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**Datum**:
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**Kommentare zum Impulspapier „Strom 2030“ des Bundesministeriums für Wirtschaft und Energie**

Sehr geehrter Herr Bundesminister Gabriel,
Sehr geehrter Herr Staatssekretär Baake,

als Unternehmen begleitet DNV GL den Prozess der Energiewende aktiv und berät sowohl Unternehmen als auch Institutionen weltweit. Gerne beteiligen wir uns daher auch mit dieser Kommentierung sowie zuvor schon mit der zum Strommarktdesign und zum neuen EEG an der energiepolitischen Debatte in Deutschland.  Der DNV GL befürwortet eine zügige, konsequente und europäisch gedachte Energiewende, mit dem Ziel der Reduktion von klimaschädlichen Emissionen. Wir hoffen mit folgenden Beiträgen einige Hinweise für die nötigen Entwicklungen der nächsten Jahren geben zu können.

Im Folgenden wird allerdings nur auf einige Trends eingegangen, bei denen der DNV GL besonderen Handlungsbedarf in der kommenden Legislaturperiode sieht. Wir möchten dennoch an dieser Stelle erwähnen, dass wir uns im täglichen Geschäft mit allen genannten Trends und den dazugehörigen Fragestellungen beschäftigen.

Mit einer Veröffentlichung unserer Stellungnahme auf der Webseite des BMWi sind wir einverstanden.

Mit freundlichen Grüßen,

**DNV GL**

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## Trend 4: Versorgungssicherheit wird im Rahmen des europäischen Strombinnenmarkts gewährleistet

Ein  gemeinsames, europäisches Monitoring der Versorgungssicherheit muss durch die EU beschlossen werden und durch ACER als derzeitige europäische Regulierungsbehörde gestaltet und überwacht werden. ACER sollte dafür mit einem stärkeren Mandat ausgestattet werden, um unabhängig  die Formulierung und Überwachung von Methoden, Prozessen und Verfahren, des durch die EU gesetzten Politikrahmens vorzunehmen.

Die Methoden, Prozessen und Verfahren, die ACER erlassen hat, sollten dann von regionalen Zentren umgesetzt werden. ENTSO-E sollte dafür eine gemeinsame Arbeitsweise der regionalen Zentren entwickeln und für die Abstimmung unter den Zentren sowie für die Abstimmung mit den nationalen TSOs sorgen.

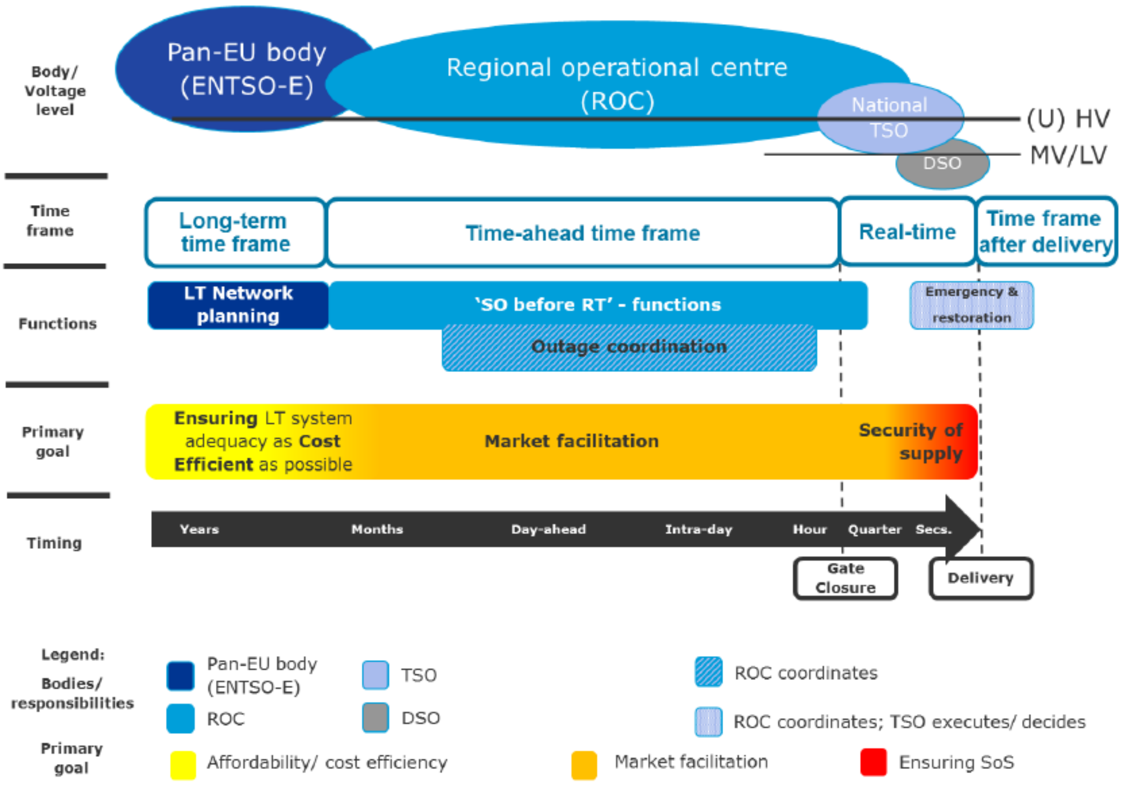

*Figure 2 Graphic representation of TM 2020 and legend (Source: DNV GL)*

Details zu diesem Ansatz können Sie im Anhang I finden. **Anhang I ist eine Kopie der DNV GL Studie „Options for future European Electricity System Operation"**.

In dieser Studie schaut DNV GL auch auf die Möglichkeit einer gemeinsamen Reserve mit Nachbarstaaten. Eine integrierte Reserve bietet nach unseren Analysen ein Kostensenkungspotenzial, das in der Größenordnung von 100 bis mehreren hundert Millionen Euro pro Jahr liegen kann. Ein Risiko besteht möglicherweise darin, dass - aus nationaler Sicht - eine gewisse Kontrolle über durch die Ressourcenbündelung verloren geht.

## Trend 10: Die Systemstabilität bleibt bei hohen Anteilen erneuerbarer Energien gewährleistet

Das Strommarktgesetz sieht einige Maßnahmen zur verbesserten Aktivierung von Flexibilität im Stromsystem vor, so z.B. die Öffnung der Ausschreibungsbedingungen für Regelleistung. Auch die Netzentgeltsystematik soll im Hinblick auf eine Aktivierung von Flexibilität hin weiterentwickelt werden (siehe auch Trend 11). Jedoch kann – auch und gerade – auf der Verteilnetzebene bei zunehmender dezentraler Einspeisung dargebotsabhängiger erneuerbarer Erzeugung einerseits, und sogenannter Gleichzeitigkeiten der Flexibiltäten andererseits die Gefahr einer zunehmenden Destabilisierung entstehen.

Damit wird ein Problem bezeichnet, das dadurch entsteht, dass Preisschwankungen im Großhandels- und Regelenergiemarkt einen parallelen Einsatz von Demand Response und Speichern auslösen, der im Verteilnetz zu Spannungsproblemen oder zur Überschreitung thermischer Limite führen kann. Dabei bietet die zunehmender Lastflexibilität sowie die Kostendegression dezentraler Speicher große Chancen für eine kosteneffiziente Stromversorgung. Die zentralen Herausforderungen sind dabei die netzdienliche Aktivierung und Steuerung der Flexibilität sowie deren angemessene Vergütung, die weder das gegenwärtige Strommarktdesign noch die gegenwärtige Netzentgeltsystematik gewährleisten. Deshalb wurden von verschiedenen Seiten Vorschläge für die Einführung dezentraler Flexibilitätsmärkte gemacht, z.B. das Konzept des Ampelmodells, das auf eine Arbeitsgruppe des BDEW (2012) zurückgeht. Dabei handelt es sich im Kern um einen dezentralen Marktplatz für Flexibilitäten, der es dem VNB ermöglichen soll, durch Spannungsprobleme oder das Überschreiten thermischer Grenzen entstehende Netzengpässe aufzulösen.

Im Rahmen eines solchen Flexibilitätsmarkts könnte der Verteilnetzbetreiber beispielsweise einen dezentralen Speicher kontrahieren, um eine temporäre Netzengpasssituation aufzulösen. Ein Flexibilitätsmarkt stellt damit eine Alternative zum Netzausbau dar; technisch gesehen ist eine deutlich verbesserte IKT-Infrastruktur („Smart Grid") Voraussetzung für seine Realisierung. Alternativen zu einem dezentralen Marktplatz sind neue, dezentrale Systemdienstleistungen, bei denen der Verteilnetzbetreiber netzdienliche Flexibilität bilateral und für längere Zeiträume kontrahiert.

Vor der Einführung eines Flexiblitätsmarkts bzw. neuer Flexibilitätsdienstleistungen sind eine ganze Reihe von Designfragen zu klären. DNV GL empfiehlt der Bundesregierung eine genaue Prüfung der verschiedenen regulatorischen Konzepte zur Aktvierung von Flexibilität für die deutschen Verteilnetze in technischer, wirtschaftlicher und regulatorischer Hinsicht. Diese haben grundsätzlich das Potenzial, technisch bestehende Flexibilitäten im Verteilnetz in effizienter Weise zu aktivieren und damit insbesondere zur Systemstabilität in einem System beizutragen, das durch fluktuierende Einspeisung einerseits und preissensitive Lastflexibilität andererseits vor erheblichen Herausforderungen steht.

Im Auftrag des Schweizer Bundesamts für Energie (BFE) hat DNV GL gemeinsam mit der ef.Ruhr innerhalb eines Gutachten die regulatorischen und technischen Voraussetzungen eines solchen Modells analysiert und deren Kosten und Nutzen quantifiziert und modelliert: DNV GL Energy und ef.Ruhr (2015), Kosten-Nutzen-Analyse einer Ampelmodelllösung für den Strommarkt der Schweiz. **Die Studie können Sie über den folgenden Link auf der Webseite des Schweizer Bundesamts für Energie einsehen: http://www.bfe.admin.ch/themen/00612/00613/04787/index.html?lang=de&dossier_id=06327**

## Trend 11: Die Netzfinanzierung erfolgt fair und systemdienlich

Da sich durch Veränderungen des Stromsektors (wie sich auch in dem Impulspapier beschrieben werden) vor allem Herausforderungen für die Verteilnetze ergeben, stehen diese im Mittelpunkt unseres Kommentars. Der mit der Energiewende verbundene Ausbau von neuen erneuerbaren Energien ist für einige Verteilnetze nicht nur mit einem signifikanten Netzausbaubedarf und Herausforderungen für die Netzstabilität verbunden, er stellt auch die Frage einer verursachungsgerechten Kostenallokation über die Netzentgelte neu. Das traditionelle Netznutzungsmodell geht davon aus, dass die Stromerzeugung überwiegend bzw. praktisch ausschließlich durch große zentrale Kraftwerke mit Anschluss an das Übertragungsnetz erfolgt, so dass der Strom über die verschiedenen Spannungsebenen an die Endverbraucher verteilt wird. Entsprechend beruht das Netzentgeltmodell in Deutschland und weiteren europäischen Staaten auf einer ausschließlichen Wälzung der Netzkosten der verschiedenen Netzebenen auf die angeschlossenen Verbraucher (sog. Ausspeisemodell). Durch den Zubau an dezentralen erneuerbaren Energien und der damit verbundenen Zunahme der stochastischen Einspeisung von Solar und Wind auf niederen Spannungsebenen sowie die Zunahme von Eigenverbrauchern („Prosumern‟), dezentralen Stromspeichern und weiteren „neuen‟ Marktteilnehmern wie Wärmepumpen und Elektroautos, kommt es zukünftig jedoch zu einer Änderungen in der geographischen und zeitlichen Verteilung von Einspeisung und Entnahme, einer zunehmenden Differenz zwischen Spitzenlast und Spitzeneinspeisung, sowie Veränderungen der Lastprofile und der Lastflüsse im Netz. Zugleich nimmt die Zahl derjenigen Stromkunden zu, die dem System bei entsprechender Anreizung Lastflexibilität zur Verfügung stellen können.

Die hiermit verbundene geänderte Inanspruchnahme des Verteilnetzes durch verschiedene Marktteilnehmer ist mit Änderungen in der Kostenverursachung und der Beeinflussbarkeit der Netzkosten durch verschiedene Netznutzer verbunden, die eine Anpassung bzw. zumindest eine Überprüfung des aktuellen Netzentgeltsystems erforderlich erscheinen lassen. Für die Zuordnung von Netzkosten auf verschiedene Netznutzer sowie für die Anreize verschiedener Netznutzer, sich netzdienlich zu verhalten (in dem sie durch Zeitpunkt und Umfang von Einspeisung und Verbrauch Netzausbau bzw. Netzkosten vermeidenden), sind die Elemente und die Ausgestaltung des Netzentgeltsystems von entscheidender Bedeutung. Im Hinblick auf die stellen sich hierbei insbesondere die folgenden Fragen:

- Inwieweit sollte generell die Kostenverursachung durch (dezentrale) Erzeugung in der Entgeltstruktur Berücksichtigung finden (z.B. durch die Einführung einer sogenannten G-Komponente)?
- In welcher Weise soll eine netzentlastende Einspeisung oder Ausspeisung zu Vergünstigungen bei der Entgeltbestimmung führen (z.B. durch die Einführung zeitlich dynamischer Netzentgelte)?
- Wie ist die Rolle von (dezentralen) Speichern, wie die von virtuellen Kraftwerken aus Netzsicht zu beurteilen und wie sollten sie regulatorisch behandelt werden (sollte z.B. die Einführung neuer Systemdienstleistungen auf Verteilnetz-Ebene ermöglicht bzw. gefördert werden)?

Aus Sicht von DNV GL ist der im Weißbuch der Bundesregierung für die Übertragungsnetze vorgeschlagene Weg einer bundesweiten Verteilung der Entgelte (Maßnahme 9) für die Verteilnetzentgelte nicht zu empfehlen: vielmehr erscheint eine differenzierte Bewertung der verschiedenen Gestaltungsparameter sinnvoll (G- vs. L-Komponente, Leistungs- vs. Arbeitskomponente, Netzentgelte vs. Netzanschlussgebühren). Hierzu sollte die Bundesregierung verschiedene Modelle einer gründlichen Prüfung unterziehen und auf dieser Basis eine neue Entgeltsystematik entwickeln. Bei der Beurteilung der Vor- und Nachteile verschiedener Netzentgeltmodelle sollten dabei insbesondere die folgenden Kriterien einbezogen werden:

- Verursachungsorientierung (inwieweit werden die Netzkosten den jeweiligen Verursachern angelastet),

- Transparenz (ist die Berechnung der Netzentgelte für die Netznutzer klar und verständlich nachvollziehbar),
- Praktikabilität (ist der Ansatz ‚technisch' durchführbar und was sind die administrativen Kosten seiner Implementierung),
- Anreizwirkung auf die Netznutzer (welche Anreize bestehen für Netznutzer, sich netzentlastend zu verhalten und damit Netzkosten zu vermeiden),
- Verteilungswirkung (welche Netznutzer werden voraussichtlich mehr und welche weniger gegenüber dem Status Quo belastet), und
- Rückwirkungen auf den Wettbewerb im Erzeugermarkt, wenn dezentrale Stromerzeuger und konventionelle Großkraftwerke oder Erzeuger im europäischen Binnenmarkt in unterschiedlichem Maße an den durch sie verursachten Netzkosten beteiligt werden.

DNV GL hat im Auftrag des Schweizer Bundesamts für Energie (BFE) im Rahmen eines Gutachtens die Auswirkungen der Veränderungen im Energiesektor auf die Verursachung von Netzkosten, sowie die Vor- und Nachteile unterschiedlicher Ansätze im Bereich der Netzanschluss- und Netznutzungsentgelte untersucht: DNV GL (2015): Weiterentwicklung Netznutzungsmodell. **Die Studie können Sie über den folgenden Link auf der Webseite des Schweizer Bundesamts für Energie einsehen: http://www.bfe.admin.ch/themen/00612/00613/04787/index.html?lang=de&dossier_id=06327**

Trend 12: Die Energiewirtschaft nutzt die Chancen der Digitalisierung.

Der Übergang von einem zumeist mit fossilen Brennstoffen gespeisten zentralistischen System zu einem von erneuerbaren Energien dominierten dezentralen System hat starken Einfluss auf Struktur und Technik der Kommunikation im europäischen Energiemarkt und die damit verbundenen Anforderungen an die Cyber Sicherheit.

Erzeugung, Übertragung, Verteilung und Verbrauch werden immer stärker automatisiert. Neben der Automatisierung der Prozesse innerhalb der einzelnen Unternehmen wird das Netz auch organisationsübergreifend automatisiert, es entsteht eine Vielzahl von Schnittstellen und Echtzeit-Kommunikationsverbindungen zwischen den Systemen der unterschiedlichsten Infrastrukturbetreiber. Mit der zunehmenden digitalen Steuerung der gesamten Energieversorgungskette, bis hinein in den direkten Einflussbereich des Endkunden (smart meter, smart home) steigt aber auch die Notwenigkeit die Informationssicherheit dieser Systeme und ihrer Interdependenzen zu gewährleisten, um die Sicherheit und die Privatsphäre aller Stakeholder zu schützen sowie die Systemstabilität und gewohnte Versorgungssicherheit aufrecht zu erhalten.

DNV GL sieht es daher kritisch, dass im vorliegenden Dokument diese Dimension der Digitalisierung und die resultierenden potentiellen Gefährdungslagen nicht als Leitfragen für die Zukunft aufgeworfen werden. Es wird vielmehr der Eindruck vermittelt, dass für Datensicherheit gut gesorgt ist. Aus Sicht des DNV GL’s bieten die neuen Gesetze zu Digitalisierung, Energiewende und zum Betrieb kritischer Infrastrukturen keine holistische Betrachtung des Themas. Eine umfassende Risikobewertung zur Einführung und zunehmenden Abhängigkeit von neuartiger Technologie, welche die Auswirkungen auf die Gesellschaft einbezieht, ist zum Schutz unserer wichtigsten kritischen Infrastrukturen notwendige Voraussetzung.

## ÜBER DNV GL

DNV GL - Energy gehört zur DNV GL Group, die mit ihrem Geschäftszweck zum Schutz von Leben, Eigentum sowie der Umwelt in bedeutenden industriellen Bereichen beiträgt. Im Vordergrund stehen unabhängige wirtschaftliche und technische Dienstleistungen in den Bereichen Risikomanagement, Klassifizierung, Zertifizierung und Testung für die Schiffs-, Öl- und Gasindustrie sowie die Energiebranche. Darüber hinaus erbringen wir auch Zertifizierungsleistungen für Kunden aus vielen weiteren Branchen. Das Unternehmen wurde 1864 gegründet und ist mit 16.000 Beschäftigten in mehr als 100 Ländern unter dem Leitmotto ´safer, smarter, greener´ aktiv.

### In der Energiewirtschaft

DNV GL vereinigt in sich die Stärken von DNV, KEMA, Garrad Hassan, WINDTEST und GL Renewables Certification. Unsere 2.500 Energieexperten unterstützen Kunden weltweit um eine sichere, zuverlässige, effiziente und nachhaltige Energieversorgung zu gewährleisten. Wir gehören zu den führenden Anbietern von Dienstleistungen entlang der gesamten Energiewertschöpfungskette einschließlich erneuerbarer Energien. Unsere Expertise erstreckt sich auf Energiemärkte und Regulierung, Onshore- und Offshore-Windkraft, Solarenergie, konventionelle Stromerzeugung, Energieübertragung und -verteilung, Smart Grids sowie nachhaltige Energienutzung. Unsere Test,- Zertifizierungs- und Beratungsdienstleistungen werden unabhängig voneinander angeboten.

Weiterführende Informationen können Sie unserer Website entnehmen: www.dnvgl.de/energy.

# Anhang I

# Options for future European Electricity System Operation

Lead authors: T. Slot and H. Dijk
In cooperation with: R. Haffner and
A. van der Welle

December 2015

**EUROPEAN COMMISSION**

Directorate-General for Energy
Directorate B — Internal Energy Market
Unit B2 — Wholesale markets; electricity & gas

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EUROPEAN COMMISSION

# Options for future European Electricity System Operation

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The consortium’s mandate was to identify and describe options for an alternative organisation of system operations and planning functions that are key for the effective, secure and cost-efficient operation of Europe's transmission networks. Any discussions related to the political context of these organisation options are excluded from this report.

General conclusions outside the scope of this work cannot be made based solely on this report.

## EXECUTIVE SUMMARY

The European power sector is undergoing important changes. Especially the increasing penetration of renewable energy sources (RES), as part of the transition to a de-carbonised power system, results in a need to continuously assess and decide upon (the adoption of) alternative technologies, policies and practices. This report focusses upon the areas of system operations and planning, and options for improvements in accommodating and dealing with the changes in the European system.

Overall, changes applied to the electricity sector should be aimed at optimizing towards the goals of the Internal Energy Market (IEM), which are to ensure affordable and competitive pricing of electricity, environmental sustainability and supply security for everybody in Europe. When also reflecting upon the main aims of TSOs as described in the mandate of ENTSO-E, we highlight the main goals that should lead any proposed changes to system operations and planning:

1. Security of supply (secure for everybody)
2. Market facilitation (affordable and competitive pricing)
3. Integration of RES (environmentally sustainable).

The current efforts to improve coordination between TSOs, and embedding these efforts into network codes are important steps. Worries among policy makers and other industry stakeholders (e.g. generation companies and large consumers) however, concern issues regarding lacks in wholesale market integration and the question whether the pace of developments in system operations can keep up with the pace of change in the system. This is driven by the fact that TSOs operate their systems based on largely national[1] approaches, resulting from the historic development of national power systems and their operations.

The pace of changes in the European system is strengthened by the fact that physical power flows do not recognise country-borders. This can have (unexpected) negative effects (e.g. loop and transit flows) and affects the (further) optimisation towards the goals of the IEM. Such impacts invoke a need to re-think the current and future framework for system operations.

With the above-mentioned challenges and the IEM goals in mind, a consortium of Ecorys, ECN and DNV GL, set out to develop a target model for transmission system operations that is implementable in 2020, and able to meet the challenges that can be expected up to at least 2025.

### *Setting the scene*

Our analysis starts by describing the current situation with regards to power system planning in more detail: aims in system planning and operations, the need to cope with different system states, operational practices in different timeframes, relevant regulatory developments/ frameworks and current coordination initiatives.

One of the important points to grasp for the reader is the fact that system planning and operations are executed in different time-frames before the actual transport (delivery) of power takes place. Please refer to Figure 1 for illustration of the different timeframes, and the

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[1] The term ‘national’ is used to describe TSOs operations within borders of a single country. It is recognised that e.g. Germany has more than one TSO.

names used throughout this report to describe these, including the related tasks / functions that are executed within these timeframes.

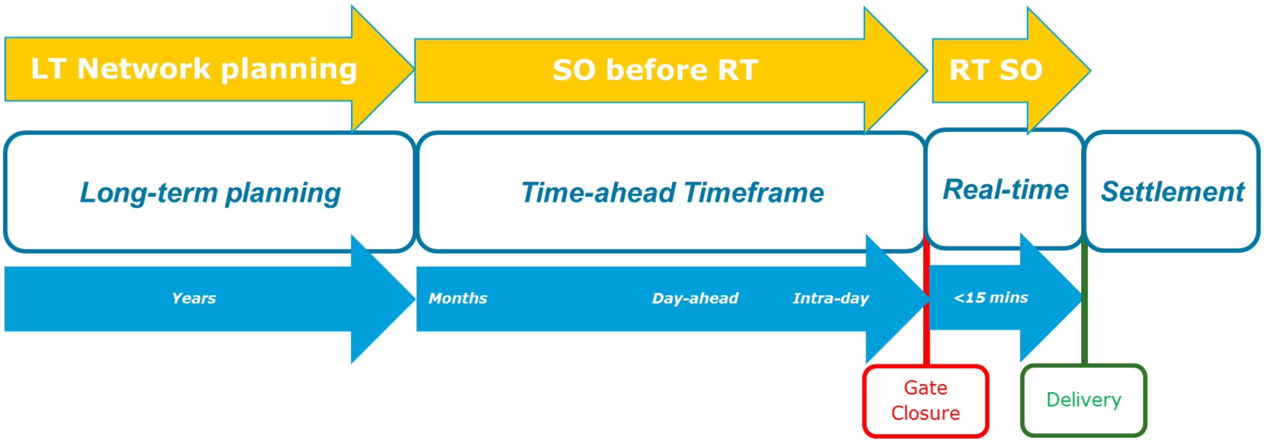

*Figure 1 Different time-frames in system planning and operations and the labels (yellow arrows) used to describe them and the related TSO functions in these timeframes*

### Requirements for SO towards 2025

As input to the development of the target model, we start by analysing more specific requirements for development of system operations towards 2025. These requirements are based upon the challenges for the electricity sector towards 2025, as identified by ACER in their 'Bridge to 2025'-paper. The resulting requirements for system planning and operations provide better insight into how these can help to further optimize towards the goals of the IEM. These requirements particularly relate to better facilitating the development and integration of wholesale markets, ensuring security of supply in the face of rapid changes in the system, (helping to) better facilitate the integration of RES (in network planning) and the efficient absorption of RES-generation (in system operations).

### Current obstacles

Further input to the target model development is provided by a more detailed analysis of current issues in system planning and operations, described as current obstacles/ barriers with regard to further optimisation towards IEM goals. These obstacles are predominantly related to the largely remaining national approach to system operations, particularly in the SO before RT-timeframe (see Figure 1). A good example of a current case that illustrates (simulated) negative effects on social welfare of 'national sub-optimization' is provided by the observed reduction of interconnection capacity available to the market on the DK1 – DE interconnector.

### *Centralisation of TSO functions and related benefits*

Based on the analyses of future requirements and current obstacles, we propose the centralisation of functions executed in the LT Network planning- and SO before RT-timeframes as a first step in developing a target model. In this context centralisation means moving functions that are executed by national TSOs (decentralised) to a regional (centralised) level, including the decision power related to these functions.

The motivation underlying this proposal is the fact that centralization of these functions across larger geographic areas (regions of Europe) can bring major benefits to the market, RES integration and security of supply. Specific qualitative and quantitative benefits of centralisation/ integration are presented, as indicated by various sources. These benefits are mainly related to network planning, and system operations functions such as capacity calculation, congestion management, adequacy assessment and balancing. Very important here, is the overview provided in Table 3, describing the different TSO functions that are executed in different timeframes and operational system states. It further illustrates our view on which functions can/ should be centralised.

The main conclusion that is drawn from this overview is that all the functions executed in the SO before RT-timeframe can/ should be centralized to be able to better realize benefits, such as the significant expected benefits (in terms of economic efficiency) associated to centralized sizing and procurement of balancing power.

### *Target Model 2020*

Targeting the requirements for 2025 and moving from today’s situation, the target model for 2020 is to erect Regional Operational Centres (ROCs) throughout Europe in which the SO before RT-functions are centralised, thereby centralizing authority over the functions across larger geographic areas. The following features are highlighted:

- The aim is to remove national borders between countries as much as possible by operating them as ‘normal’ connections within the control area of a ROC. The foreseen regional security coordinators (RSCs) can serve as a basis to further develop the ROCs
- Both LT Planning and the long-term adequacy assessments should be executed at pan-European level, coordinating the developments in the geographic regions of the different ROCs.

Our target model 2020 for the SO before RT-functions is illustrated in Figure 2. It illustrates the involved entities, voltage levels, operational time frames, high-level functions, and the main operational aims[2] in the different time frames. Further insights on options for governance and regional division, are discussed below the figure.

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[2] Although each of the three aims highlighted in this figure (Security of supply, market facilitation and cost efficieny) plays a role in decisions made in every timeframe, their (order of) importance more or less shifts depending upon the particular timeframe and operational state of the system

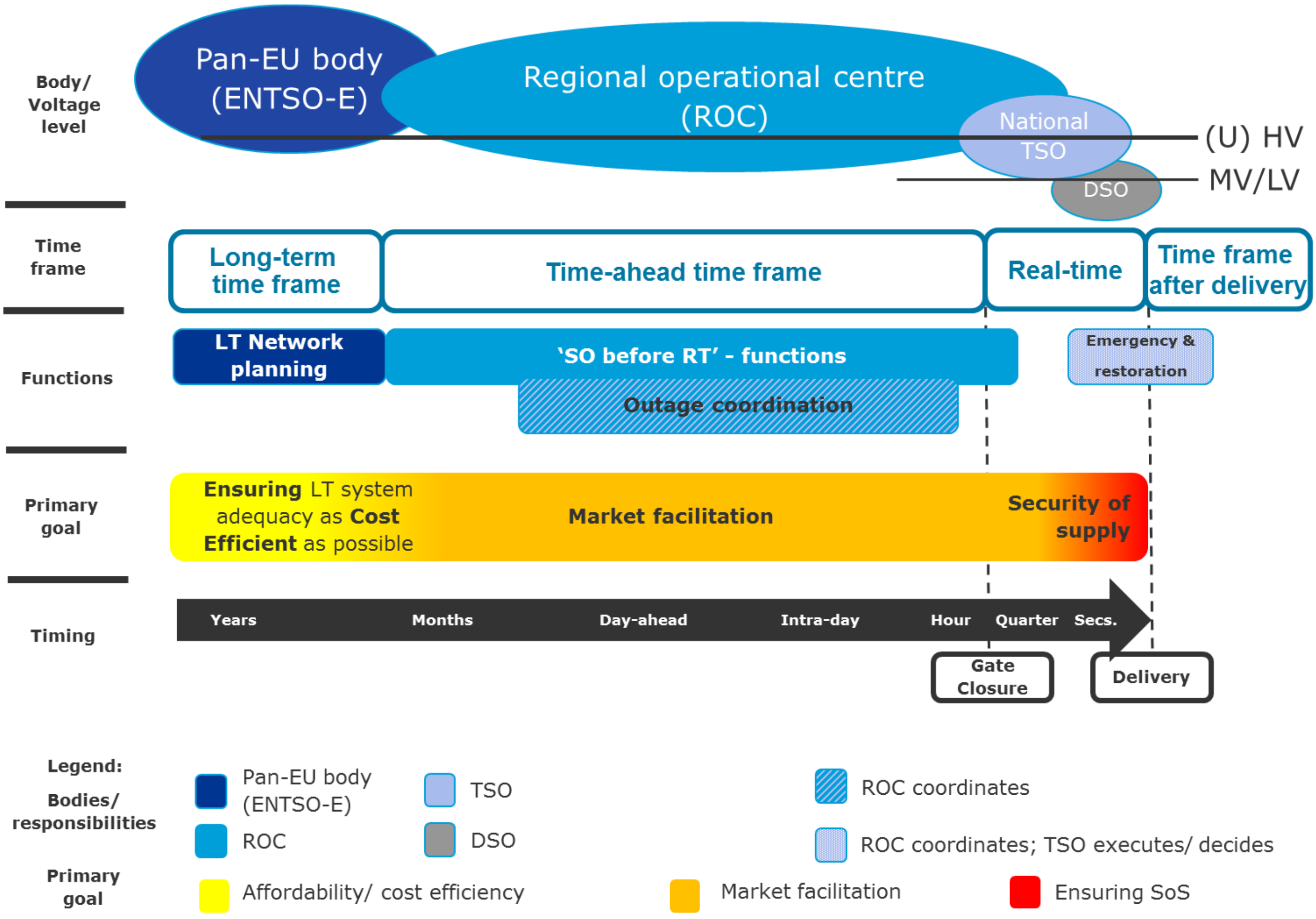

*Figure 2 Graphic representation of TM 2020 and legend (Source: DNV GL)*

### *Governance*

The parties that need to be involved in the governance of SO in TM 2020, are:

- EC to formulate general energy policy and directives[3]; legislative power
- European regulatory body (current ACER) with the power to independently check the formulation and execution of methodologies, processes and procedures in line with the general policy
- Regional centres (ROC) to execute prescribed tasks according to the formulated methodologies, processes and procedures; responsible for execution
- European entity (current ENTSO-E) for development and implementation of methods and tools for LT planning and SO. In consultation with ACER (who sets up guidelines by request of the EC) this body develops the framework (e.g. grid codes) for execution of the tasks by ROCs and ensures overall alignment between them, and with national TSOs.

The European entity for the development and implementation of methods and tools (current ENTSO-E) is responsible for development of the way of working of the foreseen ROCs in line with guidelines and/ or regulation. This is then monitored and enforced by the regulatory body (current ACER). The need for stronger mandates for the current regulatory body (ACER) was

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[3] 2015 Management Plan, EC – DG ENER, 5 August 2015

raised in various interviews with industry stakeholders, including representatives from TSOs/ ENTSO-E and the generation companies. This will be necessary to efficiently drive forward the required developments on regional/ pan-European scale, largely surpassing the national reach of NRAs.

### ***Geography***

Because borders in the electricity system can be virtually removed (no need to consider them as cross-border interconnections) when system operations is integrated across larger geographic regions, and applicable regulatory frameworks are harmonized, it is important that integrated regions with centralized functions are formed across neighbouring countries. This is necessary to be able to facilitate further development of integrated wholesale markets, based upon harmonized market frameworks (especially gate-closure times and SoS-requirements), and direct physical grid connections.

With reference to assumptions and criteria underlying our reasoning in 6.4.1, we propose a regional division that integrates currently defined Capacity Calculation Regions (CCRs) into larger areas to be able to integrally optimise these. Our proposal aligns with a recently proposed division of regions for TSO coordination as presented by the EC (Figure 9) and more or less covers the following (combinations of) regions: 1. CWE+CEE, 2. Nordic+Baltics, 3. UK+Ireland, 4. Iberia and 5. Italy+SEE

Ultimately, the SO before RT- functions could be centralised across all the synchronous areas, or even pan-European, to optimise their performance aimed at improved overall market facilitation, RES-integration (absorption) and ensuring the security of supply.

### ***High-level implementation steps of TM 2020***

Aimed at implementation of the target model within 5 years (ready in 2020), an indicative schedule with high-level implementation steps is shown below. It requires actions from TSOs, regulators and policy makers.

- 3 years for regulatory harmonisation across Europe;
  - Particularly the harmonisation of (national) security of supply guidelines and gate closure times to align the real-time timeframes
  - Further adjustments of (national and European) Energy Law, installing ROCs as the parties responsible for SO before RT-functions throughout a region;
- 1 year (in parallel to the regulatory harmonisation) for harmonisation of operational principles and alignment of practices;
  - Particularly the harmonisation of operational principles such as standardised assessments on how to increasingly facilitate markets
- 2-4 years for the implementation of necessary organisations and the required full-scale integration of inherent tools and capabilities within the ROC and governing organisations (e.g. tool development, personnel training).

# 1 INTRODUCTION

The European power sector is undergoing important changes. Especially the increasing penetration of renewable energy sources (RES), as part of the transition to a de-carbonised power system, results in a need to continuously assess and decide upon (the adoption of) alternative technologies, policies and practices. One of the key fields of study is the area of system development and operations.

Our consortium (Ecorys, ECN and DNV GL) was appointed by DG ENER to assess 'Options for future system operations'. This report describes our analysis and conclusions about a target model for system operations in Europe, in 2020.

A more specific development for the European electricity sector, which incorporates the above-described transition, is the development of the Internal Energy Market (IEM). The goal of the IEM is expressed by the EC when she states: *"Over the last two decades Europe's energy policy has consistently been geared towards achieving three main objectives: energy in the European Union should be affordable and competitively priced, environmentally sustainable and secure for everybody. A well-integrated internal energy market is a fundamental pre-requisite to achieve these objectives in a cost-effective way."*[4]

Concluding on these goals of the IEM, we point out the three aims that are key to its further development, and central to the development of a target model for system operations in this report:

1. Security of supply (secure for everybody)
2. Market facilitation (affordable and competitive pricing)
3. Integration of RES (environmentally sustainable).

Current efforts by TSOs to improve coordination between them and embed this into network codes are important steps in coping with changes in the system. Worries related to several issues however, remain. The worries of policy makers and other industry stakeholders (e.g. generation companies and large consumers) concern issues regarding lacks in wholesale market integration[5]/[6] and the question whether the pace of developments in system operations can keep up with the pace of change in the system. This is driven by the fact that TSOs operate their systems based on largely national approaches, resulting from the historic development of national power systems and their operations.

The pace of changes in the wider (European) system is strengthened by the fact that physical power flows do not recognise country-borders. This can have (unexpected) negative effects (e.g. loop and transit flows) [7] and affects the (further) optimisation towards the goals of the IEM. Such impacts invoke a need to re-think the current and future framework for system operations.

### *Goal of this report*

As mentioned above, the goal of this report is to define a target model for system operations (SO) and planning in 10 years (2025). To ensure the timely implementation, the target model should preferably be implementable within 5 years from now (2020).

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[4] Progress towards completing the Internal Energy Market, EC, 2014

[5] EURELECTRIC Members face serious and urgent problems with market integration, EURELECTRIC, 29 July 2015

[6] Technical Report Bidding Zones Review Process, ENTSO-E, January 2014

[7] THEMA Consulting group, Loop-flows – final advice, p. 1, October 2013

Underlying the development of a target model for 2020, are the following sub-questions:

1. What are requirements for SO in 2025?
2. Which functions should be alternatively organised to ensure the best fit with the overall strategic goal of a secure, affordable and sustainable energy supply to all European consumers?
3. Which geographic regions could be distinguished?
4. What is a suitable governance structure for future SO?
5. Which high level implementation stages can be distinguished to move from current state to the target model in 2020?

### *Scope*

A high level presentation of long-term planning and system operation throughout different time frames is depicted in Figure 3. These timeframes and the related functions will be further addressed in the report. For sake of clarity the time frames are explained in this introduction.

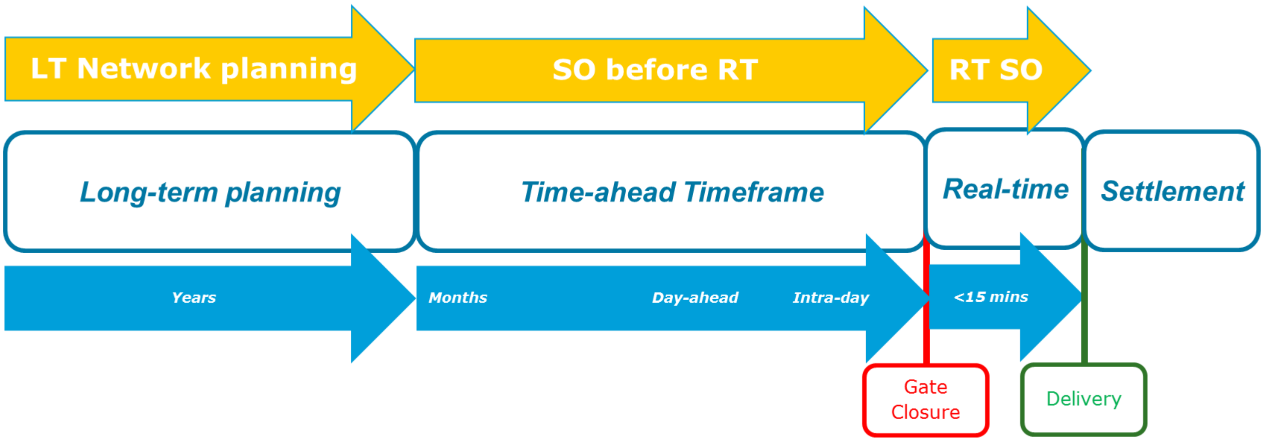

**Figure 3 Timeframes in transmission system operations, planning and settlement (Source: DNV GL)**

Currently transmission system operators (TSOs) are responsible for required operations throughout the time frames in Figure 3. More details on the (timing of) functions of transmission system operation of the power system are provided in the report.

### *Real-Time System Operations*

In the RT-time frame, the system operator needs to cope with short-term variations and sudden disruptions in demand and supply to continuously balance the system; ensuring the security of supply is the most important task in this time frame. For this purpose, the system operator performs suitable control and switching actions to bring the power system in imbalance, back to the normal operation state and/or to prevent large disturbances, e.g. blackouts[8/9]. In addition to this, a system operator also enables safe maintenance in the power system by isolating part of the power system, e.g. substations and overhead lines.

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[8] ENTSO-E has assessed the cost of a 20 GW load disconnection to be some 800 M€ per hour

[9] Cost-efficiency and the (increasing) facilitation of the market (see footnote 1) are also important guiding principles within this time frame, but due to the nature of the time frame (continuously balancing the system right before delivery), Security of supply will be the primary focus

The increasing integration of RES (including RES in the MV/ LV grid, and the activation of flexible balancing power in coordination with DSOs) poses an important challenge for system operations. To effectively facilitate the energy market and deal with the variable output of RES (particularly wind energy), a system operator nowadays needs to understand and master (new) balancing mechanisms[10] and understand the impact of his actions on neighbouring transmission systems and connected distribution systems. More and more, a system operator should be able to work from an enlarged field of view.

***System Operations in the SO before RT-time frame***

The main focus in this report is on how to (re-)organise system operations in the SO before RT-time frame highlighted in Figure 3, in years to come. The tasks executed in this this Ahead-time frame have a relatively large impact on the real-time functioning of the electricity market and the system's security of supply. Consequently, in the discussion of SO cooperation options these tasks receive relatively much attention.

***Boundary condition – Regulatory harmonization***

We highlight here that we consider regulatory harmonization to be a necessary boundary condition underlying the discussion of development options in this report. Two major issues that require regulatory harmonization, are the current national approaches to system security of supply and gate closure (times). If – at least – these issues are not aligned throughout Europe, benefits of the target model are likely to be (much) lower. This is due to remaining important differences between countries and the operating frameworks for market actors and system operators within these countries. Such factors essentially oblige current system operators to fulfil requirements within their own country-borders, which hinders the development of a level-playing for market parties across different countries. This can be (partially) accounted for by installing a governance structure with clearly defined judicial powers, entitling the respective entity to control and drive forward required cross-country and/ or pan-EU developments.

***Excluded from scope***

The aim of the study is to identify and describe options for an alternative organisation of system operations and planning functions that are key for the effective, secure and cost-efficient operation of Europe's transmission networks. In consultation with the steering group for the project, any discussions related to the political context are excluded.

## 1.1 Reader's guide

This report will be of interest to a multitude of readers involved or interested, in the future development of the European power sector, and in particular the related changes system operations in the SO before RT-timeframe may undergo.

In chapter 2, the report starts by describing the current situation of system planning and operations in Europe. As first input to development of a target model for 2020, chapter 0 describes requirements for system planning and operations towards 2025. Further input is provided by an analysis of current obstacles/ barriers (chapter 4) and possibilities for centralization of functions and its benefits in chapter 5. Chapter 6 concludes on the target

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[10] Please refer to the E-price project (EC, 2011) and Mott McDonald (2013) for more background on the development and workings of such markets

model for 2020, including our views on its governance, a geographic division between regions and high-level implementation steps.

## 1.2 Data collection

Data collection has been done through desk research and 10 interviews about the topic with carefully selected industry stakeholders.

The collection of interviewees consisted of people representing TSOs, Regional Security Coordination Initiatives (RSCIs), Generators and a DSO. The project’s steering group contained representatives from the EC. All these people not only reflected their view from different parts of the power sector, but also geographically - from across the continent.

## 2 SETTING THE SCENE

This chapter describes the current situation for transmission system planning and operations. It is meant to provide an overview of current status and developments, which essentially provides us with a basis for further discussions in later chapters. This chapter presents an overview including:

- Introduction of the main aims in system planning and operations, also referred to TSO missions
- Description of the various operational states in system operations
- Current transmission system operations and related tasks
- Important regulation
- Current cooperation.

It is noted that, with the view of assessing options for system operations, the possibilities of centralisation of a system operation function or classification of functions will be considered. In this context "centralisation" of functions means placing the authority and responsibility for a certain function or category of functions performed by several locations, into one single location.

### 2.1 Main aims in System planning and operations (TSO Missions)

Linked to different operational time frames as introduced in figure 1.1, the focus in transmission system planning and operations is on three different aims, which we will refer to as the missions of system operation throughout this document. These missions are more or less important depending upon the operational system state (discussed in 2.2) and/ or the operational timeframe (further discussed in 2.3). These tasks are included in ENTSO-E's official mandates[11] and are closely related to the goals of the IEM (described in chapter 1). We summarize the main aims for TSOs, as follows:

- Ensuring the security of supply
- Facilitating the integration of RES and the development of cross-border connections
- Facilitating the market[12]

### 2.2 Operational States

Figure 4 provides a high level overview of system operational states and operation actions. It is seen that system operation is by characterized by four states: Normal, Alert, Emergency, Blackout and Restoration State. A system state refers to a certain situation of the transmission system relative to its operational limits. The definition of the states can be found in the Network Code on Operational Security. This overview is used to position the main SO functions.

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[11] ENTSO-E's responsibilities – as available on https://www.entsoe.eu/about-entso-e/inside-entso-e/official-mandates/Pages/default.aspx are:
a. ensuring the secure and reliable operation of the increasingly complex network
b. facilitating cross-border network development and the integration of RES;
c. enhancing the creation of the Internal Electricity Market, IEM

[12] The third responsibility included in ENTSO-E's official mandate points to the creation of the IEM. However, the first two mandates (a and b in footnote 11) already point to the other two IEM goals, leaving market facilitation as a third task for TSOs to complete the highlighted goals related to the IEM in chapter 1.

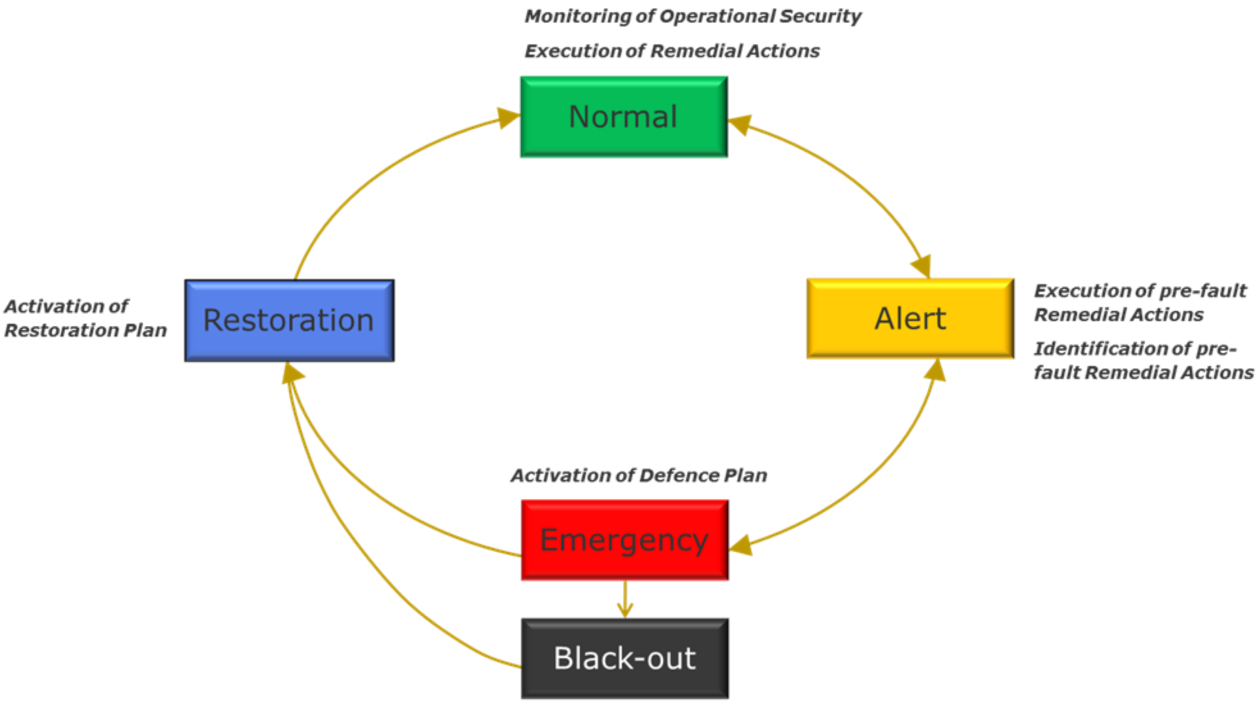

*Figure 4 Operational states of System Operation (Sources: ENTSO-E and DNV GL)*

Most of the time, a transmission system is in the normal state or the alert state. Therefore, in assessing the SO functions in relation to the electricity market, facilitation of the market is assessed when the transmission system is in the normal / alert state. It should also be noted that to keep a system state and/or to change from system state, control and/or switching actions are needed, and that automatic control/switching devices and/or operators execute these actions. In the time frame perspective, these actions are considered as real-time actions: the system state (almost) changes immediately after the execution of these actions. Operator’s involvement in the control/switch actions is also referred to as “human in the control loop”. In order to carry out these actions effectively, operators need to have an overview of the system they are responsible for, but also details of the transmission system for safety and system security reasons.

## 2.3 Current System Planning and Operations

A timeline perspective provides a useful means to position different power system planning and operations functions relative to one another, in particular when such an approach gives an overview how a system operator is fulfilling its mission (Figure 5). The overview illustrates in detail when certain functions are carried out for what purposes.

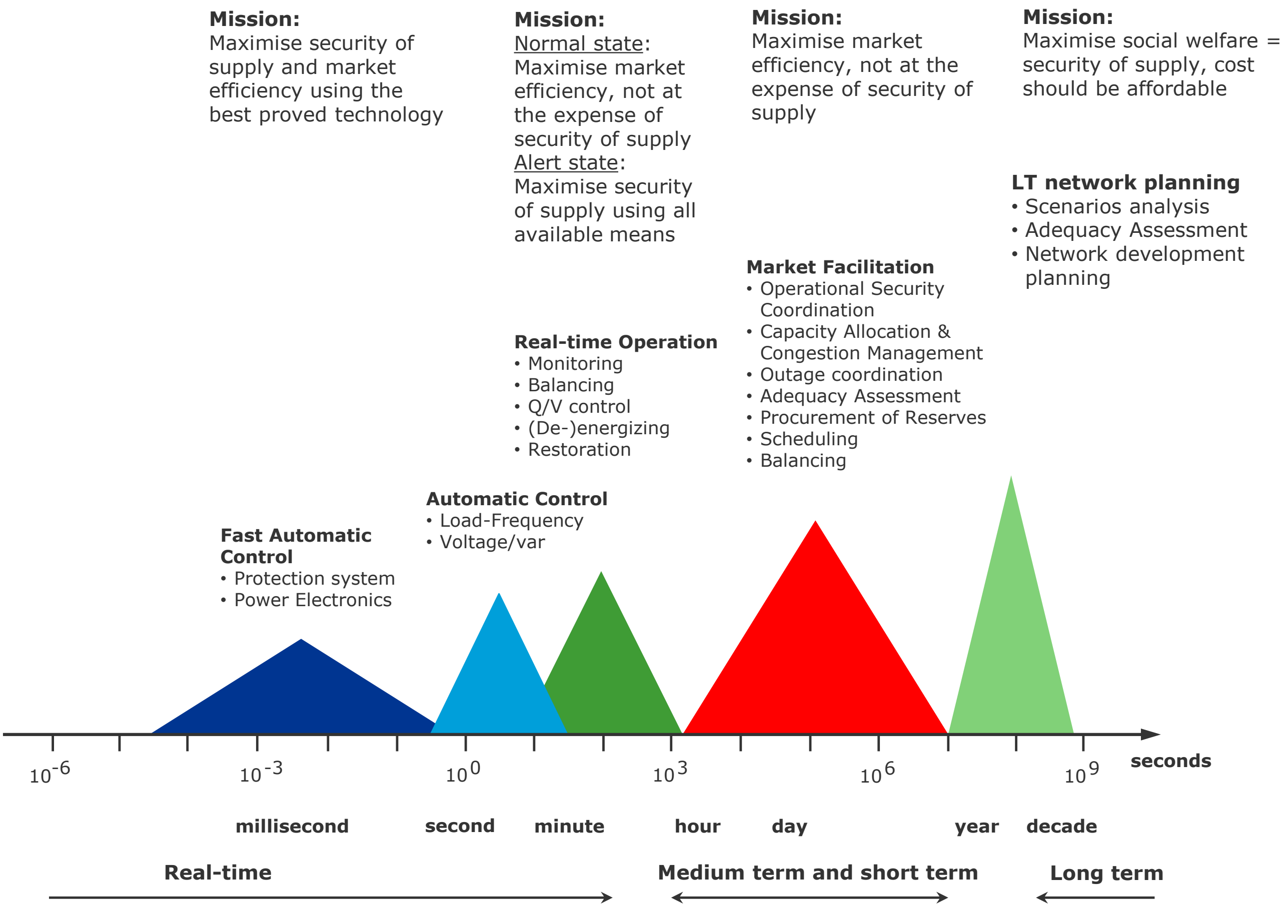

*Figure 5 Timing of current system operations functions*[13]

It is noted that the degree of automation increases as one gets closer to real-time (left side of Figure 5), i.e. fewer and fewer people but more and more devices are involved in decision making and performing actions that are essential in realising the objectives (mission) of the system operator. The further one is away from real-time, the more people are involved in decision-making and performing actions.

Two points related to the workplace can be made from this observation. The first point is that real-time activities for which the human is in the control loop, the operator (and sometimes field personnel) in this case, should have a good knowledge of the transmission system for which he is responsible in order to fulfil his function as required. For these real-time activities, the human scale is very important. Today’s practice is that most system operators are dealing with a transmission system of relatively limited complexity, because the geographic scope of the respective transmission system is generally limited to a country’s (internal) borders.

The other point is that, essentially seen, there is no geographical restriction for the workplace for all the other TSO activities. Short, medium and long term activities can performed anywhere, as long as the supporting tools, IT systems and communication facilities do not introduce limitations.

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[13] Please note that this illustration moves from right (long-term) to left (real-time). This is different from the perspective (left to right) in figure 1.1.

From Figure 5 it can be seen that the focus of a transmission system operator's mission shifts depending on the time horizon related to the following three categories of tasks:

1. Long-term network planning
2. Market facilitation
3. Real-Time operation, including:
    - Automatic control
    - Fast automatic control.

### 2.3.1 Long-term – LT Network planning

System planning relates to the activities that should be carried out to determine the needed network expansion and reinforcement to cope with future developments of all types of demand and generation. The time horizon for transmission system planning is 10 years. TYNDPs[14] that are released bi-annually by the TSOs describe the activities (methods & techniques, and software tools) that are carried in this respect. Crucial activities are scenario development, network expansion and related investment decisions, and choices of applied technology. The foreseen increase of large scale renewable energy sources introduces new challenges for network planners.

### 2.3.2 Medium and short term – Market facilitation

In medium and short-term system operations, a system operator's most important task is Market facilitation. This task covers a time period of 1 year to (less than) one hour before delivery. Within this time frame the objective is a well-functioning market: market efficiency is maximised, but not at the expense of operational security.

The European electricity market is not fully integrated. National electricity markets or control areas are separated from each other by borders in which physical interconnections of corresponding transmission systems play an important role in trading of electricity. Therefore, market facilitation is strongly related to facilitating cross-border trading. Activities that are carried out in this context include capacity allocation and congestion management, and balancing.

The SO before RT functions (SO functions in the Time-Ahead time frame) are related to

- Capacity Calculation
- Capacity Allocation and Congestion Management
- Operational Security Analysis in the Time-Ahead time frame
- Operational Security Coordination
- Outage Management
- Adequacy Assessment
- Procurement and reservation of Ancillary Services (Active Power and Reactive Power reserves)
- Scheduling
- Balancing.

Figure 6 shows a high level presentation of the interrelationship between these functions and other sub-functions. This figure can help in the discussion of how to organise these functions.

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[14] TYNDP = Ten Years Network Development Plan

The function Capacity Allocation and Congestion Management is related to Cross Border Trading, and Balancing to the Balancing Market. Note, that all decisions and actions to be taken in the context of cross border trading are based on Operational Security Analysis (and related software tools)[15]. Input for the Operational Security Analysis Method is the Common Grid Model (merged Individual Grid models) which includes scenarios/forecasts for the different time frames (1 year-ahead, week-ahead, day-ahead and intraday). The Operational Security Analysis Method is also used to assess the impact of Remedial Actions, for Outage Planning, and Adequacy Assessment. If Adequacy is not fulfilled, then, depending on the prevailing regulations, reserve from neighbouring regions can be called in, strategic reserve can be procured, or a process of involuntary load shedding can be started as last resort measure. A capacity calculation method derived from Operational Security Analysis Method and Remedial Actions related to congestions are used to provide input for the day-ahead and intraday Market Coupling (Capacity Allocation and Congestion).

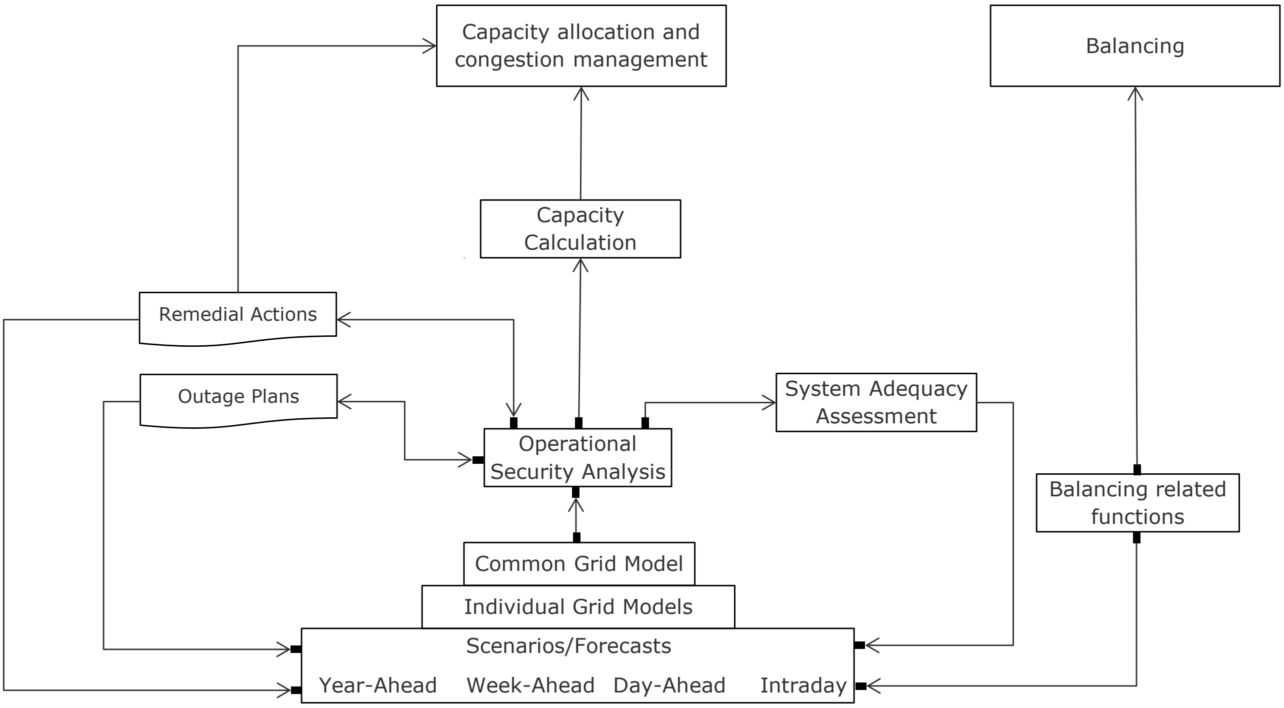

*Figure 6 Overview of SO functions in the Time-Ahead time frame (Source: DNV GL)*

From Figure 6 it is seen, that Balancing is not (directly) related to Operational Security Analyses. Indeed, strictly speaking the transmission network is not considered when performing balancing, except when network restrictions are involved. In the scheme of this figure it is assumed that information on network restriction is included in “Scenario/Forecast”. Ahead of the discussion about the organization and coordination of SO functions, it can be noted that the loose coupling with functions related to the transmission network (Operational

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[15] Quantitative benefits of both (balancing) market developments are assessed in: ‘Impact Assessment on European Electricity Balancing Market’, Mott McDonald, 2013

Security Analyses), suggests that from a functional point of view a carve out of Balancing functions should be relatively easy.

In principle, all functions in the Time Ahead time frame by system operators responsible for their respective areas, can be conducted from a single location (can be centralized), because these features are not time-critical. Limiting factors are the required IT systems and software tools.

### 2.3.3 Real-Time Operation – Security of supply (with increasing market facilitation)

Real-Time Operation covers the time frame directly after Balancing Energy Gate Closure Time in which decisions are taken and related actions executed. The main focus in Real-Time operations is on safeguarding the security of supply, while also attention is given to develop platforms/ market concepts to improve Market facilitation in this time frame (e.g. to allow highly required flexible resources for the provision of balancing energy to develop profitable business cases).

The decisions and action related to Real-Time Operation are categorised as follows:

- Operator in the loop
- Automatic Control.

#### ***Real-Time – Operator in the loop***

The main SO functions in the in the Real-Time time frame related to the normal and/or alert state are:

- Operational security monitoring
- Balancing - real-time
- Frequency control (Frequency Restoration Reserves) - manual
- Voltage/reactive power control - manual
- Switching/(De-)energizing network components for security of supply/maintenance/ construction purposes .

And for the emergency/blackout/restoration state:

- Emergency and Restoration
  - dis-(connect)
  - re-synchronise
  - frequency management.

In the Real-Time time frame an operator has sufficient time to perform actions to operate the transmission system as secure as possible and/or to facilitate the market as good as possible. In normal state of the transmission system (the system is in a secure state), the objective is to maximise market efficiency, while in the alert state of the transmission system the objective is to improve security of supply.

Functions for which operator actions are required are referred to as Operator in the loop functions. In principle, operator in the loop functions in the Real-Time time frame from multiple TSOs cannot be conducted from a single location (cannot be centralised), because of safety reasons and required knowledge of the respective transmission systems. Note, that in principle the operational security monitor function can be centralised, because strictly speaking there is no involvement of an operator in this function.

***Real-Time – Automatic Control***

In the Automatic Control time frame, control and/or switch devices take decisions and execute action according to a prescribed function. In general, decision and actions are taken to restore security of supply and/or to prevent the system from degrading to a lower level of security of supply, and ultimately from preventing a blackout. The following devices are used in the related processes:

- voltage/var control
- load frequency control
- protection system
- power electronics devices.

Automatic control functions cannot be centralised.

## 2.4 IEM goals and related regulatory change

In the following, we discuss the highlights from recently issued regulations that are built on realizing the goals of the IEM (see chapter 1). These are the 3rd Energy Package, CACM guideline and renewed grid code "establishing a Guideline on Transmission System Operation".

### 2.4.1 3rd Energy Package

The Third Internal Energy Market Package was adopted in 2009 to accelerate investments in energy infrastructure to enhance cross border trade and access to diversified sources of energy. It incorporates a multi-annual program, working out measures to address these issues. Part of this program is the implementation of the CACM-guideline, discussed in the following section.

### 2.4.2 Capacity calculation and congestion management (CACM) guideline

The adoption of the "guideline on capacity allocation and congestion management" by the European Commission (24 July 2015[16]) is a step in removing barriers/obstacles related to cross-border flows that have been identified by many stakeholders. Member States now have the challenge to implement this regulation.

CACM establishes harmonised principles for cross-border capacity calculation in day ahead and intraday market-time frames; to this end, Capacity Calculation Regions (CCRs) are defined. The CACM-guideline further sets out to:

- Further roll-out of FBMC (see example of first results in CWE – textbox below)
- Identify/ optimise 'bidding zones' and regular future re-assessment to account for system development
- Develop common cost-sharing approaches/ methods for e.g. congestion management and subsequent re-dispatching that may negatively impact upon fellow Member States (MS).

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[16] 8th Region Quarterly Report, ECRB (Energy Community Regulatory Board), Q2, 2014

**First results of Flow-Based Market Coupling (FBMC)**

The implementation of FBMC in Central West Europe (CWE-region) follows a Memorandum of Understanding (MoU) of the Pentalateral Energy Forum (PLEF), which was signed on 6 June 2007. The MoU aims to improve security of supply and foster the analysis, design and implementation of Flow-Based Market Coupling between the five countries of the CWE region[1].

The flow-based market coupling that was introduced almost half a year ago in the Central West European electricity trading market (CWE), lives up to expectations: Price convergence and price volatility throughout the region are increasing. This is noted by researchers of the company Berenschot that compared the first 73 days of flow-based market coupling with the same period before the launch.

The price difference between the Netherlands and Germany decreased by approximately EUR 5.60 per MWh (from EUR 13.30 to EUR 7.70 per MWh) between 73 days before and 73 days after introduction of flow-based market coupling. According to the analysis by Berenschot, there were no movements in energy prices and/ or seasonal factors, which may offer alternative explanation for an effect of that magnitude.

Apart from reducing price differences between countries in the CWE region an overall increase of price volatility was expected. This effect would appear as the trans-boundary tangibility of peaks in sustainable energy production. Berenschot brought the price variation in image and indeed sees a growth of volatility[2].

Increasing price volatility is likely to support the development of demand response and energy storage capacity. These will help to increase the availability of flexibility in the system and reduce the overall price level, due to low operational costs (OPEX) and the increasing capability of the power system to absorb available VRES generation.

FBMC has only just started in part of the European market. Application in the rest of Europe is expected to induce similar advantages throughout the continent.

[1] Source: http://www.coreso.eu/cwe-flow-based-market-coupling-successfully-launched/

[2] Source: Energeia, 8 September 2015, translation of part of Dutch article

### 2.4.3 Renewed Grid Code “establishing a Guideline on Transmission System Operation” (upcoming)

Regulation (EC) No 714/2009 sets out (further) non-discriminatory rules governing access to the network for cross-border exchanges in electricity with a view to ensuring the proper functioning of the IEM. Although this regulation has not yet been finalised, we consider it to be an important additional step in further harmonizing SO throughout Europe.

Some highlights of the new guideline are:

Within 12 months after entry into force of the grid code all TSOs will jointly have developed a proposal for coordinated operational security analysis, which ensures standardization of operational security analysis, at least per synchronous area.

- Coordination by a regional security coordinator (RSCs; building on the concept of RSCIs, which are described in 2.5)
- Sharing of costs of remedial actions
- Further harmonization throughout synchronous areas through RSCs, e.g. by building and operating common grid models and regional operational coordination

- Regional outage coordination
- Regional adequacy assessment; RSC advises on adequacy assessment per 'Capacity calculation region' (as defined by ENTSO-E[17]).

## 2.5 Current sector cooperation - RSCIs

Initially, Regulation No 714/2009 was developed by the EC, requiring system operators to cooperate and exchange data to better plan their systems. An important development in this respect is the development of organisations to facilitate congestion management on a regional level (e.g. CORESO, SSC and TSC). In a multi-lateral agreement between all the European TSOs, it has also been agreed to make participation in these Regional Security Coordination Initiatives (RSCIs) obligatory. However, planning and operational authority have largely remained at national level.

RSCIs monitor the operational security of the transmission system in the region and assist system operators proactively in ensuring security of supply on a European regional level. By performing these security analyses, the RSCIs provide the (control centres of) TSOs with detailed forecasts of network security levels, and propose coordinated measures.

As highlighted in 2.4.3, the RSCI's are foreseen to be replaced by RSCs, in accordance with the new Grid code on transmission system operation.

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[17] See for example: All TSOs' draft proposal for Capacity Calculation Regions (CCRs) - Draft Version 1.0, ENTSO – E, 24 September 2015

# 3 REQUIREMENTS 2025 – A 'SPOT ON THE HORIZON'

The overall goals of the IEM were highlighted in the Introduction as: 1. ensuring security of supply, 2. further facilitating the market, and 3. efficiently integrating RES to improve sustainability of the system. This chapter is aimed at identifying how these goals for the IEM can be further served by highlighting related challenges towards 2025, as identified by ACER, and using these to formulate requirements for system planning and operations towards 2025.

## 3.1 The challenges to the energy sector for 2025

The important challenges for the European Energy sector in realising the goals of the IEM, are based on ACER's work that highlights the challenges for the European energy sector towards 2025. ACER has identified the following challenges[18], with which the Consortium in general agrees:

- Establishing liquid, competitive and integrated wholesale energy market
- Enhancing Europe's security of supply
- Moving to a low carbon society with increased renewables and smart, flexible responsive energy supply
- Developing a functioning retail market that benefits consumers
- Building stakeholder dialogue, cooperation and new governance arrangements.

Instead of the enhancement of Europe's security of supply however, we feel that safeguarding the present security of supply, as part of the movement to a low carbon society, is a more realistic challenge.

To complete these challenges by 2025, SO is required to fulfil specific requirements (of course, next to requirements that need to be fulfilled by other stakeholders, required to complete these challenges). In the following section requirements for SO are identified by the Consortium, based upon the challenges that have been highlighted by ACER.

## 3.2 Determining the requirements for SO

In this section, the Consortium uses the challenges discussed in Section 3.1, to conclude on requirements for SO in 2025, in Section 3.3.

### 3.2.1 Challenge 1: Establishing a liquid, competitive and integrated wholesale energy market

This challenge requires distinguishing between the different components: market liquidity, competition and integration of wholesale markets. An important feature included in this requirement is the optimisation of shared balancing of the system across larger geographic areas; the related benefits are further elaborated on in section 5.2.

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[18] "Energy Regulation: A Bridge to 2025", Conclusions Paper, ACER, 19 September 2014 – Recommendation of the Agency for the Cooperation of Energy Regulators No 05/2014 of 19 September 2014 on the regulatory response to the future challenges emerging from developments in the internal energy market

***Market liquidity***

The Role of SO in improving liquidity of markets implies that system operators open up the SO time frames (Time-Ahead and Real-Time, refer to Figure 3) for more parties and possibilities to trade, ultimately lowering electricity prices. For SO, this will imply e.g. shorter term contracting for the provision of balancing power, and allowing for the integration of demand-side bids and alternative flexibility resources (e.g. storage and aggregators).

***Competition***

To facilitate competition better, the role for system operators would be to ensure the availability of the same information to all parties in all markets (level playing field for market operators, and generation- and demand-side resources), allowing more (smaller-sized; in terms of capacity) resources to participate in the market based on the same knowledge.

***Integration of markets***

Physical integration: Further integration of markets can be achieved through particularly the ongoing development of interconnection capacities within and between current (country) markets, the alignment of operational practices and development of new (flexible) approaches to interconnections between countries and/ or regions.

Integration of market exchanges: requires harmonised market policies (concern of regulator) and operational practices (concern for system operators) to ensure a level playing field throughout the integrated markets.

### 3.2.2 Challenge 2: Enhancing/ safeguarding Europe’s security of supply

To safeguard system security of supply throughout Europe, ACER has asserted that the European power sector needs to *“move from fragmented (national) approaches to a more coordinated (and efficient) EU-wide approach.”*[19] As described in Sections 2.4 and 2.5, both policy makers and TSOs are making progress in this area. Nonetheless, it must be highlighted that the variability, due to increasing volumes of VRES in the system, will develop further and further, and system operator’s abilities to cope with the resulting variations in system balance will increasingly be challenged.

### 3.2.3 Challenge 3: Moving to a low carbon society with increased renewables and smart, flexible responsive energy supply

Facilitating the further integration of RES, implies both an optimal investment planning for renewables construction and grid connections, and the optimal uptake of available renewable power generation in time-ahead and real-time (in line with Figure 3) aiming for minimisation of (planned) curtailment. This is not to say the renewables should get priority in dispatch, but SO should enable – to the best of its abilities – that fluctuations in renewable generation can be adequately balanced by means of (emerging) flexible demand/ generation options. To enable efficient balancing of RES in the system, it is important to have flexible resources available that can provide the system with balancing power. Examples of such resources are storage and demand-side management capacity, next to more traditional flexible generation.

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[19] “Energy Regulation: A Bridge to 2025”, Conclusions Paper, ACER, 19 September 2014

(Helping) to enable the development of such resources will help SO to ensure security of supply in the face of the growing challenge of balancing the system.

Concerning the resulting requirements for system operators, the effective integration of new (RES and balancing) capacity requires an integrated planning of system development. The efficient use of these assets once available can particularly be facilitated through the (better) use of resources across larger geographic areas.

### 3.2.4 Challenge 4: Developing a functioning retail market that benefits consumers

From an electricity network perspective, this point particularly concerns the lower voltage levels, delivering power to (household and small-business) consumers buying power on the retail market. The related challenge for (transmission) system operators is to make available to DSOs and the relevant market actors (e.g. market operators), the required information to optimise the functioning of the retail market. Such information could concern: information about generation in the transmission grid, congestions, and (planned) outages. Whatever information exchange is required to improve the functioning of retail markets throughout Europe, this should be gathered and shared between the different actors throughout Europe, based on uniform principles (harmonised definitions, methods and presentation of required information).

### 3.2.5 Challenge 5: Building stakeholder dialogue, cooperation and new governance arrangements

This challenge particularly concerns the stronger involvement of stakeholder panels and consumer representative bodies in discussions about the future energy market and the governance of the sector. For SO, this challenge involves the requirement to cooperate and discuss (more) with relevant stakeholders such as consumers, market operators and the generation-sector.

## 3.3 Concluding on the requirements for SO in 2025

From the ACER challenges discussed in the previous section, a number of requirements for SO in 2025 has been specified. These requirements have been included in

Table *1*, which also shows how the requirements cover the IEM goals and ACER challenges.

*Table 1 Concluding overview of requirements for system planning and operations and relationship to IEM goals*

| | **Requirement for system planning and operations** | **IEM goal(s) facilitated by requirement - in order of importance** | **Resulting from challenge (ACER) number** |
|---|---|---|---|
| **1** | Facilitate the effective development of RES and flexible capacity in system development | Security of supply and RES integration | 2 and 3 |
| **2** | Facilitate efficient absorption of RES-generation and (cost-) efficient availability of balancing power in system operation | RES integration, Market facilitation (cost-efficient balancing) and Security of supply | 1, 2 and 3 |
| **3** | (Helping to) improve market liquidity | Market facilitation (market integration and cost efficiency) | 1 and 3 |
| **4** | (Helping to) improve competition in the market and ensure a level playing field | Market facilitation (market integration and cost efficiency) | 1 and 3 |
| **5** | Drive the physical integration of markets (through both planning and operations) | Market facilitation (market integration and cost efficiency), Security of supply and RES integration | 1, 2 and 3 |
| **6** | Facilitate the (further) integration of market exchanges | Market facilitation (market integration and cost efficiency) | 1 |
| **7** | Ensure fair and transparent information exchange with market actors, policy makers and DSOs, based upon harmonised definitions, methods and presentation of the required information throughout the continent. | Market facilitation (market integration and cost efficiency) | 4 and 5 |

The SO functions discussed in the previous Chapter (Section 2.3) are necessary and sufficient to meet these requirements, albeit that there are options to better organize them for optimization towards achieving the IEM goals. This optimization is the focus of chapter 5, after first addressing the obstacles/ barriers to further achieving IEM goals, in chapter 4.

# 4 CURRENT OBSTACLES/ BARRIERS

To develop insight into possible improvements in power system planning and operation, our research continues with an analysis of the main issues that are highlighted as obstacles and/or barriers to improvements. Our main sources of input for this chapter are desk research and interviews with important stakeholders.

To verify the obstacles/ barriers that were found in the analysis, the Consortium has studied the particular sources and their arguments to assess the extent to which relevant arguments are provided for the obstacle/ barrier. To further support or nuance claims with regard to the issues that are found, we have assessed whether more sources have mentioned the issue as an actual barrier/ obstacle and why.

## 4.1 Obstacles/ barriers identified

Next to the overall issue of (the threat of) national sub-optimization and extensive arrangements required to facilitate cross-border trading, we have assessed obstacles/ barriers in more detail.

As with the requirements in the previous chapter, the obstacles/ barriers are linked to the IEM goals to highlight their relevance. In this case the relationship between obstacle and IEM goal(s) is based on the question of which goal(s) is/ are predominantly frustrated by the particular obstacle/ barrier. Our assessment is presented in Table 2.

*Table 2 Assessed obstacles/ barrier in relation to IEM goals*

| | **Assessed obstacle/ barrier** | **IEM goal(s) primarily frustrated by obstacle/ barrier - in order of most hindered goal** |
|---|---|---|
| **1** | Change in generation mix and change in network development take place in different speeds | Security of supply and RES integration |
| **2** | Existing flexibility in the system is not sufficiently taken into consideration | Security of supply, Market facilitation and RES integration |
| **3** | Adequacy Assessment too limited because geographical spread is not (sufficiently) considered | Market facilitation, RES integration and Security of supply |
| **4** | Barriers/ obstacles related to capacity allocation and congestion management | Market facilitation and RES integration |
| **5** | Suboptimal transmission planning (LT network planning) | RES integration, ultimately also on Market facilitation and arguably Security of supply |
| **6** | Transmission planning often does not consider application of new technology and alternative sources of flexibility | RES integration, Market facilitation and Security of supply |
| **7** | Lack of coordination, especially during (large) blackouts | Security of supply |

The obstacles/ barriers that are identified provide the basis for further assessment of their relation to particular system planning and operations functions, which in turn forms the basis for the identification of functions that could (and should) be optimised, based on their assessed improvement potential in chapter 5.

In the following paragraphs, we further discuss the obstacles/ barriers alongside their verification and the sources for this verification.

### 4.1.1 Obstacle 1: Different speeds in change in generation mix and change in network development

A common planning framework is essential for a development of pan-European grid that can host expanded RES and facilitate the future IEM maximally. Currently there is no accepted common framework for a pan-European planning methodology[20]/[21]. There is no common accepted methodology that adequately deals with uncertainties that are inherent to a liberal electricity market (e.g. establishment of generation) and with the flexibility options in the power system. The lack of a common framework now becomes clearer in the discussion on facilitation of integration of renewable energy in the power system. For example, it is asserted[22] that the public opposition to new construction of assets, e.g. of overhead lines, hinders the integration of renewable energy in the power system, and that excessive delay in the planned construction of power lines would result in local black-outs. However, other studies question this assertion and conclude that possible uncertainties about the speed of grid expansion are no reason to slow down the expansion of renewable generation, especially when the flexibility in the power system is taken into account[23].

### 4.1.2 Obstacle 2: Existing flexibility in the system is not sufficiently taken into consideration

Currently, electricity production by renewable energy sources (wind and solar power) across the entire European grid is highly volatile and can only be controlled and predicted to a limited extent. This leads to frequency fluctuations and unpredictable electricity flows over the grid. Technical measures to counteract the fluctuations are flexible power plants such as gas or hydropower plants, flexible consumers (demand response) and/ or storage.

Each country in Europe has such resources within their domestic systems available (in particular demand response), but there is a lack of a common view to mutually (cross-border/ regional) source and/ or share such capacity, particularly for balancing services. What can be recognised is that when taking the example of demand response, countries (e.g. France[24] and

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[20] Research & Development Roadmap - writing history again; 2013 – 2022, ENTSO-E

[21] Despite the lack of a common framework mentioned the ENTSO-E document (footnote 21), the e-Highway2050 venture has proposed architectures: “The proposed architectures integrate the present pan-European transmission grid, without needing a new separate ‘layer’ within this existing transmission network.” Reference: http://www.e-highway2050.eu/fileadmin/user_upload/151029-PRESS_RELEASE_V05.pdf

[22] Source: http://nuris.org/wp-content/uploads/2015/04/Weixelbraun_International-black-out-experience-and-potential-power-grid-black-outs.pdf

[23] Impacts of restricted transmission grid expansion in a 2030 perspective in Germany, Ecofys, 2013

[24] The French Block Exchange Notification of Demand Response mechanism (NEBEF) is further explained on : https://clients.rte-france.com/lang/an/clients_producteurs/services_clients/dispositif_nebef.jsp

Great-Britain[25]) develop mechanisms to source such capacity when generation capacity margins become tight. We point out the fact that making such capacity available, is primarily a responsibility of the market (consumers with responsive capacity), but considering the growing need for responsive power (negative and positive) to balance the system, shared sourcing of such capacity is likely to have major economic benefits[26]. Benefits of shared balancing are further discussed in 5.2.2.

### 4.1.3 Obstacle 3: Current Adequacy Assessment methods are not harmonised and too limited

Adequacy assessment is fundamental, because it is directly related to security of supply: it establishes to which extent the generation of electricity in a system meets the expected requirements and energy demand at a certain point of time[27]. According to a CEER report[28], there exists no common framework for assessing generation adequacy. One of the major deficiencies is that adequacy assessments in some countries are still considering isolated systems, while others use non-harmonised methodologies to consider cross-border capacity. Generation and load data correlations at supranational levels are rarely considered, and (at national level) the "copperplate approach" still prevails, whereas in practice, transmission limits occur.

System adequacy will become increasingly difficult to manage, as the operating hours of conventional units decrease in favour of energy generated from RES[29]. Existing adequacy methodologies do not effectively address the hour-on-hour climate situation and the forecast errors. Therefore, ENTSO-E is developing a Target Methodology for Adequacy Assessment to identify how often the system is not balanced or when availability of ancillary services might be affected[30].

### 4.1.4 Obstacle 4: Barriers/ obstacles related to capacity allocation and congestion management

Given the differences in regulatory and market structure between Member States, which are in one region larger than the other, implementation of the CACM guideline will have different pace in different regions and most probably will occur and be managed through different routes. Considering, for example two extremes, one can imagine that implementation in Member States related to the CWE region will be different from that in the Member States related to the 8th Region. The latter has to cope with significant heterogeneity in both its market and regulatory set-up[31].

On the other hand, concerning the interconnector (DK1 – DE) connecting Germany (in the CWE-region) and Denmark (in the Nordic-region), reduced availability of interconnection

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[25] Related documents for Demand-Side Balancing Reserve scheme in Great-Britain are available on: http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/

[26] DNV GL, Smart Energy – A Vision for Europe, March 2015, p.21

[27] ENTSO-E report, "ENTSO-E Target Methodology for Adequacy Assessment", 14 July 2014

[28] Assessment of electricity generation adequacy in European countries, CEER report

[29] Research & Development Roadmap - writing history again; 2013 – 2022, ENTSO-E

[30] ENTSO-E Target Methodology for Adequacy Assessment, ENTSO-E

[31] Towards Regional Independent Operators: a main driver for successful market integration, EURELECTRIC Discussion Paper, May 2007, Ref: 2007-384-0011

capacity to the market, results in overall negative social-welfare effects throughout the countries surrounding Denmark and Germany[32/ 33].

Moreover, related to capacity allocation and congestion, the most frequently mentioned barriers/obstacles are:

- significant heterogeneity in both market and regulatory structure in some regions[34]
- lack of common capacity calculation methodology, common allocation procedures[35/ 36] and common methodology to assess security of supply
- limited interconnection and inefficient allocation of existing cross-border capacity[37]
- suboptimal use of networks and generation resources (e.g. suboptimal allocation of capacity for balancing and security of supply[38])
- remaining restrictions on exports or disproportionate licence requirements[39], and lack of investment in interconnection capacity[40/ 41].

### 4.1.5 Obstacle 5: Sub-optimal LT transmission planning

For years there used to be only national transmission system planning. The Third Package gives instruments, such as the Ten Year Network Development Plan (TYNDP) for a European wide network planning. In the beginning (2010), the TYNDPs – published by ENTSO-E – were only a collection of national network development plans, predominantly based on national social and economic developments. This approach was largely neglecting[42] the interdependence of socio-economic developments of the Member States, which resulted in a document that is more like a patchwork of national plans. Moreover, such a fragmented approach per definition leads to sub-optimality seen from a broader perspective.

Today's approach[43], which is more coordinated than in the beginning, produces a TYNDP package that still has a patchwork character, due to which most probably sub-optimality is not completely avoided. The process description given by ACER (illustrated in Figure 7) can be used to explain this.

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[32] Investigation of welfare effects of increasing cross-border capacities on the DK1-DE interconnector, A. Moser (Institute for Power Systems and Power Economics / RWTH Aachen University), June 2014

[33] Challenges to CACM implementation – EURELECTRIC's views, presentation at Florence Forum, EURELECTRIC, 9 October 2015

[34] 8th Region Quarterly Report, ECRB, Q2, 2014

[35] EURELECTRIC, 2007, Ref: 2007-384-0011

[36] Position Paper of CWE NRAs on Flow-Based Market Coupling, March 2015

[37] Response to ERGEG Consultation – Framework Guidelines on Capacity Calculation and Congestion Management, IFIEC, November 2010

[38] IFIEC, 2010

[39] Progress towards completing the Internal Energy Market, European Commission, Brussels, 13.10.2014, COM(2014) 634 final

[40] Security of supply: National challenges requiring regional solutions (RI and capacity market developments), Tomás Gómez, CNE for the 10th EU-US Energy Regulators Round Table The Hague, The Netherlands, 8-9 April 2013

[41] Public Consultation on THE REGIONAL ENERGY STRATEGY > Summary of the Consultation Answers, Energy Community, 2012, on https://www.energy-community.org/portal/page/portal/ENC_HOME/SECRETARIAT/Consultation/STRATEGY/Summary

[42] TYNDP 2010, ENTSO-E, p. 144

[43] Source: ENTSO-E on https://www.entsoe.eu/major-projects/ten-year-network-development-plan/FAQs/Pages/TYNDP-2014-Process.aspx

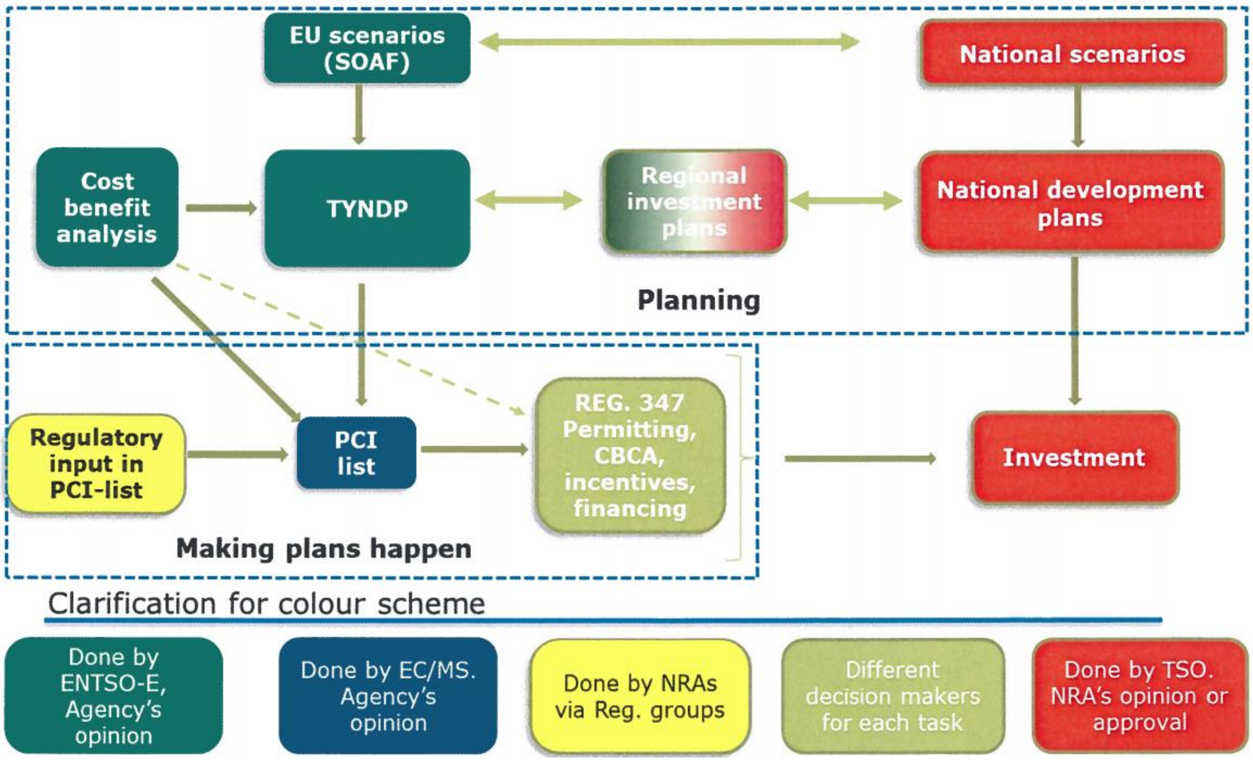

*Figure 7 The process of infrastructure development in Europe*[44]

The crucial part in this coordinated planning process is that a TSO bases its national network development plans on national scenarios, constructed from EU-scenarios. In regional context, he discusses the network development plans that he creates from the national scenarios.

This approach tends to seek for consensus: national scenarios are discussed within ENTSO-E, and national network development plans are discussed at regional level. However, in the end a TSO decides which scenarios he uses, how he applies these in the national political context, which geographical scope he uses in the network development analysis, and how he constructs network development plans. Although this process leads to more coherence in the TYNDP, it can be questioned if it will lead to optimal plans from a broader, European point of view. A truly integrated approach most probably would lead to a different development plan. This is partly 'repaired' by defining PCIs (projects of common interest).

### 4.1.6 Obstacle 6: New technology and sources of flexibility are not considered in long term planning

Most TSOs do not consider application of new technology in long term planning. The main reason is the lack of sufficient knowledge[45/46] and experience of power system planners with

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[44] Source: ACER on http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2001-2015.pdf

[45] ENTSO-E, "study roadmap towards MODULAR DEVELOPMENT PLAN on pan-EUROPEAN ELECTRICITY HIGHWAYS SYSTEM 2050 - way to 2050 pan-European power system. July 2011. A list of Technical/Technological issues (including Technology/Network development & analysis) is included. A technology based package (Work Package 3) is proposed to provide an understanding of constraints and opportunities regarding the grid technology that could be needed for future development of the grid.

new network devices, which are mostly based on power electronics (e.g. FACTS devices). Network planners are not inclined to opt for a network expansion with a component whose reliability is not yet known. Their line of reasoning is clear and understandable: in case of failure, such a component may jeopardise security of supply. Moreover, an assessment methodology for security of supply in a planning context which deals with new network components and flexibility is still under development.

Market integration benefits from flexibility. One can argue that the tendency not to use new technology which introduces flexibility in system operation, does not contribute to market integration.

### 4.1.7 Obstacle 7: Lack of coordination, especially during (large) black-out

Lack of coordination is recognised as an overall issue[47], but becomes critical in a stress situation, such as an emergency or black-out. The lessons learned from the large disturbance in the European power system on the 4th of November 2006[48/ 49] provide a good insight into what needs to be done on European level. The following omissions have been made: insufficient coordination of protect relays for load shedding, scarce information about the reason for the cascade disconnections and the consequences, and not enough coordination between network operators during the restoration phase. In general sense these lessons imply that a closer coordination between TSOs is required. Also necessary conditions are discussed of which are given below:

- an improved legal and regulatory framework to minimise the risk of large disturbances in Europe
- a set of more precisely and uniformly defined rules for coordinated real time security assessment and control to facilitate secure network operation in synchronous areas
- there is a need for a common real-time information and awareness system
- joint preparation of emergency plans with agreed protocols for consistency and coordinated actions and responsibilities by TSOs
- joint operator training programs and decision support systems[50].

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[46] European Electricity Grid Initiative 2013-2022, January 2013. This report also devoted a cluster (Cluster 2) to Power Technologies and identified the need to gain more knowledge on the costs, reliability, expected lifetime and service behaviour

[47] Discussed in multiple interviews with industry stakeholders, including TSOs

[48] The lessons to be learned from the large disturbance in the European power system on the 4th of November 2006, ERGEG, 6 February 2007, Ref: E06-BAG-01-06

[49] Development and Setup of the first European-wide real-time Awareness System (EAS) for the Transmission System Operators of ENTSO-E, J. ALBRECHT et al, Cigré 2012, C2_206_2012

[50] See for example: Benefits of coordination, WEC, 2014

# 5 CENTRALISATION OF TSO FUNCTIONS AND RELATED BENEFITS

In our opinion optimisation of TSO functions is needed to be able to optimally fulfil the identified requirements (Chapter 3) and remove the identified obstacles/ barriers (Chapter 4) in relation to the IEM goals. In accordance with the trend which has already started some years ago (particularly the development of RSCIs and the upcoming RSCs), the Consortium proposes centralisation/integration of some of the TSO functions.

This chapter deals first with the questions: which TSO functions should be centralised, and which should not? These questions are answered for the full set of TSO functions in section 5.1, in relation to the discussed requirements and obstacles across the three timeframes highlighted in Figure 3. Furthermore, section 5.2 addresses qualitative and quantitative improvements and benefits of centralisation.

## 5.1 Centralisation of TSO functions

A close look at the identified obstacles learns that, from a functional point of view, sub-optimality with respect to realizing the goals of the IEM, is the main cause. It is also noted that centralisation - functionally seen - creates the possibility for optimisation, or more precisely, avoids sub-optimality.

These two facts, sub-optimality due to a more or less separated approach and optimisation through centralization, form the main rationale for centralisation of TSO functions as a solution to optimise the removal of the identified obstacles and fulfil requirements. Optimization in a centralised setting is possible because a larger system is considered, and more and/or a variety of sources and/or resources can directly be tapped and controlled, i.e. relevant data and information can be collected and sent from a central level. Depending on the situation (timeframe), the focus of optimisation shifts from market efficiency, operational security, to the restoration of operational security.

Table 3 shows which functions (in the table we use the term ‘tasks’ to illustrate the fact that these concern specific activities performed at different levels) should be centralised in order to fulfil requirements and remove current obstacles detected in the European electricity sector, to meet the IEM goals. In this context centralised means moving functions that are executed by national TSOs (decentralised) to a regional level, which means that these function are executed at a central level. Thus, centralisation of functions as used in this study means that the related functions consider aspects from several regions in an integrated way and that methodologies are applied that have been conceived and developed from an integral point of view.

Since Table 3 addresses centralisation of functions, it serves as input for development of a target model in chapter 6: the table shows which functions considered in Section 2.3 can be centralised.

*Table 3 Target set-up for division of tasks (functions) between the Regional (Centralised) and National (Decentralised) level*

| | Long-term Network Planning | System Operation before Real-Time | | Real-time System Operation | |
|---|---|---|---|---|---|
| | | Adequacy sufficient | Adequacy insufficient | Normal & Alert State | Emergency & Restoration State |
| **Regional (Centralised)** | Mission:<br>- Maximise social welfare of the region = security of supply + affordable energy | Mission:<br>Maximize market efficiency, not at the expense of operational security | Mission:<br>Obtain market efficiency as good as possible, not at the expense of operational security limits | Mission:<br>- Normal state: maximise market efficiency, not at the expense of operational security<br>- Alert state: restore operational security as quick as possible, not at the expense of market efficiency | Mission:<br>- Restore security of operation as quick as possible |
| | Tasks:<br>- Regional scenario development/analysis and ascertainment<br>- Regional adequacy assessment and ascertainment<br>- Regional network development planning | Tasks:<br>- Capacity calculation, Congestion management<br>- Adequacy assessment, Outage coordination<br>- Scheduling<br>- Balancing<br>- Procurement of Ancillary reserves | Tasks:<br>- Restore level of adequacy by utilisation strategic reserve, demand side flexibility, loadshedding<br>- Develop a risk mitigation plan | Tasks:<br>- Operational security monitoring and alerting<br>- Operational security improvement measures identification<br>- Load frequency control<br>- Activation of balancing products | Tasks:<br>- Development of regional system defence and restoration plans<br>- Coordination of system restoration |
| **National (Decentralised)** | Mission:<br>- Maximise social welfare = security of supply + affordable energy | | | Mission:<br>- Maintain the safety and the security of operation of the local transmission system | Mission:<br>- Restore security of operation as quick as possible within the safety requirements |
| | Tasks:<br>- National scenario development/analysis<br>- National adequacy assessment<br>- National network development planning | | | Tasks:<br>Operator in the loop<br>- Operational security monitoring<br>- Voltage/reactive power control – manual<br>- Switching/ (De-)energising network components – manual<br>Automatic control<br>- Voltage/reactive control<br>- Protection system<br>- Power electronic control devices | Tasks:<br>- Real-time execution of restoration actions according to defence and restoration plans |

Table 3 shows that some functions related to Long-Term Network Planning and Real-Time System Operation need to be executed both at regional and national level.

Also, the table shows that, depending on the situation (timeframe), the focus of optimisation shifts from market efficiency, operational security, to restoration of operational security (as also highlighted in Figure 5).

The main conclusion that can be drawn from the proposed options for division of tasks/ functions in Table 3 is that functions in the 'System Operations before Real-Time'-timeframe (SO before RT-functions) can be centralised.

Before further discussing the target model in chapter 6, the centralisation of the functions and the benefits of centralisation are considered more closely in the next sections.

### 5.1.1 Long-Term network planning

From Table 3 it is seen that functions related to LT Network Planning are executed at centralised level (top half of table) as well as at de-centralised (national) level (bottom-half). The main difference between the functions related to Long-Term Network Planning at centralised and those related to national (decentralised) level obviously is the extent of the system considered. Optimisation of network planning is obtained by means of an iterative process between network planning at centralised level and network planning at national level (also see Figure 7).

In addition, it avoids sub-optimality in system planning (Obstacle 5 in Table 2) and, because of the inherent broader scope, can cope consistently with the different speed as opposed to generation mix development (Obstacle 1 in Table 2). Also, if integration implies bundling of knowledge and competences, an environment can be created in which network planners are more inclined to discuss and develop new methodologies, and to apply new technology and sources of flexibility in their solutions (Obstacle 6 in Table 2).

### 5.1.2 System Operation before Real-Time

The centralisation of TSO functions related to System Operation before Real-Time proposed in Table 3 is a reflection of the IEM goals. In order to achieve the IEM goals and to meet related requirements, centralisation/ integration of these functions (which we also have referred to as market facilitation) is needed. The electricity market is facilitated most efficiently if all related functions are carried out at regional (centralised) level. The identified obstacles related to adequacy assessment, utilisation of flexibility, and capacity allocation and congestion management can only be removed effectively, if the following necessary conditions are met:

- One methodology that is interpreted and applied unambiguously for each function in this category
- Optimal utilisation of capacity and all available resources
- Overview of all resources: their characteristics type and availability
- Maximum transparency for all market players
- Availability of grid information of and forecasts in the considered region.

These conditions relate to realising the various requirements presented in chapter 3 and are relatively easily met in a setting in which all necessary information is brought together and interpretation/ application of the methodologies and related procedures are carried out by one organisation.

It is noted that the situation in System Operation before Real-Time is split into "Adequacy sufficient" and "Adequacy insufficient". This distinction has been made to emphasise the fact that an adequacy assessment can have two outcomes. The adequacy is sufficient if for a considered period an adequacy analysis shows that a required adequacy level can be obtained. If adequacy has degraded below a certain level, other means should be considered to bring the adequacy to a maximum feasible level.

Types of means that could be considered include application of strategic reserve, demand side flexibility and/or load shedding. Since the "Adequacy insufficient" situation is an exceptional situation which can be society disruptive, development of a risk mitigation plan has been included as additional function for this situation.

### 5.1.3 Real-Time System Operation

The essential difference between Real-Time Operation at national level (decentralised) and Real-Time Operation at regional level is related to operator-in-the-loop functions. At national level operators perform real-time actions that are within their scope (safety[51] and operational security of supply), while operators acting at regional level only perform monitoring, alerting and coordination functions. The latter is possible and required because operators acting on regional level obtain a regional view and therefore are able to coordinate real-time actions from an integrated point of view. Operational security at regional level, for example, can reduce (negative) impacts of actions/ developments outside a country's borders, because of a broader scope and integrated assessment of the developments and possible solutions to occurring issues.

Table 3 shows that the Real-Time Operation functions are considered for two situations "Normal & Alert State" and "Emergency & Restoration State". For the Emergency and Restoration State, the regional system defence and restoration plans consist of coordination plans. Execution of restoration actions takes place at national level.

## 5.2 Improvements and benefits

The previous section argues that centralisation/integration of certain TSO functions is necessary to meet requirements and remove currently observed obstacles, with respect to optimization towards the IEM goals. This section further highlights the benefits of centralisation/integration of selected functions in LT Network planning and SO before RT. It concludes with an overview of quantitative insights related to a centralised/ integrated approach to various functions.

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[51] Safety in this context is related to safe execution of (maintenance or installation) in substations and/or overhead lines, For this purpose operators in a control centre perform remote switching in close coordination with field personnel.

### 5.2.1 Long-Term Network Planning

When Long-Term network planning is executed centrally, adopting an integral view across more countries, suboptimal network expansion and/or reinforcement plans are avoided because due to this integral approach. In a decentralised (national) Long-Term Network Planning approach, scenarios are developed separately i.e. from a national point of view, and the mutual impact of national systems may not be taken sufficiently into account. These two characteristic aspects of this approach may lead to grid investments which, seen from a national perspective, do not deliver the expected benefits. Examples of consequences of such investment decisions are loop and transits flows, insufficient use of assets and, in the extreme case, stranded investments.

A centralised approach can avoid these consequences of sub-optimisation that are characteristic to a predominant decentralised (national) approach. Optimal choices are made in terms of timing and geographical location. For example, consider that the postponement of investments in overhead lines as the outcome of an integrated approach could save billions. Timely realisation of cross-border connections is another example of the benefits of an integrated approach to network planning. A necessary condition for such benefits to materialize optimally is one network planning and related decision-making methodology for the considered region that effectively deals with the developments in the considered region. In addition, network planners can benefit from economies of scale in a centralised/integrated setting. Integration of RES will be more efficient: project developers are dealing with a common and consistent set of rules and more options can be considered to follow the pace of RES developments. Finally, it is noted that the integrated approach leads to optimisation of Security of supply which can be considered as a strong indicator for social welfare.

### 5.2.2 System operations before Real-Time

The specific benefits of centralisation/integration concerning various functions (balancing, capacity calculation and congestion management/ remedial actions, adequacy assessment) in the SO before RT-timeframe are highlighted below.

#### *Balancing*

Shared balancing has cost advantages residing from netting of imbalances between balancing areas and from shared procurement of balancing resources or reserves. This can be based on exchanging surpluses or based on a shared or common merit order for all balancing resources. The benefits of shared balancing are quantified in literature either using a system approach or by extrapolating results or investigations of examples of reserve sharing based on rough assumptions. Precise quantification requires detailed analysis and considerable amounts of data that are not available within the scope of this study. An often referred study performed for DG Ener mentions a potential overall benefit from integrated balancing of more than 3 billion Euros per year[52]. This is for a European electricity supply system with roughly 45% renewable energy. Other studies show either similar or lower values. Important to mention is that the calculated overall benefit includes the benefits of netting, which will be implemented throughout Europe already. Its share of the assessed benefit however, is relatively small compared to the overall benefits of integrated balancing: in the order of 100 to several hundred million euros per year for the whole of Europe. Also potential benefits of shared

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[52] MottMacdonald, 2013

procurement of balancing maybe reduced in the future by improved forecasting of wind and improved intraday trading.

Our conclusion is that shared procurement of balancing resources is expected to yield substantial benefits. The exact height of these benefits however is hard to quantify especially for future markets.

### *Capacity calculation and congestion management/ remedial actions*

For capacity calculation as well as for congestion management the mutual impact of the systems in different areas should be considered to manage loop flows and transit flows as good as possible[53].

Both Coreso and TSC applaud the benefits of a coordinated approach in executing these functions, and loudly advocate a coordinated approach[54]. Improvements are mentioned such as IT infrastructure, Common Grid model, integration of capacity calculation, optimisation of security assessment, and common DACF and IDCF processes. In fact, this form of coordination is a form of centralised and integral approach. However, it is noted that further improvement can be obtained. The current type of coordination has grown organically. As such it is a form of TSO coordination (or cooperation) which tries to meet the EC objectives by means of a bottom-up approach. This implicates that boundary conditions from all TSOs involved are included which reduces the freedom for the coordination, leading to limited efficiency gains. In a centralised approach in which, except for abovementioned functions, policy making and policy implementation also reside, boundaries conditions can be dealt with in an integral way which creates more freedom for coordination, thus leading enhanced efficiency.

For capacity calculations as well as congestion management, free-riding and spill-over effects due to network externalities in AC networks seem the main underlying reason for coordination and centralization at a higher governance level. One example of capacity calculations is the introduction of the flow-based method in CWE region, with centralized, hierarchical computation of power transfer distribution factors (PTDFs). Examples for congestion management are the Denmark - Sweden case study in 2006 with intervention of the EC as well as the recent ACER opinion on splitting one integrated bidding zone for Germany and Austria in two separate zones.

### *Adequacy assessment*

The cost for generation adequacy per country will increase due to more pronounced uncertainties and fluctuations. For adequacy assessment economies of scale due to sharing of resources over wider geographical areas seem to be most prevalent. An example of a regional adequacy assessment is provided by the Pentalateral Energy Forum[55].

If despite the sharing of resources in the region, adequacy is not fulfilled, then an integral procedure can be invoked based on prevailing regulations valid for the concerned region, to procure reserve from neighbouring regions, or to evoke a plan for involuntary load shedding as last resort measure.

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[53] ACER opinion No 09/2015 of September 2015

[54] P. De Leener, "Operational Coordination of Interconnected Electricity Networks – the way forward: "RSCIs", EU Sustainable Energy Weeks 2015, June 16th 2015

[55] Pentalateral Energy Forum, Support Group, Generation Adequacy Assessment, March 2015

### 5.2.3 Quantitative insights related to centralisation/ integration of LT Network Planning and System Operations

Insights from several previous studies (e.g. IEA, 2014; Booz & co., 2013; Siemens, 2013; Mott-McDonald, 2013; ECF, 2011) have covered potential benefits of alternative approaches to system planning and operations. Conclusions from these studies can be used to provide more insight into quantitative benefits related to the improvement potential in Network Planning and System Operations functions, such as: capacity calculation, congestion management, adequacy assessment and balancing.

The conclusions we mention here are based on these reports and must be regarded as indicative concerning the added value of a pan-European, integral approach to planning, capacity allocation, balancing and congestion management/ re-dispatch. The translation of figures from individual countries or regions to the overall European potential is also done in an indicative manner: the benefit per EUR is multiplied by the projections for power generation in Europe in 2030, which would be about 3800 TWh according to the Booz & Company report.

- The overall benefits of integration resulting from market coupling, generation adequacy, balancing and coordinated RES investments are estimated to be 13.6 EUR/MWh. This would add up to 51.7 Billion Euro per year in 2030
- Better use of low cost generation and coordinated RES investment together count for 82% of this benefit. With optimum planning (of RES and networks) Europe could save 11.2 EUR/MWh (42.6 BEUR/a) out of 13.6 EUR/MWh total potential benefit from integration. This benefit could be reached by coordination only if all parties (are able to) accept and implement the optimum solution that is determined in a coordinated way. The other 2.3 EUR/MWh or 18% origins from market coupling (0.8 EUR/MWh, 3.0 BEUR/a or 5.9%), generation adequacy (1.4 EUR/MWh, 5.3 BEUR/a or 7.4%) and balancing (0.1 EUR/MWh, 380 MEUR/a or 0.7%).
- Benefits of coordination with respect to re-dispatch cost in Germany are 0.23 EUR/MWh. When taking demand side participation into account this benefit drops to 0.05 EUR/MWh. For Europe this would respectively mean 874 and 190 MEUR per year in 2030.
- Centralisation of adequacy assessment enhances the use of cross border connections at critical moments, resulting in an overall less required generating capacity in Europe. The enhancement is expected to increase with increasing variable renewable energy in the system. The IEA mentions a benefit of 1.4 EUR/MWh based on the study of Booz & co. The Consortium made a quick assessment based on coincidence of peak loads and a conservative estimate of economy of scale of power systems. This assessment showed an advantage of 0.7 EUR/MWh. More sophistic calculations are expected to show higher values.
- ENTSO-E has estimated the cost of a 20 GW load disconnection during a large brownout to be some 800 M€ per hour; this provides quantified insight into the importance of optimised Emergency and restoration efforts with central coordination of locally required efforts (described in 5.1.3).

# 6 SYSTEM OPERATIONS TARGET MODEL 2020

This chapter describes the further development of a target model for the functions related to LT Network Planning and SO before RT. These are discussed in terms of a different positioning of authority due to centralisation, options for governance and geographic division of particularly the functions related to SO before RT.

The conclusions with respect to the target model build upon the insights with regard to centralisation of functions, as discussed in chapter 5. In general, the proposed target model is aimed at optimization towards the IEM goals of ensuring security of supply, facilitating the market and effectively integrating RES. The identified requirements for 2025 (as deducted from the challenges identified by ACER and described in chapter 3), and current obstacles/ barriers from chapter 4, can be used to reflect upon development goals and benefits, more specifically.

## 6.1 Concluding on a target model

To eliminate impacts of geographical borders that more or less obstruct the further integration of wholesale markets (or at least: that make further integration difficult), SO before RT should be integrated as much as possible across (larger) geographical areas. A harmonized operational framework is one of the first pre-conditions to further align between TSOs and their operational frameworks, creating the operational pre-conditions to integrate functions. This harmonization of operational practices is foreseen to some extent in the newly drafted SO guideline[56]. Further regulatory harmonization is also required to further shape the conditions for successful integration. Although the regulatory harmonization is not the focus of this report, we provide suggestions that could help in this, when discussing governance options in 6.3.

Considering the foreseen benefits for the different functions (highlighted in section 5.2) resulting from centralisation, the Consortium concludes on a target model for 2020 that is fit for the situation in 2025 as well, in the following.

### 6.1.1 Target model 2020

Targeting the requirements for 2025 and moving from today's situation, the target model for 2020 is to erect Regional Operational Centres (ROCs) throughout Europe in which the functions are centralised, thereby centralizing authority over the functions across larger geographic areas. The following features are highlighted:

- The aim is to remove national borders between countries as much as possible by operating them as 'normal' connections within the control area of a ROC. The foreseen regional security coordinators (RSCs) can serve as a basis to further develop the ROCs
- Both LT Planning and the long-term adequacy assessments should be executed at pan-European level, coordinating the developments in the geographic regions of the different ROCs
- Further insights on options for governance and regional division, are discussed in sections 6.3 and 0.

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[56] 'establishing a guideline on transmission system operations' (subtitle), European Commission, version of 6 October 2015

Figure 8 illustrates the target model, showing the involved entities, voltage levels, operational time frames, functions, and the main operational aims[57] in the different time frames. Note that the RSCs are renamed to Regional Operational Centres (ROCs), because their role stretches beyond the issue of security: they are also aimed at better facilitating the market and the efficient integration of RES. Also note that current TSOs will maintain a significant role in specifically real-time operations, to maintain the safety and secure operation of the local (national) transmission systems.

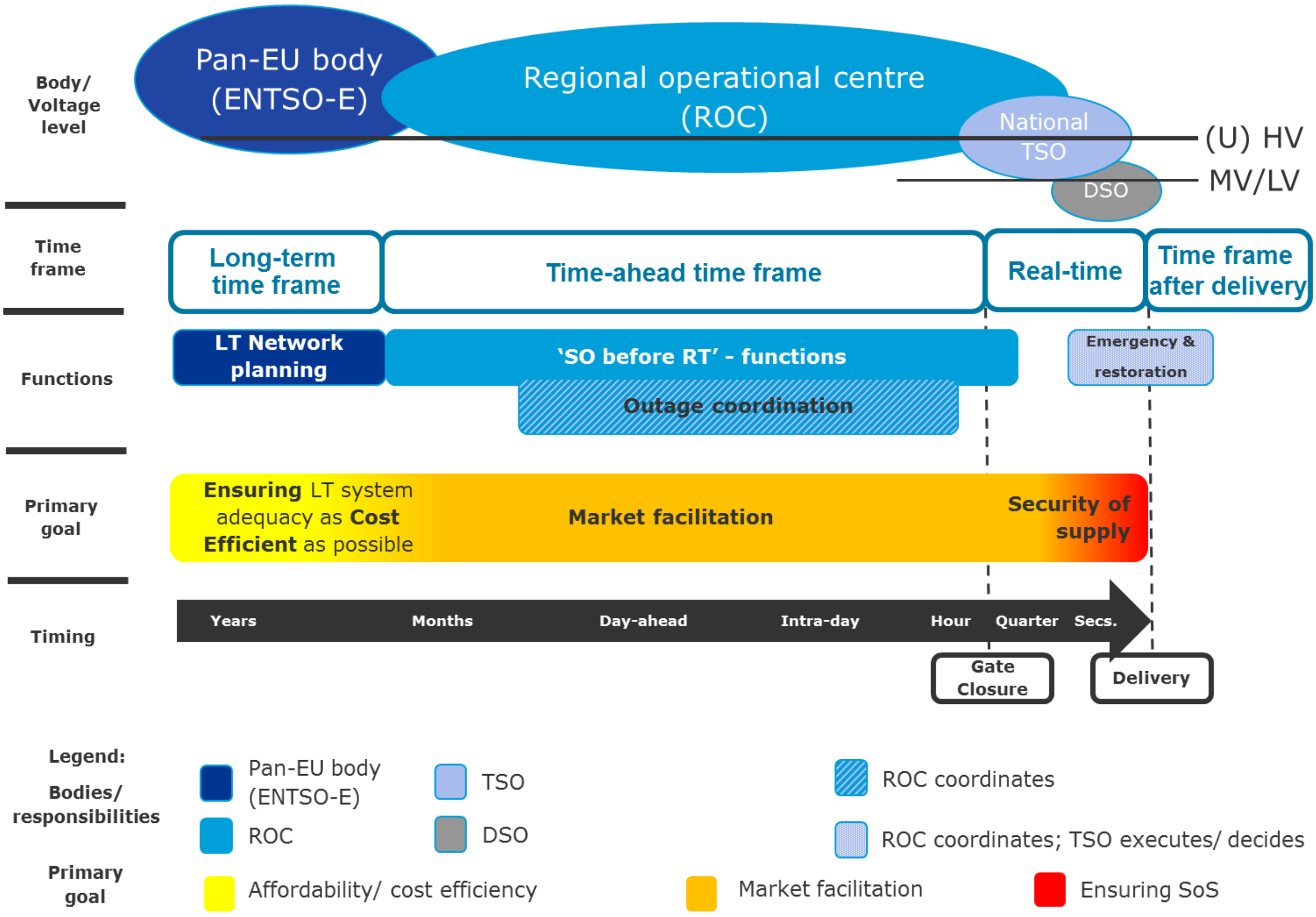

*Figure 8 Graphic representation of TM 2020[58] and legend (Source: DNV GL)*

## 6.2 Authority over the functions

The foreseen pathway of transmission system operators is to establish centralisation of a selection of SO functions by forming Regional Security Coordinators (RSCs).

Important characteristic of the RSCs is that they have an advisory role, with decision power still residing at the national levels. As mentioned in previous chapters 4 and 5, the current set-up incorporates the continuing risk of national decisions resulting in negative externalities

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[57] Although each of the three aims highlighted in this figure (Security of supply, market facilitation and cost efficieny) plays a role in decisions made in every timeframe, their (order of) importance more or less shifts depending upon the particular timeframe and operational state of the system

[58] Pan EU body is further elaborated in the section covering ‵ Governance’ (6.3)

and overall sub-optimisation. This can be prevented by integrating the authority over the SO before RT- functions to the ROC. In the following, we provide examples of centralising/ integrating authority across larger areas, both from Europe and the US.

Related to the issue of where to place authority, is the question: who owns the assets (and maintains them)? The Consortium has not focussed on this issue but recognises that it needs to be resolved before proposed regional operational centres (ROCs) can effectively manage the systems. Part of the solution to these issues could be in carefully designed and harmonised tariff components and via harmonised structures / processes to efficiently deal with e.g. outage management of assets that are owned by national TSOs.

### 6.2.1 European developments

Considering the historic development of current TSOs, integration of operations is not a new thing. The power grids in e.g. Spain and the Netherlands were operated in the past by multiple smaller (regional) entities that have merged to form the current TSOs in these countries. This is illustrated in the following text box, describing the cases of historic developments in Spain and the Netherlands.

**Historic integration of transmission system operations in Europe**
The integration of transmission system operation across geographic regions is not a new concept. Historic examples of the centralisation of system operations into integrated centres are provided by historic developments in Spain and the Netherlands.

**Spain**
Red Electrica was the first company in the world solely dedicated to transmission system operation. The company was created in 1985, taking over control of the transmission network from (previously) vertically-integrated companies involved in generation and supply of electricity throughout the different regions of the country. Red Eléctrica describes the 1990s as the 'years of consolidation' in which the Company faces numerous challenges: taking control of the acquired HV grids, the development and expansion of the transmission grid, the signing of several electricity supply agreements with neighbouring countries, the development of optical fibre and the Spain-Morocco submarine interconnection, the first between two continents. Furthermore, two main central control centres were put into operation (a main one, and one with a back-up function) in Madrid, disbanding the former regional control centres.

**The Netherlands**
In 1949, the regional utility companies in the Netherlands joined forces to establish the Association of Electricity Producing Companies (Samenwerkende elektriciteitsproductiebedrijven, SEP). SEP became the manager of the national interconnecting grid, and is responsible for deploying power plants in the most economically efficient manner. SEP is TenneT's predecessor in the area of grid management. Ultimately, in 1998, the New Electricity Act in the Netherlands establishes TenneT as the independent manager of the Dutch national transmission grid.

Sources: descriptions of Red Electrica and TenneT's history on http://www.ree.es/en/about-us/ree-2-minutes/our-history# and http://www.tennet.eu/nl/about-tennet/organisation/history.html and descriptions of the national control centre in Spain on: http://www.ree.es/en/activities/operation-of-the-electricity-system/electricity-control-centre

Considering the current path of policy makers and system operators, the harmonisation is promoting more and more alignment between TSOs in Europe, increasing potential benefits of centralisation. This statement is further supported in other publications about the subject, e.g. in a recent paper by S. Fresa: "*While it is true that research points to decentralisation as the best system to represent the specific needs of different regions, centralisation will yield higher* *benefits when (i) there are great interregional externalities and (ii) the different regions are relatively homogenous (Oates, 1972 and Lockwood, 2004)."*[59]

### 6.2.2 System Operation in the US

In order to understand better the implications of the target model proposed in this report, it can be useful to look at how transmission system operations are conducted in other areas of the world. In Appendix A, a review of system operations in the Western US is performed in order to understand whether any lessons can be learned from regions where aspects of system operations are carried out on much larger geographical areas than in Europe.

It was observed that Independent System Operators (ISOs) in the US show strong parallels to Transmission System Operators (TSOs) with respect to LT Network Planning and SO before RT. It is not uncommon that imports and exports over connections between ISO regions is utilised for participation in both energy and ancillary service (balancing) markets, mirroring the cross-border flows which occur increasingly throughout Europe, driven by various cross-border initiatives and guidelines.

Interestingly, CAISO (an ISO in the Western US) has examined the possibility of integrating its grid with that operated by PacifiCorp to form a single regional ISO with one regional marketplace to take advantage of the efficiencies gained by planning resources for a single system, rather than multiple systems[60]. The study concluded that such a move would result in significant cost savings ($3.4 billion to $9.1 billion over a period of 20 years) as well as enabling greater integration of renewables.

In Appendix A, it can also be seen that the role of Reliability Coordinator (undertaken by Peak Reliability in the western interconnection area of the US) shows similarities to that of the RSC in Europe. Peak Reliability monitors the whole of the Western US system (in real-time) and leverages its insight to ensure overall system reliability. Nonetheless ISOs, like TSOs, utilise their own control centres to monitor their own particular region (within the Western interconnection area).

## 6.3 Governance of the target model for 2020

The question now is how to organise in terms of wider governance? Which actors and institutional mechanisms need to be put in place? And what are the corresponding responsibilities?

With a new role for regional system operators and a continuing need to harmonise regulations and practices throughout Europe for further development of the IEM, alterations in the governance of SO are also required. This is particularly important to be able to safeguard an overall focus upon Europe-wide consumer interests. For example, by ensuring the further development of competition among existing market actors and opening up/ removing barriers

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[59] "Multilevel EU governance in energy infrastructure development - A New Role for ACER?", working paper by S. Fresa. Prepared in relation to the conference: "The 2020 Strategy Experience: Lessons for Regional Cooperation, EU Governance and Investment", June 2015

[60] https://www.caiso.com/Documents/WesternGridIntegrationCouldProduceSignificantCostSavings-EnvironmentalBenefits.pdf

for new (often smaller) entrants into the market. Of course, this should all be done within a set of clearly defined, yet harmonised security of supply rules.

Within the governance set-up, there should be a clear distinction between a legislative, executing and judicial body to ensure proper functioning of the sector.

### 6.3.1 Involved Actors and their responsibilities

The parties that need to be involved in the governance of SO in TM 2020, are:

- EC to formulate general energy policy and directives[61] based upon its legislative power
- European regulatory body (current ACER) with the judicial power to independently check the formulation and execution of methodologies, processes and procedures in line with the general policy
- Regional centres (RSC) to execute legally prescribed tasks according to the formulated methodologies, processes and procedures; responsible for execution
- European entity (current ENTSO-E) for development and implementation of methods and tools for LT planning and SO. In consultation with ACER (who sets up guidelines by request of the EC) this body develops the framework (e.g. grid codes) for execution of the tasks by regional SOs and ensures overall alignment between them, and with national SOs.

The European entity for the development and implementation of methods and tools (current ENTSO-E) is responsible for development of the way of working of the foreseen regional operational centres or ROCs in line with guidelines and/ or regulation. This is then monitored and enforced by the regulatory body (current ACER).

### 6.3.2 Required change to current structure

Considering the development of more centralised and integrated SO in Europe in line with the Target Model for 2020, it is required to install a judicial party that has stronger mandates in terms of enforcing targeted developments of the sector.

If the RSCs are developed into integrated ROCs, current ACER is not in a strong position to enforce required development, because it is only entitled to issue (non-binding) opinions and recommendations (including guidelines by request of EC and development of related network codes in consultation with ENTSO-E), and binding individual decisions in case national regulatory authorities (NRAs) cannot reach agreement on cross-border issues[62].

Taking the situation with regional SO in the TM 2020, these current roles for ACER will be insufficient to monitor and enforce development in the proposed direction[63]. With regards to monitoring and particularly enforcing required developments, currently the NRAs are responsible within their own country borders. When moving to a regional sector organization, various NRAs would be involved. Under the assumption that regulation will be harmonized more and more, NRAs from different member states may more easily agree on joint control and enforcement for a region. However, in the Consortium’s view it will be more straightforward in terms of efficiency and Europe-wide harmonization (more clearly enabling

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[61] 2015 Management Plan, EC – DG ENER, 5 August 2015

[62] Source: http://www.acer.europa.eu/The_agency/Mission_and_Objectives/Pages/Acts-of-the-agency.aspx

[63] This point was raised in various interviews with industry stakeholders, including representatives from the generation companies and TSOs/ ENTSO-E

further centralization and integration of SO in the long-run), to strengthen the role of a body, such as current ACER. That particular body should be better equipped to monitor and enforce required developments, aiming to improve market facilitation and ensure long and short-term security of supply in a set-up with regional integration of SO. One way of doing this is by shifting (part of the) powers (and people/ representatives) from the NRA's to current ACER. For example, this can include the power to control the development of (regional) network tariff components that are related to an ROC's operations. The need for stronger mandates for the current regulatory body (ACER) was raised in various interviews with industry stakeholders, including representatives from TSOs/ ENTSO-E and the generation companies. This will be necessary to efficiently drive forward the required developments on regional/ pan-European scale, largely surpassing the national reach of NRAs.

For possible alternatives to this set-up, we refer to Appendix A and B, which provide more insight into the governance structures of the European aviation industry (EUROCONTROL) and power system planning and operations in the Western US. Particularly the developments in EUROCONTROL concerning changes in the 'Committee of Management' aimed at facilitating more efficient decision-making may be a useful reference. Using this to reflect on future governance of transmission system operations, such a set-up (with more autonomous decision-making for the Director- General of the judicial entity – see appendix B) may be beneficial for efficient decision-making. But, on the other hand, this could increase issues with the implementation of plans because of reduced support for decisions among national representatives that have a severely reduced impact on decision-making.

## 6.4 Geographic division

The RSCs in the current draft of the system operations guideline (EC) are not explicitly linked to designated geographical areas; this is left to the system operators coming together (obligatory) to form a coordinated ('regional') group. However, because the borders in the electricity system can be removed (no need to consider them as cross-border interconnections) when system operations is integrated across larger geographic regions, and applicable regulatory frameworks are harmonized, it is important that integrated regions with centralized functions are formed across neighbouring countries.

This is necessary to be able to facilitate further development of integrated wholesale markets, based upon harmonized market frameworks (especially gate-closure times and SoS-requirements), and direct physical grid connections.  Key question now is: what should be the extent of a region in which functions related to SO before Real-Time (see Table 3) can be executed centrally and in an integrated manner?

When discussing the geographic size of regions for centralisation of the SO before RT-functions, most straightforward is to consider the current synchronous areas as designated regions. There is however, a difference in considerations related to the geographic sizing of regions between the smaller synchronous areas in Europe, and the much larger, continental part of Europe.

### *Smaller synchronous areas*

Towards 2020, the centralisation of SO before RT- functions should be, or is already, the case within the synchronous areas of smaller size: Nordic, GB, Ireland and the Baltic states. Towards 2020, these smaller areas could even be further integrated (initially Baltics and Nordic in the north, and GB and Ireland in the west) to make further integral optimisation across larger regions possible. With regard to this point we also refer to the assumptions, criteria and rationale underlying our reasoning in 6.4.1.

### *Continental Europe*

For the synchronous area spanning continental Europe, the regional scope is much larger than in the smaller areas, and also much larger than for ISOs in the US (used as reference by ENTSO-E[64]). Although we want to be ambitious in defining regional system size, we want to prevent an 'overshoot' in sizing and/ or complexity, with possible negative consequences for security of supply and affordability. Particularly, because this issue has not been assessed in detail, and in combination with the centralisation of all the functions related to SO before Real-Time. With this in mind, we point out the assumptions, criteria and rationale that are used in further reasoning about a regional division (6.4.1).

### 6.4.1 Assumptions, criteria and rationale underlying our reasoning about the geographic division

The following assumptions, criteria and rationale form the basis under our further reasoning about the regional division of Europe.

### *Assumptions*

- There are no barriers concerning IT-systems – given the current and (near) future state of developments these impose no limitations on sizing
- Any obstacles/ barriers with regard to centralized and integrated application of methods used to execute the SO before RT-functions, can be overcome – any required development and/ or adjustment of required software tools can be done relatively quick
- Complexity is determined by the number and diversity of market actors and the size of the transmission grid
- Any political barriers are not taken into account

### *Criteria*

The size of a region is determined by:

- Controllable complexity; now and in the future (future-proof)
- Options to control the risks related to large disruptions (black-outs)
- Vulnerability of the system and the extent to which this can be reduced.

### *Rationale*

We are aware of the fact that these assumptions and criteria cannot be applied in a straightforward and objective manner. They are however mentioned here explicitly to provide us with input for a well-considered regional division. But they are also for consideration by others, particularly the ones that are professionally involved in any discussions related to the issue of geographic division related to system operations. Because in principle, it can be checked to what extent the regional division that is discussed in the following paragraphs, fits within the above-mentioned criteria.

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[64] Policy paper Future TSO coordination, ENTSO-E, 2014

### 6.4.2 Considerations related to proposal for division

In the following, we highlight considerations that we deem important for the geographic sizing of regions in continental Europe. In addition, an initial division is discussed, building on these considerations and a recent proposal by the European Commission for regional sizing of TSO coordination[65].

***Current size of regional initiatives as reference***

The current size of the larger RSCIs (CORESO and TSC[66]) in Europe already spans across major parts of continental Europe. We consider this to be a good indicator for the fact that increased coordination and ultimately centralization/ integration of the SO before RT-functions across (at least) similar sized areas, is possible by 2020. Although in comparison, the functions and related responsibilities executed by the centralised ROCs will be more extensive, these can organically develop from current RSCIs and upcoming RSCs, to optimise SO before RT towards the goals of the IEM.

***Significant electrical interdependencies and their integral optimisation***

An important factor with regards to the regional division and the sizing of regions in continental Europe is the fact that the electrical interdependencies throughout the continent are large, particularly in and around the central parts of the continental system (i.e. Germany and surrounding countries). In the current system, these interdependencies have significant effects related to the so-called loop and transit flows. To ensure efficient dealing with such interdependencies and related effects through integral optimization, we advocate the integration of SO before RT-functions across areas covering the affected parts. This implies for example the centralisation of these functions across the CWE and CEE-regions.

### 6.4.3 Proposed regional division

Illustration of a regional division of centralised SO functions in line with the considerations described above, is provided in Figure 9. It shows a proposed division in (still) coordination regions for TSOs, as recently presented by the European Commission. This division accommodates the integration of currently defined Capacity Calculation regions (CCRs) into larger regions, allowing for their integral optimization with regards to the functions in the SO before RT-timeframe.

We consider the division in regional centres (including a back-up centre) in the designated areas (1, 2, 3, 4, 5) to be a good reference for regional division in the target model set-up. When developing integrated /centralised SO in line with the target model 2020, the need for sub-centres (a, b) is less obvious, because this would introduce/ maintain an additional layer in the target model and the processes involved in SO before RT.

The proposed regional division is thus to centralize/ integrate SO before RT within the 5 regions. A more ambitious division towards 2020 could even be to also include one or more of the regions 2, 3, 4 and 5 into region 1. With respect to this consideration we point out the fact

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[65] Proposal for sizing of regional TSO coordination, presented at the latest European Electricity Regulatory Forum in Florence, 9 October 2015

[66] To illustrate: TSC is constituted of the TSOs of ten countries: Austria (APG), Croatia (HOPS d.o.o.), Czech Republic (ČEPS), Denmark (Energinet.dk), Germany (50Hertz, Amprion, TenneT Germany, and TransnetBW), Hungary (MAVIR), Poland (PSE), Slovenia (ELES), Switzerland (Swissgrid) and the Netherlands (TenneT Netherlands).

that the TSOs of the UK (region 3), Portugal (region 4) and Italy (region 5) are all members of current CORESO, which includes TSOs from France, Belgium and Germany (region 1).

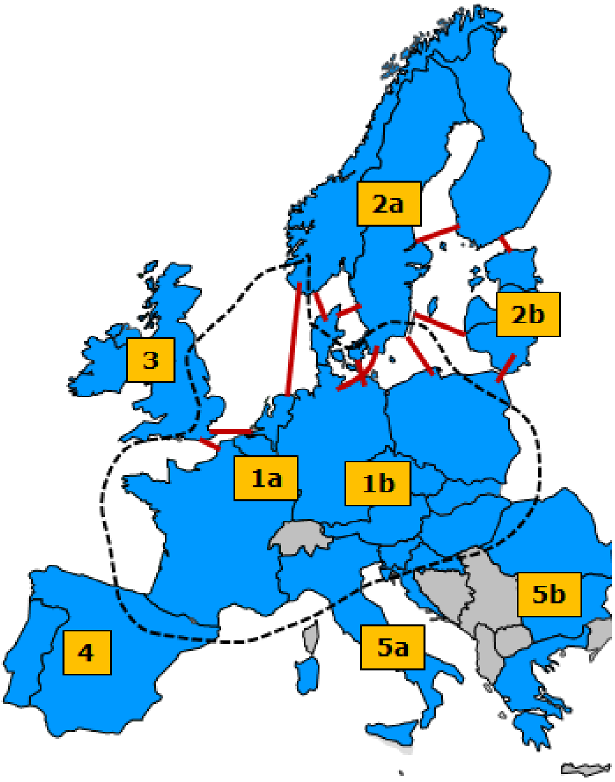

*Figure 9 Geographic division between TSO coordinating centres, as presented and discussed by EC at latest European Electricity Regulatory in Florence*[67]

*(1 = Regional centre, 1a = Regional sub-centre)*

### 6.4.4 Future development of regional boundaries

Of course the regional boundaries should not be subject to continuous adaptation, but the goals included in continued development of the IEM should be a clear target on the horizon: it could be that flows in the grid, or the grid itself changes such that sticking to the defined regional system boundaries significantly affects social welfare in (one of) the regions (e.g. through increasing inefficiencies in network use). In that case, regional boundaries should be re-considered and possibly dismissed and/or re-defined if benefits proof to be significant.

***Outlook***

In the long run, currently foreseen beyond 2025, further centralization/ integration of SO before RT-functions will be possible. Considering the functions and the benefits related to their centralisation, combined with practical insights and expert views on the feasibility of centralisation across Europe, we see the following outlook for further development of the Target Model for 2020:

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[67] Source: EC presentation at the 29th meeting of the European Electricity Regulatory Forum, Florence, 9 October 2015. Picture provided by project's steering group

Ultimately, the SO before RT- functions could be centralised across all the synchronous areas, or even pan-European, to optimise their performance aimed at improved overall market facilitation, RES-integration (absorption) and ensuring the security of supply.

### 6.5 Indicative implementation steps

The focus in this section is to identify high-level implementation steps from current SO to the target model. This is done by providing an overview of high-level implementation steps in a process that is tailored towards target model realisation in 2020.

The current draft of the renewed network code[68] serves as the 'point of departure' for the high-level implementation steps. This draft already accommodates significant alignments and harmonisation of practices between current TSOs. Although the issue of harmonisation of policies and operations/ operational principles was considered a given in the development of the target model, the process(es) should be accounted for in the pathway towards implementation.

Aimed at implementation of the target model within 5 years (ready in 2020), an indicative schedule with high-level implementation steps is shown below. It requires actions from TSOs, regulators and policy makers.

- 3 years for regulatory harmonisation across Europe;
  - Particularly the harmonisation of (national) security of supply guidelines and gate closure times to align the real-time timeframes
  - Further adjustments of (national and European) Energy Law, installing ROCs as the parties responsible for SO before RT-functions throughout a region;
- 1 year (in parallel to the regulatory harmonisation) for harmonisation of operational principles and alignment of practices;
  - Particularly the harmonisation of operational principles such as standardised assessments on how to increasingly facilitate markets
- 2-4 years for the implementation of necessary organisations and the required full-scale integration of inherent tools and capabilities within the ROC and governing organisations (e.g. tool development, personnel training).

As a reference and example, Figure 10 provides an indicative overview of the process and related duration of phases, in network code development. A similar process will be required to initiate the realization of the target model.

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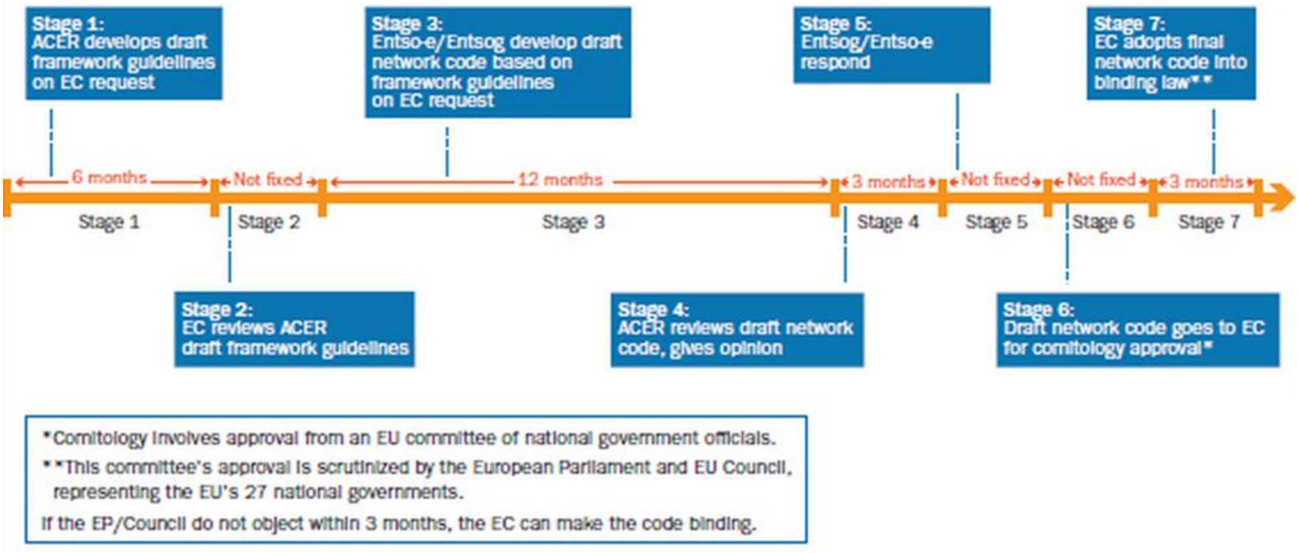
[68] Establishing a Guideline on Transmission System Operation (Draft version), EC, August 2015



*Comitology involves approval from an EU committee of national government officials.

**This committee's approval is scrutinized by the European Parliament and EU Council, representing the EU's 27 national governments.

If the EP/Council do not object within 3 months, the EC can make the code binding.

*Figure 10 Indicative schedule for network code development in Europe (Source: Platts)*

# 7 APPENDIX A

## System Operation in the US

When discussing system operation in the US, there are multiple organisations interacting with each other in any given region, which are useful to mention:

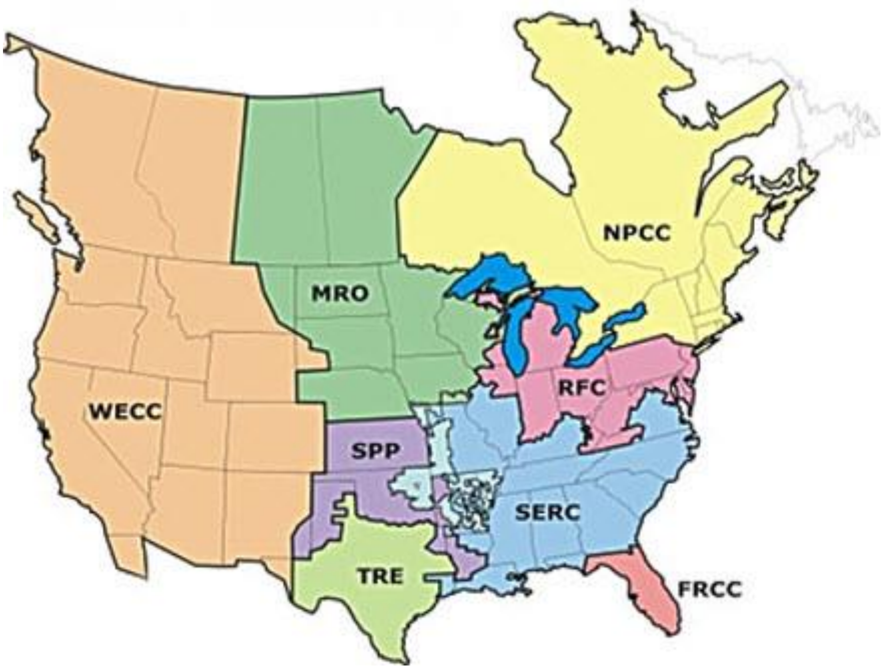
- Independent System Operators (ISOs) /Regional Transmission Organizations (RTOs)
- Regional reliability councils
- North American Electric Reliability Corporation (NERC)
- Federal Energy Regulatory Commission (FERC)/

### Independent System Operators (ISOs) /Regional Transmission Organizations (RTOs)

These are the organisations responsible for coordinating, controlling and operating the power system for a given region – including balancing activities and market operations. In America there are 7 ISOs and 4 RTOs. The difference between an ISO and RTO are small and for the purposes of this report are (mostly) negligible. However it should be mentioned that the operation of ISOs is contained within a single state, in contrast to the 'multi-state' operation of RTOs.

### Regional reliability councils

Regional reliability councils are responsible for monitoring reliability of the power network and ensuring compliance of relevant reliability standards for their respective regions (often spanning multiple ISOs/RTOs). They also have the ability to issue directives to ISOs to ensure system reliability. There are eight such entities in America, as seen in the figure below.



*Regional reliability councils in America (Source: EIA)*

## **North American Electric Reliability Corporation (NERC)**

NERC is a self-regulatory organisation responsible for ensuring the reliability of the power system throughout America, through the establishment and enforcement of reliability standards (which must then be enacted upon by the regional reliability councils). Other activities of NERC include assessing network adequacy on an annual basis via a 10-year network forecast (as well as summer and winter forecasts).

## **Federal Energy Regulatory Commission (FERC)**

Of the many responsibilities of FERC, most relevant to mention here are its responsibility to monitor and investigate energy markets, and to regulate the transmission and wholesale sale of electricity in interstate commerce. FERC may also instigate orders which ISOs must adhere to e.g. FERC Order No. 764 requiring ISOs to offer intra-hour transmission scheduling.

## The Western Electricity Coordinating Council (WECC) & Peak Reliability

In the context of this report, it is interesting to study the functioning of a regional reliability council in more detail. The Western Electricity Coordinating Council (WECC) is a prime example to focus on, with a geographical footprint equivalent to more than half of the United States. It is the only reliability council covering three countries; besides the fourteen Western US States it encompasses, it also covers two Canadian provinces and one Mexican state. Its members consist of not only ISOs, but many organisations representing different segments of the power sector – such as utilities (both investor-owned and municipal utilities) and industrial consumers. Membership is open to all entities interested in the operation of the WECC bulk electric system (i.e. the physical network making up the Western Interconnection).

In order to ensure a reliable bulk electric system to enable efficient functioning of electricity markets, WECC has four organisational goals[69]:

- ***"Regional Entity –*** *WECC is required by the U.S. Federal Energy Regulatory Commission (FERC) to monitor and enforce compliance with reliability standards by users, owners, and operators of the Bulk-Power System in the United States.*
- ***Credible Source of Interconnection-Wide Information –*** *WECC provides training, education, and information on key functions related to mandatory standards and compliance, as well as data, analysis, and studies relating to transmission system planning and renewables integration. WECC is a conduit for other data exchanges.*
- ***Western Interconnection-Wide Planning Facilitator –*** *WECC provides planning functions (transmission planning and integration of resources) and policy-related functions as requested by members.*
- ***Western Interconnection-Wide Regional Reliability Policy Facilitator –*** *WECC facilitates the identification of issues specific to reliability, creates an opportunity for discussion of the issues, and represents region-wide issues and policies at the state and federal levels".*

WECC is a non-profit organisation, and itself was formed as a result of mergers between different organisations over a number of decades. In 1967, the Western Systems Coordinating Council (WSCC) was founded by utility executives to promote reliability and facilitate coordinated planning of the power system for the Western US. Later, in 2002, WSCC was merged with two regional transmission associates (Southwest Regional Transmission Association and the Western Regional Transmission Association) to form WECC.

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[69] WECC System Operations Training Manual: https://www.wecc.biz/Administrative/System-Operations-Training-Manual-5-27-2015.pdf

In terms of reliability coordination, upon the recommendation of NERC in 1996 to establish security coordination centres and create regional security plans, the WSCC Security Process task force (which in 2002 became the WECC Reliability Coordination Subcommittee) was formed to act on the recommendations of NERC. This reliability coordination (RC) function was continued under various guises by WECC until 2014, when the RC function was separated into a separate independent company – Peak Reliability. This separation allowed the WECC Compliance unit to audit and review RC operations in the Western Interconnection.

Peak Reliability is therefore responsible today for RC of the Western Interconnection area in accordance with WECC and NERC Standards (with WECC playing a supporting role – but no longer that of the reliability coordinator). Peak Reliability's vision "*seeks to achieve the appropriate level of Bulk Electric System (BES) reliability at the least cost — considering all costs throughout the economy*"[70]. The organisations key functions include the following:

- Monitor the system to detect Reliability Standard violations, and provide an early warning of any risks to system stability/security
- Direct actions to be taken by other functional entities to mitigate problems
- Take the lead and coordinate restoration following major system emergencies.

The following table gives an overview of how various functions related to LT Network Planning and SO before RT are carried out by stakeholders in the US.

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[70] Peak Reliability: https://www.peakrc.com

| SO functions (LT Network Planning and SO before RT) | US model (with a focus on Western United States) |
|---|---|
| **Long-term planning** | Within WECC, the Transmission Expansion Planning Policy Committee's (TEPCC) responsibilities include:<br>- Conducting transmission planning studies;<br>- Preparation of *Interconnection-wide* transmission plans (i.e. between WECC and other bulk electric areas);<br>- Develop, implement, and coordinate planning processes and policy.<br>TEPCC's reports have included plans which consider 10- and 20-year planning horizons.<br>ISOs such as CAISO also perform long-term transmission planning (for their own transmission area). |
| **Balancing** | NERC establishes mandatory standards concerning power balancing (primary frequency response, automatic generation control etc.) which must be enforced by the reliability councils of the different NERC regions. For particular regions there may be slight variations introduced to these standards.<br>The ISO for a given state/area is responsible for facilitating the procurement of reserves whilst complying with the requirements of these standards. |
| **Capacity Calculation / Congestion management** | TEPCC's work includes planning studies which take into account transmission congestion and utilisation under different circumstances.<br>ISOs also take into account issues surrounding congestion management – particularly those issues occurring near real-time within their control area. |
| **Adequacy assessment** | NERC produces seasonal (winter, summer) and long-term assessments examining current and future reliability, adequacy and security of the different bulk power systems in the US.<br>ISOs also partake in this activity. |
| **Emergency and restoration** | Peak Reliability (the Reliability Coordinator for the WECC area) is responsible for coordinating and leading restoration efforts following any major system disturbance. |

# 8 APPENDIX B

## Governance in EUROCONTROL

A reference for the further development of governance could be EUROCONTROL, the European Organisation for the Safety of Air Navigation: the nature of air navigation can be compared to SO of the power system in the sense that an integrated assessment of flights over Europe is required, to plan the system (flight routes and times) before the actual flights take place. The governance set-up of EUROCONTROL is as follows:

- A Permanent Commission composed of (civil and military) representatives of the Contracting Parties (national governments), which is the supreme body of the Organisation responsible for formulating the Organisation’s general policy
- An Agency for the safety of air navigation which constitutes the organ responsible for the performance of the tasks prescribed by the Convention or entrusted to it, in pursuance thereof, by the Permanent Commission/enlarged Commission.

It must be noted that the EUROCONTROL Convention has been amended, but still awaits ratification since 1997. This is further illustrated in the textbox below.

The changes made to the Convention and the related adaptations in the governance structure, may entail valuable lessons in setting up an effective structure for SO in Europe.

The development of an effective governance structure requires a trade-off between sufficient representation at the regional level and an overall effective organisation of governance.

Although we assume that current harmonisation efforts will ensure much required harmonisation for the definition of a target model, there is no getting around the fact that (even in case of harmonised regulation and practices), SO concerns dealing with vital infrastructures of all the countries in Europe. This implies a need to form governance structures involving sufficient representation from these countries (e.g. from national regulators). Such a set-up could help to build support for realisation of a target model among current stakeholders.

**Governance in EUROCONTROL**

The European Organisation for the Safety of Air Navigation ("EUROCONTROL") is an Intergovernmental Organisation with legal personality under Public International Law. It counts to date 41 Member States. The Organisation was established by Germany, Belgium, France, the United Kingdom and Northern Ireland, Luxembourg, and the Netherlands through the EUROCONTROL International Convention relating to Co-operation for the Safety of Air Navigation signed at Brussels on 13 December 1960.

A Protocol Amending the 1960 EUROCONTROL Convention (referred to as the "amended Convention") as well as a Multilateral Agreement relating to Route Charges were signed in Brussels on 12 February 1981. Both instruments are still in force to date.

In terms of governance, under the regime of the amended Convention, the Organisation comprises two organs:

- **A Permanent Commission** composed of (civil and military) representatives of the Contracting Parties, which is the supreme body of the Organisation responsible for formulating the Organisation's general policy. The Permanent Commission approves all measures to be taken for the accomplishment of the Organisation's tasks. With regard to the Contracting Parties, the Permanent Commission takes decisions which are binding on the Contracting Parties and issues recommendations; with regard to the Agency, the Permanent Commission takes measures (e.g. amendments to the Staff Regulations, approval of cooperation agreements with States and international Organisations, etc.), gives directives, etc. Please note that for the purpose of establishing and collecting charges in accordance with the 1981 Multilateral Agreement relating to Route Charges, the Permanent Commission is named "Enlarged Commission".
- **An Agency for the safety of air navigation** which constitutes the organ responsible for the performance of the tasks prescribed by the Convention or entrusted to it, in pursuance thereof, by the Permanent Commission/enlarged Commission. The Agency is administered by a Committee of Management composed of Contracting Parties' representatives and by a Director General (co-management) (Statute of the Agency annexed to the amended Convention). The Committee of Management is named "Enlarged Committee" for the purpose of the 1981 Multilateral Agreement relating to Route Charges.

On 27 June 1997, 27 EUROCONTROL Member States signed the Protocol Consolidating the 1960 EUROCONTROL Convention as variously amended (referred to as the "revised Convention"). The ratification process of the revised Convention is not yet completed.

At the same time, EUROCONTROL Member States agreed on the early implementation of several provisions contained in the revised Convention. Accordingly, the Permanent Commission took a number of decisions which led to, for example:

- the establishment of the Provisional Council in anticipation of the Council foreseen under the revised Convention; all measures to be taken for the accomplishments of the Organisation's tasks are submitted first to the Provisional Council for adoption and then to the Permanent Commission for approval. The Provisional Council also advises the Permanent Commission on issues it deems necessary. It is composed of representatives of the Contracting Parties at the level of the Directors General for Civil Aviation; several delegates may be appointed to allow the interests of both civil aviation and national defence to be represented but each Contracting Party has only a single vote;
- the reinforcement of the powers of the Director General: to that effect, the Statute of the Agency has been amended by the Permanent Commission, in order to reduce the role of the Committee of Management to a minimum, thus allowing for an autonomous management of the Agency by the Director General.

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