grids are smartening, which often implies that more data are collected on the state of the grid, which then also need to be managed. As DSOs are increasingly involved in congestion management and system balancing, they also need these data for their own use.

DSOs also have a facilitating role in data management with a focus on retail markets. They have typically been involved in the process to switch from one retailer to another. Third-party access to retail customer data is increasingly discussed. New entrants often lack the customer data they need to come up with innovative ways to approach costumers. Making these data available in aggregated form is striking a balance between promoting competition and innovation and protecting customer privacy.

With the introduction of smarter meters, more data are being collected, so the debate around how those data need to be managed is picking up in many countries. The new EU legislative initiatives included in the 2016 Clean Energy Package include an EU Directive with provisions on smart meter functionalities that are data related (see Box 4.10).

BOX 4.10 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 20 SMART METERING FUNCTIONALITIES

Where smart metering is positively assessed as a result of cost–benefit assessment referred to in Article 19(2), or systematically rolled out, Member States shall implement smart metering systems in accordance with European standards, the provisions in Annex III, and in line with the following principles:

(a) the metering systems accurately measure actual electricity consumption and provide to final customers information on actual time of use. That information shall be made easily available and visualised to final customers at no additional cost and at near-real time in order to support automated energy efficiency programmes, demand response and other services;
(b) the security of the smart metering systems and data communication is ensured in compliance with relevant European Union security legislation having due regard of the best available techniques for ensuring the highest level of cyber security protection;
(c) the privacy and data protection of final customers is ensured in compliance with relevant Union data protection and privacy legislation;
(d) meter operators shall ensure that the meter or meters of active customers who self-generate electricity can account for electricity put into the grid from the active customers' premises;
(e) if final customers request it, metering data on their electricity input and off-take shall be made available to them, via a local standardised communication interface and/or remote access, or to a third party acting on their behalf, in an easily understandable format as provided for in Article 24, allowing them to compare deals on a like-for-like basis;
(f) appropriate advice and information shall be given to final customers at the time of installation of smart meters, in particular about their full potential with regard to meter reading management and the monitoring of energy consumption, and on the collection and processing of personal data in accordance with the applicable Union data protection legislation;
(g) smart metering systems shall enable final customers to be metered and settled at the same time resolution as the imbalance period in the national market.

4.4.4 Solving the DSO–TSO Seams Issues for Data Management

The new EU legislative initiatives included in the 2016 Clean Energy Package include an EU Directive with provisions on data management

and data formats (see Box 4.11). It ensures that customers, suppliers, TSOs and DSOs, aggregators, energy service companies and other parties which provide energy or other services to customers have access to data, but it does not prescribe how this is organized.

Some countries have already taken action by assigning the role of a data hub operator to one of the players. In Belgium, France, Austria and the Netherlands, the DSOs have taken data hub initiatives. In the Nordic countries, conversely, the role has been assigned to the TSOs. In Italy and the UK, the role was picked up by a third party, which in the case of the UK was the winner of a tender procedure, i.e. the UK Data Communications Company.

The TSO–DSO data management report by the industry associations[4] also clearly states where DSOs and TSOs agree and where they agree to disagree. Of course, both want to play the data hub operator role. In the digital world of the future, the one that operates the data might also orchestrate the system.

But before we can decide how to manage the data, we still need to decide who will play what role for congestion management and system balancing. As illustrated in this chapter, the EU Clean Energy Package sets the scene for the discussion going forward because TSO–DSO seams issues are the core of the debate in Brussels.

BOX 4.11 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLES 23 AND 24 DATA MANAGEMENT AND FORMAT

Article 23 Data management

1. When setting up the rules regarding the management and exchange of data, Member States or, where a Member State has so provided, the designated competent authorities shall specify the eligible parties which may have access to data of the final customer with their explicit consent in accordance with Regulation (EU) 2016/679. For the purpose of this Directive, data shall include metering and consumption data as well as data required for consumer switching. Eligible parties shall include at least customers, suppliers, transmission and distribution system operators, aggregators, energy service companies, and other parties which provide energy or other services to customers.
2. Member States shall organise the management of data in order to ensure efficient data access and exchange. Independently of the

data management model applied in each Member State, the party or parties responsible for data management shall provide to any eligible party with the explicit consent of the final customer, access to the data of the final customer. Eligible parties should have at their disposal in a non-discriminatory manner and simultaneously the requested data. Access to data shall be easy, while relevant procedures shall be made publicly available.

3. Member States or, where a Member State has so provided, the designated competent authorities shall authorise and certify the parties which are managing data in order to ensure that these parties comply with the requirements of this Directive. Without prejudice to the tasks of the data protection officers under Regulation (EU) 2016/679, Member States may decide to require from parties managing data the appointment of compliance officers who shall be responsible for monitoring the implementation of measures taken by the relevant parties for ensuring non-discriminatory access to data and compliance with the requirements of this Directive. Compliance officers or bodies designated pursuant Article 35(2)(d) may be required to fulfil the obligations of this paragraph.

Article 24 Data format

1. Member States shall define a common data format and a transparent procedure for eligible parties to have access to the data listed under paragraph 1 of Article 23, in order to promote competition in the retail market and avoid excessive administrative costs for the eligible parties.
2. The Commission, by means of implementing acts adopted in accordance with the advisory procedure referred to in Article 68, shall determine a common European data format and non-discriminatory and transparent procedures for accessing the data, listed under paragraph 1 of Article 23, that will replace national data format and procedure adopted by Member States in accordance with paragraph 1. Member States shall ensure that market participants apply a common European data format.
3. No additional costs shall be charged to final customers for access to their data. Member States shall be responsible for setting the relevant costs for access to data by eligible parties. Regulated entities which provide data services shall not profit from that activity.

4.5 CONCLUSION

As the role of DSOs is expected to change from a passive to active distribution grid system operation, the seams issues between TSOs and DSOs will become increasingly evident. The three important areas where such

issues could arise are congestion management, system balancing and data management. As a result, the need for DSO–TSO cooperation has become essential – as highlighted in the 2016 EU Clean Energy Package.

The extent and nature of DSO–TSO cooperation will depend on who assumes the roles of congestion management and balancing at the distribution level in the future. This in turn determines how data are managed. There seems to be a general trend that the system balancing role will continue to be the responsibility of the TSOs while DSOs will actively manage the congestions in their grids through congestion pricing systems, re-dispatching and/or curtailing. In this case, the actions of the DSOs could interfere with the balancing needs of the TSOs, especially when both start competing for local flexibility resources to execute their respective roles. Similarly, the actions of the TSO to source flexibility from service providers connected to the distribution grids could interfere with the active network management of the DSO. This calls for network codes that ensure seamless DSO–TSO cooperation, drawing lessons from the existing experiences and the network codes that have been entered into force with the aim of enhancing inter-TSO cooperation.

NOTES

1. Many of the facts and figures in this section are based on the Eurelectric paper by the DSO task force published in 2013, 'Power distribution in Europe', which used data from 2011. There is no update available.
2. See Commission regulation (EU) 2015/1222 of 24 July 2015 on establishing a guideline on capacity allocation and congestion management.
3. The European continent includes all continental EU countries, except the Baltic countries that are still connected to the Russian power system.
4. https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_TSO-DSO_DMR_web.pdf

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PART 3

Grey areas: the border between the market and the grid

5. Classical grey areas since the start of the internal market

Leonardo Meeus and Pradyumna Bhagwat

In this chapter we explore the border between the grid and the market by revisiting three power system debates. The first debate is about grid ownership. Should system operators own the grid they operate or can grid investment become a market activity? The second debate is about market operation. Is it a natural extension of system operation and therefore a monopoly activity, or is it an activity that should be opened to competition? The third debate is about energy storage. Is it an asset that only market parties should be allowed to invest in, or can it also be considered as a transmission and distribution asset that system operators can invest in as part of their monopoly activity? These three debates are the classical grey areas in regulation that have been discussed since the start of the liberalization process.

5.1 GRID OWNERSHIP

In this section, we discuss grid ownership as a classical grey area in regulation. The question is whether system operators should own the grid they operate or whether grid investment can become a market activity that is open to competition. We explore the arguments for and against market-based grid investment and illustrate how regulators have flirted with the border between the market and the grid by partially enabling competition for grid ownership. In the third part of this section we discuss local energy communities.

5.1.1 Arguments For and Against Market-based Grid Investment

Essentially, the debate is whether the grid is a natural monopoly or not. Natural monopolies occur in industries with positive economies of scale that can be captured fully only by a single firm. The whole power system

used to be considered as a natural monopoly, which justified the presence of vertically integrated utilities that operated as monopolies in a certain geographical area. Economics textbooks of the previous century also referred to power systems as an example of a natural monopoly industry. Initially, the industry trend was indeed to rely on increasingly larger-scale power plants based on nuclear and coal.

However, the industry evolved. Smaller-scale power plants burning natural gas started to come online, a trend that accelerated with the shift towards renewable energy resources. The demand for power also increased with the electrification of our modern society, and as a result the size of the production units relative to the total demand decreased. That was why we were able to introduce wholesale markets for electricity with market-based investments in power plants. The idea was that the market was big enough to have several competing players that could be sufficiently large to capture the economies of scale. This is true if the relevant market is Europe rather than the national level, which is why the internal market integration process is so important.

The transmission and distribution grids, on the contrary, continue to be considered as natural monopolies. There are many operators, but each has a monopoly within a certain geographical area (and for a certain period that can be renewed). This monopoly is granted to them by national legislation, which is typically the case for transmission grids, or by concessions that are allocated by local governments, which is typically the case for distribution grids. It could indeed be expensive to have competing transmission and distribution grids within a particular area, as it is much cheaper to have one line instead of two parallel lines with the same total capacity. This, then, argues against market-based grid investments. However, this is true only to the extent that these benefits of having a monopoly do not outweigh the costs. Monopoly costs include lack of innovation and cost inefficiencies due to imperfect regulation, and we know that regulation is imperfect by definition due to information asymmetries between the regulator and the regulated company.

The natural monopoly is often used to justify monopolies in certain industries, while history teaches us that we should continue to challenge that assumption. Paul Joskow says:

> Going back to the late 19th century, we can construct a long list of goods and services that have been subject to price and/or entry regulation (oil, natural gas production, oil and natural gas pipeline transportation, telecommunications services, surface freight transportation, electricity supplies, interest rates, bus and street car services, water and sewer services, taxi

prices, milk prices, residential rents, etc.); one does not have to be too much of a free market advocate to find the natural monopoly argument for many of these goods and services to be implausible. (Joskow 2009)

5.1.2 How Have Regulators Partly Opened the Market for Grid Investments?

There are many ways to open the market for grid investments partly and regulators in Europe have experimented with all of them. In what follows, we discuss market-based outsourcing of grid investments, independent system operators (ISOs) and the competition for border investments.

The first approach is the market-based outsourcing of grid investments. To build their grids, system operators rely on suppliers of power system equipment. These suppliers are global players that not only deliver the equipment but can also take care of the engineering and the construction. To the extent that system operators outsource their monopoly tasks to market parties on a level playing field, they in a way self-regulate their monopoly. Regulation typically interferes with outsourcing only by ensuring that the procurement process is market-based. The level of outsourcing among the operators is very different across Europe. Some operators are simply too small to manage their monopoly, which can also be a reason to outsource, and this is particularly the case at the distribution level.

The second approach is to go for an ISO. The idea is to split the operation of the grid from the ownership (step 1) and then to break the grid ownership monopoly (step 2). There is much experience with the first step, but less with the second. In the first step, a lot of new seams issues arise between the ISO and the transmission owners of the grid and they need to be managed carefully. The biggest issue is who is responsible for the reliability of the system; the trend is to give more responsibility to the ISOs. In the second step, third parties need to be able to challenge the incumbent transmission owners. This is done by assigning an investment planning role to the ISO. If the ISO then also organizes tenders for the ownership of the project, third parties can enter the business. In the USA, transmission owners have often received a ‘first right of refusal’, which has allowed them to maintain their monopolies, even though the Federal Energy Regulatory Commission continues to challenge this. Box 5.1 shows an academic debate around ISO versus TSO.

BOX 5.1 ISO MODEL VERSUS TSO MODEL

The academic debate was led by William Hogan from Harvard and Paul Joskow from MIT.

Professor Hogan argued in favour of the ISO model, which is the dominant model in the USA. It relieves the conflict of interest between transmission owners (increasing CAPEX to increase profits) and system operators (investing only if the benefits to society outweigh the costs). In an independent transmission system operator (ITSO) model, this can in theory also be dealt with by moving from RAB-based remuneration towards output regulation. ISOs have no particular interest in certain infrastructure. ISOs in the USA have a good track record in organizing and designing markets. However, this can also be done through an ITSO.

Professor Joskow argued in favour of the TSO model, which is the dominant model in the EU. The additional interface between the transmission owner and system operators can create coordination problems. TSOs can be incentivized with performance-based regulation, but this is not possible for ISOs as they are asset light. ISOs in the USA do not have such a good track record in investment planning and implementation. However, this can be addressed by giving the ISO more planning responsibilities.

The work of Professor Michael Pollitt from the Cambridge Judge Business School provides a detailed account of the experience with ISOs around the world.[1]

The third approach is to introduce competition for border investments. As we discussed in previous chapters, one of the main challenges for regulation in Europe has been that there is one system, one market, but many operators and regulatory authorities. By introducing competition for grid investments, we are adding complexity. In addition to the many operators, third parties are then able to enter the business. To reduce this complexity, regulators in Europe have often introduced competition at the borders between system operators, or at the borders between the operators and their clients. An example of the first type of border investments is an international investment. The UK and, more recently, Norway have limited the monopoly of their transmission system operator to investments within the country, introducing competition for interconnections. An example of the second type of border investments is the connection of new users. The UK and Ireland are experimenting with competition for the connection of new users to distribution grids. Of course, introducing competition at the border still means there are more issues to manage, but the seam was already there.

Note, finally, that 'competition' in power grids is about reducing the barriers for third parties to enter the business rather than about reducing price regulation. Only in exceptional cases do market prices allow investors to make a business case. In most instances, price regulation is about ensuring an income for the investor rather than about capping the profits. Grids are typically oversized because the assets are lumpy and because of the redundancy the system needs to be reliable. As a consequence, market prices and the resulting congestion revenues are typically not enough to cover the investment. Exceptional cases are at the borders between system operators and regulatory authorities, where seams issues have sometimes led to underinvestment. In these cases, merchant investors have been subject to price regulation to cap their profits (see Box 5.2).

BOX 5.2 MERCHANT PROJECTS[2]

The first international submarine electricity cable to receive a merchant exemption in Europe was the Estlink project between Estonia and Finland. It is the result of a joint venture by five energy companies operating in Finland and the Baltic states. This 350 MW HVDC project, which began operation in 2006, includes approximately 100 km of transmission cable and has an estimated cost of €110 million.

Estlink is owned by Nordic Energy Link, which was founded by three Baltic energy companies – Eesti Energia (39.9 per cent of shares), Latvenergo (25 per cent) and Lietuvos Energija (25 per cent) – and two Finnish energy companies – Pohjolan Voima and Helsingin Energia (together 10.1 per cent). The costs are borne by these project sponsors, who in turn have priority access to the transmission rights.

The second international submarine electricity cable to receive a merchant exemption in Europe was the BritNed project between the UK and the Netherlands. It was developed by a company that is jointly owned by the TSOs in those nations. This 1000 MW HVDC project includes approximately 260 km of subsea cable and has an estimated cost of €600 million. The project has been in operation since 2010 and the costs are recovered through the sale of transmission rights.

The Estlink exemption was limited in time. In November 2013, the ownership of Estlink I was sold to the TSOs Fingrid and Elering.[3] The BritNed exemption includes a cap on the profits that can be generated by the project.

5.1.3 Local Energy Communities

The development of local energy communities (LECs) that participate in the management of the electricity that they generate and consume has the ability to transform the electricity system. Such communities may not even need to be connected to a distribution network and may become self-sufficient in all aspects.

The EU Clean Energy Package recognizes local energy communities as a critical enabler for encouraging the involvement of the individual in the development of the electricity sector. The proposal states that 'local energy communities can be an efficient way of managing energy at community level by consuming the electricity they generate either directly for power or for (district) heating and cooling, with or without a connection to distribution systems'. Furthermore, it is made incumbent on the Member States to ensure implementation of legal frameworks that would enable the development of such initiatives.

Article 16 in Chapter III (Consumer Empowerment and Protection) of the Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast) deals with local energy communities (see Box 5.3).

BOX 5.3 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 16 LOCAL ENERGY COMMUNITIES

Article 16 Local Energy Communities

1. Member States shall ensure that local energy communities:
   (a) are entitled to own, establish, or lease community networks and to autonomously manage them;
   (b) can access all organised markets either directly or through aggregators or suppliers in a non-discriminatory manner;
   (c) benefit from a non-discriminatory treatment with regard to their activities, rights and obligations as final customers, generators, distribution system operators or aggregators;
   (d) are subject to fair, proportionate and transparent procedures and cost-reflective charges;
   (e) where relevant, may conclude agreements with the distribution system operator to which their network is connected on the operation of the community network.

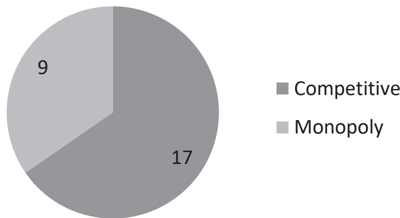
2. Member States shall provide an enabling regulatory framework that ensures that:
   (a) participation in a local energy community is voluntary;
   (b) shareholders or members of a local energy community shall not lose their rights as household customers or active customers;
   (c) shareholders or members are allowed to leave a local energy community; in such cases Article 12 shall apply;
   (d) Article 8 paragraph 3 applies to generating capacity installed by local energy communities as long as such capacity can be considered small decentralised or distributed generation;
   (e) provisions of Chapter IV apply to local energy communities that perform activities of a distribution system operator;
   (f) where relevant, a local energy community may conclude an agreement with a distribution system operator to which their network is connected on the operation of the local energy community's network;
   (g) where relevant, system users who are not shareholders or members of the local energy community connected to the distribution network operated by a local energy community shall be subject to fair and cost-reflective network charges. If such system users and local energy communities cannot reach an agreement on network charges, both parties may request the regulatory authority to determine the level of network charges in a relevant decision;
   (h) where relevant, local energy communities are subject to appropriate network charges at the connection points between the community network and the distribution network outside the energy community. Such network charges shall account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the local energy community in line with Article 59 paragraph 8.

Although LECs can be considered as enablers for greater consumer participation, some issues still exist that require further clarification. A key question that needs greater clarity regarding LECs is that of benefit distribution. How is it possible to ensure a fair benefit distribution (network charges and policy costs) between the DSO-connected customers and the LECs in the presence of a micro-grid or a parallel infrastructure?

5.2 MARKET OPERATION

In this section, we discuss market operation as a classical grey area in regulation. The question is whether the market operation is a natural extension of system operation and therefore a monopoly activity or an activity that should be opened to competition.

Monopoly (cost-of-service regulated) power exchanges can be described as not-for-profit or regulated-profit institutions that receive an income through regulated fees. These can be established by a public initiative (e.g. OMEL in Spain) or by the TSO (e.g. HUPX in Hungary). Merchant power exchanges are for-profit market institutions whose core business is to provide trading services. The income of these exchanges depends on various user fees and is linked to the volume of trades executed by the power exchange for its users. Examples of merchant power exchanges are EPEX Spot (covering Germany, France, the UK, the Netherlands, Belgium, Austria, Switzerland and Luxembourg) and Nord Pool AS. Historically, merchants were set up by market parties, financial market institutions, TSOs or a combination of private actors. Figure 5.1 illustrates the status of the market operators in the EU (excluding Cyprus and Malta). It is observed that 17 have a competitive status while 9 are monopolies. In most countries, power exchanges are a competitive activity; however, in nine countries (including Italy and Spain) they have a monopoly status. In Box 5.4 nominated electricity market operators are discussed in greater detail.



Source: Based on ACER (2015).[4]

Figure 5.1 Status of market operators in the EU (excluding Cyprus and Malta)

We start by discussing the arguments for and against merchant market operators and close the section by illustrating how regulators have partly opened the market for market operation.

BOX 5.4 NOMINATED ELECTRICITY MARKET OPERATORS (NEMOs)

Power exchanges traditionally collected and matched bids and offers within different time frames within a certain bidding zone. More recently, power exchanges are increasingly organizing trade between zones, which traditionally

has been the territory of the over-the-counter (OTC) electricity trading business in Europe (Meeus, 2011). As such, today power exchanges allocate cross-zonal capacity for different bidding zones simultaneously while clearing the energy bids and offers. The rules for the trading of electricity require an institutional framework for power exchanges which is provided by the Capacity Allocation and Congestion Management Guidelines (CACM GL). In the CACM GL, common requirements for the designation of NEMOs[5] and their tasks are outlined. In short, NEMOs can be seen as power exchanges certified to perform market coupling.[6]

In the CACM GL, it is stated that each Member State (MS) shall ensure to designate at least one NEMO in its territory (CACM, Art. 4(1,2)). However, if in an MS a national legal monopoly is in place by the time the CACM GL enters into force, that MS may refuse the designation of more than one NEMO per bidding zone (CACM, Art. 5(1)). In the majority of countries only one NEMO is active, and in most cases the regulator is in charge of the designation.

A NEMO can be designed for trading services in the day-ahead market, the intraday market or both. Today all designated NEMOs offer services in both markets.[7] NEMOs designated in an MS have the right to offer trading services with delivery in another MS without the need for designation as a NEMO in that Member State, but with exemptions. These exemptions are summed up in Art. 4(6) of the CACM GL.

The CACM, Art. 7(1) articulates the following tasks for the NEMOs: 1) to receive orders from market participants; 2) to assume overall responsibility for matching and allocating orders based on the results from single day-ahead and intraday coupling; 3) to publish prices; 4) to settle and clear contracts resulting from trades according to relevant participant agreements and regulations. Also, according to Art. 41, ‘All NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonized maximum and minimum clearing prices to be applied in all bidding zones which participate in the single day-ahead coupling.’ A proposal shall be made for the day-ahead market (DAM) and another for the intra-day market (IDM). NEMOs shall carry out market coupling operator (MCO) functions jointly with other NEMOs; for this purpose also a close collaboration with coordinated capacity calculators (CCCs)[8] is required.

The CACM GL leaves it open as to whether NEMOs should be a monopoly or competitive activity. However, in the spirit of the code, a preference for NEMOs as a competitive activity can be detected. Namely, it is stated in CAMC, Art. 5(2) that ‘For the purposes of this regulation, a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services.’

However, Art. 5(3) states that ‘if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another Member State, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States.’ Furthermore, in the same article, it is stated that ‘if the Commission deems that there is

ambiguity in carrying out the monopolistic MCO functions and other NEMO tasks, the Commission may consider appropriate legislative or other appropriate measures to further increase transparency and efficient functioning of single day-ahead and intraday coupling'.

5.2.1 Arguments For and Against Merchant Market Operators[9]

Market operators oversee organized markets, such as stock exchanges and power exchanges. They typically attract only a fraction of the total trade for stocks or power, but they provide an important reference price for the trade that takes place outside of these organized markets. Exchanges are not natural monopolies (i.e. economies of scale in the cost structure), but they are monopolistic because of positive network effects. Liquidity indeed tends to attract more liquidity.

Cost-of-service regulated power exchanges have fewer incentives to abuse market power and act anti-competitively than merchant power exchanges, but they also have fewer incentives to provide an efficient trading service or to innovate in trading systems.

The market operation is, however, more contestable than grid operation because the sunk costs to enter into this activity are relatively limited. Furthermore, merchant power exchanges could be an attractive alternative bearing in mind the integration of electricity markets. While dealing with problems related to cross-zonal trade, the national regulatory authorities frequently do not have effective and independent powers to define and enforce the needed regulation at EU level. There could be a 'regulatory gap' created with cost-of-service regulated power exchanges. A merchant power exchange has a clear incentive to cooperate in the implementation of this model as it can generate significant additional trade volumes and thus income for the power exchange. However, robust transparency requirements and governance rules should be implemented to prevent the formation of cartels through the cooperation among the power exchanges.

5.2.2 How Regulators Have Partly Opened the Market for Market Operation

System operators are market facilitators, i.e. they make transmission capacity available to the market, provide data services and in some cases also operate (part of) the market. In Europe, the conventional approach

is that transmission system operators operate the balancing markets but they do not operate the wholesale markets.

First is the operation of balancing markets. TSOs are the single buyers of balancing services. They reserve frequency containment services as well as frequency restoration services to be able to balance the system in real-time. They typically do this by tendering for these services with yearly, monthly and daily contracts. They also settle the costs of the balancing actions with market parties that are unbalanced. Some of the costs, such as the reservation costs, are socialized via the transmission tariffs. In the UK, the regulatory authority has experimented with incentive regulation for this activity, but in most other countries the regulator simply allows the system operators to pass through these costs via the tariffs without giving incentives to reduce the costs. Note that the TSOs have limited control over these costs, which also limits the effect of incentives.

Second is the operation of wholesale markets. At the beginning of the liberalization process, every country had at least one power exchange that ran the day-ahead market. In some countries, such as the UK and Germany, there were several competing power exchanges. Some initiatives were joint ventures by market players; other initiatives were subsidiaries of financial market operators, or transmission system operators, or a combination of the latter. These power exchanges then typically also ventured into the operation of forward and intra-day markets. Some of the power exchanges are 'merchant', i.e. they freely determine the fees they charge to traders, including a membership fee and a fee on the volumes traded; others are price regulated. With the introduction of market coupling on all borders in Europe, the importance of power exchanges increased. Most of the capacity that is available to trade across borders is allocated via the spot markets organized by power exchanges. As a result, the governance of the spot markets is increasingly regulated via the network codes that have been introduced by the Third Liberalization Package.

5.3 ENERGY STORAGE

In this section, we discuss energy storage as a classical grey area in regulation. Energy storage is a pivotal enabling technology in energy transition. We start by highlighting the importance of energy storage. We then provide two regulatory perspectives on the debate. This is followed

by examples where regulators have exceptionally allowed system operators to invest in energy storage. We close this section by referring to the EU regulatory framework that has been proposed for storage.

5.3.1 The Importance of Energy Storage Assets

A power system based on renewable energy needs the flexibility to balance demand and supply. Ofgem defines flexibility as ‘modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price, or an electronic message) to provide a service within the energy system’ (Ofgem, 2015).

Storing electricity is one way of providing flexibility to the system. Electrical storage can be defined as any device that can store electrical energy and make it available when required. Therefore, it could be said that while ‘copper wires’ transmit electricity over geographical distances, storage transmits electricity across time.

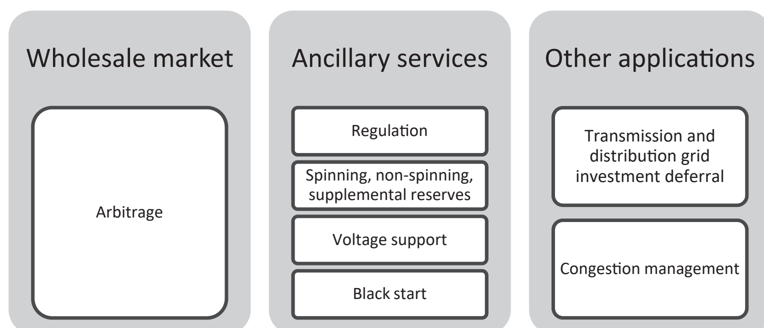
Several types of storage technologies have been proposed, tested and are being implemented. Guney and Tepe (2017) classify storage systems as chemical, electrochemical, electrical, mechanical and thermal. At the time of writing, pumped hydro, which is classified as mechanical storage, accounts for most of the storage capacity. This can be considered as a traditional storage technology as it has been around for a long time.

However, due to rapid innovation, large-scale batteries (also referred to as electrochemical storage devices) are only recently becoming economically viable. A significant growth in the battery storage installations in the EU has been observed since 2009.[10] The Association of European Automotive and Industrial Battery Manufacturers (EUROBAT) expects robust growth in storage capacity. EUROBAT projects that storage capacity, for utility-scale applications alone, will reach 14 GW by 2023 (EUROBAT, 2016).

Batteries have some unique characteristics that set them apart from the traditional storage resources. Unlike traditional technologies, these devices are modular and can be installed quickly. Hence, they are not constrained by location. Not only can batteries be installed at any location, they can also be moved to other locations as and when required, cost-effectively. This makes them an invaluable resource for providing location-specific services such as voltage control for distribution grids.

Batteries can participate in different segments of the electricity value chain (see 5.2). These devices can provide ancillary services and participate in the wholesale market (as both buyers and sellers) and can

also be used for congestion management. The ongoing energy transition requires a lot of investments in transmission and distribution grids. Managing grids smartly by using batteries and other potential sources of flexibility can defer some grid investments. Thus, the functional versatility of batteries truly makes them the 'jack of all trades'.



Source: Based on Kempener and Borden (2015).

Figure 5.2 Possible applications of utility-scale battery storage

However, this functional versatility of batteries also makes it extremely difficult to define them in the current regulatory framework. Innovation in battery technology has reignited the debate about who will master this jack of all trades. Different parts of the value chain want to invest in this technology, but should it be regulated as a production and consumption asset or as a grid asset, or both?

This is one of the key debates around the 'Clean energy for all Europeans' Package.[11] The proposal is that TSOs and DSOs can invest in energy storage only in exceptional circumstances.

Several industry associations came out with a position paper – see, for instance, the joint statement by CEDEC, EDSO for Smart Grids, GEODE and EUROBAT.[12] The European Parliament also called upon the European Commission to allow TSOs and DSOs to invest in storage, arguing that it should be considered as a separate asset class.[13] Others have expressed concerns that this would distort the market. In some countries, regulatory authorities have already allowed TSOs and DSOs to invest in energy storage (see Section 5.3.4).

In what follows, we provide two regulatory perspectives on this debate. The first is that of the wholesale and balancing market; the second

is that of location-specific grid services, such as voltage support and congestion management.

5.3.2 First Perspective: Balancing Services

At the beginning of the liberalization process, wholesale electricity markets were relatively quickly accepted, but balancing the system in real-time continued to be seen as a technical issue. Gradually it became clear that what happens in real-time determines how the market parties behave in wholesale markets. System balancing is not only technical, it is also the real-time market.

In a balancing market, the TSO is the single buyer of balancing services consisting of demand and/or supply resources that are available to respond in real-time to any signal variations in the system.[14] In some countries, TSOs are permitted to own assets (such as batteries) that could provide balancing services. This was, for instance, the case for pumped hydro storage, which is a valuable asset to balance the system and also to restore the system in case of a blackout. In this way, TSOs may mitigate any market power issues that could occur when the system is stressed.

However, if TSOs can own assets that can provide balancing services, how can they at the same time be a neutral market facilitator and single buyer of these services? TSOs can reserve balancing services by tendering for long-term contracts; they do not need to own the assets. In the case of pumped hydro, the asset will typically be used in wholesale markets as well as balancing markets, and market parties are better at optimizing the use of such a valuable resource across different markets. TSOs have been increasingly unbundled from holdings that were also active in market activities, and also have divested assets such as pumped hydro storage that could provide balancing services.

The power system is becoming increasingly decentralized. DSOs will need to manage congestion locally in their distribution grids, and balancing might even become more local in the future. To fulfil their role of neutral market facilitator at the local level, DSOs will need to procure flexibility from the decentralized energy resources connected to their distribution grids, which can include batteries. If they were also allowed to invest in batteries themselves, this would distort the market. They could foreclose the market in storage and prefer storage over other flexibility sources, such as demand response.

Note that at least part of the debate on batteries resembles the old debate on TSO ownership of pumped hydro. Not surprisingly, DSOs

have recently been stronger in their positions on storage than TSOs, which have gone through this debate before. However, there is another perspective to this debate, which allows for a different take on the issue, as we discuss below.

5.3.3 Second Perspective: Location-specific Grid Services

Unlike frequency, which is a network-wide parameter, voltages occur across points in the network and can be considered as local parameters.[15] Therefore, by definition, any voltage problem in the grid needs to be addressed locally.

System operators can solve such problems by procuring location-specific services. TSOs sometimes pay market parties to keep a power plant running in a certain location to support the voltage, even if the plant is out of the market. Alternatively, TSOs can invest in capacitors to support the grid. Capacitors are devices consisting of a pair of conductors separated by an insulator used to store electric charge (Guney and Tepe, 2017).

To solve congestion problems in transmission grids, TSOs procure location-specific balancing services. They re-dispatch the system in case of congestion by regulating upwards in one location and regulating downwards in another one. Some TSOs have also invested in phase-shifting transformers to manage the congestion in their grids. A phase-shifting transformer alters the phase displacement between two voltage points in a transmission line in order to control the quantity of active power flowing in the line.

In some parts of Europe distribution grids are now also facing congestion and voltage problems due to the rapid growth in wind power and rooftop PV installations. Batteries are modular, quick to install, mobile, and they can deal with these problems. In other words, batteries and pumped hydro are two ways to store energy from the power system and both can be used for system balancing, but batteries can also be used for location-specific grid services, which is not the case for pumped hydro. Very few locations are suitable for a pumped hydro installation, while batteries can be deployed in almost any location where the grid needs to be supported.

Should DSOs and TSOs be allowed to invest in batteries if they are used only to provide grid support, as in the case of capacitors and phase-shifting transformers? The answer is yes, and no. Market parties that provide location-specific grid services have significantly more market

power than those that provide regular balancing services. Competition in the market will therefore not work, but we can still have competition for the market instead of letting DSOs and TSOs invest in batteries. Competition for the market means tendering for long-term contracts. Note that in principle this also applies to phase shifters, capacitors and even transmission and distribution grid investments. The question is where to draw the line in this grey area of regulation. The costs and benefits of tendering need to be carefully evaluated against TSO–DSO ownership of these assets.

If TSOs and DSOs are allowed to invest in batteries in exceptional circumstances, regulatory precautions will help to deal with the potential negative side effects that may arise from such a move. The EU Clean Energy Package Proposals (see Box 5.5) include that the ownership of the asset could be limited in time, subject to consultation. The proposals also foresee cost–benefit analysis to make sure that alternative sources of flexibility have been considered before investing in batteries.

BOX 5.5 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 36 AND 54 OWNERSHIP OF STORAGE FACILITIES AND PROVISIONS OF ANCILLARY SERVICES

Article 36 Ownership of storage facilities

1. Distribution system operators shall not be allowed to own, develop, manage or operate energy storage facilities.
2. By way of derogation from paragraph 1, Member States may allow distribution system operators to own, develop, manage or operate storage facilities only if the following conditions are fulfilled:
   (a) other parties, following an open and transparent tendering procedure, have not expressed their interest to own, develop, manage or operate storage facilities;
   (b) such facilities are necessary for the distribution system operator to fulfil its obligations under this regulation for the efficient, reliable and secure operation of the distribution system; and
   (c) the regulatory authority has assessed the necessity of such derogation taking into account the conditions under points (a) and (b) of this paragraph and has granted its approval.

3. Article 35 and Article 56 shall apply to distribution system operators engaged in ownership, development, operation or management of energy storage facilities.
4. Regulatory authorities shall perform at regular intervals or at least every five years a public consultation in order to re-assess the potential interest of market parties to invest, develop, operate or manage energy storage facilities. In case the public consultation indicates that third parties are able to own, develop, operate or manage such facilities, Member States shall ensure that distribution system operators' activities in this regard are phased out.

Article 54 Ownership of storage and provision of ancillary services by transmission system operators

1. Transmission system operators shall not be allowed to own, manage or operate energy storage facilities and shall not own directly or indirectly control assets that provide ancillary services.
2. By way of derogation from paragraph 1, Member States may allow transmission system operators to own, manage or operate storage facilities and provide non-frequency ancillary services if the following conditions are fulfilled:
   (a) other parties, following an open and transparent tendering procedure, have not expressed their interest to own, control, manage or operate such facilities offering storage and/or non-frequency ancillary services to the transmission system operator;
   (b) such facilities or non-frequency ancillary services are necessary for the transmission system operators to fulfil its obligations under this regulation for the efficient, reliable and secure operation of the transmission system and they are not used to sell electricity to the market; and
   (c) the regulatory authority has assessed the necessity of such derogation taking into account the conditions under points (a) and (b) of this paragraph and has granted its approval.
3. The decision to grant derogation shall be notified to the Agency and the Commission along with relevant information about the request and the reasons for granting the derogation.
4. The transmission system operator shall perform at regular intervals or at least every five years a public consultation for the required storage services in order to assess the potential interest of market parties to invest in such facilities and terminate its own storage activities in case third parties can provide the service in a cost-effective manner.

Table 5.1 System operator investments in storage

Project owner	Location	Year	Size	R&D	Emergency	Temporary	Small-scale
UK Power Networks	Leighton Buzzard, UK	2013	6 MW	✓			
Scottish and Southern Energy Power Distribution	Orkney Islands, UK	2013	2 MW	✓			✓
Terna – EI	Southern Italy	2011	34.8 MW 3 locations		✓	✓	
Terna – PI	Sicily and Sardinia	2013	16 MW + 24 MW (planned)	✓			
Electric Transmission Texas	Presidio, Texas	2010	4 MW		✓	✓	

Source: www.energystorageexchange.org/

5.3.4 Case Studies of System Operator Investment in Storage

In the recent past, regulators in the EU (and the USA) have allowed network operators to invest in storage assets under exceptional circumstances. The exceptional circumstances that are generally cited for such investment are R&D pilots, emergency solutions for system stability, temporary solutions for network investment deferral, and battery size (i.e. small-scale batteries are not considered to have any distorting effect). In this section, we discuss briefly some cases in which the regulator has permitted system operators to own and operate storage. Table 5.1 presents a few cases where network operators were allowed to invest in storage under exceptional circumstances that we discuss below. Furthermore, we present a broad classification of the main reasoning for implementation of these devices.

Terna – Italy[16]

Italian law has permitted system operators to develop and manage battery-based distributed storage facilities provided they meet certain conditions stipulated in the decree (see Art. 17, par. 3 of the Legislative Decree No. 28 (3 March 2011) and Art. 36, par. 4 of the Legislative Decree No. 93 (1 June 2011)).

As a result of the Italian government allowing TSO ownership of batteries, the Italian TSO, Terna, has invested in storage assets, more specifically batteries. Terna classifies its storage investments into two types of projects: 1) power-intensive and 2) energy-intensive.

The power-intensive project was approved by the Ministry of Economic Development in the 2012 Defence Plan. It is intended to enhance the security of supply on two Italian islands. The pilot project is called a storage laboratory and is located in Sicily (6.8 MW installed capacity) and Sardinia (9.15 MW installed capacity). The batteries used are based on either Li-ion or Na-NiCl2 type. Based on the results of Phase I, an additional 24 MW will be installed in the future.

The aim of the energy-intensive projects, which were first envisaged in the 2011 Development Plan, is to better integrate intermittent renewables into the system. The storage system will reduce curtailment of the renewable generation, thus leading to significant savings. The project consists of developing three storage systems with a total installed capacity of 34.8 MW in southern Italy (12 MW, 12 MW and 10.8 MW). The battery chosen for this project is the Na-S type. (See Rossetto, 2015.)

UK Power Networks – United Kingdom[17]

In the United Kingdom, storage is governed by the Electricity Act (Amended) 1989. This act has been updated several times. In the current framework, no precise definition of electrical storage is provided, either as a separate asset class or as a service. In the absence of a separate definition, it is treated as generation. The UK defines generation as 'the generation of electricity at a relevant place' and the EU Directive 2009/72/EC as 'assets that produce electricity'. The DSOs and TSOs in the UK are not permitted to own storage technologies that require a licence. However, the Electricity Order 2011 provides an exemption to small generators from requiring generator licences. In the context of storage, these decisions are made on a case-by-case basis. In a way this has paved the way for DSOs to invest in battery pilots.

UK Power Networks is a DSO responsible for 14 electricity distribution networks in the UK. As part of the Smart Network Storage (SNS) Project (January 2013–December 2016), UKPN undertook a pilot project to test batteries for applications such as network investment deferral and ancillary services. Furthermore, the project analyzed other system-wide benefits that could be gained from the implementation of storage devices. In this project, UKPN collaborated with SmartestEnergy for developing innovative commercial market routes, while KiWi Power managed commercial arrangements.

The main funding for the project is from the Low Carbon Network Fund (£13.2 million). Additional funding has been provided by UKPN itself (£4.3 million) and other project partners (£1.2 million). On the technical side, the storage consists of a 6 MW (10 MWh) Li-ion battery.

Scottish and Southern Energy Power Distribution – the UK[18]

The Orkney Energy Storage Park Project, located in Kirkwall, is considered as the UK's first trial of large-scale batteries for electrical storage. This trial was initiated with the goal of 1) improving the understanding of participation of storage in commercial markets, 2) gaining experience in operating batteries, especially in mitigating intermittency issues due to the high penetration of renewables, and 3) integrating this device with the existing Active Network Management System. The battery is connected to the Orkney Isles' electricity distribution network.

The project was developed through a collaboration between Mitsubishi and Scottish and Southern Energy Power Distribution. It has been funded by Ofgem under the Tier 1 Low Carbon Network Fund. The project also has the support of NEDO (New Energy and Industrial

Technology Development Organization), Japan. The battery manufactured by Mitsubishi has a size of 2 MW and the technology used is Li-ion. The battery is housed in three 40 ft containers. The official opening ceremony of the project was held on 14 August 2013.

Electric Transmission Texas – USA[19]

Before 2010, the residents of Presidio, Texas, faced major reliability issues due to ageing transmission infrastructure. The city had only one 69 kV transmission line (built in 1948) that connected it to the nearest substation roughly 60 miles away.

Electric Transmission Texas, the transmission operator for the region, proposed to build a battery system along with the new 69 kV transmission line and an autotransformer. The main purpose of the battery was to improve system reliability by managing voltage fluctuations until the new transmission line was completed. The proposal was approved by the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT). Furthermore, the battery system was financed by ERCOT as a 'necessary transmission upgrade'. ERCOT uses a 'postage stamp' method for recovering the costs of such upgrades from its customers.

The system consists of 80 NaS battery modules with a total installed capacity of 4 MW (32 MWh) and began operations in 2010. The battery system continues to function as a backup, even after completion of the new transmission line in 2012.

5.4 CONCLUSION

In this chapter we have revisited three key classical grey areas to explore the border between the grid and the market: grid ownership, market operations and energy storage. We call them 'classical' because these issues have been a source of debate since the beginning of the liberalization process. Furthermore, the introduction of the EU Clean Energy Package has made the need for understanding and revisiting these debates even more critical for all involved stakeholders.

There are several arguments on whether system operators should own the grid they operate or whether grid investment can become a market activity that is open to competition. Scale efficiency is an oft-cited argument for monopolies in transmission and distribution. However, this assumption should be challenged continuously. The regulators in Europe

have already experimented with ways to partly open the market for grid investments such as market-based outsourcing of grid investments, independent system operators, and competition for border investments. Finally, local energy communities, which may not even need to be connected to a distribution network, can be expected to gain greater significance in the near future and could transform the electricity system.

Similarly, in the context of market operation, the question is whether this is a monopoly activity or an activity that should be opened to competition. In Europe, regulators have opened the market for market operation in wholesale power markets but not yet in balancing markets that are typically operated by TSOs.

Finally, energy storage is an essential enabling technology for energy transition. The topic is of even greater relevance due to rapid innovation, improving economic viability of batteries and their ability to participate in different segments of the electricity value chain. However, this functional versatility of batteries also makes it extremely difficult to define them in the current regulatory framework. A key debate on this topic revolves around the ownership of these assets, especially for providing balancing services and location-specific grid services. Regulators have already allowed TSOs/DSOs to invest in batteries under exceptional circumstances. Although several arguments in favour of TSO/DSO ownership are presented, the key question is whether a TSO/DSO can continue to be a neutral market facilitator. It is important that if these entities are permitted to invest in batteries, regulatory precautions would have to be implemented to help deal with the potential negative side effects that may arise.

NOTES

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2. For more information, see: de Hauteclocque and Rious, 2011; Kessel et al., 2011.
3. https://elering.ee/en/fingrid-and-elering-will-become-new-owners-estlink-1
4. ACER, 2015. List of NEMO designations. https://www.acer.europa.eu/en/Electricity/FG_and_network_codes/CACM/Pages/NEMO-Designations.aspx

5. NEMOs are defined in the CACM GL as an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling.
6. By market coupling it means the auctioning process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in a market time frame.
7. ACER, 2015. List of NEMO designations. https://www.acer.europa.eu/en/Electricity/FG_and_network_codes/CACM/Pages/NEMO-Designations.aspx
8. A CCC is set up jointly by a subset of TSOs (CACM, Art. 2(11)) and calculates the available cross-zonal transmission capacity per capacity calculation region (CCR).
9. This section is based on Meeus (2011).
10. Source: www.energystorageexchange.org/
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6. New grey areas at the frontiers of European power grids

Leonardo Meeus and Tim Schittekatte

Recently the European power grids have been moving into unknown territory, which is the case for transmission grids going offshore, and for distribution grids entering electric vehicle (EV) charging infrastructure. In many countries, regulators have used this new territory to experiment with innovative regulatory approaches, which, if found to be successful, can be imported to the rest of the system. This chapter raises the question of whether market parties should be encouraged to take the lead in the development of these two new grey areas or whether they should be part of the regulated network company's business.

In the first section of this chapter, offshore grid regulation is discussed. Regulatory frameworks for electric vehicle charging infrastructure are the topic of the second section. Lastly, a conclusion is presented.

6.1 OFFSHORE GRIDS

Investments in offshore grids are new grey areas in regulation because the border between the grid and the offshore wind farm is fuzzy. Should market parties investing in offshore wind farms connect to the onshore grid or should the grid be moved offshore towards the wind farms so that they can connect to a 'plug in the sea'? Is offshore something that the grid operators and utilities can handle, or should we open the market for companies from the offshore shipping business and/or oil and gas sectors that have more experience with infrastructure developments at sea? Such questions have inspired regulatory innovation. In this section, we introduce the offshore wind landscape in Europe. We then illustrate how regulators in Great Britain, Germany and Sweden have handled it. Finally, we discuss to what extent an EU regulatory framework for offshore grids already exists.

6.1.1 The Offshore Wind Landscape in Europe[1]

The total offshore wind capacity installed in Europe by the end of 2016 equalled 12.6 GW, which represents just over 88 per cent of the global offshore wind capacity installed. This power is delivered by 3,589 grid-connected wind turbines located at 81 different sites in 10 countries. To put this into context, 12.6 GW is slightly less than the total installed capacity in Switzerland. Of course, comparing the aggregated capacity of a national generation fleet with Europe's offshore wind capacity is unfair. Wind is not blowing 24/7, while conventional thermal generation, still the major category of the generation portfolio in most EU nations, can be switched on and off as needed.

Therefore, when comparing statistics, it makes more sense to look at electricity production. In the EU, just over 37 TWh of offshore wind electricity was generated in 2016. Annual load factors, defined as the average power generated divided by the rated peak power, ranged from 33.1 per cent to 42.9 per cent depending on the site and methodology. To put these figures into perspective, 37 TWh can be compared to the electricity consumed in Bulgaria, a country inhabited by 7.2 million people. Looking at the broader context, 10.4 per cent of the total energy consumed in the EU in 2016 was generated by wind turbines, with 9.1 per cent onshore and 1.3 per cent offshore.

Offshore wind developments in Europe started in 1993 and investments increased rapidly. In 2015 the biggest yearly capacity addition to date was observed – 3 GW of additional capacity was installed, which was twice as much as the additional capacity installed in 2014. In financial terms, 2015 saw €13.3 billion invested in new offshore wind assets. As a point of reference, that figure amounted to about half of Latvia's gross domestic product (GDP) that year. Today, about two-thirds of clean energy investment in Europe is in wind energy. 2015 was also the first year in which the total investment in new offshore wind assets was slightly higher than that in onshore wind assets.

Denmark pioneered offshore wind together with Great Britain, but while the capacity installed in Great Britain has increased significantly every year, growth in Denmark has tailed off. Germany has recently started investing seriously in offshore wind and rose from ranking as the sixth offshore wind nation in 2010 to being the second largest wind nation at the time of writing. Figure 6.1 shows the evolution of connected offshore wind generation capacity per nation between 2000 and 2016. Note that China (1.6 GW installed in 2016) and the USA (almost no installed capacity in 2016, but targets are set) are also starting to show interest in offshore wind development.

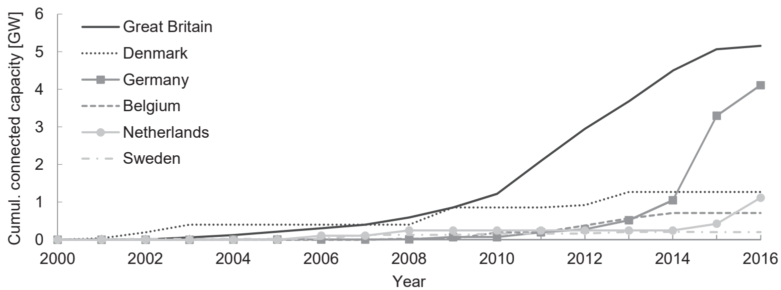


Figure 6.1 Cumulative connected offshore wind generation capacity per country[2]

6.1.2 Regulatory Framework for Connection of Offshore Wind Farms to Shore in Great Britain

At the time of writing, Great Britain was the biggest offshore wind market in the world. By the end of 2016, slightly more than 5 GW of wind power was connected to the British grid, and this capacity is expected to double by 2020. Connecting these generators to the mainland costs billions of euros. Great Britain decided to organize tenders to allow third parties – namely, offshore transmission owners (OFTOs) – to compete for the ownership and operation of offshore transmission assets. The main reasons for doing so are to encourage innovation, deliver cost-efficient investments, attract the necessary fresh capital and bring in technical expertise.

In the OFTO regime, developers of offshore generation projects may choose either to build the transmission assets themselves or to let the OFTO take charge of the construction. Until today, only the 'generator-build' model has been used. Under that model, companies bid for an OFTO licence to own and operate the connection after it has been built by the generator. The licence is obtained through a competitive tender and entitles the holder to a regulated rate of return for 20–25 years. The other option, the 'OFTO-build' model, has been deemed too risky by the wind farm developers. The risks identified include the OFTO's capability in managing interfaces with generation construction and commissioning, delivering transmission assets on time and maintaining sufficient quality. However, in the longer run, Ofgem, the British regulator, seems to be in favour of opting for the 'OFTO-build' model to enable an OFTO to take a holistic approach to transmission investment.

Therefore, Ofgem is actively working on softening the mentioned concerns.[3]

Although ultimately electricity consumers pay for the cost of the transmission system, both onshore and offshore, it is of significant importance how these expenses are recuperated. In Great Britain, the offshore generation developers pay for their connection to the mainland. Generators are charged ‘shallow’ connection costs, meaning that the generator is responsible for the costs incurred in developing the internal network within the wind farm as well as the cost of connection up to the onshore connection point. However, any costs that may be incurred for onshore reinforcements needed to accommodate the offshore connection are socialized. Wind farm owners indirectly pay the OFTOs for their connection; the wind farm owner is charged by the onshore TSO for the transmission service. For its part, the onshore TSO pays the regulated revenue, including an availability incentive, to the OFTO for 20–25 years.

Offshore wind projects are becoming larger, more complex and located at greater distances from the shore. As a result, there are potential benefits to be gained from greater coordination in the development of transmission infrastructure. However, the approach followed where OFTOs bid for individual assets focuses mainly on achieving value for money on a case-by-case basis and does not directly support coordination. Indeed, coordination between sites has been limited thus far, but Ofgem is developing measures that will help to enable coordination of offshore transmission networks while retaining the benefits of the competitive offshore transmission regime. In that light, the framework called ‘offshore wider network benefit investment’ (WNBI) is being developed. WNBI can be both developer-led or non-developer led. For a non-developer-led offshore WNBI, a more important role could be assigned to the onshore TOs. More precisely, the lead option in the last consultation of Ofgem was to let the preliminary works for this offshore infrastructure be undertaken by TOs.[4] An example of a developer-led offshore WNBI would be when a single developer invests in offshore transmission assets or capacity that go beyond that needed to connect its wind farm.

6.1.3 Regulatory Framework for Connection of Offshore Wind Farms to Shore in Germany

Germany was the fastest growing offshore wind nation in 2016 with 4.1 GW of offshore power connected to the mainland. In 2014 the government extended the country's support for offshore wind until the end of the decade. However, earlier capacity targets were reduced from the previously planned 15 GW by 2020 to 6.5 GW and from 25 GW to 15 GW by 2030. Reuters states that an important reason for capping the offshore wind expansion is the belief that onshore high-voltage power lines, needed to carry green energy from the windy north of the country to the industrial south, will not be ready in time.[5]

In Germany, the offshore connections are constructed, owned and operated by the TSOs. Germany has four TSOs, of which two, Tennet and 50Hertz, are in charge of transmission grid assets adjacent to sea territory. The way the TSOs in Germany have organized offshore grid connection can be split up into three periods, with regime changes around 2013 and 2017.

In the first period, a 'reactive TSO model' was applied. A Marine Spatial Plan, developed by the Federal Maritime and Hydrographic Agency (BSH) and the Federal Network Agency (BNetzA), which demarcates priority areas for offshore wind farm development, was enforced in 2009. Grid connection was legally guaranteed and was, therefore, not a part of the wind park developers' responsibility. The government obliged the relevant TSOs to provide a guaranteed grid connection, but the TSO in charge of the connections of offshore wind farms in the North Sea faced severe technology, supply chain and project finance challenges in providing the grid connection. Grid delays led to foregone revenues and became a grave risk for wind park developers.

Confronted with these delays, Germany worked on a new approach to offshore grid connection. The model applied in the second period was a more 'proactive TSO model'. A prominent change compared with the first period was that since 2013 an Offshore Grid Development Plan (O-NEP) had been drawn up by the German TSOs and updated yearly. This plan had to be submitted to the BNetzA. In the O-NEP, the development of the transmission system on land, the spatial planning at sea and detailed information on the status of infrastructure projects were considered. This plan, with a horizon of ten years, facilitated better the coordination (mainly in the form of hubs) of different offshore projects and allowed the TSOs to plan their budgets more carefully. Complementary

with the introduction of O-NEP, the developer's right to request connection was replaced by an objective, transparent and non-discriminatory allocation procedure that allowed for transmission assets to be shared across individual wind farms.

The third period starts with the new Offshore Wind Energy Act (Windenergie-auf-See-Gesetz, or WindSeeG), which came into force in 2017 and partly revokes previous regulation. The WindSeeG has made a significant systemic change to the regulation that governs the developing new offshore wind farms by introducing centralized auctions. In this centralized model, the pre-selection and preliminary site investigations are performed by government agencies to determine the suitability for the operation of potential offshore wind farms. First, a transitional regime will be in place for offshore wind farms commissioned between 2021 and 2025 before the new central auctioning concept is fully implemented. An Area Development Plan, established by BSH and BNetzA, replaces the O-NEP and related plans, of which the last updates were published in 2017. The new Area Development Plan will not only include the sites, capacity of offshore wind farms and time sequence for auction process but will also determine the location of converter platforms and substations as well as connection cable routes. The offshore grid planning in this third period is even more proactive than in the second period and there is a stronger role reserved for the governmental agencies and the Federal Network Agency.

In Germany, the offshore generation developer does not pay for the grid connection (super shallow grid connection cost); the cost is socialized by the TSO charging levies to the consumers. This is an additional financial support for offshore wind projects, next to the conventional renewable support received for production. By not having to pay the connection costs, generators are not exposed to a price signal that they can internalize in the total investment cost. This is a serious issue in the 'reactive TSO model' but becomes less critical in the more proactive models as in this case parties who are better informed about the connection costs are in charge of the siting decision.

It is certainly true that there were significant coordination issues between the construction of offshore generation and offshore connection in Germany in the past. However, it can be argued that by making the TSO responsible for the connection, offshore grid planning – more specifically, the coordination among generation projects – is encouraged. An example is the BorWin project (see Box 6.1) in which several offshore wind farms have been developed in a short time span in the same area

(clustering). By coordinating the project and anticipatory investment, approved by the regulator, significant economies of scale could be enjoyed.

BOX 6.1 THE BORWIN PROJECT

Originally the BorWin hub was planned to consist of four phases. HVDC voltage source converter (VSC) systems, one for each phase, had to be used to connect the offshore wind farms to the transmission grid of the TSO in the area because of the relatively large distance to shore. These HVDC VSC systems consist of a DC cable with two converter stations, one to convert the AC output of the wind turbine into DC and one to reconvert the DC output of the cable into the AC of the onshore grid.

The finalized BorWin1 and BorWin2 projects connect three offshore wind farms located about 125–150 km from shore, and total 1200 MW (i.e. 400 MW in Phase 1 started in 2009 and 800 MW in Phase 2 which began in 2012). The projects were highly innovative as BorWin1 was the first HVDC facility in Germany to use VSC and BorWin2 was the first system offering a connection to more than one offshore wind farm.

At the time of writing, BorWin3 was being constructed and was expected to come online in 2019. The link will transmit approximately 900 MW of wind power. The awarding procedure for the originally planned BorWin4 grid link has been halted. An overview of the four original phases of the BorWin hub is shown in Table 6.1.

Table 6.1 Overview of the BorWin hub[6]

Project name	Status	Number of offshore wind farms planned to be connected	Capacity line (MW)
BorWin1	Online in 2009/2010*	1	400
BorWin2	Online in 2015	2	800
BorWin3	Online in 2019, in construction	1	900
BorWin4	Expected 2019, halted	1	900

Note: *The project has had many technical difficulties since that date.

By planning the projects jointly, economies of scale could be profited from. In the case of BorWin2, by coordinating the connection of the two wind farms at an early stage, only two converter stations and one cable to shore needed to be used, instead of four stations and two cables. Also, by building offshore projects near to one another, the environmental impact, the costs associated with preparing the cable corridor and the costs of possible reinforcements needed onshore are reduced.

6.1.4 Regulatory Framework for Connection of Offshore Wind Farms to Shore in Sweden

Already in 2006, Sweden had adopted a national planning framework for 17 TWh of wind power by 2020, indicating a strong desire for incorporating wind in the generation mix.[7] Consequently, a significant expansion in the installed capacity of wind generation occurred over the past decade. The installed capacity of wind in the generation mix grew ten-fold from 2006 to 2016. Today, more than 10 per cent of electricity consumed in Sweden is generated by wind turbines. However, offshore wind power makes up a small fraction of this capacity – as of 2016, only 200 MW of the installed capacity of wind farms were offshore.

In Sweden, the offshore wind farm developer can present a proposal to develop an offshore wind farm in one of the so-called national interest areas for wind farm development. Since 2004, the Swedish Energy Agency has been responsible for defining areas on land and at sea with particularly good wind conditions that should be of national interest for wind power generation. It is possible, however, to build outside areas of national interest if certain conditions are fulfilled. In the Swedish regulatory framework, the owner of the offshore power plant is responsible for the connection to the onshore network. It is important to note that Swedish electricity law prohibits generation and transmission assets within the same company. This implies that although the connection is built by the developer, in the operation phase the generation and the grid activities must be separated.

This legal unbundling requirement can be illustrated with the Lillgrund Wind Farm, the biggest in Sweden (48 turbines, 110 MW installed), described by Söderberg and Weisbach (2008). In this project, Vattenfall Vindkraft AB is the company that owns and operates the power plants while Lillgrund Elnät AB, which owns and operates the grid connection to shore, is a subsidiary company of Vattenfall Vindkraft AB. Technicians working at Lillgrund are working with both the electrical system owned by Lillgrund Elnät AB and the wind turbines owned by Vattenfall Vindkraft AB.

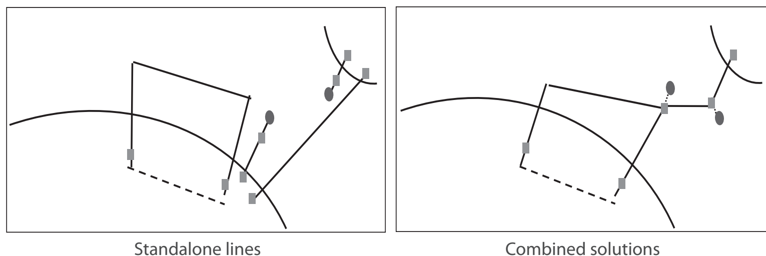
The wind developer must pay for the connection to shore and can be charged an additional fee equal to the total increase in onshore transmission investment needed to accommodate the offshore connection. This charging scheme is called ‘deep connection charging’. Note, however, that the Swedish offshore connection regime is not necessarily the

reason why offshore wind development is limited in the country today. Many other factors should be considered, such as the level of renewable support or the availability of adequate sites.

In summary, it can be said that no country with investment in offshore wind applies exactly the same governance to offshore grid connection – the matter is too broad – and yet trends are visible. The Danish model, in place since the first significant investments in offshore wind, is very similar to the German 'proactive TSO model'. Belgium and the Netherlands, both with concrete plans to develop a 'power socket at sea', are converging towards the German model. Still, Great Britain is the biggest market offshore and the British model might well prove to outperform the TSO model.

6.1.5 Towards an EU Regulatory Framework for Offshore Grids

The WindEurope association projects that by 2030, 5–11 per cent of the electricity demand in the EU will be covered by offshore wind generation. There are two possible offshore grid developments (see Figure 6.2): there could be a multiplication of standalone lines, which already exists today, or there could also be a transition towards combined solutions.



Note: wind farm; converter station; — HVDC cable; - - HVAC.

Figure 6.2 Alternative offshore grid developments[8]

- Multiplication of standalone lines (Figure 6.2, left): in the illustrated case, there are two offshore wind farms to be connected to shore, interconnection capacity is created between the two onshore grids (with a so-called interconnector) and congestion in one of the two onshore grids is relieved with an offshore line (with

a so-called bootstrap). This is achieved with two 'farm to shore' investments and two 'shore to shore' investments. The illustration assumes that the individual investments would use HVDC technology so that each of them would require a cable and two converter stations.

- Combined solutions (Figure 6.2, right): in the illustrated case, combining the farm to shore and shore to shore investments in a mixed investment would reduce the number of converter stations from eight to five – and, despite the number of cables being the same as in the non-combined solution, the total cable length would decrease. The capacity of the cables and converter stations would increase, but given the economies of scale, the effect on total costs of the reduction of the number of assets and lengths would dominate the capacity effect. The economic case for combined solutions is uncertain, however, due to the advanced HVDC hardware and software needed.

A 2014 study from the European Commission showed a potential for up to €5.1 billion worth of annual savings in the reference year 2030 when a coordinated approach to offshore grid development is undertaken.[9] In the same study, the coordinated offshore grid is shown to be profitable in all assessed scenarios. In addition to requiring fewer cables and increased cost efficiency due to economies of scale, a meshed network offers redundancy, i.e. if one cable fails, it would not necessarily mean that the electricity generated offshore would be lost.

Offshore grids are at the frontiers of the power grids where regulatory experimentation is taking place, but coordination without harmonization of the regulatory regimes is difficult. Next to different regulatory regimes, cooperation between countries offshore is also constrained by the focus on national support schemes for renewable energy sources. Concretely, to benefit from financial support the electricity generated should be fed into the nation funding the project. This becomes problematic when a wind farm is connected to several nations. However, this obstacle could be solved with the introduction of cooperation mechanisms set up under the Renewable Energy Directive (2009/28/EC). The first initiative with two collaborating nations in supporting renewable generation investment took place in 2016.[10]

A positive note here is that we are witnessing a harmonization of the instruments to support RES (see Box 6.2). This harmonization opens the door for the next step, namely coordinated RES support. However,

as long as most relevant regulatory but also technological (immature HVDC technology) barriers are not softened and eventually circumvented, it is unclear how combined solutions connecting wind farms to multiple nations would develop. We are only at the beginning of an EU regulatory framework for offshore grids.

BOX 6.2 RES SUPPORT MECHANISMS

Each country in Europe has a national renewable energy target to be achieved by 2020, i.e. to cover a certain share of their domestic energy consumption with renewable energy. To achieve that target, they can choose how to support the deployment of renewable energy sources, such as offshore wind. The support mechanisms have not been harmonized, and very few countries have chosen to collaborate to achieve their national targets. Of course, this complicates the development of an offshore grid because the support depends on where the renewable energy comes to shore. In what follows we illustrate the differences between the support schemes adopted in the same countries we focused on earlier in this chapter, i.e. Germany, Great Britain and Sweden.

Germany started with fixed feed-in tariffs. Under such a support scheme, a price per every MWh produced is guaranteed to wind developers. This price was set administratively based on the estimated levelized cost of energy (LCOE). The advantage of fixed feed-in tariffs is the increased confidence for investors, as the revenues of a windmill installed are not subject to the volatility of the market. However, this also means that the generators lack a guiding price signal and may not adapt production to the system needs. Finally, by setting the tariffs administratively there is a risk of under- or over-compensation.

Great Britain started with a quota system. Under such a support scheme, a minimum share of electricity has to be supplied from RES, and this share is increasing in time. RES producers receive a number of certificates per MWh electricity produced. The amount of certificates received per MWh produced can be technology dependent, as was the case in Great Britain from 2009 onwards. Electricity suppliers may trade certificates if they cannot reach the minimum share with their own production. An advantage of such a support scheme is that offshore generation operators have to sell their electricity in the market and thus are exposed to a price signal. On top of this market revenue, they receive a price for their green certificates which they sell in a different market. However, the price for which they can sell these certificates is very uncertain. This is the main reason the quota system in Great Britain was abandoned.

In Sweden also a quota system was introduced in 2003. In 2012, this market for certificates was coupled with that of Norway. The common Swedish–Norwegian coupled certificate market is the first of its kind in Europe.

The Swedish–Norwegian quota system is technology-neutral and has been criticized by offshore wind advocates as being an inefficient mechanism to promote offshore wind investments, considering that costs are 40–50 per cent higher than onshore investments. This support mechanism is still in place in Sweden and has recently been extended to 2030.

In contrast, Great Britain and Germany have adapted their support schemes resulting in similar approaches. Germany moved towards a sliding feed-in premium system for the deployment of offshore wind generation. A premium payment per every MWh produced is added to the revenue made from selling the electricity in the market. The magnitude of this variable premium is determined ex-post, in most cases on a monthly basis. The premium is calculated as the difference between a reference tariff level, administratively set or determined by an auction, and the (monthly) average wholesale electricity price. This means that if the market price drops, the premium goes up, and vice versa. With this support mechanism, offshore wind generators are more reactive to market signals but without their revenue risk being increased significantly.

In Great Britain, a contract for difference (CfD) is applied. A CfD is very similar to a sliding-premium mechanism. In the ex-post calculation, if the (averaged) market price is below the reference tariff level (so-called strike price in the CfD case), the same payment is received by the operator having a sliding-premium or a CfD with the same reference tariff level/strike price. However, if the (averaged) market price is above the strike price, the difference has to be paid back by the operator having a CfD to the counterparty (government), while for a sliding-premium mechanism this is not necessarily the case.

Note, finally, that there is a steady shift away from administratively determining the reference tariff levels, the remuneration per MWh electricity produced a developer expects to receive, towards a market-based approach in the form of an auction. The bidding process allows for price discovery and, with sufficient competition, the auction outcome can be cost-effective. This then also opens the door for including the grid connection in the bidding process.

6.2 ELECTRIC VEHICLE CHARGING INFRASTRUCTURE

There is little debate about a charging point in your garage: it is yours. But what about charging points in the street? You could consider them as part of the distribution network, in which case there is something to be said for making DSOs responsible for their installation and operation. But it is not that simple. Consider petrol stations. They are operated by retailers who have often also provided the infrastructure. Moreover, a

maker of electric vehicles such as Tesla can also have good arguments for rolling out a network of charging points. It is therefore not surprising that different countries have made different choices here. In other words, offshore grids are new territory for transmission grids, while electric vehicle charging infrastructures are potentially new territory for distribution grids; in both cases regulatory experimentation is ongoing.

In this section, we first discuss the electric vehicle landscape in Europe. We then discuss the role of the regulatory authority if a market-based approach is chosen for the investment in electric vehicle charging infrastructure. Next, we look at the role of the regulatory authority if the DSO approach is chosen for this investment. We finally discuss to what extent we already have an EU regulatory framework for electric vehicle charging infrastructure.

6.2.1 Electric Vehicle Landscape in Europe[11]

It is expected that electric mobility will play a key role in the EU's push for de-carbonization of the transport sector. The recent 'Clean energy for all Europeans' package proposal states that 'the deployment of electro-mobility constitutes an important element of the energy transition'. The rapid adoption of EVs is of great importance as the transport sector is still one of the most polluting sectors of the EU. Around one-quarter of Europe's greenhouse gas (GHG) emissions are the result of fuel combustion for transportation (including international aviation), and this despite past technological improvements. Additionally, EU road transport accounts for more than 70 per cent of all GHG emissions from transport apart from CO_2 emissions; it also contributes to the increased concentration of air pollutants such as NO_X and PM in several European cities.

Rapid growth in the market share of electric vehicles in automobile sales has been observed in recent years. The yearly sales of EVs in the EU, considering both battery (BEVs) and plug-in hybrids (PHEVs), increased from roughly 700 vehicles in 2010 to 149 500 in 2015. As of 2015, this means that about one car in 100 sold today is powered by electricity. Of all electric vehicle sales in that year, 90 per cent were accounted for by six Member States: the Netherlands, the United Kingdom, Germany, France, Sweden and Denmark. Outside the EU, a clear frontrunner in terms of high sales is Norway, where 22.5 per cent of all new cars sold in 2015 were electric. Globally, the threshold of 1 million electric cars on the road was exceeded that same year, closing at 1.26 million.

Looking solely at Europe (including Norway), a total of about 600 000 EVs were on the roads in 2016 versus about 250 million passenger cars with internal combustion engines. Doing the sums shows that this would mean just above 0.2 per cent of the cars on the road in Europe in 2016 were electric. This might seem like an insignificant number, but the trend indicates that the penetration of EVs will increase rapidly in the coming years. Compared with conventional vehicles, the choice of EV models is limited today. However, automobile manufacturers have been introducing more models every year.

Several direct and indirect incentives for EVs are available at the Member State level to speed up adoption; examples are up-front price reduction (lowered registration tax and VAT), exemption of road tolling or bus lane access. Currently there are no direct incentives at the EU level, but, instead, EU-wide CO_2 emission standards (130 g CO_2/km in 2015 and 95 g CO_2/km in 2021) for newly registered cars are in place. National incentives have led to the introduction of electric vehicles by manufacturers in the premium segment. It is expected that, together with the increasingly stringent emissions standards, cheaper battery costs and better battery performance to conquer 'range anxiety' will allow manufacturers to expand into the mass market arena in the near future. Several analysts predict that EVs will be cheaper than conventional cars on a total-cost-of-ownership basis by 2020–25.

In order to turn electric driving into a feasible transportation option for the future, the roll-out of public charging stations (in the streets/public parking), along with the installation of private charging points (at the home/workplace), is indispensable.[12] By the end of 2016, 70 000 public charging points were already in place in Europe, meaning that at the time of writing there was one public charging point installed for an average of nine EVs.[13] The front runner in this is the Netherlands, where 27 per cent of all these public charging points are installed. One charging point per nine cars seems like a large number. This high number can be partly explained by the fact that about 90 per cent of the European public charging points are so-called slow or normal charging points (AC, <22 kW), meaning that charging the full battery takes a matter of hours. The remaining 10 per cent are considered fast (AC, >22 kW or DC, >>25 kW) (see Box 6.3). As a reference, it would take approximately 30 minutes for an 80 per cent charge or 120 km of extra range (on a Nissan LEAF), with a 60 kW DC charger. In addition to the 70 000 public charging points, there were 390 000 private charging points in Europe in 2016, amounting to 460 000 charging points or 32 per cent of

the total charging points globally installed. It is interesting to note that in 2015–16, on a global scale, the number of public charging stations installed increased more rapidly than the number of EVs sold (71 per cent versus 53 per cent).

BOX 6.3 EVs AND SUPER (SMART) CHARGERS

The Alternative Fuels Infrastructure Directive (AFID) states:[14]

> The recharging of electric vehicles at recharging points should, if technically and financially reasonable, make use of intelligent metering systems in order to contribute to the stability of the electricity system by recharging batteries from the grid at times of low general electricity demand and to allow secure and flexible data handling. In the long term, this may also enable electric vehicles to feed power from the batteries back into the grid at times of high general electricity demand.

Today, super chargers in the range of 150–300 kW are being developed. Knowing that an average household in Central-West Europe has a peak usage of about 4 kW, this would mean that one car being charged could equal 40–75 households consuming at their peak demand. This order of magnitude indicates quite clearly that smart charging will need to be in place with the penetration of super chargers. Closer cooperation and communication between the charging infrastructure operators, EV drivers, the DSO and electricity suppliers are needed. The electricity price, in this case the aggregate of (wholesale) energy prices and distribution network charges, is the tool to coordinate charging behaviour. If coordination is accomplished, EVs could be a flexibility provider and allow the integration of more intermittent renewables at the distribution level. However, if coordination fails, EVs can become a threat to our system, especially in terms of costly network reinforcements. Knowing that cars are parked about 90 per cent of their lives, many opportunities for smart charging schemes arise.

6.2.2 Role of the Regulatory Authority if a Market-based Approach Is Chosen for the Investment in Electric Vehicle Charging Infrastructure

Market-based investment in electric charging infrastructure is easier in a private setting such as a garage or industrial site than in the public domain where space is limited. This is why cities in countries like Sweden and the Netherlands have typically used tendering to allocate these spaces for charging points to market parties.

The market-based approach has dynamic benefits of innovation. The main risk is that the infrastructure is slow to develop due to market failures, such as high transaction costs related to tendering, innovation spillover effects and other external costs. National energy policies might also want to frame or replace the market for other reasons (such as public service or political economy). Market corrections are therefore typically about accelerating development of the infrastructure and introducing public service regulations.

The first issue is acceleration. Sweden and the Netherlands are examples of countries where the context allows the regulator to wait and see whether the market will develop. However, acceleration might be needed as the business case for public charging is typically not sustainable with low penetration levels of EVs, while higher penetration levels are harder to obtain when no public charging infrastructure is in place (chicken-and-egg problem). Therefore, in Ireland, a small-scale rollout is being implemented by the DSO, as the country relies on EVs to achieve its ambitious climate objectives. Note, also, that there is only one DSO in the Republic of Ireland. Countries with more DSO consolidation will, indeed, more easily consider them as an interesting partner for market acceleration. Belgium (Flanders) is also going in the direction of a DSO pilot for charging infrastructure. In Italy, AEEGSI, the national regulator, launched a call for demonstration projects in 2010 open to both DSOs and other operators in order to test different business models for EV charging stations (see Box 6.4).

The second issue is public service obligations. Cities such as Amsterdam, Berlin and London have organized tenders to roll out infrastructure in the public domain. The city tenders typically include an obligation to invest in a certain number of poles within a certain time frame, which is similar to a universal service guarantee within the city context.

In other words, even if the approach to invest in electric vehicle charging infrastructure is market-based, there is a role for the regulator – it is not only to design the market but also to correct the market failures. Assigning a role to the DSOs is one way to correct the market failures, but there are alternatives, such as giving subsidies to market parties or imposing public service obligations on market parties. It should be added that independent of whoever installs the charging infrastructure, the DSO must take part in the development and the planning of infrastructure. DSOs have increased visibility about the site location for charging infrastructure and a better understanding of demand and charging patterns.

BOX 6.4 THE ITALIAN EXPERIENCE[15]

A call was launched for charging service providers (CSPs), who were expected to build and operate public EV charging stations between 2011 and 2015. Three possible business models were proposed, which were distinct in terms of the operator (the DSO or a third party), the number of competing retailers at the charging infrastructure and the allowed degree of competition between charging stations in a determined area. An interesting question that was tackled by this setup, next to the ownership of the charging station, was how to balance competition between EV charging stations and competition between electricity retailers at a charging station. The three possible business models were:

1. DSO with multivendor: the DSO is the operator of the charging infrastructure, but it allows the presence of several electricity retailers among which the mobile consumer can choose at the charging point. It should be added that DSOs could undertake this task only under an accounting unbundling constraint.
2. CSP with an exclusive licence in a geographic area (either multivendor or mono-vendor): this is the case of a CSP selected through a public tender by a local administrative authority (the municipality, the province, etc.).
3. CSP in competition in the same area (typically mono-vendor): in this case a mobile consumer can choose from different charging infrastructures (as is now the case for ordinary gas service stations) instead of different retailers at one charging station.

Five pilots took place including all three different approaches. Only slow-charging technology was installed (3–6 kW) as it was the only technology available at the time. In total about 500 charging points were installed, spread over nine regions.

It should be noted that the 'DSO model', even with the multivendor requirement, is no longer considered compatible by AEEGSI after the AFID. The AFID stated that an EV CSP may belong to the same vertically integrated undertaking of the DSO, but that it shall be ensured that DSOs cooperate on a non-discriminatory basis with any person establishing or operating charging points accessible to the public. In other words, the provision of charging services must be legally and functionally unbundled from the core activities of the DSO. Accounting unbundling no longer suffices.

6.2.3 Role of the Regulatory Authority if the DSO Approach Is Chosen for the Investment in Electric Vehicle Charging Infrastructure

If the approach is to rely on DSOs, the regulator needs to reflect on the scope of the DSO involvement and whether a combination of dedicated

quality-of-service regulations and innovation incentives needs to be implemented.

First is the scope of DSO involvement. The DSO in Ireland is making the investments in EV charging infrastructure, but the assets have not yet been included in the regulated asset base. The costs have been recovered via the distribution tariffs but kept in a separate company on a separate account. This means that the assets could easily be reallocated to a market party if the regulator decided to go for a market-based approach after testing the DSO approach. If they are involved, DSOs can typically own and manage the assets, but the operation is a retail activity.

Second is the dedicated quality-of-service regulations. A list of minimum functionalities is typically needed to prevent the DSOs from installing technology that allows them to capture operational benefits without enabling the potential benefits for other market parties and society. Regulators will for instance need to put in place multi-vendor requirements when they allow DSO involvement, as was the case in the Italian pilot. Key performance indicators specific to electric vehicle charging infrastructure can also be introduced with a bonus-malus incentive scheme.

Third is dedicated innovation incentives. Among the more than 2300 DSOs, there are innovation leaders and laggards. For the leaders, innovation is a company strategy that can be motivated by corporate responsibility and/or by the aspiration to expand the DSO role into new businesses. DSOs are also increasingly contested in their monopoly role (e.g. the emergence of private grids and micro-grids) and can expect to be more contested if they do not innovate quickly enough. Of course, even if there is strong internal motivation to innovate, the DSO remains a regulated entity for which the regulatory framework determines to what extent the innovation strategy of the DSO is financeable.

Incentive regulation for DSOs has been successful in mimicking competitive pressure with incentives to improve cost-efficiency and incentives to improve quality. The DSOs have achieved these improvements by innovating, but the innovation that is now required from the DSOs to enter into new businesses typically spans several regulatory periods, which is more difficult to capture in incentive regulation. Some authorities have therefore introduced dedicated R&D budgets for DSOs. This is the case in Finland, Ireland and Italy. The challenging task for the regulator, then, is to monitor whether the money is well spent. The alternative is to rely on national and EU R&D funding bodies. In countries such as Germany, Sweden and Great Britain, the DSOs compete with

other players for funding. The funding agencies select and monitor the innovation projects, which relieves the energy regulator from this task. In Sweden, they can fund the entire project. In Germany, they typically fund only part of the project, but the DSOs can then ask the regulator to approve most of the remaining costs. At EU level, the Strategic Energy Technology Plan is an instrument that contributes to the identification of projects that need funding; it is also an instrument that tries to coordinate innovation efforts in Europe.

6.2.4 EU Regulatory Framework for Electric Vehicle Charging Infrastructure

CEER conducted a consultation on the role of DSOs in new businesses related to distribution grids. In the conclusions paper, many activities have been labelled as grey areas: there is potential for a market approach, but there are also conditions under which the involvement of the DSOs can be instigated. EV charging infrastructure is one of the grey area activities listed.[16]

As discussed in this section, it is indeed a grey area, and different countries are following different approaches. The national context determines the need for intervention, for instance because the national energy policy might require an acceleration of the new businesses. The national context also conditions the appeal of the DSO intervention, for instance because the consolidation and unbundling of DSOs differ widely across Europe.

The EU Clean Energy Package proposals are a first step towards an EU regulatory framework for EV charging infrastructure (see Box 6.5).

BOX 6.5 PROPOSAL FOR A DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL ON COMMON RULES FOR THE INTERNAL MARKET IN ELECTRICITY (RECAST) – ARTICLE 33 INTEGRATION OF ELECTRO-MOBILITY INTO THE ELECTRICITY NETWORK

Article 33 Integration of electro-mobility into the electricity network

1. Member States shall provide the necessary regulatory framework to facilitate the connection of publicly accessible and private recharging points to the distribution networks. Member States shall ensure that distribution system operators cooperate on a non-discriminatory

basis with any undertaking that owns, develops, operates or manages recharging points for electric vehicles, including with regard to connection to the grid.

2. Member States may allow distribution system operators to own, develop, manage or operate recharging points for electric vehicles only if the following conditions are fulfilled:
   (a) other parties, following an open and transparent tendering procedure, have not expressed their interest to own, develop, manage or operate recharging points for electric vehicles;
   (b) the regulatory authority has granted its approval.
3. Articles 35 and 56 shall apply to distribution system operators engaged in ownership, development, operation or management of recharging points.
4. Member States shall perform at regular intervals or at least every five years a public consultation in order to re-assess the potential interest of market parties to own, develop, operate or manage recharging points for electric vehicles. In case the public consultation indicates that third parties are able to own, develop, operate or manage such points, Member States shall ensure that distribution system operators' activities in this regard are phased out.

6.3 CONCLUSION

In this chapter, two new grey areas in grid regulation are discussed: offshore grids and electric vehicle charging infrastructure. The first grey area is emerging on the edge of the transmission system, while EV charging points are integrated in distribution networks. The question is: can these two new grey areas become part of the scope of the regulated network companies or should market parties be encouraged to take the lead in the development? In short, where are the boundaries of the grid?

Regarding offshore grids, the issue can be split into two. The first issue is the connection of offshore wind farms through standalone lines or hubs. Three models are identified: the TSO-led, the third party-led and the generator-led models. The majority of European offshore wind nations (Germany, Denmark, Belgium and the Netherlands) have a TSO-led model in place. TSOs construct, operate and own the offshore infrastructure. TSOs also coordinate the development of the onshore grid and the offshore connections. In those nations, 'power sockets at sea' are being built proactively to minimize delays in the connection of offshore wind farms and to profit from economies of scale. Great Britain, the leading offshore wind nation regarding generation installed, applies

a different model, namely the third-party model. OFTOs are competing for the operation and ownership of the offshore lines. In the near future, the idea is that OFTOs would also build the connections, which is currently done by the generators. With the introduction of OFTOs, cost-efficiency and innovation are encouraged, fresh capital is attracted and technical expertise is brought in.

The second issue with offshore grids is the development of combined solutions by which wind farms could be connected to multiple nations. Combined solutions would eventually lead to a meshed offshore grid, which would allow two birds to be killed with one stone: the integration of renewables and the coupling of electricity markets overseas. Studies show that a meshed offshore grid is a more efficient solution than building multiple standalone lines and separate interconnectors. However, there are multiple technical challenges (e.g. immature HVDC technology) and regulatory challenges (e.g. unharmonized national regulatory schemes and the sharing of costs) that must be overcome to allow for the gradual build-up of a meshed offshore grid. We are only at the very beginning of an EU regulatory framework for offshore grids.

The other new grey area in grid regulation discussed is the development of EV charging infrastructure. A market-based approach and a DSO approach are identified. The regulator has different roles in each. National context matters: national energy policy, the consolidation and unbundling of DSOs can affect the suitability of a business model. However, after several years of experimentation in different Member States, it seems that a market-based approach is prevailing over a DSO one. The EU Clean Energy Package is quite clear by saying that the market-based approach should be the default approach. Only in the case where market parties have not expressed an interest to own, develop, manage or operate charging points for electric vehicles, and the regulatory authority has granted its approval, is a DSO approach allowed.

With a market-based approach in place, especially combined with a low level of EV penetration, it is important to correct the market failures, for example by giving subsidies to market parties or by imposing public service obligations on market parties. Even though market parties would own, develop and operate charging points for EVs, there is still a role for the DSO to play. More precisely, DSOs will be involved in the choice of site location and will need to cooperate with charging facilities to allow for smart charging.

NOTES

1. Main data sources: http://www.gwec.net/global-figures/global-offshore/; https://transparency.entsoe.eu/; http://data.worldbank.org; https://windeurope.org/
2. Figure 6.1 is built up using data from Higgins and Foley (2014) for the 2000–2010 period and yearly reports published by Wind Europe for the 2011–2016 period.
3. For more information, see Ofgem (2014), 'OFTO build: Providing additional flexibility through an extended framework', updated policy proposal by Ofgem, published in December 2014.
4. For more information, see 'Offshore transmission: Non-developer-led wider network benefit investment', consultation by Ofgem, published in January 2014.
5. www.reuters.com/article/germany-renewables-idUSL8N19R1IG.
6. Adapted from Anzinger and Kostka (2015).
7. This goal was revised upwards later and very recently an even more ambitious goal was announced. In June 2016, the Swedish government and the parties presented a road map for a controlled transition to an entirely renewable electricity system, with a target of 100 per cent renewable electricity production by 2040.
8. Figure from Meeus et al. (2012).
9. Data found in 'Study of the benefit of a meshed offshore grid in Northern Seas Region', PwC, Tractebel Engineering and Ecofys for the European Commission, published in July 2014.
10. In July 2016, the Danish and the German governments signed a cooperation agreement on the mutual opening of auctions for PV installations. See for example the press release from the German Ministry of Economic Affairs and Energy on 20/07/2016, link: https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2016/20160720-daenemark-und-deutschland-unterzeichnen-erste-kooperationsvereinbarung.html
11. Main sources: EEA (2016), Electric vehicles in Europe, EEA Report No 20/2016; ICCT (2016), Comparison of leading electric vehicle policy and deployment in Europe, White Paper May 2016; IEA (2016), Global EV Outlook: Beyond one million cars, 2016 edition of the IEA global EV outlook series; Element Energy (2016), Towards a European Market for Electro-Mobility, Final report for Transport and Environment; Energy & Strategy Group

Politecnico di Milano (2017), E-Mobility Report, Public report published on 26 January 2017.

12. Note that there also can exist 'Airbnb-like' private charging stations, i.e. when people would offer their charging point in the garage to other EV drivers during certain times for a self-determined price.
13. As an indication – but not a requirement in the AFID (94/2014/EU) – the average number of public charging points should be equivalent to at least one charging point per ten cars.
14. Directive 94/2014/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure, *Official Journal*, L. 307, 28 October 2014, 1–20.
15. Described in more detail in Lo Schiavo et al. (2013).
16. CEER (2015), The Future Role of DSOs – A CEER Conclusions Paper, Ref: C15-DSO-16-03.

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