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*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*

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RESEARCH
REPORT

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Executive Summary

The electricity industry is undergoing major changes mainly dictated by the need to simultaneously accomplish integration of European energy markets and build a low-carbon economy. This process was facilitated if not initiated by a wave of technological innovation. In order to ensure a timely, orderly and efficient transition towards the new low-carbon landscape the present legal and regulatory frameworks, devised long ago, must be reviewed and adapted in order to provide adequate rules and suitable incentives.

The purpose of this report is to help relevant stakeholders to take a leading role in transforming the way electricity systems are managed and operated in order to meet the twin targets of decarbonisation and increased market integration in the most efficient way. Because there are many uncertainties and some degrees of freedom as regards policy choices and their implementation, diverse future scenarios are conceivable. Instead of selecting one scenario and suggesting a mandatory approach, this report offers:

- a) A conceptual framework to assess and compare different options, showing the impact of different structural changes upon governance and regulation of electricity systems and markets.
- b) Useful checkpoints and recommendations aimed at safeguarding the internal coherence of any selected scenario.

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. Decision-makers are free to favour, endorse or even determine any given “feasible” political or technological path. However, once they have taken this primordial decision, their subsequent choices should be compatible with objective - and unfortunately complex - technical, economic and institutional constraints of electricity systems and markets. Any lack of internal consistency will make energy transition unnecessarily costly and protracted. The main goal of this report is to help decision-makers steering energy transition along a coherent course.

The transition towards low-carbon energy systems requires not only new rules, but also new roles. In particular, the role of transmission networks and the role of transmission system operators are changing and need to evolve even faster over the coming years. Given the different time-scales for investments in generation and in networks, any successful energy transition wishing to preserve current reliability standards requires timely and coherent adjustments of the role played by Transmission System Operators (TSOs). The recommendations provided take into account the need to ensure a dynamic balance between the “creative destruction” of market forces and technological innovation, on the one hand, and the intrinsic stringency of power system reliability governance, on the other hand.

In order to better grasp some structural novelties of the new world we are entering in and to identify major critical issues, the report first introduces three basic conceptual scenarios:

- Lower decarbonization within a pan-European system
- Higher decarbonization within existing Member State systems
- Higher decarbonization within decentralized systems

They correspond to three “ideal types” (extreme scenarios), not to “most likely outcomes”. It is assumed that reality will most probably be a combination of these three basic scenarios. Hybridation

may happen “by design” (i.e., because decision-makers consciously opt for a hybrid model) or “by accident” (i.e., because decisions being taken by different agents at different places and at different points in time result in a dynamic hybrid outcome that does not correspond to the expected outcome of any individual agent).

For each scenario, the report discusses in detail how the main functions and interactions of European TSOs need to change and how these changes differ between the three scenarios. The report analyses both the “hardware side” and the “software side”:

- The “hardware” side means network planning, building infra-structure assets, managing electricity transmission, etc. – i.e., the traditional, strongly investment-related and therefore heavily regulated functions.

- The “software” side includes, generally speaking, all procedures needed to manage system operation, to facilitate market operation at the interface with market operators, Distribution System Operators (DSOs) and other players in the power system – i.e. the more evolutionary, less capital-intensive, rules-related functions.

This two-side analysis enables the reader to fully realize the possible impact of structural changes upon the functioning of power systems, the functions performed by different actors and overall governance.

None of the three basic scenarios is fully consistent with the present “legacy framework” and they all require substantial changes in terms of governance mechanisms and regulatory policies. Aware of the weaknesses of the “hybridation” actually growing in the EU, either “by design” or “by accident”, the report introduces a set of “checkpoints” aimed at ensuring critical levels of coherence, consistency and resilience along the energy system journey towards a 2050 low-carbon future.

Although all three scenarios were constructed in order to fulfil EU energy and climate policy objectives, no individual scenario can easily fully meet all goals at reasonable cost. Societal expectations, technological developments and public policies are not necessarily and not always aligned, therefore this difficulty should be no surprise.

As regards the internal coherence or self-consistency of each scenario, two points deserve special attention:

- 1) Some critical system operational functions, currently mainly performed by national TSOs, will be totally or partially performed by other entities. These entities may be supra-national organizations, either emanating from or acting in close cooperation with TSOs, DSOs (individually or somehow associated) or even new players. Therefore, the legal and regulatory frameworks must be adapted, namely in order to:
 - a) Clearly define and assign each operational function, indicating, for each, appropriate cost and liability sharing mechanisms.
 - b) Establish appropriate coordination mechanisms, for both normal and abnormal situations, including appropriate redundancy safeguards and supervision tools.
- 2) Even if from the technical (system operation) point of view it is theoretically possible to ensure appropriate system reliability (assuming that the necessary legal and regulatory changes are implemented), several “black holes” may still jeopardize the efficient functioning of electricity systems and markets. The report discusses how to patch them.

Assuming that, in the short-term, implementation of 3rd Package legislation and associated Network Codes will continue and no fundamentally new legislation will be issued, serious governance issues

must be somehow addressed. In this respect, not only national/EU interfaces require continuous attention; local/national interfaces become increasingly critical for transparency and reliability. Among the many governance challenges to be addressed the following ones are particularly important:

- Regionalisation and Europeanisation of grid planning, system and market operation, leading to better coordination or mutualisation of hardware and software TSOs functions, as well as of the NRAs actions.
- Member States policies regarding security of supply and generation adequacy.
- Articulation between Member States “2030 NAPs”, network investments, systems and markets.
- Articulation of local and national grids, systems and pocket markets, implying new forms of multi-layer coordination between DSOs, TSOs, NRAs and Member States.

In the past, voluntary, informal cooperation among major actors (namely the European Commission, regulators and TSOs) has been crucial for the development of the internal energy market. This kind of cooperation can still deliver substantial results on the road to decarbonisation. However, the speed of delivering the many missing “building blocks” for the proper functioning of the system (from planning to real-time operation) needs to be considerably increased in the short-term.

After several years of high retail energy prices, consumers may have accepted the inevitability of this trend and, to some extent, they have already adapted their behaviours to this new reality. However, the increasing dependence of economic and social life upon electrical devices makes security of supply and reliability an absolute priority for all consumers. For the energy transition to succeed, governance and regulatory mechanisms have to be quickly adapted and partially redesigned with this “absolute must” in mind.

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Introduction

The electricity industry is currently undergoing major changes. The transformation is mainly dictated by the need to simultaneously accomplish the integration of European energy markets and build a low - carbon economy, which has been facilitated, if not initiated, by a wave of technological change. This policy goal has been translated into several documents approved by the European Union and established quantitative targets for 2020, 2030 and 2050 in terms of, i.e., greenhouse gas emissions and the share of renewable energy in total energy consumption. However, the present legal and regulatory frameworks are not considered to provide adequate rules or suitable incentives for a timely, orderly and efficient transition; in fact, even if all EU legislation and network codes had been properly implemented, they would not be fit for the new low-carbon landscape. Therefore, the legal and regulatory frameworks must be adapted, taking into account not only the internal market and energy and climate policy objectives, but also recent technological developments.

The “Energy Union” project recently launched by the European Commission aims at reconciling these different objectives, improving the coherence and speed of the transition towards low-carbon energy systems, while taking into account the new technological trends, the growing concerns about energy independence, the efficient use of endogenous resources and the fair allocation of the costs and benefits of the EU energy and climate policy.

The purpose of this report is to help the relevant stakeholders to take a leading role in transforming the way power systems are managed and operated in order to meet the twin targets of decarbonisation and increased market integration in the most efficient way. Because there are many uncertainties, and some level of freedom as regards policy choices and their implementation, diverse future scenarios are conceivable. Therefore, the present report provides a set of recommendations about appropriate regulatory paths and incentives that are conducive to different scenarios. The report does not prescribe a mandatory solution – it offers a conceptual framework to assess and compare different options.

The transition towards low-carbon energy systems requires not only new rules, but also new roles. In particular, the role of transmission networks and the role of transmission system operators are changing and need to evolve even faster over the coming years. The different time-scales for investments in generation and in networks should also be kept in mind.

The analysis and recommendations provided in this report take into account the current diversification of agents in charge of the system operation (System Operators - SOs, Independent System Operators - ISOs, RSCIs – Regional Security Coordination Initiatives – etc.) at both national and supra - national levels. They also consider the need to ensure a dynamic balance between the “creative destruction” of market forces and technological innovation, on the one hand, and the intrinsic stringency of power system reliability governance, on the other hand.

This report is divided into 4 chapters:

Chapter 1 describes the major trends impacting the role of TSOs in a low-carbon energy landscape. After introducing the present political, legal and regulatory framework, as well as the internal and external factors shaping the transition to low-carbon electricity systems, recent developments in the generation mix and in consumption patterns are illustrated. Following a discussion of necessary market and governance changes, three different future scenarios are presented. It is assumed that the reality will most probably be a combination of these three “ideal types”¹.

Taking into account electricity system developments described in the first chapter and their general implications, Chapters 2 and 3 discuss how the main functions and interactions of European TSOs will change and how these changes will differ between the three scenarios. Chapter 2 addresses the “hardware” side (network planning, building infra-structure assets, managing electricity transmission, etc. – the traditional, strongly investment-related and therefore heavily regulated functions), while Chapter 3 focuses on the “software” side (generally speaking, all procedures needed to manage the system operation, to facilitate the market operation at the interface with market operators, DSOs and other players in the power system – the more evolutive, less capital-intensive, rules-related functions).

Finally, Chapter 4 discusses the required regulatory and governance frameworks for each scenario, providing “checkpoints” and recommendations in order to achieve a smooth and efficient transition towards low-carbon electricity systems. Finally, the possibility of “hybridation” of the three basic scenarios is introduced and governance and regulatory requirements needed to ensure coherence of the transition process are also analysed under this perspective.

¹ “Ideal type, a common mental construct in the social sciences derived from observable reality, although not conforming to it in detail because of deliberate simplification and exaggeration. It is not ideal in the sense that it is excellent, nor is it an average; it is, rather, a constructed ideal used to approximate reality by selecting and accentuating certain elements.

The concept of the ideal type was developed by German sociologist Max Weber, who used it as an analytic tool for his historical studies.”
<http://www.britannica.com/topic/ideal-type>

1. Major trends affecting the role of TSOs in a low-carbon energy landscape

Before the liberalisation of energy markets, the electricity transmission system operation was a little noticed function, usually performed by relatively small departments within large vertically integrated utilities.

Liberalisation means competition. Competition - even if only large consumers were initially eligible - required non-discriminatory access to transmission infrastructure. In order to ensure non-discriminatory access of both suppliers and eligible consumers, people and assets assigned to the transmission system operation had to be ring-fenced from other departments within vertically integrated utilities; their mission had to be clearly defined, their performance properly monitored and their activity strictly regulated. This process, known as "unbundling", gave transmission system operators a very strong identity and very high public visibility; their role became clearly identifiable to all relevant stakeholders. In many countries, governments (e.g. Spain, UK, Norway, Portugal, Italy, Sweden, Netherlands) or utilities (e.g. Switzerland, Germany) decided to separate transmission assets from other types of electricity assets, creating new companies dedicated exclusively to the energy transmission system operation². Ownership unbundling, although not applied in all EU Member States, contributed to bolstering the identity of a new category of industry actors.

Over the last two decades, each step aimed at enlarging the scope and increasing the intensity of electricity market liberalisation resulted in more duties and more competences being assigned to transmission system operators. The 2009 EU electricity Directive (Directive 2009/72/EC) institutionalised the role of transmission system operators, confirming their vital importance in fully liberalised markets.

Nowadays, new public policies, new technologies and new consumer attitudes push transmission system operators towards new horizons and new roles. The present chapter first describes the legal and regulatory frameworks where TSOs currently perform their functions (Section 1.1); then, a brief review of the major trends that are impacting the role of TSOs is provided (Section 1.2), followed by a more specific analysis of changes on the supply and demand sides (Section 1.3). The multiple interactions between the different drivers for change, electricity markets and the system operation are discussed in Section 1.4. Finally, Section 1.5 introduces the three scenarios considered for the analytical work performed in the following Chapters 2 and 3.

² In some cases these undertakings are responsible for electricity only, in other cases they are in charge of both electricity and natural gas system operation.

1.1 The role and functions of TSOs in the current system and market structures

In vertically integrated monopolies the system operation is a straightforward task, merging the economic dispatch of generators and security objectives under a single control umbrella. A single entity is responsible for determining the output of each power plant and managing all power flows through the transmission network, including flows to distribution networks and import/export flows at interconnectors.

Liberalisation abolishes generation and supply monopolies. Hence, liberalisation brings new players into the picture and allows power plants to decide how much they want to produce (i.e., to sell, either bilaterally or to organised markets/power pools). Liberalisation also introduces a strict separation of generation, network and supply activities (“unbundling”), limiting the scope for vertical integration and defining the rights and duties of players in each area. In a liberalised framework, market and security objectives are treated separately and must be reconciled in real-time according to transparent rules previously agreed, making the system operation a much more complex task as compared to the monopolistic era.

The system operation is now allowed to interfere with the generators’ output only when their declared schedule conflicts with the overall system security. However, because the electricity market consists of several different “market places” (financial, physical, day-ahead, intra-day, balancing, etc.), the system operation must closely follow all types of market operations, and coordination between the market operation and system operation becomes increasingly complex. As system security must prevail over the individual economic interests of market agents, system operators retain the ultimate responsibility for the well-functioning of electricity markets and systems.

The liberalisation of electricity markets can be achieved in many different ways: how much and how quickly the market can be opened up usually depends on legislators; how competition is organised may be defined in several ways and typically evolves over time, following the learning patterns of market players, market operators, system operators and regulators.

One of the striking features of the European electricity liberalisation process is the absence of “market design” prescriptions in all directives and regulations, leaving Member States the freedom to decide how to design and implement national markets. This omission created a certain vacuum at the European level, since no mandatory “European market design” has been issued - e.g., initially no rules concerning data exchange between market operators and system operators were available. The Commission attempted to overcome these difficulties through the promotion of a “Market target model”, but it arrived at a time when the conflicts between “traditional” market models, on the one hand, and new EU and national policies, on the other hand, were already rather obvious. In the meantime, many system operators took a pro-active role, assuming *de facto* a leading role in the

development of the European electricity market through close cooperation with each other, along with relevant stakeholders.

This Section describes the European case, providing a brief historical perspective, as well as short descriptions of the current legal and regulatory frameworks in the European Union, and examples of voluntary cooperation among system operators.

1.1.1 The development of the European model 1996-2015

In 1988, following the 1985 European Council decision to achieve a single market by 1992 and the 1986 Single European Act, the European Commission published the first document on the Internal Energy Market³. This working paper stated that *“a more integrated European energy market should reduce energy costs, to the direct benefit of individual consumers, but also of user industries”* and, at the same time, *“encourage the maintenance or development within the Community of healthy and prosperous energy enterprises”*, thus improving the security of supply.

The transition from national monopolistic organisations to partially liberalised electricity markets took more than eight years: the first electricity Directive explicitly defining some *“common rules”* for the Internal Energy Market⁴ was approved in 1996⁵. The Commission’s approach was mainly based on the removal of all *“obstacles to the internal energy market”*, abolishing generation, supply, import and export monopolies and giving large industrial consumers the right to choose an electricity supplier from any Member State.

The first electricity Directive basically obliged Member States to *“ensure, on the basis of their institutional organisation and with due regard for the principle of subsidiarity, that, without prejudice to paragraph 2 [“Member States may impose on undertakings operating in the electricity sector, in the general economic interest, public service obligations”], 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.”*⁶ Three approaches to system access were defined (regulated, negotiated and single buyer), a dynamic minimum threshold for eligibility was introduced and unbundling and the transparency of accounts was mandated: *“Integrated electricity undertakings shall, in their internal accounting, keep separate accounts for their generation, transmission and distribution activities, and,*

3 Working Paper “The Internal Energy Market” COM(88) 238 final of 2 May 1988

4 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 027, 30/01/1997.

5 In the meantime (1990), directives on energy price transparency and energy transmission through high-voltage/high-pressure networks were approved, but their impact was very limited.

6 Article 3 of Directive 96/92/EC

where appropriate, consolidated accounts for other, non-electricity activities, as they would be required to do if the activities in question were carried out by separate undertakings, with a view to avoiding discrimination, cross-subsidisation and distortion of competition.”⁷

As regards the transmission system operation, the first electricity Directive was rather vague (see full text in Box 1 on page 15). Although the Directive defined “*transmission*”, “*interconnected system*” and “*ancillary services*”, it did not provide an explicit definition of the “system operation” and even contained a certain level of circularity – for instance, defining ancillary services as “*all services necessary for the operation of a transmission or distribution system*” and a system operator as the entity “*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.*”⁸

7 Article 14 of Directive 96/92/EC

8 Articles 2 and 7 of Directive 96/92/EC, respectively

Box 1: Transmission system operation in the 1996 Directive

CHAPTER IV

Transmission system operation

Article 7

1. Member States shall designate or shall require undertakings which own transmission systems to designate, for a period of time to be determined by Member States having regard to considerations of efficiency and economic balance, a system operator to be responsible for operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and its interconnectors with other systems, in order to guarantee security of supply.
2. 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 in accordance with Article 8 of Council Directive 83/189/EEC of 28 March 1983 laying down a procedure for the provision of information in the field of technical standards and regulations (7).
3. 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.
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, coordinated development and interoperability of the interconnected system.
5. The system operator shall not discriminate between system users or classes of system users, particularly in favour of its subsidiaries or shareholders.
6. Unless the transmission system is already independent from generation and distribution activities, the system operator shall be independent, at least in management terms, from other activities not relating to the transmission system.

Article 8

1. 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.
2. Without prejudice to the supply of electricity on the basis of contractual obligations, including those which derive from the tendering specifications, 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.
3. A Member State may require the system operator, when dispatching generating installations, to give priority to generating installations using renewable energy sources or waste or producing combined heat and power.
4. A Member State may, for reasons of security of supply, direct that priority be given to the dispatch of generating installations using indigenous primary energy fuel sources, to an extent not exceeding in any calendar year 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned.

Article 9

The transmission system operator must preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its business.

For several reasons, including the lack of detailed technical rules and the absence of any clear rules on developing a regulatory framework or settling disputes⁹, the first Directive did not deliver the expected results. In order to promote a better understanding of the remaining obstacles, as well as to facilitate the implementation of voluntary agreements, the Commission decided to set up the Florence Forum in February 1998. Although the Forum delivered “too little, too late”, it had several important consequences, namely the creation of some European professional associations, including ETSO (European Transmission System Operators) in 1999. While a voluntary professional association, ETSO played a very important role in the development of the Internal Energy Market, contributing decisively to the new identity of transmission system operators in Europe and across the globe. In 2009, ETSO was wound up and its tasks transferred to ENTSO-E, a proper European entity set up in a Directive.

The lack of progress in cross-border electricity trade and the political decision taken by the European Council in 2000 to fully liberalise some crucial sectors, including energy, within the framework of the so-called “Lisbon Agenda”, led to the second electricity Directive¹⁰, approved in 2003. This Directive asked for a full opening of all EU markets, extended to all consumers of any type and any size. A specific Regulation on cross-border trade was approved at the same time¹¹, within the so-called “second energy package”. The second electricity Directive and the new Regulation enlarged the scope and consolidated the common rules for the internal electricity market.

The second energy package finally provides a definition of “transmission system operator”:

*“ ‘transmission system operator’ means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long term ability of the system to meet reasonable demands for the transmission of electricity;”*¹²

The definition of the tasks and the duties of the transmission system operators is much more detailed in 2003 as compared to 1996, as can be seen in Boxes 2 and 3 on pages 18-20 and 21-22, respectively.

9 For a more detailed analysis see Jorge Vasconcelos, ‘Towards a European energy policy’, in Peter Ludlow (ed.), *Setting EU priorities 2007*, European Strategy Forum, 2007.

10 Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC. O.J. L 176, 15/07/2003

11 Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity. O.J. L 176, 15/07/2003

12 Article 2, Directive 2003/54/EC

Box 2: Transmission system operation in the 2003 Directive

CHAPTER IV

TRANSMISSION SYSTEM OPERATION

Article 8

Designation of Transmission System Operators

Member States shall designate, or shall require undertakings which own transmission systems to designate, for a period of time to be determined by Member States having regard to considerations of efficiency and economic balance, one or more transmission system operators. Member States shall ensure that transmission system operators act in accordance with Articles 9 to 12.

Article 9

Tasks of Transmission System Operators

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;*
- (c) managing energy flows on the system, taking into account exchanges with other interconnected systems. To that end, the transmission 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 insofar as this availability is independent from any other transmission system with which its system is interconnected;*
- (d) providing 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;*
- (e) ensuring non-discrimination as between system users or classes of system users, particularly in favour of its related undertakings;*
- (f) providing system users with the information they need for efficient access to the system.*

Article 10

Unbundling of Transmission System Operators

1. Where the transmission system operator is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organisation and decision making from other activities not relating to transmission. These rules shall not create an obligation to separate the ownership of assets of the transmission system from the vertically integrated undertaking.

2. In order to ensure the independence of the transmission system operator referred to in paragraph 1, the following minimum criteria shall apply:

- (a) those persons responsible for the management of the transmission system operator may not participate in company structures of the integrated electricity undertaking responsible, directly or indirectly, for the day-to-day operation of the generation, distribution and supply of electricity;*
- (b) appropriate measures must be taken to ensure that the professional interests of the persons responsible for the management of the transmission system operator are taken into account in a manner that ensures that they are capable of acting independently;*
- (c) the transmission system operator shall have effective decision-making rights, independent from the integrated electricity undertaking, with respect to assets necessary to operate, maintain or develop the network. This should not prevent the existence of appropriate coordination mechanisms to ensure that the economic and management supervision rights of the parent company in respect of return on assets, regulated indirectly in accordance with Article 23(2), in a subsidiary are protected. In particular, this shall enable the parent company to approve the annual financial plan, or any equivalent instrument, of the transmission system operator and to set global limits on the levels of indebtedness of its subsidiary. It shall not permit the parent company to give instructions regarding day-to-day operations, nor with respect to individual decisions concerning the construction or upgrading of transmission lines, that do not exceed the terms of the approved financial plan, or any equivalent instrument;*

(d) the transmission system operator shall establish a compliance programme, which sets out measures taken to ensure that discriminatory conduct is excluded, and ensure that observance of it is adequately monitored. The programme shall set out the specific obligations of employees to meet this objective. An annual report, setting out the measures taken, shall be submitted by the person or body responsible for monitoring the compliance programme to the regulatory authority referred to in Article 23(1) and shall be published.

Article 11

Dispatching and balancing

- 1. Without prejudice to the supply of electricity on the basis of contractual obligations, including those which derive from the tendering specifications, the transmission system operator shall, where it has this function, be responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems.*
- 2. 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 or interconnector transfers and the technical constraints on the system.*
- 3. A Member State may require the system operator, when dispatching generating installations, to give priority to generating installations using renewable energy sources or waste or producing combined heat and power.*
- 4. A Member State may, for reasons of security of supply, direct that priority be given to the dispatch of generating installations using indigenous primary energy fuel sources, to an extent not exceeding in any calendar year 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned.*
- 5. Member States may require transmission system operators to comply with minimum standards for the maintenance and development of the transmission system, including interconnection capacity.*
- 6. Transmission system operators shall procure the energy they use to cover energy losses and reserve capacity in their system according to transparent, non-discriminatory and market-based procedures, whenever they have this function.*
- 7. Rules adopted by transmission system operators for balancing the electricity system shall be objective, transparent and non-discriminatory, including rules for the charging of system users of their networks for energy imbalance. Terms and conditions, including rules and tariffs, for the provision of such services by transmission system operators shall be established pursuant to a methodology compatible with Article 23(2) in a non-discriminatory and cost-reflective way and shall be published.*

Article 12

Confidentiality for Transmission System Operators

Without prejudice to Article 18 or any other legal duty to disclose information, the transmission system operator shall preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its business. Information disclosed regarding its own activities, which may be commercially advantageous, shall be made available in a non-discriminatory manner.

Box 3: Transmission system operation in the 2003 Regulation

Article 3

Inter transmission system operator compensation mechanism

1. Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks.

(...)

Article 4

Charges for access to networks

1. Charges applied by network-operators for access to networks shall be transparent, take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and applied in a non-discriminatory manner. Those charges shall not be distance-related.

(...)

Article 5

Provision of information on interconnection capacities

1. Transmission system operators shall put in place coordination and information exchange mechanisms to ensure the security of the networks in the context of congestion management.

2. The safety, operational and planning standards used by transmission system operators shall be made public. The information published shall include a general scheme for the calculation of the total transfer capacity and the transmission reliability margin based upon the electrical and physical features of the network. Such schemes shall be subject to the approval of the regulatory authorities.

3. Transmission system operators shall publish estimates of available transfer capacity for each day, indicating any available transfer capacity already reserved. These publications shall be made at specified intervals before the day of transport and shall include, in any case, week-ahead and month-ahead estimates, as well as a quantitative indication of the expected reliability of the available capacity.

(...)

Article 6

General principles of congestion management

1. Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved. Network congestion problems shall preferentially be solved with non transaction based methods, i.e. methods that do not involve a selection between the contracts of individual market participants.

(...)

5. Transmission system operators shall, as far as technically possible, net the capacity requirements of any power flows in opposite direction over the congested interconnection line in order to use this line to its maximum capacity. Having full regard to network security, transactions that relieve the congestion shall never be denied.

In spite of the second energy package, the functioning of the Internal Energy Market was not yet satisfactory; substantial widespread price increases, persistent price differentials among neighbouring geographical regions and blackouts in some areas, particularly dramatic in 2003, convinced consumers and the European Commission that new initiatives were necessary. The Competition Directorate-General launched an extensive “sector inquiry” in 2005 and identified four major deficiencies¹³ requiring the adoption of structural measures. In September 2007 the European Commission presented a set of new legislative proposals – the so-called “third energy package” - that was adopted in 2009, following substantial amendments by the Council and by the Parliament.

In the meantime, national and regional (supra-national) wholesale electricity markets were set up. Because EU legislation never attempted to provide a blueprint for the design of wholesale energy markets, different models were implemented, creating potential and actual barriers to cross-border electricity trade. Later on, step-by-step the harmonisation of market rules and increased market-to-market coordination through “market coupling” procedures, based on voluntary cooperation among several stakeholders, including TSOs, and being bound with the CACM, has prevented the drift of such heteromorphic markets.

Although the third electricity package introduced some provisions aimed at improving the coordination of planning and the expansion of transmission networks throughout Europe, namely assigning to ENTSO-E - as a new European entity - the responsibility to deliver a biennial Ten-Year Network Development Plan (TYNDP), interconnection capacity at several borders was, and still is, scarce. It was acknowledged that one of the main reasons for this situation was the duration of the permitting process; on average ten years are necessary to build a new transmission line, of which only two to three years are used for the works. Therefore, in 2011 the Commission proposed a new infrastructure Regulation that was adopted in 2013¹⁴, laying down “*guidelines for the timely development and interoperability of priority corridors and areas of trans-European energy infrastructure*”. This Regulation was part of a package on trans-European infrastructure encompassing energy, transport and digital networks and including a €50 billion Connecting Europe Facility (CEF) to leverage priority investments.

Several factors prevented the Internal Energy Market from becoming an accomplished reality until now, namely:

13 “(1) achieving effective unbundling of network and supply activities, (2) removing the regulatory gaps (in particular for cross border issues), (3) addressing market concentration and barriers to entry, and (4) increasing transparency in market operations” - COM(2006) 851 final of 10.1.2007

14 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. O.J. L 115 of 25.04.2013

- Lack of physical cross-border infrastructure at several borders (obviously a necessary, although not sufficient condition for the development of integrated markets based upon physical networks, such as electricity).
- Lack of a single European market model – conceived either as the top-down implementation of a centralised single design or as the bottom-up construction of a hierarchical organisation of compatible market structures.
- Lack of a multi-divisional organisation able to optimise the system operation at European level (in spite of an increasing number of related rules in Network Codes and in spite of several regional efforts and projects, coordination of the system operation at European level cannot yet be considered to be fully optimised).
- Lack of effective regulation at EU level through an independent, energy specific regulatory authority.

The European institutions keep their faith on the possibility of accomplishing the Internal Energy Market in a brief period of time and remain committed to the “single energy market” venture. Political statements frequently reaffirm this commitment, monitoring reports are regularly published, some anti-trust cases have been carried out and the Competition Directorate-General in many circumstances has imposed severe remedies¹⁵, regulators continue to promote the “Europeanisation” of energy markets, *et cetera*. However, in the meantime, new European public policies (as the ones known as “20-20-20 in 2020”) “require a revolution in energy systems”¹⁶. With different speeds and different degrees of engagement across Europe, electricity systems and electricity markets started the transition towards a low-carbon landscape. This means that to be efficient both vis-à-vis the market operation and the policy targets the Internal Electricity Market that one day may be achieved will be very different from the initial “Single Market” project launched a quarter century ago.

1.1.2 The European legal framework

The Treaty on the Functioning of the EU (Treaty of Lisbon) came into force on 1 December 2009 and includes, for the first time in the history of European Treaties, a specific energy chapter (Article 194). Establishing and ensuring the proper functioning of the internal energy market are now the explicit responsibilities of the EU, although Member States have the “right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply”.

¹⁵ See list of cases in http://ec.europa.eu/competition/sectors/energy/electricity/electricity_en.html

¹⁶ European Council conclusions, 4 February 2011

Box 4: Energy in the Treaty on the Functioning of the European Union

TITLE XXI

ENERGY

Article 194

1. In the context of the establishment and functioning of the internal market and with regard for the need to preserve and improve the environment, Union policy on energy shall aim, in a spirit of solidarity between Member States, to:

(a) ensure the functioning of the energy market;

(b) ensure security of energy supply in the Union;

(c) promote energy efficiency and energy saving and the development of new and renewable forms of energy; and

(d) promote the interconnection of energy networks.

2. Without prejudice to the application of other provisions of the Treaties, the European Parliament and the Council, acting in accordance with the ordinary legislative procedure, shall establish the measures necessary to achieve the objectives in paragraph 1. Such measures shall be adopted after consultation of the Economic and Social Committee and the Committee of the Regions.

Such measures shall not affect a Member State's right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply, without prejudice to Article 192(2)(c).

3. By way of derogation from paragraph 2, the Council, acting in accordance with a special legislative procedure, shall unanimously and after consulting the European Parliament, establish the measures referred to therein when they are primarily of a fiscal nature.

Besides the Treaty, the so-called 2009 “third energy package” defines the current legal framework for the energy industry in Europe. The definitions presented in the following box (most of them first introduced in 2003) are the most relevant for the purpose of the present report:

Box 5: Definitions provided by current EU legislation¹⁷

Article 2

Definitions

For the purposes of this Directive, the following definitions apply:

3. *'transmission' means the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply;*

4. *'transmission system operator' means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity;*

5. *'distribution' means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply;*

6. *'distribution system operator' means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity;*

(...)

13. *'interconnector' means equipment used to link electricity systems;*

14. *'interconnected system' means a number of transmission and distribution systems linked together by means of one or more interconnectors;*

(...)

17. *'ancillary service' means a service necessary for the operation of a transmission or distribution system;*

18. *'system user' means a natural or legal person supplying to, or being supplied by, a transmission or distribution system;*

(...)

26. *'small isolated system' means any system with consumption of less than 3 000 GWh in the year 1996, where less than 5 % of annual consumption is obtained through interconnection with other systems;*

27. *'micro isolated system' means any system with consumption less than 500 GWh in the year 1996, where there is no connection with other systems;*

(...)

29. *'energy efficiency/demand-side management' means a global or integrated approach aimed at influencing the amount and timing of electricity consumption in order to reduce primary energy consumption and peak loads by giving precedence to investments in energy efficiency measures, or other measures, such as interruptible supply contracts, over investments to increase generation capacity, if the former are the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption and the security of supply and distribution cost aspects related to it;*

30. *'renewable energy sources' means renewable non-fossil energy sources (wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases);*

31. *'distributed generation' means generation plants connected to the distribution system;*

¹⁷ 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. O.J. L 211 of 14.8.2009

The definition of the tasks and the duties of transmission system operators is much more detailed under the “third energy package” as compared to 1996 and 2003, as can be seen in Boxes 6 and 7 on pages 27 and 28, respectively. Moreover, other provisions of Directive 2009/72/EC have substantial organizational (although not much functional) impact upon individual TSOs, namely Chapter V (Independent Transmission Operator) and the following articles from Chapter IV:

- Article 6 - “Promotion of regional cooperation”;
- Article 9 - “Unbundling of transmission systems and transmission system operators”;
- Article 10 - “Designation and certification of transmission system operators”;
- Article 11 - “Certification in relation to third countries”;
- Article 13 - “Independent system operator”;
- Article 14 - “Unbundling of transmission system owners”;
- Article 16 - “Confidentiality for transmission system operators and transmission system owners”

Box 6: Transmission system operation in the 2009 Directive

Article 12

Tasks of transmission system operators

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, operating, maintaining and developing under economic conditions secure, reliable and efficient transmission systems with due regard to the environment;*
- (b) ensuring adequate means to meet service obligations;*
- (c) contributing to security of supply through adequate transmission capacity and system reliability;*
- (d) managing electricity flows on the system, taking into account exchanges with other interconnected systems. To that end, the transmission 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, including those provided by demand response, insofar as such availability is independent from any other transmission system with which its system is interconnected;*
- (e) providing 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;*
- (f) ensuring non-discrimination as between system users or classes of system users, particularly in favour of its related undertakings;*
- (g) providing system users with the information they need for efficient access to the system; and*
- (h) collecting congestion rents and payments under the inter-transmission system operator compensation mechanism, in compliance with Article 13 of Regulation (EC) No 714/2009, granting and managing third-party access and giving reasoned explanations when it denies such access, which shall be monitored by the national regulatory authorities; in carrying out their tasks under this Article transmission system operators shall primarily facilitate market integration.*

Box 7: Transmission system operation in the 2009 Directive

Article 15

Dispatching and balancing

1. *Without prejudice to the supply of electricity on the basis of contractual obligations, including those which derive from the tendering specifications, the transmission system operator shall, where it has such a function, be responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems.*
2. *The dispatching of generating installations and the use of interconnectors shall be determined on the basis of criteria which shall be approved by national regulatory authorities where competent and which must be objective, published and applied in a non-discriminatory manner, ensuring the proper functioning of the internal market in electricity. The criteria shall take into account the economic precedence of electricity from available generating installations or interconnector transfers and the technical constraints on the system.*
3. *A Member State shall require system operators to act in accordance with Article 16 of Directive 2009/28/EC when dispatching generating installations using renewable energy sources. They also may require the system operator to give priority when dispatching generating installations producing combined heat and power.*
4. *A Member State may, for reasons of security of supply, direct that priority be given to the dispatch of generating installations using indigenous primary energy fuel sources, to an extent not exceeding, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned.*
5. *The regulatory authorities where Member States have so provided or Member States shall require transmission system operators to comply with minimum standards for the maintenance and development of the transmission system, including interconnection capacity.*
6. *Transmission system operators shall procure the energy they use to cover energy losses and reserve capacity in their system according to transparent, non-discriminatory and market-based procedures, whenever they have such a function.*
7. *Rules adopted by transmission system operators for balancing the electricity system shall be objective, transparent and non-discriminatory, including rules for charging system users of their networks for energy imbalance. The terms and conditions, including the rules and tariffs, for the provision of such services by transmission system operators shall be established pursuant to a methodology compatible with Article 37(6) in a non-discriminatory and cost-reflective way and shall be published.*

As mentioned above, the third electricity package, in particular the 2009 Regulation ¹⁸, institutionalised the collective action of TSOs by establishing a European entity named “**European Network of Transmission System Operators for Electricity**” (the ENTSO for Electricity). “*In order to ensure optimal management of the electricity transmission network and to allow trading and*

¹⁸ 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. O.J. L 211 of 14.8.2009

supplying electricity across borders in the Community". The Regulation also defines the statutory tasks of the ENTSO for Electricity in some detail - see Box 8.

Box 8: Collective EU transmission system operation in the 2009 Regulation

Article 8

Tasks of the ENTSO for Electricity

1. *The ENTSO for Electricity shall elaborate network codes in the areas referred to in paragraph 6 of this Article upon a request addressed to it by the Commission in accordance with Article 6(6).*
2. *The ENTSO for Electricity may elaborate network codes in the areas set out in paragraph 6 with a view to achieving the objectives set out in Article 4 where those network codes do not relate to areas covered by a request addressed to it by the Commission. Those network codes shall be submitted to the Agency for an opinion. That opinion shall be duly taken into account by the ENTSO for Electricity.*
3. *The ENTSO for Electricity shall adopt:*
 - (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;*
 - (b) *a non-binding Community-wide ten-year network development plan, (Community-wide network development plan), including a European generation adequacy outlook, every two years;*
 - (c) *recommendations relating to the coordination of technical cooperation between Community and third-country transmission system operators;*
 - (d) *an annual work programme;*
 - (e) *an annual report;*
 - (f) *annual summer and winter generation adequacy outlooks.*
4. *The European generation adequacy outlook referred to in point (b) of paragraph 3 shall cover the overall adequacy of the electricity system to supply current and projected demands for electricity for the next five-year period as well as for the period between five and 15 years from the date of that outlook. The European generation adequacy outlook shall build on national generation adequacy outlooks prepared by each individual transmission system operator.*
5. *The annual work programme referred to in point (d) of paragraph 3 shall contain a list and description of the network codes to be prepared, a plan on coordination of operation of the network, and research and development activities, to be realised in that year, and an indicative calendar.*
6. *The network codes referred to in paragraphs 1 and 2 shall cover the following areas, taking into account, if appropriate, regional specificities:*
 - (a) *network security and reliability rules including rules for technical transmission reserve capacity for operational network security;*
 - (b) *network connection rules;*
 - (c) *third-party access rules;*
 - (d) *data exchange and settlement rules;*
 - (e) *interoperability rules;*
 - (f) *operational procedures in an emergency;*
 - (g) *capacity-allocation and congestion-management rules;*
 - (h) *rules for trading related to technical and operational provision of network access services and system balancing;*
 - (i) *transparency rules;*
 - (j) *balancing rules including network-related reserve power rules;*

(k) rules regarding harmonised transmission tariff structures including locational signals and inter-transmission system operator compensation rules; and

(l) energy efficiency regarding electricity networks.

7. The network codes 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.

8. The ENTSO for Electricity shall monitor and analyse the implementation of the network codes and the Guidelines adopted by the Commission in accordance with Article 6(11), and their effect on the harmonisation of applicable rules aimed at facilitating market integration. The ENTSO for Electricity shall report its findings to the Agency and shall include the results of the analysis in the annual report referred to in point (e) of paragraph 3 of this Article.

9. The ENTSO for Electricity shall make available all information required by the Agency to fulfil its tasks under Article 9(1).

10. The ENTSO for Electricity shall adopt and publish a Community-wide network development plan every two years. The 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.

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 (9);

(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.

In regard to point (c) of the second subparagraph, a review of barriers to the increase of cross-border capacity of the network arising from different approval procedures or practices may be annexed to the Community-wide network development plan.

11. The Agency shall provide an opinion on the national ten-year network development plans to assess their consistency with the Community-wide network development plan. If the Agency identifies inconsistencies between a national ten-year network development plan and the Community-wide network development plan, it shall recommend amending the national ten-year network development plan or the Community-wide network development plan as appropriate. If such national ten-year network development plan is elaborated in accordance with Article 22 of Directive 2009/72/EC, the Agency shall recommend that the competent national regulatory authority amend the national ten-year network development plan in accordance with Article 22(7) of that Directive and inform the Commission thereof.

12. Upon request of the Commission, the ENTSO for Electricity shall give its views to the Commission on the adoption of the Guidelines as laid down in Article 18.

As mentioned earlier, since 1996 EU legislation has foreseen the establishment of a single electricity market where electricity sellers and buyers (generators, suppliers, traders, end-users, etc.) have the right to enter into bilateral or multilateral trading arrangements independent of the Member States where they are located, as long as those transactions are compatible with the legitimate interests of other market agents and comply with applicable market and operational rules. Handling the requests of a very large array of market players, in order to enable the development of well-functioning European wholesale and retail markets while fulfilling several reliability criteria, is a challenging task, especially given the geographical scale and the potential volume involved.

EU legislation assigns to TSOs the obligation to facilitate electricity trade, including cross-border trade, while ensuring appropriate reliability and security standards. However, until recently EU legislation did not specify how TSOs should coordinate their activities in order to ensure an effective network operation at European level. 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 715/2009¹⁹, amending Regulation (EC) No 714/2009, at last provided some concrete guidance, as shown in Box 9.

Box 9: Specification of TSO obligations at EU level

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.’;

19 O.J. L 115/39 of 25.04.2013

Besides the Treaty and the two above mentioned 2009 documents - Directive 2009/72/EC and Regulation (EC) No 714/2009 - the energy industry legal framework consists of many more pieces of legislation. The official site of the Directorate-General for Energy (DG ENER) lists 13 for electricity alone, as of 19 December 2014²⁰. The following Box recalls the main types of EU secondary legislation (the primary legislation being the Treaties)²¹.

Box 10: Basic types of EU secondary legislation ²²

There are three basic types of EU legislation: regulations, directives and decisions.

A regulation is similar to a national law with the difference that it is applicable in all EU countries.

Directives set out general rules to be transferred into national law by each country as they deem appropriate.

A decision only deals with a particular issue and specifically mentioned persons or organisations.

Regulation (EC) No 714/2009 foresees other types of documents, namely “Guidelines” and “Network Codes”²³. A *Guideline* is approved by the Commission on its own and published as “Commission Regulation” (the other type of regulation, like Regulation (EC) No 714/2009, is called “Regulation of the European Parliament and of the Council”). A *Network Code* must be approved through the “Committee procedure”²⁴, which means a Committee of representatives of the Member States chaired by the representative of the Commission and voting with a qualified majority. Fig. 1 describes different types of EU legislation governing the electricity sector in Europe at present, while Fig. 2 depicts the typical national framework in each Member State.

At EU level there is no energy regulator: no independent body “making regulation”. In the EU, there are “regulations” issued by the Council and Parliament or by the Commission and there are decisions of a regulatory nature taken by non-legislators - either the European Commission or special Committees. Usually at national level, regulation means rules and decisions taken by the

20 <https://ec.europa.eu/energy/sites/ener/files/documents/2014-12-19-ener-legislation.pdf>

21 There are two more types of unilateral acts foreseen in Article 288 of the Treaty: opinions and recommendations; unlike regulations, directives and decisions, these two have no binding force. Furthermore, the Commission also issues “atypical” acts such as communications and recommendations.

22 http://ec.europa.eu/legislation/index_en.htm

23 Article 290 of the Treaty establishes that “A legislative act may delegate to the Commission the power to adopt non-legislative acts of general application to supplement or amend certain non-essential elements of the legislative act.”

24 For a full description of the Committee Procedures (“Comitology”) see Council Decision of 17 July 2006 amending Decision 1999/468/EC laying down the procedures for the exercise of implementing powers conferred on the Commission. O.J. L 200 of 22.7.2006

designated national regulatory authority. In the next Section, the existing EU “regulatory rules” are briefly described.

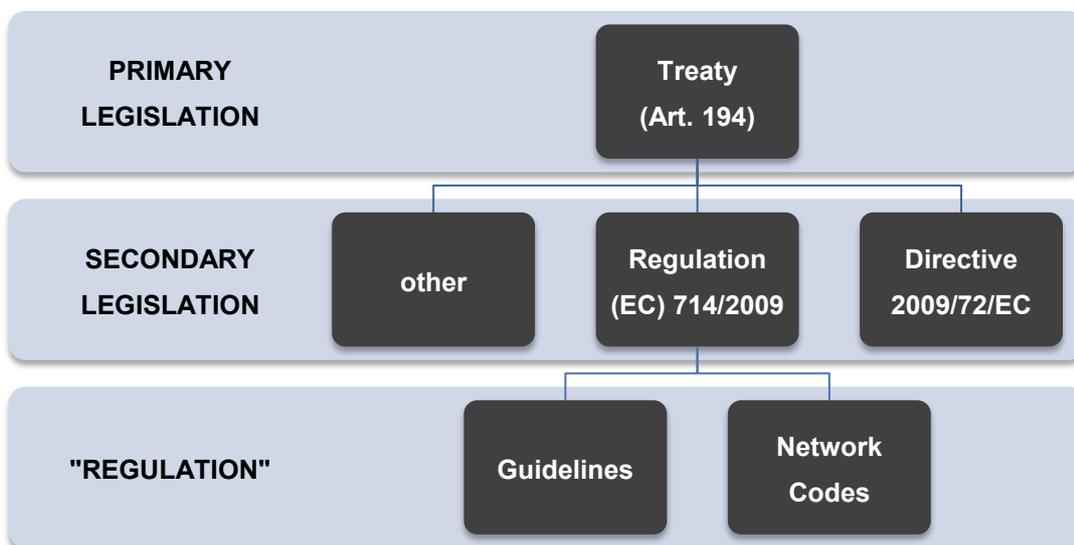


Fig. 1: The EU legal framework - electricity

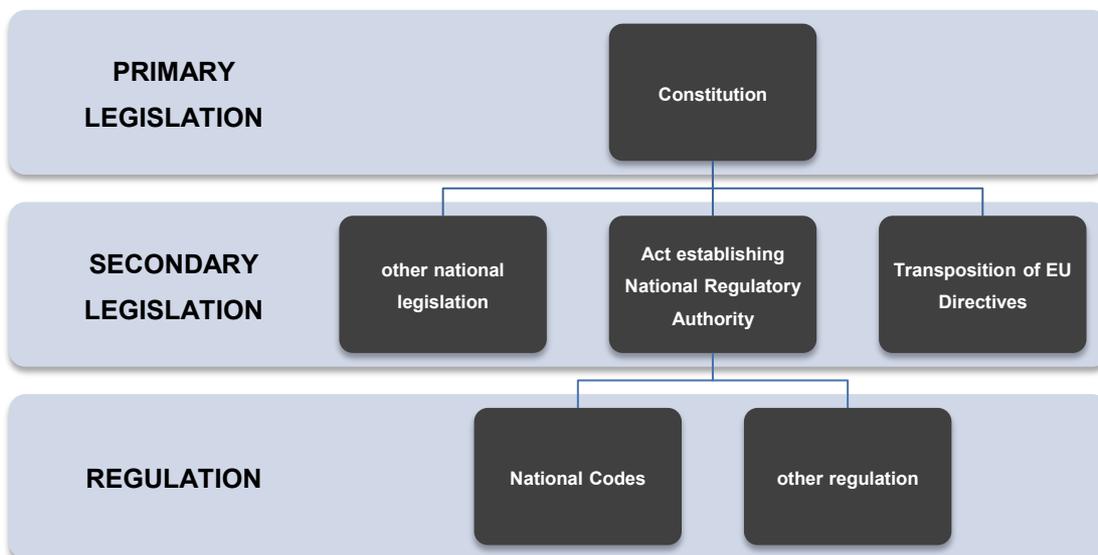


Fig. 2: The typical national legal framework - electricity

1.1.3 The European “regulatory” framework

As described in the previous Section, at EU level there is a complex legal framework, including legal acts called “regulations”, but there is no regulatory framework as such, which would be developed by an independent EU regulator, similar to the national regulatory frameworks established by

independent national regulators. This “regulatory gap” between national and EU levels was identified many years ago as a major obstacle to the proper functioning of the internal energy market²⁵, and it has not yet been overcome.

What we use to call the European “regulatory” framework is mainly a set of guidelines and network codes that have been developed since the third energy package came into force. The number and the intrinsic complexity of these documents is growing rapidly. It sometimes makes it difficult for newcomers to understand the actual functioning of the internal energy market at the EU level.

Fig. 3 describes the process leading to the approval of Network Codes.

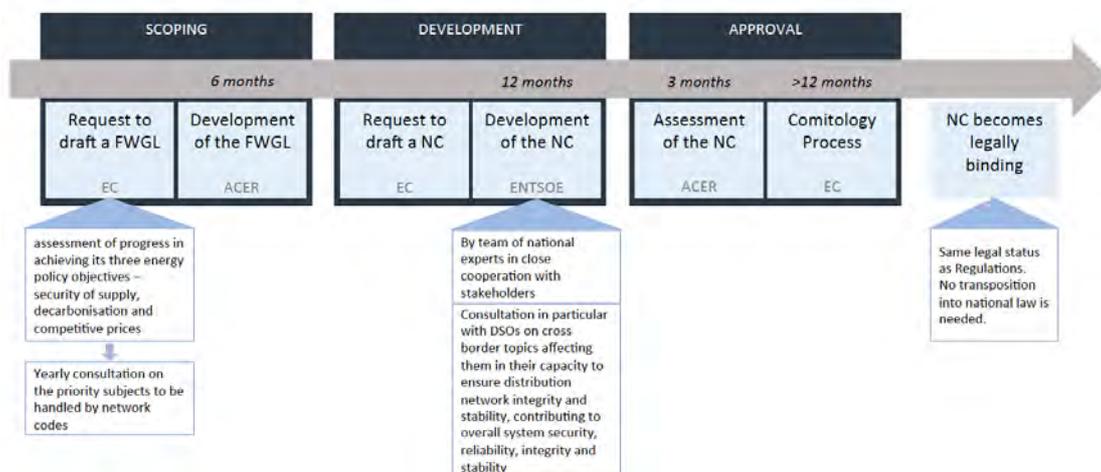


Fig. 3: Development process of Network Codes ²⁶

Fig. 4 indicates all Network Codes currently under development, while Fig. 5 shows the status of their respective developments. Table 1 provides a brief overview of each Network Code.

25 Cf. Vasconcelos, J. (2001) “Regulation of energy markets and European governance - discussion paper” CEER

26 FWGL means framework guidelines and NC means network codes.

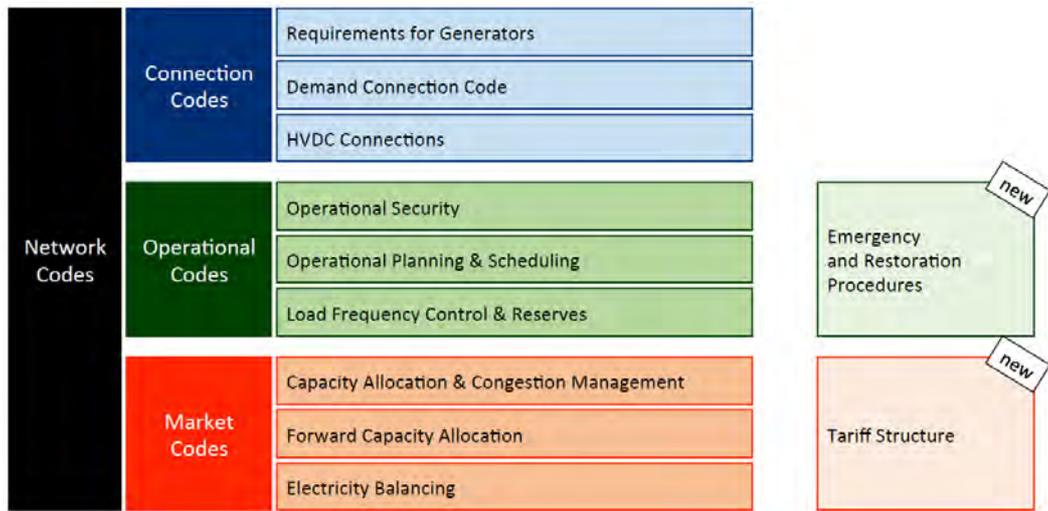


Fig. 4: Overview of Network Codes under development

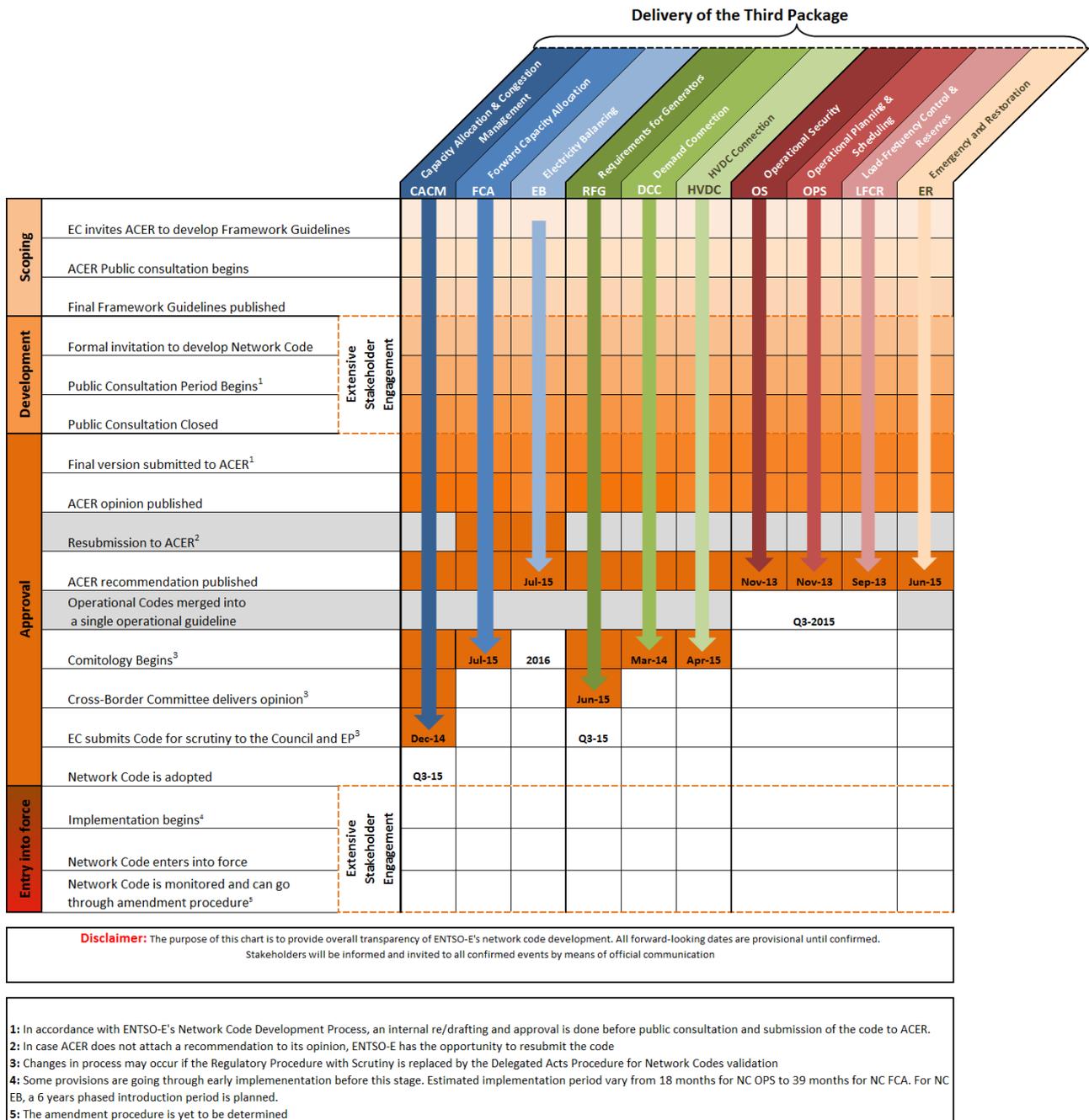


Fig. 5: Network Codes development status (July 2015) ²⁷

²⁷ <https://www.entsoe.eu/major-projects/network-code-development/updates-milestones/Pages/default.aspx>

Network Code	Timeframe	Specifications
Requirements for Generators	Adopted in Comitology Process (2015)	<ul style="list-style-type: none"> Size-dependent, technical requirements for Power Generating Modules Common framework of obligations for Network Operators to appropriately make use of the Power Generating Facilities' capabilities
Demand Connection	Comitology Process (entered 2014)	<ul style="list-style-type: none"> European rules on how demand interacts with the transmission system Ensure effective contribution to the stability of the power system by all distribution networks and demand facilities Clarify the role that demand response will play in contributing to the deployment of RES
HVDC Connection	ACER recommendation submitted (2014)	<p>Manage HVDC lines and connections:</p> <ul style="list-style-type: none"> Determine contribution to system security Promote coordinated development of the infrastructure
Operational Security	ACER recommendation submitted (2013)	<p>Framework for maintaining a secure interconnected European electricity transmission system: common, legally binding principles and rules for operating electricity transmission networks</p> <p>→ Operational Security requirements and principles; Data exchange; provisions for training of System Operator Employees</p>
Operational Planning & Scheduling	ACER recommendation submitted (2013)	<p>Common time horizons, methodologies and principles allowing to carry out coordinated Operational Security Analysis and Adequacy analysis to maintain Operational Security and support the efficient functioning of the European internal electricity market</p>
Load Frequency Control & Reserves	ACER recommendation submitted (2013)	<ul style="list-style-type: none"> Formalised harmonised system frequency quality targets Objective and harmonised requirements regarding Load-Frequency-Control (LFC) and Reserves
Emergency & Restoration²⁸	Recommended for adoption by ACER (2015)	<p>Procedures and remedial actions to be applied in the Emergency, Blackout and Restoration states</p>
Capacity Allocation & Congestion Management	Entered into force (2015)	<p>Rules that will introduce an EU Target Model: single approach to cross-border electricity trading</p> <ul style="list-style-type: none"> for cross-border capacity allocation in day-ahead and intraday timescales. Outlines the way in which capacity will be calculated across the different zones for congestion management
Forward Capacity Allocation	Comitology Process (entered 2015)	<p>Design and operation of the markets in which the right to use cross-border capacity is sold in advance</p>
Electricity Balancing	Recommended for adoption by ACER (2015)	<p>Steps for transforming balancing markets to a set of regional markets and later a pan-European market</p>

Table 1: Main contents of current electricity Network Codes

²⁸ Operational codes (OS, OPS, LFC&R) were merged and are about to enter comitology.

Despite the fact that several national markets are increasingly converging and that the European regulatory framework is increasingly driving this harmonisation process, there are still different national initiatives taking place. Perhaps the most telling example is capacity markets, a solution for rewarding generators for their potential capability to produce electricity (their installed generation capacity), in addition to the flows of energy that they actually generate and sell in the market.

An inefficient and uncoordinated way of implementing capacity markets could aggravate existing EU market inefficiencies and hold back the implementation of urgent EU market reforms. Figure 15 shows the diversity of capacity remuneration mechanisms (CRM) in Europe as of June 2014.

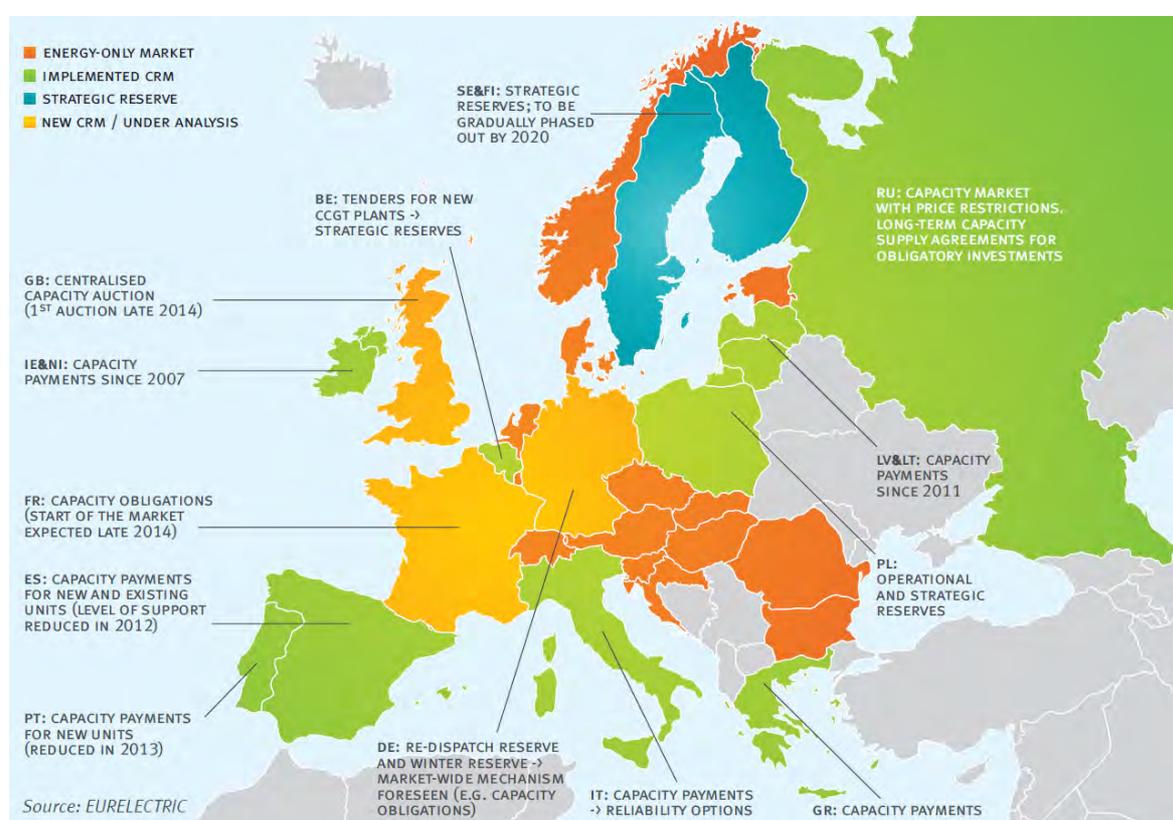


Fig. 6: Implementation of CRM across Europe. Source: Eurelectric, 2014

Reacting to this, on April 29, 2015, the European Commission launched a sector inquiry into capacity mechanisms as potential disruptions of EU markets. Commissioner for Competition Margrethe Vestager, said: *"This sector inquiry sends a clear signal to Member States to respect EU*

state aid rules when implementing capacity mechanisms, and contributes to the Commission's goal to build a true Energy Union in Europe." ²⁹

1.1.4 The functions of European TSOs today

The TSOs perform different tasks to fulfil their duties and manage the power system. The co-existence of different tasks is better presented in a TSO modular analysis framework similar to the one presented in Rious et al. (2008). These TSO functions can be classified as either hardware or software functions. The “*Hardware*” functions relate to the management of the assets of the network, implying investment in and maintenance of the network; including the connection of grid users. The “*Software*” functions relate to the operation of the grid and the system, which covers the system operation, the facilitation of the market operation at the interfaces with other agents.

Hardware function 1 - Network maintenance and expansion

Transmission planning is the process that evaluates potential investments and maintenance plans in the network. New transmission assets are evaluated in the investment plan determining when, where and how much capacity should be added, assets be maintained or upgraded, along with other technical characteristics of the assets. Scheduling of line outages and other tasks necessary to maintain network operation under some adequate reliability levels are evaluated in the maintenance plans (Pérez-Arriaga, 2013).

Transmission planning is not only necessary at national level (as the Intra-TSO network upgrade investments do), but also for interconnecting different national systems (as an Inter-TSO network upgrade investment has to do). A full separation of these two kinds of planning (internal and cross-border) can only result in inefficiencies because, on the one hand, investments needed to solve problems within one TSO control zone do not necessarily favour trade between TSO zones and, on the other hand, cross-border investments can result in inefficiencies in the internal grid which have to be solved in order to get the full potential of the cross-border investment.

Furthermore, power generation and transmission are complementary activities that must be coordinated to ensure the optimal use and development of the transmission grid (e.g., a new line can be a substitute to a new plant; and vice-versa). Before liberalisation and the unbundling of generation and transmission activities, a single vertically integrated utility planned the joint expansion of generation and transmission. It is now more difficult to plan a system expansion because generation and transmission activities are independent, and several different actors take

²⁹ http://europa.eu/rapid/press-release_IP-15-4891_en.htm

independent, uncoordinated decisions. Different regulatory approaches have been proposed to solve this power network problem (Pérez-Arriaga and Olmos, 2007):

1. *Supervised centralised planning and regulated remuneration*: Planning is made by a specialist agent (the “system operator”), and the transmission network owner is responsible for expansion proposals. In this case, the remuneration is based on the actual grid infrastructure. New facilities are included in the regulated asset base and remunerated at a specific rate of return.
2. *Traditional regulated monopoly*: The transmission company is responsible for making investment decisions, and remuneration is based on an efficient grid design and operating cost criteria using an incentive-based monopoly regulation, such as a revenue cap or price cap regulation.
3. *Market player initiative with regulatory supervision*: It is the grid users who propose network reinforcements, taking into consideration the benefits they expect to receive. The regulatory agency evaluates the proposals using pre-established criteria and organises a tender for building and maintenance. The transmission company that wins the tender is remunerated according to its bid, and the operation is left to the system operator.
4. *Merchant lines*: It is the merchant investors who develop the network and use it or collect the congestion rents or other revenue borne on their lines.

Another important issue in transmission planning is the time lag between investment horizons for generation and for the network; this may create significant uncertainty when planning the network. New generation units’ connection may create congestions in the system before the TSO can upgrade the grid. In order to solve this problem, the TSO may anticipate the connection of new users and plan the network investments to avoid congestion. This allows the TSO to deal with the time lag between the building times of new generation units and the time necessary to upgrade the network. However, this anticipation strategy is only efficient when the time differences are significant and the cost of anticipation and errors is moderate (Rious et al., 2011).

Hardware function 2 - Connection of grid users

TSOs must guarantee non-discriminatory and transparent access to the network for all grid users (generation plants, loads, etc.). However the physical constraints of the network may impose restrictions to the connection of users, and therefore it may be necessary for the TSO to expand the network or to refuse access. This asks for clear and objective rules to authorise network

connections, as well as predetermined criteria to refuse access. At European level, these rules are being proposed by ENTSO-E in the codes of network connection (Section 1.1.3).

It is frequent that short-term signals are complemented with long-term tariffs known as transmission charges. These transmission charges send other economic signals to users, to encourage them to reduce the costs of network expansion. This can be achieved if the allocation of transmission costs rely on some basic principles as explained by Pérez-Arriaga (2013):

1. The “Beneficiary pays” principle: the transmission cost should be divided among users in proportion to their aggregate economic benefits. Thus, both generators and loads should pay because both benefit from the network expansion.
2. Transmission charges should not be based on individual commercial transactions: transmission charges should depend on objective grid related characteristics, such as the location of the users of the network and the aggregated temporal patterns of power injection (for generators) and power withdrawal (for loads). Transmission charges should not depend on individual commercial transactions between users. If this principle is not met, it may result in “pancaking”, a situation in which users must pay cumulative tariffs for each region where power is expected to pass in the contract between buyer and seller, regardless of actual power flows. In fact, individual commercial transactions cannot be tracked in physical flows of electricity due to the superposition of flows resulting from the various injections and withdraws.
3. Transmission charges should be established ex ante: Transmission charges for new users should be established ex ante and not be updated for a reasonable time. Thus, predictable economic signals are sent to investors in order to choose the most suitable sites with low financial risks.
4. The format of the transmission charges matters: The format of the transmission charges has implications for the market behavior of agents. The level of distortions of the economic dispatch is not the same if connection transmission charges are structured as lump sums (€), or if volumetric charges (€/MWh) or capacity charges (€/MW) are applied instead.

Transmission charges can therefore be divided into connection charges and Use of the System (UoS) charges. Connection charges can be shallow charges or heavy charges. With the shallow charges, new users are only charged for a small portion of the fixed costs of the network. This portion only covers the cost of the infrastructure required to connect the new user. The costs of any other reinforcement in the network are socialised. Heavy charges cover the cost of both the direct connection infrastructure and the necessary network reinforcements. Thus, new users are charged the total cost of all new connection infrastructures.

Software function 1 - System operation

Electricity systems consist of generation plants, transmission and distribution networks, and loads. The transmission network is necessary to transmit the electricity from generation plants to consumption centers. The distribution networks carry the electricity to users of smaller size that are not connected to the transmission grid. Any disturbance in the system may compromise the overall reliability as well as the supply and balance of electricity. For this reason, a global operation of the system is necessary, which comprises measures required to ensure the reliability and continuity of supply, as well as coordination between the transmission and generation to keep the energy flowing to the load under certain quality conditions. In the EU, TSOs are responsible for the power system operation, taking into account externalities such as grid congestions or imbalances between generators and consumers, as explained below.

Balancing generation and demand

To keep energy flows flowing, power systems require a permanent equilibrium between generation and consumption. Even small deviations from the equilibrium (“imbalances”) affect a key parameter - the operating frequency of the system. Keeping this balance between generation and demand is a complex task because, to this day, there is no affordable massive electricity storage - which implies that actual coordination between generation and demand can only be fully assessed near the real-time operation of the system.

The primary structural consequence is that this real time power balance management is not performed by the wholesale market on its own (as a decentralised decision process), but by a “central authority” responsible for the security of the system (as does “air control” for air transportation). While this balancing task is administered by the TSO, it is also a key and essential component of the market itself (market design and market sequencing), which hence go far beyond the mission played within the proper transmission area (Glachant and Saguan, 2006). The TSOs are “market facilitators”. Power markets cannot work without the TSOs dedication to the markets.

In general terms, the balancing tools (being markets or other mechanisms) allow the TSOs to guarantee the feasibility of all operations of power injection (generation) and power withdrawal (consumption) from several minutes or hours before the real-time operation to its actual implementation in real-time. The main difference between “real-time markets” and “balancing mechanisms” is that real-time markets use the market clearing price to determine the beneficiaries and the value of electricity in real time, while balancing mechanisms impose a unilateral penalty to the imbalances. The imbalance costs are incorporated into the prices of the observed volume gap

between the power contracted previous to real-time (especially in day-ahead and intraday markets) and the actual volume of power being consumed and generated.

The way balancing services are provided, managed and charged to users has changed over time; the more sophisticated electricity markets become and the more intermittent generation is added to the system, the more balancing services play a crucial role. The role of TSOs in managing ancillary services in general and balancing services in particular has also changed substantially since liberalisation started.

Congestion management

The power flows in most of the transmission lines cannot be steered through any contractual path. They obey Kirchhoff's laws of physics and depend on the impedance of the lines as well as on the injections and withdrawals of power at the different network nodes. A congestion occurs when the network security constraints (mainly caused by the thermal limits of the lines) cannot be violated, making it impossible to deliver the desired amount of energy for grid users from one node to another. Different mechanisms can be used to clear the congestion. The choice of a particular mechanism depends on the market design and the system size, i.e., it is highly dependent on regulatory models, and may undergo significant changes in a short time period.

Theoretically, the most efficient way to determine short-term electricity prices is the nodal-pricing system (Green, 2007; Neuhoff et al., 2011). In this setting, the electricity market explicitly takes the actual operational constraints imposed by the power network into account and remunerates the corresponding actual costs of producing and transporting energy through the different nodes - which may lead to different electricity prices in each node of the system (Schweppe et al., 1988).

Another congestion management mechanism is redispatching. In this setting, the actual constraints of the electricity network are not taken into account in the daily wholesale electricity market-clearing process. One assumes that all energy is traded on a single "reference node", and therefore that the electricity price is the same for all nodes in the system. This setting may be suitable when the transmission network is sufficiently robust and when there are no structural constraints to repeatedly cause significant congestion in the system. When some congestion arises, the redispatch of some generation units is necessary to perform the system adjustments in order to clear the congestion. Thus, only the redispatched generation units are involved in the adaptation to the grid constraints. They are the only ones to receive direct economic signals on the existence of transmission constraints in the implementation of the market equilibrium.

In addition to the nodal-pricing system and the redispatch mechanism, congestion at interconnections between multiple power systems might use explicit and implicit auctions (Pérez-Arriaga and Olmos, 2005). In the explicit auctions, the interconnection capacity is allocated independent of the energy markets outcomes. In this setting, first the transmission capacity in the

interconnection is allocated, and it is only in a second phase that the generation volume and the prices of the interconnected electricity markets are determined. In the “implicit” setting, the interconnection capacity is allocated according to the merit order of energy bids made by buyers and generation companies.

When systems are interconnected radially, a “market splitting” mechanism can clear congestion by establishing different prices in the sub bidding areas of the same market administered by a single market operator. The electricity market price is the same for all the sub-areas only when there is no congestion on the interconnections. There are different sub-area prices in the event of congestion. Another mechanism known as “market coupling” is used when the adjacent markets and systems cannot be centrally managed by a single market operator (within a single PX) due to institutional constraints. Working between several neighbouring PXs, this mechanism allows agents to offer their energy locally in local exchanges, which are all coordinated with a single common price when no congestion occurs. At congestion, these PXs are decoupled from each other. Each system operator is responsible for communicating with the neighbouring system operators to coordinate their grid and system information. Thus, the congestion on interconnections is cleared through an iterative process of information exchange, and different electricity prices in the areas are determined.

Software function 2 - Interface with other actors

a) With other TSOs

One of the main objectives of energy policy in Europe is the integration of national electricity systems into a single EU market. The TSOs in the different Member States must interact and coordinate their decisions in order to achieve this goal. Coordination between TSOs is necessary in both the long term for the proper planning of the transmission network expansion and the short term for a proper system operation.

There are two basic types of coordination, “uniformisation” and “combination” (Rious et al., 2008). “Uniformisation” involves the harmonisation of the rules. Therefore, the TSOs use the same methods for the operation and planning of the system and they exchange information about the status of their systems. “Combination” involves establishing rules that allow for the coexistence of different individual mechanisms in different zones.

b) With DSOs

The transmission network is designed to balance generation and demand within a large territory in order to dispatch the most efficient generation, whereas distribution networks have been conceived to carry electricity to consumers not directly connected to the transmission grid.

Under this scheme, TSOs are responsible for managing the transmission network and the system, and they interact with several market agents. Most Distribution System Operators (DSOs) perform a more passive kind of system operation, in the sense that they are only responsible for managing their own networks. Thus, the distribution grids are mainly acting beyond the borders of observability and the control areas of TSOs, which are, up to now, very often limited to the flows at the boundaries between both networks. Some degree of interaction and coordination between the TSO and the DSOs must be found in order to have a better knowledge and control of all system conditions and to achieve an optimal and efficient system operation.

c) Market facilitation

Although this is not a direct inherent task of TSOs, they are actually responsible for developing the rules and operating some of the electricity markets, i.e., TSOs are market facilitators. As presented in the previous Section, ENTSO-E is responsible for developing the network codes to be used in Europe. These network codes are a set of rules for the connection of users to the grid, the operation of the network, and the electricity markets. De facto, ENTSO-E is responsible for developing the rules for cross-border capacity allocation in the short and long-term, congestion management and the creation of balancing markets. In addition, the TSOs are responsible for managing and operating these balancing markets in order to ensure an optimal operation of the system.

d) Institutional actors

Besides interacting with other T & D network operators, market operators, transmission network users and some market agents, TSOs are also required to interact with institutional actors, such as national regulatory authorities, the European Commission, ACER and several more or less informal fora.

Most of the functions currently performed by TSOs are described in national and EU legislation, as well as in national and EU Network Codes. However, some functions are not at all mentioned in any legislation or are not clearly defined. The following table provides a summary of the functions *de facto* performed nowadays by most European TSOs.

	Security of supply	Market facilitator
Long term (> 1 year)	System adequacy outlook Grid planning : TYNDP Long term security analysis (1 to 5 years ahead)	Year ahead capacity calculation Yearly capacity allocation (auction office)
Medium term (> 1 week, <1year)	Adequacy assessment (seasonal, monthly) Grid Security analysis Outage planning (yearly plans, monthly update)	Month ahead capacity calculation Monthly capacity allocation (auction office)
Short term (>1h, < 1 week)	Outage planning (weekly plan, daily confirmation) Grid security analysis (weekly, D-2, D-1, intraday) Generation/demand balance assessment Remedial actions ahead of real time (changes in generation schedule)	D-2 / D-1 capacity calculation Intraday capacity calculation Providing parameters to day- ahead and intra-day market coupling platforms
Real time	Continuous Security analysis (frequency deviation, grid capacities) Balancing services activation Remedial actions activation to relieve grid constraints (grid topology, generation schedule changes)	
Post real time	BRP positions settlement Grid access billing	

Table 2: Summary of functions currently performed by European TSOs

It should be pointed out that the “traditional”, pre-liberalisation TSO functions have themselves been considerably extended over the last few years. Here are some examples of such expansion:

- Adequacy assessments evolved from pure network and generation adequacy towards more general system adequacy (network, generation, voltage/reactive power, inertia, etc.). Assessments developed from pure national ones towards regional and European wide assessments.

- Stability studies (transient behavior of the system, wide area effects) nowadays include interconnections with adjacent non-EU systems (e.g. Turkey).
- Analysis of market behavior became a “standard” TSO activity. Analysis of behavior of market participants and of gaming possibilities is required for improving various products (e.g., auctioning products, balancing products), for further developing market design and the interface between market operation and system operation, as well as for performing a meaningful cost-benefit analysis concerning new transmission projects.

Sometimes, TSOs are active promoters of innovation, for instance introducing new predictive control strategies, exploring the possibilities of netting balancing needs in real time and introducing new market clearing algorithms to maximise social welfare.

1.1.5 Voluntary regional cooperation among system operators

The need for enhanced operational coordination among TSOs has been recognised for a long time and for several reasons, namely:

- improving the overall reliability of the European electricity system;
- enabling the more efficient use of existing interconnections for cross-border trade;
- ensuring system security under the increasing volume of intermittent generation.

The large power disruptions of 2003 and 2006 clearly revealed the need for enhanced coordination at EU level. The European Commission, regulators and TSOs concluded that immediate action was necessary and some TSOs started working together in order to set up appropriate voluntary structures.

In December 2008, Coreso (Coordination of Electricity System Operators), the first regional technical coordination centre for electricity was established, bringing together the French (RTE) and Belgian (Elia) transmission system operators. In February 2009 Coreso launched its operational activities in a centralised coordination centre in Brussels: “Every afternoon, seven days a week, Coreso provides forecasts of the electrical flows in the CWE area (France, Belgium, Germany, the Netherlands and Luxembourg) for the following day (so-called ‘D 1 activities’).”³⁰ Later on, National Grid from the UK, Terna from Italy and 50hertz from Germany joined Coreso.

Another initiative was also launched in December 2008: TSC – (TSO Security Cooperation). It now includes 13 TSOs (see Fig. 16) with its headquarters in Munich.

³⁰ <http://www.coreso.eu/mission/history-of-coreso/>



Fig. 7: TSC - TSO Security Cooperation ³¹

“The TSC IT tool allows member TSOs to access key data and provides them with access to advanced methods for choosing appropriate remedial actions. These IT services can be used by TSOs for day-to-day operations in their regions, starting first with day-ahead planning processes. In a second phase, these services will be expanded to grant TSOs with nearly real-time control over their operations.

TSC strives to achieve a high level of system security in the heart of Europe. This common IT platform was implemented in a joint project in 2010.” ³²

31 <http://www.tscnet.eu/where-we-are/>

32 <http://www.tscnet.eu/what-we-do/>

1.2 Major trends shaping the transition towards a low-carbon energy landscape

The transition towards low-carbon electricity systems was triggered by changes in energy policy. Back in 2007, the EU acknowledged that *“given that energy production and use are the main sources for greenhouse gas emissions, an integrated approach to climate and energy policy is needed”*³³ in order to limit the global average temperature increase to not more than 2° C above pre-industrial levels. According to the Council, *“Integration should be achieved in a mutually supportive way.”*

This *“integrated approach”* has produced several directives and regulations with significant impact upon energy markets, mainly as regards the development of electricity from renewable energy sources.

The EU pledge to cut greenhouse gas emissions was reinforced in 2009 when the Council decided *“to reduce greenhouse gas emissions by 80-95% by 2050 compared to 1990 levels”*³⁴. As noticed by the Council in 2011, this *“will require a revolution in energy systems, which must start now”*³⁵.

As regards electricity, this *“revolution in energy systems”* is enabled by a large spectrum of new technologies, briefly described below, and it is composed of two concurrent revolutions, respectively on the supply-side (Section 1.3.1) and on the demand-side (Section 1.3.2).

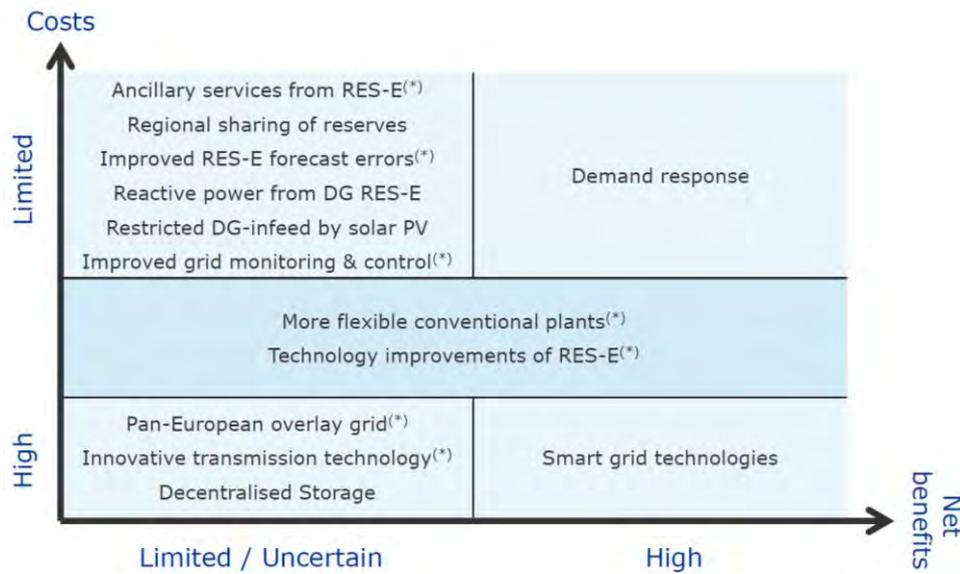
Research into further measures, which may support the successful integration of large amounts of generation from RES into the power system, have so far delivered numerous options that differ in the complexity level of their implementation, in their expected costs and in the areas that they benefit. They range from improved RES forecasts, network monitoring and control to decentralised storage systems and innovative transmission and smart grid technologies.

A report commissioned by the DG Energy of the European Commission on the integration of renewable energy in Europe (DNV GL et al., 2014) offered a scenario-based quantitative analysis of several technical measures. Besides distinguishing them according to the areas of possible cost reductions, it gives an indicative comparison of their costs and net benefits, summarised in Figure 17.

33 European Council conclusions, 8/9 March 2007

34 European Council conclusions, 29/30 October 2009

35 European Council conclusions, 4 February 2011



Source: DNV GL - Report No. 9011-700 (DNV GL et al., 2014)

Fig. 8: Comparison of costs and net benefits of selected technical solutions

Demand response (Chapter 1.3.2) is considered the most attractive option in the report, which at limited costs can facilitate both the integration of RES and overcoming the challenges posed by additional loads from an increasing penetration of heat pumps and electric vehicles. The analysis further showed that measures not requiring significant investments in additional infrastructure and technological developments, and that thus can be implemented at limited costs (top left corner in Figure 16), may lead to substantial savings if deployed in combination. Additionally, they ensure full compatibility with the existing EU Target Model for the electricity market and therefore do not pose major legislative or regulatory obstacles, in spite of the expected increase in the complexity of the system operation and market functioning resulting from their implementation. In contrast, the more expensive options require a location-specific weighing against the costs, as their economic value strongly depends on the specific situation regarding the existing distribution network and DG penetration. The report singles out storage systems by questioning whether decentralised storage will represent an economically justifiable measure by 2030 mainly because of the high capital costs, high conversion losses and the uncertainty of a major cost reduction of the technologies involved.

A brief review is enough to understand that despite the numerous, individually consistent studies and projects to assess different possible pathways to achieve a low-carbon electricity system, Europe has not yet made a decision on an overall consistent strategy to get there. A good example to demonstrate this occurrence is the position on storage devices. As mentioned before, there are parties skeptical of their future relevance due to the high costs of these technologies and the uncertain cost reduction potential that would allow them to be competitive with other options (Florence School of Regulation, *THINK report on storage*, 2012). However, other studies consider

storage systems “a key component of the future low-carbon electricity system” given their need relating “to the increase in intermittent wind and solar and to the demand peak increase” (European Commission, 2013). In other words, “there is no universal answer on whether storage is a profitable investment or adds value to a system” because “all attempts at storage valuation require making assumptions on storage regulation” (Zucker, A., Hinchliffe, T., Spisto, A., 2013). “Storage will thus be affected by the upcoming regulatory discussions emerging from the developments in the power system, such as market design and rules for RES integration or considerations on ownership and operation of storage devices” (Zucker, A., Hinchliffe, T., Spisto, A., 2013).

This dynamic is similarly reflected in the area of electric mobility, which experienced a “*turbulent period of excitement and promise as well as disappointment*” (Amsterdam Roundtables Foundation, McKinsey, 2014). The electrification of the automotive powertrain, driven either by the goal of a decarbonised European economy or simply by the automotive sector’s goal of diversifying the portfolio, still has a low impact in Europe with sales amounting up to 1% (Germany has recently confirmed a goal of 1 million vehicles in 2020; with no clear implementation strategy). However, even with low market shares, electric vehicles (EVs) could intensify the disturbances mainly occurring at the distribution level. Instead of further expanding the grid (a solution that is soon bound to reach its limit of cost effectiveness and local acceptance), the alternative of adopting some sort of “smart charging” mechanisms to optimise the EV’s interaction with the grid has been widely discussed. The extent of the interaction [be it a simple manual and voluntary orientation of the customer to price signals (Demand Response) or the automatic, remote control of the bidirectional charging and storing of electricity (V2G, Demand Side Management)] is technically almost unlimited but depends greatly on economic evaluations, the efforts for improving customer participation and the supporting policies (e.g. Eurelectric, 2015, Karlsruhe Institute of Technology, 2013). The competitiveness of smart charging with other flexibility options will be determined by new approaches to capacity remuneration and reserve markets.

Besides Demand Side Flexibilisation, it is not clear yet which flexibility measures will occur and to what extent they will characterise electricity systems in the future. Irrespective of this, it is clear that more flexibility will be integrated in the distribution and transmission grids through, amongst other things, a large amount of new Information and Communication Technology (ICT). This will combine with increasing the bidirectional interaction of the grid with its components and users, changing the interfaces with other actors of the energy systems, diversifying the short-term system operation and impacting the long-term planning.

1.3 The supply-side and the demand-side revolutions

1.3.1 The supply-side revolution

Back in 2007, the EU decided to achieve a 20 % share of energy from renewable sources in overall Community gross final energy consumption by 2020. This collective target was legally established in the 2009 renewable energy Directive 36 that also indicates the mandatory individual national targets consistent with the 20% share at EU level. More recently, the decision was taken to increase this share to at least 27% by 2030:

“An EU target of at least 27% is set for the share of renewable energy consumed in the EU in 2030. This target will be binding at EU level. It will be fulfilled through Member States contributions guided by the need to deliver collectively the EU target without preventing Member States from setting their own more ambitious national targets and supporting them, in line with the state aid guidelines, as well as taking into account their degree of integration in the internal energy market.” 37

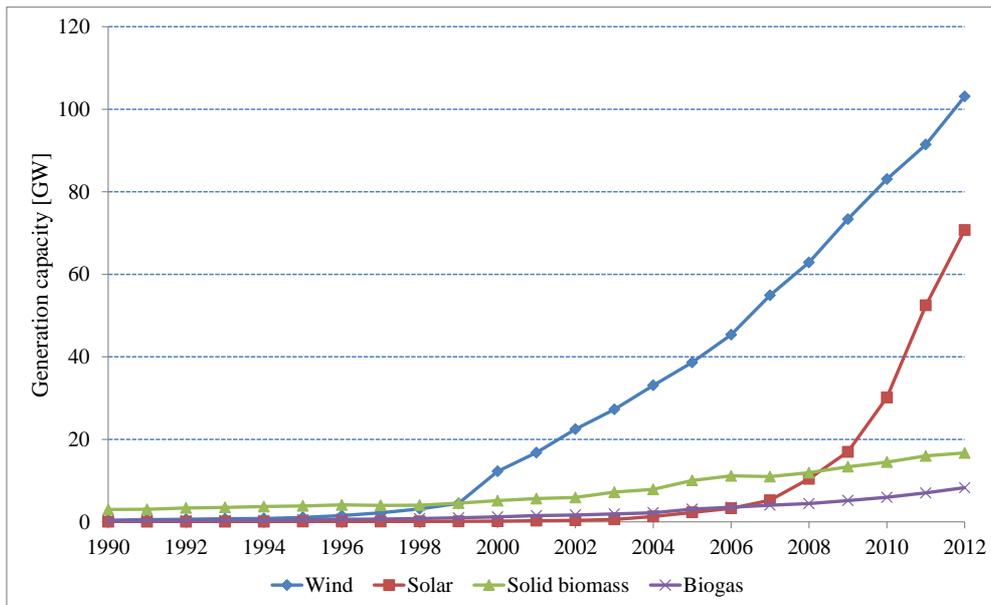
The EU commitment to cut greenhouse gas emissions, first clearly established in 2007, was strengthened in 2009 when the Council decided *“to reduce greenhouse gas emissions by 80-95% by 2050 compared to 1990 levels”*³⁸. According to the Energy Roadmap 2050 (European Commission, 2011a), this overall target translates into a share of RES in electricity consumption between 64% (in a high-energy efficiency scenario) and 97% (in a high renewables scenario).

The generation capacity of renewable energies has increased considerably in the EU-28 in the last 15 years, as shown in Figure 18. Wind and solar resources have had the largest increase in generation capacity in recent years. Wind generation capacity has increased from 4 GW in 1999 to 103 GW in 2012. Solar generation capacity has increased from 2 GW in 2005 to 71 GW in 2012.

36 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. Official Journal L/140 of 5.6.2009

37 European Council conclusions, 23/24 October 2014

38 European Council conclusions, 29/30 October 2009



Source: Eurostat (online data code: nrg_113a)

Fig. 9: Electricity generation capacities in EU-28

In the period between 2000 and 2014, the net electricity generation growth in the EU was almost entirely based on wind (117 GW), solar (88 GW) and gas (101 GW), while fuel oil, coal and nuclear net installed capacities decreased by, respectively, 26 GW, 25 GW and 13 GW³⁹. In 2000, the total installed renewable capacity (including large hydro) represented 24 % of the total installed electricity generation capacity; in 2014, this figure was 42 %⁴⁰.

The integration of such a large amount of intermittent RES has a substantial impact on the development and operation of transmission grids. If the electricity system is managed in a territory large enough, correlation among the input of the different renewable sources will be lower; hence, it will be easier for TSOs to cope with the high variability, low predictability and specific localisation of the intermittent RES. Enlarging the relevant geographical area reduces the impact of RES output uncertainty upon the system operation, as well as the stress on transmission systems. However, this implies that the TSOs face several challenges related to the management of large power flows covering vast distances, and the need of significant investments in the transmission network (Olmos et al., 2015).

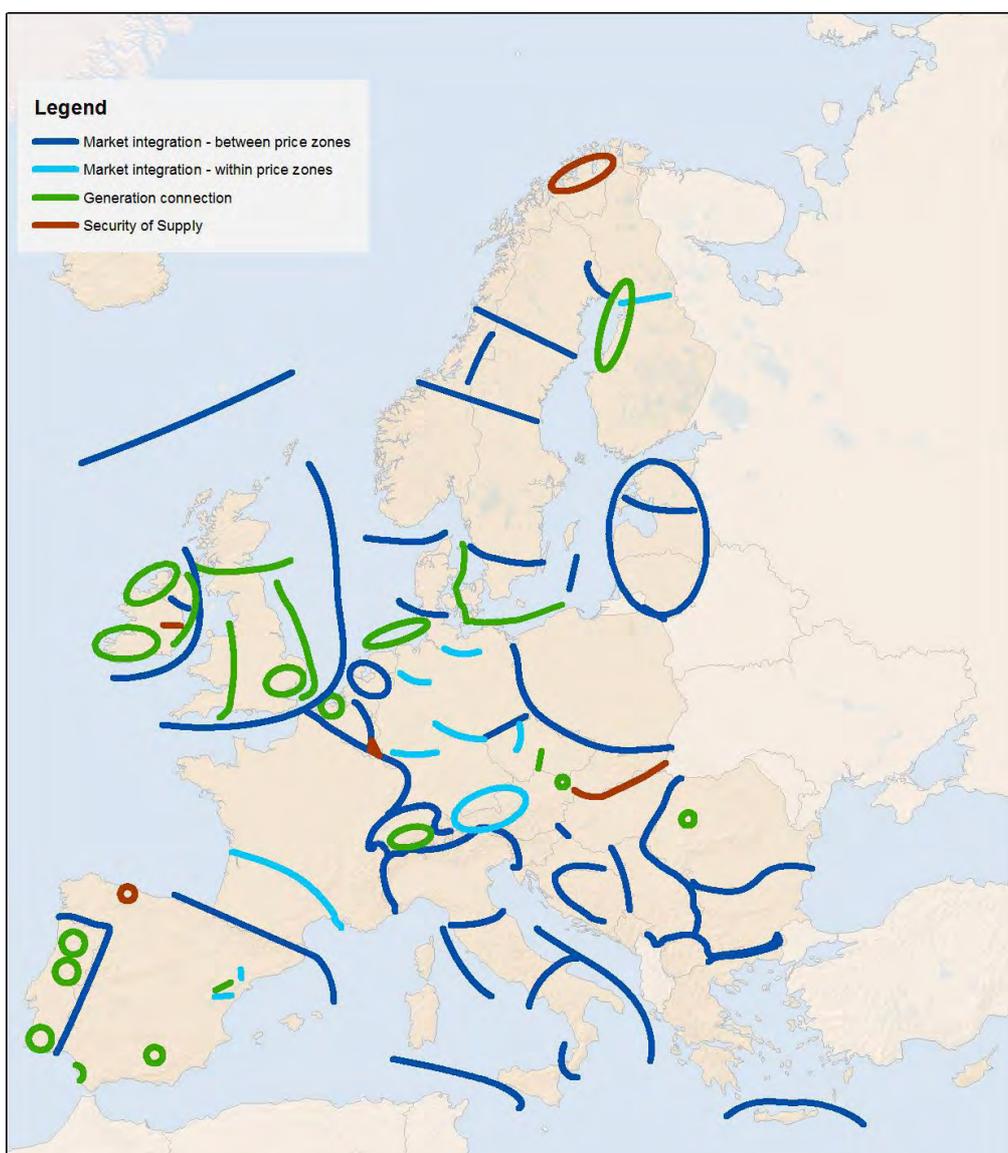
According to the ENTSO-E Ten-Year Network Development Plan (TYNDP), RES development is the major driver for grid development until 2030 (ENTSO-E, 2014a). The TYNDP predicts that the overall interconnection capacity should double on average by 2030. It also identifies about 100

39 <http://www.ewea.org/fileadmin/files/library/publications/statistics/EWEA-Annual-Statistics-2014.pdf>

40 idem

potential bottlenecks in the European electricity system for the next few years, if new transmission assets are not installed on time (see Fig. 19). These situations, in which transfer capabilities may not suffice to accommodate the necessary or likely power flow in a certain grid section at a certain point in time, can occur due to three main reasons: 1) security of supply, 2) direct connection of generation, or 3) market integration (ENTSO-E, 2014a).

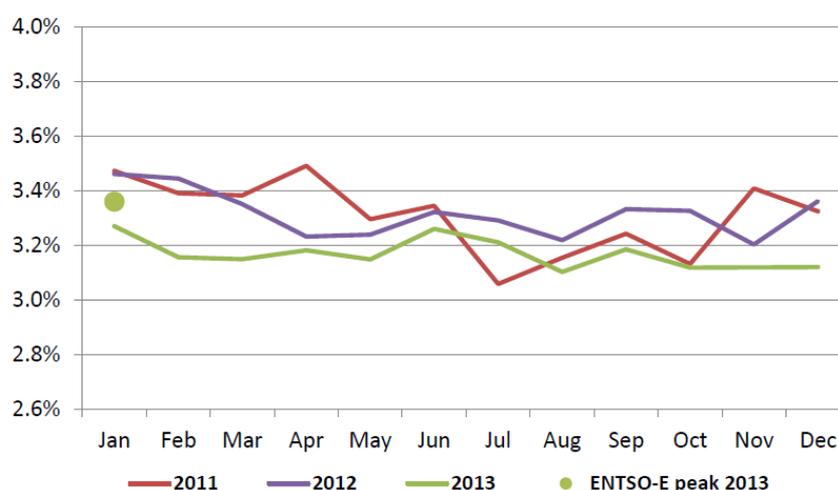
The *first* relates to the situation in which the expected quality standards in specific areas cannot be met due to insufficient supply; the *second* refers to the installation of new generation capacities in locations with a limited transmission capacity; the *third* comprises the necessary distinction to be made between inter-area balancing that is either internal to a price zone or between price zones.



Source: ENTSO-E, Ten-Year Network Development Plan 2014

Fig. 10: Map of main bottlenecks in the European electricity grid

Besides demanding upgrades of the transmission networks, the large-scale deployment of distributed generation from RES also has an impact on the provision of system services. Traditionally, large conventional power plants were the main providers of balancing and ancillary services such as black start capability, frequency response, fast response and the provision of reactive power. With an increasing share of RES in the electricity generation however, new providers are urgently needed and thus a review of how the secure operation of the power supply system can be re-organised must be undertaken. Figure 20 shows the system services reserve as part of the Net Generating Capacity (NGC) evolution for 2011 to 2013, which experienced a yearly decrease.



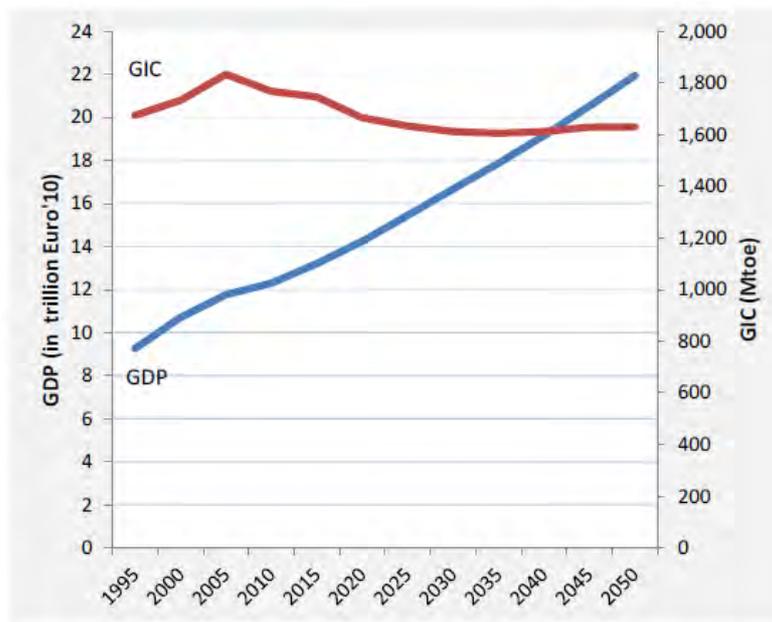
Source: ENTSO-E Yearly Statistics & Adequacy Retrospect 2013

Fig. 11: System services reserve as a part of NGC evolution.

In addition, as certain ancillary services such as the provision of reactive power for voltage control can only be provided locally, requiring distributed generators to provide them seems reasonable. More than the technical challenges, it is argued that it is the lack of a suitable framework that would guarantee fair market access and remuneration mechanisms which is the main reason why distributed generators are not yet significant providers of ancillary services. This is currently being dealt with at national level, with a wide range of approaches being tested. For an increased provision of reserve power by Distributed Generators, the most common solutions entail the alteration of prequalification requirements and the facilitation of market access through, for instance, aggregation (e.g. virtual power plants). Regarding an increased provision of reactive power, the solutions range from the introduction of legally binding requirements (e.g. in Germany, VDE 2011) to the active involvement of distribution grids or customers directly connected to the transmission grid on a voluntary-basis, which is incentivised through the monetary compensation for the delivered reactive power (e.g. in Switzerland, Swissgrid 2011).

1.3.2 The demand-side revolution

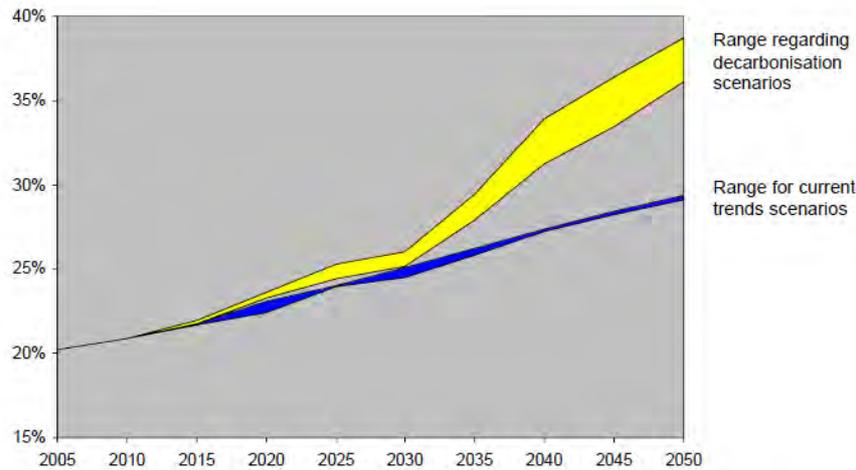
In its updated report on the trends leading up to 2050, the EC defines a Reference Scenario 2013 for the development of the EU energy system under current trends and policies. Based on those assumptions, it deduces that there will be a downward trend on energy consumption and that Gross Inland Consumption (GIC) and GDP growth decouple (Figure 21) – a development that is traced back, among other things, to the adopted legislation on energy efficiency (European Commission 2014b).



Source: EC, EU Energy Transport and GHG Emissions; Trends to 2050; Reference Scenario 2013

Fig. 12: GIC in relation to GDP.

Opposing this downward trend on energy consumption is an increasing share of the electricity of the final energy demand (see Fig. 22). According to the scenario-based outlook contained in the Energy Roadmap 2050, “*electricity will have to play a much greater role than now (almost doubling its share in final energy demand to 36-39% in 2050) and will have to contribute to the decarbonisation of transport and heating/cooling*” (European Commission, 2011a). This will also result in an increasing electricity demand in absolute terms.



Source: EC, Energy Roadmap 2050

Fig. 13: Share of electricity in the current trend and decarbonisation scenarios (in % of final energy demand)

These developments will, of course, put a further strain on an electricity system, which already has to deal with the fact that the integration of an increasing amount of RES in the power supply system has moved away from the traditional “*supply follows demand*” model because of the intermittent nature of RES. Therefore, in order to maintain the frequency equilibrium, new flexibilisation options in the power system must be explored, of which an important one is the flexibilisation of the demand side.

The importance of this measure for successfully completing the transition to low-carbon energy systems has been repeatedly publicised at European level by institutional players such as the European Commission (European Commission 2012, European Parliament 2009a, European Parliament 2012), ACER (ACER, 2014) and CEER (CEER 2011, CEER 2014). The contribution of demand flexibilisation to energy efficiency and market integration objectives, and the fact that it “*can have a comparative advantage over other sources of flexibility in delivering flexibility at particular timescales*” (Cambridge Economic Policy Associates et al., 2014), are both acknowledged and used as rationale for large-scale deployments of smart metering systems (European Commission, 2011c).

However, there are still several concerns hindering the Europe-wide progress in response to the Energy Efficiency Directive requirements. A report issued by the Smart Energy Demand Coalition in 2014 found that only a few European countries “have reached a level where Demand Response is a commercially viable product offering”, while in others the regulatory framework “remain[s] an issue and hinder[s] market growth” (SEDC, 2014). Further reservations arise from the economic uncertainties of the future, as Demand Side Response (DSR) “competes with electricity storage, higher flexibility generation, and interconnection to provide flexibility services. The value of DSR depends upon the cost and usage of these other sources of flexibility. Developments in wind

forecasting will also affect the value that demand flexibility services can provide.” (Cambridge Economic Policy Associates et al., 2014).

Despite the numerous studies on the qualitative and quantitative estimations of the benefits and challenges of Demand-Side Flexibility (DSF) measures and the open discussions, targets and strategy recommendations, it remains difficult for most Member States and at European level to assess the future worth of DSF and its position among other flexibility options. As long as there is no overall optimisation and prioritisation of the flexibilisation options either at European or national level, it is hazardous to predict the extent to which DSF will be relevant to the transmission system operation.

1.4 Policies, markets and the system operation

Before liberalisation, electricity systems were required to be reliable and to provide electricity at fair and reasonable prices. When competition was introduced, first at generation level and for large industrial customers, later on for all customers, electricity systems were required to provide the physical infrastructure for the development of efficient wholesale and retail markets. Market rules and system operational rules had to be defined in order to enable transparent, non-discriminatory and efficient interactions among market agents, market operators and system operators, while ensuring the appropriate reliability and quality of service standards.

In different countries, different market models, different system operation models and different approaches to competition were adopted with differing results.

Today, both EU public policies and national public policies require electricity systems to contribute to the development of a low-carbon economy. This means basically that:

1. Electricity generation must be increasingly based on low-carbon primary energy sources (“green electricity”).
2. The electricity system as a whole must improve its (technical and environmental) efficiency.
3. The electricity system could help other sectors – e.g. industry and transport – to reduce their carbon emissions.

The consequence of 3) is that electricity should increase its share of total final energy demand; therefore, the electricity industry is a potential winner of the transition to a low-carbon economy, while other industries, namely coal and oil, would be losers (assuming no viable Carbon Capture & Storage).

The consequence of 1) and 2) is that the electricity industry should undergo a deep structural change. This impacts not only the generation mix, the demand participation and system operation, but also the market design and the interaction between market operators and system operators. Changes in one area – say, the generation mix and generation profile – have a substantial impact upon all other areas. The problem one faces is a system of equations with several dependent and independent variables. A large number of solutions are technically feasible, although the associated economic, social and environmental costs (and benefits) are not equivalent for each and every solution.

Advanced information and communication technologies, exhibiting increasing performances and decreasing costs, help to solve the problem but, at the same time, they introduce new opportunities, new variables that can also increase the complexity of the basic problem to be solved: how to manage an efficient transition to low-carbon electricity systems?

Technology developments, as well as social behaviour, economic environments and financial markets are characterised by considerable uncertainties. The “energy transition” is therefore a highly political and institutional process, requiring several clear cut political options. However, in order to identify, compare and select different political options, it is key to have clear, comprehensive views about their implications for the way electricity markets and an electricity system operation may or may not be organised.

1.5 Three scenarios for the evolution of the European electricity system

Based on the analysis of the current legal and regulatory framework (Section 1.2), the driving forces behind the transition to low-carbon electricity systems (Section 1.3) and the conceivable interactions between operational and market changes (Section 1.4), three basic scenarios can be identified. These scenarios correspond to three “ideal types”, not to the “most likely outcomes”. They are represented in a schematic form in Figure 23.

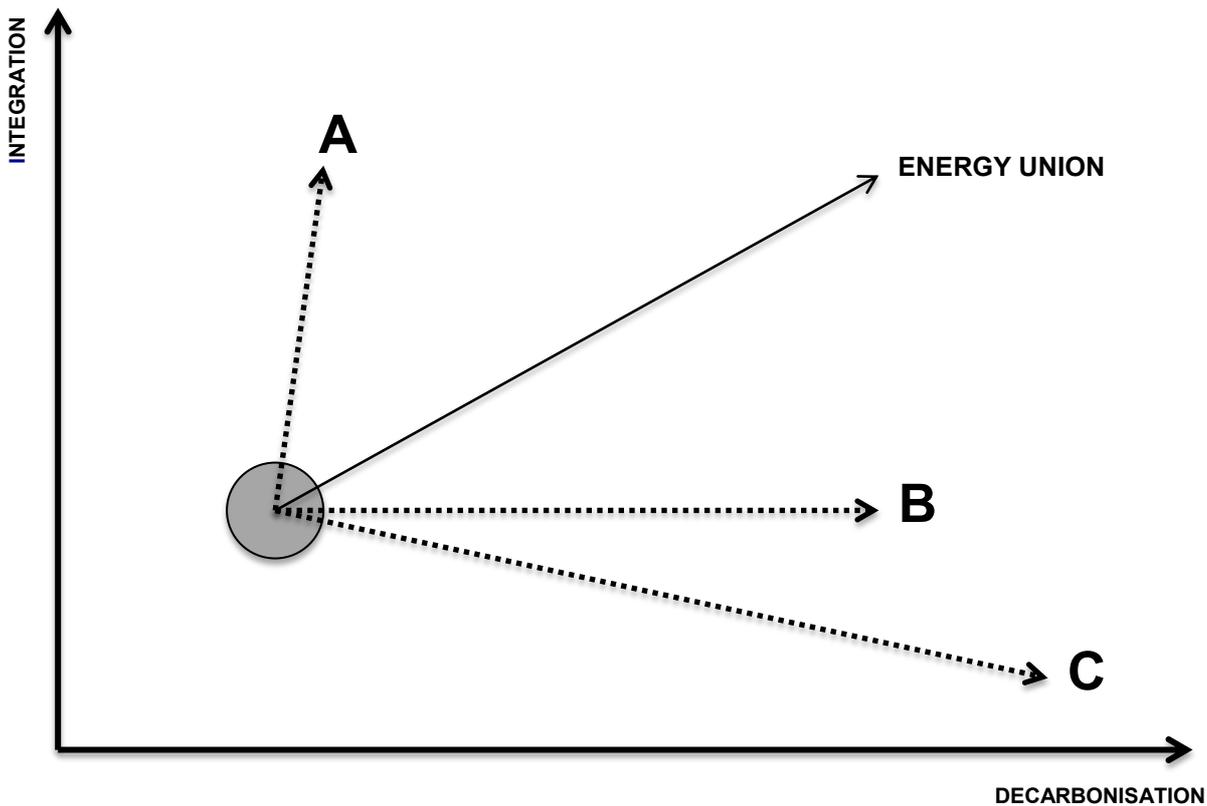


Fig. 14: Three scenarios for the evolution of the European electricity system

a) *Scenario A: Lower decarbonisation within a pan-European system*

For many years, several industry decision makers and academics considered that EU and national energy and climate policies could be accepted if, and only if, they were compatible with operational and market arrangements put in place over the previous two decades to accomplish the internal electricity market – i.e., full integration. This approach corresponds to scenario A in Figure 23: in a very strict interpretation, it may lead to increased European electricity integration, but it can hardly contribute to a higher level of decarbonisation, under the assumption that the legacy operational and market structures cannot accommodate the technological and behavioral changes required in low-carbon electricity systems. Table 3 describes the main characteristics of this scenario A.

	The need to achieve the internal market in electricity	Large amount of intermittent RES connected to the network	DER and Smart grid technologies impact on the distribution level
Network maintenance and expansion	1. Higher priority is given to cross-border interconnection projects instead of the development of national transmission networks 2. There are obstacles created by investment shortages and acceptance issues		
Connection of grid users	3. Intermittent RES generation plants are not completely free in their locational decisions		4. It may disregard the potential positive effects of innovative solutions (smart grids, prosumers, etc.)
System operation	5. More efficient system operation at European level 6. Better use within the region of the intermittent RES located far from consumption centers 7. Reduction of system operation costs. Reduced need for additional generation capacity		8. Reduced need for load management and storage systems
Interface with other TSOs	9. Coordination challenges between TSOs in the network expansion planning and system operation		
Interface with other actors (DSOs, market operation)	10. More integration and coordination of intraday and balancing markets		

Table 3: Main characteristics of scenario A: Lower decarbonisation within a pan-European system

b) *Scenario B: Higher decarbonisation within existing MS systems*

In scenario B, EU Member States basically attempt to meet their respective decarbonisation targets at national level. Each Member State implements its own energy policy that translates, i.e., into a particular electricity generation mix, imposing specific requirements upon markets, the system operation and interactions between them. In this scenario, like in scenario C, there is no real motivation to expand cross-border trade; however, the “inertia” of current EU arrangements should keep the integration *acquis* at the present level.

Table 4 describes the main characteristics of this B scenario.

	The need to achieve the internal market in electricity	Large amount of intermittent RES connected to the network	DER and Smart grid technologies impact on the distribution level
Network maintenance and expansion	1. Higher priority of national projects instead of cross-border interconnections	2. Further development of the national transmission networks 3. There are obstacles created by investment shortages and acceptance issues	
Connection of grid users		4. Intermittent RES generation plants are not completely free in their locational decisions	5. It may disregard the potential positive effects of innovative solutions (smart grids, prosumers, etc.)
System operation		6. More efficient system operation at national level 7. Better use within the country of the intermittent RES located far from consumption centers 8. Reduction of system operation costs. Reduced need for additional generation capacity and redispatch measures	9. Reduced need for load management and storage systems
Interface with other TSOs	10. Low coordination in the network maintenance and expansion, and system operation tasks		
Interface with other actors (DSOs, market operation)	11. Low integration and low coordination of intraday and balancing markets		

Table 4: Main characteristics of scenario B: Higher decarbonisation within existing MS systems

c) *Scenario C: Higher decarbonisation within decentralized systems*

Several pilot projects on “micro grids”, “smart cities” and similar “bottom-up” concepts, carried out in several countries, aim at reaching, at local level, “carbon-free” or “near carbon-free” electricity systems. If generalised, this approach, corresponding to scenario C in Figure 23, leads to very high degrees of decarbonisation while, at the same time, reduces the scope for non-local trade – even more so for cross-border trade, thus de facto decreasing the integration of national markets at EU level. Table 5 describes the main characteristics of this C scenario.

	The need to achieve the internal market electricity	Large amount of intermittent RES connected to the network	DER and Smart grid technologies impact on the distribution level
Network maintenance and expansion		<ol style="list-style-type: none"> 1. High investments in new information and communication, monitoring and distribution grid reinforcements 2. Strong competition for investments between new technologies in the distribution grid and expansion of the transmission network 	
Connection of grid users		<ol style="list-style-type: none"> 3. Significant increment in the DER connected to the distribution grid 	
System operation		<ol style="list-style-type: none"> 4. Higher degree of self-sufficiency for local networks (micro-grids, isolated grids) 5. Higher range of flexibility options in the system due to the high penetration of DER 6. The transmission grid is necessary to ensure the security of supply 	
Interface with other TSOs			
Interface with other actors (DSOs, market operation)		<ol style="list-style-type: none"> 7. Need of more interaction between TSOs and DSOs 8. Coordination challenges in the system operation between TSOs and DSOs 9. Better definition of the responsibilities between TSOs and DSOs 	

Table 5: Main characteristics of scenario C: Higher decarbonisation within decentralised systems

d) *Energy Union*

The main purpose of the “Energy Union” supported both by the Council and the Commission is to reconcile decarbonisation and market integration along the path depicted in Figure 14, enabling the active participation of actors at all levels of the Electricity Union electricity system.

2. The role of transmission networks in a low-carbon energy landscape – Hardware functions

The three scenarios for the evolution of the European electricity systems are not intended as likely future scenarios. They are deliberately/purposely extreme scenarios. That way, it is easier to derive the most important possible evolutions of TSO functions. Conclusions are then not blurred by the complexity of reality. Moreover, not only are the 3 scenarios ideal in a conceptual manner, but this “analytical abstraction” is also reinforced by our construction of an “ideally rational” framework for each of these scenarios. For a straightforward analysis, we indeed assume that all transmission system operation functions are efficiently adapted to each scenario, aligning with the location and nature of flexibility resources and network constraints. It has an even stronger implication since the analysis of these conceptual scenarios doesn’t reveal anything of how a hybrid scenario (see section 4) will absorb the novelties.

Meanwhile, the idea remains to produce recommendations for the possible and realistic future evolution of the TSO functions. Consequently, after the analysis of the possible evolutions of TSO functions in extreme scenarios, two steps will be required to reach conclusive recommendations (see section 4). First, a consistency check of scenarios will be needed, to ensure that each scenario allows the functions performed today by TSOs to continue in order to ensure reliability and system security, avoiding any black hole. Furthermore, hybrids of extreme scenarios should be considered for two main reasons. First of all, even if the characteristics of a future power system (in 2030 or 2050) are unknown, they may nevertheless be bounded by the characteristics of extreme scenarios. Besides, by nature, the existing power systems do not fit with any of the extreme scenarios but are already hybrid both in their architecture and in their functioning.

The first step in our framework is to analyse the possible evolutions of the TSO functions under the three extreme scenarios, scenario A of lower decarbonisation within a pan-European system, scenario B of higher decarbonisation within existing Member States systems, and scenario C of higher decarbonisation within decentralised systems. In this regard, this Chapter focuses on the possible evolutions of hardware TSO functions, namely the first connection of grid users, second network expansion and maintenance, and third ICT investment. Chapter 3 will then focus on the transformation of the software functions.

2.1 Connecting the dots – connection of network users ...

Network operators must take into account the characteristics of the network users in order to connect them in an efficient and reliable manner. For instance, as more and more generators

and loads are asynchronous (producing with DC or asynchronous turbines) and therefore getting connected through a DC/AC converter to the AC network, this characteristic must be taken into account in connection requirements⁴¹. The characteristics of the load are also evolving. New types of load, such as the electric vehicle are expected to be able to provide flexibility and reserves, if not storage capacity. Meanwhile, the existing load can also be retrofitted to become more flexible⁴². Overall, some scenarios dramatically change the characteristics of network users compared to those of today. This can be analysed considering the characteristics of generators, namely:

- Their notional size, and thus the voltage level (transmission or distribution level) they connect to.
- The locational constraints of good quality resources, but dispersed location of poorer quality resources (wind and PV, storage with different technologies – centralised pump hydro storage versus decentralised batteries).
- Their synchronous or asynchronous nature compared to the network frequency, hence naturally providing inertia to the power system and the frequency reserve in the first case (e.g. conventional generators – thermal, hydro or nuclear power plants) or being connected to the synchronous network through a DC/AC converter (for wind or PV generators, batteries or new asynchronous pump hydro storage).
- Their level of predictability over time.
- Their flexibility (at given output level – in particular for variable generators) and ability to provide network services (e.g. reserves, reactive power or black-start⁴³).

With this regard, it is also important to distinguish the design of rules for connection and the responsibility of connection operation. Indeed, each DSO can be in charge of the connection operation of dispersed generators on its (distribution) grid, but a broader system view is needed to define the rules because they impact upon the generation and load balance, frequency control, black start, and voltage control on the transmission grid. Although different organisations may be employed for the operation of connection in the different scenarios, the process for producing connection rules should be similar in all scenarios, even if participants

41 Remember that the classical power grid technology is alternative current (AC), vibrating at 50 Hz in Europe. It was adopted for two reasons. First, it was found to be easy to step up or down the voltage level with transformers between transmission and distribution grids. Second, it was also found easy to develop protection and switchgears on this technology because the current value is zero 100 times in one second. Generators can be synchronous, generating electricity with the same frequency as the power network, or asynchronous and then producing energy to a different possibly variable frequency. A third way to produce and even transmit electricity is to rely on an alternative technology for the power grid, to direct current (DC) with stable values.

42 Note that the ability of the load to become flexible depends on its usage, that it can be postponed, rely on another form of energy (e.g. heating with wood or a dual fuel heater), or with energy that can be stored (for instance in the form of heat, cold or in an electrochemical form).

43 Reactive power helps to maintain the local voltage level on the AC power network. As for black-start, it is a service provided by some generators that are able to start up, even if the network is blacked-out, relying on an ancillary diesel generator.

will differ from one scenario to another. Indeed, in all scenarios, considering the system-wide impact of connection rules, they should be defined at this global higher level. Although the TSO is one of the most impacted actors in the power system by the definition of connection rules (if not the most impacted one), it should not, however, set them unilaterally in order to avoid conflicts of interest. Consequently, as today, existing procedures for discussing the connection rules should be reinforced and adapted to generation at local level. Connection rules should be discussed by all the stakeholders (broadly speaking and irrespective of the scenarios), transmission and distribution grid users, TSOs and DSOs and regulators. As for the other rules in the power system, the regulator should organise the discussion to set these rules with the philosophy of a reflexive governance platform (Brousseau and Glachant, 2011). That way, each of the stakeholders can share its view on the required set of rules (in this case, connection) with the others. The regulator should then set the rules after identifying their pros and cons, benefits and costs from the discussions with and between the stakeholders. In this regard, the scenarios will differ for the main stakeholders participating in these discussions to set the connection rules.

And lastly, transmission tariffs may also be transformed in the different scenarios. Indeed, depending on them, geographical differentiations of transmission tariffs encompassing cost-reflectiveness may bring efficiency, more or less, and equity among the network users. The cost recovery of stranded assets may also be up for debate in some scenarios.

2.1.1 ...in scenario A of lower decarbonisation within a pan-European system

In an extreme scenario of a power system becoming much more integrated at EU level, but missing the decarbonisation goal (because of relying only on centralised renewable resources), we cannot expect major change for connections to the network. The sources for power and network services will still mainly connect to the transmission grid or, to a far smaller extent, to the distribution grid (as it is today in most of the European countries). Connection requirements will be very similar to those that we know today, all the more as there has already been an effort to harmonise it at a European scale with the grid codes concerning connection (namely requirements for generators, demand connection and HVDC connection). If this effort is to be pursued, it will mainly take place between the conventional centralised generators connected to the transmission grid, local control centers of the (one or

two) European ISO(s) (similar to the today's TSOs), with these discussions framed by a European regulator⁴⁴.

Meanwhile, the location of generators will more likely impact their profitability since a pan-European system will bring more competitive pressure. It should also be noted that the location of generators and the resulting cross-border flows are the main drivers of network expansion (see the last TYNDP, ENTSO-E, 2014). Consequently, it will be more efficient for the generators to pay a significant share of the network costs in this regard. Indeed, it is only with this condition that the generators will take the network cost into account while doing arbitrage with other locational costs (siting, access to primary energy and cold sources, costs arising from public opinion, etc. – see Olmos Camacho 2006)⁴⁵. The generators pay a transmission tariff reflecting the impact of the network cost. It is important for consumers to agree with the needed transmission tariff evolution (as the global cost will inevitably go up). Otherwise, EU consumers may feel they pay for costs they do not trigger and might oppose the required efficient network investments.

2.1.2 ... in scenario B of higher decarbonisation within existing Member States systems

If a higher level of decarbonisation is achieved within existing Member States systems, generators will both connect to the distribution and transmission grids depending on their centralised or dispersed nature. In this extreme scenario, generation should be focusing on big units with fewer drivers for the development of small units, a certain amount of flexibility may also arise from consumers, mostly big ones connected to the transmission grid, but also, to a limited extent, smaller consumers connected to the distribution grid. Then, because of network users connecting either to the transmission grid or to the distribution grid depending on their size, and all the more because of the interconnected nature of the transmission grid, the stakeholders participating in the discussion to set the connection rules should include all the network users but also the national TSO, and DSOs⁴⁶. It is only with the participation of

44 We will see in section 3 that the organisation of the power sector should be dramatically modified in this scenario with an important ISOfication of transmission system operation. One (or two) European ISO(s) should then be settled and national transmission owners will remain unless some of them merge. To which extent a national level remains will have to be assessed to keep the power system manageable. An EU ISO would be based on a multilayer control system extended at EU level encompassing the existing national and regional levels. The TSOs will then remain as Transmission Owners (TOs).

45 It is sometimes argued that network tariffs paid by generators introduce distortion in the energy market. To the contrary, it is rather the exemption of network tariffs or uniform network tariffs for generators that distorts competition. For instance, generators pay (or do not pay) the same tariff whether they are close or far from consumers and so require a network service with almost no cost, on the one hand, and high cost on the other hand. Moreover, the network tariff will be all the more distortive that they are expressed in €/MW and not in €/MWh because they are then a fixed cost and not a variable cost for the network users.

46 Note that, to simplify the discussion, we assume that there is only one TSO per Member State. They are, indeed, generally national entities, even if in some of the Member States, several TSOs operate different parts of the transmission grid, the most emblematic situation with this regard being in Germany.

all these stakeholders that the connection rules will ensure the reliable management of the interconnected power system. In this scenario with a national focus, these discussions should be framed by the national regulator.

The TSO will then ensure that despite the asynchronous nature of several generators and some loads (e.g. electric transportation), the management of the almost instantaneous balance between generation and load and frequency remains reliable and without partial disruption of synchronisation. The TSO will also require that these generators, even if more dispersed and volatile than the conventional generators today, can nevertheless provide network services to maintain the frequency at 50 Hertz, to produce reactive power helping to control the voltage level on the transmission grid, or to be able to black start in order to help the system restoration after a black-out. This is at least partially already included in the grid codes for connection (in particular the requirements for generation, demand connection and HVDC – this later one is not adopted yet).

In this scenario, network costs are expected to increase dramatically. Tariffs with geographical differentiation for the generators could then prompt them to locate more efficiently, taking into account not only other locational costs (siting, access to primary energy – and cold – sources, costs arising from public opinion, etc.), but also the network cost triggered by their connection and use (see, for instance, the project TransmiT led by OFGEM (2014) to reform the locational transmission tariff in Great-Britain to take into account the evolution of the energy mix with the integration of more renewable generators). As already mentioned in scenario A, the generators paying a transmission tariff reflecting their impact of the network cost is important for consumers to agree the required and efficient network investments. In scenario B, it is also important for the consumers to agree on higher decarbonisation and its impact on network costs. A cost-reflective tariff allows each network user is to pay its share of network costs according to its own impact on the grid. This applies to the generators whether they are connected to the transmission or the distribution grids. The distribution tariff could itself take different values for different connection points or locations. Compared to a situation with no cost-reflective transmission tariffs at the national scale, the need for transmission investment (and distribution investment) could be reduced to some extent because the generators will then take into account the network cost and their other locational costs (siting, access to primary energy and cold sources, costs arising from public opinion, etc.) in deciding where to locate. The locational differentiation of the tariff could also apply to the biggest consumers because they also have some flexibility of location.

2.1.3 ... in scenario C of higher decarbonisation within decentralised systems

If higher decarbonisation is achieved within decentralised systems, generators and consumers will be mainly connected to the distribution grid, and therefore by the DSO. Meanwhile, because of the interconnected nature of the transmission grid, even at the national scale and all the more at the European scale, the stakeholders participating in the discussion to set the connection rules should include all network users, the national TSO and DSOs. It is only with the participation of all these stakeholders that a reliable management of the interconnected power system will be ensured, in order to avoid that any local norm could endanger the management of the interconnected power system. Considering the decentralised nature of this (extreme) scenario and the need for a certain degree of harmonisation, these discussions should be framed by the national regulators. An extreme version of system decentralisation is the mushrooming of self-managed, independent, unregulated “micro-grids” and “load pockets”. However, it is not necessary to enter further into it, since it may be assumed that entirely independent –hence autarkic - new energy systems will not organically interact with the national or pan-European system levels.

We can then expect that the connection requirements will be very similar whether higher decarbonisation is led at a national scale (scenario B), or within decentralised systems (scenario C).

In this scenario, transmission network tariffs do not impact the location of new generators because these are located on the distribution grid, and so primarily pay this local tariff. Meanwhile, it would be efficient to implement a more-cost reflective tariff and with deeper geographical differentiation, so that microgrids can only develop when it is efficient at a more global level. Indeed, in a situation as today where transmission tariffs are uniform, the network users who have the higher incentive to see the development of microgrids are consumers located on the distribution grid, and using the transmission network to a lesser extent (because they are very close, for instance, to a generator being inserted/introduced into the transmission grid). Consequently, they pay a relatively high transmission tariff compared to the transmission grid service they need. In this situation, the development of a microgrid allows them to pay a smaller transmission bill. To the contrary, if they were paying a cost-reflective transmission tariff, this tariff would be aligned with their use of the network and, other things being equal, they would have a smaller incentive to see the development of a microgrid. Consequently, the more cost-reflective transmission tariff with locational differentiations would only allow microgrids to develop when they are efficient, and not because of a regressive incentive arising from badly shaped, non cost-reflective and inefficient transmission tariffs. This also raises the issue of the cost recovery of stranded assets (see section 2.2.3) because this recovery prevents transmission tariffs from being

cost-reflective. On the one hand, the TSO could reasonably desire to recover the cost of its stranded assets to maintain its overall financeability. On the other hand, by doing so, the TSO distorts the transmission tariff incentives and prevents the tariff from being cost-reflective, which pushes for the development of microgrids, further increasing the amount of stranded assets and fuelling this vicious circle, out of any efficient rationale. A solution for the TSO could impair its stranded (now useless) assets to make the transmission more cost-reflective and reset conditions for an efficient development of microgrids. Meanwhile, these stranded assets could be covered by a kind of public compensation to maintain the TSO financial equilibrium.

2.1.4 Comparing the grid connection function in the three scenarios

The table below sums up the possible transformation of the transmission grid connection function in the three scenarios.

Scenarios	Lower decarbonisation within a pan-European system	Higher decarbonisation within existing Member States systems	Higher decarbonisation within decentralised systems
Aspects of transmission grid connection function			
Connection rules	Consultation process integrating all the interested parties under the supervision of the regulators (as today)		
Connection operation	Mainly TOs ⁴⁷ (and possibly DSOs)	DSOs and national TSO	DSOs
Stakeholders participating in the discussion to elaborate connection rules	European ISO(s), national TOs (possibly DSOs) and centralised network users	National TSO, DSOs, distribution and transmission network users	National TSO, DSOs, distribution (and transmission) network users
Transmission tariffs	Need to be more cost-reflective with locational differentiations and a tariff structure aligned with the network cost structure to reflect the impact of network users on network costs		With impairment of stranded assets

Table 6: Grid connection function in the three scenarios

⁴⁷ Transmission Owners

Whatever the scenario, we can notice that the process setting the connection rules should include the TSO (whether it is a national one or a European one) and the network users. DSOs could also participate (when resources of generation and flexibility develop on the distribution grid). Similarly, in all the scenarios, it is worth making the transmission tariffs more cost-reflective with a real geographical differentiation to incentivise the location of generators; to the extreme of impairing the stranded assets in the scenario of higher decarbonisation within decentralised systems. Inversely, the connection operation will move from TSOs to DSOs as the power system is more decarbonised and decentralised.

2.2 Merging the meshes – network expansion and maintenance ...

The characteristics of the network users (voltage connection, location, synchronous or asynchronous nature, predictability, flexibility) deeply vary from one scenario to another. For instance, generators may be getting more and more dispersed (with decentralised generators), more and more variable with uncertain outcomes (with wind and PV generators). These characteristics of network users will inevitably change their use of the transmission network, that may be more dispersed and variable in our illustrative example. As a consequence, the network operators must take all this into account to plan, develop and maintain their assets efficiently (with this regard, see the last TYNDP by ENTSO-E in 2014).

2.2.1 ... in scenario A of lower decarbonisation within a pan-European system

In this scenario of a pan-European system, new generators, some of them being renewable or having the flexible use of storage capacity, are all assumed to be centralised (either big wind or PV farms, or biomass generators; etc.). This makes decarbonisation lower than in the other scenarios. We can also assume that they have the possibility but not the obligation to be flexibilised (spilling energy in case of excess production, providing reserves or relying on local storage capacity). Connected at the transmission grid level, they are hence competing with centralised classical resources still remaining in the system such as “CO2 compliant” thermal, hydro or nuclear generators. The consumers are assumed to be just a bit more flexible than today.

In this scenario, national imbalances persist on the European transmission network, similar to what we know today, with some countries producing (respectively consuming) more energy than others. As a result, a major swing of energy can flow through the European network over time (intraday, between days, weeks, months, seasons or years) and space (between regions), depending on the load profiles and the national energy mixes (e.g. with national focus respectively and possibly on nuclear, gas, coal, hydro or renewable energy sources).

In this pan-European scenario, flows on the transmission grid are expected to increase by a huge amount and to be more volatile across the whole European power grid. The network planning should then be done at the adequate geographical scale, meaning at the European scale, by a European System Operator, as if there was only the ENTSO-E TYNDP preparing transmission investment planning. Moreover, a higher amount of transmission assets at the European level than currently experienced will be required. The last ENTSO-E TYNDP from 2014 is an example of what may be experienced in such an EU-first scenario. One main implication in regulatory terms is that any regulatory authority acting within this scenario should carefully consider the financeability of transmission owners when regulating their revenue, since a lot of the existing TSOs (assumed to stay alive in an EU ISO frame as “Transmission Owners”) have already reached a high level of gearing (Henriot, 2014), at least in the Western part of Europe (Roland Berger, 2011).

Considering the NIMBY effects and the resulting difficulty to find new rights-of-way, a shift will be needed toward new and non-conventional transmission technologies. For example, “phase shifters” and “FACTS”⁴⁸ offer new ways of optimising the capacity and use of existing assets. “High capacity conductors” (for extension or refurbished assets) will also provide more transmission capacity. If technological difficulties are overcome and locations are found for vast current conversion stations, the wider use of DC technologies could permit more lines to be buried⁴⁹. Meanwhile, these technologies may still be more expensive than the conventional AC technologies to develop and renew the transmission network. Consequently, investment decisions may be more difficult to trigger because cost-benefit analyses with positive outcomes will be more difficult to produce. Besides, these technologies are not yet widely used by the TSOs. They consequently encompass industrial risks (problems to integrate them, problems to use them in the existing network, the unexpected interaction with other components in the network, etc.). This makes their integration more difficult and more risky in an industrial perspective in a power system whose reliability is fundamental for the whole economy. Besides, the asynchronous nature of some grid technologies (FACTS or DC lines and DC/AC converters) and generators will create a new risk of the synchronisation disruption of frequency on the interconnected network. This may make it harder, if not sometimes impossible, to integrate these technologies in some parts of the AC interconnected network⁵⁰.

48 FACTS (Flexible AC Transmission Systems) are power electronics devices used to control power flows, voltage or dynamic stability of the power network.

49 AC cables can only be buried for tens of kilometres while DC cables can easily be buried for hundreds of kilometres.

50 For instance, the use of DC lines to increase the capacity of transmission grid in Normandy in France to evacuate energy produced by the future nuclear EPR generator was not possible because of the inherent risk of synchronisation disruption.

In this scenario, flows from the transmission grid to the distribution network could increase and important investments of transformers and substations could also be required if sustained economic growth returns and increases demand for electricity at the distribution level.

In this EU-first scenario, the organisation of network maintenance will also change with the scope of flows calculation being set at a European scale. More coordination between the network owners on widespread cross-border areas will then be required to realise the maintenance operation while allowing major pan-European transits. Locally and temporarily, this may create important constraints on the European network, which may still require additional investments.

2.2.2 ... in scenario B of higher decarbonisation within existing Member States systems

In scenario B of higher decarbonisation within existing Member States systems, new generators, mainly renewable ones or storage capacity, are assumed to be either centralised (big wind or PV farms, biomass generators) or dispersed ones (small windmills or PV rooftops, heat pumps), respectively connected to the transmission or distribution grids. They are also assumed to be flexibilised (spilling energy in case of excess production, providing reserves or still relying on a smaller local storage capacity). They are competing with centralised classical resources still remaining in the system (nuclear generators, gas power plants, etc.). The consumers are themselves assumed to be flexible and demand response is more developed than today.

In this scenario, the local imbalance persists on the transmission network, similar to what we know today at the national scale with areas producing (respectively consuming) more energy than others. As a result, a major swing of energy flows can happen on the transmission network over time (intraday, between days, weeks, months, seasons or years) and space (between national regions), depending on the exploited renewable resources and the effective production of renewable generators (e.g. from windy or non-windy / sunny or non-sunny / wet or dry seasons). Since energy mixes were only developed at the national scale, cross-border transits might be limited and far in distance for overall efficiency in this scenario.

Flows on the transmission grid are hence expected to increase in a huge amount and to be more volatile at the national scale. Note also, that the new sources of energy will not be located in the same places as the older generators. However, the flows of exchange at the European level are not expected to be high in this case, since the national decarbonisation is here assumed to be realised with a national focus. The network planning should then be done at the policy driven geographical scale, meaning at the national scale, as if there were

only National Development Plans, realised by each TSO as it is today. A higher amount of transmission assets at the national level than currently experienced will then be required. The regulators should then be very careful about the financeability of TSOs, since a lot of them have already reached a high level of gearing (Henriot, 2014; Roland Berger, 2011).

Considering the NIMBY effects and the resulting difficulty of finding new rights-of-way, a shift will then be needed toward non-conventional transmission technologies, with the same advantages and drawbacks as the ones exposed in scenario A. They will offer more transit capacity at the national scale while overcoming the Not In My Back-Yard (NIMBY) effect, but present higher costs and industrial interaction risks, making them more difficult to justify in a cost-benefit analysis.

Knowing that decarbonisation could push for electrification of some energy uses (electric transportation, heating, cooling, etc.), flows from the transmission grid to the distribution network could increase, and important investments of transformers and substations could also be required, all the more if sustained economic growth was also to return.

In this scenario, the organisation of maintenance will also be impacted by the characteristics of network users and resulting flows on the transmission grid. In particular, the volatility of flows on the transmission grid will require the maintenance operation to be scheduled or rescheduled at the very last minute, or to push for more online maintenance so that the network operation is less disturbed. Locally and temporarily, it may also create important constraints on the network. This may still require additional network investments. Flexible resources of network users (demand response or spilling of renewable energy) may also be more solicited. Temporary and mobile stationary storage capacity or network assets (e.g. capacitors or FACTS) could also be used to cope with those local and temporary constraints.

2.2.3 ... in scenario C of higher decarbonisation within decentralised systems

Scenario C of higher decarbonisation within decentralised systems is characterised by generators and loads as follows. Generators are supposed to be dispersed, relying on local resources (wind, photovoltaic, biomass, geothermal, etc.) close to consumers. Generators are also assumed to be flexibilised (allowing energy spills in case of excess production, or relying on storage in the case of an energy shortage and generally providing reserves). The consumers are themselves assumed to be very flexible; and decentralised storage is supposed to be widely spread. As a consequence, the power system is made of almost autonomous (but not strictly autarkic) microgrids.

The result is that flows on the transmission grid are reduced. That is what is already searched for, e.g. with some smart cities or "eco-district" targeting energy self-supply

(Steinbeis-Europa-Zentrum, 2014). As a consequence, in this scenario, there is no more need to develop the network and only a small number of ageing assets need to be renewed (depending on the result of a cost-benefit analysis of renewed assets compared to decommissioning assets). The transmission network asset base is hence shrinking when it is still useful, not only at the national level, but also at the European level. To the extreme, this trend has already produced some grid defections (The Rocky Mountain Institute, 2014 and 2015). In this extreme situation, the network might even become useless. Transmission planning (even if focused on renewal in the scenario) should then be done at the national scale considering the limited need for cross-border assets. As already highlighted concerning the tariffs in this scenario (section 2.1.3), the regulator should manage a possible impairment of stranded assets, in particular to make transmission tariffs more cost-reflective and to ensure that microgrids develop only when it is socially efficient to do so.

Maintenance must also be adapted in this scenario compared to the current situation. Since the transmission grid is less used compared to the current situation, it is less subject to operational constraints and maintenance scheduling is less of a problem. Possibly, coordination may be required with the DSOs if maintenance on the distribution grids would require a higher reliance on the transmission grid to supply, balance or evacuate power from the maintained part of the network.

2.2.4 Comparing the network expansion and maintenance function in the three scenarios

The table below sums up the possible transformation of the network expansion and maintenance function of the transmission in the three scenarios.

Aspects of network expansion & maintenance function \ Scenarios	Lower decarbonisation within a pan-European system	Higher decarbonisation within existing Member States systems	Higher decarbonisation within decentralised systems
Investment dynamics	Transmission asset base increasing		Transmission asset base shrinking
MS Investment coordination	Cross-border coordination for pan-European projects	None needed	None needed
Maintenance scheduling	No change compared to actual management	More uncertain because of volatile use of the network	Easier because of a less used and constrained transmission grid
Maintenance organisation	Requiring cross-border coordination	Requiring coordination between transmission and distribution system operators	Possibly requiring coordination between transmission and distribution system operators

Table 7: Network expansion and maintenance function in the three scenarios

Contrasts between scenarios are high. In centralised scenarios (lower decarbonisation within a pan-European system versus higher decarbonisation within existing Member States systems), the transmission asset bases are expected to increase, raising financeability issues for TSOs and the question of adapted regulation. To the contrary, the transmission asset base should be shrinking in a scenario of decentralised systems. Coordination for investment or maintenance is rather needed in the pan-European scenario. And maintenance scheduling will be more uncertain in the scenario of higher decarbonisation within existing Member States because the network use will be more volatile.

2.3 Managing the slots – provision of ICT for proper system operation

Besides connecting, developing and maintaining the transmission grid, another fundamental function of a transmission grid is the system operation. If it is mainly a software function (see section 3), it requires also ICT assets, more precisely six main types:

1°, Measurement systems to collect information about the state of the power system and its different variables (frequency, voltage level, power flows, temperature of power lines and transformers, state of disruptors, wind force and sun irradiance, etc.).

2°, Communication channels to exchange information and instructions with network users (generation and load forecast and real time levels, technical constraints and prices, orders to modify their power patterns, etc.).

3°, Computation tools to estimate and anticipate the future state of the power system and possible constraints from its current state variables and their potential evolutions.

4°, Information systems for operating market platforms where different products will be exchanged between network users and with system operators.

5°, Data storage for some of these pieces of information to be used later on for an ex post analysis or monitoring.

6°, Devices (“grid actuators with remote control”) that allow the system operator to modify the network configuration (changing transformers taps, connecting or disconnecting power lines, nodes, capacitors or inductors etc.) to adapt it to the need of network users.

These six types of ICT assets needed for the system operation (measurement systems, communication channels, computation tools, information systems, data storage and remotely controlled grid actuators) can be developed either at the local scale, the national scale or the European scale. The most adapted and efficient solutions in this regard will vary from one scenario to another.

As for the connection function, it is important to distinguish the informal process of discussing the pros and the cons of alternative rules for those ICT assets from the proper and formal responsibility of writing and issuing these rules. Indeed, the distribution operator can hence make its network smarter with more ICT, but rules should be elaborated considering the impact for all the interested stakeholders under the supervision of the regulator. Different stakeholders may then participate in the elaboration of rules for ICT assets and different organisations may then be implemented for the deployment of those assets in the different scenarios.

2.3.1 ... in scenario A of lower decarbonisation within a pan-European system

In an extreme scenario of pan-European integration with lower decarbonisation, energy will be expected to flow throughout the whole European transmission grid. Consequently, optimisation of the network use should be realised at a European scale and the ICT investments should be adapted to this situation.

Since current measurement systems and remotely controlled actuators already allow for the management of power flows at national level, no specific large scale investment seem to be needed in this case. Only a reorganisation of the data collection would be needed at European scale. It is also worth noting that Wide Area Measurement Systems (WAMS), the last generation of large scale measurement systems, are already deployed in Europe and will continue to spread in order to have a synchronised view of frequency and major power flows over Europe⁵¹.

In this scenario, with Europeanised power flows, it is obvious that it will be more efficient for computation tools and market platforms to be organised at a European level/ on a European scale. The same also applies to the organisation of data storage and communication channels. Besides, data formats are already common to a large extent, or being harmonised (e.g. with Common Information Model standards – CIM standards⁵²). In this respect, if further standardisation is still needed, European bodies such as ENTSO-E and ACER will remain the nexus of the process.

Computation tools, data storage or communication channels could be centralised in a unique entity, as is already done by the ISOs or RTOs in the USA. Coreso and TSC (Transmission Security Coordination) are also EU models of centralised computation tools and data storage, while the various TSOs remain in charge of the direct communication channels with the network users.

Besides, even if the European scale clearly prevails in this scenario, it leaves different options open for the organisation of market platforms. For instance, a unique European market platform can be developed (for a given product – e.g. at the day-ahead stage – or several ones – e.g. both Day-Ahead and Intra-Day), or several platforms can be coupled and work shoulder to shoulder as a single entity. Those different solutions do not have the same resilience. Of course, solutions allowing redundancy will be more resilient. Redundancy can be at the same level, namely here, at the European scale. Redundancy can also be implemented at different levels, having sets of computation tools, data storage and communication systems both at the European and at the national level.

2.3.2 ... in scenario B of higher decarbonisation within existing Member States systems

In an extreme scenario of higher decarbonisation realised at the scale of Member State systems, since the development of generation and flexibility sources (storage, demand

51 www.swissgrid.ch/swissgrid/en/home/reliability/wam.html

52 www.entsoe.eu/major-projects/common-information-model-cim/Pages/default.aspx

response, etc.) is both located at the distribution and transmission levels, optimisation of these resources and the (distribution) grid configuration should be realised both at the local and national scale. It applies to the ICT investments.

Measurement systems should then be installed at the distribution level to complete those already installed on the national transmission grid. With historically unidirectional flows, measurement systems in distribution networks were previously focused at the entry interface with the transmission network. Since flows on the distribution network will become bidirectional in this scenario, measurement systems should be spread all over the distribution grids themselves in order to know the local network transit margins compared to the flows. Besides, communication channels should also reach to the decentralised network users (generators or consumers). They will, indeed, provide flexibility to the distribution grid and to the transmission grid to the same extent as centralised flexibility sources (generators or demand response).

Even if the management of the distribution system will become smarter and active in this scenario, the focus and nexus of the system operation will still remain at the transmission level. Hence, this situation raised a question about the most efficient organisation of computation tools and market platforms (for instance: centralised; but going down to the distribution level, or duplicating them at the distribution level). The same question arises for data storage (totally centralised or distributed between the transmission and distribution levels). An answer to this question may be determined by the ability of the national information system of the transmission grid to cope with the massive amount of information arising from the distribution system that should be managed in this scenario. The question of data handling should also be considered from a regulatory point of view (responsibility of data collection, data ownership, data accessibility, independency of data manager, etc.) and setting an EU principle with this consideration would allow the first corner stone of a European retail market to be raised.

Whatever the chosen solution, the standardisation of the data format is fundamental to enable communication for an efficient, secure and reliable operation of both the transmission and distribution systems. In this respect, the system-wide scale will still be prevalent in the process to elaborate these standard requirements that local data formats should all adopt. That is why the supervision of this process by the regulator is fundamental. Considering that energy and network service providers will mainly compete at the transmission / wholesale level in this scenario, it will be harmful for the system reliability to let local data standards develop, even if they are partially interoperable with the main (transmission-centred) data standards.

With the connection of part of the new generators on the distribution grid, constraints should appear on the distribution grids. They should then become smarter to manage them, relying on remotely controlled actuators.

2.3.3 ... in scenario C of higher decarbonisation within decentralised systems

In the decentralised scenario with higher decarbonisation, the development of generation and flexibility sources (storage, demand response, etc.) is local: on the distribution grids. Therefore optimisation of these resources and the (distribution) grid configuration should also be realised at the local level, like the ICT investments.

Measurement systems should then be installed at the distribution level to complete those already installed on the transmission grid. Historically, they somewhat stopped at the interface between the transmission and the distribution levels. Information there was indeed sufficient to estimate the distribution network state because power flows were unidirectional on the distribution grid at that time. But the power flows will inevitably become bidirectional on the distribution grid in a scenario of higher decarbonisation within decentralised systems, and information at the interface between the transmission and distribution grids will say nothing about the network state of the latter.

Communication channels should also reach the decentralised network users (generators or consumers), because they will be sources of flexibility for the power system (at the local level and at the interconnected level in last resort situations – see section 3.1 about the transformation of the system operation function). In addition to providing information on the state (power levels) of the network users, new ICT arrangements will also reveal their margin levels with regard to the different network services (power reserves for the interconnected transmission system, reactive power for the distribution grid, the dynamic ability to change their power levels, etc.).

Since the bulk of the management of the power system will shift to the distribution level in this scenario (see section 3.1), it will be more efficient that computation tools and market platforms be localised at the local scale and duplicated in each distribution network. Consequently, it will also be more efficient for data storage to be organised at the local scale. Of course, the TSOs should still have computation tools and storage capability to manage their own grids and the residual and last resort generation and load balancing (see section 3.1). That said, the computational capabilities of the TSO remains as it is today, with all the tools needed. Note also, that this organisation will ensure the resilience of the information system of the whole power grid. The information system of the distribution grid will, indeed, be mostly able to cope with any problem on the information system of the transmission grid.

Inversely, transmission ICT could partly rescue the information system of the distribution grid in case it experiences any problem, unless there is a redundancy of the information system of the distribution grid at the local scale.

Even if the system operation will happen mainly at the distribution level, and only as a last resort at the transmission level, the standardisation of data format may still be required to enable a formatted and easy communication for those last resort situations. With this in mind, the system-wide scale will still be prevalent in the process to elaborate these standard requirements. That is why the supervision of this process by the regulator is fundamental. Since most of the energy will be locally exchanged, those standards can only be minimal requirements that local data formats should share, while DSOs can also complement them depending on their local needs and standards.

Following the same rationale, since the core of the management of the power system will shift to the distribution level in this scenario, the distribution network should be smarter, with a more dynamic behaviour of local grids, relying on remotely controlled actuators. This would allow the distribution system operator to adapt the configuration of its grid to the generation and load patterns. It also has an organisational impact, as it will require the unbundling requirement (already imposed on TSO) to be extended to DSO to prevent any conflict of interest between network management and the related competitive activities.

2.3.4 Comparing the ICT investment function in the three scenarios

The table below sums up the possible transformation of the ICT investment function in the three scenarios, in particular which entity should drive it.

Scenarios	Lower decarbonisation within a pan-European system	Higher decarbonisation within existing Member States systems	Higher decarbonisation within decentralised systems
Aspects of transmission grid connection function			
Measurement systems	One or two EU bodies responsible for system operation	DSOs and national TSOs	DSOs
Communication channels			
Remotely controlled actuators			
Computation tools	Different possible organisations between a European System Operator and national TSOs	Different possible organisations between national DSOs & TSOs	Mainly DSOs versus TSO for last resort action for the transmission system
Market platforms			
Data storage			

Table 8: ICT investment function in the three scenarios

To conclude: these ICT investments should be realised by the most suitable/appropriate entity, aligned with the geographical scope of each scenario (respectively the European, national or local one). Meanwhile, different organisations are possible for computation tools, market platforms and data storage in the centralised scenarios (namely with a lower decarbonisation within a pan-European system or a higher decarbonisation within existing Member States systems), from very centralised organisations managed by the operator with the larger geographical scope (respectively the European System Operator in scenario A and the national TSOs in scenario B) to organisations also relying on shared responsibility between different geographical scopes and system operators (respectively the European System Operator and national TSOs in scenario A; and the national TSOs and DSOs in scenario B). Whatever the scenario, it should be noticed that the digitalisation of the system operation and market operation will maintain the need for common standards for ICT to allow interoperability between the actors in the power system.

3. The role of transmission networks in a low-carbon energy landscape – Software functions

Like the hardware functions, “software” functions of transmission and system operation will also experiment with transformations in the different scenarios. This section hence focuses on the possible evolutions of software TSO functions, namely the system operation and coordination between TSOs, as well as vertical interaction with other power system actors and institutional players.

3.1 System operation and horizontal coordination between TSOs ...

Any change from the current situation to one of the three stylised scenarios would require a major transformation of the power system operation, and even these scenarios are quite different from each other. Transformation will impact not only day-ahead and intraday markets, but also balancing and reserves markets. The definition of energy and reserves products should adapt to each scenario (including the definition of price zones and the organisation of the dispatch – being self-dispatch versus central dispatch).

Moreover, the liberalisation process has shown that horizontal coordination between TSOs has been one, if not the, key success factor. Since the different stylised scenarios do not entice the same degree of interconnectivity between the TSOs, one should then expect different organisations for the coordination of TSOs in each scenario.

3.1.1 ... in scenario A of lower decarbonisation within a pan-European system

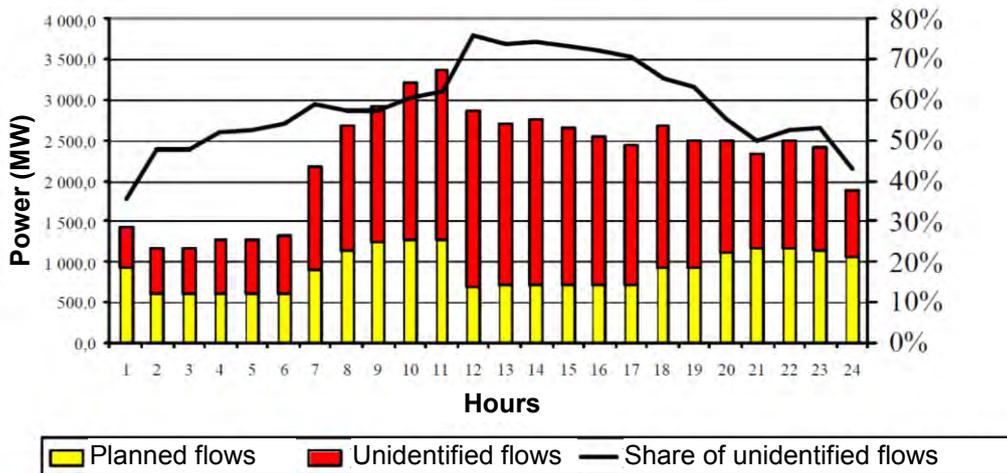
A major transformation that should arise in the pan-European scenario should be the system operation. If this scenario was to happen, it would require that the system operation be no longer organised at the national scale but at a European level. Of course, it would rely on the momentum of current arrangements, in particular the major step of harmonisation permitted by the grid codes and day-ahead market coupling (see ENTSO-E, 2014b). This harmonisation process should also expand to intraday markets as well as to balancing and reserves markets, as already planned (see ACER, 2014). A pan-European market would then expand to all the energy and reserves products, leading to a true European level playing field for all the competitive market players.

Nevertheless, one cannot expect major changes in the proper definition of electricity products. Indeed, in this scenario, no new massive integration of renewable energy is expected. The energy mix will still be grounded in conventional generation. The definition of the current electricity products fit conventional generation. The hourly or half-hourly definition of energy blocks would fit the dynamics of conventional (rather thermal) generators. Since

there would be no major shift in the energy mix in this scenario, one should not expect major changes either in the energy sources or in their location. Hence, the price zones as they are defined today at the national scale, or at the regional scale in some countries, should fit the energy mix and its location. The need for reserves in this scenario is quite predictable and stable over time (depending on the load level and unexpected outages of generators – mainly thermal ones). Reserves products could hence be defined as long term ones, up to monthly or yearly products. Consequently, no finer time and space energy and reserves products would be needed in this scenario. Self-dispatch of generators could still be the rule in this scenario, meaning that suppliers would propose bids and offers encompassing several units to mutualise their technical characteristics, in particular to better fit the definition of energy and reserves blocks. Finally, in this scenario, the question of a capacity market should be investigated and put in place with European implementation, if required.

A further ISOfication of the European transmission system operation is needed in this scenario to allow a Europeanisation of electricity markets. In a scenario of deep Europeanisation, more and more tasks of the system operation have become independent of national TSOs, even if it came from their initiative. Nordpool or market coupling were set by TSOs' subsidiaries. CASC was also set by TSOs to auction transmission capacity. TSOs have also set regional associations to share good practices about technical procedures, then extended to generation adequacy, market operation and network development planning. ENTSO-E is now in charge of all these activities at the European level.

TSOs have also seen an opportunity to cooperate in Regional Security Coordination Initiatives. While the security analysis and dispatching have historically been managed at the national or infra-national scale to ensure that flows do not exceed the capacity of power lines, several events (in particular the blackouts in Italy in 2003 and in Western Europe in 2006) have made it necessary to have a common security analysis on a broader scale, either multinational and even European-wide. Both Coreso and TSC were considered in this way. It is only with a whole view of the interconnected power system that one can understand how each part is functioning. One event - even if a bit old - makes it clear. On the 14th of July 1999, the Belgian power system suffered a situation where, on average, 59% of power flows (and up to 76%) through its network were unscheduled, creating unexpected constraints.



Source: RTE & Elia, 2002

Fig. 15: Power flows through the Belgian power network, 14th July 1999

This was because physical exchanges had not been forecasted to take place between France and the Netherlands through Belgium. Indeed, commercial exchanges were mainly planned between France, Switzerland, Germany and the Netherlands and more directly between France, Germany and the Netherlands, but not strictly between France and the Netherlands through Belgium. However, these commercial exchanges indeed led to physical exchanges between France and the Netherlands through Belgium. Coreso or TSC with their European vision of the patterns of power generation, load and flows would have been able to forecast such a situation and propose corrective actions to avoid a real time overload of the Belgium power system while there were only limited possibilities for responsive actions at that time.

Similarly, Grid Control Cooperations (German GCC – Grid Control Cooperation – IGCC, e-GCC) were set by TSOs to mutualise imbalances. That way, it avoids the following typically adverse situation. Assume that an interconnected power system is managed by two TSOs (A & B). TSO A notices a lack of energy on its national system and dispatches a power plant upward to re-balance the generation and load (on its national system); meanwhile TSO B notices an excess of energy on its national system and dispatches a power plant downward to re-balance generation on its national system. Each TSO acts in opposition to the other while their imbalances could have been mutualised.

This is inefficient for two reasons. First, it is costly because the upward dispatching of the power plant in country A is more expensive than the downward dispatching of the power plant in country B. This is a general statement because you usually have a higher number of generators that can be dispatched downward (because they are already running) than the number of generators that can be dispatched upward (because they must be started up, as

quickly as possible). Besides, it endangers the interconnected system security. Indeed, each of the TSO reduces its reserve margin, activating a balancing order (TSO A reduces its upward reserves while TSO B reduces its downward reserves) that would be needed in case a new imbalance appears. Mutualising the national imbalances before triggering balancing actions would leave the (downward and upward) reserves untouched at no cost. The TSOs would then limit their actions to the ones really needed to re-balance system-wide imbalances. In parallel, this scenario should also see the implementation of a unique EU-wide balancing market. Even if this is harmonised, it should also be adapted to the locally available balancing products allowing an efficient balancing management (e.g. replacement reserves activated several hours ahead of real time to maintain a high enough volume of frequency restoration reserves some hours later). Having different habits in system balancing (as TSOs can choose to reserve more or less power in advance; and be more or less proactive ahead of their operational balancing window), the EU-wide harmonisation of balancing will surely require a lot of discussion between TSOs to understand each other's point of view and practices, to integrate them and to find a common efficient solution adapted to the different national system dynamics (from very flexible hydro-based power systems to far less flexible thermal-based power systems).

This whole process of ISOfication will continue to expand on the European power system while transmission ownership could remain diversified at the national scale. Indeed, even if this process was pushed, some European regulatory pressure (in a broad sense from the European directives and regulations), new organisations were born from initiatives of a vanguard of TSOs before seeing other newcomer TSOs expanding them (see market coupling and price coupling of regions; RSCIs; GCCs; UCTE then ENTSOE being progressively extended). It is certain, that such a process is to be reinforced by a new European legislative production⁵³. To the contrary, any merger or reallocation of transmission assets between TSOs is constrained by the willingness of their shareholders (whether they are public or private). While we have seen several initiatives for merging part of the system operation at a multinational level in Europe, only two acquisitions of TSOs by others did occur (in 2010, the Belgian Elia acquiring the German 50Hertz with IFM; and Tennet the Dutch acquiring another German Transpower).

⁵³ Note that a further ISOfication in Europe will question the national scope of responsibility of system operation imposed on TSOs by their national law. With this regard, this scenario should require a change in the scope of responsibility of system operation toward the European level with an adequate legislative framework.

3.1.2 ... in scenario B of higher decarbonisation within existing Member States systems

In an extreme scenario of higher decarbonisation within existing Member States systems, one should not expect major changes in the scale and responsibility of the system operation (except for multi-TSO countries as already seen in the UK). The national scale should still be prevalent. Of course, it would rely on the momentum of current arrangements, in particular the major step of harmonisation permitted by the grid codes and day-ahead market coupling. This harmonisation process could also expand to intraday markets. But as soon as balancing and reserves markets are concerned and encompassed the responsibility and liability of TSOs as regards to their national law, one should expect no major change. The principle of subsidiarity is indeed central in this scenario, since decarbonisation is led at the national scale.

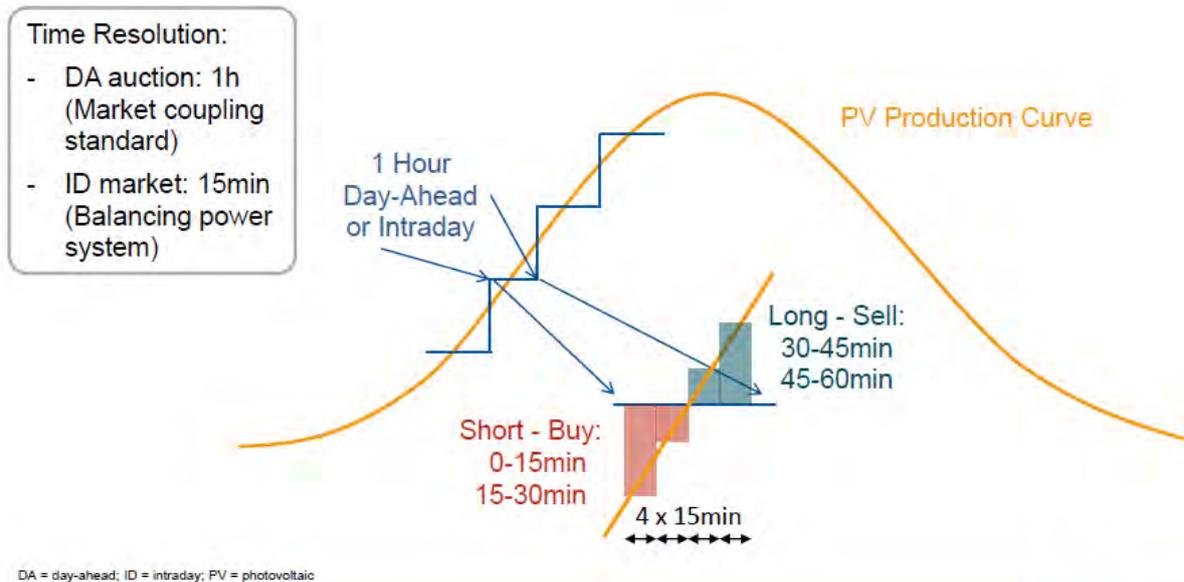
To the contrary, major changes in the definition of electricity products would be needed to facilitate and incentivise/allow for the integration of renewable energy. Indeed, in this scenario, an extremely large amount of renewable energy would create a lot of temporal and spatial constraints within the national systems for two main reasons:

1°, renewable sources, mainly wind and PV, are difficult to predict and significantly variable for a far shorter duration than an hour;

2°, they are generally located in areas where there was previously no, or a low level, of power production. Wind mills may locate in coastal or rural windy areas. PV power plants may locate in sunny areas. They may connect both on the transmission network and on the distribution network depending on their unit size.

Besides, in this scenario, a development of demand response both on the transmission and the distribution grids should be expected.

The existing electricity products as defined today would not then fit both the massive integration of renewable energy and the demand response novelties, whether these resources are concentrated or dispersed. The hourly or half-hourly definition of energy blocks would not fit the quicker dynamics of renewable generators and demand response (see figure 25, for an example with photovoltaic production). From the side of a photovoltaic generator or an aggregator aggregating PV, at the moment where the photovoltaic production ramps up in the morning, during the first half of this ramping hour, there is a deficit of energy between the energy being sold and the energy being produced by the PV. While, for the next half hour, it is the opposite and there is a surplus of energy between the energy sold and the energy produced.



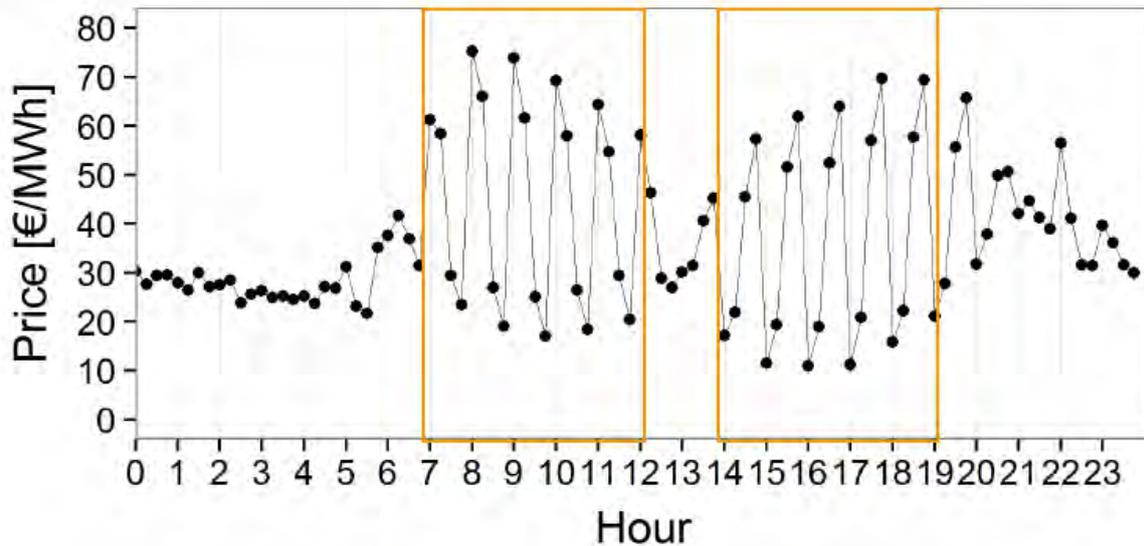
Source: Markedskraft Deutschland GmbH

Fig. 16: Market design specific reasons for ID trading in Germany: The Sunrise Quarters

Considering the expected high amount of photovoltaic production, this would create an important imbalance. That is why a specific day-ahead market, based on 15-minute products, has to be cleared just after the common coupled day-ahead market based on one-hour products. That is also the reason why the intraday market was organised for 15-minute products in Germany. That way the market players are allowed to cope with the ramp up and ramp down of PV energy (see figures 26).

For the first half of a given hour while photovoltaic is ramping up, photovoltaic producers are, on average, producing less than what they sold on the day-ahead market based on one-hour products and are then forced to buy energy to re-balance. In the opposite case, for the second half an hour (while they are ramping up), they are on average producing more than what they sold on the day-ahead market based on one-hour products and must then sell their excessive energy to re-balance. Markets with one-hour products ignore the oscillating behaviour of PV while the photovoltaic production is actually ramping up or down within the one-hour product window.

The other way around, demand response or battery-based storage capacity can be very flexible. Their flexibility will only be valued to a high enough price if the energy and reserves products have a fine enough temporal definition (see the decisions by the Federal energy regulator in the USA on this topic – FERC Order 784 (2013) and FERC Order 755 (2011)).



Source: Markedskraft Deutschland GmbH

Fig. 17: “The Sunrise Quarters” causing a systematic daily price pattern (Volume weighted average prices for quarters)

Besides, since the location of renewable energy sources in this scenario would be quite different from the location today of conventional generators, the network will have to be adapted and new congestions will appear. Hence, the today price zones defined at the national scale, or infra-national scale in some countries, would be outdated. A reflection on congestion pricing and the price zone definition is hence needed. Without a redefinition of price zones, too much redispatching would be needed. But this is inefficient because it does not give any signal where network constraints (congestion or voltage constraints) are located. It is mutualising their cost and gives ideally placed market players the opportunity to create these congestions while proposing their services at a very high cost in order to relieve those under pressure (Hogan, 1999). This problem also appears if the price zones have to be frequently redefined because the congestions are moving on the network with flows, all the more if the generation and load are variable (renewable generators and demand response), and generally more quickly than the redefinition of price zones (Stoft, 1998). Nodal pricing would handle this problem efficiently, integrating the detailed configuration of the network into the market representation. But this is to the expense of new types of costs (transaction costs, hedging costs against locational price differentials, etc.). These should then be compared with the benefits to come before a recommendation or a mitigation action with this regard. Whatever the final chosen solution, a mutual optimisation between system operation and market operation would be required to ensure a secure and efficient management of the power system.

Because of the limited predictability of renewable energy sources, the activation of reserves would be higher and less predictable over time (depending on the load level and unexpected outages of generators – mainly thermal ones). Reserves products should hence be defined on shorter periods to adapt to the actual variation induced by renewable generation. Consequently, finer time and space energy and reserves products would be needed in this scenario.

Considering the need for flexibility and the network constraints in this scenario, the system operation and market operation should be more integrated. That being said, and to sum up what was shown in the previous paragraph, the energy and reserves products should be redefined to take into account, as precisely as possible, the technical constraints, by progressively merging the system operation and market operation. A mutual optimisation of the market and technical conditions could then be achieved.

Meanwhile, generators as intermittent renewable generators (wind or PV generators) should not be isolated from balancing the responsibility usually borne by TSOs or incumbents. A generalised balancing responsibility should apply to all types of network users in particular to the intermittent renewable generators. That way, for generators putting a strain on the power system, balancing would be incentivised to find ways to compensate their intermittency (either with better generation forecast, taking the margin to sell their production day-ahead, rescheduling with intraday products, or pooling their production with those of other generators, etc.).

In this scenario, even if the system and market operation should be based on a central dispatch, it should also remain open to innovation from market actors. For instance, compared to what we see today, a wider participation of renewables, DR and decentralised resources (generation, storage and DR) to the market and system operation should be achievable. This should be eased by the redefinition of reserve and energy products. Furthermore, markets should place a higher value in resources that can track signals for reserves and balancing needs (e.g. frequency containment reserve, automatic recovery reserve, ramping), considering the very high requirement of flexibility in this scenario.

And finally, in this scenario, a capacity remuneration mechanism could be needed to provide more stable revenue to (efficient) back-up generators. Otherwise, the volatility of their revenues (from the energy-only markets) would prevent them from investing, being too unstable/unpredictable and risky.

Contrary to scenario A, this scenario B would not assume a further ISOfication of the European transmission system operation. Of course, the momentum of the current EU arrangements (ENTSOE, RSCIs, GCCs) could remain. Nevertheless, the deeper

decarbonisation is grounded on subsidiarity and national resources only in this scenario. In an extreme sense, there would be no highly organised reliance on external resources. In order to do so, the national power systems must be oversized to be able to cope alone with the variability of renewable generators (e.g. with a lot of back-up capacity – in the form of generation, storage or demand response – or with an outsized national transmission network to mutualise their indigenous renewable energy sources). The absence of cooperation for system operation at the European level would be compensated by a far higher expense in fixed costs (in generation, storage, demand response and transmission capacity).

3.1.3 ... in scenario C of higher decarbonisation within decentralised systems

In an extreme scenario of higher decarbonisation within decentralised systems, one should expect major changes in the scale and responsibility of the system operation and in the definition of energy and reserves products. Of course, this would rely on the momentum of current arrangements (grid codes and market coupling). Meanwhile remember that, in this scenario, generators are assumed to be flexibilised and close to consumers, the consumers being also flexibilised, and decentralised storage to allow for it to be widely spread.

As a consequence, the core of the system operation should shift from the transmission level to the distribution level. Indeed, balancing and reserves should be mainly organised at the local scale because the distribution grid would aim at being almost autonomous microgrids. As a result, the network constraints management should also focus on the distribution network while the transmission network should be less used as a primary action tool. This permits that the price zones for products offered at the central (say national), level as they are defined today for the wholesale market would not be necessarily questioned in this scenario. Moreover, reserves could still be shared at the transmission level to some extent and the transmission system operation could still organise an open & reliable last resort balancing.

Considering the limited role for the transmission system operation in this scenario, it does not seem essential to refine energy or reserves products with higher time granularity or higher integration between the system operation and market rules, and we see no need for a central dispatch. However, to the contrary, a reflection on interchangeable products between national TSOs could be initiated in this scenario. In parallel, it is worth noting that both the distribution system and market operations should be entirely revisited in this scenario compared to what we know today. Finer energy and reserves products with higher time granularity and higher integration between the system operation and market rules should be deployed at the local level by the distribution system operators. Furthermore, the

development of different local market models would question the fairness and the reliability of the power market because of its very local nature in this scenario.

This scenario would not assume a further ISOfication of the European transmission system operation. Once again, decarbonisation is grounded on local resources only. That said, in an extreme manner, there would be no fundamental reliance on resources at the transmission / wholesale level, either from a national or a European point of view since flexible resources are assumed to be mainly at the local level. One should nevertheless notice that the momentum of the current EU arrangements will remain in this scenario, and that imbalances could always be mutualised in a GCC-like manner, even if no major convergence of a balancing mechanism is needed here.

3.1.4 Comparing the system operation function in the three scenarios

The table below sums up the possible transformation of the system operation function in the three scenarios, in particular concerning the organisation of the day-ahead and intraday markets, the balancing and reserves markets, the definition of energy and reserves products as well as the possible ISOfication of transmission system operation functions.

Aspects of system operation function \ Scenarios	Lower decarbonisation within a pan-European system	Higher decarbonisation within existing Member States systems	Higher decarbonisation within decentralised systems
Day-ahead and intraday markets	Relies on momentum of current EU arrangements		
(Transmission) balancing and reserves markets	Pan-European system operation and markets (RSCIs, GCCs, etc.)	No driver for further pan-European markets	<ul style="list-style-type: none"> No driver for further pan-European markets TSO as the last resort balancing provider
Definition of energy and reserves products <ul style="list-style-type: none"> Energy products time granularity Reserves products time granularity Price zone definition Self- or central dispatch 	No major change: <ul style="list-style-type: none"> (half-)hourly energy products Monthly or yearly reserves products Unchanged pricing zones Self-dispatch can remain 	Need to refine energy and reserves products <ul style="list-style-type: none"> Quarter-hourly energy products Daily or intraday reserves products Reflection on congestion pricing and definition of price zones Mutual system and market operation 	No major change at the transmission level <ul style="list-style-type: none"> (half-)hourly energy products Monthly or yearly reserves products Unchanged pricing zones Self / distributed dispatch
ISOfication of transmission system operation	Required	Not needed	Not needed

Table 9: System operation function in the three scenarios

To conclude: if one should expect that the momentum of current EU arrangements should persist in the three scenarios, they should differ by the form of balancing and reserves markets, the definition of energy and reserves products and the need for ISOfication of the system operation. Balancing and reserves markets will then mainly be aligned with the relevant scope of each scenario (i.e. respectively a European, national or local level). Besides, one should expect no major change in the definition of energy and reserves products on the wholesale market in the pan-European and decentralised scenarios. But the nationally decarbonised scenario requires a definition of energy and reserves products that

should be finer and closer to physical rules with central dispatch both in order to cope with the constraints of flexibility and to push for the flexibility resources.

3.2 Interactions with other players in the power system supply chain

Setting aside the interaction with other TSOs, in a power system supply chain, a TSO interacts mainly with the DSOs, the final network users being generators and consumers directly connected to its network, market participants (that are partly the same as network users but that can also be pure traders or more financial actors) and institutional actors (in particular the national regulatory agency, national government, or the European Commission, and local communities impacted by its assets). These interactions would certainly be highly impacted by the different scenarios as compared to their nature today.

3.2.1 ... in scenario A of lower decarbonisation within a pan-European system

In an extreme scenario of a pan-European system, the interactions of a TSO with the other economic agents will end up organised mainly at the European scale. Hence, the DSOs are not expected to interact more than today with the TSO (ISO or TOs) because no important decentralised resources are expected to develop in this scenario.

The interaction of market players with TSOs is not expected to change dramatically in this scenario. As today, they will remain centralised market players with different sources of flexibility. To the extreme, market players could face one or two ISOs over Europe as a whole. Otherwise, they will still propose portfolio bids or offers for the whole set of energy and reserves products, localised in the different existing bidding zones. An important change could still occur from the new transmission arrangements in order to compel generators to optimise their location in the whole of Europe taking into account the long term constraints of the EU transmission grid. This point has already been mentioned in the theoretical literature in Europe (e.g. Comillas 2002). Nevertheless, it generally faced a fierce opposition from the generators (e.g. see Association of British generators in 2002 against losses; recent cases in Belgium and a decision in France).

If generators could see a new type of transmission tariff applied, consumers could also suffer an increase in the transmission tariff depending on the effective load increase. Indeed, in this EU-first scenario, major transmission investments are required, calling TO revenues to increase substantially. Consequently, if the load itself does not sufficiently increase, given the higher transmission revenue needed, the transmission tariff for consumers will indeed increase. Otherwise, if the load sufficiently increases, the transmission tariff for consumers could stabilise or even decrease.

The computation of a new tariff is also the main change that could test the relationship between TSOs and the institutional players (namely the regulators including ACER and the European Commission). The institutional players would have to agree on this new transmission tariff for generators (today very low under the 838/2010 regulation; see opinion by ACER, 2014). This calls for harmonisation and the resetting of the tariff structure in most of the European countries.

Besides the tariff structure, the question of transmission financeability should also pop up and impact the interaction between the TOs and the institutional players. Indeed, in this EU-first scenario, major transmission investments are required, tariffs are hence expected to increase substantially, and the TOs will need a great amount of extra financial resources (either in the form of an external equity injection or debt issuance, or an increase in regulated revenue). Regulation should then be adapted to this situation. Regulation should provide enough guaranties that tariffs and the regulatory regime will be remain stable, so that financing can be done in the easiest and cheapest manner (see Roland Berger 2011 and Henriot 2014). To conclude, the relationship related to the network codes is expected to keep on the same track as today.

3.2.2 ... in scenario B of higher decarbonisation within existing Member States systems

In an extreme scenario of a Member State-first system, the interactions of the TSO with the other economic agents occur and are organised mainly at the national scale. The DSOs are expected to interact more than they currently do with their national TSO(s) because decentralised (renewable generation or demand response) resources are expected to develop significantly in this scenario to deeper decarbonisation. It will then be necessary to better and more fully account for the mutual impact of transmission and distribution system management decisions. For instance, when a legitimate (transmission originated) balancing decision creates congestion on a distribution network. As a consequence, the congestion management decisions at the distribution level should be conceived to be either neutral with regard to the (transmission) power system balancing or having to pay a (transmission) imbalance originated by a DSO reaction. That way, either it is effectively neutral for the transmission power system or the DSO bears the cost of the actions on its network creating imbalances for the whole transmission power system. The other way around, the value of decentralised (generation or demand) resources for the management of the transmission system should not only consider their declared price in the balancing market, but also their shadow cost for the distribution system that is positive (resp. negative) if it creates (resp. relieve) a distribution network congestion, and zero otherwise. That way, the national TSO takes into account the local impact of any of the nationwide system decisions. This leaves

open the concrete organisation of the system operation between the distribution and transmission system operators. Even if the system operation becomes more relevant at distribution level, this does not mean that the distribution system operators will act in a discretionary manner. Three solutions can be envisaged:

- distribution system operators perform the system operation on their network within the format of their respective transmission system operators . Distribution system operators should then closely communicate with the TSO, in particular for the shadow cost of decentralised resources.
- the transmission system operator expands its own system operation over the distribution systems operation.
- TSO and DSOs share a kind of TSO-DSO security cooperation initiative. Note that whatever the chosen solution, the corresponding data hub design should be consistent with the chosen option and the beaded consumer data protection.

In this scenario, the interactions of market players with TSOs are also expected to change dramatically. Since decentralised resources develop and compete with centralised resources, market rules should adapt to those new resources (with a decentralised, variable but flexibilised nature) while also allowing the aggregators to participate in the market. Market players, facing the national TSO as today (and also their own local DSO), should then propose unit bids or offers for the whole set of energy and reserves products, being now (in this scenario) localised at the nodal scale within a central dispatch with shorter energy duration and reserves blocks jointly optimised. Another important change could still come from new transmission tariffs for generators. It is related to locational incentives given at the national level - taking into account the long term constraints of the power transmission grid; and with the same opposition expected as that mentioned for scenario A. Moreover, as in scenario A and for the same reason, consumers could also suffer an increase in the transmission tariff if their load does not sufficiently increase compared to the transmission revenue needs.

Once again, as for scenario A, the computation of the new tariff is a main topic that should change the relationship between TSOs and the institutional players. However, the deemed institutional players are different in that it is an EU-first scenario and restricted here to national regulators. The interaction with the European institutional players (as ACER and the European Commission) should remain limited in this scenario, focusing on the national level. Each NRA should then define a new transmission tariff for generators. The national regulation should also be adapted to the high need of financial resources for TSOs in this national scenario. To end, the relationship linked to the network codes is expected to be loosened since this scenario gives a greater role to the national subsidiarity. Note also that

the NRA will have to frame all the discussions for redefining the energy and the reserves products.

3.2.3 ... in scenario C of higher decarbonisation within decentralised systems

In a scenario of extremely decarbonised and decentralised systems, the interactions of the TSO with the other economic agents remain organised mainly at the national scale. The DSOs are expected to interact with their national TSOs mainly when they are out of local balancing resources. Similar to national scenario B, this leaves open the concrete organisation of the system operation between the distribution and the transmission system operators. DSOs could conduct the system operation on their network independently, as the transmission system operator does today. Another framework could be that the transmission system operator expands its system operation to the distribution system operation. Similarly, for connection contracts, two arrangements can be implemented, between the TSO, the DSOs and the network users connected to the transmission grid. A first option could be that the TSO imposes a quality requirement/control on the DSOs in their connection contract to the transmission grid. The DSOs are then compelled to transmit and translate those requirements in their connection contracts for the distribution grid. Another solution could be that connection to the distribution grid is necessarily a three-party contract between distribution network users, DSO and TSO, hence including, directly, the TSO requirements.

In this scenario, the interactions of market players with TSOs are also expected to change dramatically. Since markets are mainly organised at the local scale and the TSO should mainly be solicited for last resort balancing, the interactions of market players with TSOs should be very limited. Market design will have to be adapted to the highly decentralised and intermediated nature of power resources. As for the transmission level today, transparent rules will then be needed at the local level for designing the market, with the unbundling of the DSOs in order to avoid conflicts of interest. Meanwhile, there is no need for a more refined market design at the national and European scale because of the reduced volume of transactions. An important change could still happen from the application of a geographically differentiated transmission tariff to DSOs in order to induce them to optimise the development of local generation resources; and see more microgrids deployed only where it is efficient. Moreover, as in scenario A and for the same reason, consumers could also suffer from an increase in the transmission tariff if their load level does not match the transmission revenue needs. This could easily become a very pointed/prickly issue.

Once again, as for scenarios A and B, the computation of a new tariff is the main topic that should change the relationship between TSOs and the institutional players. However, the deemed institutional players are different from EU-first scenario and restrained to national

regulators only - since the interaction with the European institutional players (namely the ACER and the European Commission) should remain limited in this scenario, focused on the local level. The NRAs should then agree on a more cost-reflective transmission tariff and the impairment of transmission stranded costs (with a possible compensation by means other than a transmission tariff, e.g. state subsidy or tax). Regulation should also be adapted to the shrinking asset base, studying the required network renewal and otherwise dismantling. The NRA should also frame the discussion of the organisation of system operation at the distribution level, considering both options, by the DSO itself or with a TSO expanding its current activity to the distribution grid. Finally, the discussions related to the updates of network codes are expected to be loosened since this scenario gives a broader role to the local decision-making power.

3.2.4 Comparing the interactions between the TSO and the other stakeholders the in the three scenarios

The table below sums up the possible transformation of the interactions between the TSO and the other stakeholders (DSOs, market participants and regulators) in the three scenarios.

Interactions between the TSO and ...	Scenarios	Lower decarbonisation within a pan-European system	Higher decarbonisation within existing Member States systems	Higher decarbonisation within decentralised systems
DSOs	<ul style="list-style-type: none"> As today 	<ul style="list-style-type: none"> Different possible organisations between national DSOs & TSOs for system operation and connection arrangements 	<ul style="list-style-type: none"> For last resort provision of balancing + different possible organisations between national DSOs & TSOs for system operation and connection arrangements 	
Market participants	<ul style="list-style-type: none"> Intensive interaction through self-dispatch 	<ul style="list-style-type: none"> Intensive interaction through central dispatch 	<ul style="list-style-type: none"> Very limited (during event of last resort balancing provision) 	
Regulatory authorities	<ul style="list-style-type: none"> European-wide regulatory interaction through ACER mainly Regulation adapted to investment wave Cost-reflective tariff applied both to load and generation 	<ul style="list-style-type: none"> No interaction with ACER Regulation adapted to investment wave Cost-reflective tariff applied both to load and generation Framing discussion for organisation of distribution system operation 	<ul style="list-style-type: none"> No interaction of ACER Cost-reflective tariff including impairment of stranded assets Framing discussion for organisation of distribution system operation 	

Table 10: Interactions between the TSO and the other stakeholders in the three scenarios

Interaction between the TSO and market participants should be intensive in the pan-European and national scenarios, respectively centered on self-dispatch or on central dispatch. To the contrary, interactions with market participants should be limited in the decentralised scenario, except in extreme situations, as a last resort solution for balancing. As a consequence, interactions with DSOs should also be more limited in the pan-European and the decentralised scenario; while it should be intensive in the national scenario to guide the TSO for establishing a framework for decentralised resources useful both to the transmission and the distribution grids. As for regulation, the scope should be European in the pan-European scenario and national otherwise. Besides, it should be adapted to the investment wave on the transmission network in the pan-European and national scenarios. Cost-reflectiveness should ground the new transmission tariff design in all the scenarios, including the impairment of transmission stranded assets in the decentralised scenario. The regulator should also frame the discussion for the organisation of a new distribution system operation framework between the TSO and DSOs.

4. The case for a “hybrid scenario” and the corresponding checkpoints for an “Energy Union” low-carbon transmission framework

Introduction

The earlier chapters have demonstrated that the negotiations/proposals for the 3rd Package, dating from 2006 to 2009, are no longer as relevant, because the system has irrevocably changed and it cannot be implemented as it was first designed. The legal and regulatory framework that we have today is mainly the one forecasted in the 3rd Package, although implementation of this package is still a work in progress. However, with increasingly ambitious new (national and EU) policies and innovative new technologies, the dynamics of the power system have changed. While the hardware and the software of power systems are evolving at an ever-faster pace, the legal and regulatory frameworks have not changed significantly; hence, the gap between norms and incentives (“what should be done”), and reality (“what is actually being done”), becomes untenable. Moving from the current “legacy framework” towards a new setting (let’s call it a “2030” EU system vision) will be a long and complex process.

It is essential for the successful evolution of the EU energy policy and EU power systems that we identify and develop an understanding of this new terrain. As researchers and experts, we chose to make the novelty more explicit, and easier to grasp, by investigating three alternative scenarios concerning the evolution of power systems, assessing, for each scenario, how key TSO functions would evolve. We want the reader to fully appreciate the possible impact of structural changes upon the functioning of the power system, the functions performed by different actors and overall governance.

Three conceptual scenarios are needed to identify and investigate the new factors at play in the ongoing EU system change. They are:

1° “Full Europeanisation, but low decarbonisation” (a strong internal market is achieved, but has not been conceived to deliver a strong energy transition and climate policy);

2° “High decarbonisation, but at national level” (within 28 Germanies or Great Britains);

3° “High decarbonisation, but at local level” (within thousands of “green autonomous zones”).

As shown above in Chapters 2 and 3, and summarised in Chapters 4.1 and 4.2 below, none of these three scenarios is fully consistent with the present “legacy framework”, and they all require substantial changes in terms of governance mechanisms and regulatory policies.

The main goal of this research is not to recommend the best scenario of the EU TSOs future from the perspective of European public interest, or to prescribe an ideal road map conducive to an optimal European future.

The objective is more humble and more preliminary. It is to decipher how the European power system might evolve; the TSOs tasks, constraints and environment; as this should allow the reader to make their own conclusions of the best and worst aspects and how they should be resolved.

It is also ambitious, as understanding the ongoing motivation for change in the power system is imperative, both for the numerous interest groups and the various relevant institutional players in the shaping of any successful EU policy. We would like our research to contribute toward framing an “Energy Union” for the future of our power transmission.

In Chapter 4.3 we will consider the case of a fourth scenario, named “*Hybrid*”, because it assembles various features from each of the three basic conceptual scenarios. Firstly, it is unlikely that the EU can realise/achieve a fully European or a fully local system and framework in the coming decade. But secondly, retaining a fully national framework seems impossible given the overriding strength of the single market and its open borders, as well as the unprecedented growth of distributed generation at local level. However, thirdly and finally, it is not because “hybridation” is the solution that, in practice, will most likely work well and easily deliver. In fact, on its own, it is full of holes and foreseeable contradictions... If we can anticipate the evolution of the EU power system and TSOs, we can prepare for, and monitor, each step towards our common future.

Aware of the drawbacks of “Hybridation” actually progressing in the EU, either “by design” or “by accident”, Chapter 4.4 will examine at a set of “checkpoints” aimed at ensuring critical levels of coherence, consistency and resilience along the energy system journey towards a low-carbon future (say by 2050). We can only suggest how to begin this transition for the coming decade. The process will inevitably be full of unexpected and surprising, good and bad news. As we know little of yet, there is a high level of uncertainty around numerous issues, making it vital to establish check-points to ensure the EU system can continue to operate and implement EU policy during a process of trial and error. In particular, the governance of both the DSOs and the TSOs will have to take strides to catch up with the existing and numerous imminent transformations of the EU power system. From our current perspective, the EU DSO is still in its infancy, while some progress has already been made

with the EU TSO. Nevertheless, both would have to be fully mature by 2030: demanding a serious catch-up.

4.1 Overview of the three conceptual scenarios

The three basic conceptual scenarios were introduced to better grasp some structural novelties of the new world that we are entering into, and to identify major critical issues, as described in the following table (See Table 11 next page).

Scenario	Decarbon.	EU market integrat.	Market structure	System operation	Network governance (who is in charge of what?)	Regulation
A Fully Europeanised	Missed	More than today	EU-wide competition of centralised resources	European and national	European SO tools and markets with EU wide and/or EU regional ISO(s)	Adapted to an investment wave for (mainly cross-border) transmission; better cross-border cost allocation; supervision of complex supra-national markets and system operation. EU regulator needed, as well as coordination with NRA.
B National decarbonisation	Achieved	As today	Competing centralised and decentralised resources	National and local	TSO managing T grid DSOs managing D grids + T-D coordination needed for cross-network externality	Adapted to an investment wave for (mainly national) transmission, T-D interfaces and smart grids; local markets design; rules for coordination between local and national markets and system operation.
C Local decarbonisation	Achieved	Less than today	Mostly local resources	Mostly local	TSO for last resort actions (balancing or blackstart) in their national scope	Adapted to an investment wave for mainly smart grids; local markets design and coordination; rules for coordination between local and national markets and system operation handling of potential T and D stranded assets.

Table 11: Overview of the main structural, governance and regulatory characteristics of the three basic conceptual scenarios

4.1.1 A) A scenario of “full Europeanisation but low decarbonisation”

The following table sums up the transformation of the transmission system operation in a scenario of full Europeanisation, but low decarbonisation. It is assumed that there will be a very strong and open internal market, which will dictate/shape the operation and level of investment. The key characteristic of this market structure is EU-wide competition among “centralised” generation resources. In order to ensure the reliability and efficiency of such a large-scale unified system and market, the current trend towards a European system operation, meaning both (analytical, forecasting) computations and (control) actions at EU level, must be reinforced. From the organisational point of view, this can be achieved through the creation of either a single European ISO coordinating all TSOs, or a European system operator chairing a pool of regional ISOs. The regulatory framework needs to cope with a wave of EU transmission investments, providing the right incentives and allocating its costs to beneficiaries in a transparent and acceptable manner. The creation of a truly European energy regulator to supervise supra-national markets and all forms of cross-border transactions (energy trade, “green” electricity exchanges, provision of ancillary services, etc.) becomes inevitable, in spite of all the political and institutional difficulties. The institutional interface between this new body and national regulatory authorities also needs to be established.

While this scenario would materialise the “old” internal market model, it is most unlikely that it would deliver the expected results of the current EU energy transition and climate policy, because it ignores the ongoing decentralised green revolution, abandoning all innovations that do not fit the centralised approach.

Function		Entity in charge today	The scenario	
			Function scope	Entity in charge
Connection	Operation	TSO	Adapted to centralised and "flexibilised" RES resources	ISO(s)
	Involvement in rules design	Mostly TSO + DSOs		Mostly ISO(s) + DSOs
Network investment		TSO	Higher (cross-border) investment and use of innovative grid technologies	TOs
ICT investment	Operation	TSO	Momentum of current arrangements (grid codes) + Harmonisation of bal. and res. mkt but no finer time & space E & R products Need of EU capacity market?	Enhanced ISO bodies going beyond (ENTSOE, RSCIs, GCCs) but national TOs for investment
	Involvement in rules design	TSOs		
Sys. & market operation	Operation	TSO		
	Involvement in rules design	TSOs		
TSO coordination		TSOs		

Table 12: TSO functions transformation in scenario A - full Europeanisation but low decarbonisation

4.1.2 B) A scenario of national decarbonisation

The table that follows sums up the transformation of the transmission system operation in the case of a Member States' driven decarbonisation. The Member States fully mobilise their political, legislative, regulatory and economic resources in a strong decarbonisation process without the significant Europeanisation of electricity systems and markets. In each Member State centralised and decentralised generation resources co-exist. The system operation is still mainly conceived and carried out at national level, but with a growing need for coordination between DSOs and TSOs. The same applies to a market redesign, where "local" and "national" platforms must be compatible, thus requiring considerable harmonisation efforts at national level. Governance issues are mainly addressed at national level, leading to potentially very different market and operational architectures across the EU Member States.

The regulatory framework must be adapted to incentivise, for both types of system operators, the necessary investments, and to establish formal cooperation and coordination mechanisms from the grids planning stage to actual flow operation. Local markets may be more or less regulated, but national regulatory authorities must define or approve rules concerning all kind of transactions between the local and national levels (energy trade, "green" electricity exchanges, the provision of ancillary services, etc.).

Function	Entity in charge today	The scenario			
		Function scope	Entity in charge		
<i>Connection</i>	<i>Operation</i>	TSO	DSO		
	<i>Involvement in rules design</i>	Mostly TSO + DSOs	Mostly TSO + DSOs		
<i>Network investment</i>		TSO	Higher investment and more use of innovative grid technologies	TSO	
<i>ICT investment</i>	<i>Operation</i>	TSO	Adapting to new decentralised sources Finer time & space E & R products	DSOs	
	<i>Involvement in rules design</i>			+ TSO-DSO coordination needed for cross-network T-D externality	
<i>Sys. & market operation</i>	<i>Operation</i>				
	<i>Involvement in rules design</i>				
<i>TSO coordination</i>		TSOs	Lacking integrated reserves, balancing & intraday markets for European flexible resources integration	TSOs in current EU arrangements momentum	

Table 13: TSO functions transformation in scenario B - Member States driven national decarbonisation

4.1.3 C) A scenario of deeply local decarbonisation

The following table summarises the transformation of the transmission system operation in a local decarbonisation scenario. In a context of sharply declining costs and plenty of technological and societal innovations, the offer and demand of low-carbon energy systems meet in reduced size sets of strongly interactive devices and behaviours. The European and national power markets have lost their central role. Hundreds (or thousands) of local systems have been organised or built. DSOs or new intermediaries (being private ones with contracted services; or public ones supported by local authorities) operate all these systems, which extensively use local storage and local balancing to run autonomous small power systems, some of them strongly interconnected with other energy systems (heating, cooling, gas, mobility, etc.).

TSOs subsist with their infrastructures and tools, most of them accepted as “sunk costs” from the past. They still play a role - but limited to what central resources can deliver in a fragmented decentralised low-carbon world.

From the governance point of view, ensuring proper coordination among a large number of quasi-autonomous systems, including both normal and abnormal system conditions, represents a formidable challenge.

The regulatory framework has lost a significant part of its substance as these local systems are much more “self-regulated” than traditional centralised (national) systems. However, regulation must address the definition and implementation of distribution network tariffs with the high decentralisation of agents, “random” transactions and potentially high stranded costs. Furthermore, interactions among agents from different local systems must be regulated, in addition to the provision of “back-up” services. An important part of the new regulatory framework is the management of many “stranded assets”, the definition of a new class of actions for the TSOs within new incentive and cost allocation schemes.

Function		Entity in charge today	The scenario	
			Function scope	Entity in charge
Connection	Operation	TSO	Shifting from T to D	DSO
	Involvement in rules design	Mostly TSO + DSOs		Sharing DSOs / TSO??
Network investment		TSO	Shrinking with only partial renewal	TSO
ICT investment	Operation	TSO	Expanding toward distribution	DSOs
	Involvement in rules design	TSO		Sharing DSOs / TSO??
System & market operation	Operation	TSO	Shifting from transmission to distribution & adapting to decentralised sources	DSO + TSO for last resort balancing
	Involvement in rules design	TSO		Sharing DSOs / TSO??
TSO coordination		TSOs	Transnational imbalance mutualisation	TSOs in momentum of current EU arrangements

Table 14: TSO functions transformation in scenario C - local decarbonisation

4.2 Consistency and feasibility of the three basic scenarios

After having analysed in detail each one of the three basic scenarios, two main questions arise:

- Are the scenarios consistent? (i.e., are they able to deliver what a society expects from the energy transition, namely decarbonisation and the Europeanisation of electricity markets?)
- Are the scenarios feasible? (i.e., is each scenario self-consistent, or does it contain incoherent features that render the system potentially unreliable or unstable?)

Although all three scenarios were constructed in order to fulfil EU energy and climate policy objectives, no individual scenario can easily fully meet all of the goals at a reasonable cost. Societal expectations, technological developments and public policies are not necessarily, and not always, aligned, therefore this difficulty should be of no surprise.

As regards their internal coherence or self-consistency, it should be pointed out that implementation of any scenario requires substantial changes in the current legal and regulatory frameworks. In particular, two points deserve special attention:

- 1) Some critical system operational functions, currently mainly performed by national TSOs, will be totally or partially performed by other entities. These entities may be supra-national organizations, either emanating from or acting in close cooperation with TSOs, DSOs (individually or somehow associated) or even new players. Therefore, the legal and regulatory frameworks must be adapted, namely in order to:
 - i) Clearly define and assign each system operational function, indicating, for each, appropriate cost and liability sharing mechanisms.
 - ii) Establish appropriate coordination mechanisms, for both normal and abnormal situations, including appropriate redundancy safeguards and supervision tools.
- 2) Even if from the technical (system operation) point of view it is theoretically possible to ensure appropriate system reliability (assuming that the necessary legal and regulatory changes are implemented), several “black holes” may still jeopardize the efficient functioning of electricity systems and markets. The report discusses how to patch them.

Table 15 describes both the major “black holes” that need to be patched up and the main expected transfers at system operation level.

Scenario	Performable TSO functions?	TSO functions performed by	Black holes to patch up
<i>Fully European</i>	Yes	ISOs for software & TOs for hardware	Where's the EU wide real regulator? How to communicate with NRAs? Liabilities in case of critical situation where the computation / action sharing of liabilities is not robust → mutualisation toward EU ISO /TO bodies?
<i>National decarbonisation</i>	Yes	TSO & DSOs	Coordination arrangement to be built in order to handle cross network externality 3 solutions Extending SO by TSO toward D Enhancing SO by DSO with communication with the TSO TSO-DSO joint Security Cooperation Initiative
<i>Local decarbonisation</i>	Yes	DSOs developing similar skills as TSOs today	How regulation can be fair & reliable if different market models pop up at local level? Liabilities in case of critical situation between DSOs and TSO → TSO as a mutualisation body for a critical situation?

Table 15: Scenarios consistency check

1° In a fully Europeanised system, the companies invested in grid infrastructures are still alive and cannot be deprived of their assets. They may lose their rights on the “System Operation”, which is a statutory role given by legislation and regulation. They then become “Transmission Owners” (TOs) while the grids are operated by new entities created under the model of “Independent System Operators” (ISOs). On the hardware part of the European grid, it is unclear how the transmission investments are conceived, planned and made; financed and allocated to users through tariffs or prices for services. On the software part of the European grid, how will the coexistence of several layers of grids (the proper EU “super grid”; the several regional transmission zones; the remaining national and sub-national sub-systems) work? What will be the definition of responsibility and liability if the computation of the system operation, and the requisite actions to be undertaken, are indistinct and

clearly non-competitive?? What type of rights or duties will be given to the regional operators by the Member States?

2° In a national decarbonisation scenario, the role of the DSOs will inevitably grow because low-carbon energy will not be fully centralised, even if the central types of bio-mass, bio-fuels, bio-gas, off-shore grids (etc., such as nuclear) will play a big role. How will this come to life? Might TSOs keep the bulk of their current functions and finally extend them to distribution operation? Or will DSOs increasingly push for a combined DSO and TSO power to negotiate and enforce detailed protocols of coordination and cooperation? Will we see more and more “TSO-DSO joint Security Cooperation Initiatives”?

3° Inevitably, in a local decarbonisation scenario, DSOs will become “small TSOs”, leading to four questions. Firstly, the transmission grid will still be able to link, and to bridge, many or most of the local zones of operation. How, then, will the proper role and the system responsibilities of the TSO be defined? Secondly, what will happen to the “voluntarily fully autarchic” local zones when confronted with the unexpected ruptures of their self-sufficiency? Thirdly, how will DSOs manage the interactions of their numerous local zones at their many common borders? Fourthly, in a scenario of radical decentralisation, many micro-grids owners and operators will not be DSOs, but private or local public undertakings. How will these interact with the DSOs or the TSO if they act outside of the DSO and TSO regulatory framework?

4.3 The case for a “Hybrid scenario”

We will now consider the case for a fourth scenario, named “Hybrid”, because it assembles various features from each of the three conceptual scenarios previously analysed. What makes a “Hybrid” scenario likely? And is this hybridation a magic bullet, or rather a mere contradiction? Will hybridation happen “by design” (i.e., because decision-makers consciously opt for a hybrid model) or “by accident” (i.e., because decisions being taken by different agents at different places and at different points in time result in a dynamic hybrid outcome that does not correspond to the expected outcome of any individual agent)?

4.3.1 Is there any “hybrid” scenario to regroup the best of all three conceptual worlds?

All three conceptual scenarios previously analysed have weak points; but two of them (A and C - the EU and the local) show serious feasibility difficulties, which make

the “MS national” scenario the more realistic option in a “conservative” approach to the EU energy transition (i.e., taking into account current institutional inertia).

a- Hardware feasibility: The existing method for EU generation cannot be fully localised or fully Europeanised in the course of ten years. The grids themselves cannot be transitioned within this time frame. Thus, a longer period of time is necessary to achieve a fully decentralised or fully European set-up. Any transition will presumably be a protracted process, during which the “hardware” functions of the EU power system will remain “hybrid”.

b- Software feasibility: a full reallocation of most of the “system operation” responsibilities (both data and processing tools, plus full control or decision making) to fully European players or fully local (being existing DSOs or new local “micro grids operators”) in a decade is not more realistic. On the one hand, full Europeanisation would involve challenging the strength of existing MS transmission operation frameworks (as the duly legal and regulatory frameworks for system operation). On the other hand, the full decentralisation of the system operation would involve dealing with the weaknesses (operational tools; professional skills; assets and resources) of new players, not the existing TSOs. Any transition will be a lengthy and difficult process because both the framework for operation and the capabilities to operate will long resist a full or speedy transformation.

4.3.2 While the “MS national” scenario is less hypothetical, it has serious weaknesses

a- Full “nationalisation” of the hardware functions is not realistic because, on the one hand, distributed generation at local level is already substantial in many countries while, on the other hand, interactions between national systems are high enough to push TSOs into a real “hardware dialogue” (see how much the Nordics and the Benelux are building new cross-border lines; or the new France-Italy 1bn euro link under the Alps).

b- Full “nationalisation” of the software functions is not any more realistic. On the one hand, there is already considerable Europeanisation of the market operation in several countries, and cooperation between TSOs has already followed (think ENTSO-E, RCSI, TSC, Coreso). On the other hand, the European Commission has serious weapons to impede a full “renationalisation” by MS. This arsenal includes the Commission’s “Internal Market” and “State Aid” powers (see, for instance, the new sector enquiry on “Generation Capacity mechanisms” launched at the end of April 2015).

4.3.3 The three conceptual scenarios are more conceptual than actual

It is not a surprise that the three conceptual scenarios are more conceptual than actual. But, it doesn't necessarily mean that any hybrid option is a better option or "more realistic". It may be that hybridation has certain good properties "per se"; be they economic, technological or systemic. Hybridation might permit a better use of the various low-carbon resources of the EU (from biomass and PV to onshore and offshore wind). Hybridation might keep options open and allow for the gradual discovery and experimentation of new ways of generating power, operating grids and using markets, even new means of efficiently consuming energy.

4.3.4 Conceptually, hybridation is mainly a phase of difficulty and transition

However, there are also obviously strong contradictions and major drawbacks to hybridation. The co-existence of three levels of system hardware and software inevitably raises conflicts and contradictions. These three levels do not require the same set of rules, nor the same roles, for the same governance to enforce these rules reasonably well. This is a big concern, and decision-makers should be fully aware of this fact and prepared to respond to it.

While nobody yet knows which system we will end up with by 2030, we already know that it won't be that referenced in the 3rd EU Package. Regardless of whether "hybridation" is the more likely scenario, it will not be an easy solution, either in its implementation or delivery, as the process is full of holes and contradictions.

4.3.5 Towards an EU Regulation 2.0.

Our existing EU regulatory frame is questioned both at its top and at its bottom.

At its top we do not find yet the robust Europeanized frame corresponding to the cross-border system and cross-border markets that are expanding. One expects a deeper regional coordination for grid planning and system operation as well as open market platforms for intra-day and balancing. This also implies an effective cross-border frame for grid and system costs-benefits analysis, costs allocation and revenues collection; if not for financing and building. Hence a really Europeanized (or regionalized) regulatory frame.

At the bottom of the existing EU regulatory frame we do not find yet a coherent response to the convergence of low carbon objectives and wave of innovation. Most of the national regulatory frames do not have yet reorganized for distributed generation, demand response and smart technologies. With presumably less grid traffic to come but more services to deliver, less revenue certainty but new investment to be made, and more trade-offs between capital and operation expenditures (Capex vs Opex), the whole architecture of network regulation has to be rethought and reviewed. It goes up to create a brand new regulatory frame for brand new interactions between transmission grids and distributions grids, national system and local systems.

Between this more Europeanized top and this more local bottom the regulation for security of supply has to move and to catch up. More distributed and more intermittent generation resources ask for new system rules, with less “socialization”, more responsibility for players (incl. for demand), and finer localisation and time definitions of products, prices and actions. The adequacy of the generation set might even not be guaranteed anymore in energy markets transformed by massive RES integration. However one does not expect a robust pricing of system flexibility or an efficient capacity market to be built without a clear regulation of reliability standards, of cross-border contracting and activation of capacity related services.

And, at the end of this wide EU-local loop, it is the resulting menu of grid access and tariffs, services definition and revenues opportunities which will create the incentives for a long wave of low-carbon investments and technology innovation (see IEA 2015).

4.4 Checkpoints for the launching of an “Energy Union” system and “grid framework”

All of the limitations, deficiencies and contradictions observed in any scenario, including “hybridation”, call for a set of checkpoints to facilitate the coming “Energy Union” and make the best of existing limits and constraints. A set of relevant checkpoints should advance the process of full decarbonisation, and ensure successful EU integration within a relatively secure power system, toward a long-lasting “Energy Union”.

We will start our recommendations by looking at the “*primary checkpoints*”, targeting the likely properties of an EU hybrid scenario which could conflict with the main goals of the EU policy (being 1° an open internal market; 2° secure power system; 3° low-

carbon and high level innovation). In the second part, we will look at the “secondary checkpoints”, relating to governance issues.

a/ Primary checkpoints: a matrix with “Three dimensions and Two channels”

Our primary checkpoints aim at keeping control of the key properties deemed necessary for the internal market, and for the power system, on the long road toward an EU energy transition. There are three dimensions of “EU policy” at stake there - and each is questioned by the new properties of the power system and market:

- First, to keep an open and unbiased internal market where players can easily enter, act, invest, operate, innovate and move across the EU.
- Second, to protect the security of the power system: the reliability of its operation and the adequacy of its structural evolution.
- Third, and last but not least, to favour a low-carbon trajectory and the necessary corresponding technological wave of innovation.

Having already identified two channels of power transmission grid functions (noted in previous chapters as the hardware’s functions and the software’s functions) at work, and having added the three key EU policy dimensions at stake, we end up with a table of recommended checkpoints, being a matrix of 2 lines for the two channels of grid functions and 3 columns for the three dimensions of the system and market, as illustrated in the table below.

Network functions	EU policy goals		
	Open internal market	Secure power system	low-carbon and high level of innovation
Hardware			
Software			

Table 16: Primary checkpoints

b/ Secondary checkpoints: the Governance issues

Our recommended Energy Union checkpoints also cover a set of governance issues. The primary checkpoints, as referred to above, are not providing a fully defined, fully implementable and non-ambiguous set of rules and actions according to each possible state of the EU system, market and environment. Good and bad surprises will occur, to some extent. Therefore, the primary recommended checkpoints have to

be completed by secondary “governance checkpoints”, which anticipate the institutional control keys for the stakeholders’ interactions in the process of aligning actions and rules to a shifting reality.

Since three distinct operational levels must be considered (local, national and EU), the above described checkpoints must be applied at each interface between them. Figure 18 shows these interfaces and indicates the Sections where the respective analysis will be performed.

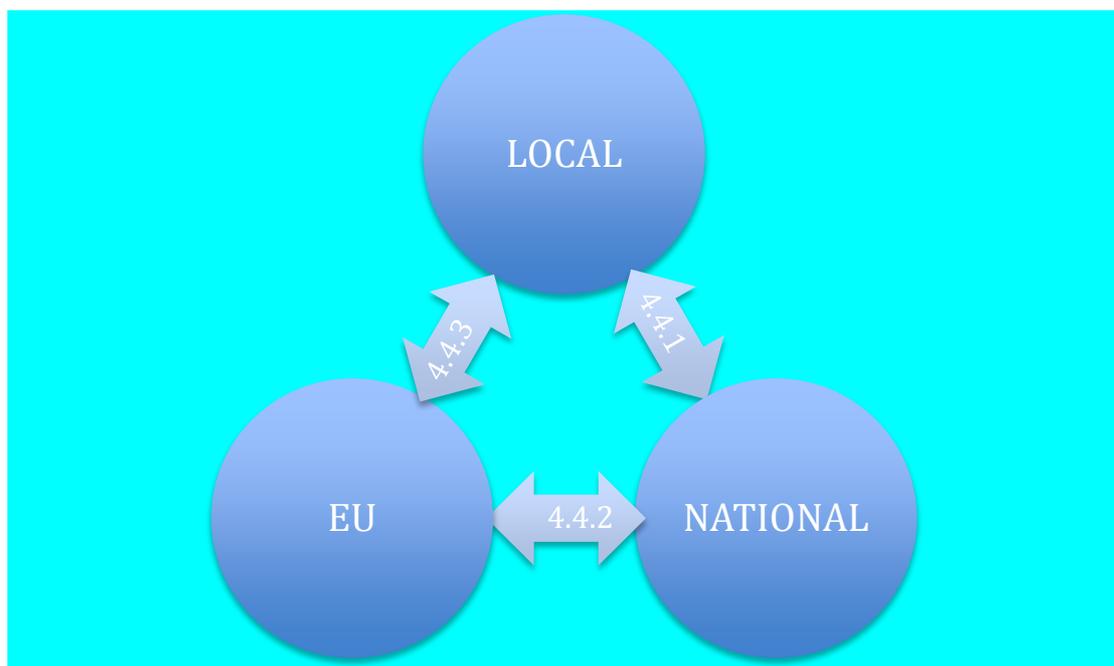


Fig. 18: Critical Interfaces

4.4.1 Recommended checkpoints to better articulate the local level with the national level vis-à-vis the three main EU policy goals

In any hybrid scenario, the local and the national levels co-exist. One may think of the communication between them as a purely “subsidiarity matter”. And this is mainly true from a restrictive “governance” point of view: institutionally the local interacts with and reports at MS level and not at an EU level. However, this does little to alleviate concerns of a de facto “hybrid” scenario for an “EU system and market” policy. Subsidiarity is a key European principle because all subsidiarity affairs are assumed to be of no fundamental impact on the EU policy, power system and market. This strong “neutrality” principle between the local and the European has to be monitored. This would be particularly important if any type of articulation between local and national levels was also reasonably EU internal market friendly, plus resilient enough

vis-à-vis system reliability and adequacy, and favourable enough to low-carbon transition and technological innovation. This neutrality is far from being granted in the practice of existing hybridation because of serious contradictions that grow, or can grow, between the local and the national MS levels.

Of course, it is not the task of the European level to select what best suits the trajectory of each Member State. But, as independent experts and researchers, we have to flag the areas where the Energy Union would need safeguards. It is there to favour minimal consistency and the robustness of local scenarios vis-à-vis the MS national “2030” trajectories. These national trajectories will be given by the MS as “building blocks” toward the EU level “2030 trajectory”. Here lies one of the big gambles of the growing hybrid EU power system: change happens quickly and widely at the local level; where only national authorities and national frameworks can keep the playing/game open enough, secure enough and innovative enough for the EU common interest.

a- Internal Market dimension

On the hardware side of grid functions (grid investments and connections), coherence between DSOs and TSO(s) is not yet given. The information relevant for grid planning, the way DSOs and TSOs define formats and the protocols of information gathering and information exchange would have to become consistent and interoperable. The same seems necessary to give reciprocal consistency to the DSOs/TSOs respective grid planning methodologies and system scenarios.

On the software side (operation and interactions), we could fear a wave of foreclosure of the mushrooming local markets by local incumbents and / or integrated national companies. What safeguards should be implemented to keep local affairs open? A similarly workable gateway, and interoperability, would be welcome between the operation of the local markets and systems and the national ones. If none is provided, a deep fragmentation and balkanisation of the EU system and market could be voluntarily, and quietly, built at the local level: where the EU level cannot act or react. There is a major tension there. Economists would call it a “trade-off” between the respected and required autonomy to choose and experiment at local level, and the threat of an easy foreclosure by local cartels, monopolists or dominant players.

b- Reliability and Adequacy dimension

On the hardware side of grid functions (grid investments and connections), we also find a real issue. For the past few years, most of the new generation capacity investment has been made at the distribution level, while interactions between this

new RES generation set and the rest of the system occur via the transmission grid. A minimum of consistency should come for the format and the protocols of information gathering and exchange between the DSOs and TSOs. A similar move could give consistency to the DSOs/TSOs respective grid planning methodologies and system scenarios. Why should MS policy care that much about generation adequacy and grid adequacy at each MS national level, if neither is checked at the MS local level to see if it is already deeply influencing the MS national level outcome?

On the software side (operation and interactions), the national security of the system operation relies more and more on distributed generation behaviour and the responsiveness to the local and national system needs. Again, one could expect a definition of the respective roles and responsibilities (rights and duties; actions and liabilities) of DSOs and TSOs (as for: information and monitoring standards; congestion management; balancing procurement; emergency handling; etc.).

c- The Low Carbon and Technological Wave dimension

On the hardware side of the grid functions (grid investments and connections), we hope that more and more low-carbon, energy efficient or system responsive innovations and novelties will appear and grow at the local level; either for distributed generation, or consumers behaviour, or both (“prosumers”). A main concern, for the success of this awaited wave, is to retain the scope and scale of incentives for economies, which can be gained at national level. This suggests that DSOs should ensure a minimum of technology pluralism and grid user neutrality in their grid planning and connections (both for methodology and implementation).

On the software side (operation and interactions), a similar concern to “keep locals open to changes and novelties” suggests finding safeguards against the worst scenario, that “existing suppliers or integrated companies take all and pick themselves as winners”. It would also be welcome to get at local level a pro-active demand activation enabling.

4.4.2 Recommended primary checkpoints to better articulate the national level with the EU level, vis-à-vis the three main EU policy goals

In any hybrid scenario, the national and the EU levels co-exist. This topic is familiar because it is the enduring story of building the internal market since the Single Act in 1986. As there are at least three dimensions of interest there (= internal market; reliability and adequacy; low-carbon and a technological wave), one cannot expect to find the same single combination of these three dimensions in each and every EU

country. However, each of these three dimensions has a strong EU common interest and none can be fully disregarded as purely of “national choice and MS sovereignty”.

a- Internal Market dimension

On the hardware side of grid functions (grid investments & connections), the way MS TSOs plan and build their grids shapes the way the infrastructure of the EU internal market is framed or constrained. The EU internal market should reach an EU level playing field, as with: an open TSO data base; explicitly interoperable system scenarios and analysis; joint projects suppressing the border seams between adjacent TSOs zones etc. For the transmission connections, one could expect a harmonised and transparent set of connection options, and price calculation harmonisation (=i.e., not the same price everywhere, but everywhere a consistent logic in the pricing of connection options).

On the software side (operation and interactions), one could expect a coordinated management of the interdependence between the national system and market zones. A coordinated approach to the system operation, to maximise the benefits delivered by the internal market, is needed. Hence, one expects regional sets of: forecast, capacity calculation, and a menu of potential actions, as well as a regional approach to an efficient zoning of grids and the operation of markets. In the same vein, one should deliver a regional approach to enhanced RES integration, system flexibility maturity, demand response enabling, etc.

b- Reliability and Adequacy dimension

On the hardware side of grid functions (grid investments & connections), one expects the same as above for planning (an EU level playing field for: an open data base; explicitly interoperable system scenarios and analysis; etc.) to get greater consistency between interdependent TSOs. It should go to a regional approach to grid planning, as to a regional monitoring of the MS' Security of Supply infrastructure planning consistency.

On the software side (operation and interactions), one would expect deeper coordination of the TSOs as; regional assessment of generation adequacy, security of supply and the handling of “emergency” scenarios, as well as regional arrangements to increase system flexibility and responsiveness both for supply and for demand. As national TSOs control zones are still kept as a core of system operation, a deep harmonisation of the TSOs' behaviour and tools is needed. The handling of intraday, balancing and reserves has to converge between adjacent TSOs; the products, certification, activation and trade rules etc. have to be harmonised.

c- Low Carbon & Technological Wave dimension

On the hardware side of grid functions (grid investments and connections), it is important to understand how national TSOs conceive of their “tool-box”, and how they build their contributions to MS policy targets and 2030 trajectories. It could come via transparency by revealing “low-carbon” assumptions made by TSOs in their system scenarios and grid planning. It could also act as voluntary guide lines for technology plurality for the connections & users; sustained by ex-ante transparency for the connection charges calculation. Another way could be the TSOs defining KPIs (“Key Performance Indicators”), permitting to follow, ex post, the contribution of the national transmission grids to the MS trajectories within the National Action Plan(s).

On the software side (operation and interactions), we would welcome safeguards for technology pluralism and users neutrality. This welcome would extend to a pro-active demand system enabling role.

4.4.3 Recommended checkpoints to better articulate the EU level with the local level

How could the EU level address anything legitimate or relevant for the local level to achieve a common EU interest? It is, of course, a quite irritating question for many EU citizens and authorities. The EU level is no more than the EU level; and each European is better off when choosing locally what to eat at breakfast (as at lunch...). However, it is well known why we ended up with EU common rules for fishing or hunting endangered species, as well as why the “EU” frames the MS action vis-à-vis the basic freedom of any EU citizen or undertaking to move and exist inside the EU. It is because logically a local action principle cannot significantly jeopardise a fundamental principle having being legally established at a higher level (in this case, at EU level).

We have identified three of these “fundamental principles” at the EU energy level: 1° openness and non-discrimination in the internal market; 2° reliability and adequacy of the power system; 3° the effective twinning of low-carbon action within a technological and innovation wave. The aim, here, is not European harmonisation, as such. Europeans prize and value local actions; so they can freely deviate, differentiate or ignore each other. Nothing wrong: very welcome. The only EU aim, should be asking for a minimal level of consistency with the highest EU common interest, for people building the frameworks for local actions. Any kind of national guidelines or voluntary “Covenant of Mayors” could look at how the welcome autonomy and diversity in local actions does not derail into systematically killing any common targeting, or

common interest, expressed at EU level. This aim is minimalist by nature: it calls mainly for some safeguards or voluntary limits.

a- Internal Market dimension

On the hardware side of grid functions (*grid investments and connections*), initiatives could be taken to favour guidelines or codes of conduct defining what is friendly/unfriendly to the internal market in the planning and connection principles used by local grids for their corresponding “pocket markets”. A key debate is if “purely closed shop” micro-grids (as a “mall”, an “industry park”, a “university research park”, a “municipal collective housing”, etc.) could escape those principles. Such a debate, to better know what is, and isn’t, at stake is necessary and urgent.

On the software side (*operation and interactions*), there are similar concerns and hopes. Could voluntary guidelines or commitments define the “internal market” friendly operation principles for local grids and pocket markets? Initiatives looking to be consistent with the coming “Advanced EU Target Model”, expected to be working in 2020, are necessary.

b- Reliability and Adequacy dimension

On the hardware side of grid functions (*grid investments and connections*), the growing importance of distributed generation makes the EU power system tremble in its roots: the local grids. One would give the whole EU tree more stability and resilience by establishing a minimal coherence and interoperability of local information data-base, data processing and access. It might also help to provide some visibility or sharing of the actual planning methods and developing the system scenarios.

On the software side (*operation and interactions*), the not very positive role played by some distribution grids in the 2006 EU blackout management cannot be ignored. And, at that time, the local generation set was not at all what it has become. Medium-size cities’ airports do not self-manage their skies because there, at local level, some of what has been already said is needed: coherence, interoperability, openness... Working definitions of local grid players’ roles, responsibility, rights, duties, liabilities etc. for congestion, balancing, emergency etc. are urgently needed.

c- The Low Carbon and Technological Wave dimension

On the hardware side of grid functions (*grid investments and connections*), it is important to understand how local players operate in the common journey toward energy transition. It might be some way of revealing the “low-carbon” assumptions for

system scenarios and grid planning. It could also go toward ex ante transparency for the calculation of connection charges within technology plurality for connections and users. Advanced DSOs might also define their own KPIs (“Key Performance Indicators”) permitting us to follow their role in the MS trajectory(ies) revealed by the National Action Plan(s). Local players should be interested in showing how their investments structure the common manoeuvre against climate change and for smart energy systems.

On the software side (operation and interactions), the EU expected wave of low-carbon, energy efficient and responsive innovation might benefit from voluntary safeguards for technology pluralism and user neutrality; as well as a pro-active demand system enabling role.

The Governance issues

The set of “primary” checkpoints proposed above do not guarantee a smooth energy transition for the coming decades (say 2020-2050). Only the opposite can be guaranteed: they will not be sufficient. They only offer a framework to begin this transition, which will inevitably be full of uncertainty, surprises, incredible errors and unexpected lucky strikes.

It is why these primary checkpoints have to be complemented by secondary ones. They are a matter of “governance” (i.e. the “definition of roles”). Proper governance is what would help to organise the interactions of the energy system stakeholders in the discovery process of better implementation / adaptation of the primary rules. Of course, here or there, a deeper shake up or rupture of the primary rules will also occur in the future. Therefore, the established governance itself will be questioned, at times, by earthquakes and tornadoes (the authors hope that “no tsunami” will ever happen in the EU...).

To be realistic, the existing EU governance set-up cannot easily remedy a strong deficiency with primary rules. First, it is impossible to create a “governance framework”, which simultaneously works perfectly well at EU, MS and local levels. The process by which governance is created at each of these three levels is not and will never be coordinated, coherent and unified. We will forever live in a “multi-level” world of governance. Second, the process by which rules are defined, enacted and adapted is, itself, at least as fragmented (if not more) than the process of building governance. It is very difficult to match the two processes of rule making and governance building. Third, many forms of EU governance (notably forums,

committees, consultations; etc.) have no effective decision making process: too many veto rights and then bargaining strategies that are too strong. They also lack clearly binding implementation principles with no direct delegation of power to a responsible 'Managing Third Party'. Thus is European life. We lived with this, from the Single Act (1986) to the 1st energy Package (1996). No doubt, the Energy Union will again find a way of going ahead with our baroque framework for EU governance.

Nevertheless, as recently expressed by the departing head of ENTSOE (and of the National Grid): “Yes, we know it looks quite baroque there, in the EU, but. But nowhere in the world had anyone done more than the EU for establishing a gigantic-scale open market for power”. Let’s hope that we will make it –again- “just workable enough” to better combining our internal market, our reliability and adequacy, with a low-carbon trajectory and a wave of innovation.

4.4.4 Secondary checkpoints for better governance between the local and the national level

As already stated, in any hybrid scenario the local and the national levels co-exist. One may think that the articulation between them is a purely “subsidiarity matter”. It is not very likely, as most of the expected wave of investments, changes and innovation should be located at this local level. And then, all the new dynamics of the MS policy, system and markets could end up located at this level and be transmitted throughout the EU via the national MS level. In this setting, they indicate the quality and the robustness of the link between the local and the MS levels, which become the key factor of success for each MS 2030 trajectory expressed in MS NAPs. All MS being aggregated, these NAPs will also be producing the whole –right or wrong-trajectory of the EU policy, system and market.

It is, hence, the duty of independent EU experts and researchers to share what they see as offering a more open and more robust governance of the many possible local trajectories of energy transition within the proper MS national trajectories.

a- Internal Market dimension

On the hardware side of grid functions (grid investments and connections), the main concern is to continue the expansion of local grids, providing access and connection to the national markets (and beyond: the European). It is legitimate for “fully private” grid undertakings (we mean: really autarchic and closed “microgrids”) to refuse to give access to their own set of system resources. When there is no “essential facility” acting as a “natural monopoly” vis-à-vis third parties, there is no mandate for “Third

Party Access”. However, this will never be the case with each and every regulated DSO. All DSOs are “statutory entities” managing “franchised monopolies”, and then have an obligation to offer a reasonable two-way access between their local system and the national one. This suggests thinking about the following arrangements. 1°: looking for a structural guarantee of independence and neutrality of the DSOs in a full unbundling from all suppliers. 2°: opening dialogue and consultation at the national level between DSOs, TSOs, NRAs and categories of grid users to follow the state and evolution of “access and connection issues” between the local systems and the national ones; and making recommendations of improvements. Various new forms of DSO governance, at national level, could be explored as: the national DSO body; a joint committee of transmission and distribution grid operators; DSOs voluntary task force; DSOs initiatives; etc. The NRAs will control the accuracy of the outcome.

On the software side (operation and interactions), given the small individual size of “pocket markets” and their cumulative part within the national market guarantees the DSOs’ neutrality and openness in a full unbundling from any supplier are also necessary. One also needs a dialogue at national level between the DSOs, TSOs, Regulators and Third Parties to look at workable regulatory frameworks guaranteeing access, openness, technology plurality and users neutrality in the operation of local grids and pocket markets. Again, the NRAs should keep control of the accuracy of the outcome.

b- Reliability and Adequacy dimension

On the hardware side of grid functions (grid investments and connections), the growing interactions between DSOs and TSOs have to be better addressed by enlightened forms of cooperative governance at the national level. It could lead to the emergence of national principles of harmonisation, or “good practices” for local grids planning and connection principles. National dialogues between DSOs, TSOs and NRAs can go toward enhancing coordination of the transmission and distribution in grid planning and connection principles; under the umbrella of the NRAs’ content checking.

On the software side (operation and interactions), DSOs, TSOs, NRAs and Third Parties need to clarify and better define the respective system and market responsibilities of the DSOs and TSOs in the management of reliability and adequacy (as: information and monitoring standards; ownership and access to data; congestion; balancing (including the definition of products); emergency; etc.). All of this should again be conducted under the supervision of the NRA.

c- Low Carbon and Technological Wave dimension

On the hardware side of grid functions (*grid investments and connections*), more explicit links between the local “hardware” functions and the low-carbon and innovation trajectory, defined at national level, are needed. Might advanced DSOs be encouraged to define their own “low-carbon” friendly and “innovation friendly” best practice or code of conduct? Could it stretch as far as pencilling local networks KPIs logically consistent with a follow-up of each kind of National Action Plan 2020-2030? This matter could also be in the realm of NRAs or the Government, or any other national relevant entity.

On the software side (*operation and interactions*), it is necessary to achieve a similar approach for new forms of governance addressing principles of local grids operation which are low-carbon friendly, technologically pluralist and its users neutral, and logically consistent with the main trajectory of the national action plans. As earlier noted, many different forms of governance of DSOs may be explored, such as: the national DSO body; the joint committee of grid operators; DSOs voluntary task force; advanced DSOs initiatives; etc. This will most likely be considered as the NRAs duties, but not in every MS.

4.4.5 Secondary checkpoints for better governance between the national and the EU level

Assuming that, in the short-term, implementation of 3rd Package legislation and associated Network Codes will continue and no new legislation will be issued, a core governance issue between the national (the MS) and the European levels is the one of a full and deeper Europeanisation “à la Third Package” for the transmission grids and related power markets facilitation. This issue has at least three different dimensions being - from the softest to the hardest:

1° TSOs information, data, calculation, analysis, proposals;

2° TSOs decisions, actions, responsibility and liabilities;

3° TSOs assets, resources, revenue collection, financing, balance sheet.

It is key to treat these three levels of Europeanisation differently because of their different institutional flexibility, industry sensitivity and European priority.

The first level (being: Information, data, calculation, analysis, proposals, etc.), can easily be “regionalised” or “Europeanised” as soon as all the TSOs will (many already do) see the benefits and start cooperating more. It is the story told by TSC, Coreso

and the ENTSO-E voluntary regionalisation called “RSCIs”. It is already the practice for producing the TYNDP as well as in existing regional planning. It is also exemplified by the platforms built for the benefits of Day Ahead and Intraday markets.

The second level (decisions, actions, responsibility and liabilities) raises really critical questions. They mainly deal with the difficulty of assigning decision powers to different levels of TSO organisation (national TSOs, Regional RSCIs, European “ISO”) having to co-exist and tightly coordinate altogether in system operation. In practice, the transmission grid in Europe constitutes one single grid with so many interactions that any splitting of decision-making (with possible overlapping between the different levels) raises serious questions on separation of responsibilities and liabilities between the different levels of decision making.

The third level (assets, resources, revenue collection, financing, balance sheet, etc.), has for long been the hard core of resistance to regionalisation or Europeanisation of EU transmission grids. Experts and academics can only see that the Nordic countries and Germany still have not merged their TSOs while those are visibly smaller than their respective wholesale markets: will national interests and national politics finally unlock this deadlock? Two new “open fields” might bring some novelty there. On the one hand, the creation of vast “off-shore” domains calls for new grids to be built from scratch (architecture; technology; regulation; operation). New forms of governance may arise. On the other hand, the still unsuccessful onshore “EU Super-grid” policy may become reality anytime - if countries were agreeing on. An EU “Super-grid” could start by being the mutualisation of existing lines within a “multi-MS corridor”. All these existing lines could then be technologically upgraded to the highest standards and jointly operated as a common EU backbone /EU corridor.

This general TSOs’ landscape having been addressed, we are going to recommend some MS/EU governance checkpoints on the following lines.

a- Internal Market dimension

On the hardware part of grid functions (grid investments & connections) the main concern is to keep national grids expansion providing access and connexion to the other national markets as if only one fully European market was existing. At some point this key European principle will have to be translated into a mutualised governance being put above (or across) the TSO borders.

TSOs should regionalise by themselves the “light dimension” of their grid planning (data; methodology) as they already did for system analysis. At least voluntarily (as with ENTSO-E RSCIs). Once mature enough, this could become an EU kind of

“legally binding Light ISO” (collecting data; performing more advanced calculation with more robust scenarios; offering menus for national TSOs decision making) with an amendment to 3d Package voted as an ordinary EU law. At a further stage, coming from a “Nordic” or “Pentalateral”-like cooperation between voluntary MS, some RTOs might emerge. It might well be a North-Sea off-shore grid entity or an onshore Super-grid corridor’s one (twinning a kind of mutualisation of off-shore support schemes and support policies among the same MS). Parallel to this reinforced TSO cooperation, ACER should receive strengthened powers mirroring this TSOs planning governance to check if EU common interest principles are reasonably implemented.

On the software part (operation and interactions)

There are robust EU principles having being established. They come from the logic of the EU building and the legal order of our constitutional treaty, plus some important legal decisions (as DG COMP versus Swedish TSO Svenska Kraftnät). The EU TSOs have no right to give systematic ex-ante preference to commodity trade and power flows inside the borders of their control zones vis-a-vis the crossing of these borders.

Increased regionalisation of system operation for forecasting, capacity calculation, proposals of menu of actions, and an efficient regional approach to “zoning grids and markets” can be expected.

Other aspects of this MS/EU governance issue

This higher regionalisation of the EU grids and systems call for a deeper review of the existing organisation of the NRAs as to get them engaged in the regionalisation of grid planning and system operation. It also calls to review the internal governance of both ENTSO-E and ACER. Should TSOs continue to managing ENTSO-e simultaneously as their general assembly, their executive board and their higher European advocacy body – since the 3rd Package did not define more precisely what a European statutory body is? And, symmetrically, should NRAs having to keep a so unilateral power on the Board of ACER - except to mirror ENTSO-E? Could more flexible or more pluralist forms of governance being explored on both sides?

Could the regulatory gap concerning Power Exchanges (PXs) being addressed too? PXs manage core platforms of the EU internal market but are not proper parts of the EU regulatory frame. They even claim being “free marketers” by statute. Could EU law and regulation bridge that gap?

How will the existing and coming grid codes continue to be updated and adapted to the changing circumstances to come? What will be the respective roles of ENTSO-E, ACER, NRAs, Third Parties and the EU Commission in this process?

As we have just seen, the EU has not yet found a stable frame of governance for a deeper Europeanisation of its applied grid and market regulation, and of its applied system operation.

b- Reliability & Adequacy dimension

On the hardware part of grid functions (grid investments & connections) a significant regionalisation of the TSOs for security analysis, scenarios, and menus of actions is also expected; as well as for the monitoring of MS “Security of Supply” infrastructure planning consistency. How will TSOs, NRAs and ACER combine in the making of this upgrade and the many other adaptations to come?

On the software part (operation and interactions) a similar regionalisation of the TSOs when assessing generation adequacy of the regional MS is expected; setting emergency scenarios consistent with regional generation adequacy arrangements; suggesting arrangements for higher flexibilisation of regional supply and demand (it however requires a consequent European legislative upgrade to touch upon demand).

c- Low Carbon & Technological Wave dimension

On the hardware part of grid functions (grid investments and connections) an issue arises as regional planning would be influenced by a regional TSOs entity while MS will commit only on their own vis-a-vis Commission via National Action Plans. These NAPs will enter as reference scenarios in the work process of the TSOs regional entity through NRAs validation. Would this regional TSOs entity also act as a consultant, advisor or reviewer of the NAPs in its region? How will a regional entity organise its work to deliver to national scenarios a regional value added knowing that systems at countries level will diverge regarding the set of technologies, the load and demand characteristics as well as for reliability standards?

On the software part (operation and interactions) we might expect similar issues in articulating regionalisation of TSOs with the MS commitments within NAPs; as well as to articulating the new Fora to come and the more restricted mandate of certain NRAs and of ACER.

4.4.6 Secondary checkpoints for better governance between the local and the European levels

Most of this issue “Local / European” happens at the infra-country level where MS have an exclusive right to take decisions and frame regulation. It does not seem that this will change. As the Energy Union will be defined and built within the existing institutional frame it will take this as given.

Therefore, Energy Union has no blueprint for DSOs. It will let MS decide how they will manage the DSOs and the articulation between their own DSOs and TSOs.

At the EU level, reinforced by the likely creation of an EU regulator, action will mainly be indirect and come via the interfaces EU/TSOs or EU/NRAs that already exist; and the new ones to come from the scenarios that we have explored. Some other lines of action might also come from outside the energy industry; as from the “Digital Single Market Strategy for Europe” where the EU is looking for a common frame for platforms, online intermediaries, data and cloud, and the collaborative economy.

This said, at this “Local/European” level, variety and autonomy will flourish for long all across the EU.

Conclusion for all governance issues

In terms of governance the EU is entering very challenging times due to the “hybridation” of its systems and markets.

A big challenge –as we have seen- is the regionalisation of grid planning, system and market operation which should deliver a better coordination or mutualisation of hardware and software TSOs functions as well as of the NRAs actions. It also touches MS policies regarding security of supply and generation adequacy. ACER might become a good referee there, if allowed by a new legal frame.

As big (as a challenge) is the articulation between MS “2030 NAPs”, the grids, the systems and the markets. No such articulation is provided yet but NAPs will ask for some links and bridges between them as they become the actual “building blocks” of EU level energy policy targets. MS NAPs should then be articulated in a certain way with TSOs & DSOs actions.

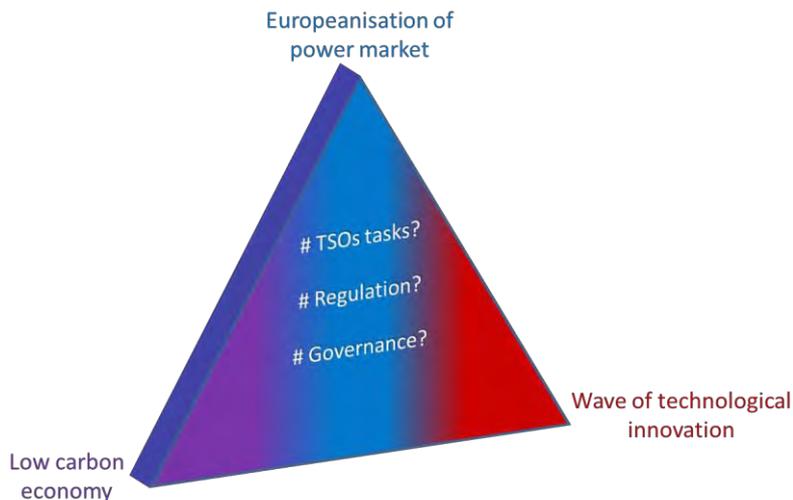
Another key challenge is the articulation for local and national grids, systems and pocket markets, between DSOs, TSOs, NRAs and MS. This concerns equally internal market, reliability and adequacy, pluralism of low-carbon paths and openness to innovation waves. While it will inevitably be said “national affairs only” it will actually more and more become the foundations of the entire EU system and market

transformation. What will we, Europeans, get as governance for this local and distributed process will be decided country by country with some indirect action via the channels EU/TSOs or EU/NRAs. Will we be able to also create and informal while; a reasonable “EU sunshine regulation” working through influence and good reasoning? OCDE and IEA do work through influence and good reasoning every day. Might we find a way to copy their recipe (see IEA 2015)?

5. General Conclusions

The EU power transmission enters a brand new world which has not been foreseen by the former three “single energy market” packages. This is because major changes are dictated by the need to simultaneously accomplish integration of European energy markets and build a low-carbon economy; and because these changes are reinforced by a wave of coming or already come technological innovation.

Florence School of Regulation did build in this report a conceptual framework to understand where the European power system and transmission networks are going to; and what are the biggest challenges and alternatives for the EU power regulation and governance.



Florence School of Regulation is not pushing any roadmap or blueprint. We are only offering “food for thought”: knowledge frames to understand how the power landscape moves. It will be up to decision makers and stakeholders to draw the actual future that EU deserves and will get.

Our research report did give the reader five big contributions.

1°: An analysis of how “*European Integration*”, “*Low-Carbon Target*” and “*Wave of Innovation*” shake up the EU power system and transmission industry.

2°: Three conceptual scenarios of evolution being: #1# *Full European Market Integration*; #2# *National only Low Carbon System & Policy*; #3# *Local only Low Carbon System & Policy*.

3° A detailed application of these scenarios to the core tasks performed by a typical EU TSO: *Hardware tasks* (as network planning and investment); and *Software tasks* (as balancing, congestion, cross-border exchange, market facilitation, relationships with DSOs or NRAs, etc.).

4° A fourth scenario being “*Hybrid*” where Low-Carbon Target and Wave of Innovation co-exist at three levels (European, National and Local) but with a substantial regulatory gap if the current frame is not updated.

5° A set of check-points to build an EU multi-layer coordination frame and make our power system transition to a European Low-Carbon System coherent, efficient and resilient enough to succeed.

To conclude our work, we would like to draw attention to seven key points.

Firstly, although all three scenarios were constructed in order to fulfil EU energy and climate policy objectives, no individual scenario can easily and fully meet all goals at reasonable cost. It should be no surprise as in real life the societal expectations, the technological developments and the public policies are not necessarily and not always aligned.

Secondly, some critical system operational functions, currently mainly performed by national TSOs, will be totally or partially performed by other entities. These entities may be supra-national organizations, either emanating from or acting in close cooperation with TSOs, DSOs (individually or somehow associated) or even new players.

Thirdly, therefore, the legal and regulatory frameworks must be adapted, namely in order to clearly define and assign each operational function, indicating, for each, appropriate cost and liability sharing mechanisms. It is also needed to establish appropriate coordination mechanisms, for both normal and abnormal situations, including appropriate redundancy safeguards and supervision tools.

Fourthly, even if from the technical (system operation) point of view it is theoretically possible to ensure appropriate system reliability (assuming that the necessary legal and regulatory changes are implemented), several “black holes” may still jeopardize the efficient functioning of electricity systems and markets. The Energy Union will have to patch them.

Fifthly, assuming that, in the short-term, implementation of 3rd Package legislation and associated Network Codes will continue and no fundamentally new legislation will be issued, serious governance issues must be somehow addressed. In this respect, not only national/EU interfaces require continuous attention; local/national interfaces become increasingly critical for transparency and reliability.

Sixthly, among the many governance challenges to be addressed the following are particularly important. 1° the regionalisation and Europeanisation of grid planning, system and market operation, leading to better coordination or mutualisation of hardware and software TSOs functions, as well as of the NRAs actions. 2° the Member States policies regarding security of supply and generation adequacy. 3° the articulation between Member States “2030 NAPs”, network investments, systems and markets. 4° the articulation of local and national grids, systems and pocket markets, implying new forms of multi-layer coordination between DSOs, TSOs, NRAs and Member States.

Seventhly, in the past, voluntary, informal cooperation among major actors (namely the European Commission, regulators and TSOs) has been crucial for the development of the internal energy market. This kind of cooperation can still deliver substantial results on the road to decarbonisation. However, the speed of delivering

the many missing “building blocks” for the proper functioning of the system (from planning to real-time operation) needs to be considerably increased in the short-term.

For the Energy Union transition (to a low carbon economy in a European market open to a wave of innovation) to succeed, governance and regulatory mechanisms have to be quickly adapted and partially redesigned with the reliability “absolute must” in mind.

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The Florence School of Regulation (FSR) was founded in 2004 as a partnership between the Council of the European Energy Regulators (CEER) and the European University Institute (EUI), and it works closely with the European Commission. The Florence School of Regulation, dealing with the main network industries, has developed a strong core of general regulatory topics and concepts as well as inter-sectoral discussion of regulatory practices and policies.

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