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FLORENCE SCHOOL OF REGULATION

MOVING THE ELECTRICITY TRANSMISSION SYSTEM TOWARDS A DECARBONISED AND INTEGRATED EUROPE:

MISSING PILLARS AND ROADBLOCKS

RESEARCH REPORT
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Abstract

The establishment of a seamless electricity transmission system and the completion of a single market for electricity in Europe are currently hindered by the lack of adequate answers to several, often basic, questions concerning the coordination of actions and decisions, the sharing of costs and benefits, and solidarity beyond costs and benefits.

This research report, prepared by the Florence School of Regulation, looks at the development of the past decades and identifies the existence of three core 'missing pillars' which explain, at least partially, why the European electricity system is affected by numerous blocking factors.

The report presents two case studies that show the importance and utility of looking at what is blocking the integration and the decarbonisation of the European electricity sector through the lens of coordination, sharing and solidarity. By doing that, the report offers a set of non-technical recommendations that points out key roles, tasks and responsibilities at national and European level for removing the two 'roadblocks' represented, on the one hand, by redispatching costs and, on the other, by capacity adequacy and electricity crisis management.

Keywords

European electricity network regulation, European electricity market integration, transmission system operation, capacity adequacy, electricity crisis management.

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Executive Summary

The purpose of this research report prepared by the Florence School of Regulation is to revisit the development of the European electricity system over the last decades and offer an analytical framework, showing where the EU has not yet achieved its target of creating a single market for electricity in Europe.[1] The report consists of two parts and five chapters overall.

The ***first part of the report*** provides the context of the research and develops the analytical framework.

Chapter 1 shows that several 'basic questions' related to the establishment of a liberalised and integrated electricity system at European level have either not been addressed by policy-makers or have received scant attention. The absence of adequate and timely answers to these questions reveals the existence of three fundamental 'missing pillars' to the realisation of a European seamless electricity transmission system and the corresponding single market for power. These core missing pillars are:

1) Coordination of actions and decisions;
2) Sharing of costs and benefits;
3) Solidarity beyond costs and benefits.

First, coordination of the actions and decisions undertaken at national and supra-national level by market players, network operators and regulatory bodies is necessary to achieve consistent infrastructure development, reliable system operation and efficient commercial transactions. *Second, sharing the costs and benefits* of electricity production and delivery among the multiple stakeholders is essential to promote the efficient use of available resources and the acceptance of public policies like market integration and decarbonisation. *Finally, solidarity beyond costs and benefits* is needed when abnormal conditions materialise, when usual coordination and sharing mechanisms no longer apply, and continuity of supply becomes the main concern.

Chapters 2 and 3 confirm the need to adequately consider the three missing pillars and to adopt clear and coherent decisions. This is achieved by providing an extensive check-list of 12 critical issues that may represent just as many 'blocking factors' to the integration and decarbonisation of the electricity industry in Europe. In particular, ***Chapter 2*** delineates eight problems strictly related to the *issue of coordination*. They are:

1) Lack of comprehensive coordination of system planning;

[1] The authors would like to thank the support of three European transmission system operators (APG, TenneT and Swissgrid). They would also thank them for the fruitful and free exchange of views on the issues addressed by this report.

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 a common reserve contracting and cost allocation;
6) No intraday cross-border allocation with auctions;
7) Lack of harmonised load shedding coordination;
8) Lack of comprehensive coordination for solidarity.

Chapter 3 presents four barriers related to the *issue of harmonisation*. They are:

1) No harmonisation of congestion rent allocation schemes;
2) Lack of harmonisation of capacity remuneration mechanisms;
3) Absence of transmission tariffs harmonisation across European countries;
4) Lack of harmonisation of 'State aid' to large energy consumers.

On some of these 12 critical issues, Europe is moving forward, while on others it is not. Indeed, the massive deployment of renewables and the overall impressive wave of technological innovation in ICT (digitalisation) are introducing new challenges – but also new opportunities – for which prompt policy response is urgent.

The ***second part of the report*** narrows the focus, offering *a detailed analysis of two critical issues* to illustrate how the methodology developed in the first part concretely works and to show how the creation of a seamless European transmission system for electricity can be blocked. The two 'roadblocks' discussed here are:

1) *Redispatching actions*;
2) *Capacity adequacy and crisis management*.

Chapter 4 analyses them, describing *the issues at stake*, the reasons why they were not tackled before and explains why they are currently hampering the process of Europeanisation.

First, *redispatching actions* are implemented by TSOs following market closure to relieve network congestions and ensure that the outcome of market transactions is compatible with the secure operation of the system. The fast deployment of RES and the growth of trade in electricity across borders over the last few years have increased the need for TSOs to implement redispatching actions and the corresponding costs. The lack of a common definition and actual data on costs, the potential redistributive impact of any allocative mechanism and the national liability of each TSO make the development of proper sharing mechanisms a sensitive topic. In turn, this slows down the development of coordination and cooperation of TSOs on redispatching actions and the optimal operation of the European interconnected system.

Second, the *assessment of capacity adequacy and the management of 'electricity crises'* are affected by the progressive deployment of variable renewable energy sources and by the growing interdependence among strongly interconnected power systems where Member States retain the right to choose their energy mix. Targeted adequacy policies adopted at national level run the risk of distorting the internal market and 'picking the winner' in the investment process. Similarly, the national responsibility of each TSO for the continuity of supply in its own country and, at times, national distrust in neighbours explain why solidarity, although most needed, is not always shown during emergency situations and ex-ante rules for that are not in place.

Looking at the two roadblocks through the lens of the three core missing pillars, ***Chapter 5*** takes an additional step and suggests *a set of seven concrete recommendations* illustrating how the methodology proposed in the report could help to unlock the situation. Three suggestions target the removal of the roadblock attached to redispatching actions, while the remaining four target the one attached to capacity adequacy and crisis management.

--- ***Nota Bene*** ---

The proposed recommendations do not pretend to offer a fully-fledged roadmap or a comprehensive set of technical solutions to the two critical issues. Their more modest but fundamental goal is to show the necessity and the utility of framing any of the problems blocking the integration of the European electricity system in terms of (i) coordination, (ii) sharing and (iii) solidarity. Fundamental questions on roles, tasks and liabilities must be addressed first. Technical solutions, coherent with the answers provided to these fundamental questions, can be properly identified only at a later stage.

In the context of the current discussion on the legislative proposals presented by the European Commission in late 2016, different Member States, industry stakeholders and the society at large can have alternative and even opposing views on how to address the critical issues and the roadblocks defined in the report. Depending on their understanding of such a complex thread of interrelated problems and their specific visions or interests, they can support different solutions. Nevertheless, if they all acknowledge the necessity to address, in their proposals, the missing pillars and provide a clear answer to the basic issues of coordination, sharing and solidarity, then concrete progress in the integration of the electricity system will be possible to the benefit of the European citizens.

Introduction[2]

January 2017 will be remembered as one of the coldest months in the recent history of Europe. Even if not as low as those recorded in February 2012, temperatures were from five to ten degrees below the historical average. Rivers in Central Europe were frozen and snow fell heavily in Istanbul and South East Europe.

Electricity consumption skyrocketed, especially in countries like France that deeply rely upon it for heating households and offices. Despite general discussions of overcapacity in electricity, available generation in Europe was rather limited in those weeks for several reasons: low hydropower capacity due to frozen rivers and empty reservoirs, lack of wind and short sunny days, exceptional maintenance and security checks on some French nuclear reactors.

The overall supply and demand balance was tight in many European power systems. On 11 January RTE, the French Transmission System Operator (TSO), announced that demand could exceed domestic supply and import capacity during the following week: emergency actions like load shedding could not be excluded. The situation in Belgium and Italy was not much better.

At the same time, the Romanian government introduced emergency measures, allowing the curtailment of electricity export in case of need. Affected by severe capacity shortages, Bulgaria and Greece imposed reductions in export capacity as well. In some areas electric load had to be occasionally shed.

Citizens and firms in Central West Europe were luckier. Close coordination by the respective TSOs and an improvement in weather conditions enabled the system to overcome the worst moments without curtailing demand. By the end of the third week of January, the tight balance between supply and demand had eased somewhat and prices, which had reached record levels in most of the European power exchanges, began to decrease.

What does this story tell us? What can we learn from it?

It basically tells us that more than 20 years since the beginning of a European energy policy – the first Directive on an internal market for electricity was adopted in 1996 – issues like solidarity, coordination and cost and benefit sharing are still not well established in the EU, at least as far as the electricity sector is concerned.

Solidarity, for instance, is still missing because emergency plans and actions remain mainly national in focus. Supply to internal customers is considered to be the priority and support is not always provided to neighbours facing hard times. Coordination among the different actors of the energy system remains difficult, especially when a national border lies between them.

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[2] The authors of the research report would like to thank APG, TenneT and Swissgrid for their support and the valuable exchange of views. They would like to thank Anne Marie Kehoe as well, for the revision of text and the useful comments on previous drafts.

However, coordination is not only missing under exceptional conditions. It is often missing under normal conditions as well. Many factors can be blamed for this absence: lack of information transparency, poorly defined roles and a lack of general rules on how to share costs and benefits.

The 'electricity crisis' of January 2017 teaches us that the risks behind the still missing 'pillars' of the European edifice are relevant, and not only in narrow economic terms. Simply imagine how a blackout affecting several countries arising from issues with cross-border coordination can be exploited to negatively fuel the current strained debate over the future of Europe. Or the resentment that can arise from households left in darkness due to the decision of a neighbouring country to curtail cross-border capacity to avoid, during a period of major capacity shortage, price spikes in its domestic market.

*

This report, building on the results of a previous study,[3] aims to analyse the issues of *coordination*, *sharing* and *solidarity* in the context of the European electricity sector and to provide some concrete recommendations about the necessary short-term evolution of the functioning of the European transmission system.

Our work is divided into two parts, the first of which consists of three chapters, while the second of two.

In *Chapter 1*, the analytical framework is presented and the issues of coordination, sharing and solidarity are described in detail. Looking back at the development of the European energy policy, the chapter shows that these three 'missing pillars' are related to policy questions, sometimes very basic ones, that have not been clearly addressed at the appropriate time or not addressed at all in the past two decades.

Chapters 2 and 3 then provide an overview of 12 'blocking factors', which are impeding the integration process, the transition to a low-carbon economy and the full embrace of the current digital revolution. Their existence, the chapters show, can be mainly explained in terms of the missing pillars presented in Chapter 1.

Building on this background, the second part of the report zooms in and examines two major topics that are particularly relevant in the recent development of the European power sector: i) redispatching actions and ii) capacity adequacy and crisis management. *Chapter 4* provides a description of these 'roadblocks' and shows how they are the direct consequences of the missing pillars mentioned above.

Finally, *Chapter 5* takes an additional step and suggests a few practical recommendations on how to handle and 'remove' those roadblocks to further the Europeanisation process of the electricity industry.

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[3] Glachant J.M., V. Rious and J. Vasconcelos (2015), *A conceptual framework for the evolution of the operation and regulation of electricity transmission systems towards a decarbonised and increasingly integrated electricity system in the EU*, Florence, EUI.

The exercise proposed in this study is particularly relevant after the publication of the so-called 'Winter Package' by the European Commission (EC).[4] However, our report does not aim to analyse all the numerous proposals put forward by the EC. Its purpose is more modest and more fundamental.

Our work illustrates that the existing EU electricity 'building' is still fragile and suffers from some weaknesses due to questions that were avoided or not properly answered in the past and the ensuing missing pillars of *coordination*, *sharing* and *solidarity*.

Our study shows how this analytical framework concretely works in the case of redispatching actions and in that of capacity adequacy and crisis management. It offers, for these two specific issues, some coherent recommendations that are not technical in nature but rather indications of how to identify and allocate important roles and tasks, so that some of the basic, long overdue questions can finally be addressed.

Different stakeholders in or around the power industry and different European countries may have alternative and even opposing views on the solutions proposed. It is natural in a public debate concerning complex questions, where significant and conflicting interests are at stake. However, what the report wants to highlight is the relevance of the issues we raised and the need to address these core structural failings. If there is a desire to proceed with the Europeanisation of the electricity sector, this must be done: by you the readers, by us the Europeans.

If any practitioner, decision-maker or scholar is particularly keen on this ultimate objective, she or he is very welcome to follow in the spirit set out in this report and perform a similar exercise on some other important topics that are blocking the development of the European power sector. By doing that, she or he will certainly feed the debate on the Winter Package and improve the quality of the current policy decision-making process.

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A final remark. Our study is quite long and not always easy to read. It is the price to pay for a comprehensive view and detailed analysis. However, time-constrained readers will get all our main points simply by reading the short executive summaries provided at the beginning of each chapter. Each summary, in three minutes reading, summarises the key points and conclusions of the respective chapter and gives the reader a nice and fast opportunity to understand the essentials the report would like to convey.

[4] The official name of the Package published by the EC on 30 November 2016 is "Clean Energy for All Europeans". It comprises several communications and legislative proposals that are available on the EC webpage.

Part 1 – *"Some unanswered questions – too basic or too difficult to tackle?"*

The ongoing EU 'energy transition' requires the electricity industry to simultaneously accomplish the supra-national integration of European energy markets and contribute to a low-carbon economy, while embracing the current digital revolution.

As we mentioned in a previous report, *"because there are many uncertainties and some degrees of freedom as regards policy choices and their implementation, diverse future scenarios are conceivable".*[5] Consequently, we did not – and we do not – suggest or recommend any particular scenario. In place of offering recommendations, we provided a conceptual framework, which assessed and compared different options, showing the impact of different structural changes upon the governance and regulation of electricity systems and markets. In order to enable a timely, organised and efficient transition, it is crucial to recognise that *"although several alternative paths may lead to decarbonisation and integration of present electricity systems, each path presents its own governance and regulatory challenges and it commands specific actions"*[6]. In other words, the previous report stressed that whatever policy and technology choices are made, it is crucial to ensure the internal consistency of the selected path, in particular as regards the governance architecture and regulatory strategy; otherwise, the energy transition will be unnecessarily costly and protracted.

In the present report, we go beyond the comparative analysis of alternative governance and regulatory requirements – we provide more concrete recommendations about the necessary short-term evolution of the functioning of the European transmission system. These recommendations illustrate that any sound way for the EU to progress has to be based, to a large extent, on the critical analysis of past failures observed during the transition from national monopolies to liberalised and increasingly integrated electricity markets in the EU.

The failure to provide clear and timely answers to some basic questions is one of the reasons why full integration of national EU electricity markets has not yet been achieved and large price differences persist across the EU Member States.

Since the beginning of electricity liberalisation in Europe, some basic questions have been persistently avoided. Very often, the explanation given for this attitude was that these were too basic questions that markets would solve in the best possible way, hence legislative or regulatory interventions were not necessary.

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[5] Glachant J.M., V. Rious and J. Vasconcelos (2015), *A conceptual framework for the evolution of the operation and regulation of electricity transmission systems towards a decarbonised and increasingly integrated electricity system in the EU*, Florence, EUI.
[6] *Ibid*.

Twenty-one years after the first Directive on an internal market for electricity, several issues remain, which neither the markets nor legislators or regulators have managed to resolve. It has had a marked effect upon the completion of the Internal Energy Market (IEM) and is making the transition to low-carbon electricity systems more difficult and costlier. Therefore, it is imperative to directly and comprehensively address these issues and the underlying difficulties and associated implications. This is the main aim of the present report.

In some cases, unanswered questions result from the fact that various roles, responsibilities and obligations are not well enough, or even not at all, defined in the current legal framework governing the EU electricity market. In the 'old system' of voluntary agreements among monopolies, roles and responsibilities were a matter of gentlemen's agreement. When the process of liberalisation commenced, these agreements were not transposed into law. However, 21 years later, it is crucial to be more explicit and lay down the terms of those agreements more transparently in legislation.

There has been much confusion surrounding the functions and responsibilities of certain bodies, especially in the past decade. We have seen EU legislators avoiding basic political questions, but imposing instead detailed technical solutions that would have been better addressed by regulators and system operators, had these political questions been answered. We have observed system operators and market operators taking decisions that should have been addressed by legislators and regulators, because without some of these decisions their operational duties could not be properly fulfilled. We have seen regulators forgetting their legal duties to promote *"a competitive, secure and environmentally sustainable internal market in electricity within the Community"* and to eliminate *"restrictions on trade in electricity between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows across the Community"*, because they feared negative reactions from national consumers, undertakings or politicians.

As the European Commission recently launched a comprehensive set of legislative proposals ("*Clean Energy for All Europeans*"), it is the right moment to revisit these unanswered questions and to consider some possible solutions. This is necessary, not just to come closer to a truly Internal Energy Market, which is transparent, efficient and reliable, thus fulfilling a long-established political goal, but also in order to speed-up the efficient transition towards low-carbon energy systems in the EU.

The first part of this report provides a short 'check-list' of critical issues that should be used as a yardstick to assess the usefulness of any legislative proposal aimed at answering the fundamental questions and solving the essential problems that have hampered the realisation of the Internal Electricity Market. We hope this list helps to focus the debate on the most crucial topics, thus avoiding premature discussions about important but 'second-order' issues, i.e. issues that, from a logical viewpoint, should be addressed only after the fundamental questions got a clear answer.

*

The ‘unanswered questions’ addressed in this report will be divided into three groups, corresponding to three basic concepts: coordination, sharing and solidarity. They represent the ‘missing pillars’ of the Internal Energy Market for both electricity and natural gas.

Coordination

Whenever market mechanisms are introduced for the electricity industry, the need for new forms of coordination inevitably arises. Whenever a supra-national electricity market is established by law in interconnected systems, it becomes necessary to coordinate the functioning of the supra-national market. As described in the present report, neither of these issues is adequately addressed in present legislation.

Coordination is critical at two levels:

1) system planning

2) market and system operation, in particular as regards:

- system operation in general;
- remedies policy in general and redispatching in particular;
- reserve contracting (and cost allocation procedures);
- intraday auction-based cross-border allocation;
- load shedding.

Although important progress has been achieved, namely as regards the coordination of system planning and of system operation under normal conditions, it is urgent to clearly define the roles and the procedures associated with all of the above-mentioned areas.

Sharing

The design of coordination schemes for normal market conditions involves choices about how to share costs and benefits on a permanent basis. Sharing requires, first of all, a clear identification of purpose (‘where the system should go’ in terms of increased efficiency, expansion, adaptation to new policy goals, etc.), followed by a clear identification of costs (including rents, the ‘cost of non-Europe’, etc.). It is only afterwards that meaningful and coherent economic signals can be designed.

Cost allocation and incentive design may be based upon sophisticated scientific principles and complex software tools. However, this regulatory paraphernalia should not work against the legal and political principle of *“improving and integrating competitive electricity markets in the Community”*.[7]

Explicit sharing solutions are urgent in several areas, namely:

[7] Article 1 of Directive 2009/72/EC.

- congestion rent allocation;
- capacity remuneration;
- remedial actions in general and redispatching in particular.

Solidarity

Under abnormal market conditions (e.g. when non-EU primary energy suppliers interrupt their export flows or when extreme weather conditions cause massive outages in a given area), special coordination mechanisms are needed. In these circumstances, burden (and benefit) sharing procedures usually derogate from the standard rules; continuity of supply is then the main concern. However, for the effective functioning of systems and markets, it is necessary to establish ex-ante how to operate the system and how to share costs and benefits during the transient period. The general principle of 'solidarity', enshrined in the EU Treaty and in EU energy legislation, must be translated into very concrete operational procedures.

Chapter 1 – Overview

Executive Summary

In the last 25 years, the European Union has embarked on a transition from national, publicly owned electric monopolies to liberalised and increasingly integrated electricity markets. However, since the beginning of this long journey some basic questions have been persistently avoided by policy-makers or have received mainly partial and untimely answers. The failure to properly address these issues has meant that some of the building blocks to the Europeanisation of the electricity industry are still missing. In turn, this has slowed down the completion of the Internal Energy Market and is making the drive towards a low-carbon economy more difficult and expensive.

The first chapter of the report sets out the analytical framework and the context of the research. In particular, it identifies and describes three core missing pillars: i) coordination of actions and decisions; ii) sharing of costs and benefits; and iii) solidarity beyond costs and benefits (a list of 12 blocking factors will be discussed in subsequent chapters).

First, *coordination* in the electricity industry is required to achieve consistent infrastructure development, reliable system operation, and efficient commercial transactions. Each of these three major objectives are interdependent, requiring a holistic analysis of the specific coordination mechanisms to adopt among the different available possibilities.

In the 1990s, the transition to liberalised national markets and their integration at supra-national level called for the revision of the existing solutions and, in some cases, for their adjustment or outright substitution. Unfortunately, EU legislation provided little or no concrete guidance for the definition of new coordination mechanisms. Member States adopted different market models, while TSOs and market operators carried on with legacy contracts or initiated new ad hoc bilateral transactions. Old rules were adapted in a piecemeal way, mainly on a voluntary basis. ‘Bottom up’ initiatives, like that of market coupling, tackled only partially and slowly the fragmented landscape which had emerged from the misapplication of the subsidiarity principle and the underestimation of the relevance of coordination. Recently, some important issues have been addressed through Commission Regulations. This represents a step forward, but it will not be enough to achieve the necessary degree of coordination mentioned above.

Second, *sharing* costs and benefits is essential and is not a trivial problem in real world electricity systems and markets. Limited resources, like the capacity of congested transmission lines, must be allocated to the different network users. Actors responsible for the provision of public goods, such as frequency regulation and voltage support, must be identified and remunerated. In general, appropriate incentives and penalties are necessary to promote the efficient use of available resources and the effective achievement of public goals.

The liberalisation and the integration of electricity markets launched in the 1990s, together with the energy transition pursued since the end of the 2000s, called for clear decisions on how to share the profits and the costs of cooperation. This did not always occur, because clear decisions would have required the identification of legitimate winners and losers among different categories of market actors and network users, and among different Member States. Regrettably, the reluctance to openly discuss redistributive principles often slowed down the decision-making process or led to the adoption of inefficient solutions.

Lastly, *solidarity* is a key principle in the European Treaties. Member States are supposed to express it to their peers under abnormal conditions, when continuity of supply is the main concern and the usual coordination and sharing mechanisms are suspended. It requires the ex-ante definition of roles and operational rules for the management of emergencies as soon as they materialise.

After the 'gas wars' of the last decade, the importance of solidarity has been acknowledged in relation to natural gas, while in the electricity sector it is for the moment still a vague reference, lacking concrete substance. The Directive on electricity security of supply, drafted after the 2003 Italian blackout, is almost useless from a practical point of view and even the current draft of a Network Code on emergency and restoration provides no substantial operational definition of solidarity.

1.1 Introduction

This Chapter presents a list of several unanswered questions, describing the organisational context and historical perspective through which they must be analysed. In some cases, these issues were completely avoided; in other cases, insufficient or imperfect answers were provided. These have led to failings which can be grouped under three different categories:

1) Coordination

Whenever market mechanisms are introduced in the electricity industry, the need for new forms of coordination inevitably arises. In particular, it is necessary to coordinate:

a) economic transactions and

b) market operation with system operation.

Furthermore, it becomes necessary to review the way technical coordination (i.e. system operation) is performed.

On the other hand, whenever a supra-national electricity market is established by law in interconnected systems, it becomes necessary to coordinate the functioning of the supra-national market. Furthermore, it becomes necessary to review the way technical cooperation among the interconnected Transmission System Operators (TSOs) is performed.

2) Sharing

The design of coordination schemes for normal market conditions involves choices about how to share the costs and benefits on a permanent basis. Distinct choices affect Member States and/or particular groups (generators, consumers, network operators, etc.) in different ways. Answering these questions related to sharing requires the implementation of redistributive actions – someone will 'give' and someone else will 'receive'; someone will benefit 'today', others 'tomorrow'; etc. In democratic and market-based polities, these choices are based on fundamental (economic, ethical, etc.) principles of burden and profit sharing, not on the threat of force, arguments of authority or other means of coercion.

The reluctance to openly discuss these principles and to explicitly address these questions means that redistribution has either been done implicitly or it has been avoided in order to go ahead, maintaining the status quo. This has been the cause of many conflicts, inefficiencies and unfair situations; and it delays the necessary adoption of new agreements.

The question of 'sharing' has often been avoided not only at EU level, but also at Member State level. Sharing requires, first of all, a clear identification of purpose (‘where the system should go’ in terms of increased efficiency, expansion, adaptation to new policy goals, etc.), followed by a clear identification of costs (including rents, the ‘cost of non-Europe’, etc.). It is only afterwards that can meaningful and coherent economic signals can be designed.

3) Solidarity

Under abnormal market conditions (e.g. when non-EU primary energy suppliers interrupt their export flows or when extreme weather conditions cause massive outages in a given area), special coordination mechanisms are needed. Under these circumstances, burden (and benefit) sharing procedures usually derogate from the standard rules; continuity of supply is then the main concern. However, for the successful functioning of systems and markets it is necessary to establish ex-ante how to operate the system and how to share costs and benefits during the transient period. The general principle of ‘solidarity’, enshrined in the EU Treaty and in EU energy legislation, must be translated into very concrete operational procedures.

Each of these three issues – coordination, sharing, and solidarity - are core building blocks or pillars, which will be discussed in more detail in the coming sub-Chapter 1.2.

1.2 The three ‘missing pillars’

1.2.1 Missing Pillar 1: Coordination in electricity systems

1.2.1.1 Why coordination is important

Coordination is a prerequisite for the fulfilment of three major objectives:

- Consistent development of cross-border and national infrastructure (networks), i.e. efficient infrastructure investment;
- Reliable system operation, i.e. the secure and safe use of the available infrastructure and other resources;
- Trade development, i.e. efficient markets.

These three aspects are not independent: in fact, they build a precedence chain (see Fig. 1.1). If electricity could be traded like shares on the stock exchange, without an underlying physical network, the space of possible transactions would be considerable. However, the physical infrastructure (i.e. topology, transmission capacity, electrical and mechanical characteristics of the different components, etc.) represents a severe restriction on the way energy can flow in order to be exchanged and the system can be safely and reliably operated, when implementing these exchange-related flows. System operation is further bound by the location and characteristics of generators, consumers and other facilities such as pump storage plants. The combined effect of infrastructure and operational restrictions clearly limits the type and volume of commercial transactions that can be carried out. Finally, market rules themselves may further limit the space of feasible electricity transactions (for instance, by giving precedence to power plants based on some primary energy sources).

Because these three ‘spheres’ (infrastructure, system operation, market operation) are interrelated, coordination within each sphere should be open to interaction with coordination with the other spheres. In other words: although for practical reasons it is convenient to treat each of these three forms of coordination separately, from time to time (e.g. when considering a substantial market reform) it is useful – even indispensable – to look in detail at the whole system dynamics over time, within a holistic analysis of how the three forms of coordination interrelate.

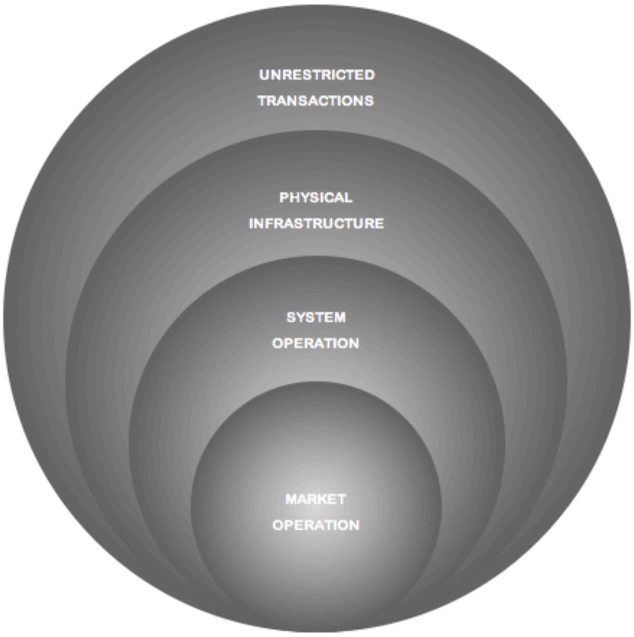


Fig 1.1: Successive restrictions of the electricity transactions space

1.2.1.2 How coordination can be implemented

Coordination is always crucial in order to ensure the proper functioning of interconnected electricity systems, both at planning and at operational stage.

At the level of planning, it is obvious that the construction of any cross-border line, as well as related infrastructures on both sides of the border, requires coordination between the respective TSOs. It is not only rights-of-way and equipment specification that must be agreed between the TSOs, but also commissioning procedures and the very timing of the project need to be jointly decided by the concerned parties. Somehow, cross-border lines must fit within the national transmission network expansion plans of the neighbouring countries. Therefore, their existence implies a certain degree of network planning coordination between countries, also taking into account merchant lines. If the interconnected network is supposed to physically support the functioning of a single, supra-national integrated electricity market, then all relevant aspects related to the expansion, operation and maintenance of cross-border lines should be collectively discussed and agreed by the concerned interconnected TSOs. Finally, one should recall that planning means, by definition, the coordination of different resources *"to achieve or do something"*[8] – not only at EU level, but also at national or local level.

If we now turn to the operational level, four different types of coordination are actually required (see Fig. 1.2):

[8] http://www.merriam-webster.com/dictionary/planning.

1. Technical coordination between generators (injections) and loads (withdrawals), controlling physical flows throughout the whole system – known as ‘system operation’;
2. Commercial coordination between supply and demand, directing financial flows – known as ‘market operation’;
3. Coordination between the technical/physical and the commercial/financial processes – i.e. between system operation and market operation;
4. International coordination among actors from different countries inside an interconnected electricity system (international coordination can be organised in different ways, corresponding to different types of interaction at each level of coordination: technical, commercial and technical/commercial).

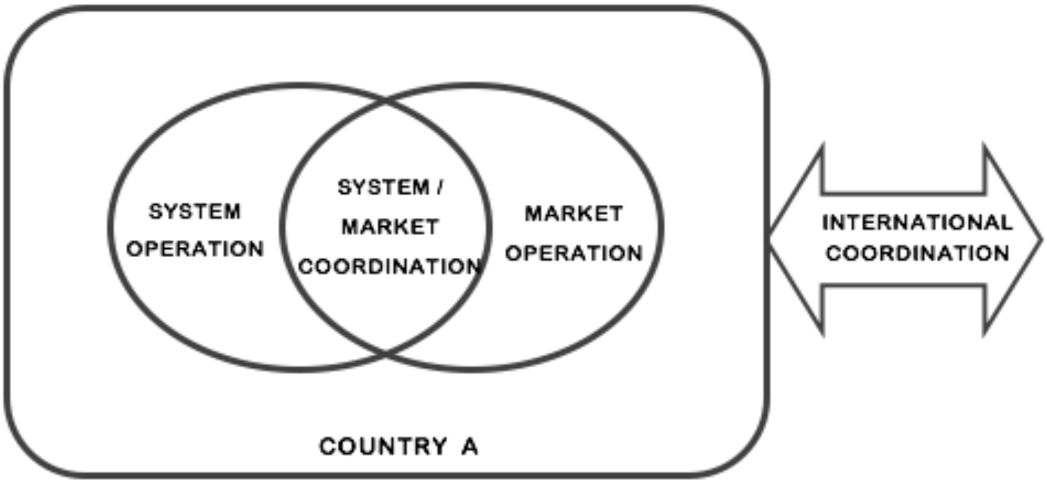


Fig 1.2: Operational coordination in interconnected electricity systems and markets

There are many different possible ways of organising coordination. We will briefly discuss here how international coordination can be arranged.

If the TSOs of the interconnected system merged into one Single System Operator (SSO) and the different existing market operators merged into one Single Market Operator (SMO), the outcome would be a situation similar to the one currently existing at national level (although in some countries several TSOs coexist). Indeed, we will end up with a single system operator and a single market operator throughout international transactions (see Fig. 1.3).

Fig 1.3: Single Market Operator / Single System Operator

Coordination between system and market operators would be a straightforward iterative process similar to the current situation in most EU Member States – see Fig. 1.4.

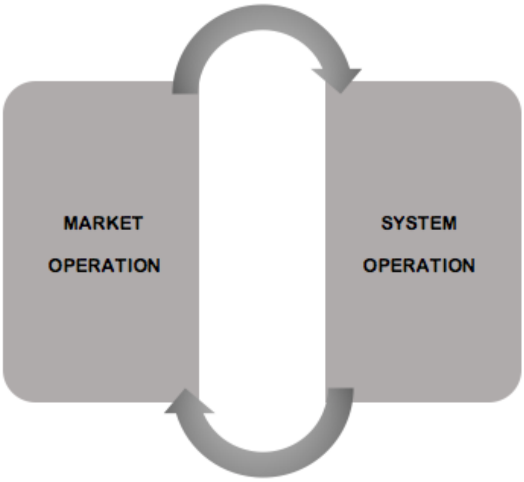


Fig 1.4: Coordination between SSO and SMO: an iterative process

Another conceivable architecture consists of one Single Market Operator (SMO) coexisting with Multiple System Operators (MSOs), as depicted in Fig. 1.5. The Nordic model works in this way.

Fig 1.5: Single Market Operator / Multiple System Operators

In this case, two alternative coordination strategies could be implemented, as indicated in Figures 1.6 and 1.7 – respectively, parallel and sequential coordination. In the 'parallel' case, each system operator interacts bilaterally and simultaneously with the single market operator; in the 'sequential' case, first there is a horizontal coordination process among system operators and then, once their coordination is accomplished, a vertical coordination process with the single market operator. In both cases, several iterations may be necessary in order to reach a satisfactory solution.

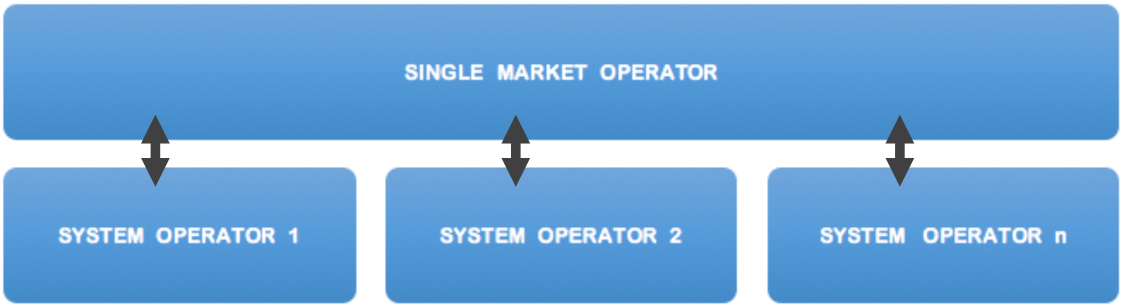


Fig 1.6: Parallel coordination

Fig 1.7: Sequential coordination

Conversely, it is conceivable to have one Single System Operator (SSO) coexisting with Multiple Market Operators (MMOs), as described in Fig. 1.8.

Fig 1.8: Single System Operator / Multiple Market Operators

As in the previous case, which was characterised by a single market operator and multiple TSOs, both parallel and sequential coordination strategies could be implemented between the individual TSO and the many MOs (it suffices to exchange the words 'market' and 'system' in Figures 1.6 and 1.7 above to visualise how they would work).

The present situation in the European Union is not as integrated as the above-portrayed scenarios. It still corresponds to a very fragmented landscape, with numerous national system operators and market operators – see Fig. 1.9. Technical and economic concerns vary from country to country and, as George Orwell would say, all operators are equal, but some operators are more equal than others.

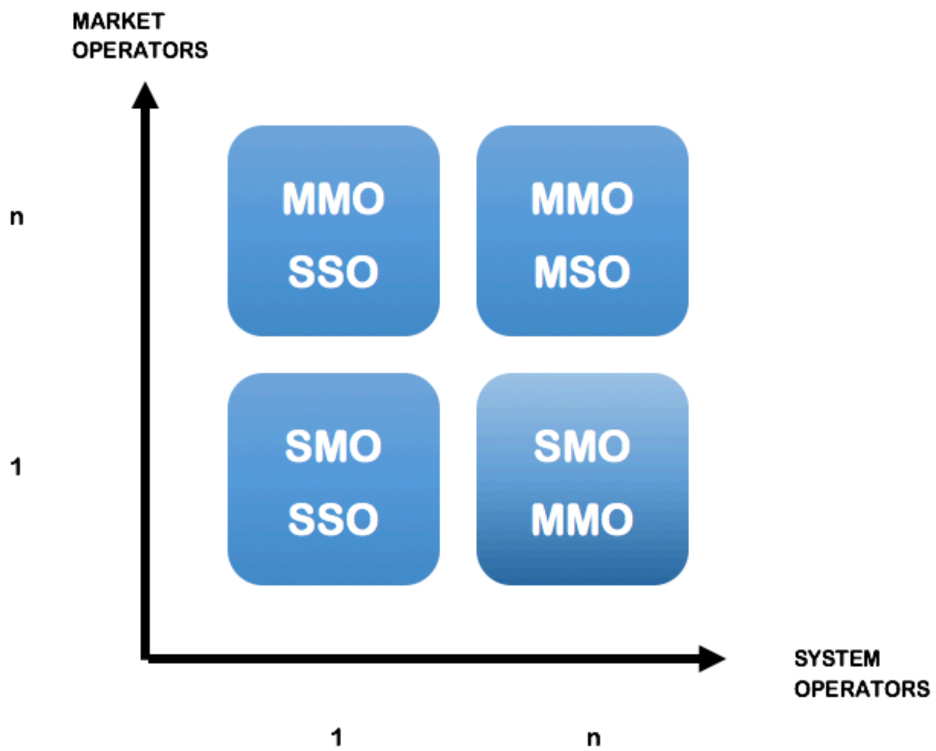
Fig 1.9: Multiple System Operators / Multiple Market Operators

Under the current circumstances in Europe, several coordination strategies are possible, combining functional (market/system operation) and geographical dimensions according to different sequences. For example, one may give higher priority to the geographical (e.g. regional) approach or to the functional (e.g. market coupling) method.

It should be pointed out that, in the analytical framework of this chapter, ‘market operation’, ‘system operation’ and ‘coordination’ are ‘information processing entities’: they act basically as algorithms with their associated data inputs and outputs. From the point of view of information and complexity analysis, ownership of these entities is not the key point. However, while ownership can be irrelevant from the computational point of view, it plays a very important role in terms of accountability, liability and incentives.

From the complexity analysis point of view, the ‘two single’ scenario is the ‘best’ one. With only one TSO and only one MO, we get the lowest degree of complexity and therefore the fastest computational performance. Conversely, the ‘multiple/multiple’ scenario, with multiple TSOs and multiple MOs, requires more computational resources and, therefore, is slower. Computational time becomes less critical as the performance of processors and storage devices increases; however, there is a cost factor to be considered and, moreover, the more time that is available for market agents and system operators to perform their tasks, the better. In practice, time is still very critical for real-time applications, when reliability and control of the interconnected system are at stake.

In summary, Fig 1.10 shows the possible combinations of system and market operators.



MMO: Multiple Market Operators MSO: Multiple System Operators

SMO: Single Market Operator SSO: Single System Operator

Fig 1.10: Possible combinations of market and system operators in any interconnected system

1.2.1.3 The different issues being arranged by coordination

Coordination in electricity systems and markets deals with four types of issues: ‘roles’, ‘rules’, ‘infrastructure assets’ and ‘enforcement’:

1) **Roles**, clearly defining the rights and duties of each party involved in the process: the coordinators, the coordinated and the supervisors/regulators;
2) **Rules**, establishing the methods and procedures and implementing the corresponding ‘software’ for all forms of agreed coordination, including rules for cost and benefit allocation;
3) **Infrastructure assets**, providing the necessary ‘hardware’, regarding both electrical facilities and the information and communication systems which are needed to implement the ‘software’ of the rules (this requires coordinated investments and maintenance protocols);
4) **Enforcement**, establishing the necessary procedures for monitoring, dispute settlement, etc.

Although coordination is also feasible among heterogeneous parties (for example, interconnected transmission networks may exhibit different sizes and voltage structures at national level, while coupled wholesale markets may exhibit different volumes and numbers of associated agents), a certain degree of harmonisation is in principle required. For example:

1) The harmonisation of gate closure times enables more efficient market coordination among coupled markets; different closure times make coordination more complex, more expensive and more prone to opportunistic behaviour;
2) Non-harmonised transmission tariffs introduce a certain degree of distortion of competition among generators/suppliers located in different countries; considerable differences in transmission tariff structures may *de facto* inhibit cross-border trade, hence making the coordination of cross-border trade impossible for economic and not for technical reasons.

The lack of appropriate harmonisation may lead to inefficient and unfair outcomes (as in example 1 of gate closures) or even to the disruption of coordination and its eventual collapse (as in example 2 of tariffs). Therefore, it may be stated that a certain degree of harmonisation is a precondition for coordination – and even for the existence of supra-national electricity systems and markets.

Associated with the coordination issue, two typical harmonisation questions usually arise:

a) What should be harmonised?
b) To what extent should it be harmonised?

In some cases, harmonisation itself may be seen as a form of coordination (e.g. harmonising transmission tariffs may be considered as tariff setting coordination across several jurisdictions).

However, different coordination strategies lead to different redistributional effects. Different coordination mechanisms imply different ways of sharing costs and benefits resulting from the interconnection of national systems and from the coupling of national markets. Therefore, the two concepts of 'coordination' and 'sharing' are closely related in actual decision-making.

In our analysis of these unanswered questions, we distinguish between intrinsic or first-order coordination issues (Chapter 2) and more harmonisation-related, second-order coordination topics (Chapter 3).

First-order coordination is more focused on procedures, from a technical/functional point of view. On the contrary, second-order coordination is more focused on an economic point of view. This distinction is useful for a clearer writing of the report while real life frequently mixes them up.

1.2.1.4 Operational coordination and liberalisation in the European Union legal framework

Within a vertically integrated monopoly, operational coordination, including all relevant aspects, is performed by a single 'control centre' (although some functions may be delegated to regional centres). Consumers 'participate' in system operation by switching on and off their devices, but they cannot choose which generator supplies them. The control centre decides, taking into account, simultaneously, economic and technical criteria.

In continental Europe, in the old days of national monopolies, international coordination of the system operation was performed on a voluntary basis through a self-regulated body (UCPTE), set up by the national transmission operators (almost all of them part of a vertically integrated undertaking) in 1951.This body defined both technical and commercial conditions for cross-border transactions (exclusively between national monopolies).[9]

Liberalisation introduces a new set of agents free to decide how much, when and where to produce, to sell and to buy electricity. However, this commercial freedom must remain compatible with the safe and reliable operation of the whole system; in some cases, technical constraints may limit the freedom of individual agents. Obviously, being more decentralised, with many more players, a liberalised system requires more – and more complex – coordination than a vertically integrated monopoly.

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[9] A similar voluntary organisation was created in 1963 in the Nordic countries (NORDEL). On the 1st of July 2009, all existing European technical coordination associations merged into the European Network of Transmission System Operators for Electricity (ENTSO-E).

The first electricity Directive, approved in 1996,[10] simultaneously liberalised national markets and cross-border trade. However, it did not provide any guidance on coordination, leaving it to the Member States to decide how to design and implement new coordination mechanisms. All that the Directive offered as practical rules for the organisation of the sector were a few vague statements (see Box 1.1).

As regards cross-border coordination, the Directive just stated, in an incredibly naive way, that *"the system operator shall provide to the operator of any other system with which its system is interconnected sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system"*.

Box 1.1: Common rules for the organisation of the EU electricity industry, 1996 Directive

- *Member States shall ensure, on the basis of their institutional organization and with due regard for the principle of subsidiarity, that (...) electricity undertakings are operated in accordance with the principles of this Directive, with a view to achieving a competitive market in electricity, and shall not discriminate between these undertakings as regards either rights or obligations. The two approaches to system access referred to in Articles 17 and 18* [regulated, negotiated or single buyer] *must lead to equivalent economic results and hence to a directly comparable level of opening-up of markets and to a directly comparable degree of access to electricity markets.*
- *Member States shall ensure that technical rules establishing the minimum technical design and operational requirements for the connection to the system of generating installations, distribution systems, directly connected consumers' equipment, interconnector circuits and direct lines are developed and published. These requirements shall ensure the interoperability of systems and shall be objective and non-discriminatory. They shall be notified to the Commission (...).*
- *The system operator shall be responsible for managing energy flows on the system, taking into account exchanges with other interconnected systems. To that end, the system operator shall be responsible for ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services.*
- *The system operator shall not discriminate between system users or classes of system users, particularly in favour of its subsidiaries or shareholders.*
- *The transmission system operator shall be responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems.*

[10] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, *Official Journal,* L 27/20, 30 January 1997.

− *The dispatching of generating installations and the use of interconnectors shall be determined on the basis of criteria which may be approved by the Member State and which must be objective, published and applied in a non-discriminatory manner which ensures the proper functioning of the internal market in electricity. They shall take into account the economic precedence of electricity from available generating installations of interconnector transfers and the technical constraints on the system.*

This is a clear case of misapplication of the subsidiarity principle. If there was no physical interconnection between electricity systems, each Member State might freely define the technical and commercial coordination mechanisms in its own way. In an interconnected system, however, cross-border transactions are only possible if there is a certain degree of harmonisation of technical and commercial rules among Member States. Even worse: in an interconnected system, if a suitable cross-border coordination mechanism is not agreed, the decision of one Member State concerning its internal coordination mechanisms may have a negative impact upon coordination – and performance – in neighbouring systems.

In interconnected network industries, subsidiarity requires some rules (not all rules!) to be collectively established at supra-national level, because that is the only place where these rules can be agreed and enforced. Politically and statistically, it is fair to state that parallel decisions of individual Member States will not deliver, spontaneously, the kind of supra-national coordination that enables the functioning of a Single Energy Market.

For example, if one Member State sets up a mandatory power pool and in one of its neighbours the market is exclusively based on bilateral contracts, there is a problem of coordination and the outcome will be the absence of cross-border transactions until some degree of harmonisation and coordination is achieved (this situation happened actually at several EU internal and external borders).

Managing different forms of coordination with each neighbour is not a very efficient way of promoting cross-border trade. Moreover, it creates insurmountable obstacles for agents located in different, non-adjacent Member States, wishing to enter into a business relationship. The only logical way out of this patchwork jungle is to agree on appropriate coordination mechanisms and some degree of harmonisation at supra-national level. In interconnected network industries, *"due regard for the principle of subsidiarity"* means addressing and explicitly solving, at EU level, issues that can only be solved at EU level, not leaving Member States with problems that they cannot solve individually.

The lack of coordination mechanisms in the first European electricity Directive led to two parallel movements:

− At the national level, Member States adopted different market models and different coordination mechanisms. A few Member States had liberalised their respective markets before 1996, while in other Member States the Directive was transposed with considerable delay and reluctance. In 1998, for instance, England was about to abandon the power pool introduced eight years before, Spain had just introduced a mandatory power pool, Germany opened the market to competition without any regulation or normative market model and in France the electricity *ancien régime* would still last two more years. The combined absence of harmonisation and appropriate coordination created 15 parallel national markets (this number obviously increased with the 2004 and successive EU enlargements). Each Member State adopted different national coordination mechanisms, according to its basic market model choices.

- At EU level, a certain void was created, since the old UCPTE rules were not compatible with liberalised markets and no new rules had been enforced – not even designed! Legacy contracts were further carried out, some new bilateral ad hoc transactions were initiated and transmission network operators succeeded in 'keeping the lights on', adapting the old rules in a piecemeal, 'pragmatic' manner and keeping their communication channels and coordination procedures in place as long as these were not challenged by regulation or the courts. A few market operators took the lead in promoting 'market coupling' in their realm through voluntary agreements and received support from TSOs, regulators and the European Commission.

The 'operational coordination' issue was not properly addressed by EU legislation for twenty years, i.e. until 2015. It is the 'Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management' which established the foundations.[11] Until then, it was mainly a non-regulated, contractual TSO relationship.

The 2009 'Third Energy Package' was more concerned with breaking coordination within vertically integrated undertakings through 'unbundling' than about the design and enforcement of suitable new forms of coordination among TSOs and market operators, as revealed by the following statement:

"Without effective separation of networks from activities of generation and supply (effective unbundling), there is an inherent risk of discrimination not only in the operation of the network but also in the incentives for vertically integrated undertakings to invest adequately in their networks".[12]

As regards operational coordination, the 2009 electricity Directive maintains the same *laissez-faire* approach of the 1996 Directive. Each TSO is responsible for *"managing electricity flows on the system, taking into account exchanges with other interconnected systems"* and for *"providing to the operator of any other system with which its system is interconnected sufficient information to ensure the secure and*

[11] *Official Journal*, L 197/24, 25 July 2015.
[12] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, *Official Journal*, L 211/55, 14 August 2009.

efficient operation, coordinated development and interoperability of the interconnected system". The word 'coordination' never appears – although the Directive devotes one full article with 623 words to the *"Independence of the staff and the management of the transmission system operator"* and an even longer article to the *"Compliance programme and compliance officer"*.

The lack of importance attached to operational coordination by the 2009 electricity Directive is further highlighted by the description of the relevant tasks assigned to the national regulatory authorities (NRAs): *"eliminating restrictions on trade in electricity between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows across the Community"*.

Trade is here related to investments in cross-border capacity and to market integration, but the crucial role of operational coordination as the basic enabler of efficient trade is completely overlooked.

In fact, the 2009 Directive implicitly acknowledges the importance of operational coordination, but it decides not to address the subject, leaving it entirely to TSOs and NRAs, without providing any specific guidance:

"Regulatory authorities shall cooperate at least at a regional level to:

(a) foster the creation of operational arrangements in order to enable an optimal management of the network, promote joint electricity exchanges and the allocation of cross-border capacity, and to enable an adequate level of interconnection capacity, including through new interconnection, within the region and between regions to allow for development of effective competition and improvement of security of supply, without discriminating between supply undertakings in different Member States;

(b) coordinate the development of all network codes for the relevant transmission system operators and other market actors; and

(c) coordinate the development of the rules governing the management of congestion".

It is remarkable that the Directive is so concerned and so prescriptive about the independence of TSOs' staff and, at the same time, so unconcerned about the crucial issue of *operational arrangements* that decisively influence the whole EU market architecture and exhibit a larger potential for discrimination.

The 2009 European electricity Regulation follows the same light approach on operational coordination, although it provides more guidance to TSOs than the Directive.[13] In particular, the Regulation establishes that:

"The ENTSO for Electricity shall adopt:

[13] Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003, *Official Journal*, L 211/15, 14 August 2009.

(a) common network operation tools to ensure coordination of network operation in normal and emergency conditions, including a common incidents classification scale, and research plans".

This is the only place, in all current primary EU electricity legislation, where explicit reference to the *coordination of network operation* is made. However, nothing is said about the substance of such cooperation, nor about the relationship between network operation and market operation.

The 2009 Regulation also defined the procedures for the preparation and approval of a new set of Network Codes. These documents "*shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes which do not affect cross-border trade"*.

Annex I of the 2009 Regulation (*Guidelines on the management and allocation of available transfer capacity of interconnections between national systems*) devotes several paragraphs to coordination. Although in this context 'coordination' is mainly seen as a means to determine and to allocate interconnection capacities, it is also recognised that coordination needs to go beyond that narrow scope:

"With a view to promoting fair and efficient competition and cross-border trade, coordination between TSOs within the regions set out in point 3.2 shall include all the steps from capacity calculation and optimisation of allocation to secure operation of the network, with clear assignments of responsibility. Such coordination shall include, in particular:

(a) the use of a common transmission model dealing efficiently with interdependent physical loop-flows and having regard to discrepancies between physical and commercial flows,

(b) allocation and nomination of capacity to deal efficiently with interdependent physical loop-flows,

(c) identical obligations on capacity holders to provide information on their intended use of the capacity, i.e. nomination of capacity (for explicit auctions),

(d) identical timeframes and closing times,

(e) identical structure for the allocation of capacity among different timeframes (for example, 1 day, 3 hours, 1 week, etc.) and in terms of blocks of capacity sold (amount of power in MW, MWh, etc.),

(f) consistent contractual framework with market participants,

(g) verification of flows to comply with the network security requirements for operational planning and for real-time operation,

(h) accounting and settlement of congestion-management actions".

In spite of the above-mentioned provisions, which clearly go further than the 2009 and previous Directives, the 2009 Regulation is still very vague on operational coordination. Proceeding along a line of endless recursions, the 2009 Regulation foresees the possibility for the European Commission to issue Guidelines:

"This Regulation should lay down basic principles with regard to tarification and capacity allocation, whilst providing for the adoption of Guidelines detailing further relevant principles and methodologies, in order to allow rapid adaptation to changed circumstances".[14]

Although this sounds very technical and specifically related to tarification of cross-border transactions, the 2009 Regulation then establishes in Article 18 that:

"Where appropriate, Guidelines providing the minimum degree of harmonisation required to achieve the aim of this Regulation shall also specify:

(…)

(b) details of rules for the trading of electricity".

This little, almost unnoticed, opening was in fact used in the *Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management* to establish the basic structure of a new coordination model among market operators and TSOs. These apparently minor and very 'technical' Guidelines go so far as to create new entities like the 'market coupling operator', a key actor in the organisation of market coupling, not foreseen in any previous piece of legislation.

From a political point of view, the Commission Regulation, being a delegated act, is always weaker than a Regulation of the European Parliament and of the Council. From a legal point of view too, it is a lower-level piece of legislation. Therefore, it is surprising – and questionable – that one of the most important cornerstones of the Internal Energy Market was produced so late and only through the most obscure and opaque of all the EU decision-making procedures, the so-called 'Comitology', as a Commission Regulation.

On the one hand, it is very positive to have, at last, effective coordination rules clearly defined in a piece of EU legislation which are being implemented, independently of their legislative 'status'. On the other hand, however, the 2015 Commission Regulation does not address some key issues and it introduces new, difficult problems, namely as regards governance. And it is doubtful that this document has the political and legal force to provide the most suitable solutions.

One of the most delicate problems is the coordination between market operators and system operators. The proposal submitted by market operators to regulators in April 2016,[15] specifying how to jointly set up and perform the Market Coupling Operator (MCO) function (the 'MCO Plan') deserved criticism and a 'request for amendment'

[14] *Ibid*., Whereas 10.

[15] See the *All NEMO proposal for the MCO Plan*, 14 April 2016, available on the Ofgem website. NEMOs are the Nominated Electricity Market Operators according to Article 4(1) of Regulation (EU) 2015/1222.

by regulators.[16] TSOs were sceptical as well.[17] In diplomatic language, TSOs rightly pointed out that trying to fix the broad EU coordination problem through the narrow angle of cross-border capacity allocation is a fundamental mistake:[18]

"Developing, operating, and governing market coupling is a highly complex task at the heart of cross-border trade and capacity allocation. Even more, market coupling is an essential infrastructure for wholesale market functioning as well as for system operation and ultimately for security of supply. As markets integrate further and move closer to real time, there is an increasing need for TSOs to get involved in how power exchanges design and operate market coupling operation functions".

In the meantime, market operators enhanced their organisation at EU level, creating a new body, predestined to play an increasingly important role in the construction of the IEM.[19] Because EU legislators did not want to explicitly address ex-ante the key coordination question and the related governance issues, a solution must be engineered *ex-post*. Given the intricate nature of the current legal and decision-making framework, the quality of the outcome is far from guaranteed.

1.2.2 Missing Pillar 2: Sharing

Coordination mechanisms – of all sorts: planning/investment, system operation, market operation, and system/market interaction – inevitably lead to choices about how to share (future or already available) resources.

In the planning phase, public policies, market needs and security of supply concerns must be taken into account (see Fig. 1.11). These inputs, together with some internal planning criteria, such as reliability standards, adequacy level and efficiency indicators, provide the necessary ingredients for infrastructure (and in particular network) planning.

Any network plan encloses a large number of trade-offs among diverse, and sometimes contradictory, goals, as it organises a comprehensive set of resources and processes necessary to achieve these desired goals. If this network is interconnected with other networks, some degree of planning coordination among the respective planning bodies is necessary, for obvious reasons; this may require further trade-offs. Besides dealing with all these inevitable, more or less explicit trade-offs, network planning must also cope with several uncertainties like demand growth and the location of new generating units.

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[16] See the *Request for amendment by all NRAs agreed at the energy regulators' forum on all NEMOs' proposal for the plan on joint performance of MCO functions (MCO Plan*), 26 September 2016, available on the Ofgem website.

[17] ENTSO-E, Governance of the market coupling operation functions transmission system operators' perspective, July 2016, available on the ENTSO-E website.

[18] *Ibid*.

[19] The NEMO Committee has been established to manage joint responsibilities of NEMOs under CACM. See the joint press release on the Epexspot website.

Once a network plan is approved, it needs to be implemented through appropriate investments. The resulting network provides the necessary physical resources to achieve the desired goals and it materialises the trade-offs decided at the planning stage.

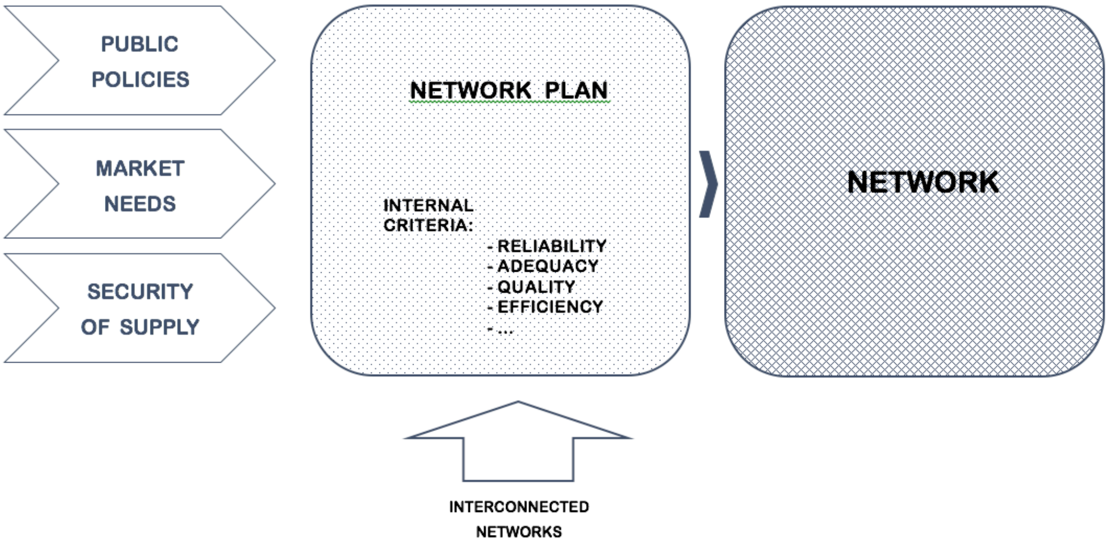

Fig 1.11: Schematic description of network planning

In the ideal world of perfect planning, absolute certainty and flawless networks, it would be relatively easy to share the available network assets among all network users in a perfectly efficient and fair way. However, in the real and imperfect world it is more difficult to ensure efficiency and fairness to all network users, at all times. The compound effect of planning mistakes and unintended consequences, unexpected delays and uncertainties create situations where some network users are better off than others and situations where inefficiency is persistent. Under these circumstances, sharing the available network resources, i.e. allocating costs and benefits to different network users, becomes a less trivial regulatory problem. The definition of appropriate incentives or penalties to be applied to network owners and operators is another key, but hard regulatory challenge.

Once a network is built, it must be operated. System operation takes into account two different kinds of inputs:

- Market requirements, i.e. a description of what all market agents want to do and how their transactions impact upon (are mapped onto) the network;
- Regulatory constraints, i.e. rules imposed by legislation and/or sector regulation such as giving priority dispatch to power plants using some types of primary energy.

Basically, system operation is an attempt to fulfil market requirements while respecting regulatory constraints, as well as the intrinsic, physical network constraints. System operation transforms a passive set of physical resources (lines, cables, substations, etc.) into an active system that enables the continuous performance of successive electricity transactions among network users.

The use of the network is associated with four main technical electricity characteristics (see Fig. 1.12):

- Capacity, available transmission volume (global and at each network branch) changes according to different use patterns by generators and loads;
- Frequency, frequency of the electrical current must be kept within very strict limits around 50 Hz;
- Voltage, at each network node, voltage must be kept within given limits;
- Security, to each operating point (characterised by a well-defined set of node voltages and power flows) corresponds a certain quantitative degree of stability for the electricity system as a whole.

Three of these electricity characteristics (frequency, voltage and security) are ‘public goods’, i.e. they are characteristics of electricity which are non-excludable and non-rivalrous when being consumed by network users. They are equally available for these network users. Capacity, on the other hand, has a different nature. It is a ‘club good’, i.e. its consumption by network users is non-rivalrous only up to a point (as long as congestion is absent). Capacity is also excludable because if one network user – or a limited number of – is/are allowed to take the full capacity of a power line, all others are excluded from the use of that same power line.

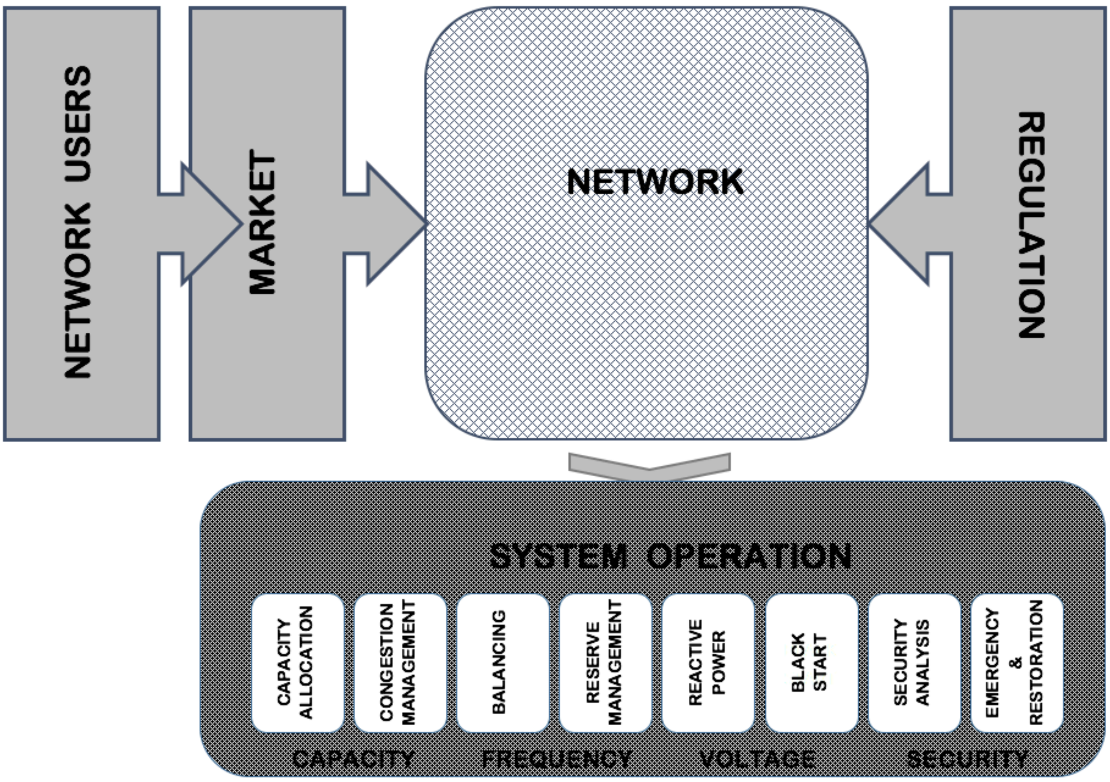

Fig 1.12: Schematic description of network/system operation

As regards the three public goods – frequency, voltage and security – there are two main questions that also impact network users:

- Who should be allowed and who should be obliged to provide the necessary ‘system services’ (or ‘ancillary services’) that create these public goods?
- How should those providing the required system services be remunerated? In particular, to which extent can/shall a fair remuneration be established through market mechanisms?

As regards capacity, how to share the available transmission capacity among network users is a fundamental regulatory challenge in liberalised markets. In Europe, as in many other places, the complexity of the problem was too often underestimated, in spite of early warnings, such as the paradigmatic position expressed by William Hogan from Harvard University in his submission to the US Federal regulator FERC in 1991:

“Of course, it is difficult to separate good access from bad access, or to separate the calls for reasonable transmission limitations designed to protect reliability from unreasonable barriers designed to protect vested interests. Furthermore, the policy-makers have heard it all before elsewhere in the defense of heavy regulation and limited access in the case of airlines, trains, trucks, telephones, natural gas, and so on. The instinct of many reformers is to get the prices right, provide access to the transmission system and let the new competitors enter.

In the broad policy debate, therefore, natural suspicion arises when utility industry executives and system operators (the insiders’ insiders) warn of the complexity of the transmission grid and the dangers of open access. Pressed by the desire to move ahead, it is easy to dismiss the arcane features of transmission grids – including loop flow, reactive power compensation, frequency control and contingency analyses – as mere operational details. Given the experience in other industries, it is tempting to assume that these details can be ignored for purposes of the grand policy design.

In the case of electric power transmission, however, the details do matter and they have a potentially dramatic impact on the character of possible reforms. The detail in electric power transmission may not be so easy to dismiss – much that seems obvious isn’t.(…)

At a minimum, existing congested transmission systems will complicate the transition to a new electricity market. For the foreseeable future, therefore, the transmission *grid needs new rules that replace a reliance on the familiar fictions with a respect for the unfamiliar facts"*.[20]

Unfortunately, Bill Hogan's assumption proved right: details were *"ignored for purposes of the grand policy design"* not only in the USA, but also in Europe and in other parts of the world.

In the European Union, the three founders of European energy regulation clearly pointed out the importance of *operational details* shortly after the first energy Directives were approved, at the First European Electricity Regulation Forum, in Florence. The importance of coordination and fair sharing of costs and benefits was also underlined in a joint statement they presented in October 1998, at the Second European Electricity Regulation Forum:

"Although the basic duties of system operators and the way they manage transmission networks are the same everywhere, the way system operators interact with producers, customers and other agents depends on the organisation of electricity trade. Transparency of transmission access, use – including pricing – and operation rules is a key factor for the success of the internal electricity market. In particular, it is important to have a clear distinction between the following functions and their associated costs:

a) *operation, maintenance and development of the transmission system;*
b) *technical system co-ordination;*
c) *commercial co-ordination"*.[21]

The same European regulation pioneers even indicated the crucial *operational details* missing in the first electricity Directive:

[20] Hogan W.W. (1991), *Transmission capacity rights for the congested highway: A contract network proposal*, Testimony submitted to the Federal Energy Regulatory Commission, available on the Harvard website.

[21] This statement was later published in Vasconcelos J., M. Ordóñez and P. Ranci (1999), Transmission and Trade of Electricity in Europe, *Oil & Gas Law and Taxation Review*, vol. 17 (2).

5. WHAT THE IEM DIRECTIVE DOESN'T SAY

The IEM directive includes other provisions aimed at ensuring non-discriminatory network access. However, these provisions require further clarification. The following table points out what is missing there.

Article	Requirement	Missing
7.3	The system operator shall be responsible for ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services.	Explicit definitions of: ▪ security ▪ reliability ▪ efficiency ▪ ancillary services
7.4	The system operator shall provide to the operator of any other system with which its system is interconnected sufficient information to ensure the secure and efficient operation, co-ordinated development and interoperability of the interconnected system.	Concerning the information to be provided: ▪ contents ▪ frequency ▪ medium ▪ extension
8.1	The system operator shall be responsible for determining the use of inter-connectors with other systems.	Criteria for the definition of interconnection access rules, namely: ▪ computation of available interconnection capacity ▪ allocation of interconnection capacity among different users ▪ treatment of loop flows ▪ treatment of transit transactions

Although significant progress has been achieved on the *"use of inter-connectors"*, first on a voluntary basis (agreement reached at the Florence Forum in early 2000), then through the 2003 and 2009 electricity Regulations, and subsequent Network Codes, progress on the other topics has been extremely slow: for instance, no general solution for cross-border balancing has been implemented yet.

1.2.3 Missing Pillar 3: Solidarity

In his 2016 'State of the Union Address', President Juncker recalled that *"the word solidarity appears 16 times in the Treaties which all our Member States agreed and ratified"*.[22] This section investigates the use of 'solidarity' in relevant EU energy texts. A quick analysis already shows that the concept of solidarity is more applied and much more developed in the natural gas industry than in the electricity sector. In

[22] Junker J.C. (2016), *State of the Union 2016*, available at the European Union website.

electricity, until now, solidarity is just a vague reference lacking operational substance.

¤ Third Energy Package

In the 2009 electricity Directive the word solidarity appears only once, in the preamble, related to unbundling:

"To ensure, in addition, respect for the international obligations of the Community, and solidarity and energy security within the Community, the Commission should have the right to give an opinion on certification in relation to a transmission system owner or a transmission system operator which is controlled by a person or persons from a third country or third countries".

It the 2009 electricity Regulation the word solidarity does not appear. It also does not appear in the twin natural gas Regulation.[23] However, it appears seven times in the 2009 natural gas Directive,[24] namely in the preamble and in a dedicated article, besides in a reference similar to the one in the preamble of the electricity Directive. The gas preamble explains that:

"In order to contribute to security of supply whilst maintaining a spirit of solidarity between Member States, notably in the event of an energy supply crisis, it is important to provide a framework for regional cooperation in a spirit of solidarity. Such cooperation may rely, if Member States so decide, first and foremost on market-based mechanisms. Cooperation for the promotion of regional and bilateral solidarity should not impose a disproportionate burden on or discriminate between market participants".

The subsequent Article 6 of the 2009 natural gas Directive reads as follows:

"Regional solidarity

1. In order to safeguard a secure supply on the internal market in natural gas, Member States shall cooperate in order to promote regional and bilateral solidarity.

2. Such cooperation shall cover situations resulting or likely to result in the short term in a severe disruption of supply affecting a Member State. It shall include:

(a) coordination of national emergency measures referred to in Article 8 of Council Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply (1); [OJ L 127, 29.4.2004, p. 92.]

(b) identification and, where necessary, development or upgrading of electricity and natural gas interconnections; and

[23] Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005, *Official Journal*, L 211/36, 14 August 2009.
[24] Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC, *Official Journal*, L 211/94,14 August 2009.

(c) conditions and practical modalities for mutual assistance.

3. The Commission and the other Member States shall be kept informed of such cooperation.

4. The Commission may adopt Guidelines for regional cooperation in a spirit of solidarity. Those measures, designed to amend non-essential elements of this Directive by supplementing it, shall be adopted in accordance with the regulatory procedure with scrutiny referred to in Article 51(3)".

¤ Energy Security Strategy

In the 2014 Commission's Communication on a 'European Energy Security Strategy' the word solidarity appears 14 times.[25] This document recalls that:

"For most citizens, energy is available 'on tap', it is ubiquitous and un-intrusive. This has a major influence on the factors that affect national decisions on energy policy, with security of supply not being on par with other considerations.

Nevertheless, in the winters of 2006 and 2009, temporary disruptions of gas supplies strongly hit EU citizens in some of the eastern Member States. This was a stark 'wake up call' pointing to the need for a common European energy policy".

The document then indicates that:

"Too often energy security issues are addressed only at a national level without taking fully into account the interdependence of Member States. The key to improved energy security lies first in a more collective approach through a functioning internal market and greater cooperation at regional and European levels, in particular for coordinating network developments and opening up markets, and second, in a more coherent external action. (…)

In the long term, the Union's energy security is inseparable from and significantly fostered by its need to move to a competitive, low-carbon economy which reduces the use of imported fossil fuels".

The proposed strategy *"is based on eight key pillars that together promote closer cooperation beneficial for all Member States while respecting national energy choices, and are underpinned by the principle of solidarity"*.

The second pillar of this strategy is labelled *"Strengthening emergency/solidarity mechanisms including coordination of risk assessments and contingency plans; and protecting strategic infrastructure"* and its goal is *"to ensure that the best possible preparation and planning improve resilience to sudden disruptions in energy supplies, that strategic infrastructures are protected and that the most vulnerable*

[25] European Commission (2014), *Communication from the Commission to the European Parliament and the Council on a European Energy Security Strategy*, COM(2014) 330 final, Brussels, 28 May 2014.

Member States are collectively supported". In this context, the Commission announced that it would:

"Propose to Member States and industry new contingency coordination mechanisms and plans to deliver energy to countries in times of need, based on risk assessments (energy security stress tests). The immediate focus should be on all Member States on the eastern border of the EU".

¤ Energy Union

As a follow-up to the 'European Energy Security Strategy' Communication, but within the new Energy Union framework, parallel initiatives on gas and electricity were launched. In 2015, the European Commission launched a public consultation on a 'new market design' and, as a complement to it, another public consultation on risk preparedness, aimed at exploring the need for a new legal instrument for electricity security of supply.[26] According to the Commission:

"A large majority of respondents is in favour of requiring Member States to draw up risk preparedness plans, covering results of risk assessments, preventive measures as well as measures to be taken in crisis situations. Whilst acknowledging the need for a common approach and more regional co-operation, a significant number of stakeholders also state that there should be sufficient room for tailor-made, national responses to security of supply concerns, as there are substantial differences between national electricity systems".

As a follow-up to the consultation, the Commission presented, on November 30, 2016, a Proposal for a Regulation of the European Parliament and of the Council on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC.[27]

In the Communication from the Commission on 'A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy' (February 2015) the word solidarity appears eight times.[28] In this document, the very first of the five dimensions describing the new Energy Union is *"Energy security, solidarity and trust"*. It is because *"the spirit of solidarity in energy matters is explicitly mentioned in the Treaty and is at the heart of the Energy Union"*. Therefore, according to this key Energy Union document, *"our vision is of an Energy Union where Member States see that they depend on each other to deliver secure energy to their citizens, based on true solidarity and trust, and of an Energy Union that speaks with one voice in*

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[26] Information on the results of the consultation are available at https://ec.europa.eu/energy/en/consultations/public-consultation-risk-preparedness-area-security-electricity-supply.

[27] European Commission (2016), *Proposal for a Regulation of the European Parliament and of the Council on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC*, COM(2016) 862 final, Brussels, 30 November 2016.

[28] European Commission (2015), *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank on a Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy*, COM(2015) 80 final, Brussels, 25 February 2015.

global affairs". However, this document does not provide concrete guidance as regards electricity; it only mentions that:

"Member States, transmission system operators, the energy industry and all other stakeholders have to work closely together to ensure a high-level of energy security for European citizens and companies".

In addition, it also recognises that:

"Many Member States currently have inadequate security of electricity supply frameworks in place and they use outdated and inconsistent approaches to assessing security of electricity supply. Working together with Member States, the Commission will establish a range of acceptable risk levels for supply interruptions, and an objective, EU-wide, fact-based security of supply assessment addressing the situation in Member States. This will take into account cross-border flows, variable renewable production, demand response and storage possibilities. Capacity mechanisms should only be developed to address security of supply if a regional system adequacy assessment points to such a need, taking into account the potential for energy efficiency and demand-side response".

¤ Security of supply Directives

The Commission's preoccupation with security of supply mainly concerns natural gas. This is evident now, when comparing the 'weak' electricity consultation process with the 'strong' legislative proposal on the security of gas supply presented by the Commission in February 2016.[29] To be fair, this difference was already apparent in the first security of supply Directives: Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard the security of electricity supply and infrastructure investment[30] has no mention of solidarity, while Council Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard the security of natural gas supply acknowledges that *"The establishment of genuine solidarity between Member States in major emergency supply situations is essential, even more so as Member States become increasingly interdependent regarding security of supply"*.[31] This Council Directive was replaced in 2010 by a Regulation that mentioned the word solidarity 13 times.[32]

Directive 2005/89/EC was proposed shortly after the September 28, 2003 blackout that left Italy in the dark for several hours. However, the initial proposal presented by the European Commission was watered down by the Council to such an extent that

[29] The word solidarity appears 13 times in the *Proposal for a Regulation of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010*, COM(2016) 52 final, Brussels, 16 February 2016.
[30] *Official Journal*, L 33/22, 4 February 2006.
[31] *Official Journal*, L 127/92, 29 April 2004.
[32] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC, *Official Journal*, L 295/1, 12 November 2010.

the final product is almost useless, from a practical point of view. In fact, this Directive is a mere *"framework within which Member States are to define transparent, stable and non-discriminatory policies on security of electricity supply compatible with the requirements of a competitive internal market for electricity"* (Article 1.2). Its Article 3.1 recommends that:

"Member States shall ensure a high level of security of electricity supply by taking the necessary measures to facilitate a stable investment climate and by defining the roles and responsibilities of competent authorities, including regulatory authorities where relevant, and all relevant market actors and publishing information thereon. The relevant market actors include, inter alia, transmission and distribution system operators, electricity generators, suppliers and final customers".

¤ Network Codes

In April 2014, ENTSO-E was mandated to draft the *Network Code on Emergency and Restoration* according to the requirements set out in framework guidelines by the Agency for the Cooperation of Energy Regulators (ACER). The final draft was submitted to ACER in March 2015. ACER recommended adoption of this code in June 2015. The draft is still awaiting validation by the European Parliament and the Council, as per the arcane Comitology procedures.[33] This draft Network Code[34] lays down minimum requirements on the following matters:

"a) the management of Emergency, Blackout and Restoration States;

b) the coordination of European system operation in Emergency, Blackout and Restoration States in a common and coherent way;

c) simulations and tests for the purpose of reliable, efficient and fast restoration from Emergency or Blackout System States; and

d) the tools and facilities needed for the purpose of reliable, efficient and fast restoration from Emergency or Blackout System States".

The word solidarity does not appear in the draft *Network Code on Emergency and Restoration.* The Code also does not contain the words 'sharing',[35] 'benefit', 'profit' or 'burden'. There is an article on 'Recovery of Costs' but all it says is that *"The costs borne by regulated Network Operators stemming from the obligations laid down in this Network Code shall be assessed by the competent regulatory authorities".*

This *Network Code on Emergency and Restoration,* although addressing some very relevant issues for the proper functioning of the European interconnected electricity

[33] Information on the validation process of the Network Codes is available on the ENTSO-E website.
[34] https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20ER/150325_ENTSO-E_NC%20ER_final.pdf.
[35] The word 'share' only appears once in the context of frequency management: *"During system Restoration, each TSO shall identify and monitor: (...)*
b) the TSOs with which it shares a Synchronised Region or Synchronised Regions".

system, clearly does not provide a substantial (or even procedural) operational definition of solidarity.

1.3 European blocking factors

The lack of appropriate, sufficient and explicit coordination, sharing and solidarity rules has created many obstacles in the development of the internal energy market and it is hindering the transition towards a low-carbon economy. The list of issues which are blocking the process is, unfortunately, long and ranges from short-term operation to long-term issues; from system operation to grid tariffs, planning and building; from mundane day-to-day or intraday to infrequent events or hazards.

In our report, 12 different blocking factors are analysed. They are grouped into two chapters: Chapter 2 deals with inherent coordination problems, while Chapter 3 addresses topics more related to the lack of harmonisation.

As explained in Section 1.2.1, both the well-functioning of supra-national markets and the reliable operation of interconnected systems require some forms of tight coordination among the relevant stakeholders, in particular among TSOs. A certain degree of coordination is a necessary pre-condition for the very existence and functioning of supra-national infrastructures. Electricity markets too, at any level (regional, national or supra-national), also require a certain degree of coordination between system and market operation. Obviously, and logically, the functioning of supra-national electricity markets requires more extensive and complex types of coordination than isolated national markets.

Effective coordination implies, first of all, sharing responsibilities, agreeing on role distribution as well as on common rules. Coordination also implies direct and indirect costs:

- Direct costs are related to the establishment and operation of the associated infrastructures. They are both the *coordinated infrastructure* (e.g. interconnectors in interconnected electricity networks) and the *coordinating infrastructure* (e.g. information and communication networks connecting system operators in order to enable proper monitoring and control).
- Indirect costs result from the act of coordination, e.g. coordination between market and system operation may lead to the redispatching of some power plants with obvious costs for their owners.

The reluctance to explicitly define comprehensive benefit and cost sharing mechanisms, especially as regards indirect costs and benefits, usually leads to insufficient or imperfect forms of coordination, thus affecting the respective markets.

The lack of harmonisation may be the result of insufficient cooperation and coordination among the responsible stakeholders. However, unlike the issues to be addressed in Chapter 2, the issues to be handled in Chapter 3 are not, per se, intrinsic coordination problems. Efficient coordination requires a certain degree of harmonisation; however, the need for harmonisation goes beyond coordination issues: a well-coordinated system is not necessarily a level playing field.

The following tables indicate the blocking factors handled in the coming Chapter 2 and the following Chapter 3.

Chapter 2 – ‘First-order coordination’ blocking factors

Blocking factor	Section
Lack of comprehensive coordination of system planning, further to the TYNDP	2.1
Lack of comprehensive coordination of cross-border investments	
Lack of comprehensive coordination of system operation	2.2.1
Lack of a common redispatching approach	2.2.2
Lack of common reserve contracting and cost allocation	2.2.3
Lack of intraday cross-border allocation with auction	2.2.4
Lack of harmonised load shedding coordination	2.2.5
Lack of comprehensive coordination for Solidarity	2.3

Chapter 3 – ‘Second-order coordination’ blocking factors

Blocking factor	Section
No harmonisation of common congestion rent allocation scheme	3.1
No harmonisation of capacity remuneration mechanisms	3.2
No harmonisation of transmission tariffs across countries and TSO zones	3.3
No harmonisation of ‘State aid’ to big energy consumers (through reduced network tariffs)	3.4

For each of these issues, we will discuss the following aspects:

a) Purpose and need for coordination;

b) Formal process and current status in defining methodologies, codification and implementation;

c) Analysis of probable reasons as to why it took so long to get to the present situation and, where applicable, why there is some progress now;

d) The focus of current stakeholders in completing and implementing all foreseen procedures and methodologies;

e) Beyond liberalisation and integration, are the implemented/foreseen solutions suitable for the ongoing energy transition (decarbonisation and digitalisation)?

Chapter 2 – Blocking factors for European first-order coordination

Executive Summary

On the basis of the analytical framework developed in Chapter 1, the second chapter of the report deals with problems related to coordination. Eight factors which are blocking the integration of European electricity systems and the transition to a low-carbon economy are delineated.

First, in the past few years, there have been improvements in the level of interconnections between national grids, but a *lack of comprehensive coordination of system planning* and a *lack of comprehensive coordination of cross-border investments* are still observable. The Ten-Year Network Development Plan (TYNDP) aims to ensure the necessary transparency regarding the evolution of the entire transmission network in Europe. In addition, EU legislation foresees the definition of a list of Projects of Common Interest, identified as priority projects benefiting from special permitting procedures and funding. ENTSO-E has been committed to the TYNDP process and is working on its continuous improvement. However, the current coordination mechanisms cannot overcome delays due to lengthy authorisation processes or opposition at local level. Clear decisions on how to share interconnection costs and benefits are needed.

Second, the *lack of comprehensive coordination of system operation* is presently detectable. Regional Security Coordinators (RSCs), recently established all over the continent, are expected to promote cooperation in system operation, with the TSOs remaining in charge of the final decisions and liable towards their NRAs. Significant efforts will be required in the next years to align national legislation and fully develop RSCs' functionalities and governance.

Additionally, the *lack of a common redispatching approach* is leading to the fragmentation of the electricity markets at the closing loop. At present, remedial measures like redispatching are taken mainly on the grounds of bilateral or multilateral agreements that often rest on oversimplified cost sharing principles and insufficient data exchange. Unfair and inefficient decisions are frequently the result, while congestions on transmission lines are sometimes pushed to the national borders. The CACM Commission Regulation aims to overcome these problems by establishing clear rules but, for the moment, fragmentation and inefficiencies are still visible.

In the meantime, the *lack of common reserve contracting and cost allocation* is increasing the burden for the TSOs to procure spinning reserve and other ancillary services. To date, progress in the integration of electricity balancing markets has been limited due to both the wide array of solutions adopted in the past at national level and the importance of balancing arrangements for security of supply. A

Commission Regulation is expected to be issued in 2017, but no common model for the procurement of ancillary services, possibly open to the participation of demand resources, has emerged yet.

Currently, there is *no intraday cross-border allocation with auctions*. Indeed, there is still no consensus on the way to design intraday markets and the XBID Project has not been implemented yet, due to the complexity of developing an IT platform that links several markets and allows trading up to one hour before real time.

The EU also suffers from the *lack of harmonised load shedding coordination*. The drafted Network Code on emergency and restoration aims to establish a formal framework and general principles. Participation of demand side resources should be considered and explicit choices should be taken on how to share the costs and how to deal with the consequences of load shedding. Clear ex-ante rules are much needed.

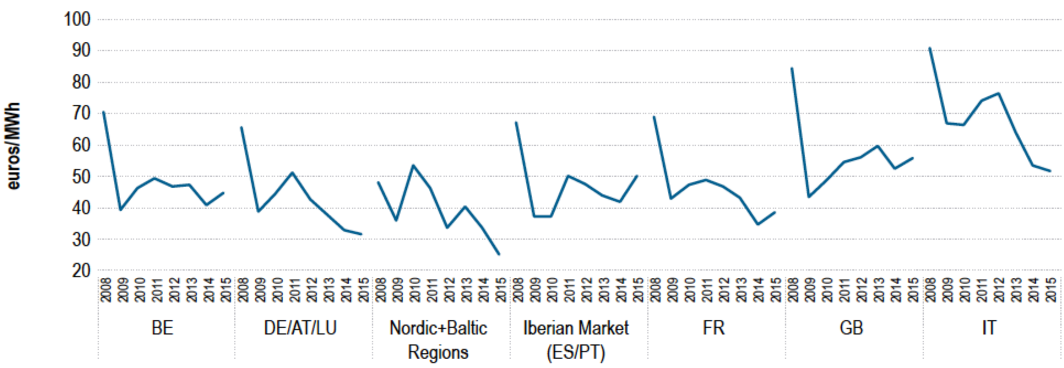
Finally, there is a *lack of comprehensive coordination for solidarity,* which may limit the possibility for the whole system to deal with exceptional events threatening energy supply. In the past, European TSOs usually showed solidarity with each other and ensured an effective and strong level of coordination, but that happened mainly on a voluntary basis. The drafted Network Code on emergency and restoration establishes procedures to be applied in states of emergency, blackout and restoration, directly calling for a duty to support neighbouring systems in difficulty. Nevertheless, no concrete solidarity mechanism or any explicit ex-ante guidance on how to share costs is offered at the moment.

2.1 System planning

Since the electricity systems are supposed to serve one single supra-national electricity market, their planning must be well coordinated – much more coordinated now than in the past, when interconnections were just seen as a means to enhance overall reliability and explore bilateral complementarities.

2.1.1 Purpose and need for coordination

If enough interconnection capacity were available, liberalisation would have led to a reasonable degree of 'price convergence' (if not a single wholesale price across the entire EU, at least small differences between price zones). Unfortunately, 21 years after the first electricity Directive, we are still very far from price convergence, as the figure below clearly shows,[36] and regulators point out that *"in recent years, despite investments in the transmission networks and some improvements in capacity calculation methods, the volume of tradable cross-zonal capacities in the EU and Norway has remained relatively limited"*.[37]



Source: Energy Market Observatory System (EMOS), Platts and power exchanges (2016).

Fig 2.1: Day-ahead wholesale electricity prices in seven European markets (2008 – 2015)

If markets and regulation had worked as expected, new transmission capacity, both internal and cross-border, should have been built in order to enable more trade across the EU. However, this did not happen, as Fig. 2.2 and 2.3 clearly illustrate.

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[36] ACER/CEER (2016), *Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015*, p. 7.
[37] *Ibid.*, p. 13.

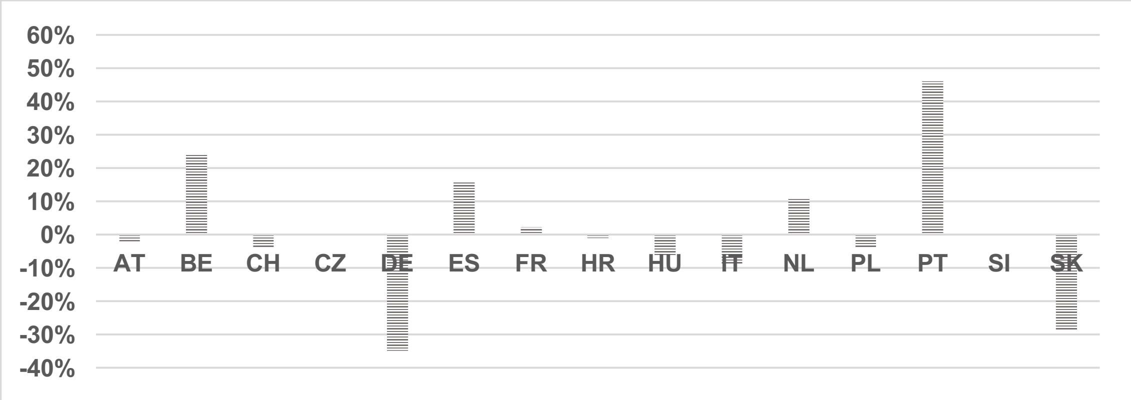

Fig 2.2: 220 kV circuit length variation in selected countries where data is available (2000 – 2015). Source: ENTSO-E

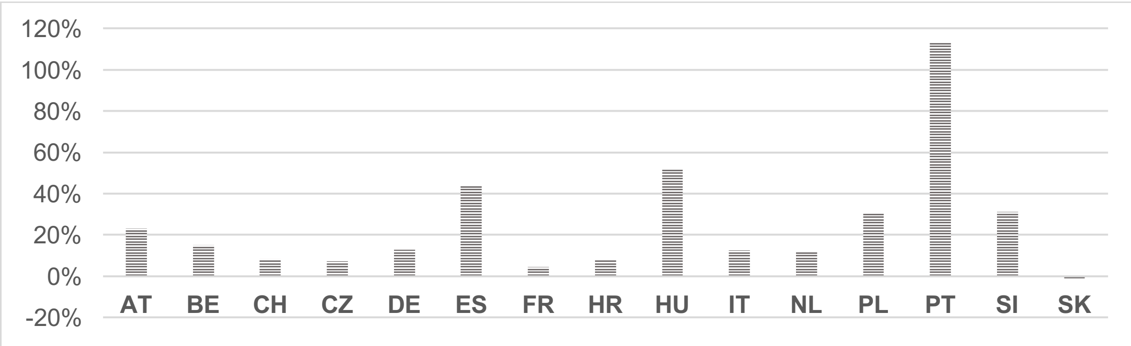

Fig 2.3: 400 kV circuit length variation in selected countries where data is available (2000 – 2015). Source: ENTSO-E

Beyond market integration, interconnection capacity also contributes to increase security of supply. Two blocking factors were identified on reaching the necessary interconnection capacity:

1) The lack of comprehensive coordination of system planning, further to the Ten Year Network Development Plan (TYNDP), prepared by the ENTSO for electricity; and
2) The lack of comprehensive coordination of cross-border investments.

In order to better understand these two issues, a description is provided in the following sections of how system planning is performed in Europe and which levels of coordination currently exist, both for planning and for investment.

2.1.2 System planning in Europe

System planning is a central task of all TSOs in Europe. Studies conducted by national TSOs identify the necessary reinforcements to provide adequate transmission capacity, access to all users and reliable operation of the network, fulfilling a set of planning criteria and rules that are applicable and established at national level. At this stage, the analysis of possible cross-border impacts is usually coordinated with neighbouring systems.

The Nordic countries[38] provide an example where systemic coordinated planning among the involved TSOs from a regional perspective has a long tradition, all following agreed planning rules and methodologies, within a clear mandate from governments and in close cooperation with a well-established regional market.

However, to ensure the optimal management of the European interconnected electricity system and the development of an efficient internal, supra-national electricity market, which takes into account European policies on decarbonisation, tight coordination needs to be implemented at a full European scale and not just at the bilateral or regional level.

Regulation (EC) No 714/2009 laid the foundations for EU-wide network planning coordination. It established the creation of the ENTSO for Electricity and assigned to it, as one of its core tasks, the adoption of *"a non-binding Community-wide ten-year network development plan (Community-wide network development plan), including a European generation adequacy outlook, every two years"* (Art. 8). This *"Community-wide network development plan shall include the modelling of the integrated network, scenario development, a European generation adequacy outlook and an assessment of the resilience of the system"*.

This ten-year network development plan (TYNDP) ensures the necessary transparency regarding the evolution of the entire electricity transmission network in the EU. It should be also underlined that the TYNDP is associated with a European adequacy outlook that, "*shall build on national generation adequacy outlooks prepared by each individual transmission system operator"*.

According to the 2009 electricity Regulation,

"The Community-wide network development plan shall, in particular:

(a) build on national investment plans, taking into account regional investment plans as referred to in Article 12(1), and, if appropriate, Community aspects of network planning including the guidelines for trans-European energy networks in accordance with Decision No 1364/2006/EC of the European Parliament and of the Council (OJ L 262, 22.9.2006, p. 1.);

(b) regarding cross-border interconnections, also build on the reasonable needs of different system users and integrate long-term commitments from investors referred to in Article 8 and Articles 13 and 22 of Directive 2009/72/EC; and

(c) identify investment gaps, notably with respect to cross-border capacities".

Four years later, in the 2013 Regulation on guidelines for trans-European energy infrastructure, strong doubts were expressed about the effectiveness of the TYNDP and associated mechanisms to deliver the necessary interconnection capacity:

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[38] These countries are Denmark, Finland, Norway and Sweden.

"Despite the fact that Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity (2) and Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas (3) provide for an internal market in energy, the market remains fragmented due to insufficient interconnections between national energy networks and to the suboptimal utilisation of existing energy infrastructure. However, Union-wide integrated networks and deployment of smart grids are vital for ensuring a competitive and properly functioning integrated market, for achieving an optimal utilisation of energy infrastructure, for increased energy efficiency and integration of distributed renewable energy sources and for promoting growth, employment and sustainable development".[39]

However, instead of reinforcing the existing mechanisms within the existing governance structure, that Regulation (EU) No 347/2013 introduces a new concept, the *Projects of Common Interest* (PCIs), and proudly creates a new, parallel governance structure, the twelve *Regional Groups*. It also makes its supremacy clear:

"Projects of common interest included on the Union list pursuant to paragraph 4 of this Article shall become an integral part of the relevant regional investment plans under Article 12 of Regulations (EC) No 714/2009 and (EC) No 715/2009 and of the relevant national 10-year network development plans under Article 22 of Directives 2009/72/EC and 2009/73/EC and other national infrastructure plans concerned, as appropriate. Those projects shall be conferred the highest possible priority within each of those plans".[40]

In order to ensure some coherence within a transparent framework, the 2013 Regulation assigned to ENTSO-E the responsibility for establishing *"methodologies, including on network and market modelling, for a harmonised energy system-wide cost-benefit analysis at Union level for projects of common interest"*, to be used also in the biennial TYNDP, thus allowing a transparent and objective comparison of the projects of common interest.

In Spring 2014, the European Commission recognised that:

"Europe needs to achieve a better functioning and a more integrated energy market. Priority projects should be accelerated to join up existing energy islands and ensure delivery of the existing interconnection target of at least 10% of the installed

[39] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009, *Official Journal*, L 115/39, 25 April 2013.
[40] *Ibid*.

electricity production capacity by 2020. By 2030, Member States should be on track to meet a 15% interconnection target".[41]

In the meantime, these quantitative interconnection targets have been endorsed by the European Council (October 2014).

The following figure describes the relationship among different tools of network planning and investment coordination in the EU.

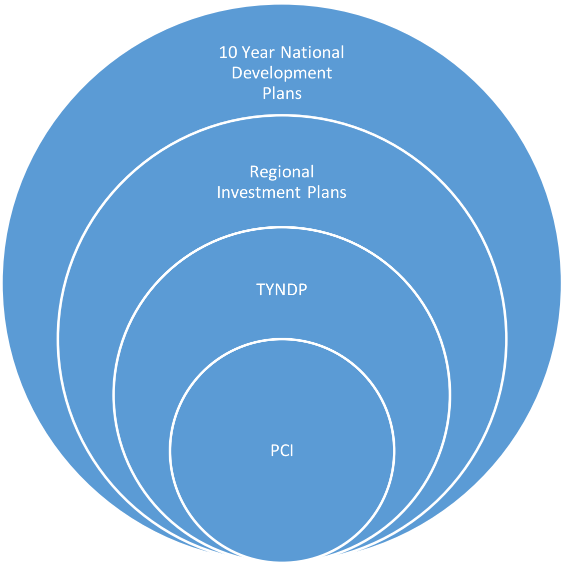

Fig 2.4: European planning coordination from national development plans to projects of common interest

2.1.3 Current status in Europe

This Section describes the evolution of coordinated network planning and investment since the creation of ENTSO-E and TYNDP through Regulation (EC) No 714/2009, seven years ago.

¤ TYNDP 2010

The first TYNDP was published in 2010 by ENTSO-E,[42] only one year after the publication of the 2009 electricity Regulation. This fact clearly showed ENTSO-E's commitment to fulfil the Regulation objectives. TYNDP 2010 was defined as a pilot project initiating a *learning-by-doing* process to prepare the ground for the next releases. Some of these building foundations were defined as part of its objectives, namely: testing the necessary processes using for the first time Europe-wide

[41] European Commission (2014), *Communication from the Commission to the European Parliament and the Council on a European Energy Security Strategy*, *op. cit.*, p. 20.
[42] The Plan is available on the ENTSO-E website.

methodologies and getting feedback from stakeholders regarding content and future collaboration.

In general terms, the methodological aspects considered in TYNDP 2010 were related to the selection of projects to be included in the plan and how they were evaluated based on a selection of foreseen scenarios for given time-scales.

Additionally, TYNDP 2010 also provided descriptions of future conditions of the electricity power system in Europe and the challenges related to the development of the transmission network. Those were considered very important recommendations from the industry to the EU energy and climate change policy debate.

For the first time, this network development report provided in a single document the most up-to-date information about all major planned or envisaged transmission investment projects of European importance as proposed and assembled by national TSOs.

Although evaluations were mainly of descriptive and qualitative nature, TYNDP 2010 also indicated, for the first time, future methodological needs.

This report represented an important step towards a new European planning approach, although still with a strong national and regional rather than a truly pan-European perspective.

Table 2.1: Overview of methodological aspects and principles considered in TYNDP 2010. Adapted from: “Ten-Year Network Development Plan 2010-2020, ENTSO-E, June 2010”

Topic	Description	Methodological context
Included projects	Projects proposed by TSOs for inclusion	Projects background is given on a description of investment needs provided by all six TYNDP regional groups. The investment needs are sorted into main categories which include generation and demand evolution, cross-border capacity, reliable grid operation and equipment ageing. Subsequently, the projects are listed within the context of each regional group.
Time horizon	2020	Two scenarios: conservative scenario and a best estimate scenario.
Definition of scenarios	Bottom-up approach (TSOs predict the evolution of the generation and demand based on current observations and their assessment of future evolution)	Two Generation/Load bottom-up scenarios highlighting trends for the coming 5-15 years, with assessment of Generation Adequacy and compared to EU 2020 targets. The interest of top-down scenarios has been demonstrated, highlighting the need for stakeholders’ support and cooperation.
Market studies	Not performed	Market studies are considered necessary in all European regions in order to have a global view on the investment needs and acquire the necessary input elements for the evaluation of the projects. TYNDP 2010 focuses on regions and states in which this work has already been initiated.
Network studies	Presentation of grid planning principles	A comprehensive description of the grid planning principles commonly used by TSOs is provided in the annex to TYNDP 2010. In general terms, this would mean that all mature projects have successfully passed the technical analysis.
Evaluation of projects	First sketch of economic analysis and criteria for prioritisation is discussed	The parameters that the TSOs need to take into account in order to accurately assess the socio-economic value of an investment are presented. Cost-benefit analysis with respect to social welfare is performed for every transmission project, but using different metrics from country to country, based on the respective regulatory regimes and national/regional requirements. Large-scale market studies are required for a consistent assessment of investment needs and provide basic inputs to project evaluations. Common evaluation criteria for projects of European importance will be part of future grid codes and consulted with stakeholders.
Stakeholder involvement	Consultation	A stakeholder consultation was performed after the first draft release to get the feedback from stakeholders on contents and future involvement.

¤ TYNDP 2012

TYNDP 2012, the first official network plan, introduced some improvements, namely as regards the use of both top-down and bottom-up definition of scenarios. For the first time, projects from non ENTSO-E members, so-called third party projects, were introduced. The cost benefit analysis of every project was presented through a multi-criteria assessment scale.

TYNDP 2012 introduced the monitoring of the TYNDP 2010 projects and this practice has been maintained since then in the years between successive TYNDP reports. The monitoring exercise, according to the ENTSO-E website, represents "*an effort to further increase transparency and usability of the TYNDP, and responding to the recommendations of ACER (…). The content of the monitoring reports have been extended over time. The report publishes quantitative data (e.g. percentage of project commissioned / delayed) along with the reasoning for changes in the status of projects*".[43]

The 2012 report described the need to develop specific top-down coordination "*relying on common standards and subsidiarity to take advantage of TSOs' local expertise and workforce*". Indeed, several working groups of TSO experts for a total of about 200 people across Europe contributed to prepare the TYNDP 2012 package.[44]

The complexity of the first official release demonstrated the need to improve background work and some procedures and methods:

"ENTSO-E is already building on the gathered feedback to strengthen all the involved procedures and further improve the methodology implementation. The goal is threefold:

1. To accelerate and strengthen data collection, consistency checks and processing,

2. to facilitate common model calibration and

3. to coordinate regional groups, articulate pan-European and regional assessment and merge all results consistently".

[43] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-monitoring/Pages/default.aspx.

[44] TYNDP 2102 Package main contents: TYNDP 2012 report; the six regional investment plans – Baltic Sea (NO, SE, DK, FI, EE, LV, LT, PL, DE); Continental South East (HU, SI, RO, RS, BG, MK, ME, BA, HR, IT, EL); Continental Central East (AT, HR, CZ, DE, HU, PL, RO, SK, SI); Continental South West (FR, PT, ES); Continental Central South (FR, DE, CH, AT, IT, SI); North Sea (IE, NI, GB, NO, DK, NL, BE, LU, DE, FR); the Scenario Outlook and Adequacy Forecast (SO&AF) 2012 – 2030.

Table 2.2: Overview of methodological aspects and principles considered for TYNDP 2012. Adapted from: “10-Year Network Development Plan 2012, ENTSO-E, July 2012”

Topic	Description	Methodological context
Included projects	Projects proposed by TSOs for inclusion Third party projects (non ENTSO-E members)	The background of the projects is given on a description of investment needs provided by all six TYNDP regional groups. The investment needs are sorted into main categories, which include generation and demand evolution, cross-border capacity, reliable grid operation and equipment ageing. Subsequently, the projects are listed within the context of each regional group.
Time horizon	2020 and 2030	Four visions up to 2030.
Definition of scenarios	Top-down and Bottom-up approach	The Scenario EU 2020 has been built top-down, based on the European 20-20-20 objectives and the NREAPs 2) (it is the reference scenario). The Scenario SAF-B extrapolates information from market players’ presented investments perspectives in a bottom-up approach.
Market studies	Performed The market study answers the question “which generation (location / type) is going to serve which demand (location)?”	Based on a 1-node-per country (or price zone) principle with simplified transmission capacity limitation modelling between the nodes. TYNDP 2012 provided the possibility to run in parallel several market study tools at regional levels, in order to better adapt to the specifics of every region. All simulations derived from a single database depicting the scenarios to ensure consistency between all six European regions.
Network studies	Performed	Inputs to common network studies are default pan-European Power Systems Models, where the specific generation and load dispatch stemming from the market studies is blended. Network studies answer the question “will the dispatch of generation and load given in every case generated by the market study result in power flows that endanger the safe operation of the system (accounting especially for the N-1 rule)?”.
Evaluation of projects	Transmission projects valuated against a multi-criteria scale developed by ENTSO-E	Assessment of the grid transfer capability increase is provided for every project. All other dimensions are assessed via three-level indicators: social and economic welfare, RES integration and improved security of supply.
Stakeholder involvement	Consultation	Eight week period for stakeholder consultation.

¤ TYNDP 2014

TYNDP 2014 was defined by Regulation 347/2013 as the sole basis for the second Union list of PCIs. It maintained the top-down and bottom-up approach in scenario definition. A new procedure for the inclusion of third party projects and an improved cost-benefit analysis (CBA) methodology were included. A monitoring update of earlier TYNDP investments was maintained and the Long-Term Network Development Stakeholder Group (LTND SG) was established.

The stronger interaction with stakeholders was added due to the perception of *“increased relevance in the European energy industry and the need to enhance common understanding about the transmission infrastructure in Europe”* and the need *“to create an open and transparent environment in which all involved parties can discuss and debate”*.

Table 2.3: Overview of methodological aspects and principles considered for TYNDP 2014. Adapted from: “10-Year Network Development Plan 2014, ENTSO-E, July 2014”

Topic	Description	Methodological context
Included projects	Projects proposed by TSOs for inclusion Third party projects.	New procedure for the inclusion of third party projects.
Time horizon	2030	Four Visions for 2030 representing possible extremes of the future so that the pathway realised in the future falls with a high level of certainty in the range described by the Visions. Different concept from the 2020 scenarios used in the TYNDP 2012; these aimed to estimate the evolution of parameters under different assumptions, while the 2030 Visions are designed to estimate the extreme values between which the evolution of parameters is expected to occur.
Definition of scenarios	Top-down and Bottom-up approach	Two visions build from the bottom-up based on each country's energy policy, while the other two visions assume a top-down approach, with a more harmonised European integration.
Market studies	Pan-European and regional	Pan-European market studies introduced to improve both the scenario building and the assessment of projects. They aim to provide the boundary conditions for the regional market studies necessary to ensure a consistent and harmonised framework for the regional assessment of the projects with the CBA methodology. Regional market studies deliver bulk power flows and pinpoint which specific cases need to be further studied via network studies; they also deliver the economic part of the CBA assessment.
Network studies	Regional network studies	Analyse how the grid handles the various cases of generation dispatch identified during the regional market studies and deliver the technical part of the CBA assessment.
Evaluation of projects	CBA multi-criteria methodology tested throughout the whole TYNDP 2014 portfolio even before the validation of the CBA methodology end 2014	CBA implemented in the TYNDP 2014 for four 2030 Visions. Goal to have a system wide cost-benefit analysis, allowing a homogenous assessment of all TYNDP projects and assessment of candidate Projects of Common Interest. Included an assessment of storage projects in addition to Transmission projects.
Stakeholder involvement	Consultation and launching of the Long-Term Network Development Stakeholders Group	Interactions with stakeholders included in every phase of development. Long-Term Network Development Stakeholders Group (LTND SG), gathering European organisations and incorporating the major stakeholders of ENTSO-E. Public consultation.

¤ **TYNDP 2016**

TYNDP 2016 placed a focus on common planning studies where interconnection targets were agreed. This reinforced the link with Regulation (EC) No 714/2009 in terms of identifying "*…investment gaps, notably with respect to cross-border capacities*" and marked a significant step towards comprehensive coordinated planning. This release contained the first formal use of the CBA methodology.

The plan also provided insight into several challenges for the power system in terms of power system profitability and operational concerns by 2030.

Table 2.4: Overview of methodological aspects and principles considered for TYNDP 2016. Adapted from: “10-Year Network Development Plan 2016, ENTSO-E, December 2016”

Topic	Description	Methodological context
Included projects	Projects proposed by TSOs for inclusion and third party projects	The TYNDP 2016 project list has been set throughout a public process from March to October 2016 under the aegis of the EC, and the active supervision of the NDSG, acting as ethical committee.
Time horizon	2020 and 2030	Five scenarios, with four 2030 ‘Visions’ comparable to those of the TYNDP 2014 but refocused to the EU 2030 goals, updated with various evolutions and designed with new methodologies; as well as a new 2020 ‘Expected Progress’ scenario.
Definition of scenarios	Limited set of representative visions realised with the involvement of all impacted stakeholders	The four 2030 visions are built around two axes: The level of centralisation in the governance of the decarbonisation policies (more European or more national) and the level of progress in meeting the European targets for the reduction of greenhouse gas emissions. Two of the visions have a stronger bottom-up approach, while the other two visions have a stronger top-down approach.
Market studies	Pan-European	Pan-European market studies seem to have been fully internalised in the process of scenario building and the assessment of projects. Regional market studies consider the boundary conditions from pan-European market studies and deliver bulk power flows and pinpoint which specific cases need to be further studied via network studies; they also deliver the economic part of the CBA assessment.
Network studies	Regional network studies	Analyse how the grid handles the various cases of generation dispatch identified during the regional market studies and deliver the technical part of the CBA assessment.
Evaluation of projects	Formal use of CBA assessment	CBA methodologies complemented with more transparent rules to define the reference grid for projects assessments. Project promoters have been invited to complete the ENTSO-E CBA results with their own information and comments to build self-supporting projects assessment sheets and better support the establishment of the third PCI list.
Stakeholder involvement	Consultation and Network Development Stakeholder Group	Interactions with stakeholders included in every phase of development. The group now called the Network Development Stakeholders Group (NDSG) gathers European organisations and incorporates the major stakeholders of ENTSO-E. Public consultation.

¤ **TYNDP 2018**, according to information mentioned in public discussion fora, takes the TYNDP 2016 experience in common planning and identification of system needs as a basis and proposes to go further, highlighting operational challenges. It pursues added stakeholder and external interaction in the definition of scenarios. On top of that, the alignment of scenarios with ENTSO-G will be pursued.

Progress evaluation

Starting from a mere list of projects in 2010, the TYNDP is evolving into a coordinated planning tool, providing the identification of projects with increasingly complete methodologies and relevant information concerning system changes and technical and economic challenges for generation associated with the energy transition. TYNDP 2018 outline reveals ENTSO-E's interest in taking that direction further.

Planning results

According to the TYNDP 2016 executive summary, the proposed set of projects will meet the 10% interconnection capacity goal by 2020, only missing the critical Spain-France interconnection. Overall, in order to meet Europe's goals towards 2030 in terms of energy and climate policy, market efficiency and security of supply, the TYNDP 2016 estimates up to 150 billion euros of investments in grid infrastructure.

TYNDP 2016 identifies the necessary projects to deliver the required infrastructure to support the energy transition and market integration. However, according to TYNDP monitoring reports, a significant percentage of projects is subject to delays and many projects are being rescheduled. This is strongly highlighted by ENTSO-E in the executive summary of TYNDP 2016 draft report for regulatory opinion:

"*The TYNDP 2016, unfortunately, confirms the trend identified in the previous TYNDPs, with moderate progress: about 25% of TYNDP investments suffered delays in the past two years (compared with 33% in 2014), though more are being rescheduled (22% now compared with 12% in 2014). TYNDP monitoring also shows that of the TYNDP 2014 investments in a design or permitting stage two years ago, at present 20% are under construction, and 5% has been commissioned. Making the comparison with TYNDP 2012, these levels are respectively 30% and 10%. Implementation monitoring also shows that of the TYNDP 2016 investments presently in design or permitting phase, on average these items have faced a delay of one year since 2014, and three years since 2012"*.[45]

Improving coordination at the planning level is necessary, as discussed above, but these results also show that strong focus must be placed on how to make the foreseen reinforcements a reality, i.e. how to implement TYNDP, how to transform planned projects into tangible assets through investment.

[45] http://tyndp.entsoe.eu/projects/2016-11-28-1600-exec-report.pdf.

Two main factors, also involving PCI projects, are commonly referred to as the major obstacles responsible for delays (they are not really coordination issues):

- Low public acceptance from local populations (to overcome this obstacle it is necessary to improve wide participation of stakeholders in the decision-making process, as well as strong and coherent political support from the European to the local level);
- Lengthy permitting procedures (best practices across Europe should be harmonised to streamline the permit granting process and penalties should be foreseen if deadlines are not met).

Very often, when a project is identified in the TYNDP or has a PCI label and experiences further delays, this fuels the argument which questions the need of the project itself and reinforces public reluctance to accept new transmission lines. Sometimes, this reluctance also results from the lack of convincing answers to some basic questions, such as "what is the real benefit of that line to our community?".

Coordination of TYNDP with 'national ten year plans'

The 2009 Regulation prescribes that the TYNDP shall *"build on national investment plans"* and that *"the Agency* [ACER] *shall provide an opinion on the national ten-year network development plans to assess their consistency with the Community-wide network development plan".* However, it is not clear how much coordination is performed and how much national, regional and Union-wide plans impact upon each other.

A project identified at national level is usually proposed for inclusion in the TYNDP, but if a project is identified in the framework of the TYNDP process, it is not clear whether it must be incorporated in the respective national plans. From this perspective, could the TYNDP have a more binding nature concerning projects that seem to be robust in the face of uncertainty and changing conditions? If a project identified in the TYNDP is necessary to deliver the European electricity infrastructure, in particular as regards the 10% or 15% targets, and it is not implemented, then there are no consequences for those delaying or aborting the project.

2.1.4 Meeting the energy transition

The 1996 and 2003 electricity Directives assumed that market forces would lead to a quick harmonisation of wholesale energy prices across Europe, for the benefit of energy consumers. In the meantime, insufficient convergence of wholesale electricity prices due to insufficient interconnection capacities between national energy networks has been recognised as a failure of the Internal Energy Market; legal and regulatory action has been undertaken since 2009 to overcome this problem.

The TYNDP concept and process, introduced by the 2009 electricity Regulation, was a logical attempt to fix the problem, providing – at last – an answer to the question "How can network planning coordination be ensured in a fully liberalised and partially Europeanised electricity market?" However, the TYNDP is the tardy reply to a question that should have been answered 21 years ago and its evolution over the past six years shows how difficult it is to properly implement that solution, especially if the corresponding question "How can transmission network investment coordination be ensured in a fully liberalised and partially Europeanised electricity market?" has not yet been effectively addressed.

Now, the question is whether the TYNDP instrument can be useful in order to promote the energy transition in Europe. There is no reason why it should not be fit for purpose. However, this requires a two-fold effort:

- On the one hand, to pursue and accelerate the very impressive trend embodied in recent TYNDP editions in order to improve procedural and methodological features, as well as quantity and consistency of the data set;
- On the other hand, to immediately take into due account the new stakeholders, devices and processes that are shaping the energy transition, providing a quantum leap in terms of stakeholder participation, conceptual framework and planning tools, i.e. reinventing transmission network planning coordination in the three-dimensional space of digitalisation, decarbonisation and integration of electricity systems.

In recent years, cross-border capacity has increased more significantly than in the past, as shown in the following tables.

Table 2.5: EU transmission circuit length in km

(Based on ENTSO-E statistical fact sheet from 2010 to 2015)[46]

	AC Circuits including cable [km]				DC Cable [km]
Year	220–285 kV	300–330 kV	Over 350 kV	Total	Total
2010	136943	4790	147195	288928	n/d
2011	140761	4470	148642	293873	5368
2012	142656	4527	150909	298092	5368
2013	141359	9141	151743	302243	5260
2014	141096	9859	156019	306974	5719
2015	140407	10962	157183	308552	5781
Variation 2010-2015	2.5%	128.9%	6.8%	6.8%	7.7%

[46] https://www.entsoe.eu/publications/statistics/statistical-factsheet/Pages/default.aspx.

Table 2.6: Number of cross-border lines in the ENTSO-E area

(Based on ENTSO-E available statistical fact sheet data from 2013 to 2015)

	Number of cross-frontier lines in the ENTSO-E area				DC Cable [km]
Year	220–285 kV	300–330 kV	Over 350 kV	Total	Total
2013	89	18	123	319	22
2014	93	18	127	327	23
2015	93	18	128	328	27

Investment in cross-border lines is essential to increase cross-border capacity and to enhance electricity market integration. However, cross-border lines do not tell the full story since internal capacity and internal reinforcements also play a key role in defining cross-border capacity and market integration.

The Connecting Europe Facility (CEF) fund has been supporting many interconnection and reinforcement projects in Europe to develop the electricity market.[47] According to the CEF Energy Key figures brochure,[48] published in November 2016, by the end of 2016, 36 actions involving PCIs in electricity for a total of €1,004.5 million have been supported.

[47] https://ec.europa.eu/inea/en/connecting-europe-facility/cef-energy/cef-energy-projects-and-actions.
[48] https://ec.europa.eu/inea/sites/inea/files/cef_energy_key_figures_c4_24112016.pdf.

2.2 Market and system operation

System operation must ensure that the electricity system is able to match generation and demand under secure and efficient conditions. This must be done following market decisions in each trading period and respecting technical restrictions while, at the same time, ensuring the availability of reserves for possible contingencies and ancillary services to support the power system in real-time.

The draft Regulation establishing a network code on electricity emergency and restoration highlights in its preamble the importance of interdependency in system operation:

"Even though each TSO is responsible for maintaining operational security in its control area, the secure and efficient operation of the Union's electricity system is a task shared between all the Union TSOs since all national systems are, to a certain extent, interconnected and a fault in one control area could affect other areas. The efficient operation of the Union's electricity system also requires a close collaboration and coordination between stakeholders".[49]

Market and system operation are at the core of the interconnected networks and of the internal energy markets in Europe for electricity and natural gas. Since security risks and efficiency gains are very sensitive aspects and have impact on the whole interconnected system, tight coordination among TSOs, on the one hand, but also between TSOs and all market players and operators, on the other hand, is crucial. It should also be pointed out that some physically interconnected systems do not correspond to EU Member States.

Several blocking factors have hindered the necessary development of tight system and market coordination at the EU level, in particular the following ones that will be discussed in the subsequent Sections:

- Lack of comprehensive coordination of system operation;
- Lack of common remedies policy and redispatching approach;
- No common reserve contracting and cost allocation procedures;
- No intraday auction-based cross-border allocation;
- Lack of harmonised load shedding coordination.

2.2.1 Lack of comprehensive coordination of system operation

Purpose and need for coordination

Network operators must provide non-discriminatory access to networks at Europe-wide level, therefore the use of networks and interconnectors must be coordinated to some extent. Furthermore, although system security is a national responsibility,

[49] https://ec.europa.eu/energy/sites/ener/files/documents/nc_er_ener_vs_13_ecbc_on_24_25-10-2016finalasvotedfor_publication.pdf.

systems are highly interdependent and any problem can easily spread to large areas of an interconnected network. Therefore, system operation coordination mechanisms among TSOs are required. Market operation impacts upon system operation everywhere. In order to optimise the functioning of power exchanges and market functioning in increasingly larger areas, it is necessary to improve system operation across the relevant areas.

Following the introduction of competition in electricity, system operation coordination has been performed by TSOs in different regions in Europe according to different levels of coordination and formalisation, ranging from voluntary agreements to mandatory rules enforced by supra-national regulatory bodies.

The following paragraphs describe how system operation coordination was carried out before the Third Energy Package and how it is developed today, in line with the family of operational guidelines (the Regulation establishing a network code on emergency and restoration and the Regulation establishing a guideline on system operation) that has been published.[50]

Operational coordination before the Third Package

Before the Third Energy Package of 2009, regional organisations such as UCTE (Union for the Coordination of Transmission of Electricity), NORDEL (cooperation between the transmission system operators in Denmark, Finland, Iceland, Norway and Sweden), BALTSO (cooperation organisation of Estonian, Latvian and Lithuanian Transmission System Operators), UKTSOA (United Kingdom Transmission System Operators Association), ATSOI (Association of the Transmission System Operators of Ireland) promoted the coordination and development of the European interconnected system through non-binding rules agreed voluntarily by all their members. Moreover, they regularly published statistical information concerning system development and operation.

In parallel to these voluntary regional arrangements, procedure manuals and binding network codes were adopted at national level, following the introduction of independent energy regulation in EU Member States.

The following statements are taken from the ENTSO-E website and illustrate part of the historic evolution of these regional organisations.[51][52]

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[50] http://ec.europa.eu/energy/en/topics/wholesale-market/electricity-network-codes.
[51] https://www.entsoe.eu/news-events/former-associations/ucte/Pages/default.aspx.
[52] https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/110422_UCPTE-UCTE_The50yearSuccessStory.pdf.

FROM ENTSO-E website: Union for the Coordination of the Transmission of Electricity (UCTE)

"The Union for the Co-ordination of Transmission of Electricity coordinated the operation and development of the electricity transmission grid for the Continental European synchronously operated transmission grid, thus providing a reliable platform to all participants of the Internal Electricity Market and beyond.

Since 1951, the Union for the Coordination of Production and Transmission of Electricity (UCPTE) had coordinated synchronous operations through meetings of experts and managers from at first a small number of interconnected companies at the interface of Switzerland, France and Germany, and over various stages from a growing number of companies and countries. The UCPTE's operational and planning recommendations helped ensure reliable supply of electricity in Continental Europe.

In 1999, UCTE re-defined itself as an association of TSOs in the context of the Internal Energy Market. Building on its experience with recommendations, UCTE turned to make its technical standards more binding through the Operation Handbook and the Multi-Lateral Agreement between its members. These standards became indispensable for the reliable international operation of the high voltage grids which are all working at one "heart beat": the 50 Hz UCTE frequency related to the nominal balance between generation and the electricity demand of some 500 million people in one of the biggest electrical synchronous interconnections worldwide.

In its final year of existence, UCTE represented 29 transmission system operators of 24 countries in continental Europe.

On 1 July 2009 UCTE was wound up. All operational tasks were transferred to ENTSO-E.

UCPTE/UCTE The 50 Year Success Story – Evolution of a European Interconnected Grid gives a chronological account on the development of the interconnected electricity grid of Continental Europe and provides facts and figures on the work of UCPTE and UCTE until their transition into ENTSO-E, in July 2009".

FROM ENTSO-E website:

"In addition to the UCTE as a technical association, the NORDEL, UKTSOA, ATSOI and BALTSO also existed with the same goals in other parts of Europe. The main focus on market was organised by activities of ETSO (It was becoming quite clear, especially under the rearranged market design, that a shift from a more voluntary to an enforcement-based platform would be needed if a sufficient level of compliance were to be guaranteed). Furthermore, the EU talked much about the so called "20-20-20 targets" (standing for 20% decarbonisation, a 20% increase in the share of renewable energy sources (RES) fed in and a 20% improvement in energy efficiency by 2020) which meant that the share of RES in the generation mix was now rapidly

growing favoured by the current legislative climate, and particularly difficult for the grid to catch up. Such intentions voiced by the EU required more co-ordinated action, involving not only TSOs, but all relevant parties, such as generators, legislators, regulators, research institutes and stakeholders. To address these pressing issues, and in anticipation of the 3rd package of energy legislation, all TSO associations embarked on an intensified cooperative commitment which was given a legal foundation through the establishment of the new pan-European body ENTSO-E (European Network of TSOs for Electricity) on 19 December 2008. Among its founding members were all of the UCTE's TSOs.

This reorganisation resulted in the merging of the existing associations, including the UCTE, which was wound up by mid 2009.

Operational coordination following the Third Package

Following the adoption of the operational guidelines, foreseen in the 2009 electricity Regulation, operational coordination in Europe has been consistently enforced at national and at pan-European level.

The following box contains some of the principles laid out in the 4th May 2016 draft Regulation establishing a guideline on electricity transmission system operation,[53] reflecting the need for harmonised rules for all system players and also the need to further enhance coordination among TSOs via their mandatory participation in regional security coordinators (RSCs).

(3) Harmonised rules on system operation for transmission system operators ('TSOs'), distribution system operators ('DSOs') and significant grid users ('SGUs') should be set out in order to provide a clear legal framework for system operation, facilitate Union-wide trade in electricity, ensure system security, ensure the availability and exchange of necessary data and information between TSOs and between TSOs and all other stakeholders, facilitate the integration of renewable energy sources, allow more efficient use of the network and increase competition for the benefit of consumers.

(4) To ensure the operational security of the interconnected transmission system, it is essential to define a common set of minimum requirements for Union-wide system operation, for the cross-border cooperation between the TSOs and for utilising relevant characteristics of the connected DSOs and SGUs.

(5) All TSOs should comply with the common minimum requirements on procedures necessary to prepare real-time operation, to develop individual and deliver common grid models, to facilitate the efficient and coordinated use of remedial actions which are necessary for real-time operation in order to maintain the operational security,

[53] https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf.

quality and stability of the interconnected transmission system, and to support the efficient functioning of the European internal electricity market and facilitate the integration of renewable energy sources ('RES').

(6) While there are currently a number of voluntary regional cooperation initiatives in system operations promoted by TSOs, formalised coordination between TSOs is necessary for operating the Union transmission system in order to address the transformation of the Union electricity market. The rules for system operation provided for in this Regulation require an institutional framework for enhanced coordination between TSOs, including the mandatory participation of TSOs in regional security coordinators ('RSCs'). The common requirements for the establishment of RSCs and for their tasks set out in this Regulation constitute a first step towards further regional coordination and integration of system operation and should facilitate the achievement of the aims of Regulation (EC) No 714/2009 and ensure higher security of supply standards in the Union.

(7) This Regulation should set out a framework for the mandated cooperation of TSOs via the appointment of RSCs. RSCs should issue recommendations to the TSOs of the capacity calculation region for which it is appointed. TSOs should, individually, decide whether to follow or not the recommendations of the RSC. The TSO should remain responsible for maintaining operational security of its control area.

According to the operational guidelines, RSCs are entities owned or controlled by their clients, the TSOs, in one or more Capacity Calculation Regions (CCR).[54] They provide services to support TSOs in regional coordination, aiming at creating economies of scale and at providing the most cost-efficient solutions at the regional level in dealing with maximising the capacity offered to the market and in defining remedial actions to cope with network restrictions.

The principles to be used by the RSCs are agreed by all TSOs in each Capacity Calculation Region.

RSCs are designed to provide advice on the most adequate measures to TSOs, who have the capability to control the network in real time. Hence, the RSCs are not equipped to take direct control of the grid.

All European TSOs will delegate services at least to one regional security coordinator.

The following table presents the main areas covered by the 2016 draft Regulation establishing a guideline on electricity transmission system operation.

[54] As defined in Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management, Capacity Calculation Region means a *"geographic area in which coordinated capacity calculation is applied"*.

Table 2.7: Overview of System Operation Guidelines. Adapted from ENTSO-E website[55]

	System Operation Guidelines
Regulation	Pending. The draft Regulation establishing a guideline on system operation received a positive vote in Comitology on 4 May 2016.
Covered areas	The System Operation Guideline is one of the network codes/guidelines drafted under the Third Energy Package. In 2015, the European Commission, ACER and ENTSO-E agreed to merge the three operational network codes into a single System Operation Guideline during their preparatory work for Comitology. The new guideline is composed of the former network codes on Operational Planning and Scheduling (NC OPS), Operational Security (NC OS), and Load Frequency Control and Reserve (NC LFCR).
Operational security	Basis for the power system to function with a satisfactory level of security and quality of supply, as well as efficient utilisation of infrastructure and resources. It will do so by focusing on common operational security principles, pan-European operational security, coordination of system operation, and some important aspects for grid users connected to the transmission grid. Measures aim to enhance capacity to maintain operational security and support the efficient functioning of the European internal electricity market.
OPS	It focuses on the planning phase, ahead of real time operations. It determines the roles and responsibilities for Transmission System Operators (TSOs), Distribution System Operators (DSOs) and significant grid users (SGUs) towards the operational scheduling procedures and prescribes how these different parties exchange data. The approach taken is to define the minimum requirements needed to ensure a planning process that is coherent and coordinated across Europe. First, the code determines common methodologies and principles that allow for a coordinated approach towards operational security analysis and adequacy analysis. Second, the code determines how to coordinate availability plans, allowing for a more optimal planning of outages for the maintenance of relevant assets.
LFCR	Focus on frequency quality criteria, frequency control structure, frequency containment reserves, frequency restoration reserves, replacement reserves, exchange of reserves and synchronous time control. These LFCR provisions will also help to ensure the efficient utilisation of infrastructure and resources.

[55] https://www.entsoe.eu/major-projects/network-code-development/system-operation/Pages/default.aspx.

In 2013, Regulation (EU) No 347/2013 substantially reinforced the responsibilities of TSOs in system operation coordination, as recalled in the following box.

Article 21

Amendments to Regulation (EC) No 714/2009

Regulation (EC) No 714/2009 is hereby amended as follows: (1) Article 8 is amended as follows:

(a) in paragraph 3, point (a) is replaced by the following:

'(a) common network operation tools to ensure coordination of network operation in normal and emergency conditions, including a common incident classification scale, and research plans. These tools shall specify inter alia:

(i) the information, including appropriate day ahead, intra-day and real-time information, useful for improving operational coordination, as well as the optimal frequency for the collection and sharing of such information;

(ii) the technological platform for the exchange of information in real time and where appropriate, the technological platforms for the collection, processing and transmission of the other information referred to in point (i), as well as for the implementation of the procedures capable of increasing operational coordination between transmission system operators with a view to such coordination becoming Union-wide;

(iii) how transmission system operators make available the operational information to other transmission system operators or any entity duly mandated to support them to achieve operational coordination, and to the Agency; and

(iv) that transmission system operators designate a contact point in charge of answering inquiries from other transmission system operators or from any entity duly mandated as referred to in point (iii), or from the Agency concerning such information.

The ENTSO for Electricity shall submit the adopted specifications on points (i) to (iv) above to the Agency and to the Commission by 16 May 2015.

Within 12 months of the adoption of the specifications, the Agency shall issue an opinion in which it considers whether they sufficiently contribute to the promotion of cross-border trade and to ensuring the optimal management, coordinated operation, efficient use and sound technical evolution of the European electricity transmission network.'

Current status

It is expected that considerable effort will be required during the coming years in order to align all national frameworks with the new binding regulations on system operation and to specify the terms and conditions or methodologies that are required by the regulations and will need agreement by all concerned TSOs and approval by all the national regulatory authorities.

As an essential implementation aspect, monitoring and reporting is performed by ENTSO-E. However, the draft regulation on system operation does not establish enforcement mechanisms.

Article 14 Monitoring

ENTSO for Electricity shall monitor the implementation of this Regulation in accordance with Article 8(8) of Regulation (EC) No 714/2009. Monitoring shall cover at least the following matters:

(a) operational security indicators in accordance with Article 15;

(b) load-frequency control in accordance with Article 16;

(c) regional coordination assessment in accordance with Article 17;

(d) identification of any divergences in the national implementation of this Regulation for the terms and conditions or methodologies listed in Article 6(3);

(e) identification of any additional improvements of tools and services in accordance with subparagraphs (a) and (b) of Article 55(1), beyond the improvements identified by the TSOs in accordance with Article 55(1)(e);

(f) identification of any necessary improvements in the annual report on incidents classification scale in accordance with Article 15, which are necessary in order to support sustainable and long-term operational security; and

(g) identification of any difficulties concerning cooperation on secure system operation with third country TSOs.

This implementation will be carried out simultaneously with the implementation of the Regulations on market guidelines, which will require a significant effort in terms of ensuring the consistency and reliability of procedures.

The definition and implementation of quite an extensive list of terms, conditions and methodologies (Article 6 of Regulation on system operation) with national, regional or pan-European impact, still leave a considerable margin for national specificities, in line with the exclusive national responsibility for system operation.

The approval of the above-mentioned terms, conditions and methodologies requires the unanimous support of all relevant regulatory authorities.

While it is expected that RSCs will play increasingly important roles in optimising system operation and market functioning, the responsibility for operational decisions still belongs to the national TSOs and are applied according to national regulations.

For the time being, liability mechanisms, enforcement rules and regulation are all national.

When the process reaches maturity and confidence, further services or responsibilities, even more close to real time, might be added. Currently, RSCs are only focused on operational planning.

2.2.2 Common redispatching approach

The most common – and in a certain way the 'easiest' – form of market intervention is called "redispatching" and basically consists of changing the scheduled output of some generators until the newly computed load-flows fit the technical restrictions of the underlying physical infrastructure.

Purpose and need for coordination

Whenever market outcomes are incompatible with reliable system operation some kind of remedial action is necessary. Redispatching is a typical remedial action and may have very strong redistributive impacts.

While large areas of day-ahead market coupling have been created in the EU, still there is no common redispatching approach, which leads to the substantial fragmentation of power markets at the closing loop, where all day-ahead or intraday transactions enter their final settlement stage.

In a market that strives to be more and more integrated and, at the same time, becomes highly volatile, a common framework for remedial measures allowing for a more efficient use of the grid and increased security of the electricity system is of paramount importance.

Ex-ante allocation of available cross-border capacities through appropriate market-based algorithms provides for effective preventive congestion management. However, congestion management after capacity has been allocated is often necessary, making the use of remedial actions inescapable. The associated costs must be identified and recovered through appropriate market-based or regulatory mechanisms.

The CACM Regulation provides the framework for the day-ahead and intraday markets time frame capacity allocation and congestion management. Here, the remedial measures considered are redispatching and countertrading:

- Redispatching: the TSO must assess, based on defined criteria, which generator's output will be modified in order to change physical flows in the transmission system and relieve a physical congestion;
- Countertrading: the TSO must buy and sell electricity to balance demand between two bidding zones to relieve a physical congestion.

Before the CACM, redispatching and countertrading often relied on bilateral or multilateral agreements. Many different agreements lacked appropriate coordination and were often based on a limited exchange of data and very simple cost sharing principles. Very often, these uncoordinated and oversimplified methods (due to a limited evaluation of the causes of the restrictions) led to unfair decisions concerning the choices of generators to redispatch and, consequently, to unfair and inefficient sharing of costs and benefits.

The CACM Regulation aims to overcome all these risks by establishing clear rules on how to perform redispatching and countertrading and also how to quantify the associated costs and benefits.

The following table is extracted from the 'ACER Market Monitoring Report 2015'.[56] According to ACER, it is still difficult to compare the total cost of remedial actions between Member States due to the lack of harmonised definitions.

Table 2.8: Network congestion related volumes and costs of remedial actions – 2014 (GWh, thousand euros). Source: ACER/CEER (2015)

Country	Re-dispatching GWh	Re-dispatching thousand euros	Counter-trading GWh	Counter-trading thousand euros	Other thousand euros	Contributions from other TSOs thousand euros	Total cost 2014 thousand euros
ES	9,460	809,148	0	116	0	62	809,202
GB	5,402	164,626	89	4,184	90,242	0	259,053
PL	7,560	106,169	382	23,858	0	18,583	111,444
DE	2,593	108,161	52	1,327	1,083	380	110,191
NO	NA	32,209	NA	1,525	1,077	360	34,451
NL	293	11,753	9	0	0	0	11,753
FI	NA	1,651	NA	8,477	0	2	10,126
FR	0	6,018	0	0	0	0	6,018
AT	1,089	4,413	0	0	174	0	4,587
CZ	54	334	2	0	4	-2,437	2,776
EE	0	0	23	717	0	0	717
LV	6	0	8	709	0	0	709
PT	0	0	0	0	0	0	0
HR	0	0	0	0	0	0	0
SK	0	0	11	0	0	0	0
LU	0	0	0	0	0	0	0
SI	0	0	2	-15,244	0	0	0
DK	0	NA	113	NA	0	2,310	-2,310
IT	11	NA	66	NA	0	0	NA
CH	6	NA	75	NA	0	0	NA

Source: Data provided by NRAs through the ERI questionnaire (2015).

Note: For 2014, the Agency requested data for congestion-related remedial actions. Positive euro values for remedial actions refer to costs incurred to TSOs, and negative values to their revenues, whereas positive values for contributions refer to money received from other TSOs and negative to money paid to other TSOs. Denmark, Italy, Switzerland, did not provide details on costs or did not have the data available. Norway reported only on the costs of remedial actions. Denmark reported only the total compensation received from other TSOs. Countries that are not present in the table did not submit any remedial action data.

Preventive and remedial congestion management measures are very interdependent. In case preventive measures are used, such as offering less cross-

[56] ACER/CEER (2015), *Annual Report on the Results of Monitoring the Internal Electricity Markets in 2014*, p. 171.

border capacity, then less remedial measures, such as redispatching and countertrading, will be necessary. The report by ACER highlights that cross-zonal exchanges in the process of capacity calculation are sometimes limited in order to solve TSOs internal congestion problems.

Current status

The CACM Regulation, entered into force on 13 August 2015, establishes the tasks and the deadlines (Articles 9, 35, 74) for developing the methodologies for coordinated redispatching and countertrading as well as cost sharing.

> *Article 9*
>
> *Adoption of terms and conditions or methodologies*
>
> *6.*
>
> *(c) the methodology for coordinated redispatching and countertrading in accordance with Article 35(1);*
>
> *(h) the redispatching or countertrading cost sharing methodology in accordance with Article 74(1).*

> *Article 35*
>
> *Coordinated redispatching and countertrading*
>
> *1. Within 16 months after the regulatory approval on capacity calculation regions referred to in Article 15, all the TSOs in each capacity calculation region shall develop a proposal for a common methodology for coordinated redispatching and countertrading. The proposal shall be subject to consultation in accordance with Article 12.*

> *Article 74*
>
> *Redispatching and countertrading cost sharing methodology*
>
> *1. No later than 16 months after the decision on the capacity calculation regions is taken, all TSOs in each capacity calculation region shall develop a proposal for a common methodology for redispatching and countertrading cost sharing.*

In November 2016, ACER approved the proposal from all TSOs for the determination of capacity calculation regions.[57] According to the Regulation timelines, the definition of the coordinated redispatching and countertrading methodology is therefore formally on track.

During the public consultation process, the definition of Capacity Calculation Regions proved to be a challenge in its own right since it builds on the definition of the bidding zones and will define the regions where the capacity calculation methodologies will be applied. This will strongly influence where and if congestions could be verified and the subsequent incurred incomes for grid reinforcements or costs of remedial measures.

The ACER decision indicates the need to merge CCRs as the most effective way to optimise capacity allocation and congestion management in regions that already have major cross-border flows.

The capacity calculation methodologies will define, to a large extent, the signals that will be provided from the market in terms of network reinforcement needs considering available cross-border capacity and congestion income distribution as well as internal restrictions leading to a redispatch and cost sharing. It should be pointed out, that some of the physically interconnected non-EU Member States are not involved in this process, which makes efficient operational coordination even more difficult to achieve and operation less reliable.

2.2.3 No common reserve contracting and cost allocation

Given the current mix of generation with growing shares of RES, large electricity trade volumes tend to move closer to real time and the role of intraday and balancing power markets tends to increase.

Purpose and need for coordination

The enhanced coordination – and, eventually, integration – of electricity balancing markets is fundamental to the successful assimilation of volatile RES and constitutes a fundamental building block in the completion of the European internal electricity market. However, to date limited progress has been achieved. This is due to the wide diversity of current balancing markets in Europe and to the importance of balancing to ensure security of supply. Both factors further stress the harmonisation challenge.

[57] Decision No 06/2016 of ACER is available at http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

This challenge was recognised by ACER, when developing the framework guidelines for the electricity balancing network code, in the following terms:[58]

> *The core element of the Framework Guidelines are the models for cross-border exchanges of balancing energy that should first emerge in different geographical areas and gradually, i.e. within 6 years after the entry into force of the Network Code on Electricity Balancing, be integrated into one European platform where all TSOs would have access to different types of balancing energy while taking into account the transmission capacities available between different areas.*

Electricity balancing represents a cost that is included in the transmission network tariff or in separate components of regulated tariffs. An integrated market where balancing resources can be effectively shared and optimised across countries will result in important benefits for all consumers. This optimisation requires the possibility not only of contracting and sharing cross-border reserves, but also of identifying the amount and location of reserves across a region or across Europe that will ensure system security needs and provide the most cost effective solution.

The supporting document published by ENTSO-E together with the draft proposal for the Electricity Balancing (EB) guidelines summarises as the 'Added value of EB' the particular aspects and challenges that are related to an integrated balancing market – from the point of view of the EU network of TSOs.[59]

> *"The targets and methods to foster Balancing Market integration as set forth in the FG EB aim to reduce total costs and to increase Social Welfare while ensuring Operational Security.*
>
> *In a recent Impact Assessment, commissioned by the European Commission, it has been assessed that reasonable benefits can be gained by integrating Balancing Markets. Nevertheless, it also needs to be pointed out that compared to the other electricity market timeframes the Balancing Markets represent only 2-3% of the total turnover volume of wholesale markets. Hence, the potential cost saving of integrating Balancing Markets can be considered to be relatively small. As the Balancing Services are the last resort action for TSOs to ensure Operational Security, the most important objective in developing integrated Balancing Markets is to keep the lights on while facilitating market integration.*
>
> *While the integration of the European energy markets apart from Balancing is following rather clear target models, as is the case for example in capacity allocation set out in the Network Codes on Capacity Allocation and Congestion Management (NC CACM) and Forward Capacity Allocation (NC FCA), clear target models for the*

58 http://www.acer.europa.eu/en/electricity/fg_and_network_codes/pages/balancing.aspx.
59 ENTSO-E (2014), Supporting document for the Network Code on Electricity Balancing, 6 August 2014, available on the ENTSO-E website.

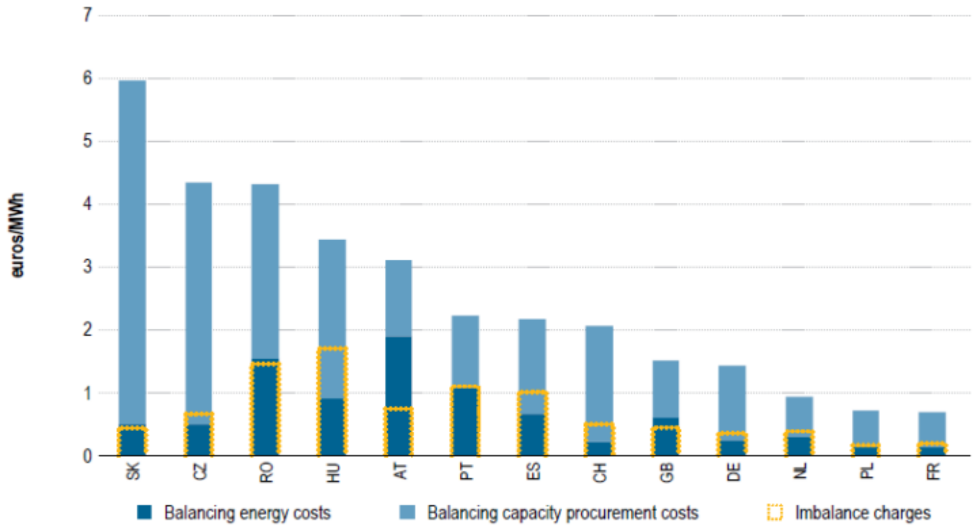
different kinds of Balancing Services have not been detailed. Hence, rather than detailing such target models, the NC EB lays out the processes to develop and implement the steps towards realising these efficiency gains while maintaining Operational Security. TSOs have to develop models for market-based cooperation, first on regional level and later on European level pursuant to the deadlines defined in the NC EB.

The NC EB provides for a phased approach to foster cooperation amongst TSOs in various areas of Balancing. The key concept of Coordinated Balancing Areas (CoBAs) is introduced in the NC EB which establishes a flexible obligation for cooperation to ensure a swift transition towards the relevant target.

The NC EB provides a foundation for a coordinated set of Balancing rules, incorporating the benefit of learning from experience, en route towards a regional or pan-European Balancing Market".[60]

Another approach is coming from the EU Agency for Cooperation of Energy Regulators. The 'ACER Market Monitoring Report 2015' underlines the need to further integrate balancing markets in order to increase efficiency and overall benefits.[61] Those conclusions are supported, to a large extent, by the significant variation of balancing service prices observed in Europe and the currently very limited exchange of balancing services across European borders. The pictures below are taken from the ACER report (p. 209 and p. 212).

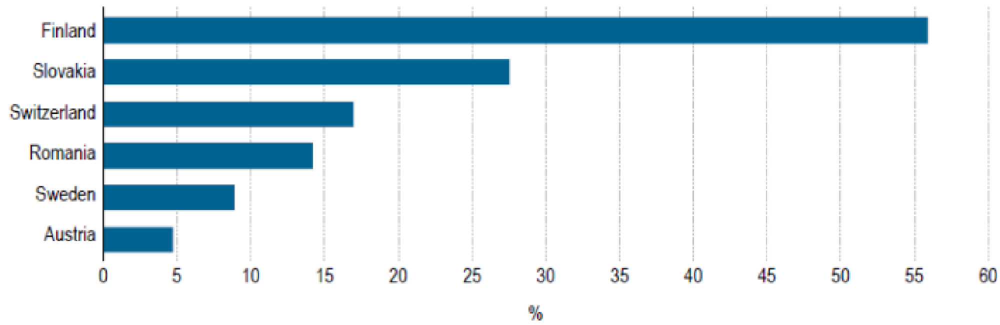
[60] *Ibid.*, p. 11.
[61] ACER/CEER (2015), *op. cit.*, p. 205.



Source: Data provided by NRAs through the ERI, Platts and ACER calculations (2015).

Note: Poland applies central dispatch, and the procurement costs of reserves reported by the TSO are only a share of the overall costs of reserves in the Polish electricity system.

Fig 2.5: Overall costs of balancing (capacity and energy) and imbalance charges over national electricity demand in a selection of European markets – 2014 (euro/MWh). Source: ACER/CEER (2015)



Source: Data provided by NRAs through the ERI, Platts and ACER calculations (2015).

Note: Only those countries which reported any level of cross-border exchange are shown in the figure.

Fig 2.6: EU balancing capacity contracted abroad as a percentage of the system requirement of reserve capacity (upward FCR) – 2014 (%). Source: ACER/CEER (2015)

Current status

The Commission Regulation establishing a guideline on electricity balancing is taking the final steps in the Comitology process and is expected to be published in 2017.

The objectives and purpose of the 'Electricity Balancing Guideline' in terms of cooperation and exchange of balancing services are defined in its first article.

Article 1

Subject matter and scope

1. This Regulation lays down detailed guidelines on electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves.

2. The requirements set forth by this Regulation shall apply to TSOs, DSOs including closed distribution systems, regulatory authorities, the Agency, ENTSO-E, third parties to whom responsibilities have been delegated or assigned, where applicable, and market participants.

Having in mind the need to test how balancing markets could be implemented in practice, several cross-border pilot projects have been put in place by ENTSO-E.[62]

The project TERRE (Trans-European Replacement Reserve Exchange) stands out as the one with a more trans-European perspective and, apparently, is in an advanced and promising stage.

The effective functioning of balancing markets is one of the critical aspects to ensure system security: replacement reserves represent the outer layer immediately after frequency restoration reserves and frequency containment reserves. This explains why balancing remains a TSO responsibility. Reliability and confidence in balancing markets is an important aspect when switching from established traditional solutions to new, more market-based and coordinated approaches across Europe. Different regional schemes are already running in parallel and need to be progressively harmonised.

The participation of consumers either directly or indirectly through aggregators and based on new digital technologies is an essential aspect to be accommodated in the new model for balancing markets.

2.2.4 No intraday cross-border allocation with auction

Intraday markets are gaining increased importance due to growing amounts of intermittent RES generation. Intraday markets allow market participants to level their positions after the changes that result from the day-ahead market and before real-time.

[62] More information on pilot projects proposed by ENTSO-E and their status of implementation can be found at https://www.entsoe.eu/major-projects/network-code-implementation/cross-border-electricity-balancing-pilot-projects/Pages/default.aspx .

Purpose and need for coordination

Wide and efficient intraday markets are becoming crucial for the success of the internal market.

Regulation (EC) No 714/2009 established the congestion management methods for single day-ahead and intraday market time-frames, allowing the use of continuous trading in the case of intraday markets.

The Capacity Allocation and Congestion Management (CACM) Regulation describes in its preamble the possible use of different methods:

> *(13) Capacity should be allocated in the day-ahead and intraday market time-frames using implicit allocation methods, in particular methods which allocate electricity and capacity together. In the case of single day-ahead coupling, this method should be implicit auction and in the case of single intraday coupling it should be continuous implicit allocation. The method of implicit auction should rely on effective and timely interfaces between TSOs, power exchanges and a series of other parties to ensure capacity is allocated and congestion managed in an efficient manner.*
>
> *(14) For efficiency reasons and in order to implement single day-ahead and intraday coupling as soon as possible, single day-ahead and intraday coupling should make use of existing market operators and already implemented solutions where appropriate, without precluding competition from new operators.*

Formal status in implementing the CACM Regulation

The Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management is currently in the implementation phase and both the day-ahead and intraday timeframes are testing the platforms that can be used to serve at EU level. The intraday market coupling project initiative is called the XBID project.

A brief description of this project is provided in the ENTSO-E web page highlighting the continuous nature of the intraday market.[63]

> *"The Regulation No 2015/1222 on Capacity Allocation and Congestion Management (CACM) defines the rules for a continuous intraday market that allows market participants to trade up to at least one hour before real-time. Coupling national intraday markets will increase intraday liquidity, benefiting market players and facilitating RES integration.*

[63] https://www.entsoe.eu/about-entso-e/market/enhancing-regional-cooperation/Pages/Regional%20Cooperation.aspx.

To help realise this goal TSOs from 12 countries, along with power exchanges (PXs), have launched the cross border Intraday (XBID) Market Project [which] will enable the creation of a joint integrated intraday cross-zonal market. The overarching objective of the XBID solution is to create one integrated European intraday market.

This single intraday cross-zonal market solution will be based on a common IT system forming the backbone of the European solution, linking the local trading systems operated by the PXs as well as the available cross-zonal transmission capacity provided by the TSOs. Bids and offers submitted by market participants in one country can be matched by those submitted by market participants in any other country within the IT systems' reach, provided there is cross-zonal capacity available".

ENTSO-E, in its 9 August 2016 'Report on the progress and potential problems with the implementation of Single Day-Ahead and Intraday Coupling', highlights the many results achieved so far and the 2017 implementation goal, but notes that the XBID project *"continues to be a complex project to deliver"*.

The referred complexity relates to several aspects including the need to link multiple countries into a single platform, the close relationship between intraday markets and real-time operation, and the many parts involved in defining the process including TSOs, NEMOs (i.e. market operators) and NRAs.

All these issues drive the need for clarity about cost-sharing and cost recovery and clear governance in terms of roles and responsibilities.

Liquidity in intraday markets is considered a vital element to ensure effective competition; currently, liquidity is relatively low in the majority of national intraday markets. The picture below is taken from the 'ACER Market Monitoring Report 2015' and presents the evolution of traded volumes in the period 2011 to 2014.[64] According to the report, many factors contributed to the observed increase in traded volumes in different markets. As such, it is difficult to identify the causes for higher liquidity.

However, according to the ACER evaluation, *"the three markets with the highest ID liquidity (Italy, Portugal and Spain) are characterised by a high penetration of renewable-based generation, the presence of exclusive ID auctions and obligatory unit bidding*".[65] A special comment is further added concerning the example of Germany, where "*the presence of local or regional ID implicit auctions seems to attract ID liquidity and may play a role in improving ID competition. In Italy, Spain and Portugal, the precise impact of ID auctions in liquidity is uncertain and difficult to disentangle from other factors, as their respective ID markets also present exclusivity and unit bidding, which is unique in Europe. The recent developments presented*

[64] ACER/CEER (2015), *op. cit.*, p. 195.
[65] *Ibid*., p. 199.

above for Germany would confirm that auctions may contribute to increased liquidity and competition in the ID market".[66]

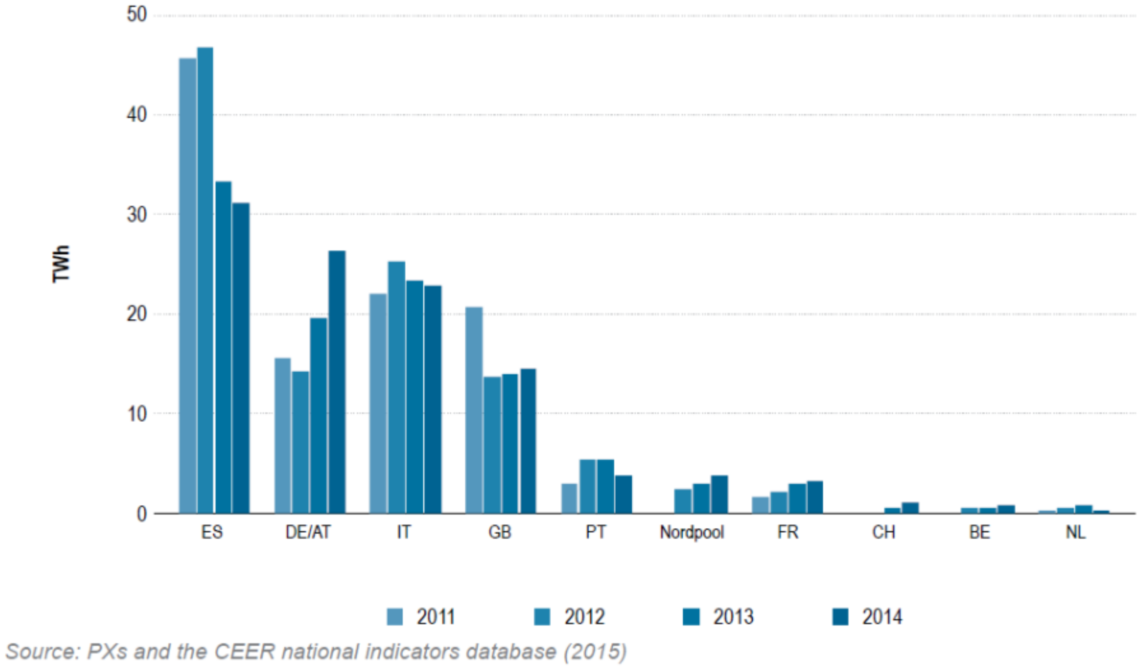


Fig 2.7: Intraday traded volumes in a selection of EU markets – 2011-2014 (TWh). Source: ACER/CEER (2015), p. 195

There is no consensus yet about the best model for intraday power markets. Some studies suggest that cross-border allocation with auctions could improve the intraday market performance.[67] Aspects such as greater market depth, easy access to market participants, more effective implementation and more market reliability are referred to in the literature.

2.2.5 Lack of harmonised load shedding coordination

Coordination principles for under-frequency or under-voltage load shedding schemes have been well established and functioning for many years.

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[66] *Ivi.*

[67] Neuhoff K., N. Ritter, A. Salah-Abou-El-Enien and P. Vassilopoulos (2016), Intraday Markets for Power: Discretizing the Continuous Trading?, *Discussion Papers*, No 1544, German Institute for Economic Research (DIW Berlin).

Current status

The network code on electricity emergency and restoration establishes a formal framework and principles, where all TSOs should design the system defence plans which will include the automatic under or over frequency control schemes and automatic schemes against voltage collapse. Frequency management procedures will require additional regional coordination within each synchronous area.

Article 11

Design of the system defence plan

1. By [12 months after entry into force of this Regulation], each TSO shall design a system defence plan in consultation with relevant DSOs, SGUs, national regulatory authorities, other competent authorities, neighbouring TSOs and the other TSOs in its synchronous area.

2. When designing its system defence plan, each TSO shall take into account at least the following elements:

(a) the operational security limits set out in accordance with Article 25 of Regulation (EU) 2017/XXX [SO GLs];

(b) the behaviour and capabilities of load and generation within the synchronous area;

(c) the specific needs of the high priority significant grid users listed pursuant to point (e) of paragraph 4; and

(d) the characteristics of its transmission system and of the underlying DSOs systems.

[…]

6. The measures contained in the system defence plan shall comply with the following principles:

(a) their impact on the system users shall be minimal;

(b) they shall be economically efficient;

(c) only those measures that are necessary shall be activated; and

(d) they shall not lead the TSO's transmission system or the interconnected transmission systems into emergency state or blackout state.

The participation of resources on the demand side, as a first response to avoid automatic load-shedding, is an aspect that should be considered in future system operation.

Further to the automatic under or over frequency control schemes and automatic schemes against voltage collapse currently implemented, there may be eventual situations where load shedding could be necessary due to unforeseen and extreme events that would disrupt system adequacy in Europe. In such extreme cases, it would be necessary to have key principles to share the burden between Member States and to manage the abnormal situation. Although it is clear that all efforts should focus on having a reliable adequacy assessment across Europe, there is currently no explicit definition of what should be done to deal with the consequences in those extreme and, hopefully, unlikely cases. This also seems to be a case where solidarity among Member States would play an important role.

2.3 Solidarity among Member States in the electricity sector

2.3.1 Lack of comprehensive coordination for Solidarity

As explained in Section 1.2.5, the concept of solidarity is more applied and much more developed in the natural gas industry than in the electricity sector, where only vague references without operational substance can be traced. Solidarity is seen here from the perspective of security of supply.

Purpose and need for coordination

Some examples will show that even in the electricity sector situations may exist where coordination and solidarity are necessary to deal with events that have the potential to disrupt energy supply if not properly addressed. The solar eclipse of 2015 is a case where strong coordination was successfully put in place on a voluntary basis to ensure system security.

The impact analysis report prepared by ENTSO-E provides a good description of the event and the main concerns related to the exchange of balancing reserves:[68]

> *"On 20 March 2015 a solar eclipse will pass over the Atlantic Ocean between 07:40 and 11:50 UTC (08:40-12:50 CET) and the eclipse will be visible across Europe. The reduction in solar radiation will directly affect the output of the photovoltaics (PV) and for the first time this is expected to have a relevant impact on the secure operation of the European power system. In the synchronous area of Continental Europe and the synchronous area of Great Britain preliminary studies to evaluate the impact of the solar eclipse and possible countermeasures to be taken by the TSOs have been performed. In 2015 the installed capacity on PV in the synchronous region of Continental Europe is expected to reach 90 GW and the eclipse may potentially cause a reduction of the PV infeed by more than 30 GW during clear sky conditions. This situation will pose a serious challenge to the regulating capability of the interconnected power system in terms of available regulation capacity, regulation speed and geographical location of reserves. Although a solar eclipse is perfectly predictable the transformation from solar radiation to electric power is associated with uncertainties which call for a careful coordination throughout the entire interconnected power system of Continental Europe including adjacent power systems".*

[68] ENTSO-E (2015), Solar Eclipse 2015 – Impact Analysis – Report prepared by Regional Group Continental Europe and Synchronous Area Great Britain, Brussels, 19 February 2015.

The recommendations of the mentioned report, directed to individual TSOs and the Continental Europe Regional Security Coordinators Initiative, express some implicit solidarity and the importance of regional coordination in these type of events:

> *"Not all the TSOs will be affected by the eclipse on the same scale, but all will see the same impact on the frequency; some countries are not affected by PV variations, but can support the other TSOs by providing them reserves. The main challenge for the TSOs will be to coordinate the use of the reserves in order to balance the power in real time without creating overloads on the grid. Therefore coordination procedures should be exercised well in advance.*
>
> *The proposed recommendations to the TSOs from Continental Europe synchronous region can be split in two levels.*
>
> ***Individual TSOs***
>
> *[…]*
>
> *- Each TSO shall increase control reserves as much as necessary for its own needs. In case of high probability not to cover its own control block/area, each TSO shall estimate and declare to other TSOs the amount of control reserve he will need in real time.*
>
> *- TSOs which can provide more control reserve than they need shall propose these reserves to help frequency management in real-time.*
>
> *[…]*
>
> ***Continental Europe synchronous area coordination***
>
> *[…]*
>
> *- RSCIs can be involved in D-2, D-1 and ID to check forecast files, detect potential constraints due to reserve exchanges, evaluate limits, propose remedial actions.*
>
> *- If necessary TSOs will set up an extraordinary operational coordination until the day of the eclipse,including day-ahead and real-time teleconference to coordinate PV forecasts, real-time frequency management, reserve exchanges and flow management".*

The network code on electricity emergency and restoration goes beyond the System Operation guidelines Regulation and establishes the additional procedures and remedial actions to be applied in the Emergency, Blackout and Restoration states. It also describes in its preamble that *"Each TSO should support any other TSO in emergency, blackout or restoration state, upon request, where such support does not lead the system of the requested TSO into emergency or blackout state"*.

Article 14

Inter-TSO assistance and coordination in emergency state

1. Upon request from a TSO in emergency state, each TSO shall provide through interconnectors any possible assistance to the requesting TSO, provided this does not cause its transmission system or the interconnected transmission systems to enter into emergency or blackout state.

Linked to the solidarity mechanism and beyond the network code on electricity emergency and restoration, there is the case of an ultimate action of load shedding in case the system adequacy would not be ensured for a given period of time. Coordination of key principles for sharing the burden and costs would be necessary to transparently decide on the effective actions to be taken.

Current status

Although the relevance and benefits of coordination can be exemplified and some solidarity principles are suggested, there is no solidarity mechanism to serve as a framework in the observed cases. Cost sharing is also performed without any explicit ex-ante guidance or *ex-post* reference.

Even in the network code on electricity emergency and restoration, the aspects of cost recovery are dealt with in a very loose manner: *"The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms".*

Chapter 3 – Blocking factors for European second-order coordination

Executive Summary

Chapter 3 addresses issues related to harmonisation. Four factors are identified as somewhat blocking the integration of European electricity systems and the transition to a low-carbon economy.

To begin, there is *no harmonisation of congestion rent allocation schemes* in Europe. Current EU legislation establishes some general rules and the CACM Commission Regulation sets a timeframe for the definition of tasks and methodologies. Nonetheless, some fundamental questions related to the distribution of resources remain unanswered.

The *lack of harmonisation of capacity remuneration mechanisms* represents a second blocking factor. The issue is strictly connected to reliability and its enforcement in liberalised and interconnected electricity systems. With the restrucutring of the industry in the 1990s, European policy-makers faced important questions on how to guarantee reliability in the new competitive setting, but failed to provide clear answers. Due to a general state of overcapacity, reinforced by a massive investment cycle in CCGT, Member States usually adopted a *laissez-faire* approach towards reliability. The 1996 electricity Directive reflected such confidence in the free market forces, barely mentioning the issue and the significant implications of interconnecting several national electricity systems, where the choice of generation mix remains a national prerogative. A mandate to monitor capacity adequacy was introduced for every Member State by the second electricity Directive in 2003, but the Commission did not develop a common European approach. Incredibly, nothing concrete happened in Europe even after the wave of blackouts that affected several electricity systems around the world in 2003.

In more recent years, the problem of ensuring system reliability has become even more complex and difficult because of the development of a strong European climate policy, mainly based on the deployment of renewable energy sources in the electricity sector. New ways to assess system reliability became necessary, but the Third Energy Package adopted in 2009 was more concerned with enhancing competition and did not provide any clear guidance. The pre-existing and fragmented planning and capacity adequacy analysis methods remained in place. It is only recently that the situation has begun to change.

The EU is now repeating the same flawed approach to capacity mechanisms. Allowing the participation of market players from neighbouring countries and avoiding to support capacity that negatively impacts on environmental policies is good but not enough. Applying abstract competition policies will not provide the solution either. In an interconnected electricity system with a growing penetration of

intermittent renewables, no meaningful assessment of capacity adequacy can be performed at national level. Besides, the choice of generation mix, a Member State's prerogative, affects the methodologies and the data sets needed to perform such an assessment. Therefore, a comprehensive and consistent EU regulatory framework is required to reconcile the freedom of the Member States to choose their generation portfolio with the overall reliability of the interconnected systems and the efficiency of the internal market.

The absence of transmission tariffs harmonisation across European countries constitutes a third blocking factor. Currently, there are differences in the level and structure of transmission tariffs in EU Member States and, for the past several years, there has been an ongoing debate on the opportunity of further harmonisation. Recent research promoted by ACER concluded that in the short term transmission tariffs are not a priority. However, in the long term there is a case for harmonisation, based on the need for greater consistency and the application of tariffs that better reflect the costs generated by market participants and minimise distortions.

A final factor that can block the Europeanisation of the electricity industry is the *lack of harmonisation of 'State aid' to large energy consumers*. Member States can exempt large energy consumers from the full payment of network tariffs and levies like those for the subsidisation of renewables. The European Commission has already approved several exemptions, but their proliferation can distort competition in some energy intensive industries and undermine support for the energy transition.

3.1 Congestion rent allocation

Congestion rents arise whenever there is a discrepancy between energy trade requests and transmission network capacity. The lack of sufficient network capacity – as compared to trade requests – blocks the market process and fragments the wider market into smaller zones, exhibiting different prices and different price dynamics. A 'congestion rent' is a benefit made from this price differential. The allocation of congestion rents is key to provide suitable incentives to TSOs, both in the short run operation and in long-term planning.

Purpose and need for harmonisation

In the EU, in spite of the persistent lack of interconnection capacity, there is still no common congestion rent allocation scheme. The combined result of insufficient interconnection capacity and congestion rent allocation schemes which are not harmonised creates serious distortions of competition within the internal electricity market.

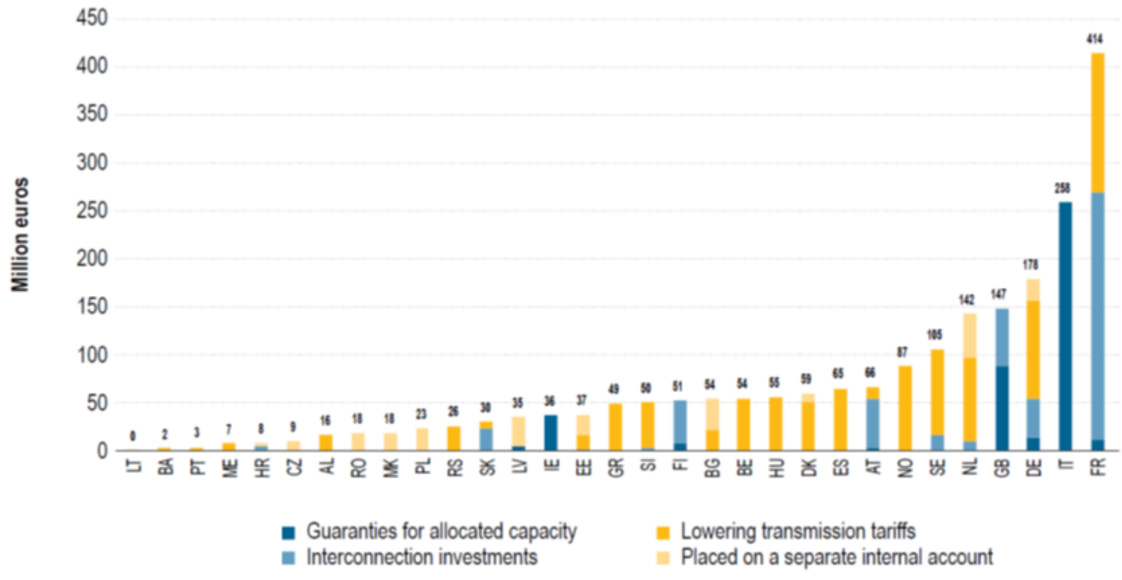
Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity states the principles to be followed regarding the use of revenues resulting from the allocation of interconnection capacity:

> *"Article 16*
>
> *General principles of congestion management*
>
> *…*
>
> *6.*
>
> *Any revenues resulting from the allocation of interconnection shall be used for the following purposes:*
>
> *(a) guaranteeing the actual availability of the allocated capacity; and/or*
>
> *(b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.*
>
> *If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) of the first subparagraph, they may be used, subject to approval by the regulatory authorities of the Member States concerned, up to a maximum amount to be decided by those regulatory authorities, as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs.*
>
> *…".*

The established general principles, although providing a framework for the allocation of congestion rents, do not ensure the correct incentives and use for the reinforcement of interconnections. If the congestion rents are used to guarantee the actual availability of the allocated capacity, i.e. covering redispatching costs, they may be avoiding necessary internal reinforcements in the bidding zone, therefore not contributing to a more interconnected market operation. If the congestion rents are applied in the calculation of transmission tariffs, the correct incentives for network development will not be visible as well.

The figure below, extracted from the 'ACER Market Monitoring Report 2015', shows, for each country, the total congestion revenues in 2014 and the way these revenues were allocated. According to the report, *"The total congestion revenue received by TSOs in 2014 increased by 317 million euros, or by almost 16% compared to 2013, and amounted to 2,314 million euros. The highest year-to-year income increase was reported by TSOs in Sweden, Great Britain and France, whereas the highest income decrease was reported by TSOs in Germany, the Netherlands and Italy"*.[69]

Different uses for congestion income can be observed in Fig. 3.1: interconnection investments represent less than half of total revenue.



Source: Data provided by ENTSO-E (2015).

Fig 3.1: Congestion revenues – 2014 (million euros). Source: ACER/CEER (2015)

In Section 2.2.2 on redispatching it was argued that congestion rents should come only from real congestion in the interconnectors, all other internal restrictions leading to a redispatch should be treated as redispatching costs and properly allocated

[69] ACER/CEER (2015), *op. cit.*, p. 173.

according to the origin of the restriction. This would provide a more transparent set of signals when dealing with complex issues such as interconnection reinforcements.

Interconnection reinforcements create winners and losers: the area with lower prices will experience price increases while the area with higher prices will benefit from reduced prices. Sometimes policy-makers and regulators have difficulty managing and communicating these situations.

Harmonisation is needed to ensure clarity on the need for reinforcements and on the allocation of congestion rents.

Current status

CACM Regulation (entered into force 13 August 2015) establishes the tasks and the deadlines (Articles 9, 73) for developing the methodology for congestion income distribution.

"Article 9 Adoption of terms and conditions or methodologies
6.
(k) share congestion income in accordance with the methodology jointly developed in accordance with Article 73;

Article 73 Congestion income distribution methodology
1.By 12 months after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology for sharing congestion income".

The proposal from all TSOs on congestion income distribution methodology (Article 73) was submitted to ACER in August 2016, according to the CACM timeline.

This draft methodology lays down the simple rules which need to be followed to collect and distribute the Congestion Income to the Bidding Zone Borders and, after the assignment of Congestion Income to each Interconnector, the TSO on each side of the Bidding Zone border shall receive their share of this Congestion Income.

Different arrangements between borders have been in place and now the proposed methodology establishes a common set of rules.

Although, according to the scope defined in the CACM Regulation (EU) 2015/1222, the methodology defines how to split congestion rents between borders, fundamental issues such as harmonisation of congestion rents allocation are not addressed and remain open questions.

3.2 No harmonisation of capacity remuneration mechanisms

'Capacity remuneration mechanisms' or 'capacity payments' *tout court* is one of the most contentious issues of the current electricity debate in the European Union. Given the amounts of money at stake, this is no surprise. This is also one of the topics that best illustrates how the combined reluctance of politicians and energy experts in addressing very basic questions leads to a huge – and, unfortunately for consumers, hugely expensive – smoke screen. Instead of answering a few very basic and practical political and technical questions and thereupon building a consistent – and relatively simple – monitoring, warning and rewarding system, political and technical decision-makers eluded those questions and invented theoretical arguments and sophisticated 'answers' in the abstract realm of market theory. 'Answers' that usually address the symptoms, not the roots, of the disease.

This Section is divided into five parts, according to the following scheme:

1. Introduction to the very basic capacity issues;
2. Capacity under monopoly;
3. Capacity under liberalisation – distinguishing between two phases: 1996-2003 and 2003-2006;
4. Capacity under decarbonisation;
5. Capacity under the new DG Competition policy.

At each stage, the main questions are explained in a simple language and the logical answers to these questions are discussed, also showing how the questions were eluded and where we are today. Combining these five parts, the reader will be in a position to realise how to get rid of past traps and how to address capacity issues in a forward-looking, consistent energy transition process.

3.2.1 'Capacity': who decides how much is needed and who pays for it?

In developed countries, consumers expect to be *almost* always supplied with electricity. When unusual storms or accidents interrupt supply for some minutes or hours – a few days in the worst case – consumers usually complain, although they accept that it is 'impossible' to *always* prevent such disruptions. When technical restrictions or human errors produce a supply interruption, consumers also complain, usually being less tolerant than in the case of natural disasters. In these situations, enough generation capacity is installed in the country, but due to unexpected events some consumers are not supplied for some time. These unexpected events may be related to the following subjects:

1. Generation capacity – power plant outages may temporarily reduce the amount of available overall generating capacity and associated power output below demand level. Under these circumstances, if no alternative means are available – e.g. interconnections with neighbouring countries where enough capacity is

available – supply interruptions are inevitable. Power plant outages may be caused by equipment failure, lack of cooling water, plant operator error, etc.;

2. Transmission capacity – transmission line or substation outages may temporarily reduce the amount of available transmission capacity in some network areas, thus decreasing power flows and limiting the ability to supply all demand;[70]
3. System operation – even if enough generation and transmission capacities are available, it may happen that some consumers cannot be supplied. This may result, in turn, from two different types of events:
   a) System restrictions – electricity systems are designed based on some assumptions about standard patterns of generation and demand. If, for some unexpected reason, either generation or demand profiles are suddenly changed, the system may be unable to cope with these changes, either transiently or in steady-state. In order to ensure stability of the whole system, some generators and/or consumers may have to be disconnected from the network;
   b) Human error – system operators rely on a large spectrum of measurements and computer simulations that provide the necessary information to manage the electricity system in real-time. Machine-based errors may appear along the processing chain that mislead system operators, inducing them to take the wrong decision; even when the information available to operators is complete and consistent, they may misjudge the situation, undertaking inappropriate actions that may trigger some kind of load shedding.

In the context of the above-described cases, it is common to use the expression 'reliability'.

Another type of event, much less common in developed countries, is the disruption of primary energy supply to power plants. This may be caused by natural events (e.g. scarce water inflows in rivers where hydropower plants are located due to unusual lengthy drought periods) or by political incidents (e.g. interruption of natural gas supply due to transit fee disputes between supplier and transit countries). In this context, it is common to use the expression 'security of energy supply'.

Focussing on 'reliability' issues only, it is important to understand how reliability was ensured in the past, under the monopolistic regime, how liberalisation challenged the old model and how decarbonisation and digitisation add new layers of complexity.

3.2.2 'Capacity' under monopoly

In the old days of vertically integrated monopolies and centralised planning, the basic task of the planner was to provide an investment plan that considered:

[70] Some Transmission System Operators publish in their website real-time information about outages – see, for instance, https://www.nationalgridus.com/upstate-ny-business/storms-outages/outage-map.

a) The primary energy choices of the State (for example, imposing or forbidding nuclear power plants; subsidising domestic coal, etc.), the evolution of primary energy prices in world markets and the costs of power plant technologies;

b) The expected growth of electricity demand and its location;

c) The desired 'reliability' level – basically determining how many supply interruptions, and which volumes of associated not-supplied energy, were acceptable.

Based on these inputs, planners provided an optimal investment plan including both power plants (their size, location, type of primary energy used, year of commissioning, etc.) and network facilities (overhead lines, cables, substations – including their location, capacity, year of commissioning, etc.).

To assess the desired aggregate reliability level, each electricity system component must be assigned a given failure rate. Knowing the failure rate or 'mean time between failures' and the useful life period of each individual component, it is then possible to compute the overall electricity system reliability index for every hour of each year of the planning horizon. Different types of redundancy must be included in the system, i.e. several components must be duplicated, in order to guarantee an acceptable overall performance level.

As consumers became more affluent and demanding in developed countries, i.e. less tolerant to electricity disruptions, planners increased the amount of redundancy and tended to oversize everything, from generation capacity to transmission lines, to low-voltage transformers, in order to be 'on the safe side'. This 'safety' policy had obvious financial costs, leading to increasing tariffs. However, as long as these cost increases could be offset by economies of scale at generation level, they remained 'hidden' and consumers were satisfied.

One way to improve reliability while, at the same time, avoiding unnecessary redundancy and associated costs, is to replace <u>deterministic</u> reliability models through <u>probabilistic</u> ones. This allows planners and operators to optimise redundancy, preventive maintenance, etc.

Accuracy of any reliability analysis depends on the quality of the statistical data used. Very often, data series are incomplete or inconsistent, therefore some 'educated guesses' have to be used by those making the analysis. The central planner had all available information, she decided which data to use and how, and she was the only responsible agent for system reliability.

3.2.3 'Capacity' under liberalisation

The end of generation and supply monopolies challenged the central planner's role for two main reasons:

- Investors are free to decide if, when and where to build a new power plant or to refurbish an existing one;
- Generators, suppliers, traders and other agents are free to establish any type of contractual arrangements, as long as these are compatible both with the regulatory framework and with available infrastructure resources.

Whenever legislators decided to liberalise the electricity sector, they took one of three views vis-à-vis reliability:

1) *Laissez-faire*: market forces will provide for the necessary generation investments and will determine the 'right' value of reliability and security of energy supply. Therefore, legislators and regulators do not need to address the issue;

2) Ex-ante obligation: for example, imposing upon each electricity supplier a legal obligation to procure long-term capacity contracts corresponding to their respective present contractual volumes;

3) *Ex-post* intervention: the government or the regulator set up a monitoring mechanism to assess reliability and security of supply levels, triggering tendering procedures for new generation capacity whenever the need arises (i.e. in case the market fails to deliver the expected capacity investments that guarantee the desired reliability levels).

The first phase (1996-2003)

In the early days of liberalisation, most governments adopted the laissez-faire attitude. The 1996 electricity Directive mentions the word 'reliability' only once (*"Whereas each transmission system must be subject to central management and control in order to ensure the security, **reliability** and efficiency of the system in the interests of producers and their customers"*) and 'tolerates' long-term planning in the following terms (Article 3):

"Having full regard to the relevant provisions of the Treaty, in particular Article 90, Member States may impose on undertakings operating in the electricity sector, in the general economic interest, public service obligations which may relate to security, including security of supply, regularity, quality and price of supplies and to environmental protection. Such obligations must be clearly defined, transparent, non-discriminatory and verifiable; they, and any revision thereof, shall be published and notified to the Commission by Member States without delay. As a means of carrying out the above mentioned public service obligations, Member States which so wish may introduce the implementation of long-term planning".

Long-term planning was defined as follows (Article 2):

"long-term planning shall mean the planning of the need for investment in generation and transmission capacity on a long-term basis, with a view to meeting the demand for electricity of the system and securing supplies to customers".

In the 1990s, when electricity liberalisation was adopted in the European Union, long-term planning was not at all a fashionable concept. The first electricity Directive was negotiated between 1991 and 1996 and the concepts of ‘public service’ and ‘long-term planning’, strongly supported by the French government and opposed by the European Commission and by most Member States, was at the very heart of the political battle.

The 1996 Directive also allowed Member States to *“choose between an authorization procedure and/or a tendering procedure”* for the construction of new generating capacity. The tendering procedure corresponded to the so-called ‘Single Buyer’ model (*“single buyer shall mean any legal person who, within the system where he is established, is responsible for the unified management of the transmission system and/or for centralized electricity purchasing and selling”* – Article 2), strongly supported by the French government and opposed by everybody else. According to the 1996 Directive (Article 6):

“1. Where they opt for the tendering procedure, Member States or any competent body designated by the Member State concerned shall draw up an inventory of new means of production, including replacement capacity, on the basis of the regular estimate referred to in paragraph 2. The inventory shall take account of the need for interconnection of systems. The requisite capacity shall be allocated by means of a tendering procedure in accordance with the procedure laid down in this Article.

2. The transmission system operator or any other competent authority designated by the Member State concerned shall draw up and publish under State supervision, at least every two years, a regular estimate of the generating and transmission capacity which is likely to be connected to the system, of the need for interconnectors with other systems, of potential transmission capacity and of the demand for electricity. The estimate shall cover a period defined by each Member State”.

The obligation to publish “*at least every two years, a regular estimate of the:*

- *generating and transmission capacity which is likely to be connected to the system;*
- *need for interconnectors with other systems;*
- *potential transmission capacity;*
- *demand for electricity”,*

was imposed only upon Member States that opted for the tendering procedure. In the other Member States, such obligation did not exist, therefore information about the expected evolution of generation and transmission capacities was not published.

As regards interconnections, the 1996 Directive just established that *“The system operator shall provide to the operator of any other system with which its system is interconnected sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system”* (Article 7).

In brief, the 1996 Directive, although aiming at laying down *“common rules (…) relating to the organization and functioning of the electricity sector”* eluded the fundamental question of a such quest:

<u>How to balance Member States’ freedom to choose their energy mix with the need to develop a common transmission infrastructure supporting a common electricity market, knowing that, due to physical and technical features, any interconnected electricity system impresses upon all interconnected partners *de facto* common reliability levels (independently of their will to agree on legally binding common standards)?</u>

In particular, the amount of installed generating capacity (and the associated reserve margin as compared to peak demand) and the technical characteristics of the generators (for instance, as regards their automatic response to frequency deviations in the network), in any Member State, influence the overall reliability of electricity systems in all interconnected Member States. Reliability is a common good.

The European legislator’s *laissez-faire* attitude regarding the functioning of electricity markets, embodied in the absence of any specific rules and in mere statements of general principles (such as: *“Member States (…) shall not discriminate between these* [electricity] *undertakings as regards either rights or obligations”; “The system operator shall not discriminate between system users or classes of system users”*), expresses the belief that competition law would be enough to avoid market distortions and to ensure efficient and fair market outcomes, whatever shape these electricity markets would take at national level. This attitude was common to the liberalisation of almost all sectors in Europe (including network industries such as transport and communications) and it was common all over the world in the early 1990s. In different degrees, this approach succeeded in liberalising energy markets at national level in many countries, in different continents. However:

1) Imagining that market forces alone could drive 15 national markets, organised in different ways, to ‘naturally’ evolve towards a single electricity market without strong regulatory intervention was a mistake. Institutions are always necessary for the proper functioning of efficient markets and they are indispensable for the functioning of supra-national markets. This mistake was soon addressed, first through the negotiation of voluntary agreements (1998-2000) and later on through successive legislative and regulatory measures; in the meantime, the amount of ‘cross-border’ regulations is astronomical.

2) There is no technical, economic or institutional justification – and there is indeed no empirical evidence – to make us believe that market forces can self-organise and self-regulate electricity reliability. Legislators could have allowed market forces alone to shape markets and, at the same time, provide a suitable legal framework to protect the ‘common good’ reliability, thus avoiding the potential risk of an impoverished technical quality of service, blackouts, etc. But the 1996 Directive did not attempt to establish common reliability standards or, at least,

procedures to define and enforce such standards. It did not even set up any mechanism to monitor reliability and security of supply at European level, although Article 6, quoted above, clearly shows that the legislator was aware of the issues at stake.

Although the Single Buyer Model (i.e. the tendering procedure) was accepted as a legitimate and legal alternative to the full liberal approach (i.e. the mere authorisation procedure), it was never implemented…not even by France.

The *laissez-faire* approach was extremely convenient because liberalisation started from a situation of generation overcapacity in most EU Member States and investors built so many new power plants that overcapacity steadily increased, as can be seen in the following picture. Taking 1990 as a reference, installed capacity always increased faster than final electricity consumption. In particular:

- In 2000, compared to 1990, consumption had increased 17% while total installed capacity had increased by 21%.
- At the end of 2014, compared to 1990, electricity demand had increased by 25%, while total installed capacity had increased by 74%.

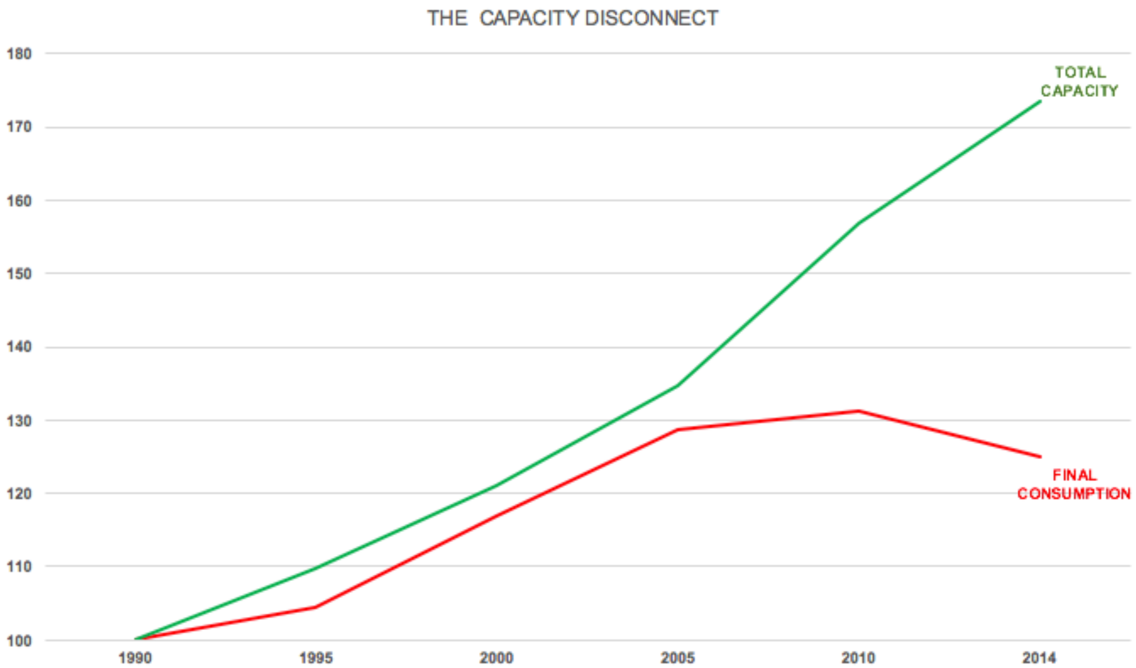


Fig 3.2: Final electricity consumption and total installed electricity generation capacity in the EU-28, 1990 – 2014. Source: elaboration based on data from Eurostat

Initially, the capacity increase was mainly due to the “dash-for-gas” of the 1990s and 2000s: combined-cycle gas turbines’ (CCGT) installed capacity in the EU-28 increased from 1.8 GW in 1990 to 45 GW in 2000 and to 100 GW in 2010.

In the 21st century, wind and solar generation took the lead in terms of new capacity additions, as can be seen in Table 3.1 and in Figure 3.3. As wind and solar power plants can only generate electricity when the wind blows or the sun shines, 'one MW' of their installed capacity cannot be directly compared to 'one MW' of gas-fired power plants, able to generate four or more times further electricity during the year. Nevertheless, there is generation overcapacity in the European Union.[71]

Table 3.1: Installed electricity generation capacity in the EU-28, 1990 – 2014. Source: Eurostat

	1990	1995	2000	2005	2010	2014
Nuclear	121 070	128 435	136 637	134 994	131 731	123 515
Hydro	119 652	127 466	132 866	143 363	147 591	150 280
Tide, wave, ocean	240	240	241	240	241	244
Geothermal	499	480	604	687	762	820
Solar	10	49	179	2 297	30 149	89 088
Wind	454	2 430	12 711	40 399	84 567	129 080
Combustible fuels	321 479	353 250	391 490	435 099	487 932	482 466
Industrial wastes	*459*	*732*	*1 134*	*514*	*1 820*	*1 863*
Municipal wastes	*968*	*1 418*	*2 488*	*4 537*	*6 153*	*7 103*
Solid biofuels	*2 987*	*3 862*	*5 329*	*10 019*	*14 221*	*16 948*
Biogases	*260*	*530*	*1 268*	*3 091*	*5 965*	*9 719*
Liquid biofuels	*0*	*0*	*0*	*704*	*1 068*	*1 741*
Other sources	10	142	229	943	883	2 164

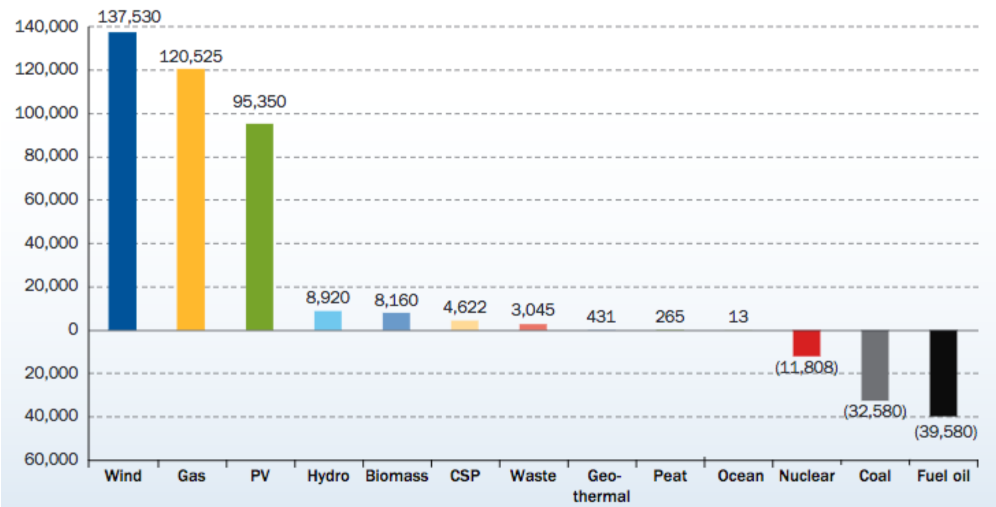


Fig 3.3: Net electricity generation capacity in the EU, 1995 – 2015 [MW]. Source: EWEA (2016), Wind in power: 2015 European statistics, p. 8

[71] Unfortunately, transmission under-capacity prevents electricity consumers throughout Europe from fully reaping the benefits of generation overcapacity.

The second phase (2003-2006)

In the year 2000, the European Council decided to fully liberalise the electricity and natural gas markets. In order to speed up the liberalisation process a new electricity Directive was approved in June 2003. This new Directive limited the tendering procedure foreseen in the 1996 Directive to exceptional cases only, according to the following rules:

Article 7

Tendering for new capacity

1. Member States shall ensure the possibility, in the interests of security of supply, of providing for new capacity or energy efficiency/demand-side management measures through a tendering procedure or any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. These procedures can, however, only be launched if on the basis of the authorisation procedure the generating capacity being built or the energy efficiency/demand-side management measures being taken are not sufficient to ensure security of supply.

2. Member States may ensure the possibility, in the interests of environmental protection and the promotion of infant new technologies, of tendering for new capacity on the basis of published criteria. This tender may relate to new capacity or energy efficiency/demand-side management measures. A tendering procedure can, however, only be launched if on the basis of the authorisation procedure the generating capacity being built or the measures being taken are not sufficient to achieve these objectives.

3. Details of the tendering procedure for means of generating capacity and energy efficiency/demand-side management measures shall be published in the Official Journal of the European Union at least six months prior to the closing date for tenders.

The tender specifications shall be made available to any interested undertaking established in the territory of a Member State so that it has sufficient time in which to submit a tender.

With a view to ensuring transparency and non-discrimination the tender specifications shall contain a detailed description of the contract specifications and of the procedure to be followed by all tenderers and an exhaustive list of criteria governing the selection of tenderers and the award of the contract, including incentives, such as subsidies, which are covered by the tender. These specifications may also relate to the fields referred to in Article 6(2).

4. In invitations to tender for the requisite generating capacity, consideration must also be given to electricity supply offers with long term guarantees from existing generating units, provided that additional requirements can be met in this way.

5. Member States shall designate an authority or a public body or a private body independent from electricity generation, transmission, distribution and supply activities, which may be a regulatory authority referred to in Article 23(1), to be responsible for the organisation, monitoring and control of the tendering procedure referred to in paragraphs 1 to 4. Where a transmission system operator is fully independent from other activities not relating to the transmission system in ownership terms, the transmission system operator may be designated as the body responsible for organising, monitoring and controlling the tendering procedure. This authority or body shall take all necessary steps to ensure confidentiality of the information contained in the tenders.

Given the fact that no Member State had opted for the tendering procedure/single buyer model, it was logical to remove this option from the new Directive, aimed at fully liberalising energy markets.

The 2003 Directive mentions the word 'reliability' only once, although in a different context as compared to the previous Directive. It now appears in a reference to the tasks of TSO (Article 9):

"Each transmission system operator shall be responsible for:

(a) ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity;

(b) contributing to security of supply through adequate transmission capacity and system reliability; (…)".

'Long-term planning' is still mentioned in the 2003 Directive, although in a rather obscure way (Article 3):

"In relation to security of supply, energy efficiency/demand-side management and for the fulfilment of environmental goals, as referred to in this paragraph, Member States may introduce the implementation of long term planning, taking into account the possibility of third parties seeking access to the system".

However, the 2003 Directive introduced a very interesting and important provision on security of supply:

Article 4

Monitoring of security of supply

Member States shall ensure the monitoring of security of supply issues. Where Member States consider it appropriate they may delegate this task to the regulatory authorities referred to in Article 23(1). This monitoring shall, in particular, cover the supply/demand balance on the national market, the level of expected future demand and envisaged additional capacity being planned or under construction, and the *quality and level of maintenance of the networks, as well as measures to cover peak demand and to deal with shortfalls of one or more suppliers. The competent authorities shall publish every two years, by 31 July at the latest, a report outlining the findings resulting from the monitoring of these issues, as well as any measures taken or envisaged to address them and shall forward this report to the Commission forthwith.*

Now, a mandatory security of supply monitoring mechanism is introduced for all Member States, not just for those opting for tendering procedures. However, the language used is less accurate than in the corresponding provisions of the old Directive, in particular as regards transmission and interconnections, as can be seen in the following table.

Table 3.2: Comparing the language on security of supply/reliability monitoring in the 1996 and 2003 electricity Directives

TOPIC	1996 Directive	2003 Directive
GENERATION CAPACITY	*generating (…) capacity which is likely to be connected to the system;*	- *supply/demand balance on the national market* - *envisaged additional capacity being planned or under construction*
DEMAND	*demand for electricity*	- *level of expected future demand* - *measures to cover peak demand*
TRANSMISSION	- *transmission capacity which is likely to be connected to the system;* - *potential transmission capacity;*	- *quality and level of maintenance of the networks*
INTERCONNECTION	*need for interconnectors with other systems;*	
SUPPLY		*measures (…) to deal with shortfalls of one or more suppliers*

Despite the not so clear language, Article 4 of the 2003 electricity Directive could have been used by the European Commission to promote a common European approach to security of supply and reliability through:

a) harmonisation of national reports concerning methodologies, data, etc.;

b) critical assessment of the national reports;

c) establishment of a EU system and market computer model to enable extrapolation of national conclusions to EU level, through appropriate synthesis of EU reliability and security of supply indicators from the respective national indicators.

However, the European Commission did not plan to follow that approach at the time of publication and, following unexpected events, the Commission decided to completely ignore this 'technical' Article 4 and to embark on a new and very ambitious – political – approach. Immediately after the 2003 Directive was approved, several blackouts occurred in the USA and in the EU, in both cases affecting several States, in August and in September 2003,[72] leading many people to believe that electricity markets were unable to ensure security of supply and needed to be somehow 'fixed' in order to avoid further disturbances.

The United States reacted, as usual, in a very pragmatic way, addressing the core problem. The legislator decided to set up a new 'Electric Reliability Organization', *"the purpose of which is to establish and enforce reliability standards for the bulk-power system",*[73] under direct supervision and control of the Federal Energy Regulatory Commission (FERC). This organisation opened its operation in June 2006.[74] In March 2007, the first legally-binding reliability standards for the USA electricity transmission system were approved and subsequently enforced (June 2007). Reliability Standards impose requirements on the users, owners and operators of the transmission system to assure that they fulfil their responsibilities in reliable grid operations. Since 2007, FERC has *"approved over 100 mandatory Reliability Standards that address many facets of maintaining and improving bulk power system reliability, issued directives and ordered standards to be developed as well as reviewed thousands of electric reliability organization compliance and enforcement actions".*[75]

In Europe, on the contrary, neither the Commission nor Member States were willing to solve the very real technical coordination problem through the establishment of an effective 'federal' governance similar to the one introduced in the USA. In December 2003, the European Commission made a proposal for a Directive on security of electricity supply.[76] This proposal called upon national regulatory authorities to *"set performance standards for transmission and distribution system operators"* and to approve the *"document setting out [transmission system operators'] intentions for the provision of adequate level of cross-border interconnection capacity"*. These national performance standards could not have ensured proper EU reliability coordination,

[72] A list of the worst blackouts occurred in the past half century is available at www.power-technology.com/features/featurethe-10-worst-blackouts-in-the-last-50-years-4486990/.
[73] Energy Policy Act of 2005. Section 1211 Electric Reliability Standards.
[74] A presentation of the North American Electric Reliability Corporation is available on the NERC website.
[75] FERC (2016), *Reliability Primer*, available at https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.
[76] European Commission (2003), *Proposal for a Directive of the European Parliament and of the Council concerning measures to safeguard security of electricity supply and infrastructure investment*, COM(2003) 740 final, Brussels, 10 December 2003.

but at least they would have promoted a more transparent technical dialogue between network users, network operators and regulators throughout the European Union. Unfortunately, these proposals were rejected by the Member States in the Council and the final text, approved in January 2006,[77] provides for no coordination mechanism, assigns no explicit function to regulatory authorities and, consequently, had no practical impact. It is almost unbelievable that a Directive supposed to address reliability concerns, minimising the risk of large-scale blackouts similar to the 2003 events, mentions the word 'reliability' just once – and in a collateral context, not even legally-binding (Whereas 5):

"When promoting electricity from renewable energy sources, it is necessary to ensure the availability of associated back-up capacity, where technically necessary, in order to maintain the reliability and security of the network".

The equivalent directive on natural gas[78] was equally weak, assigning coordination of security of supply to a Gas Coordinating Group, *"composed of representatives of Member States and representative bodies of the industry concerned and of relevant consumers, under the chairmanship of the Commission",* thus excluding regulators, and not setting up any competent technical body to prepare and enforce operational and reliability standards.[79]

The European scepticism of the merits of regulation, supra-State coordination and competitive markets to ensure reliability and security of supply is in sharp contrast with the US approach. There, following the large August 14, 2003 blackout, legislation was passed which provides a clear and comprehensive federal regulatory framework to handle network reliability issues. And, since 2007, more than 100 Reliability Standards have been approved by the Federal Regulator and enforced by TSOs and integrated companies. In the EU, the first Network Code establishing a guideline on system operation was still pending approval on December 31, 2016 – more than 13 years after the large blackout of September 28, 2003 that disconnected more than 50 million consumers for several hours in Italy; and more than 10 years after the 2006 incident that disconnected more than 10 million consumers from Germany to several other countries.

As new generation capacity continued to come online massively – in the period 1990-2005, each year generation capacity additions amounted to, on average, 7.5 GW fossil-fuel (of which 4.5 GW combined-cycle) and 2.5 GW wind – and no new big blackouts occurred after 2006, the political and social pressure to address reliability issues decreased very fast.

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[77] Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, *Official Journal*, L 33/22, 4 February 2006.

[78] Council Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply, *Official Journal*, L 127/92, 29 April 2004.

[79] When Russia cut gas supplies through Ukraine, in January 2006, the Coordinating Group had no idea about how flows could be technically reversed in order to supply Eastern European countries with gas from Western Europe.

Another way to look at the figures in the period 1990-2005 is as follows: new combined-cycle installed generation alone increased by 68.6 GW, corresponding to a maximum yearly output of 601 TWh; while final electricity consumption increased by 619 TWh in the same period.

In brief, it is fair to state that during the first decade of electricity liberalisation (1996-2006) the related issues of capacity adequacy and reliability standards and reliability enforcement were either not at all or not properly addressed in the European Union: the *laissez-faire* attitude was clearly dominant in most – if not all – Member States. This was due, in part, to the abundant, sustained, 'free-market' generation capacity investments. On the other hand, addressing reliability issues in an interconnected system covering several States is a difficult political and administrative task, if the institutional supra-State framework does not provide for suitable governance instruments, as is the case in the European Union.

These crucial issues of capacity and reliability were also not addressed during the second decade of liberalisation (2006-2016). However, in the meantime, important changes occurred – in policy and in electricity markets in Europe, as well as in technology – that require a different, more complex approach than the one that would have been suitable in the first phase. The next Section discusses these changes and their impact upon the dual issues of capacity and reliability.

3.2.4 'Capacity' under decarbonisation

The October 27 2005 informal European Council meeting held at Hampton Court, under the UK Presidency, represents a very important milestone in the EU energy sector for two main reasons. At that meeting, Heads of State and Government decided to:

1. try – again – to develop a common European energy policy;
2. bring together energy and climate policies.

This informal agreement was restated at the formal December 2005 Council meeting:

"The European Council stresses the importance of an integrated approach to climate change, energy and competitiveness objectives, and underlines that strategies to invest in cleaner and more sustainable energy both in the EU and more widely can support a range of policy objectives, including energy security, competitiveness, employment, air quality and reduced greenhouse gas emissions".[80]

[80] www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/87642.pdf.

During 2006 the European Commission prepared several policy documents and in January 2007 proposed 'An energy policy for Europe'.[81] In March 2007 the European Council endorsed that document and concluded that:

"The challenges of climate change need to be tackled effectively and urgently. Recent studies on this subject have contributed to a growing awareness and knowledge of the long-term consequences, including the consequences for global economic development, and have stressed the need for decisive and immediate action. The European Council underlines the vital importance of achieving the strategic objective of limiting the global average temperature increase to not more than 2°C above pre-industrial levels.

Given that energy production and use are the main sources for greenhouse gas emissions, an integrated approach to climate and energy policy is needed to realise this objective.

Integration should be achieved in a mutually supportive way. With this in mind, the Energy Policy for Europe (EPE) will pursue the following three objectives, fully respecting Member States' choice of energy mix and sovereignty over primary energy sources and underpinned by a spirit of solidarity amongst Member States:

- *increasing security of supply;*
- *ensuring the competitiveness of European economies and the availability of affordable energy;*
- *promoting environmental sustainability and combating climate change".*[82]

Based on this new 'integrated' approach, the European Commission proposed, in January 2008, the so-called '20-20-20 by 2020' Package. Almost all relevant legally-binding documents were approved in Spring 2009, namely the following ones:

- Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC;[83]
- Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community;[84]
- Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020.[85]

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[81] European Commission (2007), *Communication from the Commission to the European Council and the European Parliament on An energy policy for Europe*, COM(2007) 1 final, Brussels, 10 January 2007.
[82] www.consilium.europa.eu/ueDocs/cms_Data/docs/pressData/en/ec/93135.pdf.
[83] *Official Journal*, L 140/16, 5 June 2009.
[84] *Official Journal*, L 140/63, 5 June 2009.
[85] *Official Journal*, L 140/136, 5 June 2009.

The renewables Directive 2009/28/EC *"sets mandatory national targets for the overall share of energy from renewable sources in gross final consumption of energy and for the share of energy from renewable sources in transport"*, according to the figures in Annex I of the Directive. Eight out of twenty-seven Member States accepted a target for the share of energy from renewable sources in gross final consumption of energy higher than 25% (Denmark, Estonia, Latvia, Austria, Portugal, Slovenia, Finland and Sweden), while other four Member States indicated shares between 20% and 25%. Member States have also adopted national renewable energy action plans, indicating targets for each energy related sector: electricity, heating and cooling, and transport. According to the national plans, the share of electricity from renewable sources in final EU electricity consumption by 2020 is around 34%.

The EU commitment to cut greenhouse gas emissions was strengthened in October 2009, when the European Council decided *"to reduce greenhouse gas emissions by 80-95 % by 2050 compared to1990 levels".*[86]

One expected result of the 'integrated' climate and energy policy was the expansion of power plants based on renewable sources of energy. This result has been achieved, as pointed out by the European Commission in the latest progress report, published in 2015:

"Total installed capacity of renewable electricity generation has increased significantly over the last 20 years, in particular through rapid growth of installed wind and PV capacity. To put into perspective, while electricity generation capacity from renewable sources in 2013 reached around 380 GW, the existing electricity generation capacity of fossil fuel plants in the EU was around 450GW in 2013".[87]

The European Council pointed out, back in 2011, that decarbonisation, i.e. *"reducing greenhouse gas emissions by 80-95% by 2050 compared to 1990 as agreed in October 2009", "will require a revolution in energy systems, which must start now".*[88] However, recognising the disruptive consequences of new policies and technologies is one thing, actively shaping the *"revolution in energy systems"* is a very different story. For many years, most policy makers and academics ignored the need to redesign energy markets, either because they believed that the EU Emissions Trading System would harmoniously interact with pre-existent electricity and natural gas markets, or because they thought that energy markets would automatically adapt to the boundary conditions imposed by the new policies. Unfortunately, none of these hypotheses turned out to be true and although the EU has developed a coherent *integrated approach* in terms of objectives and targets (called the *Energy Union*), it still lacks a consistent operational *integrated approach*. Such approach requires the simultaneous reform of both system and market operation in order to

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[86] www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/110889.pdf.

[87] European Commission (2015), *Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: Renewable energy progress report*, COM(2015) 293 final, Brussels, 15 June 2015.

[88] www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/119175.pdf.

take into account the structural changes observed and expected in EU electricity systems in the 21st century.

There are at least three reasons that make the old EU market model unfit for decarbonisation:

1) Almost all power plants based on renewable energy sources enjoy a State guaranteed selling price (feed-in tariff, market premium, tax credit, etc. – all different mechanisms lead to the same end-result: subsidised electricity generation prices). In the year 2000, subsidised power plants represented less than 2% of total installed generation capacity and less than 1% of gross electricity generation in the EU-28. In 2014, wind and solar accounted for 12% of total gross electricity generation and all renewable sources were responsible for 29% (up from 14% in 2000). The impact of these figures on wholesale electricity market prices cannot be overlooked: if the trend goes on, wholesale prices will be increasingly depressed and no incentive for new conventional capacity will emerge from the market; on the other hand, if subsidies are suddenly stopped, decarbonisation targets will not be achieved. Decision-makers did not want to address this question ex-ante, keeping the old *laissez-faire* attitude; now, they pretend that renewable-based power plants could and should 'compete in the market', i.e. that a simple market-based approach will deliver the right balance between capacity and demand growth;
2) The output of most power plants based on renewable energy sources (water, wind and sun) is weather dependent. Hydropower plants with associated large reservoirs can mitigate primary energy variability, but even these plants are not immune to weather changes, as some severe droughts have taught us, from Norway to Brazil. The methodology for evaluating capacity adequacy must consider this new reality;
3) The electrical machines and surrounding electronic devices that form a power plant have different mechanical and electrical characteristics, according to the primary energy used and the associated technologies. Substantial changes in the primary energy mix – and, consequently, in the associated technological mix – in any given electricity system, prompt behavioural changes, in electrical terms, both at the individual plant level and at the system level. This affects the dynamic stability of the whole interconnected system.

The last point is particularly important because it underlines the close and increasingly intimate relationship between 'capacity' and 'reliability', thus highlighting the dangers of a *laissez-faire* attitude. In the first decade of liberalisation, the main justification for the *laissez-faire* policy was the fact that 'the market' was delivering enough (even too much) new capacity; therefore, there was no need to monitor capacity developments in the EU. Moreover, since reliability was seen mainly as an issue of reserve margins and reserve margins were comfortably high, there was no need – or, at least, no hurry – to change reliability standards and reliability governance.

As pointed out in previous Sections, this is a fallacy, because reliability depends on much more than reserve margins and ensuring a certain level of reliability requires the design and implementation of appropriate coordination mechanisms. These coordination rules implicitly or explicitly involve decisions about how to share costs and benefits among the different network users across the interconnected system. Therefore they should be carefully scrutinised. In other words, reliability involves more than mere quantitative aspects, closely related to capacity and capacity reserve margins, being independent of the underlying market structure. In fully liberalised markets operating upon a supra-State interconnected network, the actions of market agents, both in the short-term and in the long-term, must be taken into account in a consistent and coordinated manner in order to manage the whole system in the most reliable way, while enabling markets to operate efficiently. The 'quality' of coordination, expressed in terms of reliability standards and rules, as well as in terms of reliability governance, is as important as the quantitative (capacity related) dimension of reliability.

Decarbonisation changes the structure and functioning of electricity systems very deeply. Here are some major consequences:

1. The 'quantity' of available generation capacity in the system must be evaluated in different ways, according to the renewable energy used in the different power plants; therefore, the evaluation of 'reserve margins' becomes a much more complex task than in the past;
2. The widespread introduction of new electronic control and power conversion devices changes the dynamic behaviour of the electricity system;
3. The massive and very fast increase in generation capacity (in the period 2005-2014, total installed capacity increased by 29%, corresponding to 219 GW) was not matched by similar growth of transmission capacity (in the period 2010-2015, the length of AC circuits increased by 6.8%), thus amplifying the potential for conflicting requests for transmission capacity.

In this new, low-carbon world, capacity and reliability must be assessed in a very different way as compared to the old days of centralised power systems built around very large conventional power plants. The qualitative dimension becomes increasingly important and complex. The fallacious *laissez-faire* reasoning "market delivers enough generating capacity, *ergo* market delivers enough reliability and there is no need for new reliability governance" just does not hold anymore.

Back in 2007, when the so-called Third Energy Package was launched, the European Commission somehow recognised the need to move away from the *laissez-faire* attitude towards a more pro-active approach regarding system planning and operation in general. However, this acknowledgement was not followed by the introduction of new rules, not even of a new conceptual framework or new guidelines. The Third Package, approved in 2009, set up new bodies (namely

ENTSO and ACER) and left them the task to develop new rules. However, because the Third Package was mainly concerned with *"improving and integrating competitive electricity markets in the Community"*,[89] no guidance was provided about how to translate "*an integrated approach to climate and energy policy"* in terms of system planning and operation. The 2009 electricity Directive is too vague and does not provide either for appropriate EU planning or operational coordination, as can be seen from the following quotes:

On climate change (no references appear on sustainability or integrated approach):

"In relation to security of supply, energy efficiency/demand-side management and for the fulfilment of environmental goals and goals for energy from renewable sources, as referred to in this paragraph, Member States may introduce the implementation of long-term planning, taking into account the possibility of third parties seeking access to the system".[90]

"Member States shall implement measures to achieve the objectives of social and economic cohesion and environmental protection, which shall include energy efficiency/demand-side management measures and means to combat climate change, and security of supply, where appropriate. Such measures may include, in particular, the provision of adequate economic incentives, using, where appropriate, all existing national and Community tools, for the maintenance and construction of the necessary network infrastructure, including interconnection capacity".[91]

On monitoring the security of supply and capacity tendering:

"Member States shall ensure the monitoring of security of supply issues. Where Member States consider it appropriate, they may delegate that task to the regulatory authorities referred to in Article 35. Such monitoring shall, in particular, cover the balance of supply and demand on the national market, the level of expected future demand and envisaged additional capacity being planned or under construction, and the quality and level of maintenance of the networks, as well as measures to cover peak demand and to deal with shortfalls of one or more suppliers. The competent authorities shall publish every two years, by 31 July, a report outlining the findings resulting from the monitoring of those issues, as well as any measures taken or envisaged to address them and shall forward that report to the Commission forthwith".[92]

"Member States shall ensure the possibility, in the interests of security of supply, of providing for new capacity or energy efficiency/demand-side management measures through a tendering procedure or any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. Those procedures may, however, be launched only where, on the basis of the authorisation procedure, the

[89] Article 1 of Directive 2009/72/EC, *op. cit.*
[90] Article 3 (2).
[91] Article 3 (10).
[92] Article 4.

generating capacity to be built or the energy efficiency/demand-side management measures to be taken are insufficient to ensure security of supply".[93]

"Member States may ensure the possibility, in the interests of environmental protection and the promotion of infant new technologies, of tendering for new capacity on the basis of published criteria. Such tendering may relate to new capacity or to energy efficiency/demand-side management measures. A tendering procedure may, however, be launched only where, on the basis of the authorisation procedure the generating capacity to be built or the measures to be taken, are insufficient to achieve those objectives".[94]

On planning and adequacy:

"Every year, transmission system operators shall submit to the regulatory authority a ten-year network development plan based on existing and forecast supply and demand after having consulted all the relevant stakeholders. That network development plan shall contain efficient measures in order to guarantee the adequacy of the system and the security of supply".[95]

"When elaborating the ten-year network development plan, the transmission system operator shall make reasonable assumptions about the evolution of the generation, supply, consumption and exchanges with other countries, taking into account investment plans for regional and Community-wide networks".[96]

On EU planning and operational coordination:

"The regulatory authority shall examine whether the ten-year network development plan covers all investment needs identified during the consultation process, and whether it is consistent with the non-binding Community-wide ten-year network development plan (Community-wide network development plan) referred to in Article 8(3)(b) of Regulation (EC) No 714/2009. If any doubt arises as to the consistency with the Community-wide network development plan, the regulatory authority shall consult the Agency. The regulatory authority may require the transmission system operator to amend its ten-year network development plan".[97]

"Regulatory authorities shall cooperate at least at a regional level to:

(a) foster the creation of operational arrangements in order to enable an optimal management of the network, promote joint electricity exchanges and the allocation of cross-border capacity, and to enable an adequate level of interconnection capacity, including through new interconnection, within the region and between regions to allow for development of effective competition and improvement of security of supply, without discriminating between supply undertakings in different Member States;

[93]Article 8 (8).
[94]Article 8 (2).
[95]Article 22 (1).
[96]Article 22 (3).
[97] Article 22, (5).

(b) coordinate the development of all network codes for the relevant transmission system operators and other market actors;

and

(*c) coordinate the development of the rules governing the management of congestion".*[98]

"The Commission may adopt Guidelines on the extent of the duties of the regulatory authorities to cooperate with each other and with the Agency. Those measures, designed to amend non-essential elements of this Directive by supplementing it, shall be adopted in accordance with the regulatory procedure with scrutiny referred to in Article 46(2)".[99]

The accompanying electricity Regulation (EC) No 714/2009[100] is mainly concerned with *"enhancing competition within the internal market in electricity"*.[101] It makes no reference to any integrated approach, nor even to climate, decarbonisation or carbon. In fact, the text of the Regulation clearly shows that for his authors energy and climate policies are not on the same foot, 'sustainability' being a by-product of liberalisation:

"The internal market in electricity, which has been progressively implemented since 1999, aims to deliver real choice for all consumers in the Community, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices and higher standards of service, and to contribute to security of supply and sustainability".[102]

Decarbonisation requires a new approach to security of supply and capacity adequacy analysis, clearly distinguishing between the political instant (definition of the energy mix) and the regulatory instant (providing procedural definitions of reliability compatible with national energy mix options and with the internal market). This was already clearly explained in 2004[103] and again in 2006, by an author of the present report in the following terms:

"If an interconnected system has to support the development of an integrated market, co-ordination is necessary in several fields, such as: long-term planning of interconnectors and other transmission facilities, short-term planning of operation, emergency procedures, restoration procedures, protection strategies and settings, balancing and settlement.

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[98] Article 38 (2).
[99] Article 38 (5).
[100] Regulation (EC) No 714/2009 of the European Parliament And of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003, *Official Journal*, L 211/15, 14 August 2009.
[101] Article 1.
[102] Whereas (1).
[103] Vasconcelos J., Some brief remarks on security of electricity supply. *Opening panel at CIGRE conference*, 30 August 2004.

The development of a new set of rules, enabling the more efficient, reliable and secure operation of the interconnected system and supporting the development of an integrated and efficient wholesale electricity market, requires the will and ability of all system operators, the active participation of all network users and close regulatory supervision. Although very important steps have been already undertaken in the EU, progress in this area is still urgently needed.

Within the new, competitive and unbundled legal framework, network operators must adopt a different approach to network reliability as they did in the old days of vertically-integrated monopolies. Probabilistic methods play an increasingly important role and new mathematical tools are being introduced. Planning methodologies must be fully transparent to network users and regulators.

The reliability standards of each network operator must be clearly identified and published. Where integration into a supra-national market has been decided, a certain degree of harmonization is needed. (…)

A procedural definition of security of supply under new forms of organization of electricity markets is needed, especially where liberalization and unbundling have been introduced. This definition should be technically sound and accepted by the stakeholders; it should lead to a set of quantitative measurements and to the publication of monitoring reports on a regular basis.

Once the primary energy mix is defined in quantitative terms, assessing security of electricity supply still requires some generation related assumptions. For instance, it is necessary to estimate the availability of power plants – this is not trivial given the introduction of new technologies and new products from different manufacturers, as well as the existence of different maintenance and operation strategies of producers competing in the wholesale market. It is also necessary to estimate the expected output of power plants – again, this is not a trivial task, since it is necessary to define the set of statistical data used to compute the output of hydro, wind or solar power stations and different stakeholders may have different views about the required level of data robustness, according to their own capacity mix. The estimated energy outputs will also have an obvious impact upon the necessary reserve margins and system costs; this fact reinforces the probability of stakeholders adopting very different views on the appropriate selection of statistical data.

Moreover, some primary energy choices – e.g. decentralized generation – may have a considerable impact upon network planning and operation strategies. Transmission and distribution networks must be constructed in such a way that electricity can flow efficiently from points of generation to points of consumption; the size, type and location of power plants clearly influence the grid topology and the associated necessary investments. The impact of the chosen primary energy mix upon network costs requires a neutral, objective assessment of costs and benefits; it is hard to believe that producers and network operators, having contradictory interests, will provide the most suitable analytical work.

When discussing security of electricity supply, one should carefully examine the geographical boundaries of the region under study. (…)

Defining security of electricity supply at regional, supra-national level, is a new challenge from the technical point of view and it may take some time before we reach an acceptable result; however, this technical challenge is a minor one as compared to the big political challenge that was establishing the principle of a single energy market and the common rules for its functioning".[104]

Back in 2008, the European Commission published a Green Paper[105] where the need to take a different approach to energy networks and their renewed importance for the successful achievement of EU policies was explicitly recognised:

"The task of modernising the power grid to integrate more distributed generation units and "smart" technologies to allow better demand management and to absorb large amounts of renewable energy generation, going beyond 2020, must become a top priority for the EU. (…)

The new renewable energy and climate change legislation, including the "20-20-20" goals, urgently needs to be reflected in network planning and programmes in the public and private sectors.

The EU must develop a comprehensive strategy on integrating renewable energy sources into the grid, in full cooperation with national and regional authorities and market actors. This should address such issues as cost allocation along the supply chain, back-up costs, transmission technologies, the link between local and European grids and regulatory coherence. The EU, Member States, and local and regional authorities should also encourage and facilitate decentralised energy production, which contributes to energy security and offers an important opportunity for regional development, creating growth and jobs".

However, these very sound statements were not incorporated in the Third Energy Package.

The 'internal market first' approach has guided regulatory policies across the EU, as well as at EU level (ACER, European Commission) and it has influenced all Network Codes foreseen in Regulation (EC) No 714/2009. Basically, the specific technical challenges of decarbonisation have been avoided or their importance systematically minimised, in order to keep the old planning and capacity adequacy analysis methods in place for as long as possible. This situation is now slowly changing, as illustrated by the "Mid-term Adequacy Forecast" 2016 recently published by ENTSO-E, *"the first Pan-European probabilistic assessment of adequacy"* that *"takes into*

[104] Vasconcelos J., Security of energy supply: prophecies and fallacies, *2nd Annual Conference*, Florence School of Regulation, 12 May 2006.

[105] European Commission (2008), *Green paper. Towards a secure, sustainable and competitive European energy network*, COM(2008) 782 final, Brussels, 13 November 2008.

account transformation of the power system with increasing variable generation from renewable energy sources".[106]

3.2.5 'Capacity' under the new DG Competition policy

Article 107 TFEU establishes as a general rule that:

"Save as otherwise provided in the Treaties, any aid granted by a Member State or through State resources in any form whatsoever which distorts or threatens to distort competition by favouring certain undertakings or the production of certain goods shall, in so far as it affects trade between Member States, be incompatible with the internal market".

However, numbers 2 and 3 of the same Article establish, respectively, which forms of aid *"shall be compatible with the internal market"* or *"may be considered to be compatible with the internal market"*.

Article 108 TFEU establishes that:

"The Commission shall, in cooperation with Member States, keep under constant review all systems of aid existing in those States. (...)

The Commission shall be informed, in sufficient time to enable it to submit its comments, of any plans to grant or alter aid. If it considers that any such plan is not compatible with the internal market having regard to Article 107, it shall without delay initiate the procedure provided for in paragraph 2. The Member State concerned shall not put its proposed measures into effect until this procedure has resulted in a final decision".

These Articles leave a considerable discretionary latitude in the hands of the European Commission.

In order to provide *"a clearer and more coherent architecture of State aid control"* the European Commission published in 2012 a Communication on EU State Aid Modernisation.[107] This document states in the introduction that:

"The single market is Europe's best asset for generating sustainable growth. An effective internal market requires the deployment of two instruments: first, regulation to create one integrated market without national borders and, second, competition policy including State aid control to ensure that the functioning of that internal market is not distorted by anticompetitive behaviour of companies or by Member States favouring some actors to the detriment of others".

In fact, the document addresses the second mentioned instrument (competition policy), and not the first one (regulation). However, it should be pointed out that, in

[106] https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2016_FINAL_REPORT.pdf.

[107] European Commission (2012), *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on EU State Aid Modernisation (SAM)*, COM(2012) 209 final, Brussels, 8 May 2012.

the EU internal market, discussing a regulation without establishing a regulator to implement it, is like refining a competition policy without DG COMP – it cannot work. While the EU financial market regulators were created in 2011 as part of the European System of Financial Supervision; in network industries, including electricity, there are, as of yet, no EU regulators (ACER is an agency for the cooperation of Member States energy regulators, it is not the European Energy Authority).

The same document foresees the *"revision and streamlining of State aid guidelines"*, including environmental aid. In line with this announcement, the European Commission published in 2014 the "Guidelines on State aid for environmental protection and energy 2014-2020" (hereafter called *Guidelines*).[108]

In the introduction, the *Guidelines* stress the need to phase-out environmentally harmful subsidies and recall the importance of the Europe 2020 strategy, as well as of the Commission's proposal for 2030 energy and climate targets,[109] namely as regards the achievement of an *"ambitious commitment to reduce greenhouse gas emissions in line with the 2050 roadmap"*, following *"a cost-efficient approach"* and *"providing flexibility to Member States to define a low-carbon transition appropriate to their specific circumstances"*.

The *Guidelines* cover many energy relevant aid measures, such as: energy from renewable sources, energy efficiency measures (including cogeneration and district heating and cooling), reductions in funding support for electricity from renewable sources, energy infrastructure and generation adequacy measures. As regards the last point, the *Guidelines* provide the following definitions:

"generation adequacy means a level of generated capacity which is deemed to be adequate to meet demand levels in the Member State in any given period, based on the use of a conventional statistical indicator used by organisations which the Union institutions recognise as performing an essential role in the creation of a single market in electricity, for example ENTSO-E;

generation adequacy measure means a mechanism which has the aim of ensuring that certain generation adequacy levels are met at national level".

When addressing aid to energy from renewable sources the *Guidelines* indicate that:

"These Guidelines apply to the period up to 2020. However, they should prepare the ground for achieving the objectives set in the 2030 Framework. Notably, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way. These

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[108] European Commission (2014), Communication from the Commission on Guidelines on State aid for environmental protection and energy 2014-2020, *Official Journal*, C 200/1, 28 June 2014.

[109] European Commission (2014), *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on A policy framework for climate and energy in the period from 2020 to 2030*, COM(2014) 15 final, Brussels, 22 January 2014.

Guidelines are consistent with that objective and will ensure the transition to a cost-effective delivery through market-based mechanisms. (…)

Aid to electricity from renewable energy sources should in principle contribute to integrating renewable electricity in the market. However, for certain small types of installations, this may not be feasible or appropriate. (…)

In order to incentivise the market integration of electricity from renewable sources, it is important that beneficiaries sell their electricity directly in the market and are subject to market obligations. The following cumulative conditions apply from 1 January 2016 to all new aid schemes and measures:

(a) aid is granted as a premium in addition to the market price (premium) whereby the generators sell its electricity directly in the market;

(b) beneficiaries are subject to standard balancing responsibilities, unless no liquid intra-day markets exist;

and

(c) measures are put in place to ensure that generators have no incentive to generate electricity under negative prices. (…)

From 1 January 2017, the following requirements apply:

Aid is granted in a competitive bidding process on the basis of clear, transparent and non-discriminatory criteria, unless:

(a) Member States demonstrate that only one or a very limited number of projects or sites could be eligible;

or

(b) Member States demonstrate that a competitive bidding process would lead to higher support levels (for example to avoid strategic bidding);

or

(c) Member States demonstrate that a competitive bidding process would result in low project realisation rates (avoid underbidding)".

Besides requiring the introduction of 'competition for the market', through mandatory auctions for new renewable capacities from 1 January 2017, the *Guidelines* also require 'competition in the market': "*integrating renewable electricity in the market".* Obviously, the market being mentioned there is the legacy 'standard' market from the era of centralised, conventional power plants. Not the market design of the future, where 90% of electricity generation will come from renewable sources of primary energy, most of them connected to medium and low voltage level networks. Requiring electricity producers from renewable sources to "*sell their electricity directly in the market"* and making them "*subject to standard balancing responsibilities"* delays the necessary market reform and slows down the development of electricity from renewable sources. It creates the illusion that the 'old' market model and the old planning (capacity) and operational (reliability) rules are compatible with the 'new' *"ambitious commitment to reduce greenhouse gas emissions in line with the 2050 roadmap".*

This approach is not helping the European Union to achieve 2020 (and beyond) renewable energy targets; neither it is helping the European Union to become, again, a world leader in renewable energy. In the period 2010-2015, investments on renewable energy in Europe decreased by 60%; in the meantime, the volume of investment in renewable energy in China is more than twice the corresponding EU figure, as can be seen in the following table.

Table 3.3: Some figures on investment in RES in Europe and China

$ bn	Europe	China
2004	25	3
2010	113	40
2015	49	103

Source: Frankfurt School-UNEP Centre/BNEF (2016), *Global Trends in Renewable Energy Investment 2016*, p. 14.

When addressing aid for generation adequacy in the *Guidelines*, the European Commission indicates that it is aware of the new challenges faced by the electricity sector:

3.9. **Aid for generation adequacy**

(216) With the increasing share of renewable energy sources, electricity generation is in many Member States shifting from a system of relatively stable and continuous supply towards a system with more numerous and small-scale supply of variable sources. The shift raises new challenges for ensuring generation adequacy.

(217) Moreover, market and regulatory failures may cause insufficient investment in generation capacity, for example, in a situation where wholesale prices are capped and electricity markets fail to generate sufficient investment incentives.

(218) As a result, some Member States consider the introduction of measures to ensure generation adequacy, typically by granting support to generators for the mere availability of generation capacity ([93]).

3.9.1. *Objective of common interest*

(219) Measures for generation adequacy can be designed in a variety of ways, in the form of investment and operating aid (in principle only rewarding the commitment to be available to deliver electricity), and can pursue different objectives. They may for example aim at addressing short-term concerns brought about by the lack of flexible generation capacity to meet sudden swings in variable wind and solar production, or they may define a target for generation adequacy, which Member States may wish to ensure regardless of short-term considerations.

(220) Aid for generation adequacy may contradict the objective of phasing out environmentally harmful subsidies including for fossil fuels. Member States should therefore primarily consider alternative ways of achieving generation adequacy which do not have a negative impact on the objective of phasing out environmentally or economically harmful subsidies, such as facilitating demand side management and increasing interconnection capacity.

(221) The precise objective, at which the measure is aimed, should be clearly defined, including when and where the generation adequacy problem is expected to arise. The identification of a generation adequacy problem should be consistent with the generation adequacy analysis carried out regularly by the European Network of Transmission Operators for electricity in accordance with the internal energy market legislation (94).

3.9.2. *Need for State intervention*

(222) The nature and causes of the generation adequacy problem, and therefore of the need for State aid to ensure generation adequacy, should be properly analysed and quantified, for example, in terms of lack of peak-load or seasonal capacity or peak demand in case of failure of the short-term wholesale market to match demand and supply. The unit of measure for quantification should be described and its method of calculation should be provided.

(223) The Member States should clearly demonstrate the reasons why the market cannot be expected to deliver adequate capacity in the absence of intervention, by taking account of on-going market and technology developments (95).

(224) In its assessment, the Commission will take account, among others and when applicable, of the following elements to be provided by the Member State:

(a) assessment of the impact of variable generation, including that originating from neighbouring systems;

(b) assessment of the impact of demand-side participation, including a description of measures to encourage demand side management (96);

(c) assessment of the actual or potential existence of interconnectors, including a description of projects under construction and planned;

(d) assessment of any other element which might cause or exacerbate the generation adequacy problem, such as regulatory or market failures, including for example caps on wholesale prices.

(94) Regulation (EC) No 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity, in particular Article 8 on tasks of the ENTSO for electricity (OJ L 211 14.8.2009, p. 15) In particular, the methodology developed by ENTSO-E, the European Association of Transmission System Operators, for its assessments of EU-level generation adequacy can provide a valid reference.
(95) Such developments can include, for example, the development of market coupling, intraday markets, balancing markets and ancillary services markets and storage of electricity.
(96) The Commission will also take account of plans related to the roll out of smart meters in accordance with Annex I of Directive 2009/72/EC as well as to the requirements under the Energy Efficiency Directive.

However, this text is very far from the above-mentioned ‘Communication on EU State Aid Modernisation’, where it was clearly stated that an “*effective internal market requires the deployment of two instruments: <u>first, regulation</u> to create one integrated market without national borders”.*

If such a consistent, long-term EU regulatory policy were already in place, anyone would easily benefit from:

- all the assessments mentioned in point (224), which would be regularly performed and published;

- the identification of *"when and where the generation adequacy problem is expected to arise"* (221), which would be routinely performed and published at EU level, triggering suitable warning signals and launching appropriate preventive measures, compliant with previously approved procedures;
- the definition of generation adequacy problems, which would automatically be delivered at EU level, i.e., taking into account, simultaneously, the energy mix of all Member States and all existing and planned transmission capacities;
- capacity adequacy assessment which would routinely consider *"the development of market coupling, intraday markets, balancing markets and ancillary services markets and storage of electricity"*, as well as the *"roll out of smart meters"* and many other aspects, according to harmonised methodologies and data sets.

In fact, it is the opposite which is true, and these *Guidelines* assume that such consistent EU regulatory policy does not exist and they establish some criteria to evaluate 'capacity related State aid' cases on a national basis. Unfortunately, this approach based on *Guidelines* is technically flawed because, in an interconnected system with the current penetration of intermittent generation, no meaningful assessment of capacity adequacy can be performed at the national level. What may look like an issue of capacity inadequacy at national scale may disappear when the analysis is performed on an EU scale. And vice-versa, one Member State may believe that it has no capacity adequacy problem, based on a national assessment, while it may turn out that, because of the combined effects of energy mix options in the other Member States, there will be a problem in the future.

Requiring market agents from neighbouring Member States to be allowed to participate in capacity mechanisms in a given Member State as a precondition for the approval of 'State aid cases' may seem very supportive of the internal market. However, if the analysis is performed at the national level only and does not take in due account the technical intricacies of reliability and capacity adequacy throughout a large interconnected system with increasing volumes of intermittent generation and increasing amounts of electronic control devices, it does not lead to more reliable, more efficient and more integrated markets.

The <u>second instrument</u> (competition policy) is fundamental *"to ensure that the functioning of that internal market is not distorted by anticompetitive behavior"*, but if it is based on incomplete information it will be of little value. Only a robust and consistent EU regulatory framework, taking into due account EU long-term policies, as well as Member State primary energy and technology options and the technical characteristics of the whole interconnected system can ensure the functioning of the internal electricity market and can provide the conceptual framework and the necessary data to accurately assess the behaviour of market agents and States.

The major conceptual weakness of the *Guidelines*, i.e. the absence of a coherent vision on the combination of EU markets and policies, is reflected in the recent 'Final

Report of the Sector Inquiry on Capacity Mechanisms',[110] published on November 30, 2016. Instead of addressing capacity and reliability issues within the complex framework of EU policies, the Final Report follows the 'market first' approach, described in the previous Section, ignoring EU climate policy. This is acknowledged in a very candid way in the Report's last footnote, preceding the list of overall conclusions:

"These conclusions focus primarily on the ability of various types of capacity mechanisms to address problems of security of electricity supply in the most cost effective and least market distortive way. Capacity mechanisms can however affect the generation mix and therefore interact with policy instruments aimed at fostering decarbonisation. As recognised by the Energy and Environmental Aid Guidelines in paragraphs (220) and (233)(e), the design of capacity mechanisms should take into account these impacts in order to contribute to the overall coherence of EU energy policy in electricity markets".

Capacity mechanisms can indeed affect the generation mix. For sure, the generation mix affects the methodologies and the data sets needed to perform a sensible capacity adequacy assessment. And, as long as the Treaty is not changed, the generation mix is determined by Member States, not by competition policy. To reconcile Member States' freedom with the overall reliability of interconnected systems and the efficiency of supra-State markets, a comprehensive, consistent EU regulatory framework is indispensable. Only within this framework can *"the most cost effective and least market distortive"* capacity mechanisms be designed.

[110] European Commission (2016), *Report from the Commission – Final Report of the Sector Inquiry on Capacity Mechanisms*, COM(2016) 752 final, Brussels, 30 November 2016.

3.3 Structure of transmission tariffs

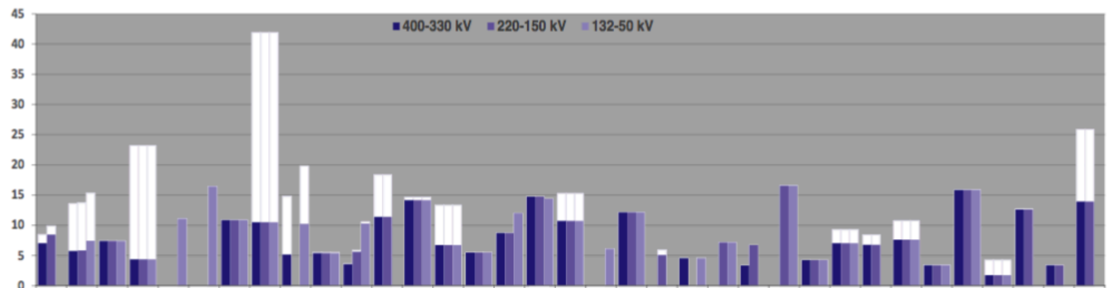
Since 2003, all transmission and distribution electricity and natural gas network tariffs in the EU should be “fixed or approved” by national regulatory authorities. However, given the existing regulatory diversity in Europe – not to mention multiple government interventions in tariff setting – it is not an easy task to compare energy network tariffs across Europe. The difficulty concerns both quantitative and qualitative aspects; in other words, it concerns:

- tariff levels (how much, on average, is paid for each energy unit flowing through a given network);
- tariff structures (what is paid – i.e. which costs are included; who pays; how they are paid – i.e. which variables are used to assign costs to network users; where it is paid – whether tariffs are national, regional or nodal; when – i.e., whether tariffs are time-of-use dependent or not).

Current status

Fig. 3.4 shows the diversity of transmission tariff levels across Europe.[111]

Euro per MWh



		AT	BE	BA	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GB	GR	HU	IS
TOTAL	400-330 kV	8.48	13.63	7.41	23.19	-	-	10.86	41.94	14.79	5.49	3.66	18.35	14.63	13.34	5.48	8.70
	220-150 kV	9.88	13.73	7.41	23.19	-	-	10.86	41.94	-	5.49	5.86	18.35	14.63	13.34	5.48	8.70
	132-50 kV	-	15.33	7.41	23.19	11.11	16.40	10.86	41.94	19.83	5.49	10.60	-	14.63	13.34	5.48	12.01
TSO	400-330 kV	7.05	5.74	7.41	4.36	-	-	10.86	10.51	5.19	5.39	3.56	11.40	14.17	6.72	5.48	8.70
	220-150 kV	8.45	5.84	7.41	4.36	-	-	10.86	10.51	-	5.39	5.63	11.40	14.17	6.72	5.48	8.70
	132-50 kV	-	7.44	7.41	4.36	11.10	16.40	10.86	10.51	10.23	5.39	10.28	-	14.17	6.72	5.48	12.01

		IE	IT	LV	LT	LU	MK	ME	NL	NI	NO	PL	PT	RO	RS	SK	SI	ES	SE	CH
TOTAL	400-330 kV	14.74	15.28	-	12.15	-	4.55	-	3.36	-	4.23	9.27	8.43	10.78	3.39	15.87	4.24	12.71	3.41	25.89
	220-150 kV	14.74	15.28	-	12.15	5.92	-	7.15	6.70	16.58	4.23	9.27	8.43	10.78	3.39	15.87	4.24	12.71	3.41	25.89
	132-50 kV	14.37	15.28	6.07	12.15	-	4.55	7.15	-	16.58	4.23	9.27	-	10.78	3.39	15.87	4.24	-	-	-
TSO	400-330 kV	14.74	10.70	-	12.15	-	4.55	-	3.36	-	4.23	7.05	6.75	7.62	3.37	15.87	1.75	12.60	3.41	13.92
	220-150 kV	14.74	10.70	-	12.15	5.07	-	7.15	6.70	16.58	4.23	7.05	6.75	7.62	3.37	15.87	1.75	12.60	3.41	13.92
	132-50 kV	14.37	10.70	6.07	12.15	-	4.55	7.15	-	16.58	4.23	7.05	-	7.62	3.37	15.87	1.75	-	-	-

■ Charges related to TSO activities: infrastructure (Depreciation, return on capital and OPEX), losses, system services, congestion.

□ Other regulatory charges not directly related to TSO activities: stranded costs, public interest contribution, renewable energy and others. Details in Appendix 6.

Fig 3.4: Unit Transmission Tariffs as computed by ENTSO-E

Figure 3.5 on the next page illustrates the structural diversity of electricity transmission tariffs in general.

[111] ENTSO-E (2016), Overview of Transmission Tariffs in Europe: Synthesis 2016, June 2016, p. 11.

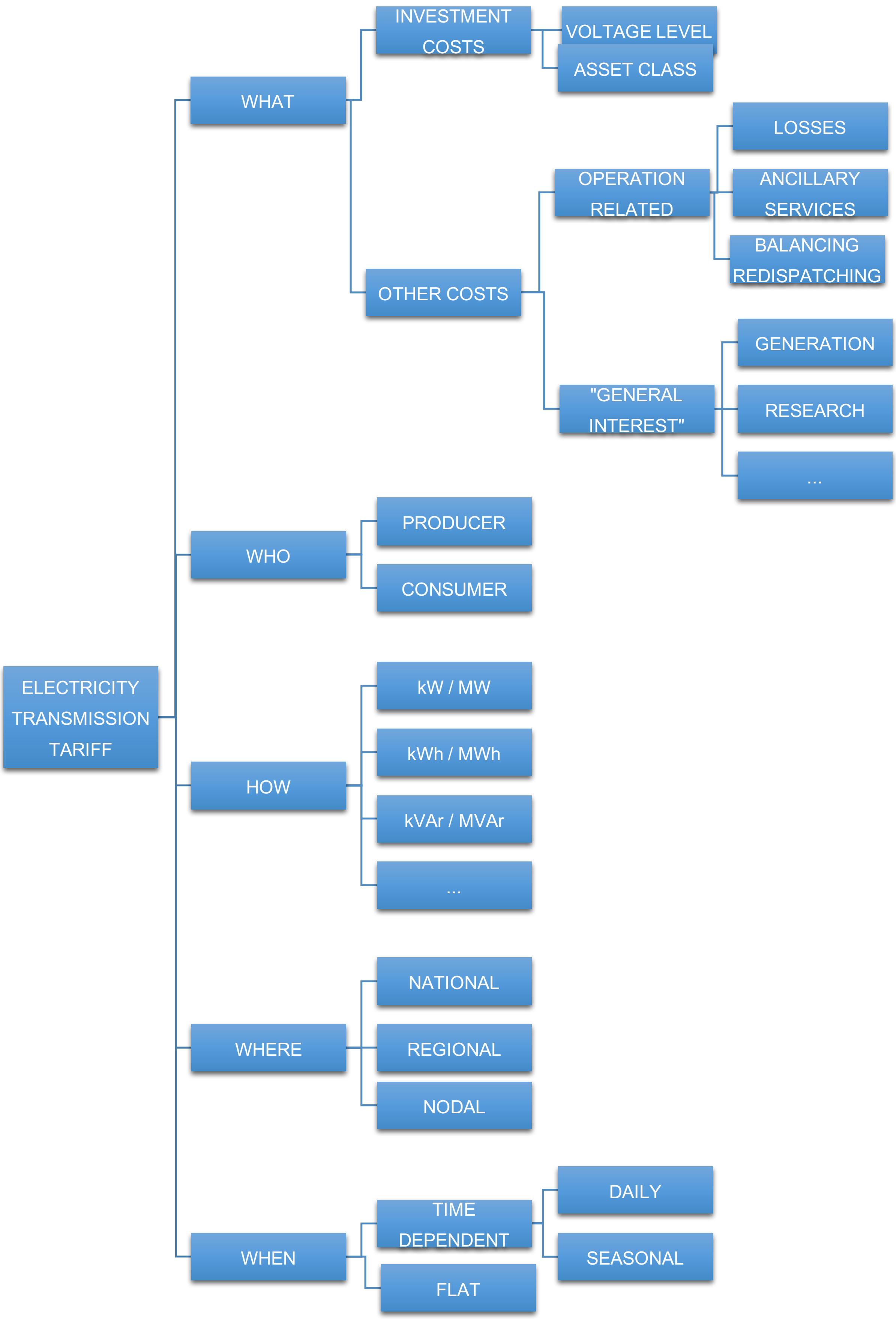


Fig 3.5: Potential structural diversity of electricity transmission tariffs

The following table shows the existing diversity of electricity transmission tariff structures in Europe concerning some selected features.[112]

Table 3.4: Diversity of transmission tariff structures in Europe – selected features

	Sharing of network operator charges		Price signal		Are losses included in the tariffs charged by TSO?	Are system services included in tariffs charged by TSO?
	Generation	Load	Seasonal	Location		
Austria	43%	57%	No	No	Yes	Yes
Belgium	7%	93%	X	No	No	Yes
Bosnia & Herzegovina	0%	100%	No	No	Yes	Yes
Bulgaria	0%	100%	No	No	Yes	Yes
Croatia	0%	100%	X	No	Yes	Yes
Cyprus	0%	100%	No	No	Yes	Yes
Czech Republic	0%	100%	No	No	Yes	Yes
Denmark	3%	97%	No	No	Yes	Yes
Estonia	0%	100%	X	No	Yes	Yes
Finland	19%	81%	X	No	Yes	Yes
France	2%	98%	XXX	No	Yes	Yes
Germany	0%	100%	No	No	Yes	Yes
Great Britain	23%	77%	No	Yes	No	Yes
Greece	0%	100%	X	No	No	Yes
Hungary	0%	100%	No	No	Yes	Yes
Iceland	0%	100%	No	No	Yes	Yes
Ireland	25%	75%	No	Yes	No	Yes
Italy	0%	100%	No	No	Yes	Yes
Latvia	0%	100%	No	No	Yes	Yes
Lithuania	0%	100%	No	No	Yes	Yes
Luxembourg	0%	100%	No	No	Yes	Yes
FYROM	0%	100%	No	No	Yes	Yes
Montenegro	33%	67%	X	No	Yes	Yes
Netherlands	0%	100%	No	No	Yes	Yes
Northern Ireland	25%	75%	XXX	Yes	No	No
Norway	38%	62%	X	Yes	Yes	Yes
Poland	0%	100%	No	No	Yes	Yes
Portugal	8%	92%	XX	No	No	No
Romania	8%	92%	No	Yes	Yes	Yes
Serbia	0%	100%	X	No	Yes	Yes
Slovak Republic	3%	97%	No	No	Yes	Yes
Slovenia	0%	100%	XXX	No	Yes	Yes
Spain	5%	95%	XXX	No	No	Yes
Sweden	41%	59%	No	Yes	Yes	Yes
Switzerland	0%	100%	No	No	No	No

Remarks:

(1) The % shares of network charges between G and L are provided for the base case charge.

(2) The "X" indicates time differentiation. With one "X", there is only one time differentiation (for example,"day-night", "summer-winter"). With two "X" (or more), there are two (or more) time differentiations.

Table 3.5 shows the different composition of transmission lines, by voltage level, managed by TSOs in Europe.[113]

[112] *Ibid*., p. 9.
[113] *Ibid*., p. 34.

Table 3.5: Weight of different voltage levels operated by TSOs in Europe

% km	400-330 kV	220 -150 kV	132-50 kV
Austria	34%	47%	19%
Belgium (Elia)	15%	47%	38%
Bosnia and Herzegovina	14%	24%	62%
Bulgaria (NEK)	17%	19%	64%
Croatia	17%	16%	67%
Cyprus	0%	0%	100%
Czech Republic (CEPS)	64%	35%	2%
Denmark (Energinet.dk)	28%	48%	24%
Estonia (Elering)	32%	3%	65%
Finland (Fingrid)	33%	15%	53%
France (RTE)	21%	27%	53%
Germany	61%	39%	0%
Great Britain (NGT)	53%	28%	20%
Greece (ADMIE)	27%	73%	0%
Hungary (Mavir)	67%	29%	4%
Iceland (Landsnet)	0%	27%	74%
Ireland (EirGrid)	11%	29%	60%
Italy (Terna)	17%	40%	43%
Latvia Augstsprieguma Tikls)	26%	0%	74%
Lithuania (Litgrid)	26%	0%	74%
Luxembourg	0%	100%	0%
FYROM	27%	0%	73%
Montenegro	23%	28%	49%
Netherlands (TenneT)	24%	52%	25%
Northern Ireland (SONI)	0%	38%	62%
Norway (Statnett)	74%	0%	26%
Poland (PSE)	44%	56%	1%
Portugal (REN)	30%	70%	0%
Romania (Transelectrica)	55%	44%	0%
Serbia (EMS)	18%	21%	62%
Slovak Republic (SEPS)	68%	29%	3%
Slovenia (Eles)	24%	12%	65%
Spain (REE)	49%	45%	6%
Sweden (Svenska K.)	74%	26%	0%
Switzerland	27%	73%	0%

Remarks:

- Percentages are calculated as the ratio between the kilometers of circuits for each voltage level and total kilometers of circuits operated by each TSO.

Figure 3.6 shows the voltage threshold between distribution and transmission networks, as well as the voltage levels managed by DSOs in each Member State.[114]

[114] Eurelectric (2013), *Power Distribution in Europe: facts and Figures*, p. 15 (the document is available at www.eurelectric.org/media/113155/dso_report-web_final-2013-030-0764-01-e.pdf).

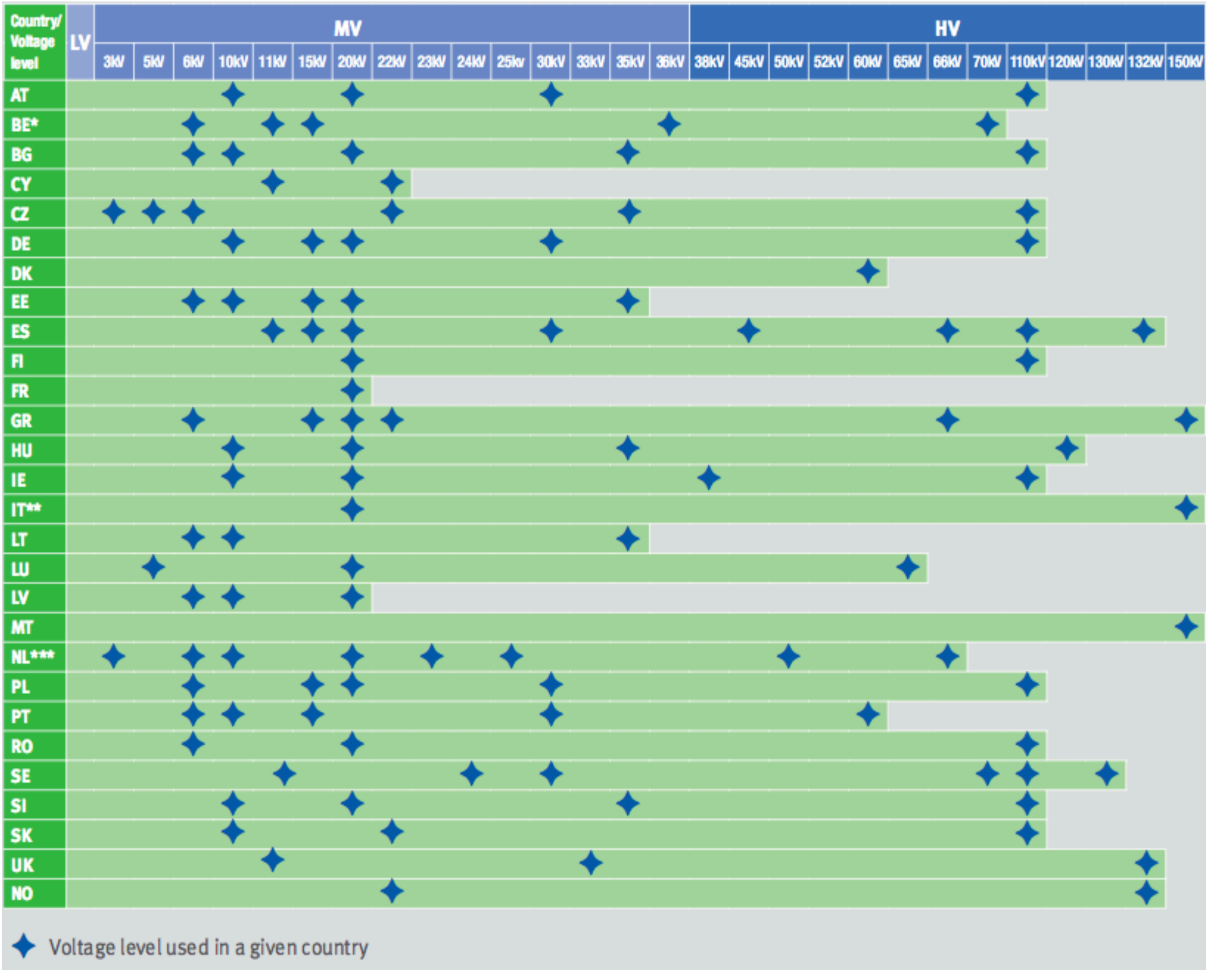


Fig 3.6: Voltage levels managed by DNOs in the EU in 2011

Purpose and need for harmonisation

Potentially, differences in transmission tariff structures among the EU Member States may lead to market distortions in the internal energy market. However, this risk should not be overstated, first of all because average transmission tariffs are much lower than wholesale energy prices; hence, their impact on cross-border trade is limited.

The major factor that may distort cross-border trade, in terms of transmission tariff structure, is the different allocation of transmission costs to generators and consumers. Yet, as shown in Figure 3.7, all the continental EU Member States but Austria have opted for full or almost full direct charging to consumers.

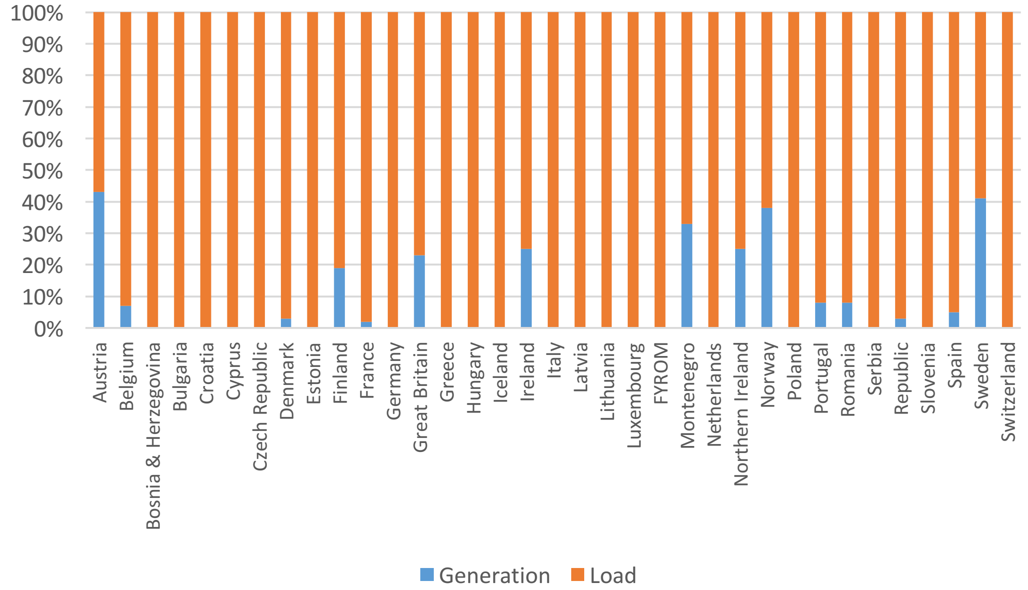


Fig 3. 7 Share of Generation and Load network charges in %. Source: ENTSO-E (2016)

Moreover, in continental Europe:

- Locational price signals are almost non-existent;
- System services and losses are predominantly included in transmission tariffs.

Harmonisation of the ratio between generation and load in favour of load was decided by national regulators on a voluntary basis at the very beginning of electricity liberalisation in Europe, in the late 1990s. In fact, this was one of the first – and one of the very few – times where national regulators achieved a relevant result at the EU level by just using their powers at the national level in a sensible and coordinated way – i.e. deciding to implement the same solution at the same time in all Member States. This approach does not require specific EU legislation and it does not require a supra-national body to enforce the collective decision. But it requires, of course, a very strong commitment of all national regulators to the internal energy market – and a certain quantum of peer pressure.

Ten years later, Regulation (EC) No 714/2009 established an open framework for a progressive harmonisation of transmission tariffs in Europe:

Article 18

Guidelines

…

2. Guidelines may also determine appropriate rules leading to a progressive harmonisation of the underlying principles for the setting of charges applied to *producers and consumers (load) under national tariff systems, including the reflection of the inter-transmission system operator compensation mechanism in national network charges and the provision of appropriate and efficient locational signals, in accordance with the principles set out in Article 14.*

The issue has been debated since then and the central remaining question is whether there should be a legal framework for further harmonisation of transmission tariffs.

In order to provide supporting information for policy decisions, ACER recently sponsored a study called 'Scoping towards potential harmonisation of electricity transmission tariff structures'.[115]

"The benefits of a shorter-term regulatory response on harmonisation (e.g. removal of G-charges or greater harmonisation of the G-L split) are, in the consultant's view, unlikely to outweigh potential costs. Given a general lack of evidence and certainty that differences in tariff structures in practice lead to inefficient outcomes, CEPA concludes that the benefits of shorter-term regulatory response would be highly uncertain. …

In the longer term, CEPA believes that there is a stronger case for further harmonisation, based on the need for greater consistency and application of tariff structures that reflect the costs generated by market participants' decisions. CEPA proposes that Member States establish a clear and harmonised set of principles based on an agreement on the balance between the policy objectives set out in the Third Package. Specifically, the consultant proposes cost reflectivity and cost recovery, as well as transparency and predictability, as key factors to be considered".

The conclusions drawn from the study indicate that no clear case for further harmonisation can be found:

"The Agency notes a potential for the current absence of harmonised tariff structures to impact negatively on the efficiency of the IEM, potentially distorting the market participants' investment and operational decisions. However, according to CEPA's investigation, the distortions are not evident at the moment and highly uncertain in the future, and the evidence and associated impact are not easily identifiable or are not material. The Agency notes the current ambitious market reform including the Network Codes currently being progressed and the Energy Union Strategy, and considers it reasonable to deliver those first. In that regards, the Agency agrees with

[115] ACER (2015), *Scoping towards potential harmonisation of electricity transmission tariff structures. Conclusions and next steps*, December 2015.

CEPA's conclusion that any potential distortions, or benefits of harmonisation, would be more easily appraised in the future, as markets become more integrated and reforms are delivered. Equally, a visible and measurable distortion from the absence of, or a benefit of further harmonisation, should be observable in order to set out clear and objective principles needed for the development of a Network Code. In conclusion, the Agency considers a formal Framework Guidelines process to be a disproportionate response at this stage".

ACER also outlines the main aspects to be considered when setting transmission tariffs aiming "*to be fed into the new Energy Market Design considerations, in coordination with CEER's work on distribution tariffs*":

More specifically, the following aspects may be considered in establishing a common set of transmission tariff principles:

- *Cost reflectivity principle. Consider the role of transmission tariffs in line with the new Energy Market Design and policy objectives and identify the cost categories included in the transmission tariff. The latter would consider the types of costs included in transmission tariffs in combination with future electricity market design, such as the definition of generation charges referred to in Commission Regulation (EU) No 838/2010, and the charging method for each cost category.*
- *Explore various options behind the cost recovery principle to ensure transmission costs are recovered in the least distortionary manner.*
- *Transparency and predictability.*

3.4 The lack of harmonisation of 'State aid' to large energy consumers through discounts on network tariffs and ancillary services.

Many Member States have exempted large industrial consumers from the payment of certain components of transmission tariffs. This may create distortions of competition in some energy-intensive industries; however, it does not seem to be a serious problem in the electricity industry itself.

The legal basis for special treatment of large electricity consumers consists of three main documents that will be briefly introduced in what follows.

1. COUNCIL DIRECTIVE 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity.[116]

This Directive foresees the possibility of several exemptions and acknowledges that:

"(28) Certain exemptions or reductions in the tax level may prove necessary; notably because of the lack of a stronger harmonisation at Community level, because of the risks of a loss of international competitiveness or because of social or environmental considerations.

(29) Businesses entering into agreements to significantly enhance environmental protection and energy efficiency deserve attention; among these businesses, energy intensive ones merit specific treatment."

Article 17 of this Directive provides special treatment to energy-intensive consumers in the following terms:

Article 17

1. Provided the minimum levels of taxation prescribed in this Directive are respected on average for each business, Member States may apply tax reductions on the consumption of energy products used for heating purposes or for the purposes of Article 8(2)(b) and (c) and on electricity in the following cases:

(a) in favour of energy-intensive business

An 'energy-intensive business' shall mean a business entity, as referred to in Article 11, where either the purchases of energy products and electricity amount to at least 3,0 % of the production value or the national energy tax payable amounts to at least 0,5 % of the added value. Within this definition, Member States may apply more restrictive concepts, including sales value, process and sector definitions.

[116] Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity, *Official Journal*, L 283/51, 31 October 2003.

'Purchases of energy products and electricity' shall mean the actual cost of energy purchased or generated within the business. Only electricity, heat and energy products that are used for heating purposes or for the purposes of Article 8(2)(b) and (c) are included. All taxes are included, except deductible VAT.

'Production value' shall mean turnover, including subsidies directly linked to the price of the product, plus or minus the changes in stocks of finished products, work in progress and goods and services purchased for resale, minus the purchases of goods and services for resale.

'Value added' shall mean the total turnover liable to VAT including export sales minus the total purchases liable to VAT including imports.

Member States, which currently apply national energy tax systems in which energy-intensive businesses are defined according to criteria other than energy costs in comparison with production value and national energy tax payable in comparison with value added, shall be allowed a transitional period until no later than 1 January 2007 to adapt to the definition set out in point (a) first subparagraph;

(b) where agreements are concluded with undertakings or associations of undertakings, or where tradable permit schemes or equivalent arrangements are implemented, as far as they lead to the achievement of environmental protection objectives or to improvements in energy efficiency.

2. Notwithstanding Article 4(1), Member States may apply a level of taxation down to zero to energy products and electricity as defined in Article 2, when used by energy-intensive businesses as defined in paragraph 1 of this Article.

3. Notwithstanding Article 4(1), Member States may apply a level of taxation down to 50 % of the minimum levels in this Directive to energy products and electricity as defined in Article 2, when used by business entities as defined in Article 11, which are not energy-intensive as defined in paragraph 1 of this Article.

4. Businesses that benefit from the possibilities referred to in paragraphs 2 and 3 shall enter into the agreements, tradable permit schemes or equivalent arrangements as referred to in paragraph 1(b). The agreements, tradable permit schemes or equivalent arrangements must lead to the achievement of environmental objectives or increased energy efficiency, broadly equivalent to what would have been achieved if the standard Community minimum rates had been observed.

2. DIRECTIVE 2003/87/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.[117]

[117] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, *Official Journal*, L 275/32, 25 October 2003. This Directive was amended subsequently by the Directive 2009/29/EC.

This Directive foresees “measures to support certain energy-intensive industries in the event of carbon leakage”. The risk of carbon leakage is defined as follows (Article 10a):

“15. A sector or subsector shall be deemed to be exposed to a significant risk of carbon leakage if:

(a) the sum of direct and indirect additional costs induced by the implementation of this Directive would lead to a substantial increase of production costs, calculated as a proportion of the gross value added, of at least 5 %; and

(b) the intensity of trade with third countries, defined as the ratio between the total value of exports to third countries plus the value of imports from third countries and the total market size for the Community (annual turnover plus total imports from third countries), is above10 %.

16. Notwithstanding paragraph 15, a sector or subsector is also deemed to be exposed to a significant risk of carbon leakage if:

(a) the sum of direct and indirect additional costs induced by the implementation of this Directive would lead to a particularly high increase of production costs, calculated as a proportion of the gross value added, of at least 30 %; or

(b) the intensity of trade with third countries, defined as the ratio between the total value of exports to third countries plus the value of imports from third countries and the total market size for the Community (annual turnover plus total imports from third countries), is above30 %.”

This Directive establishes that (Article 10a, nr.6):

6. Member States may also adopt financial measures in favour of sectors or subsectors determined to be exposed to a significant risk of carbon leakage due to costs relating to greenhouse gas emissions passed on in electricity prices, in order to compensate for those costs and where such financial measures are in accordance with state aid rules applicable and to be adopted in this area.

Those measures shall be based on ex-ante benchmarks of the indirect emissions of CO_2 per unit of production. The ex-ante benchmarks shall be calculated for a given sector or subsector as the product of the electricity consumption per unit of production corresponding to the most efficient available technologies and of the CO_2 emissions of the relevant European electricity production mix.

Germany and France have already allocated, respectively, 245 M€ (2015) and 93 M€ (2016) per year to subsidise electricity prices of industries exposed to the risk of carbon leakage. Most Member States have not yet made use of this possibility, while others have applied very small amounts (e.g. Spain – 4 M€).

3. COMMUNICATION FROM THE COMMISSION Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01)[118]

These Guidelines also foresee the possibility of providing special treatment to large energy consumers:

3.7.2. *Aid in the form of reductions in the funding of support for energy from renewable sources* (81)

(181) The funding of support to energy from renewable sources through charges does as such not target a negative externality and accordingly has no direct environmental effect. Those charges are, therefore, fundamentally different from the indirect taxes on electricity set out in paragraph (167) even if they may also result in higher electricity prices. The increase in electricity costs may be explicit through a specific charge which is levied from electricity consumers on top of the electricity price or indirect through additional costs faced by electricity suppliers due to obligations to buy renewable energy which are subsequently passed on to their customers, the electricity consumers. A typical example would be the mandatory purchase by electricity suppliers of a certain percentage of renewable energy through green certificates for which the supplier is not compensated.

(182) In principle and to the extent that the costs of financing renewable energy support are recovered from energy consumers, they should be recovered in a way that does not discriminate between consumers of energy. However, some targeted reductions in these costs may be needed to secure a sufficient financing base for support to energy from renewable sources and hence help reaching the renewable energy targets set at EU level (82). On the one hand, in order to avoid that undertakings particularly affected by the financing costs of renewable energy support are put at a significant competitive disadvantage, Member States may wish to grant partial compensation for these additional costs. Without such compensation the financing of renewable support may be unsustainable and public acceptance of setting up ambitious renewable energy support measures may be limited. On the other hand, if such compensation is too high or awarded to too many electricity consumers, the overall funding of support to energy from renewable sources might be threatened as well and the public acceptance for renewable energy support may be equally hampered and distortions of competition and trade may be particularly high.

(183) For the assessment of State aid to compensate for the financing of support to energy from renewable sources, the Commission will only apply the conditions set out in this Section and in Section 3.2.7.

Based on these Guidelines, DG COMP has approved exemptions up to 95% of transmission costs for large electricity consumers in Germany, France[119] and Italy;[120]

[118] European Commission (2014), Communication from the Commission on Guidelines on State aid for environmental protection and energy 2014-2020, *Official Journal*, C 200/1, 28 June 2014.

[119] Case SA.43468 (2016/NN). Final decision CE C(2016) 5251 final of 11.08.2016. See also:

- Loi n° 2015-1786 du 29 décembre 2015 de finances rectificative pour 2015.
- Décret n° 2016-141 du 11 février 2016 relatif au statut d'électro-intensif et à la réduction de tarif d'utilisation du réseau public de transport accordée aux sites fortement consommateurs d'électricité.

[120] See:

- Decreto-Legge n. 83/12, convertito dalla Legge n. 134/12;

reductions up to 85% in Poland[121] and Denmark;[122] and in several other Member States (some cases still pending).

In Germany, for instance, only 42% of industrial demand pays the full tariff corresponding to renewable energy support (6,88 cent/kWh), as shown in Fig 3.8.[123] 43% of industrial demand pays a reduced tariff between 0,05 and 1,38 cent/kWh.

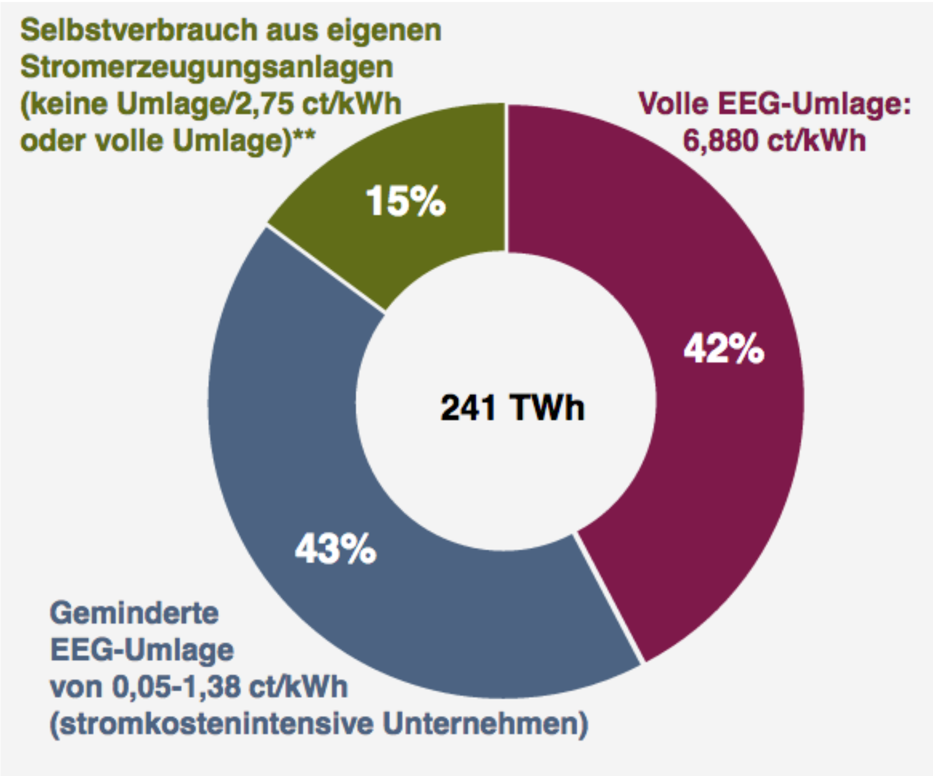


Fig 3.8: Contribution of industrial electricity demand to the payment of renewable subsidies in Germany, 2017 tariffs

− AEEGSI Delibera 17 novembre 2016 677/2016/R/eel.

[121] Case 37345 (2015/NN.). See also: http://ec.europa.eu/competition/state_aid/cases/261395/261395_1832252_133_2.pdf.

[122] Case SA.44863. See also: http://europa.eu/rapid/press-release_IP-16-4353_en.htm

[123] https://www.bdew.de/internet.nsf/res/17C4483BB515C7F4C125807A0035E077/$file/161124_BDEW_Strompreisanalyse_November2016.pdf.

Part 2 – *"Removing roadblocks with the appropriate pillars"*

Chapter 4 – Roadblocks on the path to a true European power system

Executive Summary

The first part of our report, consisting of chapters form 1 to 3, illustrates that, although it has been more than two decades since its inception, the creation of a single, integrated European power market is still a work in progress. A series of issues, which stem from inadequate or ineffective solutions from decision-makers to basic policy questions, is hindering the integration process. Compounded by the current challenges of decarbonisation and digitalisation, those factors constitute 'roadblocks' in the path towards the establishment of a truly 'Europeanised' power market with seamless transmission system operation and operators.

In our view, two of these roadblocks are particularly relevant and deserve full consideration. They are redispatching actions, on the one hand, and capacity adequacy and crisis management, on the other hand. Chapter 4 analyses them, describing the issues at stake, the reasons why they were not tackled before and explains why they are currently hampering the process of Europeanisation.

Redispatching actions are the actions which are implemented following market closure by TSOs to relieve network congestions. By asking certain power plants to reduce or to increase generation, TSOs try to cope with the variability of RES production while also trying to reconcile market outcomes with the electricity flows that the interconnected European grid is physically able to accommodate with a reasonable security margin. The fast deployment of RES and the growth of trade in electricity across borders over the last few years have increased the need for TSOs to implement redispatching actions and the corresponding costs. The need and the benefits of coordination and cooperation of TSOs on the issue have become, respectively, more urgent and apparent.

Cross-border redispatching actions call for stronger coordination among TSOs and for appropriate cost sharing mechanisms, which are rarely in place today. In the current legal and regulatory framework this is hardly a surprise. The lack of a common definition and actual data on redispatching costs, the potential redistributive impact of any allocative mechanism and the national liability of the TSOs – subject to national regulatory oversight – make the development of proper sharing mechanisms a sensitive topic. In turn, this slows down the development of coordination and cooperation of TSOs on redispatching actions and the optimal operation of the European interconnected system.

Capacity adequacy is the ability of a power system to cover demand at any time using its generation and demand response resources. Historically, capacity adequacy has been assessed at national level and vertically integrated public monopolies were entrusted with its promotion. Due to growing interconnections between the grids of European countries, national systems are becoming more and more interdependent, thereby making any capacity assessment performed in isolation at national level of little meaning. Developments in neighbouring countries have today profound impacts on any domestic power system, as illustrated recently by the 'electricity crisis' of January 2017.

Concerns over the lack of reliable capacity are today widespread in Europe and several governments have introduced or are planning to introduce capacity remuneration mechanisms next to the traditional energy-only markets. In many cases, these policies are implemented in an uncoordinated way and on the basis of capacity assessments that do not capture the full impact of interconnections and resources in neighbouring countries. Overinvestment in generation capacity and distortions to the functioning of the internal energy market are concrete possibilities.

Interdependence among national systems also affects *crisis management*. Extreme conditions, as for instance a strong cold snap in winter or a prolonged heat wave, can severely stress power systems and call for emergency actions to ensure continuity of supply. Traditionally, national TSOs have been responsible for keeping the lights on by managing scarce resources during times of crisis. Their national responsibility and, at times, distrust of neighbours, explain why solidarity, although most needed, is not always shown in these difficult periods and coordination of power systems remains fragile in Europe.

4.1 Introduction

Twelve blocking factors have been presented in chapters 2 and 3, creating respectively first-order and second-order coordination issues for the implementation of a well-functioning European power market and system. Among these issues, European institutions and stakeholders are already coping and advancing with regard to issues like the lack of comprehensive coordination of system planning, the lack of comprehensive coordination of cross-border investments, the lack of common reserve contracting and cost allocation, and the lack of intraday cross-border capacity allocation with auctions.

However, European institutions and stakeholders have achieved little or no improvements at all regarding some issues that, from our point of view, represent two major 'roadblocks' on the path towards an integrated and decarbonised European power sector. These two barriers, which this chapter will investigate in more detail as examples and case studies, are:

- Roadblock (1): 'dealing with redispatching actions';
- Roadblock (2): 'capacity adequacy and crisis management'.

The first issue of 'redispatching actions' encompasses two of the blocking factors mentioned in the previous chapters, i.e. the lack of comprehensive system operation and the lack of a common redispatching approach. On the other hand, the second issue, 'capacity adequacy and crisis management', incorporates three different blocking factors, i.e. the lack of a common definition of power security of supply, the lack of harmonisation of load shedding schemes, and the lack of comprehensive coordination for solidarity.

This fourth chapter aims to illustrate our core methodology, as demonstrated in the first three chapters of the report. According to this, to fully and comprehensively overcome any particular *roadblock*, one would first have to ensure that all the relevant blocking *factors* are addressed and tackled. By applying this methodology, one would drive the European market and system integration through tighter and more efficient system-wide coordination and solidarity.

To show how our methodology treats these roadblocks in the building of a more efficient European power architecture, we proceed as follows. For each of these issues, we look in detail at three aspects. *First*, we describe the issue, in particular the potential or concrete inefficiencies on exchanges and investment decisions arising from it. *Second*, we question why the issue has not been tackled before, by looking at the root of the problem (at a technical, organisational, economic, institutional, legal and political level). *Finally*, we explain why the issue acts as a roadblock in the process of building a more efficient European power system, in terms of cost sharing, coordination and solidarity.

4.2 Roadblock One: dealing with redispatching actions

4.2.1 What's the issue?

TSOs are legally responsible for the management of power flows on their national network. As a consequence, if they notice that the power flows resulting from the decisions of market players and the market outcome exceed the maximal flows acceptable through wires and other network devices, they will take redispatching actions in order to modify these flows.[124] Redispatching actions, which are taken outside of the day-ahead and the intraday electricity markets, can be *preventive*, if they are carried out before real time, i.e. 'long' before congestions concretely materialise, or *curative*, if they are taken in real time, i.e. just before or after congestions materialise.

Since most national markets have a single price zone,[125] TSOs generally use 'redispatching' to manage power flows at national scale. Indeed, having a single price zone for a whole country assumes that the national power network is a copper plate with no internal bottlenecks. This assumption is usually unrealistic from the physical point of view and TSOs often act and implement redispatching actions as a last resort to relieve internal network congestions.

Congestions also occur at the borders between national price zones. These bottlenecks have been mainly managed in the past with explicit and implicit capacity auctions, but congestion levels along interconnections or on national grid lines highly interactive with cross-border trade have recently become so high, that 'cross-border redispatching actions' are now regularly needed. An example of this trend is represented by the power network in the Central Eastern Europe area (CEE), which was stressed or highly stressed for 62% of the time in 2015, requiring cross-border coordination between TSOs at the day-ahead stage (Coreso, 2015).

It is important to note that the real-time network constraints that must be managed through redispatching actions are the consequence of problems occurring earlier, ahead of time, which are not properly addressed by the current market design. In Europe, congestion management is actually based on a set of tools. First, there are mechanisms for transmission capacity calculation between pre-defined bidding zones (ATC-based or flow-based products) and, second, there are mechanisms for the allocation of transmission capacity at different time horizons, from year-ahead to intraday.[126]

[124] We assume here that all zero cost actions that TSOs can take in order to reduce the level of power flowing through congested network elements (e.g. changes in network topology via the coupling or decoupling of network nodes, changes in phase-shifting transformer taps, etc.) have already been implemented.

[125] Exceptions are represented by Norway, Sweden, Denmark and Italy.

[126] In the long run, investments on the transmission network and in generation down the congested lines can also solve the problem. For instance, the installation of phase-shifters at a border can help to manage cross-border congestions. This is what happened in the last few years between Germany and Poland.

It is then the 'market design' which nurtures operational constraints. Uniform pricing across large bidding zones creates unscheduled loop-flows and transit flows, while smaller bidding zones with borders more aligned with the congested lines reduce the need for cross-border redispatching actions because, in the latter case, markets are better equipped to take into account the physical limits of what the grid can effectively accommodate.

Nevertheless, better designed bidding zones do not fully eliminate the need for redispatching. First, because unforeseen events like sudden outages or changes in renewables output can trigger congestions. Second, because transmission capacity auctions between smaller and better configured bidding zones may not be optimal to deal with all the network constraints present in the European power system (Sadowska and Willems, 2013). Indeed, zonal pricing alone does not ensure that the available network capacity is entirely used and in the most efficient way, because market players do not have access to the whole physical details of the network topology and to the precise location of all alternative generators. Therefore, a combination of zonal pricing with properly defined zones and limited redispatching can provide a more efficient allocation of resources and welfare maximisation.

It is often extremely difficult and sometimes impossible in practice to distinguish between national and cross-border redispatching.[127] This happens because the European power grid is highly meshed, at least in the CWE and in the CEE areas, and congestions occur mainly on 'internal' lines due to intermingled internal and international power exchanges (Duthaler, 2009).

The difficulty of assessing the origin of many congestions and, as a result, the impossibility of identifying in a thorough and systematic way who is 'responsible' for them often prevents any meaningful discrimination between internal and cross-border redispatching. In turn, this makes the sharing of redispatching costs even more important and difficult to perform properly.

Currently, different methods are implemented to share cross-border redispatching costs.[128] In continental Europe, TSOs distinguish between cross-border redispatching actions required to relieve congestions on interconnections and cross-border redispatching actions required to relieve congestions on internal lines. For cross-border redispatching actions required to relieve congestions on interconnections, the current practice is to equally share costs between the TSOs on both ends of the line. However, this situation represents only a minority of cases. For cross-border redispatching actions required to relieve congestions on internal lines, the most frequent case in fact, the principle of 'requester pays' usually applies. According to it, the costs of remedial measures are paid by the TSOs who have asked other TSOs for assistance, regardless of whether they have or have not

[127] An exception is for parts of national networks that are organised as antennas. Consequently, cross-border flows cannot have an impact on them and the cause of a congestion can be more easily identified.

[128] ENTSO-E mentioned in 2012 that an agreement on the sharing of cross-border redispatching costs had been decided for 65% of inter-TSOs borders and that similar agreements were under discussion for an additional 10% of borders (ACER & ENTSO-E, 2012).

caused the problem (Vukasovic and Vujasinovic, 2014). However, to our knowledge, it is not mentioned anywhere how the costs of remedial actions resulting from proposals suggested by RSCs like Coreso or TSC are allocated (in these cases the need for redispatching is not flagged by a single TSO but by the RSC and the 'requester pays' principle cannot be applied).

In the Nordic power system, a distinction is made between the actions taken day-ahead and the actions taken in real time. The cost of actions taken day-ahead is borne by the TSO that takes the decision. As for cross-border redispatching actions decided intraday or in real time, a further distinction is taken between actions to manage flows on interconnections and actions taken to manage flows on internal lines. For congestions on interconnections between bidding zones, cross-border redispatching costs are shared between the TSOs according to the *"average market price of the two bidding zones [involved]"* (ACER & ENTSO-E, 2012). For congestion within a bidding zone, the respective TSO bears the full technical, financial and operative liability for countertrading, meaning that each TSO bears the costs of countertrading (ACER & ENTSO-E, 2012).

Given the variety of methods for the allocation of costs, it is important to question the incentives such methods provide to i) manage efficiently and reliably the power flows in real time with redispatching; ii) manage efficiently and reliably the power flows before real time by offering adequate cross-border capacity for market exchanges; and iii) invest adequately in cross-border transmission capacity in the long run.

About the first two points – i.e. the efficient and reliable management of power flows in real time with redispatching and the provision of adequate cross-border capacity for market exchanges – the efficiency of the cost sharing methods currently in use is questionable.

As for the cost sharing of redispatching actions in continental Europe, it incentivises TSOs to wait until the last minute to request coordinated actions for relieving internal constraints. The logic behind it is quite simple. By waiting, it may happen that another TSO faces a stronger constraint on its grid and makes the request first: in this case the payment for the remedial action is going to be borne by that TSO. However, such logic is risky and consequential for the whole interconnected system, because waiting until the last minute may make it more difficult to find adequate solutions to relieve the congestion or to deal with other, subsequent, congestions that may result from the management of the first one.

A similar problem exists in the cost sharing method applied in the Nordic area, because any redispatching action <u>before real time</u> is to be managed by the country where the constraint is appearing. In addition, TSOs have the incentive to change the transmission capacity they offer for market transactions, because by doing so they influence market prices and the way redispatching costs are shared <u>in real time</u> (history shows that this kind of incentive exists both in theory and practice, Glachant and Pignon, 2005). Due to these inefficient short-term incentives in the current Nordic sharing scheme for cross-border redispatching costs, TSOs do not receive efficient economic signals for investment in network interconnections.

4.2.2 Why wasn't it tackled before?

The issue of how to share cross-border redispatching costs has not yet been tackled for a series of reasons of different nature: technical, organisation, institutional, legal and political.

First, from a technical point of view, the implementation of cross-border redispatching actions on a large scale is quite new. Coreso and TSC, the two Regional Security Coordination Initiatives (RSCIs) launched in 2008, began to perform security analysis close to real time in 2009. Coreso mentioned already in 2010 that *"[it] has been able to propose coordinated actions that were less costly than the solutions foreseen by individual TSOs [in 2009]"*, while TSC started to test multilateral redispatching actions in 2012. Multilateral redispatching actions did not just appear only six years ago, but at the beginning they were implemented with much less intensity than now. To have an idea of that, it is enough to say that stressed or highly stressed situations occurred only 11% of the time in the CWE area in 2009. Such a number was three times bigger in 2015. Similarly, in the Central South Europe area (CSE) stressed or highly stressed situations occurred 24% of the time in 2010 and 34% in 2015. The frequency of coordinated redispatching is increasing so much, that it makes the issue of reshaping the methods for redispatching cost sharing increasingly significant (Marinescu et al., 2005).

Until quite recently, redispatching actions were mainly used at national scale only, while they are now increasingly implemented at cross-border level too. This is because cross-border interconnection capacity in the past, even if in some cases frequently saturated, was adapted to the generation portfolio. Its location was inherited from the previous era of vertically integrated companies, exchanging energy through long-term cross-border contracts. However, since the beginning of the liberalisation process, cross-border exchanges of power have increased and the network assets have been used closer to their technical security limits. Besides that, the European generation portfolio and its location have changed dramatically in recent years, in particular due to the large and swift deployment of RES, which now represent the main driver of network expansion in Europe (ENTSO-E, 2016). Until the new wave of grid assets planned or under construction become operational, the European power network will not be adapted to the generation portfolio and the power system will remain difficult to manage. Unscheduled flows (loop flows and transit flows) and the resulting constraints on the network have already become more frequent. Since it is almost impossible to manage congestion resulting from unscheduled flows at national scale, the need for coordinated actions among TSOs has become more apparent and so too does the issue of sharing the ensuing costs.

Second, the question of sharing redispatching costs is also difficult to tackle from an organisational point of view. Public debate often mixes the market and the technical operation of the power system and there is confusion between the methods and responsibilities to solve market operation issues on the one hand and technical operation issues on the other.

In addition to that, the matter of cross-border sharing of the redispatching cost encompasses a large number of TSOs (seven TSOs in Coreso and 13 in TSC). It is clearly more difficult to find a consensual solution to move from the status quo with such a high number of actors involved. Moreover, until quite recently the redispatching costs to be shared were limited and some TSOs thought it was not a priority to modify their sharing rules (see for instance, ČEPS, 2011), despite being aware of the poor incentives as a result (Vukasovic and Vujasinovic, 2014). An essential question of governance then emerges about the definition of cost sharing mechanisms. Governance should be such that it avoids deadlock, e.g. a situation where each TSO has a veto right and can block the whole decision process. Nevertheless, without more details on this point, one could expect that individual veto is the default rule for the moment.

Third, the redistributive impact of changing the sharing rule of cross-border redispatching costs represents an institutional barrier. Real or expected losers will oppose such change and will be able to block it, as far as the governance is based on the veto rights of a country or zone.

From an institutional point of view, the lack of any accurate and neutral measurement of cross-border redispatching costs can also be a problem. Since it is difficult, if not entirely impossible, to distinguish between national and cross-border redispatching, it is then obviously demanding to correctly allocate the associated costs.

Due to the uncertainty of the measurement of redispatching costs, the impact of changing the sharing rules cannot be determined with precision as well, i.e. the share of costs borne by the different TSOs is unclear and can only be roughly estimated. As a consequence of that, inaction prevails and current sharing rules are maintained. Even more worrying is the fact that such rules are not questioned anymore, despite their drawbacks being well known.

Fourth, the existing legal framework helps to explain why the sharing of cross-border redispatching costs has not been tackled until now. Indeed, the responsibility of each TSO is defined only at national level, either for balancing or managing power flows. For the moment, there is no strong European regulation framing the obligation of TSOs at a regional or European level, although power flows on the European network are cross-border by nature from a physical and economic point of view.

From a legal point of view, it has to be noted that existing EU legislation does not seem to be well applied to this specific case, thereby contributing to the currently blocked situation. Indeed, the 2009 electricity Directive states that regulators shall cooperate to improve the functioning of the internal energy market. Applied to the present issue, the principle affirmed in the Directive would imply that national regulators have to find ways to share the associated costs. Unfortunately, they did not do that and the issue is still pending.

Fifth and finally, a political barrier can also explain why the question of sharing cross-border redispatching costs has not yet been confronted. The issue is potentially a political hot topic because it implies an agreement on cross-country payments. From the past experience of the Inter-TSO Compensation (ITC) scheme or the more recent debate on the Cross-Border Cost Allocation (CBCA) of Projects of Common Interests (PCIs), one should be aware of how difficult this kind of mechanisms are to agree upon and how difficult it is to make them evolve (see for ITC Pérez-Arriaga and Olmos, 2009 and see for CBCA Meeus and Keyaerts, 2014).

This barrier is augmented by the absence of clear measurements of cross-border redispatching costs. They are published neither in an aggregated manner nor in a disaggregated one (some TSOs do provide some pieces of information like, for instance, the cross-border redispatching cost in Finland and France[129] or the volume of cross-border redispatching in the TenneT control zone[130]). It is obviously difficult – if not entirely impossible – to discuss rationally something that is not accurately measured. The issue is then open to interpretation and anyone can have a legitimate concern that anyone else will try to force her to pay more for cross-border redispatching than is justified. This fear can be conveyed by TSOs or by regulators: in the context of incentive regulation, every slice of cross-border redispatching costs paid by foreigners contributes to seemingly reduced domestic costs.

From a political point of view, the redistribution of cross-border redispatching costs according to some explicit rules may even sound contradictory, because historically redispatching costs used to be socialised at national level (this has usually been done through network tariffs, mainly paid by electricity consumers, hidden behind national market design rules or managed through a limitation of cross-border exchanges). The decision to socialise those costs was in line with the traditional assumption that national grids should be considered as a copper plate, thereby facilitating electricity trade, and in line with the political idea spread in Europe that electricity is a public service that everybody should have access to under the same conditions, whatever the location within national borders (think of remote islands for France or Spain).

Finally, from a political point of view, cross-border redispatching costs should not even exist. Indeed, while building the European market, it was thought that cross-border congestions would have been managed through market mechanisms alone (auctions, market coupling, etc.). However, this is not a panacea from a technical and an economic point of view. Without political acceptance of the existence of cross-border redispatching, it then seems difficult to open a sound discussion on sharing the associated costs.

4.2.3 Is it a roadblock?

The failure to solve the issue of cross-border redispatching actions and the sharing the associated costs is blocking the building of the IEM for three reasons: system reliability, coordination or even governance, as well as in terms of cost sharing.

[129] See the RTE webpage dedicated to redispatching, countertrading and associated costs https://clients.rte-france.com/lang/an/visiteurs/vie/redispatch_countertrade_and_costs.jsp and the Fingrid webpage dedicated to countertrade http://www.fingrid.fi/en/electricity-market/market-integration/countertrade/Pages/default.aspx.

[130] See TenneT (2015).

First, ‘management of network constraints’ is by nature essential for the European power market, in particular as a matter of reliability. Redispatching, whether implemented at national or at cross-border scale is the last resort to relieve network constraints, thereby it is indispensable for the successful functioning of the IEM.

Second, ‘dealing with redispatching actions’ raises a matter of cross-border coordination, in a bilateral and multilateral way. In this regard, TSOs have already been tackling the issue for the past several years through the development of the RSCIs. At the same time, other topics related to the management of network constraints must addressed at a fundamental level in order to unlock transmission congestion and make the European power system as seamless as possible. Focusing on redispatching actions, one should not forget that part of the congestions in real time result from poorly defined bidding zones (either due to short term and infrequent constraints or to more structural ones) and flexible resources (demand-response or curtailment of RES) that are not fully utilised. These issues must also be treated in order to foster the integration of European electricity markets and increase competition through a network more efficiently used. These issues thus raise the matter of coordination. To a greater extent, they raise the issue of governance, because dealing with them requires revamping some of the national market designs and making them converge toward a common target model.

The *third and last* reason that makes cross-border redispatching actions a roadblock in the project of a more efficient European system is the question of how to share the costs related to congestion management as a whole. It concerns obviously the question of how to share redispatching costs, since redispatching actions are implemented to solve congestions. But it is also linked to the redefinition of bidding zones, because it modifies how the costs of cross-border network constraints are shared day-ahead and intraday through differences in energy prices. It is also related to cross-border cost allocation of network investment and existing transmission assets. Sharing these costs may be perceived only as a matter of equity between the users of the European power network and the allocation of congestion and network costs. However, the allocation of these costs provides key incentives for generators and consumers to use the transmission network in a more or less efficient way. And more importantly, it also incentivises TSOs in the way they manage the network, providing transmission capacity to the market and network users, and in developing the network itself in the long term. Considering the central role of the TSOs in power flow management, such incentives must be designed with care to ensure efficient power flow management, the provision of capacity to the market and network development. Unfortunately, as we have seen in section 4.2.1, the current sharing rules of cross-border redispatching costs provide inefficient and even counter-productive incentives to TSOs. Changing the rules on how to share cross-border redispatching costs should then provide better incentives to manage congestion as a whole. Consequently, better defined bidding zones and cross-border cost allocation would then increase available transmission capacity and make it more reliable.

4.3 Capacity adequacy and crisis management

4.3.1 What's the issue?

When a TSO faces a situation that is too risky to cope with because the load is too high compared to available generation, electricity markets might stop working properly and *crisis management* rules are to be called upon to avoid an overall blackout. It is a last resort solution that bypasses the market economic rationale (Joskow and Tirole, 2005), to go straight to capping demand with load shedding or shedding only those consumers with a confirmed low willingness to pay (interruptible consumers). In order to limit the frequency of load shedding to an acceptable level given the estimated value of lost load, *capacity adequacy* must be monitored from a system-wide perspective, i.e. someone has to monitor if generation and demand response capacity in the system is able to cover the higher levels of the non-flexible load in the system.

Since power systems were built at national scale, crisis management plans have been defined at this scale as well and have not been not harmonised at the European or even regional level, despite the fact that today national systems are deeply interconnected and interacting. Consequently, one could expect crisis management at European level to be not fully coordinated (yet). This was particularly illustrated by the Europe-wide partial blackout that occurred in 2006. Since then, even if ENTSO-E (2010, 2015) has pushed toward a convergence of crisis management with a first document in 2010 and then with the Network Code on Emergency and Restoration currently under Comitology review, nevertheless, a lot of country variations are still possible in designing national crisis management schemes. This variability and the lack of coordination/harmonisation in turn impacts particularly upon the geographical distribution of load shedding and is likely to keep it uneven (De Boeck & Van Hertem, 2014).

Increasingly, there are widespread concerns on capacity adequacy and risk of crises due to supply shortage. However, these concerns are limited to some national situations and do not cover the whole of Europe. Nevertheless, with interconnections and market coupling ensuring that power flows toward the areas with the highest price, in particular in the case of supply scarcity, capacity adequacy issues are no longer national and may also concern neighbouring countries. Moreover, because of interconnections, two countries could simultaneously experience capacity shortage and may not be able to easily rely upon each other. Indeed, EU network codes give the right to a TSO to curtail cross-border transactions, if it faces an emergency situation in its control area (see Box 4.1). Hence, a TSO could first experience an emergency situation, curtail cross-border transactions to solve its internal problems, and in this way trigger an emergency situation for one of the neighbouring TSOs.

Box 4.1: Treatment of cross-border transactions in emergency situations

The Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (ACER, 2011) states that: *“The CACM Network Code(s) shall provide that curtailment of cross-zonal transactions is applied only in emergency situations and ensure that the affected TSOs avoid any discrimination between the different types of commercial exchanges, between the relevant time frames and between exchanges internal to countries and cross-border exchanges”*.
Besides, article 12 §1 of the Network Code on Emergency and Restoration specifies that: *“Each TSO upon request from a neighbouring TSO in Emergency State shall provide through Interconnectors any possible assistance to the requesting TSO, provided it does not endanger the Operational Security of its Transmission System or of the interconnected Transmission. This assistance includes, but is not limited to, a curtailment of Cross Zonal Allocated Capacities”*.
Article 12 §3 also mentions that *“each TSO shall announce and duly prepare any manual opening of an Interconnector in coordination with neighbouring TSOs, respecting that this action will not endanger the Operational Security of the remaining interconnected Transmission System”*.

Whether capacity shortage is experienced in one or several interconnected countries at a time, coordination is essential to manage this kind of stretched situation.
As a preliminary step, before considering and providing solutions, it is fundamental to have a metric of capacity adequacy. Such a metric, or even several ones, generally exist at national level and the one(s) used is most often not harmonised across Europe (AF Mercados EMI et al. 2016). For instance, in France, the power system has a target of a 3-hour loss of load expectation (LOLE), meaning that capacity adequacy must be guaranteed throughout the year except for 3 hours at maximum. Belgium, the Netherlands and Norway rely on a similar metric but specifically focused on critical situations. They then target the number of hours during a very cold winter, happening once every twenty years, during which the load cannot be covered by available generation and demand response capacity. In Great Britain, capacity adequacy was defined by capacity margin, but the UK Department of Energy & Climate Change has more recently underlined that such metric is not appropriate for security of supply, because it does not sufficiently take into account the intermittency of renewable generation.
More than the metrics, until a few years ago there was no common methodology to assess the adequacy of individual EU power systems and the adequacy at regional or European level. However, the situation is changing: since 2013 the TSOs in the Pentalateral Energy Forum (covering seven countries: Austria, Belgium, France, Germany, Luxembourg, the Netherland and Switzerland) have worked together and develop a common methodology to assess adequacy, taking into account interconnection capacity, even if only in a simplified way (PLEF TSOs, 2015). ENTSO-E (2016) has relied on the same methodology to assess capacity adequacy

at European level. Consequently, if the issue of building common metrics and methodology was a problem in the past, the TSOs and ENTSO-E now have to continue to refine those metrics and methodology in order to better include in their analysis i) transmission capacity among countries and ii) concerns about flexibility resulting from the massive integration of RES in the power systems. Diffusion and acceptance by the stakeholders must also be pursued.

The lack of capacity adequacy, i.e. the lack of generation and demand response to cover peak load, is currently addressed as a national problem, even if it can span neighbouring countries. For instance, during the winter 2016-17, Belgium, France and Italy in Western Europe, and Bulgaria, Greece and Romania in South-East Europe experienced tight situations.

Some countries have hence been considering the introduction of or have already introduced capacity remuneration mechanisms (CRMs) to foster generation and demand response investments and bridge the perceived capacity gap.

One can notice a wide diversity of mechanisms (European Commission, 2016). For instance, capacity payments have been existing in Spain, Ireland and Portugal for a decade or more. A capacity market has been introduced in France in 2016. Capacity auctions have been implemented in Great Britain in 2015 and Italy is expected to do the same in 2017. Strategic reserves have been implemented in Sweden and Finland since the mid-2000s, in Belgium since 2014 and in Denmark since 2016. Germany has also introduced a regional strategic reserve to cope with North-South network constraints and is considering the introduction of a country-wide strategic reserve as of the end of 2017. The introduction of CRMs at national level reflects the widespread belief that capacity adequacy is an issue better addressed at national level rather than from the regional or European dimension, despite the fact that national power systems are today interconnected and interdependent.

The development of such mechanisms has been all the more tempting as the European power system has experienced several years of decreasing and low prices, hampering market-driven generation investments. As a result, there is a general suspicion that capacity remuneration mechanisms may be implemented to subsidise national generators, especially as cross-border resources are generally not allowed to benefit from these mechanisms. Such a pattern will result in inefficient investments and will possibly lead to generation overcapacity.

4.3.2 Why wasn’t it tackled before?

Different reasons – technical, organisational, institutional and legal ones – explain why the issue of capacity adequacy and crisis management schemes has not been confronted in the past at an earlier stage.

First, there are technical reasons. In this regard, the key issue is the lack of a common definition of security of supply. Indeed, with no common language, it was difficult for TSOs and regulators to openly and widely discuss this topic. In the past, each country was using its own metrics to measure security of electricity supply (frequency of load shedding, amplitude of main load shedding event, average

capacity margin or capacity margin in a crisis situation, etc.). It is often impossible to simply translate one of them into the other and to easily compare the situation of the various countries, because those metrics often measure different aspects of security of supply and, as a result, are not interchangeable. It is by finding and defining common metrics that a concrete discussion on this topic can start.
A *second* technical reason relates specifically to the nature of electricity crises. Fortunately, such crises are very rare; however, it is then difficult to test alternatives and to improve existing crisis management schemes on a "learning by doing" basis. It is always possible to assess the impact of different combinations of national crisis management schemes by using computational tools, but the absence of any concrete and immediate impact makes the matter less urgent for the policy-makers, although it is imperative one. The major disturbance experienced by the European power system in 2006 confirms this tendency. It is only after that event that a convergence of crisis management schemes was acknowledged as necessary. While TSOs at ENTSO-E did work on it, confronting the harmonisation of national crisis management schemes, considerable freedom is still in place, as for the activation of load shedding in the case of extreme events. While crisis management schemes are, of course, a very technical issue, we may face the scenario where some countries are not addressing their own capacity adequacy, in contradiction with their neighbours at regional or European level. A better regulatory and governance framework is hence needed to reconsider the crisis management schemes and to coordinate them in order to come up with the best possible solution at regional or European level.
Third, these first two technical reasons raise an organisational concern, which also explains why this problem was not tackled before. Indeed, changing existing habits on such a technical topic as crisis management is a very long and demanding process. And different TSOs do not face with the same strength the same issue at the same moment, resulting in some 'losers and winners' from the process. As a consequence, the convergence process of national crisis management schemes can be slow, because TSOs have to negotiate among themselves what to change and when to change in order for most of them to belong to the 'winners' category.
A *fourth* technical and essential reason why capacity adequacy was not previously addressed at European level is that it is not a concern which affects the whole of Europe in the same way, but only some of the Member States and with different (specific) problems. This naturally fosters a 'nationalistic' point of view on the issue. Indeed, France is lacking peaking units and Great Britain firm base load units; Germany has been missing capacity in the South, while Italy needs flexibility to cope with variable RES. Since it is not the same and unique concern for all European countries, it is understandable that capacity adequacy became a relevant European-wide topic only once the European Commission and some stakeholders had noticed that interaction with the internal market and cross-border participation to CRMs were an issue.
From an economic point of view, the issue of capacity adequacy and crisis management at European level was not previously confronted and the economic

literature on the topic is recent. For example, Finon (2015) raised the question of capacity adequacy but with no concrete solution, neither to integrate interconnection in capacity adequacy assessment nor capacity remuneration mechanisms. Mastropietro (2016) showed the challenges for cross-border participation to capacity remuneration mechanisms. Besides, practitioners like CEER (2016), Roques (2016) or Frontier Economics (2014) investigated how cross-border participation can be implemented in capacity remuneration mechanisms. With no solid theoretical basis, coping with capacity adequacy at regional level is still challenging.

Fifth and lastly, the main reason why capacity adequacy and crisis management were not tackled before is legal. Indeed, the European Commission has not developed significant direct power concerning national security of supply, at least in terms of market design. Security of supply is usually part of the national remit. Market design targeting security of supply at European level has only been addressed by the European Commission on a case-by-case basis with already available tools, mainly State aid and competition law to force the Member States to change the rules of their capacity remuneration mechanisms; or with its 'sector inquiry' to provide guidance for designing future mechanisms (European Commission, 2016). With such 'DG Competition' tools, it is difficult to have in-depth modifications of market rules ending in a harmonised EU market design (De Hauteclocque and Glachant, 2009).

Capacity adequacy and crisis management are obviously a matter for the internal energy market. When they are not considered at European level, they can block the IEM with national tropism and some kind of protectionism on national assets. The 2009 electricity Directive has already stated that regulators shall cooperate to improve the functioning of the IEM. However, this has not yet been faced from the point of view of capacity adequacy and crisis management.

4.3.3 Is it a roadblock?

The absence of a European field for capacity adequacy and crisis management is a roadblock for the building of an integrated power market, because a true and equitable level of European solidarity is missing, which is also hampering generation and demand response investments. Management of disruption remains uneven. Besides, even if the Network Code on emergency and restoration has already been drafted, the management of cross-border contracts by countries experiencing shortage is still uncertain, because appreciation is still open in the code on the target level of security of supply and on the governance to set it and determine the crisis management. The uneven development of capacity remuneration mechanisms shows that national thinking and management still prevail when it comes to capacity adequacy, while the recent events of winter 2016/17 made clear that it is rather a regional issue.

In terms of coordination, non-harmonised national remuneration mechanisms also risk generating a major delay in building the European power market, while the day-ahead and intraday markets are more and more integrated and progress in harmonising and integrating the balancing markets is also already underway. Investment may then be far more incentivised in some markets than in others (even if more investment incentives are indeed generally needed). Besides, the tight situation recorded this winter shows that some countries are still tempted to have a nationally oriented crisis management policy (e.g. in South-East Europe), potentially triggering adequacy issues in interconnected power systems.

In technical terms, the historical problem of a lack of common language and methodology to assess adequacy was a blocking point, but it can be progressively overcome as shown by the Pentalateral forum or the last mid-term capacity assessment by ENTSO-E. It will help the whole EU to have a better view of the actual available capacity which fully takes into account access to interconnection.

4.4 Table summary

This chapter is summarised in the table below, fisrt detailing (second column) the issue for each of the two topics discussed (redispatching actions as well as capacity adequacy and crisis management), then (third column) the different reasons that explain why these topics were not fully confronted in the past and, lastly, the reasons why they represent roadblocks on the path toward the building of a more efficient and integrated Europe-wide power market.

Table 4.2: Summary of the findings.

	What's the issue?	Why wasn't it tackled before?	Is it a roadblock?
Roadblock 1: Dealing with re-dispatching actions	Difficult distinction between national and cross-border redispatching. Cost sharing rules sending inefficient incentives. A set of other solutions to manage congestion: investments in interconnections, market design (bidding zones) and allocation of transmission capacity.	Technical: quite a recent problem. Economic: debate mixes market and technical operation. Organisational: governance adapted to such a big number of TSOs to find a consensus. Institutional: redistributive impact of changing the rule/lack of measurement of cross-border redispatching costs. Legal: national liability of TSOs + no definition of liability at the European level + lack of cooperation of regulators to improve IEM regarding cross-border redispatching actions under the umbrella of the 2009 Directive. Political: difficult to find an agreement on cross-border payment/perception that redispatching is only a national matter.	Security of supply: redispatching is a last resort action to relieve network constraints... Coordination: … requiring coordination at European scale. Cost sharing: a central point in the discussion of congestion management (for stakeholders' incentives and redistributive impacts) as a whole, while it is a cornerstone of the European market to foster competition.

	What's the issue?	Why wasn't it tackled before?	Is it a roadblock?
Roadblock 2: Capacity adequacy and crisis management	Historically national building of network and design of capacity adequacy policy and crisis management schemes. Concerns on capacity adequacy and risk of crises only perceived at the national scale and lacking the regional or European stake. National answer to the problem (in particular in the form of capacity remuneration mechanisms).	Technical: lack of common measure and methodology until recently / rare crises making any harmonisation seem less urgent. Organisational: difficulty to change habits on a hot and risky technical topic. Economic: possible 'losers and winners' if changes required because habits may have to be changed / weak economic literature on these topics. Institutional: National thinking on these issues. Legal: No or limited direct power of the European Commission concerning security of supply + lack of cooperation of regulators to improve IEM regarding cross-border assessment and management of capacity adequacy under the umbrella of the 2009 Directive. Political: acceptability of shared capacity adequacy and crisis management.	Solidarity: a true European and equitable solidarity is missing. Coordination: IEM stepping back with national capacity remuneration mechanisms and nationally oriented crisis management triggering adequacy issues in interconnected power systems.

Chapter 5 – Recommendations to handle the roadblocks

Executive Summary

To illustrate how to handle the roadblocks represented by redispatching actions, or by capacity adequacy and crisis management, Chapter 5 provides seven broad recommendations. They tackle the core 'missing pillars' identified in the first part of the report. Our recommendations are not comprehensive and ultimate technical solutions to those issues. We identify instead a few key tasks and then suggest entities that can best perform them.

Redispatching actions are currently hindering progress in the Europeanisation of the electricity sector due to the inadequate coordination between market and system operation. As a 'coordination issue', TSOs shall then assess and periodically review the efficiency of the bidding zone configuration for the day-ahead and intraday electricity markets and its ability to reflect structurally congested lines. In case such configuration proves to be inadequate, a redrawing of the zones shall be undertaken by the TSOs at the ENTSO-E level. NRAs shall oversee the process.

However, the TSOs gathered in ENTSO-E are 'technical experts' that can deliver the best coordinating mechanisms needed by the European power market and system only if national governments and NRAs agree on the 'sharing issue', by defining a framework for sharing the resulting costs and benefits. If no sharing framework is agreed among countries and NRAs, the TSOs alone could hardly unlock the current situation.

A common methodology for cost calculation and cost allocation is also required to cope with the economic implications of redispatching actions and foster cooperation among TSOs at the bilateral and multilateral level. NRAs shall develop this common methodology within ACER, ensuring fairness and efficient signals for the TSOs. Member States shall support the process and avoid blocking it because of conflicting national objectives.

Capacity adequacy and crisis management too are obstructing the integration process because each Member State tend to adopt a national approach and to lack trust in its neighbours when security of supply is at stake. Coordination is limited and even solidarity is too rarely implemented. Therefore, the development of a common methodology for assessing capacity adequacy and valuing it cross-border is an important step to improve transparency and trust, hence making coordination easier to implement. TSOs shall be responsible for the definition of such methodology at the ENTSO-E level. Once the methodology is adopted, Member States and the European Commission shall use it to assess the need for capacity remuneration mechanisms at the regional or national level.

During a crisis, 'every man for himself' is the rule often followed by the Member States. However, closing borders usually worsens the situation and further reduces trust between countries. When a shortage of electricity occurs, Member States should rather show solidarity and help each other.

In particular, if the crisis affects a single country, neighbouring Member States shall have a legal duty to provide support by granting full access to their own domestic resources at market prices. Transactions shall not be curtailed, even if this implies price spikes in the countries providing help. On the contrary, if the crisis affects several countries at the same time, then the affected TSOs of those countries shall be in charge of managing the situation under the supervision of the NRAs, pooling and coordinating the available resources in order to minimise the risk of blackouts and the impact on the most vulnerable consumers. Emergency plans, based on rules for solidarity agreed by the Member States, need to be prepared in advance at the multilateral level.

The above recommendations must be clearly specified in EU legislation, providing in this way some answers to the long pending questions illustrated in the first part of the report. Other recommendations are possible as well, but our report does not address them, as it does not address the legislative proposals published in late 2016 by the European Commission. It is up to the numerous practitioners, decision-makers, or even scholars, to do that and demonstrate – from their point of view and interest – what is missing and what could be done to further the integration of European power systems in the context of the decarbonisation and the digitalisation of the energy system.

5.1 Introduction

The first part of the report considers some basic questions that have not been properly addressed in the past two decades. The lack of or the inadequate answers provided by the European energy policy reveal the weakness of three pillars, which are essential for the construction in Europe of an internal market for electricity, able to foster the transition towards a low-carbon economy and to embrace the current digital revolution. These pillars, detailed in Chapter 1, are: the coordination of actions and decisions, the sharing of costs and benefits, and solidarity beyond costs and benefits (see Fig. 5.1).

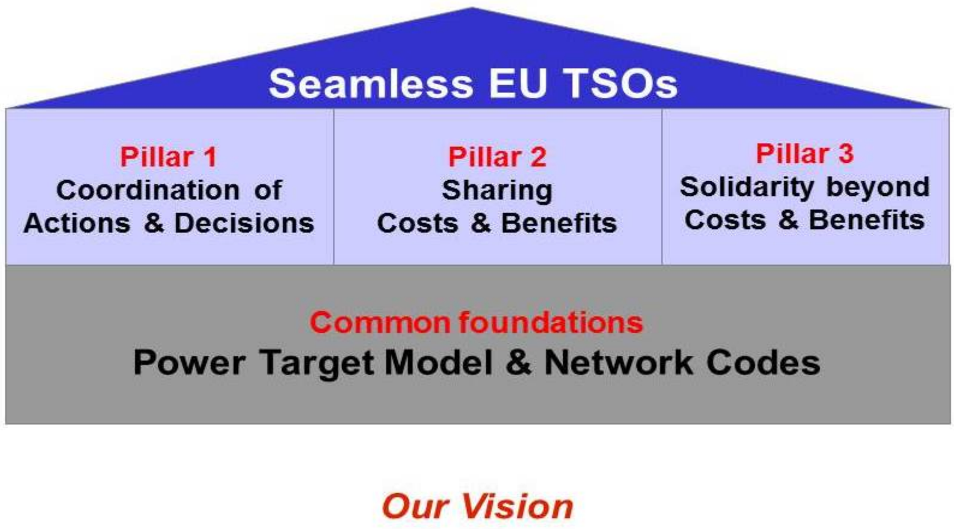


Fig 5.1: Diagram of the missing pillars

Chapters 2 and 3 then complement the first part of the report by providing an overview of 12 blocking factors that stem from these unanswered questions which are hindering the completion of an efficient and effective internal market for electricity in Europe.

Based on that broad analysis, the second part of the report narrows the focus on two specific issues, which represent two roadblocks on the path towards the establishment of a truly Europeanised power market with seamless transmission system operation and operators. They gather together several of the blocking factors presented in Chapters 2 and 3 and are labelled in Chapter 4 respectively as:

1) dealing with redispatching actions;
2) capacity adequacy and crisis management.

The goal of this fifth and final Chapter is not to provide the ultimate technical solutions to those complex issues. It suggests rather a set of possible options and general recommendations for practitioners and policy-makers in the context of the current debate over the Energy Union and the Winter Package (Clean Energy for All Europeans), proposed by the European Commission at the end of 2016.

In order to provide such a set of recommendations on how to unlock what is currently blocking the Europeanisation process, reference is made to the framework defined by the three missing pillars and by the European Power Target Model. The latter emerged 'informally' in the past few years during the drafting of the Framework Guidelines and the Network Codes by ENTSO-E, ACER, the EC and Member States. It currently constitutes the common foundations of the internal market for electricity and is characterised by three key elements:

1) The definition of a Europe-wide merit order and an energy price equilibrium in the day-ahead market from bids made in organised power exchanges;
2) A simplification of the underlying physical infrastructure through the assumption that national grids can work as a copper plate or a small set of copper plates (bidding zones), where transmission capacity is efficiently allocated together with energy (implicit auctioning);
3) Reconciliation of the market outcomes and the physical needs at the balancing stage through redispatching and other remedial actions performed by the TSOs.[131]

The combined effect of these key elements is market coupling, i.e. the emergence of a single price for all European interconnected power systems, as long as no congestion occurs over interconnections or, in the case of flow-based coupled markets, over any defined critical network element of the interconnected systems. Such a single price is computed on the basis of the efficient use of both transmission and generation capacity and is theoretically able to adequately remunerate generation costs.[132]

This Chapter is structured as follows. Section 5.2 presents three possible recommendations for removing the first roadblock, i.e. '*dealing with redispatching actions'*. Section 5.3 then illustrates four suggestions to remove the second roadblock, i.e. '*capacity adequacy and crisis management'*. Finally, section 5.4 briefly concludes by summarising the previous sections and providing some additional comments and suggestions for further research.

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[131] Glachant J.M. (2016), Mapping the course of the EU "Power Target Model"… on its own terms, *EUI Working Paper RSCAS* 2016/23, pp. 2-3.

[132] Another element of the EU Power Target Model, as initially articulated by the EC, is the reliance on energy-only markets (EOM). However, as it is discussed in Chapter 3, there are several reasons for doubting that EOMs are enough to remunerate investment in generation capacity, especially after the massive penetration of renewables in the electricity mix. Therefore, despite the rather negative view of the EC, capacity remuneration mechanisms have been implemented or are under discussion in several European countries. For a discussion of energy-only markets as part of the EU Power Target Model and its ability to foster the transition towards a low-carbon economy, see among others Keay M. (2013), The EU "Target Model" for electricity markets: fit for purpose?. *Oxford Energy Comment*, OIES.

5.2 Recommendations to handle Roadblock One: '*Dealing with Redispatching Actions*'

The analysis in Chapter 4 shows that in the past years the frequency of congestions in the European power grid has increased and TSOs have resorted more often to remedial measures in order to preserve a secure functioning of the system. Redispatching of power plants, a curative measure for relieving grid congestions, has been particularly used in countries like Germany, Spain, the United Kingdom and Poland, at a significant cost for the system.[133]

The fast and large deployment of renewable energy sources, often characterised by intermittent generation, and the inadequacies in the way market and system operations are coordinated (e.g. the non optimal configuration of bidding zones) are considered to be the main causes behind the increased frequency of congestions and their less predictable dynamics and location, which require TSOs to intervene closer to real time operation.[134] In some cases, the slow pace of grid expansion, often due to local opposition and lengthy permitting procedures, is to blame as well. This is particularly relevant in areas where a lot of intermittent renewables has been connected. With transmission capacity lagging behind generation capacity developments, the physical constraints of the network become more apparent and market outcomes, based on the assumption that control areas work like a copper plate, are less sustainable.

Therefore, the analysis confirms that two of the three pillars identified in the first part of the report are actually missing and contribute to blocking the Europeanisation of the electricity sector. *Coordination of actions and decisions* is missing because players acting on wholesale power markets perform their transactions without properly taking into account the structural constraints of the physical grid (imperfect coordination between market and system operation).[135] *Sharing costs and benefits* is missing as well because there are currently few or no efficient and fair mechanisms in place for the allocation of the escalating costs generated by bilateral and multilateral redispatching actions. In turn, this worsens the issue of coordination, because the lack of a fair mechanism for sharing costs discourages the use of coordinated remedial actions which results in an increase in costs and a fragmentation of the IEM along the control zone borders.[136]

[133] According to the terminology adopted by ACER, redispatching, counter-trading and curtailment of allocated capacity are curative measures; changing grid topology is a preventive remedial measure instead. According to the data provided by ACER, the cost of redispatching (internal and cross-border) in 2015 alone has been larger than 2.1 billion euro (it was only around 1.3 billion in 2014). See ACER/CEER (2016), *Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015*, 2016, pp. 26-28. Anyway, it might be noted as well that electricity markets in some of the countries with the highest redispatching costs are among the most liquid in Europe, with clear advantages for market players and final consumers.

[134] *Ibid*.

[135] See section 1.2.1.2 of this report.

[136] The massive deployment of wind capacity in the North of Germany and the delay in the strengthening of the grid assets connecting the North and the South of the country are at the origin of

Given this state of affairs, the conceptual framework developed in this research report suggests three broad recommendations (see Fig. 5.2):

1) Reconfiguration by the TSOs of the bidding zones for day-ahead and intraday markets;
2) Definition of regulatory principles at European level for the adoption of the results of the bidding zone review;
3) Adoption by the NRAs of a common methodology for the calculation and allocation of costs.

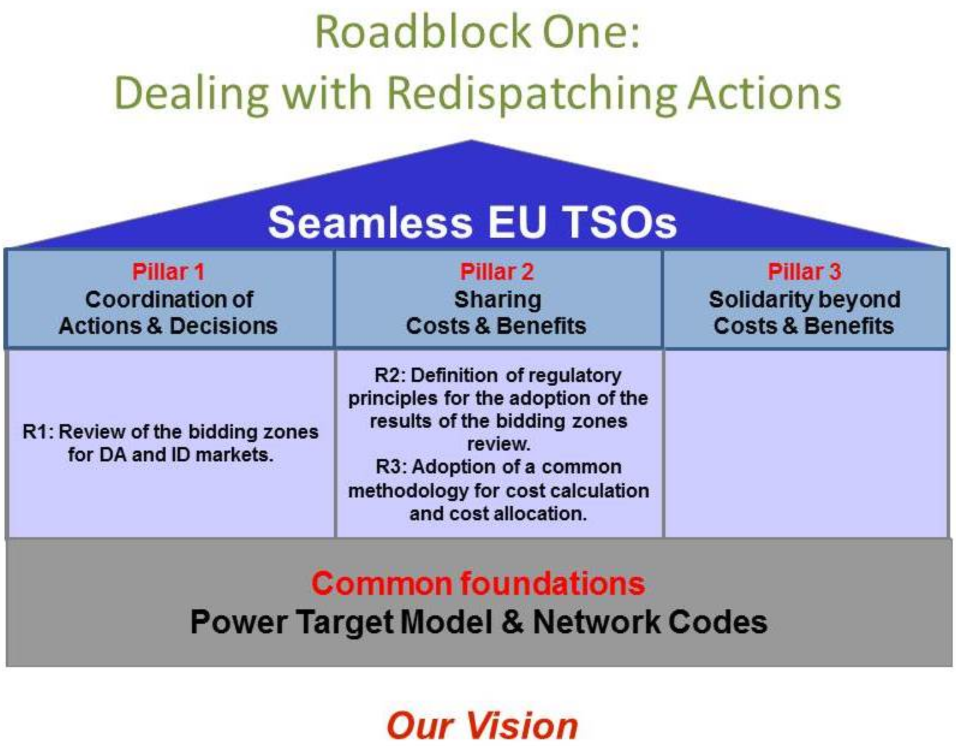

Fig 5.2: Recommendations to handle Roadblock One

5.2.1 Under the pillar of 'Coordination of Actions and Decisions'

As explained in the previous chapter, one of the deep-rooted reasons for the increased use of redispatching actions in Europe is the inadequate configuration of bidding zones for day-ahead and intraday electricity markets. The assumption that national grids are like a copper plate, where market players can sell and buy power almost without any restraint, is an essential element of the European Power Target Model. However, for a zonal market to work efficiently, bidding zones should not be structurally affected by internal congestions. Today, most of the European bidding

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significant unscheduled flows negatively affecting Poland and other central European power systems. The impossibility to find other satisfactory solutions led the German TSO 50Hertz and the Polish TSO PSE Operator to install phase shifters on the interconnections between Germany and Poland, providing the option to limit power overflows from Germany to Poland.

zones follow national borders, often hiding relevant bottlenecks to the flow of electricity foreseen by the commercial transactions executed in wholesale markets. Therefore, redispatching is indispensable not only to adjust the system to unexpected outages or errors in the forecast of load and generation by intermittent RES, but also to reconcile market outcomes with the flows that the grid can accommodate.

With better defined bidding zones, the result of market transactions would naturally be less alien to the physical reality of the grid and require less adjustment after gate closure.[137] That is why a first recommendation to deal with redispatching actions is to review the configuration of the bidding zones and redraw/split them whenever structural congestions are pointed out.[138]

The assessment and review of the bidding zone configuration must be undertaken at global level, as foreseen by the Network Code on Capacity Allocation and Congestion Management. TSOs and their European association ENTSO-E are particularly well positioned to carry out this review and eventually redraw the zone configuration so that it is more in line with the physical reality of the European interconnected grid. Indeed, since TSOs are in charge of system operation and security, they have a profound knowledge of how the network under their control works and where congestions usually take place. They have also developed models for simulating and forecasting energy flows under different conditions. Provided they work together at European level, it is difficult to think of a more experienced and competent entity for performing the bidding zone assessment and review.

Hence, the coming EU legislation should openly state the duty of TSOs to collectively assess and review the current bidding zone configuration and repeat such exercise periodically. As European technical experts, TSOs should be relatively free in performing this task, as long as they complete it within a reasonable period of time. ACER, it goes without saying, will have to monitor the progress of the reconfiguration by the TSOs from the point of view of EU regulation.

However, it is important to remember that a reconfiguration of the price zones is likely to produce significant consequences and have an economic impact on specific stakeholders. A power plant, for instance, could face a considerably changed competitive context, if included in a different bidding zone where the supply-demand

[137] As described in Chapter 2, the current physical reality of the power grid in Europe is, to a large extent, a legacy of the pre-liberalisation and pre-integration era. Besides, it is often not in line with the recent developments in generation capacity and is hardly adequate for the achievement of the EU decarbonisation goals in a cost effective way. Therefore, an optimal management of the current infrastructure is a first fundamental step to take, but it is not enough. In the long run, it is equally important to provide the right framework for the optimal expansion of the network. However, since the adaptation of the network requires a long period of time (from 10 to 20 years) and since some improvements on this issue have already been achieved (see Section 2.1), it is not a main focus of the recommendations presented in this chapter.

[138] A zone configuration subject to continuous changes has negative consequences for market operators, because it increases the uncertainty generators and buyers of electricity have to cope with. Therefore, the assessment and review of bidding zone configuration shall not be too frequent or triggered by modest and possibly temporary congestions.

balance is in favour of the latter. The same also applies to electric consumers, who could end up paying higher prices for energy. Besides that, there are still diverging views on how a change in the configuration of bidding zones impacts on the efficient use of infrastructure, on market liquidity and hedging, on market power and investment incentives. Finally, transition costs may be not trivial. This explains why the debate surrounding the issue of bidding zone configuration is politically sensitive and little progress has been achieved in the past couple of years.[139]

'Technical experts', as the TSOs gathered in ENTSO-E are, cannot legitimately take fundamental decisions like redefining the configuration of bidding zones in a vacuum of pre-defined rules to assess winners and losers, and to share costs and benefits among them. Such complementary rules are really 'regulatory principles' and not technical reasoning. That is why they have to be set by regulatory authorities or national governments, or both, with a loop with ACER Guidelines. The European technical experts at ENTSO-E need a clear 'regulatory framework', unlocking the present state of national 'costs and benefits sharing', sealed in the current structure of the European bidding zones.

To state this second recommendation descending from our analytical framework even more plainly, the pillar of 'coordination' cannot work well in complete separation from the pillar of 'sharing'. And since sharing is often a politically delicate issue, the involvement and backing by national governments and NRAs are needed. Indeed, national authorities have to agree at European level on a clear framework for sharing the costs and the benefits of reconfiguring the bidding zones. On the contrary, if national authorities block the European 'sharing' process at national level, then the quest for developing the best 'coordinating' mechanisms at European level may remain blocked as well.

5.2.2 Under the pillar of '*Sharing Costs and Benefits'*

In the medium to long term, the review of the bidding zones configuration, supported by a clear regulatory framework for sharing costs and benefits agreed by national authorities, could effectively treat one of the deep causes behind the problem of redispatching actions. However, such review does not provide any suggestion for coping in the shorter term with the immediate symptoms of the problem posed by

[139] In August 2012, ACER invited ENTSO-E to initiate a pilot project on the assessment and review of the bidding zone configuration. A Technical Report was published by ENTSO-E in January 2014, followed by a Market Report by ACER in March 2014. Based on those early results, ENTSO-E began in Spring 2015 an investigation on the technical and economic efficiency of the current European bidding zones, together with the possibility of splitting the German-Austrian single zone. The results of this study, initially expected by the end of 2016, are now due by the end of 2017. In the meanwhile ACER issued in September 2015 a non-binding opinion calling for the split of the German-Austrian zone. The opinion was appealed in November 2015 by the Austrian regulator E-Control but reaffirmed by ACER in Fall 2016. For more details see: ENTSO-E (2014), *Technical Report. Bidding Zone Review Process*; and ACER (2014), *Report on the influence of existing bidding zones on electricity markets*.

redispatching, that is the escalating costs borne by system operators in managing the grid and the way in which these costs can or should be shared.

As presented in Chapter 4, TSOs in Europe have discussed and sometimes agreed on how to share costs related to remedial actions at the bilateral or multilateral level. Unfortunately, partial or inadequate solutions have often been adopted, like those based on the 'requester pays' principle. Even the precise amount and distribution of those costs is currently not totally clear. As ACER underlined in autumn 2016, data on the volumes and costs of congestion related remedial measures in Europe are not complete nor easily comparable. Some NRAs do not provide such data to ACER or do not have it at all, while others make available information that is only partial or does not correspond to the same definition.[140]

This lack of data harmonisation and transparency is detrimental to the solution of the sharing problem, because it is clearly difficult to agree on a mechanism for cost sharing when there is no consensus on how to measure those costs and no generally accepted quantification exists at present.[141]

In addition to that, it is important to remember that TSOs are a regulated business and the recovery of their costs via grid tariffs has to be approved by national regulators. Therefore, a decision on the way to allocate redispatching costs to the different TSOs must involve the NRAs as well. Actually, given the right of NRAs to allow or disallow the expenses incurred by the TSOs, it is advisable that the NRAs are collectively in charge of the definition of harmonised mechanisms for sharing redispatching costs. The decision would be ideally taking place at European level to avoid issues of compatibility and harmonisation. In this respect, ACER is the proper entity to carry out this regulatory effort, because all NRAs are part of it and, in the case of initial diverging opinions, choices could be taken through a majority vote.[142]

Due to the growing economic relevance of the issue, NRAs should act with relative urgency and propose a methodology for cost calculation and cost allocation in the next year or two, possibly before the end of the bidding zone review process by the TSOs.

The mechanism for cost allocation should be fair, hence less politically unacceptable, and should provide sound economic signals to system operators, thereby fostering an efficient and effective use of redispatching actions. This is mostly not the case today because the cost of cross border redispatching and other remedial measures is usually redistributed on the basis of the 'requester pays' principle. The TSO calling for cross-border redispatch bears the costs of it,

[140] ACER/CEER (2016), *Op. cit.*, pp. 26-28.

[141] To be clear, redispatching costs are measured at national level in order to allow cost recovery for the TSOs. However, the way they are classified, aggregated and reported is not the same in every European Member State, so that it is at the moment impossible to know with precision their amount on a comparable basis.

[142] ACER is not the European regulator for energy but rather an entity for the discussion of and the decision on cross-border issues in energy regulation. Its role in this respect is to promote the convergence of regulatory solutions in Europe.

irrespective of its responsibility for the congestion that the redispatching action is intended to cope with. At first glance, principles like the 'polluter pays' should be followed instead, but they often present important practical limitations as well (who is the polluter? Why should it be the last one to use capacity?). In the everyday operation of the system it is not easy to understand the cause of a congestion, i.e. the identity of the polluter, and it is not easy even to distinguish between redispatching to cope with internal or with external congestions (it is possible to use internal redispatching to solve cross-border congestions and vice versa). Some form of cost socialisation could be an alternative and inevitable solution.[143]

However, it is not the aim of this report to identify or to define the best cost sharing mechanism to apply to redispatching costs. That is a task for technical experts (to propose or suggest) and for regulatory experts (to define, compare and, finally, to choose). What is relevant to stress at this point is that the Europeanisation of the electricity sector is blocked by the absence of such a methodology and that the best entity for taking a decision on it is the body of the European NRAs, i.e. ACER. Indeed, once a methodology for both cost calculation and cost allocation has received the regulatory backing by the European gathering of national regulators, increased cooperation among TSOs on redispatching actions is likely to follow swiftly.

[143] It is important to underline that cost socialisation does not necessarily imply solidarity. As it is explained in Chapter 1, solidarity should kick in only under extreme conditions, when normal market mechanisms do not work properly. Under normal conditions, general coordination and sharing principles are to be followed.

5.3 Recommendations to handle Roadblock Two: *'Capacity Adequacy and Crisis Management'*

The analysis in Chapter 3 and 4 illustrates that there is a growing concern in Europe for the capacity adequacy of electricity systems. Indeed, the relative decline in electricity consumption but not in peak demand recorded in the last decade and the massive subsidy-driven deployment of RES have led to a reduction in wholesale electricity prices. A drop in new investments in conventional generation capacity has followed, coupled with the retirement or the mothballing of several old or uncompetitive power plants, mostly running on fossil fuels and nuclear energy.

As a result of these trends, dependable capacity like that based on natural gas or coal is currently lower than it was up to four or five years ago.[144] Despite apparently wide reserve margins in overall capacity, quite a few European electricity systems do not appear to be fully adequate, especially when adverse weather conditions materialise (the January 2017 electricity shortage exemplifies it perfectly with critical situations in France, Belgium, Switzerland, Italy, Romania, Bulgaria and Greece). Several national governments, afraid of security of supply and possibly also concerned with the economic viability of their electric utilities, have introduced or are planning the introduction of capacity remuneration mechanisms (CRMs) next to the traditional energy-only markets.

Therefore, the analysis confirms that all of the three pillars identified in the first part of the report are truly missing and are blocking the creation of a single European power market with seamless transmission system operation and operators. *Coordination of actions and decisions* is missing because Member States tend to adopt a national approach to the issue of capacity adequacy. The establishment of uncoordinated national CRMs represents a significant change vis-à-vis the Power Target Model which emerged during the implementation of the Third Energy Package. It is a change, as many have suggested, with the power to distort and fragment the Internal Energy Market before it is fully completed. *Solidarity beyond costs and benefits* and the *sharing of costs and benefits* are also missing because, in times of crisis, Member States tend to adopt an 'every man for himself' approach, where they put their own interests first and limit or totally avoid to cooperate and help their neighbours in difficulty. This attitude does not promote trust and cooperation among Member States, eventually worsening the problem of coordinating actions and decisions: if a country will not show solidarity during a crisis, why should one of its interconnected neighbours consider capacity in that country while assessing its own capacity adequacy? And in a similar fashion: why should a country develop a CRM open to cross-border participation from another country that will curtail interconnection capacity during a severe shortage of energy?

[144] Between 2010 and 2014 installed capacity in the EU has increased from 883.9 GW to 977.7 GW (+10,6%). However, as also illustrated in Table 3.1, in the same time interval the amount of nuclear and fossil fuel fired generation capacity has decreased by 8.2 GW and 13.6 GW respectively. Preliminary data from an industry association (Eurelectric) confirm the trend for 2015, with significant amounts of nuclear and fossil fuel capacity either permanently retired or mothballed.

Given this background, the conceptual framework developed in this research report suggests four potential recommendations (see Fig. 5.3):

1) Adoption by the TSOs of a common methodology to assess capacity adequacy and to value it cross-border;
2) Recourse to the common methodology for assessing the need of CRMs;
3) Provision of full access to neighbouring resources under market conditions when a crisis affects a single Member State;
4) Coordination and sharing of scarce available resources by TSOs during multilateral crises.

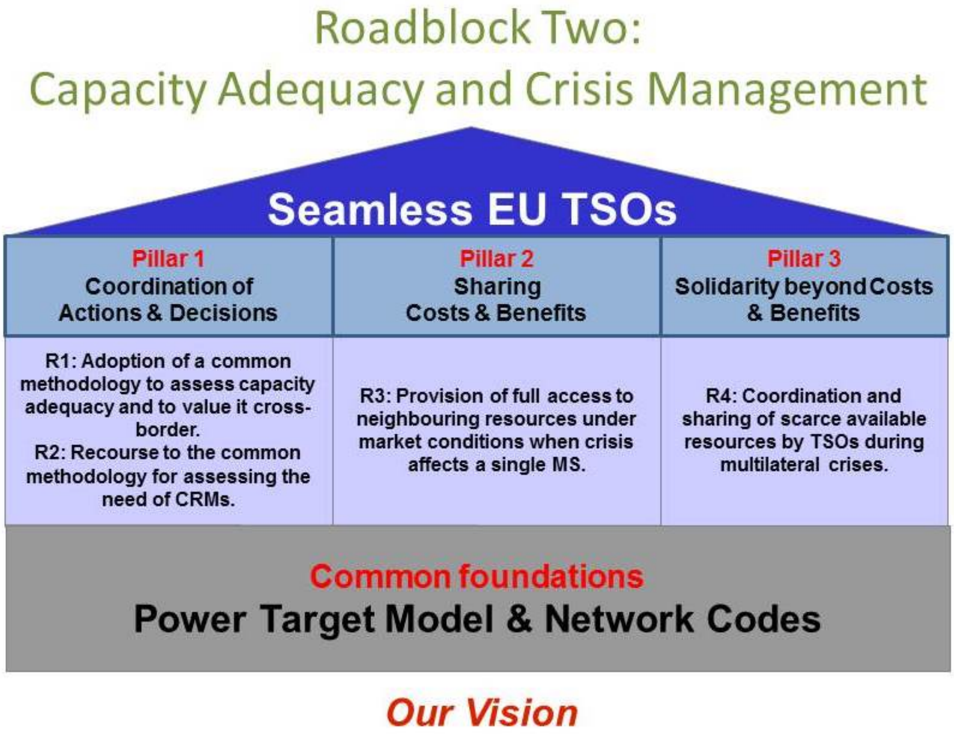

Fig 5.3: Recommendations to handle Roadblock Two

5.3.1 Under the pillar of 'Coordination of Actions and Decisions'

The adequacy of power systems has been traditionally assessed in Europe by TSOs at national level through the adoption of a variety of metrics and computational methodologies. Criteria used to select adequacy standards were and sometimes still are today neither public nor transparent. Furthermore, methodologies developed in the past for power systems centred on conventional generation are often characterised by a deterministic approach that is not suitable for assessing the adequacy of systems with growing shares of intermittent RES. Finally, system adequacy was usually evaluated in isolation, with little or no attention paid to the contribution interconnected neighbouring systems could provide. As a result, assessments performed at national level were and still are today not easily comparable and tend to underestimate or to overestimate the effective adequacy level of a specific system, depending on the concrete impact of interconnected capacity (i.e. interdependence is not properly assessed).

Trusting neighbouring countries and developing coordinated policies within this existing heterogeneous information background for capacity adequacy is difficult and the temptation for national governments and TSOs to pursue adequacy on its own is inevitably strong.

Thus, a first important recommendation to remove this roadblock on the integration process is for European countries to adopt a common methodology for assessing capacity adequacy and to value it cross-border. The idea is to develop a common 'language' and to use it for judging the situation at national level in a comprehensive way, i.e. considering also resources from other countries that can be used to cover domestic demand in case of need.

European TSOs have already started to perform adequacy assessments at the regional or at European level, taking into consideration interconnections among national grids and the growing role of intermittent RES. TSOs belonging to the Pentalateral Energy Forum (PLEF) area did it in 2015, while ENTSO-E undertook in early 2016 its first Mid-term Adequacy Forecast (MAF), covering the whole continent. Indeed, the expertise and experience gained by the TSOs could be capitalised on by granting them in EU legislation the explicit task of developing within the ENTSO-E framework the above mentioned common methodology for capacity adequacy assessment.

Such methodology, based on a practical definition of adequacy and security of supply agreed by the Member States,[145] will then enhance the transparency of the adequacy assessment process and expand trust among national governments, TSOs and other stakeholders.

Comparability of the results obtained from the use of the common methodology could well be the basis for discussing the need and the nature of public policies tackling adequacy and security of supply.

A second recommendation to handle this roadblock consists actually in providing a 'special' status to the methodology: once developed by ENTSO-E, it should be the official tool for assessing capacity adequacy in the EU and in any single Member State. It should also be the only accepted tool to prove the need for a CRM: both Member States and the European Commission should stick to it and should not resort to any other criteria, even during a formal case handled by DG Competition.

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[145] The definition of an adequacy standard is not a merely technical issue, but involves economic and social considerations about the proper level of security of supply a given system should be characterised by. However, once such standard is defined, technical experts can develop a methodology for assessing whether a system satisfies it or not. This, in the view of the research report, should be the task attributed to the TSOs and their European association ENTSO-E.

The recourse to the common methodology for evaluating the case of a CRM will improve coordination among the Member States in the field of capacity adequacy. National governments, as a matter of fact, will retain the possibility of whether or not to establish a CRM next to the energy-only market, but the justification underpinning their decision, i.e. the lack of capacity adequacy, will be scrutinised through the common methodology. It will then be easier to decide whether a CRM is really needed or if, on the contrary, interconnections and capacity in neighbouring systems can ensure an adequate level of capacity to the concerned Member State.

5.3.2 Under the pillar of 'Sharing Costs and Benefits'

Speaking the same language and sharing the same knowledge when dealing with capacity adequacy helps to coordinate security of supply policies and potentially induce a more European stance. Nevertheless, coordination on capacity adequacy is not enough for effectively coping with electricity shortages in the short term. When a system is clearly unable to meet its load due, for instance, to extreme cold waves or to disruptions in the supply of a fundamental fuel like natural gas, additional resources located beyond national borders have to be activated to cover internal demand.

With supply shortage taking place in one country, then electricity will flow, if allowed, from its neighbours through interconnections. Generators in those countries will have to increase production and consumers located there will bear higher energy prices. If cross-border capacity is not curtailed and prices are free to adjust, markets will be able to allocate capacity efficiently and provide resources to the country suffering from capacity shortage.

Clearly, the ensuing costs will have to be recovered. Market mechanisms prices will do that, thereby providing the allocative mechanism for sharing costs and benefits when capacity is missing in one power system.

5.3.3 Under the pillar of 'Solidarity beyond Costs and Benefits'

Cases of capacity shortage raise the issue of solidarity because of the profound negative impact a blackout has on society and because markets are not always able to cope with such situations, especially when the lack of capacity is significant and is extended to more than one power system at the same time.

During these 'electricity crises', solidarity is needed and improvements to the current state of affairs have to be realised, if the EU wants to fulfil the aspirations set in the Treaties and reaffirmed in numerous Council conclusions.

One of the major concerns that undermines the 'spirit of solidarity' in this area is the possibility that a Member State is prevented, in the time of need, from relying on resources located in neighbouring countries (the electricity shortage in January 2017 shows how this possibility is far from remote). Indeed, the fact that resources located ‘abroad’ could be out of reach when most needed is one of the reasons why adequacy assessments traditionally do not consider capacity located outside national borders.

If a crisis affects only one Member State, then every other neighbouring Member State has the duty to help the State in trouble by providing full access to its own resources. Capacity on interconnections should not be curtailed, even if this can imply a stark increase in electricity prices in the country providing solidarity. As said in the previous section, solidarity is not for free in this case but comes at a price defined by market forces which are still able to allocate efficiently scarce resources.

European States have already moved some steps in this direction, with national governments expressing formal commitment to respect firm cross-border contracts even at times of scarcity and to allow market transactions to freely occur and allocate resources, even to consumers located beyond national borders. A good example of this can be found in the Joint Declaration for Regional Cooperation on Security of Electricity Supply in the Framework of the Internal Energy Market that 12 European Energy Ministers signed at the margin of a Council meeting in June 2015. Among other things, they stressed that *“we will not restrict cross-border trade of electricity including in times of high prices reflecting market scarcity and we will follow EU-regulations on cross-border trade also with respect to ensuring secure system operation”*.[146]

Of course, such statements of intents should become binding rules to be applied during a real electricity crisis. Enforceability must then be ensured, with a mechanism to be defined. Nevertheless, such general principle agreed at the highest political level by the Member States of the European Union is a typical case of how it is possible to unpick a lock in the common operation of the European power system. It is one of the ways in which actions by the NRAs gathered at ACER and by the TSOs gathered at ENTSO-E are headed in the right direction by deleting former national priorities or national veto rights, when they unduly block the common operation of the EU power system and market.

On the contrary, when a crisis is multilateral, i.e. scarcity affects simultaneously two or more neighbouring countries, markets may stop working properly and governments have an even stronger temptation to act unilaterally, closing borders and not providing any help to the neighbours. This ‘every man for himself’ tendency worsens the situation and must be avoided. Therefore, TSOs have to receive a clear and strong mandate for coordinating and sharing among Member States the scarce available resources during multilateral crises, with the aim to minimise the overall risk of blackouts and the impact on the most vulnerable electricity consumers, i.e. households and small enterprises that cannot easily switch to other sources of energy for satisfying their needs.

[146] The Joint Declaration by the 12 Energy Ministers is available at http://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2015/20150608-gabriel-zeitenwende-strom-versorgungssicherheit.html.

Thanks to their long lasting experience in providing continuous and secure system operation, TSOs, under the supervision of NRAs, are the most suitable entities for preparing emergency plans in advance and managing multilateral crises.

5.4 Conclusions

The integration of European power markets is often considered a never ending story. Anytime it seems the endpoint is on the horizon, a new challenge suddenly emerges and new solutions must be implemented in order to overcome it.

Ten to 15 years ago it seemed that unbundling national incumbents and establishing independent NRAs would be the definitive breakthrough to establishing a level playing field at European level and a functioning internal market for electricity. However, as this research report extensively shows, several issues, mainly related to coordination, cost and benefit sharing, and solidarity, were in reality not properly addressed. Some of them have become even more relevant due to the deep transformations the electricity industry is currently witnessing. This calls for renewed efforts and for new actions that finally tackle the long overdue questions.

Focusing the attention on the two specific problems highlighted in Chapter 4, the report confirms that three crucial pillars are missing and offers seven different recommendations that can help to unlock the process towards a more integrated and decarbonised power system. These recommendations are not comprehensive technical solutions to complex issues that require advanced engineering expertise; rather, they identify some key tasks and suggest entities that could perform them, thereby providing some answers to the long pending questions presented in the first part of the report. These answers could then be transposed into the current EU legislative process, if the aim is to further the Europeanisation of the electricity sector.

With regard to *redispatching actions*, the report highlights the need to solve, on the one hand, an issue of coordination (who should review the coordination between market operation and system operation through the redefinition of the bidding zones?) and, on the other hand, two issues of sharing costs and benefits (what regulatory principles should be adopted for sharing the costs and the benefits resulting from the reconfiguration of the bidding zones? How are redispatching costs computed and allocated between the TSOs?).

With regard to *capacity adequacy and crisis management*, the report similarly singles out a coordination issue (how are policies for ensuring capacity adequacy assessed and coordinated?), a sharing issue (how should the additional costs for coping with energy shortages be allocated?) and a solidarity issue (how should solidarity be provided during a crisis?).

Key tasks for national governments, TSOs, NRAs and their European associations are then coherently identified.

Obviously, other solutions for handling the roadblocks mentioned above are possible as well. For instance, both redispatching actions and security of supply concerns can be dealt with, in the long run, through the expansion of the network and the development of a truly integrated European power grid, adapted to the physical distribution of generation and load. However, the report does not further elaborate on this issue, which could be explored in another research project.

Our present report does not even provide a systematic analysis of the many legislative proposals made public in November 2016 by the European Commission. The aim is, more modestly, to provide a methodology that any practitioner, decision-maker or scholar could follow while pursuing her own vision or interest. To test that the contribution of any proposal is consistent with the Europeanisation of the electricity market and the power system, she should check how the missing pillars are addressed. By doing that, she will improve the overall quality of the policy debate and better assess the outcome of the whole decision-making process.

The only salient point that we would like to underline again in this conclusion is that technical experts, as the TSOs grouped at ENTSO-E are, cannot alone address the barriers to the truly European operation of the market and system for power, when the regulatory framework has not been adeqately clarified in terms of 'sharing the costs and benefits' and 'solidarity beyond costs and benefits'.

Better coordination of TSOs and ENTSO-E at EU level requires an improved regulatory framework for 'sharing' and 'solidarity' at EU level. If each European country (either as national regulator or national government) retains all of its existing national preferences and priorities, and all of its national veto rights on any change affecting national players or interests, the TSOs cannot reach, at EU level, the best coordination framework needed by the single market and the European power system. National authorities (either NRAs or governments, or both) have to open and clear the regulatory path towards the best coordination tools and processes at EU level. We have seen in this chapter that the Member States did it at the margins of an EU Council in order to unpick some national locks in power crises. Similarly, the current debate on the Winter Package offers another excellent occasion for national authorities to clarify the regulatory landscape in which TSOs and ENTSO-E operate.

Greater Europeanisation of the market and the system is really needed when cross-border interactions between national players have already outpaced the capability of securing and framing the common market and system only at national level. No one in any country should think that keeping the existing situation is without costs. Avoiding a decision at national level on what has to be decided at EU level (i.e. 'sharing' and 'solidarity') does not ensure the continuation of a reasonable and balanced situation. On the contrary, the current status quo is a source of many inefficiencies (i.e. it is expensive) and of unfair, or even dangerous, situations (remember what happened in January 2017).

General conclusions

In the three first chapters of this report, the Florence School of Regulation revisited the developments of the last three decades and identified several basic policy questions that were not comprehensively addressed or were avoided altogether. In turn, the absence of adequate policy decisions in the several energy packages adopted so far has contributed to failings in three core areas which are essential to the completion of a single European electricity market and the transition to a low-carbon economy.

These core ‘missing pillars’ are:

- Coordination of actions and decisions;
- Sharing of costs and benefits;
- Solidarity beyond costs and benefits.

The negative impact of these weaknesses on the achievement of European goals in the electricity industry has been elucidated through the assessment of 12 critical issues that may block the establishment of a seamless European electricity market, the cross-border integration of an efficient and secure system operation, the timely development of an interconnected network, and the smooth and least expensive decarbonisation of the generation mix.

Our report does not aim to provide a list of technical solutions for those ‘blocking factors’. Our aim is to show, with the help of a ‘check-list’, the significance of the identified missing pillars and the necessity of tackling them in order to further the integration of markets and accelerate the energy transition without an excessive increase in costs.

To illustrate how the analytical framework developed in the report can be useful in the current debate over the Winter Package, two specific critical issues were discussed in more detail and some concrete recommendations presented in chapters 4 and 5. The two issues, according to us (the authors), represent real roadblocks on the path towards a fully Europeanised electricity system with a low-carbon generation mix. They are:

1. Dealing with redispatching actions;
2. Capacity adequacy and crisis management.

The recommendations we propose for removing these two hurdles do not constitute a fully-fledged roadmap. Rather, we illustrate how basic decisions on roles and tasks can, and should, be taken before the definition of any specific technical solution. Fundamental and coherent choices in terms of coordination, sharing and solidarity must be rendered explicit by Member States and European institutions. This is a preliminary requirement for any further step in the integration and decarbonisation process of the electricity sector.

To end our report, we would like to draw attention to nine points.

1) Policy-makers must explicitly and comprehensively address basic questions related to coordination, sharing, and solidarity, if they want to avoid slowing down the completion of the Internal Energy Market and increasing the costs of the transition to a decarbonised energy system.

2) The liberalisation and the integration of national electricity systems in Europe require the revision and the coherent upgrade of coordination mechanisms at national and supra-national level, to ensure the achievement of consistent infrastructure development, reliable system operation and efficient commercial transactions. The subsidiarity principle should be applied with care, given the relevance of coordination mechanisms in the electricity sector and the difficulty of developing satisfactory solutions in a decentralised way.

3) Clear principles on how to share the costs and benefits of the integrated electricity system and the energy transition must be agreed upon. This can be a sensitive political issue, since it may require an agreement defining short-term winners and losers among different categories of market actors and network users. Different Member States may similarly win or lose. Nonetheless, outlining such principles is imperative in order to accelerate the decision-making process and foster the adoption of efficient and effective solutions.

4) Solidarity in the electricity sector is currently underdeveloped from a formal point of view, especially in comparison to natural gas. Ex-ante roles and operational rules for the management of emergency situations must be established to ensure that no country will be left alone, when abnormal conditions materialise and continuity of supply becomes the main concern.

5) As we have shown, at least a dozen critical issues are currently challenging the European Union with reference to the completion of the single power market and the transition to a low-carbon economy. In our view, two of them deserve particular and immediate attention. As stated above, they are, firstly, redispatching actions and, secondly, capacity adequacy and crisis management. Regarding the first issue, the need for redispatching actions and their cost for the system have grown significantly in recent years due to the fast deployment of intermittent renewables, the increase in cross-border trade and the inadequate coordination between market and system operation. The call for a legal and regulatory framework enabling stronger coordination among TSOs and appropriate cost-sharing mechanisms is evident here. Regarding the second issue, the deployment of intermittent renewables and the interdependency among interconnected electricity systems are making the traditional methods for assessing system adequacy of limited value. Moreover, such methods could lead to wrong conclusions, like overinvestment and distortions to the IEM, when performed in isolation at national level in order to judge the need for capacity remuneration mechanisms. The national liability of TSOs and a common distrust of neighbours when security of supply is at stake explain why solidarity is not always shown in the management of crises and cooperation across borders remains fragile.

6) The removal of the roadblock attached to redispatching actions requires that TSOs gathered in ENTSO-E improve the coordination mechanisms between system and market operation by periodically assessing the configuration of market bidding zones and redraw them in case they do not adequately reflect structural congestions. Similarly, NRAs shall take the responsibility to develop within ACER a common methodology for the calculation and the allocation of redispatching costs, ensuring fairness and efficient signals for the TSOs and for network users, both short-term and long-term.

7) In order to remove the obstacle attached to capacity adequacy and crisis management, TSOs shall develop, at ENTSO-E level, a common methodology for assessing capacity adequacy and valuing it cross-border. Its use by the Member States and the European Commission, to assess the need for capacity remuneration mechanisms, will expand transparency and mutual trust. Besides, countries shall demonstrate solidarity during crisis situations. When a crisis affects a single country, its neighbours shall provide support by granting full access to their domestic resources at market prices (i.e. market transactions shall not be curtailed). On the contrary, in case of a multilateral shortage, the involved TSOs shall act according to pre-established rules in order to minimise service disruptions and the impact on the most vulnerable consumers, by pooling and coordinating the scarce available resources.

8) Bodies acting at European level, like ENTSO-E and ACER, can propose technical or regulatory solutions to solve the issues of coordination, sharing and solidarity. However, they cannot entirely remove the current roadblocks on their own. They need first a clear agreement by Member States and EU institutions on the regulatory framework for sharing the costs and the benefits of the integrated power system, and for solidarity under abnormal circumstances. If this agreement on fundamental principles is absent because of diverging national interests and the veto rights of Member States, then technical European bodies cannot do much more than slowly develop piecemeal, suboptimal and temporary solutions.

9) Different stakeholders may have and most probably will have alternative and even opposing views on the recommendations proposed in this report. This depends on their specific interests, skills and resources, or their current understanding of the complicated problems under discussion. However, we believe that any practitioner, decision-maker or scholar wishing to propose her own solutions should address, at least, the missing pillars identified in the present report and provide his or her preferred answer to the basic issues of coordination, sharing and solidarity discussed here.

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