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International Smart Grid Action Network (ISGAN)

Annex 6 : Power T&D Systems

FLEXIBLE POWER DELIVERY SYSTEMS:
An Overview of Policies and Regulations and Expansion Planning and Market Analysis for the United States and Europe

ISGAN Discussion Paper

Annex 6 Power T&D Systems, Tasks 1 and 2

December 2013

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An Overview of Policies and Regulations and Expansion Planning and Market Analysis for the United States and Europe

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Abstract: With the changing dynamics of electric grid systems around the world, decision-makers – both institutional and technological – are facing numerous new challenges to operating, planning, and expanding their systems.[1] New technologies are challenging conventional regulatory regimes and new policies and consumer demands are similarly challenging the currently available technologies. For example, as the demand for cleaner energy sources gains ground all over the globe, technological improvements are necessary to integrate large amounts of variable energy sources such as solar and wind into various electricity systems, while ensuring acceptable levels of reliability and security of the system. Similarly, as consumers engage more with electricity systems, demand profiles and consumer choice, among other demand-side elements, are also challenging our system, providing opportunities for demand-side management and related technologies. In this rapidly changing landscape, regulators and policy-makers must consider how consumer participation and new technologies interact with the market place.

This discussion paper from ISGAN Annex 6 Power Transmission & Distribution Systems Tasks 1 and 2 focuses on achieving flexible power delivery by examining the policies and regulations, as well as expansion, planning, and market analysis for the United States and Europe. This review

[1] Electricity systems integrate technologies, polices and markets across generation, transmission, distribution, and end-users.

looks at how policies and regulations have changed to accommodate new developments in the operation, planning, and market areas of each grid system. Additionally, it highlights certain efforts undertaken to better understand and implement the policy and regulatory changes in these processes as both the United States and Europe work towards achieving a modernized grid system, specifically including the increased deployment and use of smart grid technologies, e.g., synchrophasor measurement technologies, net metering, distributed generation, energy storage, advanced metering infrastructure.

About ISGAN Discussion Papers: ISGAN discussion papers are meant as input documents to the global discussion about smart grids. Each is a statement by the author(s) regarding a topic of international interest. They reflect works in progress in the development of smart grids in the different regions of the world. Their aim is not to communicate a final outcome or to advise decision-makers, rather to lay the ground work for further research and analysis.

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1 Executive Summary

THE HOLISTIC APPROACH TO SMARTER ELECTRIC SYSTEMS

ISGAN Annex 6 is working to establish a long-term vision for the development of smarter electricity systems. Flexibility, visibility, and understanding of grid operations are important characteristics that enable deployment of technologies to develop a more modern, smarter electric grid system that can securely, reliably, and resiliently adapt to the panoply of challenges it is likely to encounter in the coming decades. This effort will improve general understanding of smart grid technologies applicable to or influencing system performance, transmission capacity, and operation practices; accelerate their development and deployment; and, promote adoption of related enabling regulatory and government policies.

Addressing challenges such as changes in load profiles, electricity resources, disruptions, and development requires a systematic, holistic, integrated approach that considers not only the enabling technologies, but also the "rules of engagement" that facilitate their deployment. These "rules" include the laws and regulations that govern the electricity system, from generation to end user; the planning, operation, and "grid management" structure and implementation; and, the policy, market, and regulatory approaches employed or considered to enable achieving a smarter grid. As illustrated by Figure 1, across all elements of the "grid space" (outlined in red), it is also important to ensure efficient, reliable, and secure system operation as well as cost-effective system planning and expansion.

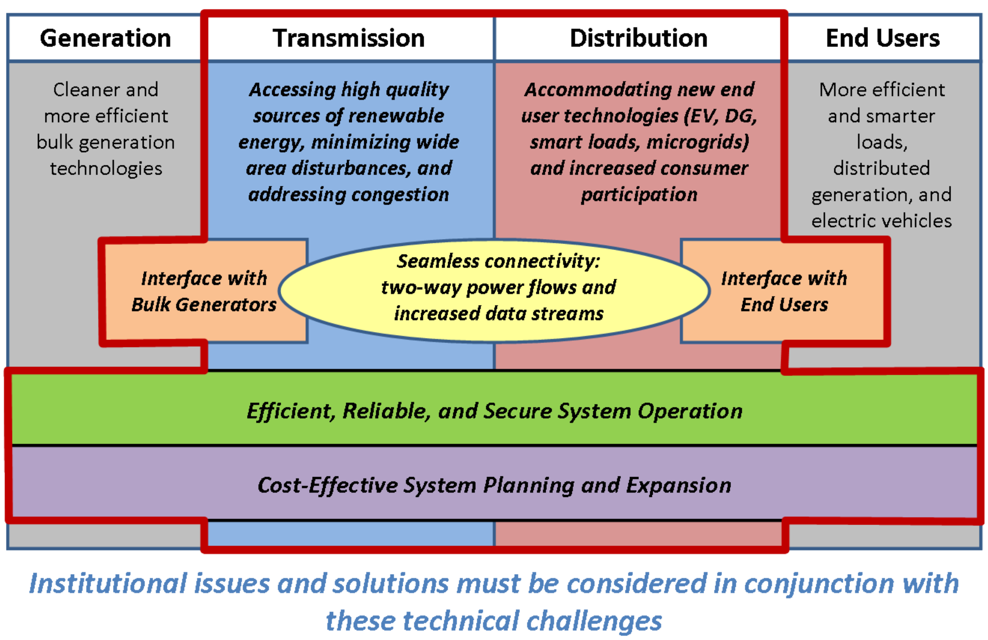

Figure 1. Grid space encompasses conventional elements as well as their institutions and other drivers (e.g., markets, policies, regulations)

The United States Electric System

The United States (U.S.) “grid” is a highly complex and dynamic system that operates in connection with Canada and Mexico (together comprising the North American grid). The U.S. electric system comprises three electrically independent networks—the Eastern, Western, and Electric Reliability Council of Texas (ERCOT) Interconnections—that are connected via direct current (DC) links (see Figure 2). This system is further divided into over 140 control areas responsible for balancing generation and consumption of electricity at all times. The U.S. electric system has no linear or singular operational or management structure.

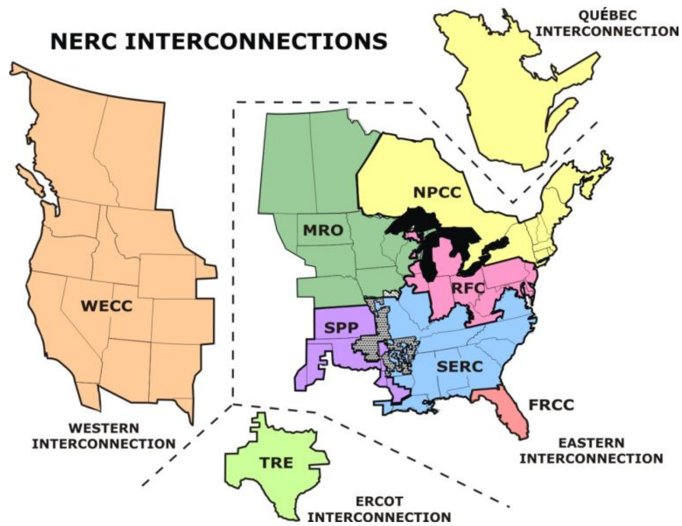

Figure 2. North American Electric Reliability Corporation (NERC) Regions across the North American interconnections

In the U.S., electricity markets and the electricity industry broadly have been undergoing major paradigm shifts over the past few decades. The introduction of open transmission access and restructured electricity markets in the 1990s has led to fundamental changes in ownership structures and planning and operational responsibilities. Because of the national scope of these issues, regional planning and cooperation among all levels of government and interested stakeholders have been encouraged by federal entities, including the U.S. Department of Energy (DOE) and the U.S. Federal Energy Regulatory Commission (FERC). One recent example of this is the DOE-funded Interconnection Wide Transmission Planning process in which five grantee-organizations within the three North American Interconnections in the U.S. have worked to analyze how best to approach the planning and build-out of their transmission systems moving forward.

The European Electric System

Power transmission in Europe is characterized by a high degree of interconnections and inter-area power exchanges, congestion, volatility, and diversity of operating conditions. The power system is subject to the thrust of pan-European market integration and the need to face the variability of renewables such as wind and solar from a system-wide approach, while guaranteeing reliability of supply. The European grid comprises five synchronous areas, 34 countries, and 41 transmission system operators (TSOs) (see Figure 3).

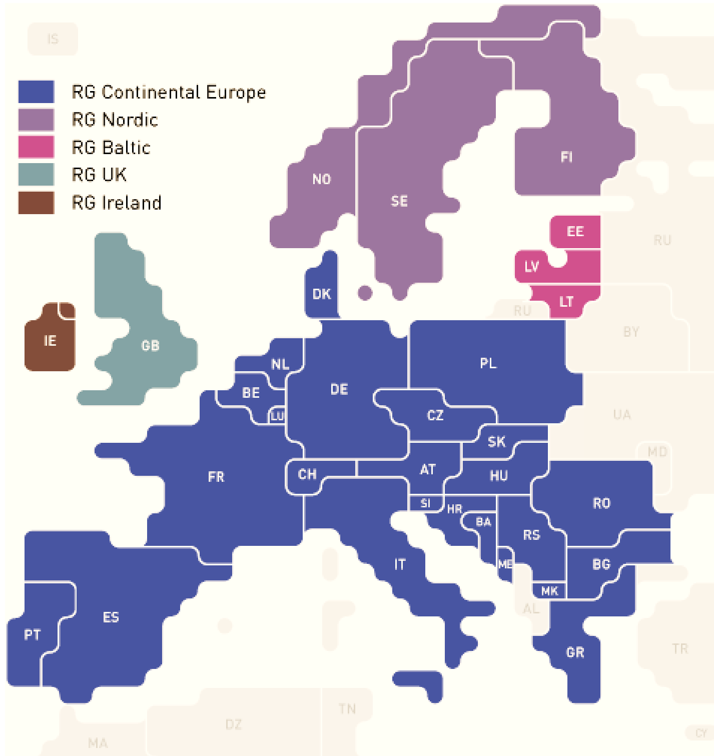

Figure 3. Synchronous zones in Europe

In recent years, electric power systems have been experiencing profound transformations. In the European Union (EU), issues concerning security of energy supply, electricity market restructuring, and environmental constraints represent key drivers for new trends that may have significant impact on the design and operation of the electric power system; this is particularly true for the transmission system. Moreover, and most critically, the European energy sector has been deeply changing as the EU member states decided in 2007 to lay down ambitious environmental targets to be achieved by 2020. Through these efforts, the European electric grids are on a critical path to meet the EU's climate change and energy policy objectives for 2020 and beyond.

Further issues faced by transmission planners nowadays are related to social and environmental constraints to the building (and in some cases even refurbishment) of transmission infrastructure. Aging European grid assets, increased penetration of distributed energy resources, and active demand will play a role in the power system and impact the upstream transmission. The period when generation was considered fully predictable and consumption fully stochastic is evolving to an era where generation becomes partially stochastic and, at the same time, the amount of controllable consumption rises. The combination of all these challenges requires a long and costly technical, market, and regulatory re-engineering process of the European energy system.

REGULATORY AND POLICY ENVIRONMENTS

In both the U.S. and Europe, there are many non-technical factors that drive or challenge the development of a smarter grid through deployment of technologies. Additionally, the hierarchy of governments and cross-border organizations add complexity to the already diverse challenges that are present in each electric system. Strategic measures taken by appropriate authorities can help to define the "rules of engagement" to better enable achieving a smarter grid.

United States Regulations and Polices – Past and Present

Traditionally, in the U.S., local electric utilities, municipalities, or cooperatives were granted a state-protected monopoly under the premise that insulation from competition was necessary to ensure reliable and cost-effective service. Beginning in the late 1980s and early 1990s, electricity regulators in some jurisdictions began experimenting with a deregulated market model. The unquestioned premise that the generation, transmission, and distribution of electricity, in order to operate effectively, must be protected by a legal monopoly no longer has universal agreement.

States and the federal government have separate but connected authorities in the electricity sector. The jurisdictional line between federal and state regulatory authority is not always clear. States have more flexibility within their borders to promote the public interest of both the state and federal governments and to determine how the energy needs of their citizens will be met, e.g., through renewable portfolio standard (RPS) programs. State public utility commissions (PUCs) are the primary regulatory bodies that govern the electricity sector within the borders of their states. PUCs are generally responsible for the retail rates of electricity and the siting of transmission projects. While the federal government is an important player in planning and building energy infrastructure, and can be a driver of innovation, most of the regulatory innovation in energy policy happens at the state level.

In the U.S., two federal entities have primary legal and regulatory jurisdiction over the electricity sector: Congress and the FERC. Congressional legislation has provided the legal authority for federal agencies to regulate and/or support innovation within the electricity sector. The FERC, with jurisdiction over wholesale transmission rates (among other authorities), has undertaken a series of orders to address some of the challenges facing the electricity sector, e.g., increased variable generation, transmission cost allocation, how regions of the electric system are managed, how electricity is traded, and how the electric system is operated and planned.

The overall regulatory framework for transmission planning and cost allocation is in a state of flux, influenced by the changing technological landscape. The FERC issued Order 1000 in 2011, building from previous FERC orders, with two primary objectives: (1) ensuring that transmission planning processes at the regional level are non-discriminatory, efficient, and cost-effective and (2) ensuring that transmission needs chosen via regional planning methods allocate costs fairly to those that receive benefits. Since the FERC issued Order 1000, states have been working to self-organize into qualified regions and submit plans to the FERC for review and approval. Some legal issues and challenges have arisen in connection with regional planning and cost allocation outcomes under Order 1000.

Many electricity markets operate within the structure of a regional transmission organization (RTO) or independent system operator (ISO). RTOs are voluntary associations of utilities that own electrical transmission lines interconnected to form a regional grid and that agree to delegate operational control of the grid to the association. There are six major

RTOs/ISOs in the U.S. that serve about two-thirds of the country's electricity consumers. Entities that do not participate in an RTO or ISO are accounted for under the North American Electric Reliability Corporation (NERC) "reliability regions." RTOs/ISOs play a significant role in overseeing the long-term planning for system operation needs and to coordinate operation of the transmission system.

Electric system infrastructure is often subject to regulation by other federal entities in the U.S. for environmental performance (e.g., generation and transmission/distribution emissions), environmental impact and historic preservation (e.g., for new transmission line construction), endangered species, and wetlands, to name some examples. Moreover, states often have similar regulations that must be complied with to obtain proper state permitting for new generation and transmission projects. These additional constraints add another layer of complexity to the planning and expansion of electric system infrastructure.

European Energy Policies – Past and Present

European energy policy has been based on three "pillars," namely increasing the generation from renewable energy and reducing CO_2 emissions (sustainability), guaranteeing security of energy supply (security), and integrating the European electricity market (competitiveness). In order to achieve these objectives, the transmission grid plays a central role within EU energy policy. In fact, a truly pan-European approach is needed for the planning and operation of electricity infrastructure, especially where a significant cross-border impact is concerned. In 2006, the European Commission (EC) issued the Trans-European Energy Networks (TEN-E) Guidelines document featuring a list of infrastructures recognized as priority projects of European interest. Notwithstanding some improvements in unlocking some TEN-E priority projects of European interest, the situation for the completion of such projects stayed critical.

In order to overcome this critical situation, the EC issued two additional communications in November 2010: (1) the first defined energy strategy in Europe towards 2020 targets and called for a step change in the way energy infrastructure and networks in Europe are planned, constructed, and operated and (2) the second set the creation of a pan-European methodological approach in prioritizing the projects of European interest as a key measure towards EU targets for 2020 and beyond.

To ensure timely integration of renewable generation capacities in Northern and Southern Europe and foster further market integration, four crucial priority corridors of the European power system were identified: (1) Offshore grid in the North Seas and connection to Northern and Central Europe, (2) Completion of the Baltic Energy Market Interconnection Plan, (3) Interconnections in South Western Europe, and (4) Connections in Central Eastern and South Eastern Europe. In addition to these four priority corridors, smart grid deployment and electricity highway development across Europe have been included as priority areas for infrastructure expansion towards 2020 and beyond. The realization that a potential pan-European supergrid is a complex process indicated that can only be considered in a long-term perspective (after 2020), as there are still several techno-economic, technological, regulatory, market, and socio-environmental issues that will have to be properly handled and solved over the years.

In view of fostering cooperation and harmonization in transmission planning and operation, as well as the dialogue between TSOs and institutions (primarily the EC and the regulating bodies), the EC promoted the creation of the European Network of Transmission System Operators for Electricity (ENTSO-E), the body of TSOs at the European level. ENTSO-E comprises 41 TSOs from 34 countries, some of which are not part of the EU.

An important contribution to the identification of common development according to EU objectives was given by the first (pilot) ENTSO-E Ten-Year Network Development Plan (TYNDP) 2010–2020, issued in 2010, extended then in 2012, and to be updated every two years thereafter.

TRANSMISSION OPERATION AND MANAGEMENT

Diversity of grid resources and operational strategies often add complexity to the grid. Understanding these factors and having appropriate visibility into their impacts on grid operation is paramount. Both the U.S. and Europe strive to achieve this through the deployment of smart grid technologies.

United States Electric System Operation

Operating and managing the grid is a multi-layered, complex system-wide task. Operation of the electric system does not happen unilaterally by a single entity, but rather is accomplished across a wide variety of organizations, from the state to the federal level, acting in concert across various functions. Moreover, the U.S. transmission system is managed across a variety of industry standards that vary according to jurisdiction. State and federal entities have jurisdiction over different aspects of electric system operation and management, primarily divided between transmission and distribution.

The distinction between transmission and distribution is one of size and scope. Transmission refers to the transport of electrons at high voltages from generating infrastructure to converting stations (substations or transformers) 100 kV or higher. In distribution systems, electricity is at much lower voltages; typically, the network would include medium-voltage (13 kV to 69 kV) power lines for commercial and industrial customers and low-voltage (less than 1 kV) power lines for residential customers (see Figure 4).

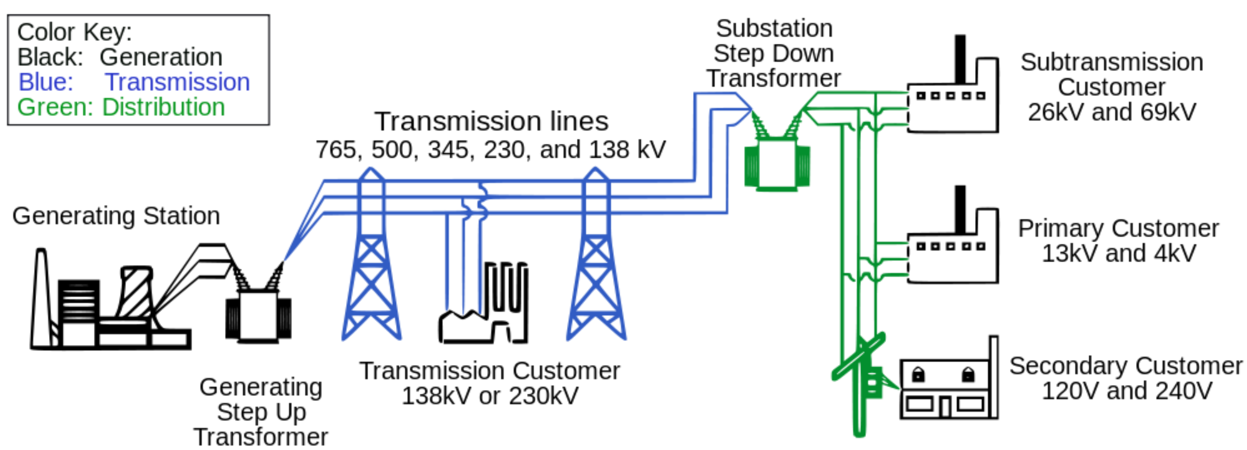

Figure 4. Schematic of the generation, transmission, and distribution system in the U.S.

At the federal level, NERC facilitates 15 reliability coordinators among the eight NERC regional reliability entities. The reliability coordinator ensures that schedules of power delivery are being met and oversees the individual balancing authorities. Balancing authorities are the entities that integrate resource plans ahead of time, maintain load-interchange-generation balance within a balancing authority area, and support interconnection frequency in real-time. Coordination between RTOs/ISOs and the various reliability areas and organizations constitutes the majority of the power flow in operating and managing the bulk power system. However, operating the electric system in the U.S. is a complicated matter.

At the "local" (distribution) level, the owner of the local distribution system is responsible for operation and maintenance and ensures the delivery of electricity to its customers. While the distribution and transmission systems traditionally had clearly defined relationships, their boundaries are blurring. Now, distribution systems entail or encompass broader concepts such as distributed generation (DG) and net metering.

European Electric System Operation

The major challenges of transmission system operation in Europe are due to the extension of the electricity market and to the integration of large amounts of renewables, in particular wind and photovoltaic (PV), and DG. As security limits are tested, jurisdictional issues may prevent optimal decisions from being implemented. For example, the technology and control strategies of DG inherently modify the dynamics of the power system, possibly causing stability problems. Overall, increased TSO/distribution system operator (DSO) coordination is needed, with changes on both the technical and regulatory sides.

However, the complexity of system behavior is increasing, as is the need for inter-TSO coordination. Enhanced analysis tools to assess online the security of the whole system and identify control actions are increasingly needed. ENTSO-E aims to support security of operation by harmonization of operating rules and cooperation among TSOs. Following are some highlights of the emerging issues relevant to operation:

(1) Security implications of the penetration of growing amounts of non-dispatchable renewable energy sources (RES), mainly wind and PV, allow reduction of the consumption share covered by fossil-fueled power plants, introducing a number of criticalities in power system planning and operation. Retrofitting programs of existing PV installations, in order to permit their continued connection to the system in cases of frequency disturbances, have been carried out particularly in Italy and Germany—the countries exhibiting the highest PV installed capacity.

(2) High power flow exchange between areas affecting the stability of operation of the European power system is increasingly dependent on the stability of each of its areas, as disturbances may propagate over wide areas.

(3) Deterministic frequency deviations from the setpoint, occurring around the change of the hour, recognized as a consequence of the market design, as generators change their scheduled output in steps every hour, implying a reduction of power reserves to face sudden power imbalances.

TRANSMISSION EXPANSION PLANNING

Transmission planning and expansion are often connected efforts. Several organizations provide various expertise to address the changing demands on a jurisdiction's electricity system. Understanding and identifying system solutions can be challenging. Scenario analyses help inform these solutions and the optimization of the electric system to address various concerns, including but not limited to reliability, social impacts (e.g., cost and environment), and resource availability.

Current Planning and Expansion in the United States

Transmission planning in the U.S. identifies efficient and cost-effective transmission expansion options. The need to accommodate variable energy resources into the grid in a coordinated and reliable way through cooperation lends itself to regional planning because of the large amounts of transmission infrastructure usually required for such projects. The more that systems can work with other systems across seams in a holistic way, the whole North American grid will be more secure and stable. One successful example is the previously mentioned Interconnection Wide Transmission Planning (IWTP) process through which the organizations are directed to develop 20-year transmission plans. The IWTP process addresses prospective needs of the respective interconnections.

Transmission planning may align along state and RTO/ISO boundaries, as in the case of the states of California and New York. Transmission planning in the larger regional markets spanning multiple states is more complex and implicates both federal and state planning mechanisms.

The DOE is supporting the development and maintenance of several different optimization tools, broadly referred to as the SuperOPF, along with the underlying MATPOWER package, an open-source power system simulation and optimization tool used widely in the power systems field, especially in academia. The unifying themes running through the various SuperOPF-based tools include the simultaneous, explicit modeling of multiple system states, where each state has a full set of optimal power flow (OPF) variables, constraints and costs, a stochastic or weighted cost across the various states, and additional variables, costs and constraints that tie these states together.

The introduction of electricity markets, together with increasing interregional trade and the integration of renewables, has made transmission expansion planning more complicated. Uncertainty about, for example, fuel prices, the location, amount and type of new generation, and electricity demand propogates through planning, expansion, and investment decisions.

Transmission expansion in the U.S. is accomplished through a variety of mechanisms. Transmission expansion is a natural outgrowth of the transmission planning process. The planning process may be seen as the analytical framework by which the actual physical expansion of the transmission network within a given grid system. Analyzing the physical needs of the system requires considering a number of variables that affect the physical and technological makeup of the respective grid components. Understanding and managing congestion is an integral component of transmission expansion. The DOE is required to conduct a triennial national electricity congestion study.

Expansion decisions must keep the grid operating securely and reliably. The ability to make decisions regarding actual expansion and build-out of generation and transmission infrastructure needs lies with the asset owners. While the RTO/ISO has planning authority, as noted above, states have authority over siting of transmission infrastructure. Each RTO/ISO plays a role in the transmission planning and expansion in its respective service area. The RTO/ISO engages in transmission expansion according to analysis of transmission needs and proposed changes to the transmission system as well as develops plans and forecasts for the region's future transmission and energy needs. These organizations make expansion decisions according to the outcomes of their planning processes.

Current Planning and Expansion in Europe

The transmission expansion planning process is a complex task in which the network planners need to handle several uncertainties and risk situations. In the past, before electricity market liberalization, in a centrally managed power system the vertically integrated operator could in general control the whole power system. Now, in a liberalized environment, the TSO, responsible for transmission, shall plan the expansion of its network by minimizing transmission costs (investment and operation), overcome bottlenecks, and pursue maximum social welfare, when requested by specific regulation, while meeting static and dynamic technical constraints to ensure secure and economically efficient operation. Socio-environmental constraints must also increasingly be taken into account in the planning process.

Some important criticalities make the task of a TSO at the same time crucial and very delicate. In fact, changes in future system conditions significantly affect benefits of transmission expansion. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or overestimate the true benefit of the project and may lead to less than optimal decision making. This can only be taken into account by using different scenarios. Now, it is of paramount importance to consider socio-environmental aspects for a more complete and systematic cost-benefit analysis. In some cases, environmental constraints and social opposition have obliged the transmission planners to reshape the rank of the investigated alternatives.

The European TSOs aim at two main objectives when planning the development of their grid: (1) maximizing system reliability and security of supply and (2) fostering the market to allow an efficient use of generation, thereby minimizing the total costs for the system. European countries have various objectives with their transmission planning. Features like the network planning timeframe, the utilization of deterministic and probabilistic criteria, also with consideration of market issues, are quantitatively and qualitatively compared for some European country systems.

For what concerns cost benefit analyses and market value in the European planning practice, most TSOs, taking also into account the aspects of environmental safeguard, evaluate and rank from the techno-economic perspective several possible alternatives stemming from the planning analyses and which—as a necessary pre-condition—fulfill the priority target of realizing a secure transmission grid. Given the high costs of investments and the long lifetime of the transmission assets, it is crucial to make the right decision at the right time. However, the future evolution is uncertain, and public opposition tends to halt hardly any transmission expansion projects. Comprehensive cost-benefit analysis, accounting for a wide range of benefits and costs, can also reduce the issue of public acceptance while identifying the projects that are of "real" relevance for the European energy policies.

As the availability of renewable electricity sources is continuously increasing, and new and variable generation sources are expected to be developed further away from major consumption sites, electricity must be transported over longer and longer distances and across national borders to be delivered where consumption needs arise. A pan-European network is required to enable integration of TSOs and benefit from the different behaviors of consumption and generation to use, e.g., the wind energy from North-Western Europe, the solar energy from Southern Europe, and the biomass from Eastern Europe.

To this aim, the concept of an innovative "Electricity Highway System" has been introduced. To address these challenges, the e-Highway 2050 research project[2] aims to develop foundations of a modular and robust expansion of the pan-European electricity highway system network capable of meeting future European needs (e.g., energy policy, integrating renewables, international electricity market, and security of supply).

MARKET STRUCTURE AND OPERATIONS

Electricity markets are designed and operated through a variety of mechanisms, often depending on how the electricity system is operated and managed.

United States Electricity Markets

In the U.S., electricity markets are highly complex. There is no national electricity market, and a variety of types of planning and operational paradigms exist in different regions. There are five centralized electricity markets in the Eastern Interconnection, characterized by the existence of RTOs and ISOs, centrally cleared market prices, and various forward and real-time market settlements. The Western Interconnection has only one centralized market.

Despite the range of institutional configurations, there is some consistency in jurisdictional issues. States have jurisdiction over the rates charged for retail power and for siting of infrastructure, including transmission. The FERC has jurisdiction over the rates charged for using a bulk transmission system in centralized markets and independently-owned utility territory. Federal power marketing administrations (PMAs) are not subject to FERC jurisdiction because they are part of the DOE. All FERC-jurisdictional utilities and transmission owners and operators are subject to open access requirements. But, following open access rules does not necessarily mean implementing a centralized, formal electricity market.

Regional centralized electricity market rules and operation are influenced by a variety of factors, including federal statutes, federal regulations, RTO/ISO guidance, stakeholder input, NERC reliability standards, and the forces of competitive markets. Centralized electricity markets are designed and operated by the RTOs or ISOs, along with input from industry stakeholders, and are subject to FERC approval. In general, the trade and transportation of wholesale electricity is regulated or governed by the federal government, while retail sale of electricity is regulated by state-level regulatory authorities. The FERC approves transmission

[2] The e-Highway2050 project is supported by the EU Seventh Framework Programme and is aimed at developing a methodology to support the planning of the Pan-European Transmission Network, focusing on 2020 to 2050, to ensure the reliable delivery of renewable electricity and pan-European market integration.

tariffs, but states regulate consumer tariffs. Four distinct types of markets that typically make up a centralized market are (1) capacity markets, (2) energy markets, (3) ancillary service markets, and (4) transmission capacity markets. Outside of centralized markets, the firm transmission or transmission constraint market allows for open access of the transmission system. The RTO or ISO is an important player in the electricity system in the U.S. because of their power to shape and operate markets across large portions of the country among a diverse set of fuel sources dealing with a variety of geographic and institutional issues. While RTOs and ISOs are not legislative- or rule-making bodies, they implement legislation and rules such as the mandate for the open access transmission system.

European Electricity Markets

As far as the European electricity market is concerned, the European Council announced two ambitious targets in February 2011: (1) completion of the internal energy market by 2014 and (2) no member state electrically isolated from the rest of the EU by 2015. The integration of different national electricity markets toward the European objective of a single internal energy market is clearly a benefit for the whole system, bringing more actors into the playing field, thus increasing cross-border competition and improving the social welfare of the coupled markets.

Until now, the main impact studies and most noteworthy regulatory efforts have been focused on the integration of the national day-ahead market through the progressive enlargement of the market coupling. It is important to notice that the integration of electricity markets closer to real-time, the most critical for the proper functioning of the system, is an important goal to achieve at a pan-European level.

The European market is undergoing an integration process. However, the way the process is implemented will definitely impact the efficiency of the resulting market and also the flexibility of grid operation. The real challenges include the regulatory harmonization of both day-ahead and balancing markets, and the implementation from the methodological and information and communications technology standpoints. In fact, the algorithmic and computational requirements posed by the integrated market problem accounting for all specific rules are very demanding.

2 Introduction

The main objective of ISGAN Annex 6 is to establish a long-term vision for the development of smarter electricity systems. The Annex's efforts consist of improving general understanding of smart grid technologies applicable to or influencing system performance, transmission capacity, and operation practices; accelerating their development and deployment; and, promoting adoption of related enabling regulatory and government policies. Member countries include Austria, Belgium, France, India, Italy, Norway, South Africa, Sweden, and the United States (U.S.).

Flexibility, visibility, and understanding of grid operations are important characteristics that enable deployment of technologies to develop a more modern, smarter electric grid system which can securely, reliably, and resiliently adapt to the panoply of challenges it is likely to encounter in the coming decades. Such challenges will run the gamut from changes in load profiles, electricity resources, disruptions, and development. Addressing these challenges and others requires a systematic and integrated approach that considers not only the enabling technologies, but also the "rules of engagement" that facilitate their deployment.

In the sections that follow, this discussion paper examines the "rules of engagement" for policies, regulations, and markets, providing an overview for the U.S. and Europe. The rules include the laws and regulations that govern the electricity system, from generation to end user; the planning, operation, and "grid management" structure and implementation; and, the policy, market, and regulatory approaches and challenges.

2.1 United States

The U.S. "grid" is a highly complex and dynamic system, operating in connection with two additional sovereign countries, in and across the 48 contiguous U.S. states. It comprises three electrically-independent networks (see Figure 5) —the Eastern, Western and Electric Reliability Council of Texas (ERCOT) Interconnections—that are connected via direct current (DC) links, which are further divided into over 140 control areas responsible for balancing generation and consumption of electricity at all times. The U.S. electricity system has no linear or singular operational or management structure. Together, generation facilities, transmission lines, and the related technology infrastructure that accomplishes the delivery of electricity from generation facilities are referred to as the bulk power system.[3] An additional level of delivery is accomplished at the

> ***United States Grid***
> - *>350,000 miles of transmission lines at 138 kV or above*
> - *140 control areas, >5,000,000 miles of distribution lines transmitting at under 138 kV*
> - *>7,000 power plants*
> - *> 140,000,000 customers*
>
> (see Figure 6)

[3] Transmission is defined by North American Electric Reliability Corporation (NERC) as the wires and necessary support structures transmitting electricity at 100kV or greater; also according to NERC, the Bulk Power System or

distribution level where the power is delivered to residential, commercial, and most industrial customers. The bulk power system is operated and managed through a network of federal, state and local entities, each charged with separate yet overlapping obligations and responsibilities related to planning and operating infrastructure and markets.

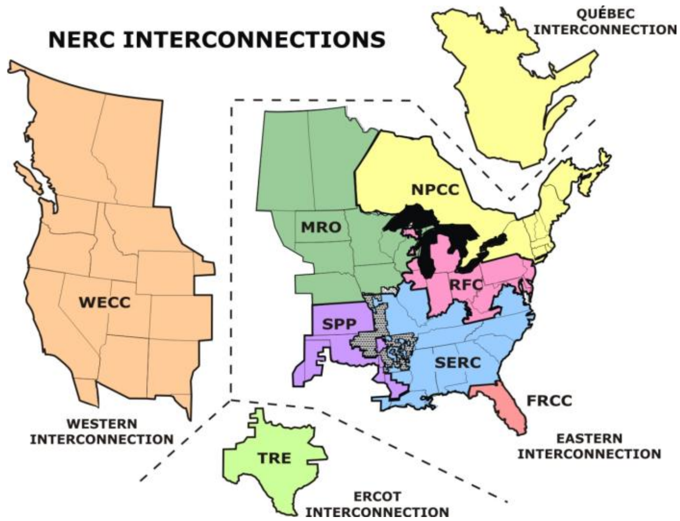

Figure 5. North American Electric Reliability Corporation (NERC) Regions across the North American interconnections

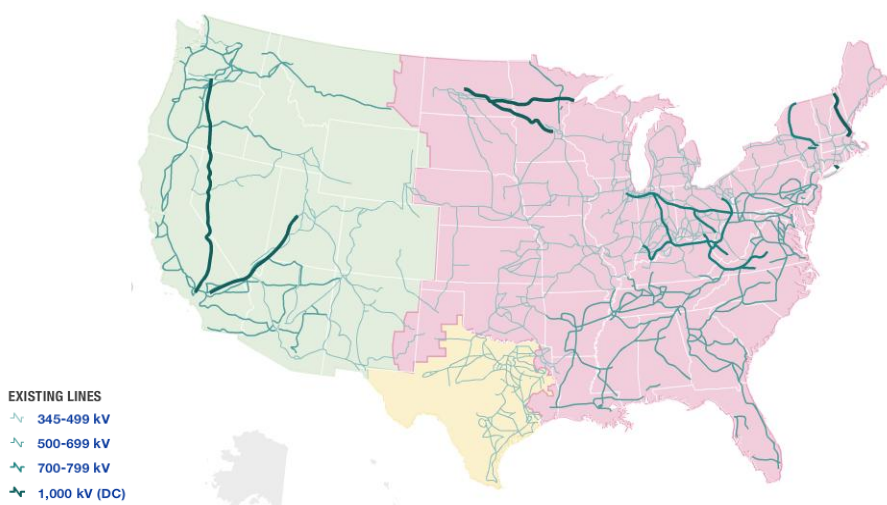

Figure 6. Transmission Lines (345kV-1,000kV) across the United States [1]

Over the past few decades, portions of the U.S. electric system have undergone fundamental changes to the way electricity generation is planned, sited, and paid for. More recently, the industry has been focusing attention on how electricity delivery planning and investment may need to change in order to address technological as well as structural changes,

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Bulk Electric System (which for practical purposes are one and the same) does not include distribution systems, which operate at a much lower voltage.

such as a shift toward more transparency in planning processes and a perceived need to coordinate planning over larger areas. Industry stakeholders, including regulators, anticipate continuing fundamental changes over the next decade as advances in technology allow for a greater utilization of localized electricity production and awareness of the need to reduce electricity-related carbon emissions increases in urgency. The technologies, tools, and techniques that will facilitate this progression are generally deployed under the banner of advancing the overall smart grid vision, and include advanced metering infrastructure (AMI), demand-side management (DSM) and demand response, distribution automation, storage, distributed generation (DG), net metering, and synchrophasor measurement technologies (which provide real-time, dynamic grid status information between the actual electricity transmittal point and the grid control center).

More robust coordination among U.S. stakeholders is underway to better understand the potential implications of new technologies, tools and techniques on the U.S. electric grid.

In the U.S., electricity markets and the electricity industry broadly have been undergoing major paradigm shifts over the past few decades. The introduction of open transmission access and restructured electricity markets in the 1990s has led to fundamental changes in ownership structures and planning and operational responsibilities. Since the 1990s, changes across markets, technologies, and policies in the electric grid “space” have driven towards milestones and influenced further policies and market changes (see Figure 7). For instance, in restructured electricity markets, the entity in charge of planning the transmission system is not responsible for planning generation. At the same time the industry is adjusting to these changes, a number of local, regional and national issues have arisen as well: historically low natural gas prices and abundant supply [2]; increased installation of DG, such as residential solar installation [3]; growing implementation of utility DSM programs [4]; and increasing amounts of variable energy resources. All of this is playing out against a backdrop of increased concerns about reliability and resiliency of the system, as well as cyber- and national security concerns. As we continue to move forward, projections of market, policy, and technology changes will continue to evolve to meet national, and even state, targets (see Figure 8). One of the areas that the U.S. Department of Energy (DOE) is funding to help with grid modernization, including the integration of renewable, is energy storage. The DOE has developed an Energy Storage Program Planning Document [5], which describes the market, policy and technology needs for energy storage to help enable grid modernization. Additional information about DOE’s energy storage program is available on the DOE website. [6]

Because of the national scope of these issues, regional planning and cooperation among all levels of government and interested stakeholders have been encouraged by federal entities, including the DOE and the Federal Energy Regulatory Commission (FERC). The increased communication among stakeholders has been a welcome shift for most in the industry. A recent example of this cooperative method is the DOE’s funding of the Interconnection Wide Transmission Planning (IWTP) process, which awarded five grants to organizations within the three major North American Interconnections to analyze how best to approach the planning and build out of the transmission system moving forward. As a part of the IWTP process, each of the interconnections is engaged in long-term studies to examine, among other things, electricity infrastructure needs.

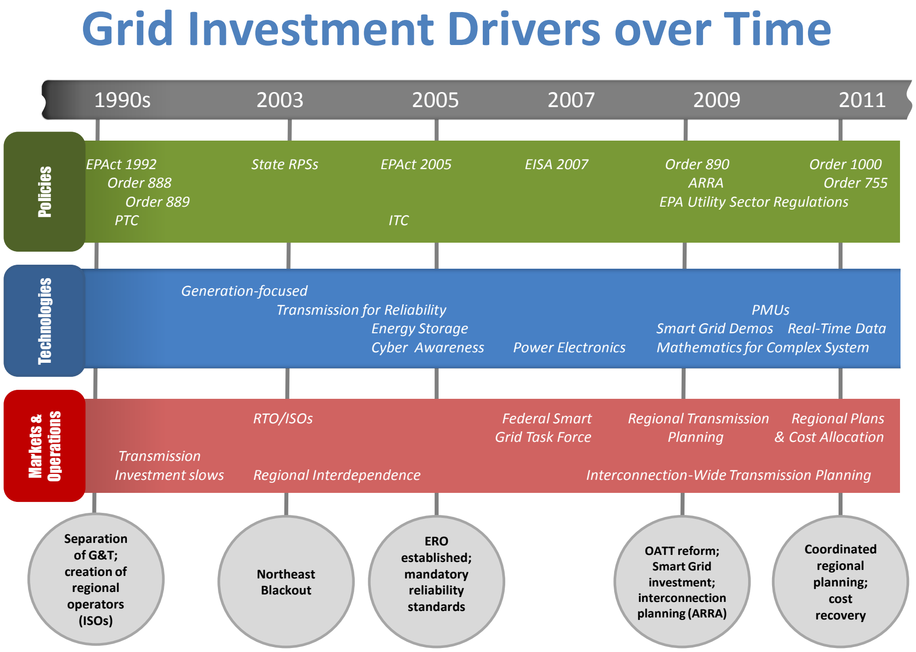


Figure 7. Historical grid investment drivers over time [7]

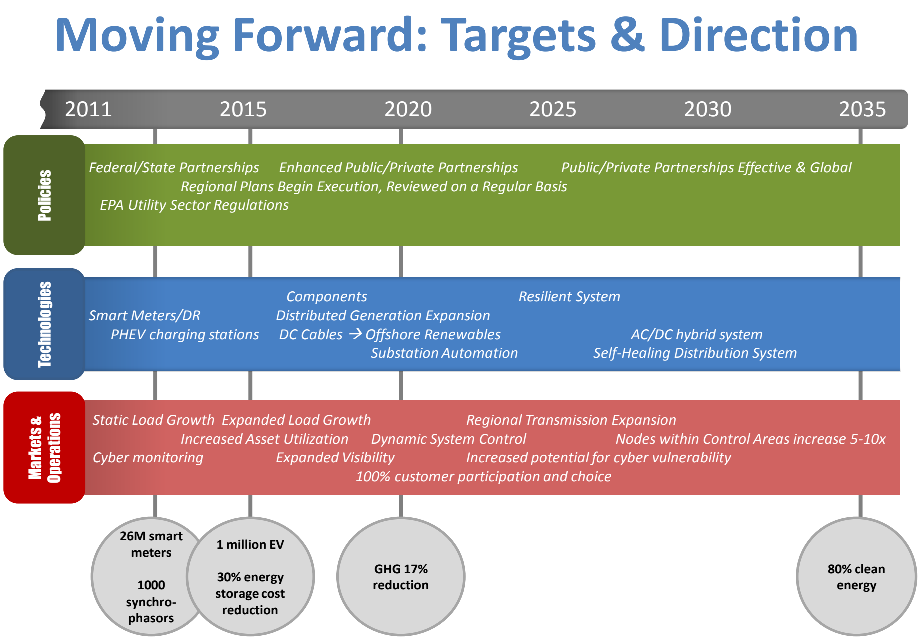
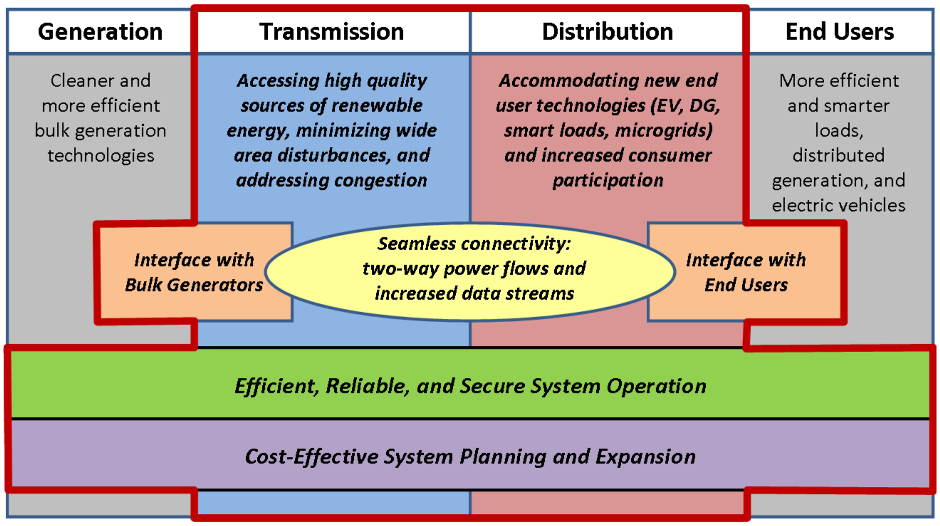


Figure 8. Targets and direction moving forward in the grid space [7]

This discussion paper will look at the various issues that have faced and continue to pose challenges to the electric system in the U.S., with an eye towards what policy, regulatory, and market solutions are being considered to address them. It is important to recognize that the scope of this discussion paper will primarily cross the transmission and distribution areas of the electric system while interfacing with generation and end users. However, this discussion paper will not specifically address those efforts directed solely at generation or end users. Moreover, an essential element considered in this space (outlined in red, see Figure 9) is the overlay of institutional issues, such as policies, regulations, and markets, on transmission planning, operation, and expansion. Distribution planning, operation, and expansion are generally under state authority and will not be discussed in detail.



Institutional issues and solutions must be considered in conjunction with these technical challenges

Figure 9. The grid space encompasses conventional elements as well as their institutions and other drivers (e.g., markets, policies, regulations) [7]

2.2 Europe

Power transmission in Europe is characterized by a high degree of interconnections and inter-area power exchanges, congestion, volatility, and diversity of operating conditions. The power system is subject to the thrust of pan-European market integration and the need to face the variability of renewables such as wind and solar from a system-wide approach, while guaranteeing reliability of supply. Transmission system operators (TSOs), regulating authorities, state governments, and the European Union (EU) need proper coordination in order to set consistent ground rules and regulations for efficiently and reliably planning and operating the European grid consisting of five synchronous areas, 34 countries, and 41 TSOs.

In the recent years, electric power systems have been experiencing profound transformations. In the EU, issues concerning security of energy supply, electricity market restructuring and environmental constraints represent key drivers for new trends which may have significant impact on the design and the operation of the electric power system. This is particularly true for the transmission system.

As a matter of fact, the ongoing energy market liberalization process in Europe is leading to the development and operation of regional electricity markets, facilitating cross-border power transactions; the resulting steady increase of inter-area power exchanges is generally causing a higher amount of congestion affecting electricity transmission networks. In addition, the restructuring of electricity systems, with the consequent separation (unbundling) of generation and transmission functions and the competition within the generation sector, has introduced further uncertainties within current transmission planning processes.

Moreover, and most critically, the European energy sector has been deeply changing as the EU member states decided in 2007 to lay down ambitious environmental targets to be achieved by 2020 [8]: 20% greenhouse gases emissions reduction (compared to the 1990 level), 20% overall energy demand covered by renewable energy sources (RES) (it was 8.5% in 2005), and 20% reduction in the global primary energy used (i.e., saving 13 % when compared to 2006 levels). This is a first step towards a more profound decarbonization of the European electricity sector by 2050, with the ambitious goal to achieve greenhouse gases emissions reduction of 80%–95% (compared to the 1990 level). [9]

The European electricity grids are on the critical path to meet the EU's climate change and energy policy objectives for 2020 and beyond. In fact, this trend imposes new challenges particularly to the TSOs, who have to reliably integrate an increasing amount of variable RES power plants into the grid and cope with rapid and less predictable flow patterns, while keeping acceptable margins to guarantee security of supply and progressively removing all obstacles to the creation of a unified European energy market. This is especially true for those systems that have to deal with fast growing RES penetration, as anticipated in order to meet their respective national 2020 targets. To achieve this goal within a pan-European perspective, TSOs might also exploit possible back-up services provided by complementary resources (e.g., energy storage) remotely situated. However, this can only be implemented at the expenses of a more intense utilization of already congested cross-border sections of the transmission grids.

Further issues faced by transmission planners nowadays are related to social and environmental constraints to the building (and in some cases even refurbishment) of transmission infrastructures, within a background of aging European grid assets. Looking at further developments of the European power system, it is also expected that the increased penetration of distributed energy resources and active demand will play a role in the power system and impact the upstream transmission. Overall, the period when generation was considered as fully predictable and consumption fully stochastic is evolving to an era where generation becomes partially stochastic and, at the same time, the amount of controllable consumption rises.

The combination of all these challenges requires a long and costly technical, market and regulatory re-engineering process of the European energy system.

2.3 References

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[2] U.S. Energy Information Agency, "Annual Energy Outlook 2013," (Washington, DC: U.S. Department of Energy, 2013).

[3] GTM Research & Solar Energy Industries Association, "U.S. Solar Market Insight Report Q2 2013 Executive Summary" (Washington, DC: Solar Energy Industries Association, 2013).

[4] Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," prepared by Energy Infrastructure Advocates (Washington, DC: Edison Electric Institute, July 2013).

[5] U.S. Department of Energy, "Energy Storage Program Planning Document" (Washington, DC: U.S. Department of Energy, December 2013), http://energy.gov/oe/downloads/energy-storage-program-planning-document.

[6] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability homepage, www.oe.energy.gov.

[7] U.S. Department of Energy, "Plugging America Into Clean Energy: Future Needs of the Electricity Grid" (presented at Grid Tech Team Workshop, November 15, 2011).

[8] European Commission, "An Energy Policy for Europe," COM(2007) final (Brussels, Belgium: Commission of the European Communities, January 2007).

[9] European Commission, "Energy Roadmap 2050," COM(2011) final (Brussels, Belgium: Commission of the European Communities, December 2011).

3 Legislative and Regulatory Evolution

In both the U.S. and Europe, there are many non-technical factors that drive or challenge the development of a smarter grid through deployment of technologies. Additionally, the hierarchy of governments and cross-border organizations add complexity to the already diverse challenges that are present in each electric system. Strategic measures taken by appropriate authorities can help to define the "rules of engagement" to better enable achieving a smarter grid.

3.1 United States

The following sections provide a brief description of the legal foundations for U.S. electricity policy, which will serve as a foundation for discussion on the current state of transmission and distribution systems. Traditionally, in the U.S., local electric utilities, municipalities, or cooperatives were granted a state-protected monopoly under the premise that insulation from competition was necessary to ensure reliable and cost-effective service. These state-protected monopolies existed pursuant to the "regulatory compact," meaning that the state limited competition in the electricity industry by establishing strict barriers on entry into the market and allowed the company to earn a reasonable profit. In exchange, the utility provided reliable electricity service at not more than just and reasonable rates.[4] In the past two decades, this regulated paradigm is shifting toward one of deregulation and competition within markets.

3.1.1 Regulatory Environment: Past and Present

Beginning in the late 1980s and early 1990s, electricity regulators in some jurisdictions began experimenting with a deregulated market model. [1] In certain jurisdictions, such as the Northeast, the competitive model became predominant. In other areas of the U.S., like parts of the West and much of the Southeast, the regulated, vertically integrated[5] business model remained in place. At that time, many industry analysts forecasted the rise in competitive markets and predicted the advantages of competition would continue to de-emphasize the central role the vertically integrated utility had played in the electricity market up to that point. At the same time, there are those who forecast that market deregulation and completion will ultimately not help consumers and the vertically integrated utility will remain impactful in

[4] "Just and reasonable" is the standard generally applied to rate-making decisions by state public utility commissions and the FERC in the United States.

[5] A vertically integrated utility is one in which the same entity owns and operates the generation, transmission, and distribution assets, as well as other systems needed to deliver electricity to the utility's customers. As a result of the FERC's Open Access Transmission Tariff, related orders directing a shift towards liberalizing access to transmission infrastructure, and state policies, many integrated utilities found it prudent to divest most or all of their transmission infrastructure. Known as unbundling, the divestiture of generation and/or transmission assets can be either actual or virtual.

electricity markets. [2,3] In fact, the unquestioned premise that the generation, transmission, and distribution of electricity, in order to operate effectively, must be protected by legal monopoly no longer has universal agreement. For instance, transmission infrastructure owners must provide equal access to this infrastructure under regulated tariffs. [4] The same rules must apply to all players. This requirement and others like it (which emanate from the FERC as explained in greater detail below) have influenced modern electricity regulation and related policies (both state and federal).

Key Energy Laws in the United States

- *Federal Power Act 1920/1935*
- *Public Utility Holding Company Act of 1935*
- *Public Utility Regulatory Policies Act of 1978*
- *Energy Policy Act of 1992*
- *Energy Policy Act of 2005*
- *Energy Independence and Security Act 2007*
- *American Reinvestment and Recovery Act 2009*

3.1.2 Legislation and Federal Energy Regulatory Commission Orders

In the U.S., two federal entities have primary legal and regulatory jurisdiction over the electricity industry: Congress and the FERC. Congressional legislation has evolved from merely creating licensing agencies and enabling basic regulatory regimes to a paradigm focused more on creating standards by which industries must abide and federal agencies must work to uphold. The FERC has overseen a shift from a traditionally regulated industry, where monopoly companies are required to serve customers in exchange for a regulated rate of return, to an industry with increased competition. FERC continues to refine the regulations that make this new paradigm effective and efficient.

This section will present foundational laws and regulations relevant to U.S. energy policy, electricity industry ownership structures, and operational paradigms.[6] While this section is not intended to present an exhaustive review of all laws and regulations that shaped the electricity landscape into its modern form, it is intended to provide the reader with enough background to fully appreciate the current legal and regulatory framework by which electricity transmission in the U.S. is planned, developed, and paid for. Highlights and additional information on select statutes are provided in the Appendix Section 8.2.

3.1.2.1 Key Energy Laws in the United States

The Federal Power Act (FPA) is the oldest law governing the energy sector in the United States; it is still in effect. Originally enacted in 1920 as the Federal Water Power Act, the FPA created the Federal Power Commission (which later became the FERC), to coordinate jurisdiction over hydropower which was originally under the auspices of individual state's jurisdiction. The Act was subsequently amended by a host of other energy-related legislation, including the Public Utility Holding Company Act (PUHCA), the Public Utility Regulatory Policies Act (PURPA), and the Energy Policy Acts of 1992 (EPAct 1992) and 2005 (EPAct 2005).

The PUHCA was enacted to force the divestiture or to limit the scope of operations of large conglomerate public utility holding companies. Prior to the PUHCA, complex corporate

[6] Also see Section 8.2 for summaries of selected laws and regulations affecting the electricity industry.

structures allowed extraordinary profits and rendered regulation very difficult to administer. The PUHCA was repealed by EPAct 2005 because subsequent legislation and changes in the structure of the markets, particularly the deregulation of natural gas, rendered it obsolete.[7]

After the oil crisis of 1973, Congress reacted to calls for energy regulation reform, which resulted in the Department of Energy Organization Act of 1977. This law created the DOE and transferred authorities of the Federal Power Commission to both the DOE and the FERC, an independent regulatory commission within DOE. The DOE has a very broad mission to facilitate a robust energy economy. It accomplishes this by providing technological, policy, and informational resources to states, the private sector, and other federal agencies across every facet of the energy production and delivery sectors. The DOE often leads efforts to coordinate between industry, the federal government, and the myriad of regional and local regulatory and planning bodies on energy policy and regulatory matters.

The PURPA is one of the earliest legislative precursors to electricity de-regulation. The goal of the PURPA was to encourage conservation of electricity and operational efficiency in generating units. To this end, the PURPA required utilities to procure electricity from alternate sources, called "qualifying facilities," at the avoided cost of electricity.[8] By requiring utilities to accommodate power generated by third-parties on their transmission and distribution assets, compliance with the PURPA demonstrated that it was possible for the industry to unbundle generation from delivery. The PURPA is still in effect.

After the PURPA was enacted, the next significant piece of federal electricity legislation was the EPAct 1992. This law required, among other things, that the FERC ensure that owners of transmission infrastructure provide equal access to all electricity providers. The FERC operationalized open access via Order 888 and by creating the Open Access Transmission Tariff (OATT), discussed in greater detail below.

The EPAct 1992 was followed by several implementing orders from the FERC, and superseded in part by the EPAct 2005. The EPAct 2005 was a natural offshoot of the EPAct 1992 and extended and amplified many policies set in place during previous years under the earlier act. The focus of the legislation was largely aimed at providing federal financial support to renewable industries, namely wind, solar, and biofuels. Yet, this legislation also extended key tax credits for the fossil industry. While no provision of the bill specifically focused on electricity transmission initiatives, the EPAct 2005 extended key transmission investment-related tax provisions established under the EPAct 1992. The EPAct 2005 also authorized the FERC to certify a national electricity reliability organization, responsible for creating and enforcing mandatory reliability standards for the bulk power system. In 2006, the FERC

[7] By 2005, many aspects of the law were superseded by other laws subsequently passed. Additionally, the practice of using conglomerate public utility holding companies was no longer in vogue, or even feasible, under modern day energy regulation. The FERC, however, retained the authority in EPAct 2005 to oversee transactions and other financial activities of public utility holding companies through grants of access to those companies' books and records.

[8] PURPA addresses what it means to procure energy from alternative sources that are more efficient and economical. The Act describes a "qualifying facility" as either a small generator with a renewable energy source or a cogeneration facility, which produces both electricity and useful thermal heat (see http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp).

certified the North American Electric Reliability Corporation (NERC) as the electric reliability organization to create and enforce reliability standards.

More recently, the Energy Independence and Security Act of 2007 (EISA) and the American Reinvestment and Recovery Act of 2009 (ARRA) were enacted to confront the need to consolidate energy policy from several discrete pieces of legislation and to address insufficiencies in the energy policy landscape. The EISA sought to incentivize the development and deployment of a renewable energy industry, in addition to addressing other important energy issues such as growing concern over reliance on foreign oil.

The ARRA provided substantially increased federal funding for key tax provisions (chiefly for wind and solar) of the EPAct 2005 and was the foundation for a dramatic increase in the development and integration of variable energy into the grid. Partly as a result, the planning and expansion of the transmission system to accommodate these resources has been a large part of the national conversation in energy infrastructure. It is important to note that the ARRA was not an "energy" law directly. It did, however, create energy-focused programs, particularly the Section 1603 Treasury grant that provided up to a 30% cash credit to qualified renewable energy projects. This law is still operative today and provides the enabling legal authority for much of the current financial support structure for national energy programs.

3.1.2.2 Federal Energy Regulatory Commission Overview

At the federal level, electricity transmission regulation is the purview of the FERC, primarily through issuance of orders. The FERC has primary jurisdiction over the rates transmission providers can charge for use of their equipment, known as tariffs, and ensures these tariffs are just and reasonable. FERC orders also have been used to make broader shifts in industry paradigms, such as by requiring open access of transmission equipment. The FERC wields substantial power to shape national transmission policy. For instance, the FERC has undertaken a series of orders to address some of the issues caused by increased renewable generation. Even before the industry faced the challenge of integrating variable energy resources into the existing transmission system, the FERC sought to address flaws in how transmission rights were bought and sold and cost obligations were allocated in markets. This section discusses several significant orders that FERC has issued, which are organized around the following themes: how regions of the electricity system are managed, how electricity is traded, and how the system is operated and planned.[9]

In 1999, the FERC issued Order 2000. The order dealt with Regional Transmission Organization (RTO) formation. Order 2000 established what it means to be an RTO[10], and it created a regulatory environment that incentivizes or encourages membership in such an organization. The FERC wanted large, wholly inclusive regional planning bodies. Further, the FERC wanted the operation and planning of the transmission system to be formatted under an open architecture organization for transparency and consistency purposes. Nevertheless, these

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[9] Note that FERC orders are numbered (e.g., Order 1000), but that these numbers are not sequential or necessarily have other meaning. A selection of FERC orders in chronological order is presented in Section 8.2.

[10] FERC Order 2000 established minimum characteristics that an entity seeking recognition by the FERC must establish.

goals were not fully met as a result of significant pushback by several states and many utilities. Order 2000, however, was instrumental in creating a major shift in the way planning, operation, and management of the grid is accomplished.

Order 888 was issued in April 1996. The FERC, through creation of the OATT sought to eliminate "undue discrimination" in electricity transmission. According to the FERC, the goals of Order 888 are "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers." [5] To achieve these goals, the FERC required all public utilities that own or operate transmission infrastructure to have on file open access non- discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. As a result of Order 888 and due to a more level playing field with increased access and the removal of the utilities' ability to charge themselves preferential rates for transmission transactions, many integrated utilities found it necessary to unbundle their transmission and generation services.

There are two types of unbundling. The first, "functional unbundling," occurs when an entity owns both transmission and generation infrastructure and "functionally" separates the transmission and generation operations into two distinct enterprises, yet retains the same parent ownership. The second, "actual unbundling," means to divest transmission infrastructure and operate only generation, or divest generation and operate only transmission (although this is not common and it is the former that is what happens most often).

Because these assets were constructed with a cost-recovery model in place that included no-longer-available rate structures, some formerly integrated utilities faced "stranded" or unrecoverable costs. As such, the concept of stranded costs plays an important role in the divestiture of the infrastructure. To the extent that Order 888 led to stranded costs, utilities and asset owners sought to recover these expenses from ratepayers. This is permitted so long as such costs are legitimate, verifiable, or prudently incurred.[11] [6,7] This reformation of the wholesale market helped give rise to stand-alone transmission companies, and enhanced the role of the local utility in administering the distribution system.[12]

Building from Order 888, the FERC issued Order 890 in 2007. Order 890 addresses primarily the potential for discrimination under the OATT. The FERC required that utilities and transmission organizations (including RTOs and Independent System Operators (ISOs)) strengthen their OATT to eliminate the potential for undue discrimination when assigning the companies available transfer capacity (ATC). According to the FERC, "ATC is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. Transmission providers currently calculate the ATC for their systems using different assumptions and methodologies." [8] The FERC found that the absence of consistent methodology increases the potential for discriminatory practices and, consequently, required consistent calculations, development of standards, and increased transparency in the calculation process. Further, the FERC required

[11] This also relates to the earlier "just and reasonable" discussion.
[12] The problem of stranded costs also arises in a competitive retail market where distribution companies must now compete for customers who have a choice in electricity provider.

transmission providers to demonstrate that they engage in "coordinated, open and transparent transmission planning." [8]

3.1.3 Current Regulatory Environment

The overall regulatory framework for transmission planning and cost allocation (the question of who pays for what) is in a state of flux, influenced by the changing technological landscape. Energy law has paralleled the evolution of environmental law, and shifts in societal prerogatives have influenced shifts in policy. For example, the regulation of coal-fired power plants illustrates the need to mitigate carbon emissions, and the tax incentives for renewable resource development illustrate the need for sustainable and green sources of energy.

Currently, the most formative and contested regulatory mechanism employed on the federal and regional level is FERC Order 1000. Issued in 2011, Order 1000 builds from previous FERC orders culminating in two primary objectives: 1) ensuring that transmission planning processes at the regional level are non-discriminatory, efficient, and cost effective and 2) ensuring that transmission needs chosen via regional planning methods allocate costs fairly to those that receive benefits. The two prongs of Order 1000 and its substantive effects operate across both the regional planning and market operation aspects of the electricity industry.

As to the first prong of Order 1000, regional planning, each transmission provider is required to participate in a regional planning process to develop a regional transmission plan that complies with FERC Order 890. As mentioned above, Order 890 mandates non-discriminatory access to transmission infrastructure. Expanding beyond just those transmission needs identified by the transmission asset owner, regional planning processes must provide all stakeholders the opportunity to provide input regarding public policy requirements. Those players who might warrant input into the process include public and private utilities, public utility commissions (PUCs), generation owners, and consumer advocacy groups, among others. During the planning process, transmission providers have an affirmative obligation to evaluate transmission alternatives that may be more efficient or cost effective, and to give those alternatives identified comparable consideration.

FERC Order 1000 has two primary objectives:

1) *ensuring that transmission planning processes at the regional level is non-discriminatory, efficient, and cost effective*
2) *ensuring that transmission needs chosen via regional planning methods allocate costs fairly to those that receive benefits.*

To do this, transmission providers are required to achieve a specific set of objectives. As such, they must first plan their systems. This means they must develop robust and concrete long- and short-term plans that identify current and projected future needs of the system to meet demand. They must do so in consultation with the stakeholders that rely on the system and on which the system relies. This includes the identification of and compliance with public policies (including state public policies) to satisfy the interests of public and private stakeholders. Importantly, Order 1000 does not require that plans produce legal commitments (e.g., commitments to invest in generation, transmission, and demand response or energy efficiency). Order 1000 seeks to incentivize state regulators, regional market operators, and participants to implement the outcomes of the planning process.

The second prong of Order 1000 addresses the question of cost allocation. Ensuring that the costs of transmission upgrades are allocated to those who receive the maximum benefit from them is essential, particularly in light of upgrades to service in urban areas from generation in more remote places. In such cases, the question of how to spread the cost of these projects is important. To this end, the FERC requires that the specific cost allocation method chosen for the particular project satisfies six regional cost allocation principles. [9] While the FERC does not mandate that any specific method be used, the following six principles must be satisfied:

1. The project allocates costs roughly commensurate with the benefits delivered therefrom.
2. Involuntary allocation of costs to non-beneficiaries is unacceptable, meaning those who will not benefit from the project do not have to pay.
3. Benefit-to-cost threshold ratio must not exclude projects with significant net benefits; for example, substantially increased pan-system reliability or resiliency is a legitimate net benefit.
4. Extra-regional cost allocation is not acceptable unless the "outside" region agrees to share the cost.
5. The cost allocation methodology and the intended beneficiaries must be "transparent."
6. Different allocation methods could apply to different types of transmission facilities; meaning that there is not a "one size fits all" methodology.

These principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities. As a result, these six principles do not apply to other new transmission facilities that are developed outside of a regional planning this process. Therefore, a developer or individual entity is not foreclosed to voluntarily assume the costs of a new transmission facility.

Significant legal issues and challenges have arisen in connection with regional planning and cost allocation outcomes under Order 1000. Since the FERC issued Order 1000, states have been working to self-organize into qualified regions and submit plans to the FERC for review and approval. The FERC has reviewed and directed revisions to several regional plans submitted during Fall 2012. Despite this ongoing process, several legal questions remain, some of which are the subject of litigation. [10,11] Such issues include whether the FERC can legally order the development and submission of these plans, given that the FERC is not a planning agency and that its authority in this space is generally limited to authorizing rates for transmission service and wholesale sales in interstate commerce.

In June 2012, the FERC issued Order 764, an important order dealing with transmission dispatch and rate structure. Order 764 mandated that transmission owners providing transmission service to variable energy resource generators update their transmission schedules, essentially matching their generating output to load requirements, at 15-minute intervals. [12] The technology that allows such frequent reporting, and essentially seeks to better match demand to load, is a precursor to smart grid applications. Availability and penetration of advanced technology (e.g., synchrophasors and smart meters) will continue to better facilitate an enhanced ability for an automated grid to tailor generation and transmission services to the needs of the end user. The FERC will continue to be at the forefront of national electricity development, particularly as nascent technologies begin to emerge from the research and development stages into commercial deployment and utilities seek new and innovative ways to recoup investments in them. Additionally, as states and regional entities (i.e., RTOs) seek new ways to structure markets so that utilities can continue to operate profitably and provide the services that society relies upon in the face of shrinking revenues (as a result of efficiency measures, consumer self-generation, etc.), increased state and federal cooperation will be necessitated.

3.1.4 Relevant Organizations and Authorities

The jurisdictional lines between federal and state regulatory authorities is not always clear. As discussed above, the FERC is an important federal agency in creating and applying regulatory mechanisms and to this end is responsible for ensuring that interstate transmission rates are just and reasonable and not unduly preferential to a particular entity. Yet, it cannot order utilities to make investments, cannot mandate generation or transmission be built, and cannot mandate particular methods of planning or cost allocation. These functions are the sole province of the states. While the federal government is an important player in planning and building energy infrastructure, and can be a driver of innovation, most of the regulatory innovation in energy policy happens at the state level.

State PUCs are the primary regulatory bodies that control the energy industry within the borders of the state. Fundamentally, PUCs are responsible for the retail rates of electricity (distribution level) and the siting of transmission projects. States themselves (through the PUC) have significant power to dictate how the energy needs of the citizens will be met. While the market is also a significant factor (money to be made from building electricity assets is a powerful force), state PUCs and the attendant political process is an important step to actually deploying assets within a particular state.

For example, states may grant a utility an exclusive service territory, including control over facilities and services essential to consumers. In return, the utility accepts an obligation to serve (this is the regulatory compact discussed above). The state defines the utility's obligation to serve, doing so in varying ways (e.g., determining the best mix of conventional, renewable, DG, demand response, and energy efficiency resources). Broadly, the states' objectives may be summarized as the need to diversify their resource bases from historic dependence on conventional generation owned by the local utility to a mix of regional, diverse resources. Contrast this with federal or FERC objectives, as evidenced by Order 1000. The FERC wants to incentivize regional wholesale markets that are competitive, cost effective, and responsive to consumer needs.

At the state level, one of the biggest game changers has been the development of state renewable portfolio standard (RPS) programs. An RPS is a state-level legislative mandate that requires retail electric utilities to procure a designated amount of electricity or a designated percentage of electricity from qualified renewable energy resources, typically including a timeframe for compliance. For example, the state of New York has a mandatory RPS of 29% by 2015. [13] The state of New Jersey mandates that 1100 MW must be generated from offshore wind by 2025. [14] How each utility contributes to the overall state compliance goal will vary by jurisdiction. Currently, 29 states plus the District of Columbia have mandatory RPSs, with a number of others instituting non-binding RPS goals. [15] RPS programs are primary drivers of the increased penetration of renewable energy generation in the U.S. within the last decade.

To this end, RPS programs create a market for Renewable Energy/Electricity Credits (RECs). A REC equates to the "renewableness" of the power a particular generator creates. Generally, an owner of one MWh of electricity produced from a qualified renewable resource owns one REC. This credit or certificate can then be sold in a national market. Often, utilities will buy RECs from other jurisdictions to help satisfy their jursidictional RPS requirements. When a REC is sold, however, the generator of the MWh can no longer claim the "green" attribute of the power. When a generator (or a purchaser) wants to retain the "green" attribute of the renewable power, the REC must be retired, and no longer traded in the REC market.

Additionally, many electricity markets operate within the structure of a RTO or ISO. RTOs, as noted above, "are voluntary associations of utilities that own electrical transmission lines interconnected to form a regional grid and that agree to delegate operational control of the grid to the association." [11] See Figure 5 for a map of these organizations in North America. There are six major ISOs or RTOs within the United States: ISO-New England (ISO-NE), New York-ISO (NYISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Midcontinent-ISO (MISO),[13] California-ISO (CAISO), and Southwest Power Pool (SPP). RTOs and ISOs serve about two-thirds of U.S. electricity consumers. [16] Entities that do not participate in an RTO or ISO (again, membership is voluntary) are accounted for under the NERC "reliability regions" (see Figure 5).

ISOs were largely the result of Order 888 (the FERC's effort to standardize the national energy markets), which defined the characteristics of an ISO, predicated on FERC approval finding that the organization promoted competition within the wholesale electricity market and lessened barriers to entry. ISOs "predate" RTOs, which are largely the result of Order 2000, in which FERC sought to standardize the national electricity marketplace by defining quite specifically what it meant to be an RTO. A patchwork of independently operated transmission systems with limited communications or oversight is not the optimal paradigm for ensuring the reliability of electricity. The RTOs are essential in promoting competition in the wholesale electricity markets. Importantly, the RTOs and ISOs do not own any infrastructure; yet, they play a significant role in overseeing the long-term planning for system operation needs by working closely with infrastructure owners and coordinating operation of the transmission system. ISOs and RTOs engage in transmission services, such as operating the Open Access Same Time Information System (OASIS), which the FERC mandated with Order 888, as a mechanism to increase transparency of operators' open access procedures.

[13] Effective April 26, 2013, MISO amended its Certificate of Incorporation on file with the state of Delaware to reflect a change in its legal name to "Midcontinent Independent System Operator, Inc." No other changes to MISO resulted from this change. See the MISO website for more information: https://www.misoenergy.org/AboutUs/MediaCenter/pages/MediaCenter.aspx.

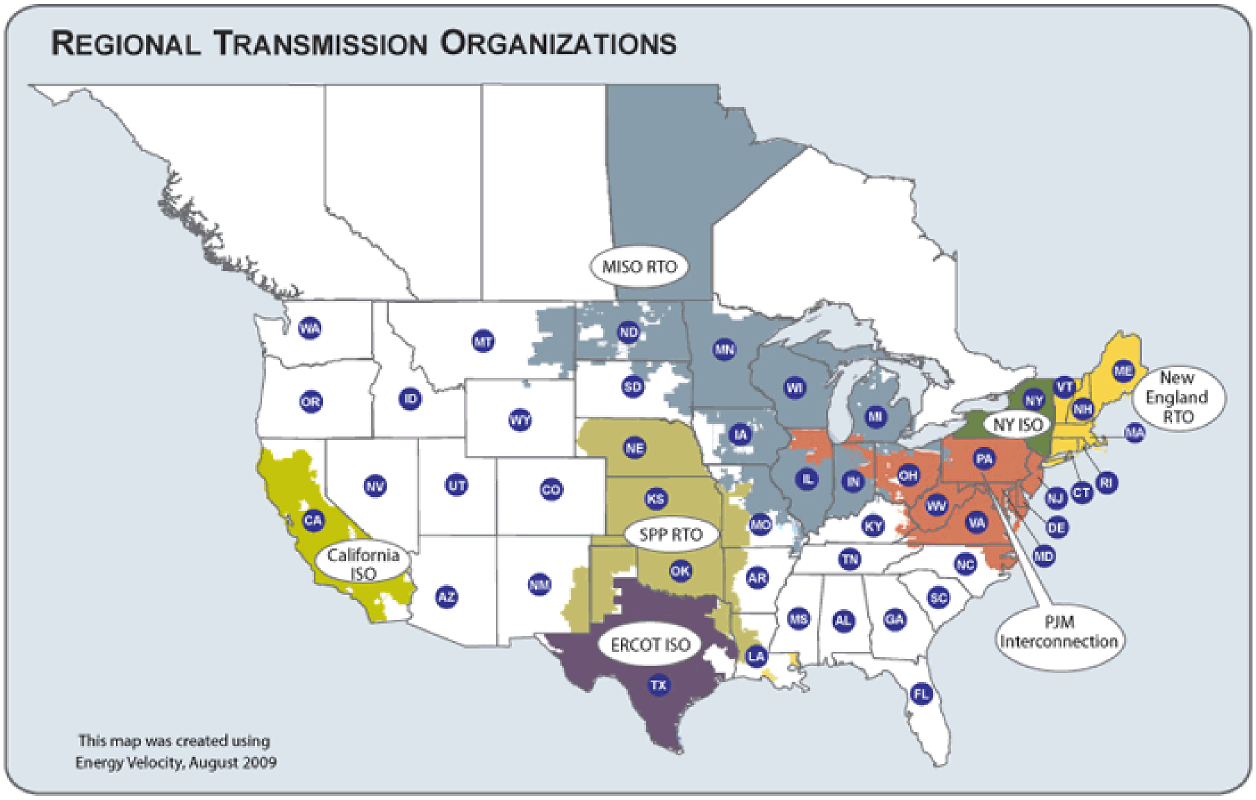

Figure 10. Regional transmission organizations in North America [17]

While two-thirds of the nation's electricity load is served by RTO and ISO regions, a large geographic portion of the country operates under more traditional market structures, including the Southeast and the West. The Southeast electric market is a bilateral market that includes all or parts of 12 states and spans two NERC regions: the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Council (SERC). Bilateral markets consist of contracts between power generating companies and load serving entities, which can be retail electric providers, municipally owned utilities, and cooperatives.

The power markets in the West are also bilateral markets that include parts or all of 10 states excluding most of California. These markets include the Northwest Power Pool, the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern-Nevada Power Area within the Western Electric Coordinating Council (WECC). Throughout the West, there are many balancing authorities that operate independently, but some work together and have joint transmission planning and reserve sharing agreements. The balancing authorities are responsible for operating the transmission grid reliably, with duties including dispatching generation, procuring power, and maintaining adequate reserves.

Moving from the regional level to the federal or national level, the DOE is not primarily a regulatory body. Chiefly, the DOE is a technical agency whose mission is to "ensure America's security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions." [18] The DOE provides technical expertise, mostly in research and development, to states and other regulatory bodies. [19,20] The DOE also acts as a conduit for federal financing of energy-related infrastructure projects.

Additionally, the DOE Office of Electricity Delivery and Energy Reliability (OE) administers an international permitting program for the export of domestically produced electricity, known as an export authorizations, [21] and a separate permitting program (Presidential permits) for the construction, operation, maintenance, or connection at the borders of the U.S. of facilities for the transmission of electric energy between the U.S. and a foreign country. [22] In reviewing applications for export authorizations or Presidential permits, DOE considers the impacts of the proposed export or transmission project on electricity system reliability. A table of relevant laws and processes for Canada, the U.S., and Mexico is provided in Appendix Section 8.2.3. Furthermore, the EPAct 2005 tasks the DOE with developing mechanisms for and leading transmission project permitting coordination and implementation. [23] DOE's OE also develops a triennial National Congestion Study to inform the potential designation of National Interest Electric Transmission Corridors (National Corridors). [24]

> A National Corridor designation itself does not preempt state authority or any state actions. The designation does not constitute a determination that transmission must, or even should, be built; it is not a proposal to build a transmission facility and it does not direct anyone to make a proposal to build additional transmission facilities. Furthermore, a National Corridor is not a siting decision, nor does it dictate the route of a proposed transmission project. The National Corridor designation serves to spotlight the congestion or constraint problems adversely affecting consumers in the area and under certain circumstances could provide FERC with limited siting authority pursuant to FPA § 216(b). [25]

Electricity system infrastructure is often subject to regulation by agencies other than the DOE and the FERC. For example, the Environmental Protection Agency (EPA) promulgates environmental regulations to protect human health and the environment. [26] Some of EPA's air, water, and waste regulations impact the electricity industry, including several recent and pending regulations.[14] While most environmental regulations directly affect generation infrastructure, such as the pending carbon emission standards for power plants, some EPA regulations can affect distribution and transmission.

When federal agencies make decisions, such as for transmission facility permitting, they must consider the broader "environmental" impacts of those decisions prior to issuing them. For example, the National Environmental Policy Act of 1969 (NEPA) requires federal agencies undertaking a major federal action that could significantly affect the environment to evaluate the impacts of the federal action and to document (either through an environmental assessment or a more detailed environmental impact statement) the environmental impacts of and alternatives to the major federal action. [27] Certain federal actions are excluded from the

[14] Some recent EPA regulations impacting the electricity include the Mercury and Air Toxics Standards Rule (finalized Dec 2011), the Cross State Air Pollution Rule (pending in the U.S. Supreme Court), the Coal Combustion Residuals Rule (pending EPA finalization), the Cooling Water Intake Structures rule under Clean Water Act Section 316(b) (pending EPA finalization), and the Greenhouse Gas New Source Performance Standards (pending EPA proposal). See www.epa.gov for more information on EPA's regulations.

NEPA review if they meet the criteria for approved categorical exclusions, e.g., export of electricity using existing facilities is not expected to have an environmental impact.

Additionally, federal undertakings are also subject to review under Section 106 of the National Historic Preservation Act (NHPA), which requires federal agencies to review the historic and cultural resource impacts from the proposed federal undertaking.[15] Federal permitting decisions, such as for transmission infrastructure, constitute major federal actions and federal undertakings under NEPA and Section 106, respectively. Federal agencies must conclude their NEPA and Section 106 reviews before issuing decisions on proposed projects. However, neither NEPA nor Section 106 is the determining factor for a permitting agency's decision; instead, they inform the permitting agency's decisions and any conditions to the permitting agency's decision.

Other laws and regulations may also be applicable to activities within the electricity system. Those discussed above are examples chosen to illustrate how complex the process is, especially at the federal level, on electricity sector issues. States may also have their own versions of NEPA and Section 106, among other regulations, which must be complied with for a project to gain state approval.

3.2 Europe

3.2.1 Toward Competitive Electricity Markets in Europe: A Historical Perspective

The drive toward liberalizing energy markets in Europe, and specifically in the EU, forms part of a greater global process of liberalization and deregulation. The objective in the EU is to establish the internal energy market, which should cover both the electricity and the natural gas industry sectors. This forms part of the internal market process that was launched in 1986. To understand the developments and negotiations that took place at the EU level between 1990 and 1996 to prepare the moves toward the first EU Directive[16] on electricity market opening, it is important to recall three of the basic reasons for energy liberalization that fall within the political, economic, and legal frameworks. [28]

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[15] The American Council for Historic Preservation (ACHP) provides an overview and resources for Section 106 review: http://www.achp.gov/work106.html.

[16] An EU directive is the most important legislative instrument alongside the EU regulation. It is issued by the European Council, more frequently jointly together with the European Parliament (under the co-decision path, depending on the field), generally upon proposal of European Commission. A directive is binding on the member states in terms of objective to be achieved but leaves it to the national authorities to decide on how the agreed EU objective is to be incorporated into their domestic legal systems. Its purpose is in fact twofold: securing the necessary uniformity of EU law and respecting the diversity of national traditions and structures. What a directive primarily aims for is not the unification of the law, but its harmonization within EU. On the contrary, a regulation targets the unification of law within EU. The third category of EU legal acts is the one of decisions, which are the means normally available to the EU institutions to order that a measure be taken in an individual case (either a member state or an individual or undertaking). Differently from directives, regulations and decisions, that constitute the binding EU legislation, a communication is a "soft legislation" instrument used by the European Commission to express its opinions and proposals to member states and other EU institutions, and to commit itself to take action to foster the therein objectives. A package normally groups different EU acts of a specific field.

The political motives have been based on the liberalization trends (also in the energy sector) started in the 1970s and 1980s in different parts of the world and extended by the EU in the fields of electricity and gas, also considering the EU's involvement and integration in global trade and the world economy. This evolution has also aimed to achieve greater competitiveness for energy markets.

The second reason for energy liberalization is economic, targeting the reduction of electricity prices; electricity bought in Europe is generally more expensive than in the U.S. or in other parts of the world. More competitive market prices should contribute (in certain circumstances) to the reduction of costs for enterprises, and then to a greater competitiveness of European enterprises (energy-consuming industries) on the international markets. At the same time, due to pressures from the market and from competition, energy-producing industries should also make themselves as efficient and competitive as possible. This would result in better opportunities for European industries, ensuring that they create economic growth and employment.

The third reason for energy liberalization in Europe is legal in nature. The EU Treaty [29] defines the internal market as "an area without internal frontiers in which the free movement of goods, persons, services and capital is ensured in accordance with the provisions of the Treaty." The EU Treaty provisions imply that some forms of energy, like oil, gas, and electricity (electricity also to be considered as a good, as stated by the European Court of Justice), are subject to the general rules contained therein. This forms the legal reason why the European Commission (EC), as guardian of the EU Treaty, had a duty to take action to complete the internal market, including the energy field.

At the beginning of 1990s, one of the main difficulties and challenges for opening competition in the electricity market across Europe was the wide variety of organizations and structures among utilities in Europe. Some countries had a central electricity supply system, integrating generation, transmission, and distribution all in the same monopolistic, vertically integrated structure. Other countries left electricity supply up to regional and even municipal utilities, with generation and transmission also in the hands of various participants. The picture concerning ownership of generation, transmission, and distribution facilities was also very heterogeneous. In some countries, plant and networks were publicly owned, in other ones private or mixed ownership prevailed. In some countries, public authorities were strongly involved in defining and regulating issues of "Public Service" (with differences across EU member states).

The EC recognized the variety of existing supply structures and the different starting points in terms of historical, cultural, legal, and economic conditions in the different countries.

When addressing this issue at the European level, the commission originally based its ideas for the establishment of the internal energy market on four general principles: a gradual approach to enable the industry to adjust to its new competitive environment; a degree of subsidiarity to enable member states to choose the system they feel fits their situation best; the avoidance of excessive regulation; and, a continuing political dialogue with all the institutions of the EU.

As a first step, in 1990 and 1991, the European Council of Ministers adopted two directives on electricity and gas transit and another directive on price transparency for gas and electricity price.[17]

Clearly, the monopolistic utilities in Europe had no intention to open the energy market to other participants and tried to derail the liberalization process; in the beginning, with support of some political parties, they succeeded. In 1992, the EC presented its first proposal for the internal market for electricity. It was based on the three main elements of the creation of a transparent and non-discriminatory system for granting production licenses: the unbundling of management and accounting of the production, transmission and distribution functions of vertically integrated undertakings, and the introduction of limited third-party access to the transmission and distribution networks.

The theory behind third-party access is to enable producers and consumers to conclude contracts directly with each other, thus furthering the objectives of competition and competitive prices. This access is important to encourage competition on both the consumers' and the generators' side of the electricity market, by exposing both ends of the market to such pressures. The original proposal contained a form of obligatory or regulated third-party access to electricity networks to facilitate such direct contractual relationships.

In 1993, the EC amended its proposals after the European Parliament had asked for a large number of modifications. As a major concession to those in Parliament who were concerned about the mandatory nature of the original third-party access concept, the EC replaced this by negotiated third-party access. This means that producers and consumers will contract supplies directly with each other, but they will have to negotiate access to the network with its operator. By means of a tendering or an authorization procedure, the proposal covered the procedures necessary for the construction of new production capacity.

However, this new approach to third-party access failed to win over all the member states, and during negotiations in the European Council in 1994, the French Government put forward an alternative scheme for the third-party access concept, that of the single buyer. Stated schematically, this would mean a single entity being responsible for the management, security, and all electricity purchase and sale activities within a particular network, allowing for only limited open market to contract foreign or independent supplies. The single buyer approach represents something very different to energy liberalization, in which the consumer market is opened to a limited degree only. At the request of the European Council, the EC studied this French approach and concluded that it was incompatible with the EU Treaty and could not coexist with the EC's own negotiated access approach. However, as a compromise for finding a way out of the political deadlock in negotiations, the EC suggested modifying the so-called single buyer model in a number of areas to bring it in line with the EU Treaty and to ensure fair competition, full reciprocity and equivalent economic consequences as between the two models. In 1995, the Spanish Presidency of the Council of Ministers presented a full compromise text for the electricity directive, including the option of a modified single-buyer

[17] The two provisions for the electricity sector are: the "Council Directive 90/377/EEC of 29 June 1990 concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users " and the "Council Directive 90/547/EEC of 29 October 1990 on the transit of electricity through transmission grids".

model together with the existing option of third-party access, but it was not completely successful. It became clear that disagreement persisted on one basic issue, namely the degree of market opening in the first phase of market liberalization, depending on the consumption threshold above which consumers would be eligible to take part in the first phase. From the beginning of 1996, the Italian Presidency of the Council of Ministers tried to solve this final issue, with a proposal on market opening in a range between 20%–40% of total electricity consumption, in which member states would be free to identify which customers would be eligible to participate and which would be supported by safeguard and transparency measures.

At the meeting of the Energy Council in May 1996, all member states could agree to the structure and principles of this approach; however, they failed to reach agreement on the percentages, further progress in market opening, and duration of the necessary transition periods. At a further extraordinary meeting of the Energy Council, held in Luxembourg in June 1996, political agreement was finally found on the whole electricity directive and its terms were confirmed by the formal adoption of a "common position" by the Energy Council in July. This was the result of many discussions since 1992 and reflected the broad degree of consensus and compromise at last found between the EU's member states and between the EU's institutions. In accordance with the EC's own intentions, the compromise consisted not in creating one uniform system throughout Europe, but in providing for a measure of subsidiarity and flexibility for member states when applying these rules to their particular national situation, while at the same time avoiding excessive regulation. This was reflected in the number of options and models member states can choose from in the first Directive concerning common rules of the internal market in electricity (adopted as 96/92/EC Directive on December 19, 1996). [30] This Directive establishes common rules for the generation, transmission and distribution of electricity.

In the final text, the following principles underlay the Directive:

- Equivalence (free choice and combinations of options provided that they lead to equivalent economic results and to a directly comparable level of opening up markets and to a directly comparable degree of access to electricity markets)
- Reciprocity (safeguard clause against unfair competition between unequal market systems)
- Public service (member states may impose obligations upon electricity companies to meet requirements related to security of supply, regularity, quality, and price of supply and related to environmental protection)

It must be highlighted that the first electricity market Directive, which played a crucial, significant role in the sector liberalization in Europe, was, however, insufficient to set the full conditions for an extended electricity market opening. For this reason, it was then replaced and repealed by the second electricity market Directive (2003/54/EC) (which was in turn replaced by the third electricity market Directive 2009/72/EC), as described Section 3.2.2.

3.2.2 EU Policy Overview

The EU policy for the electric power industry aims at the three targets: system competitiveness, environmental sustainability, and security of electricity supply. The main goals of the electricity markets' liberalization and integration process consist in improving power supply services, lowering electricity prices, and, thus, increasing competitiveness of European (especially industrial) companies. As discussed in Section 3.2.1, the EU legislation for the electric power industry is mostly based on the directives, regulations, and decisions of the European Parliament and of the Council, as well as on the national legislative provisions of the EU member states. The EU directives have to be mandatorily implemented into the national legislations of all EU member states and establish only the most general principles to be applied to the power system industry regulation. Detailed determination of regulatory methods and forms is left to the legislative and executive bodies of member states (see also Section 3.2.1).

After replacing the first Directive 96/92/EC, the second Directive 2003/54/EC [31] played the most important role for the EU's electric power industry since 2003, setting further common rules for the European electricity market. Also, this Directive, like the first one, aimed at progressive market opening for competition, elimination of discrimination, and higher level of integration of electricity markets of member states.

In accordance with the Directive, member states have been compelled to ensure equality of access of EU electricity companies to national consumers. Technical rules establishing the minimum design and operational requirements for the connection of new facilities are to be objective and non-discriminatory. The authorization procedures for new generating capacity should also satisfy objective, transparent, and non-discriminatory criteria. If, on the basis of the authorization procedure, the generating capacity being built is not sufficient to ensure security of supply, member states can launch tendering or other non-discriminatory procedure for new generation or DSM. Member states shall designate a body independent of electricity generation, transmission, distribution, and supply activities to be a regulatory authority responsible for the tendering procedure.

The Directive has paid attention to customer protection. To ensure that all household customers can receive electricity at reasonable prices, member states can appoint suppliers of last resort. Distribution companies shall be obliged to connect customers to their grids under regulated terms and tariffs. It is also important that member states ensure that any eligible customer has the possibility of changing power supplier and to make sure that customers can choose suppliers consciously (the suppliers are obliged to specify the contribution of each energy source to the overall fuel mix and their environmental impact). Since July 1, 2007, all customers have been eligible.

To provide security of power supply, member states must ensure the monitoring of supply security issues. This can be done by regulatory authorities or by other entities. This monitoring includes current and future supply/demand balance and quality of network maintenance. Measures to cover peak demand and to deal with suppliers outages should also be monitored.

Member states shall designate one or more TSOs, who are responsible for the following:

- Expanding transmission systems: transmission systems should be reasonably expanded to meet load demands increases and improve security of supply.
- Operating the system: TSOs manage energy flows in the system and ancillary services for secure, reliable, and efficient system operation.
- Information communication: other TSOs are provided with the necessary information to ensure efficient operation, development, and interoperability of the

interconnected system while system users being provided with the information for efficient access to the system.
- Ensuring non-discrimination.

If a TSO is part of a vertically integrated undertaking, it shall be independent of other activities not related to transmission. Ownership separation of transmission assets from the undertaking is not necessary. To ensure independence of the TSO with respect to the undertaking, the following criteria are applied:

- Persons responsible for the TSO management may not participate in company structures dealing with generation, distribution and supply of electricity.
- Appropriate measures should be taken to stimulate persons responsible for the TSO management to act independently.
- The TSO shall have decision-making rights concerning assets necessary to operate, maintain and develop the network. These rights should be independent of the integrated undertaking.
- The TSO shall take measures to exclude discriminatory behavior.

If TSOs are responsible for reserves or loss compensation, they shall procure the reserve capacity and energy according to transparent, non-discriminatory, and market-based procedures. Only one kind of discrimination is officially allowed: a member state may require its TSO to give priority to renewable energy or energy produced in combined cycle.

Member states shall also designate one or more distribution system operators (DSOs) to create a secure, reliable, and efficient distribution system taking into account environmental issues. DSOs must not discriminate between system users and shall provide customers with all necessary information for efficient access to the distribution system. If a DSO is responsible for reserves or loss compensation, it shall procure the reserve capacity and energy according to transparent, non-discriminatory, and market-based procedures. During dispatching, a priority can be given to renewable energy or energy produced in a combined cycle.

If a DSO is part of a vertically integrated utility, it shall be independent of other utility departments at least in terms of its legal form, organization, and decision making. Ownership separation of DSO assets from the vertically integrated company is not necessary. To ensure the independence of the DSO, the same criteria ensuring TSO independence are applied. One entity is allowed to combine TSO and DSO activities (a combined operator). For a combined operator legal, organizational and decision-making unbundling is also applied without obligatory asset separation.

For transmission and distribution systems, the principle of third-party access is implemented. The essence of the principle is that any eligible customer can access networks without any discrimination. The access is based on published regulated tariffs and technical rules that are applicable to all eligible system users. The system operator can refuse access to the network only if there is no sufficient capacity.

In addition to the third-party access principle, another regulatory regime is applied. This is based on direct lines. According to the Directive, member states shall ensure that all electricity producers and undertakings are able to supply their subsidiaries and eligible customers through direct lines. All consumers should have a possibility to be supplied through a direct line by a producer or supply undertaking. The authorization criteria for the direct line construction should be objective and non-discriminatory. The possibility to supply or to be supplied through a direct line should not affect the possibility of contracting electricity through the common grid. Nevertheless, it is up to member states whether a certain direct line is authorized or not. Authorization for a direct line can be refused if the line can obstruct public service obligations or customer protection provisions.

According to the Directive, member states may decide not to apply the provisions concerning authorization and tendering for new capacity, third-party access, and direct lines, if their application would obstruct the performance of the obligations imposed on electric companies. However, this is only possible as far as the development of trade is not significantly affected and in contrast with interests of the EU (including competition among eligible customers). The directive also requires that each member state designates at least one regulatory authority, which is independent of the interests of the electricity industry. These authorities are responsible for ensuring market and competition efficiency, non-discrimination and monitoring of some market elements, rules and mechanisms. The regulators shall also be responsible for regulation of terms and conditions for connection and access to networks and the provision of balancing services.

In September 2007, a new proposal on the common rules for the European electricity market was presented as part of the so-called EU Third Legislative Package[18] [32] and in July 2009 it became the third EU Directive on electricity market (Directive 2009/72/EC). [33] This document, starting from the principles contained in the Directive 2003/54/EC brings new regulatory elements to the EU electric power industry. The new Directive 2009/72/EC entered into force on September 3, 2009 and was implemented by all EU member states by March 3, 2011, when the former Directive 2003/54/EC was repealed.

The background of the new Directive is that legal and decision-making unbundling of transmission networks from other power system businesses was not sufficient since it did not prevent discrimination of market participants in favor of the vertically integrated undertakings. Therefore, it was suggested that ownership unbundling of transmission assets should be granted. Member states must ensure that the same person cannot exercise control over a generation or supply company while having control over a TSO or over a transmission system. Vice versa, control over TSO or over a transmission system precludes the possibility of exercising any control over a generation or supply undertaking. One person is allowed to hold interests in both a generation or supply undertaking and a TSO or a transmission company, but this shareholder should have no controlling or blocking rights in both undertakings and can neither be a member of a board nor appoint board members. The new Directive also suggests an alternative option; instead of obligatory ownership unbundling, member states may force vertically integrated undertakings to transfer network management to an independent system

[18] The Third Legislative Package consists of two directives, one concerning common rules for the internal market in gas (2009/73/EC), one concerning common rules for the internal market in electricity (2009/72/EC) and three regulations, one on conditions for access to the natural gas transmission networks ((EC) No 715/2009), one on conditions for access to the network for cross-border exchange of electricity ((EC) No 714/2009) and one on the establishment of the Agency for the Cooperation of Energy Regulators ACER ((EC) No 713/2009). They were adopted in July 2009.

operator (ISO) or an independent transmission operator (ITO). ISOs/ITOs shall be completely independent of the vertically integrated company and perform all TSO functions.

The new Directive states that the current legislation allows new infrastructure to be exempted from regulated third-party access for a predetermined period. This exemption regime is perceived to provide a positive possibility that can bring benefit to network development, security of supply, and competition. Therefore, it is proposed to take measures to apply the exemption regime more widely.

Towards the establishment of a more integrated and efficient electricity market in the EU, great attention is paid by the Third Package to the improvement of the cooperation mechanisms of regulating authorities. This process has led to the creation of an Agency for the Cooperation of Energy Regulators (ACER), which aims to harmonize the regulatory mechanisms of electric power industries of different EU member states (as stated in the Regulation [EC] No. 713/2009 establishing the ACER [34]). The Agency provides a framework for cooperation of national regulators, monitors the cooperation between TSOs, makes regulatory decisions on some cross-border issues, and serve as an advisor for the EC concerning market regulation issues. ACER has close cooperation with the European Network of Transmission System Operators for Electricity (ENTSO-E),[19] the European TSO association founded in 2008 which embraces all previous TSO European organizations like the Union for the Co-ordination of Transmission of Electricity, Nordel, the United Kingdom Transmission System Operators Association, the Association of the Transmission System Operators of Ireland, the Baltic Transmission System Operators, and the European Transmission System Operators. [35] (See also Sections 3.2.3 and 4.2.) As far as the technical and market codes are concerned, the Agency is empowered to ask TSOs to modify their code drafts or to tackle more specific issues in detail. It is also able to recommend that the EC makes these codes legally binding where voluntary implementation by TSOs seems to be insufficient or unsuitable for certain issues. ACER makes decisions concerning the regulatory regime to be applied to infrastructure assets connecting territories of two or more member states.

In summary, the new agency acts as a supranational regulator with broad regulatory power in the European electric power industry. In addition to the creation of ACER, the Regulation No. 713/2009 suggests more market regulation power for the national regulators. The national regulating authorities have the power to perform the following duties:

- Monitor compliance of TSOs and DSOs with the third-party access rules, unbundling obligations, balancing mechanisms, managing congestion and interconnection management.
- Review the investment plans of TSOs and provide an assessment of the extent to which the plans are consistent with the European-wide, long-term network development plan.
- Monitor network security and reliability and review network security and reliability rules.
- Monitor transparency obligations.

[19] ENTSO-E is in charge of drafting grid codes, pan-European development plans, R&D Roadmap, system adequacy reports.

- Monitor the level of market opening and competition and promote competition in cooperation with responsible authorities.
- Ensure that consumer protection measures are effective.

Also, national regulators have the power to receive any data concerning operational decisions of companies, which will be obliged to keep these records for five years. The regulators are able to impose dissuasive sanctions.

The national regulators should be completely independent of any public or private entity, even of governments. For that purpose, it is proposed that regulatory authorities have legal personality, budgetary autonomy, appropriate human and financial resources, and independent management.

3.2.3 Infrastructure Regulation Developments

The central role of the transmission grid within the EU energy policy calls for a truly pan-European approach to the planning and operation of the electricity infrastructures, especially for those having a significant cross-border impact. The strategic importance of strengthening cross-border transmission networks in Europe has been remarked by different documents of the EC. [36, 37, 38, 39, 40]

Concerning the development of new transmission infrastructure, the European TSOs have substantially kept a national scope so far. However, this approach proved unable to provide a pan-European view and take into account the cross-border needs originated by complementary generation sources located in different European places. To fill this gap, in 2006, the EC issued the Trans-European Energy Networks (TEN-E) Guidelines document, featuring a list of infrastructure recognized as priority projects of European interest. After a few years, this approach has led to the following limitations: it is static, it was collected from the different TSOs from the bottom up, and it did not highlight the rapidly changing pan-European priorities. In addition, notwithstanding some improvements in unlocking some TEN-E priority projects of European interest due, for example, to the intervention of a European Coordinator, the situation for the completion of such projects stayed critical. In fact, out of 32 TEN-E priority projects of European interest, as of March 2010, only a small quota of them, 16%, had been completed, and 29% of them identified as projects under construction, while the relevant share of 55% was still in the authorization and/or in the study or reconsideration phase. [41]

In this frame, in order to overcome this critical situation, the EC issued two communications in November 2010. The first one defined energy strategy priorities in Europe towards 2020 targets and called for a step change in the way energy infrastructures and networks in Europe are planned, constructed, and operated. The second one, more specifically, set the creation of a pan-European methodological approach in prioritizing the projects of European interest as a key measure towards EU targets for 2020 and beyond. In this direction, a crucial role is played by ENTSO-E which has to progressively implement the necessary transmission development evolution steps to address the EU requirements. Although the creation of ENTSO-E was initiated by the adoption of the EU third legislative package on the gas and electricity markets, not all ENTSO-E members are within the EU.

An important contribution to this process was given by the first (pilot) ENTSO-E Ten-Year Network Development Plan (TYNDP) 2010–2020 [42], issued in 2010, extended then in 2012 [43], and to be updated every two years thereafter.[20] Although the TYNDP is still obtained by means of a bottom-up data collection from the national TSOs, including internal system projects reflecting local (regional or national) grid issues and bottlenecks, a gradual change fostered by the EC in favor of a new top-down pan-European approach, especially for cross-border impact projects investigation, has started in the recent years. The TYNDP 2014, however, tries to overcome these drawbacks by a more in-depth consultation process and especially by focusing on a common cost benefit analysis methodology.

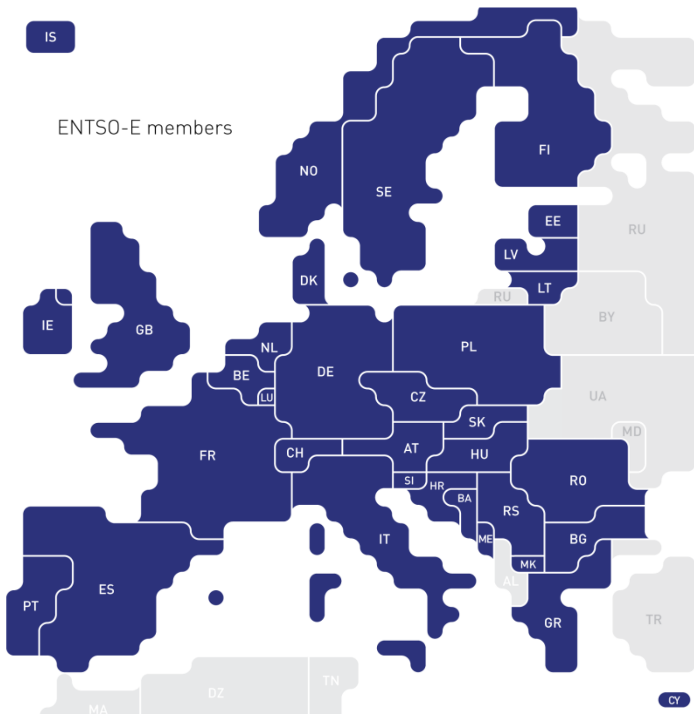

Figure 11. Countries participating in ENTSO-E [35]

3.2.4 The EC 2010 Energy Infrastructure Package

As mentioned, a completely new EU transmission infrastructure policy based on a European vision is necessary to deliver the energy networks that Europe needs in the next two decades. This also means changing the current TEN-E practice, featured by predefined (and inflexible) project lists, towards a new pan-European approach. The EU established the following steps in the so-called 2010 Energy Infrastructure Package issued by the EC in November 2010 (which was completed in October 2011 by a proposal for a new regulation [44] which has been amended and approved in April 2013 by the European Council and the European Parliament) and is currently in place (repealing the TEN-E instrument):

[20] The TYNDP 2014 package is expected to be in public consultation March-April 2014.

- Identification of the energy infrastructures leading towards a pan-European smart network (so-called "supergrid").
- Focus on a limited number of European 2020 priorities, where EU action can play a major role, to meet the long-term objectives.
- Selection and frequent update of concrete projects necessary to implement the European priorities in a flexible manner so as to respond to changing market conditions and technology development within predefined priority corridors and areas.
- Support of the implementation of European priority projects through new approaches and tools, aiming at fostering regional cooperation, streamlining permitting procedures, improving methods and information for decision makers and citizens, as well as applying innovative financial instruments.

This infrastructure policy framework sets the creation of a pan-European approach to prioritize the projects of European interest based on an adequate Europe-wide transmission investment cost-benefit methodology as a key measure towards EU targets for 2020 and beyond.

Four crucial priority corridors of the European power system are identified that will have to be more urgently developed and reinforced to ensure timely integration of renewable generation capacities in Northern and Southern Europe and foster further market integration (see also Figure 12):

- Offshore grid in the North Seas and connection to Northern and Central Europe
- Completion of the BEMIP (Baltic Energy Market Interconnection Plan)
- Interconnections in South Western Europe
- Connections in Central Eastern and South Eastern Europe

In the electricity sector, in addition to these four priority corridors, smart grids deployment and electricity highways development across Europe have been also included as priority areas for infrastructure expansion towards 2020 and beyond. [39,44] These highways, which can be thought as the axes of a potential pan-European supergrid [45], need to be built stepwise, ensuring progressive compatibility with the existing network, based on a modular development plan. [46]

The realization of a potential pan-European supergrid, as mentioned above, is a complex process that can only be considered in a long-term perspective (after 2020), as there are still several techno-economic, technological, regulatory, market, and socio-environmental issues that will have to be properly handled and solved over the years. Towards this goal, different stages for an incremental evolution from the current European grid are to be foreseen considering the needed progressive re-engineering process and the relevant paradigm shift with respect to the traditional approach to transmission system development and operation adopted so far in Europe. [47,48]

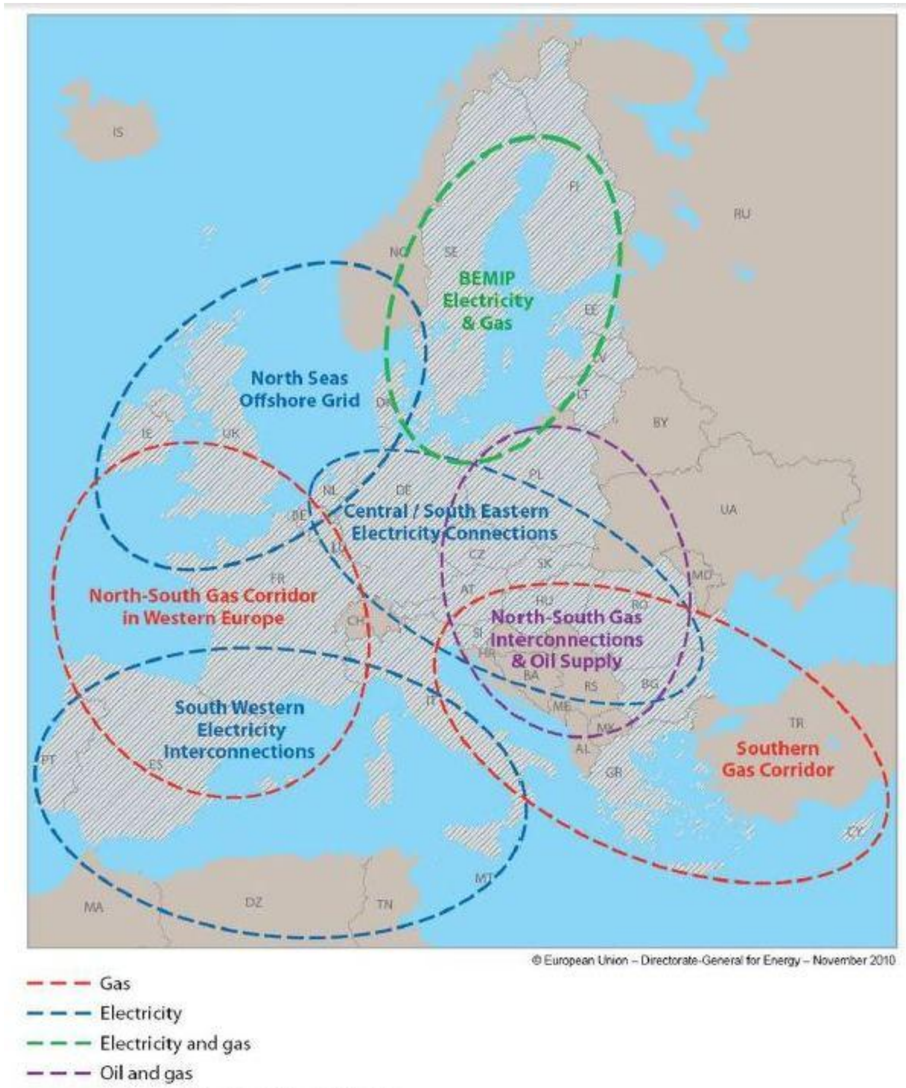

Figure 12. Priority corridors in Europe [39]

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4 Transmission Operation and Management

4.1 United States

Operating and managing the grid is a multi-layered, complex system-wide task. Actual operation of the grid infrastructure does not happen unilaterally by a single entity or even similarly situated entities on a national level, but rather is accomplished across a wide variety of organizations, acting in concert across various functions. It includes many players across many local, state, regional and federal entities. Understanding the relationship these entities have to one another and to the transmission and distribution (T&D) system is integral to understanding the T&D system itself. This section will examine these various entities and the functions they perform, beginning with the most "national" in scope, and ending with the most localized. Additionally, this section is closely related to Section 5.1, which discusses U.S. transmission planning and expansion.

At the highest level, the U.S. is connected by three distinct grids. The Quebec Interconnection is the fourth interconnection comprising the North American grid. These systems operate almost entirely independent from one another, but there is limited flow of electricity across the seams of the interconnections. High-voltage direct current (HVDC) transmission systems enable the transfer of power between the interconnections. These systems require a rectifier to convert from one region's alternating current (AC) system to DC where HVDC lines then transmit to the next region where an inverter converts the DC back to AC in the new region. Six DC ties connect the Western Interconnection with the Eastern Interconnection within the U.S., with one additional tie in Canada. There is also an additional intertie between the ERCOT Interconnection and Mexico. The ERCOT Interconnection is linked to the Eastern Interconnection by two DC interties.

Within the interconnections, the transfer of electricity from one place to another happens across more regional boundaries, such as from one RTO to another, or from a region where there is no RTO or ISO to an area where the system is operated by such an organization, or vice versa. Capacity at these seams is limited due to the ownership of physical infrastructure, membership of particular RTO/ISO entities, and different electricity policy structures of regions. [1] Efficient control of the power flow across these seams is an essential component of managing the electric grid. Generally, those organizations responsible for managing the power flow across the seams of the RTOs are those in the best position to understand the needs of the system.

4.1.1 Operating and Oversight Organizations

The U.S. transmission system is managed across a variety of industry standards and will vary according to jurisdiction. The three interconnections, or macro-regional operating areas, comprising the U.S. grid system (the Eastern Interconnection, the Western Interconnection, and ERCOT Interconnection) are minimally connected but primarily operate as distinct systems, with key connection points existing along the seams, as noted above. (See Figure 5, page 19.)

States and federal entities have jurisdiction over different aspects of planning and building new transmission lines and other bulk-power delivery equipment. The differences essentially break down in the following way: states have authority over physically siting new lines and developing rates for retail electricity; the FERC has authority over approving interstate transmission rates and cost recovery allocation for transmission projects. Both state and federal regulators play a role in planning. Thus, transmission planning differs from state to state and by region depending on both the structure of the market in that state or region and the requirements of the regulators in a particular state. Where a project is wholly intrastate, certain planning mechanisms become less important, specifically the need to coordinate siting decisions between different states. However, even for intra-state lines, the cost recovery and rate-setting is still overseen by the FERC.[21]

Through the FERC's role of approving rates for transmission lines, it has become more involved with transmission planning policy; a significant driver of rates is the physical system on which the electricity is traded and transported. Thus, the string of orders approved by the FERC, including Orders 888 [2], 890 [3] and 1000 [4] (see Appendix Section 8.2.2) have increased regional requirements for system expansion planning. These orders require that projects must be approved by a regional area prior to being sent to the FERC for review and approval. The most recent action, Order 1000, requires open, transparent, and inclusive regional and inter-regional planning processes and development of regional cost allocation methodologies, among other requirements.

Regional entities that are registered to perform planning authority functions[22] still have control over the process, and this process differs from region to region.[23] For example, in a RTO/ISO market, the long-term reliability planning and reliability responsibility within the RTO/ISO's footprint boundaries falls to the RTO/ISO, which is an independently operated entity comprised of utility and transmission asset owners. Member entities usually include traditional investor owned utilities that remain vertically integrated, individual generator and transmission owners or operators, as well as municipal and cooperative utilities that operate on an unregulated basis. Membership in an RTO/ISO is voluntary, but the independent organization does operate the bulk power system to ensure reliability and designs the market in which the power is provided. Therefore, if the utility or generator was not a member of the ISO, such an entity would still be subject to its rates and reliability planning.

In addition to the interconnections and RTOs/ISOs, there are also four federal power marketing administrations (PMAs) that play an important role in regional power delivery

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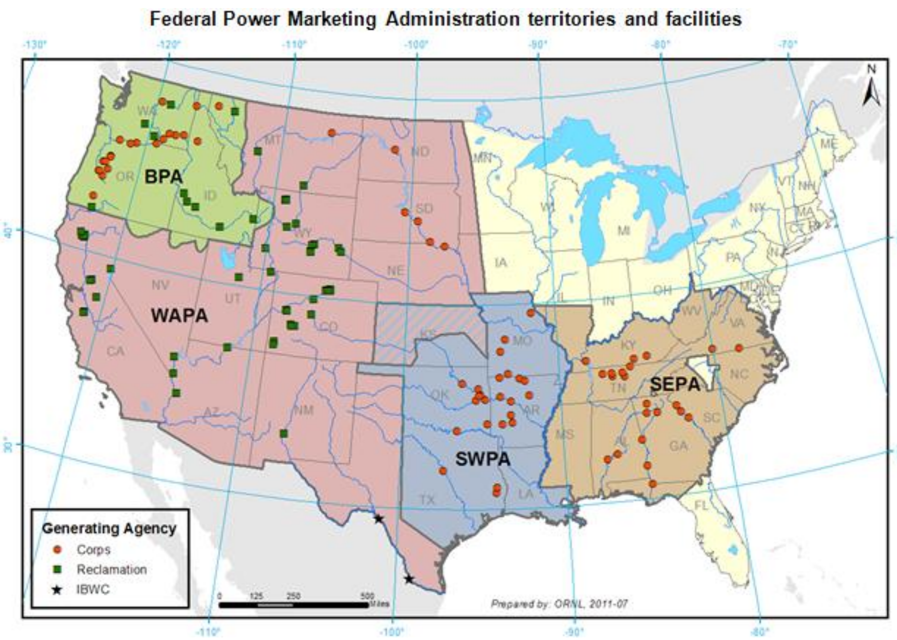
[21] The exception is lines located in the ERCOT Interconnection, which is not FERC jurisdictional. ERCOT does interconnect with other states, but has been exempted from federal oversight. See the Midnight Connection Jared M. Fleisher, "ERCOT's Jurisdictional Status: A Legal History and Contemporary Appraisal," Texas Journal of Oil, Gas and Energy Law, March 19, 2008.

[22] The NERC Reliability Functional Model defines the set of functions that must be performed to ensure the reliability of the bulk electric system. It also explains the relationship between and among the entities responsible for performing the tasks within each function. Version 5 is available online: http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf.

[23] All bulk power system owners, operators, and users are required to register with NERC, with a monthly release of the Active Compliance Registry publicly posted to the web: http://www.nerc.com/pa/comp/Registration%20and%20Certification%20DL/NERC_Compliance_Registry_Matrix_Excel20130930.xls.

systems, with a core functionality of generation, delivery (transmission), and helping ensure reliability of power derived from hydroelectric plants within the respective PMA areas of operations. (See Figure 13). Similarly, the Tennessee Valley Authority (TVA), a corporation owned by the U.S. government, provides electricity for nine million people in parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee, and Virginia. TVA sells electricity to 155 local power companies and directly to industry and U.S. federal facilities.

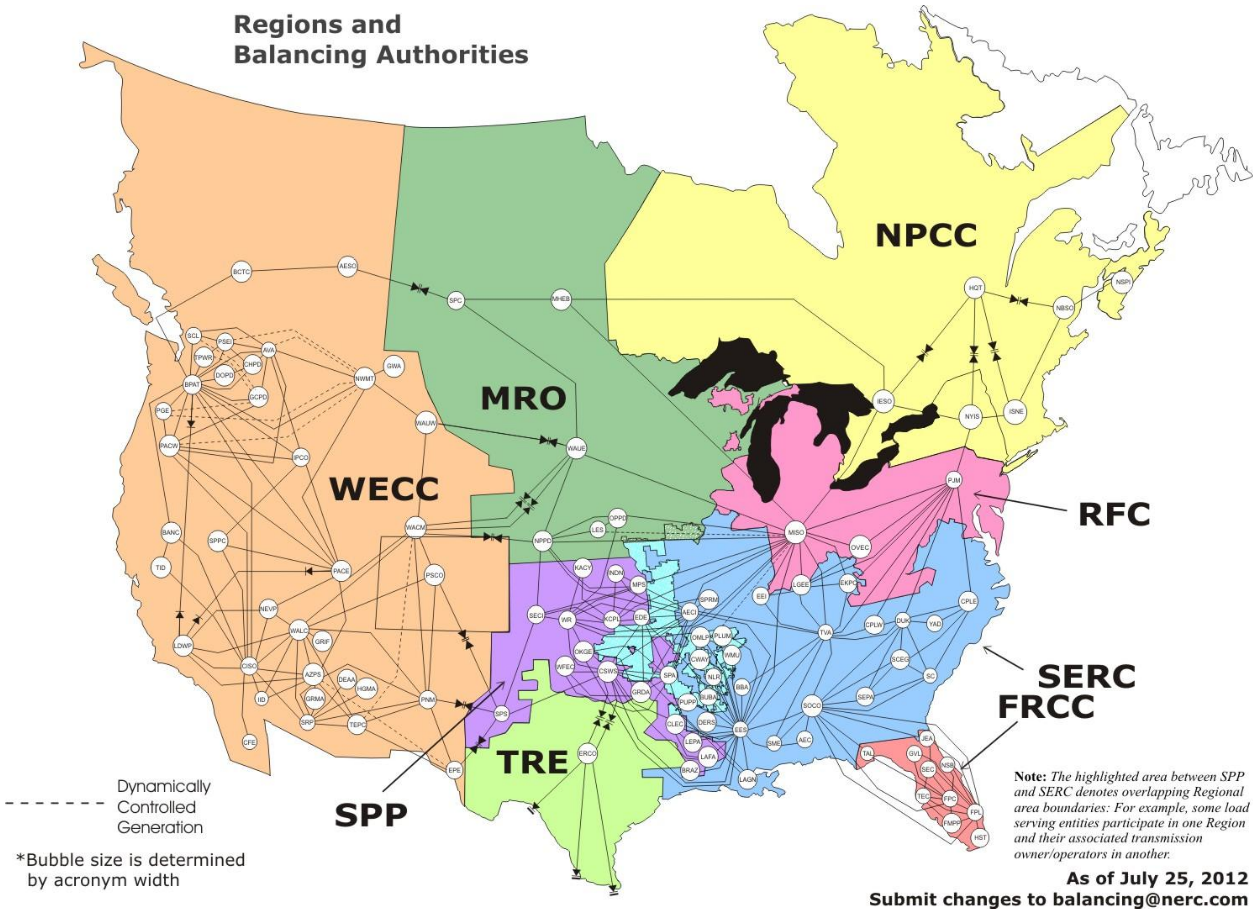


BPA – Bonneville Power Administration; WAPA – Western Area Power Administration;
SWPA – Southwestern Power Administration; SEPA – Southeastern Power Administration;
Corp – U.S. Army Corps of Engineers; Reclamation – U.S. Bureau of Reclamation;
IBWC – International Boundary and Water Commission

Figure 13. U.S. Power Marketing Administrations (PMAs) [5]

NERC also facilitates 15 reliability coordinators among the eight NERC regional reliability entities (see Figure 14). According to NERC, the reliability coordinator ensures that schedules of power delivery are being met. [6] The reliability coordinator oversees the individual balancing authorities (see Figure 14). Balancing authorities are "[t]he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area and supports interconnection frequency in real time."[24] Balancing authorities may be thought of as the "front lines" of electricity dispatch and ensure real-time reliability within the balancing authority area.

[24] "The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The Balancing authority maintains load-resource balance within this area." See NERC Glossary of Terms.



Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); ReliabilityFirst Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool, RE (SPP); Texas Reliability Entity (TRE); Western Electricity Coordinating Council (WECC)

Figure 14. NERC regions and balancing authorities [7]

4.1.2 Transmission System Operation and Reliability

The coordination between the RTOs/ISOs and the various reliability areas and organizations constitutes the majority of the power flow in operating and managing the bulk power system. The FERC devolves authority to NERC to develop continent-wide reliability standards for which its regional entities oversee compliance. [8]

Reliability coordinators are the highest level entities that oversee and may take preventative measures in ensuring the reliable operation of the bulk power system. The oversight happens in real-time and is focused on wide area visibility, as the reliability coordinator has the ability to establish interconnection reliability operating limits, which are far beyond the purview of any transmission operator's scope. The reliability coordinator's area consists of all the transmission, generation, and loads within the geographical area and may coincide with one or more balancing authority areas. The balancing authorities, in their respective balancing authority areas, are responsible for administering these standards and for ensuring that those actually dispatching the power meet them. When power is transmitted across balancing authority areas, the transaction is called an interchange and is approved and monitored by an interchange authority. Either the balancing authority or the reliability coordinator, depending on the operational structure of the region, will be vested with operational control at a given time; a single entity can simultaneously perform both reliability roles. Additionally, in areas where the transmission system is operated independently, the transmission facilities control center may be responsible for the real-time dispatch of power, as is the case in the state of Vermont, where Vermont Electric Power Company (VELCO) operates the statewide transmission grid.

Further adding to this complexity is the distinction between generation and transmission ownership and operational responsibilities, and the state and federal tension that exists between jurisdiction over siting. Importantly, the FERC has exclusive jurisdiction over establishing wholesale transmission rates while state PUCs and similar organizations have jurisdiction over cost recovery, allocation, and rate of return for generation infrastructure owners. The strong states' rights tradition in the U.S. creates tension between the two levels of government and cooperation is necessary to successfully engage in transmission planning.

As one can see, operating the electric system in the U.S. is a complicated matter. Below, this discussion paper will discuss the various seams of the bulk power system, focusing on high-level concepts necessary for context in presenting the coordination efforts underway in transmission planning and market design.

4.1.3 Distribution Distinctions

In the U.S., the distinction between transmission and distribution is one of size and scope. Transmission refers to the transport of electrons at high voltages from generating infrastructure to converting stations (substations or transformers), as mentioned above, 100 kV or higher. Just as transmission refers to the transport of electricity at high voltages, distribution systems transport electricity at much lower voltages, usually at voltages below 69 kV, with local feeders operating at 12–15 kV or below. While transmission infrastructure usually spans larger distances and may include DC lines, distribution infrastructure relies on numerous sub-transmission stations to step the power down to residential levels, which are usually located closer to the load. As such, distribution systems are typically owned and operated directly by a utility, whereas an independent transmission company may own and/or operate only the transmission infrastructure within the system.

It is helpful to understand that, in the U.S., distribution is generally a state-level issue. Both unregulated (such as municipal districts) and regulated electricity providers, and vertically integrated independently-owned utilities may own and operate distribution systems. The owner of the local distribution system is responsible for operation and maintenance and ensures the delivery of electricity to retail residential, commercial, and small industrial customers. Traditionally, the distribution system and transmission system each had a well-defined relationship, which facilitated clearly defined roles for each mechanism of electricity delivery. However, transmission and distribution systems are likely to interact more in the future. The Annex 6 workshop in Milan focused on transmission/distribution interactions. [9]

As a result, the distribution system also entails or encompasses the broad concept of DG, including feed-in tariffs and net metering. These largely localized concepts occur at the residential or individual customer level, and deal with electricity service to a residential, commercial, or small industrial user. DG, which is localized production of electricity, e.g., solar photovoltaic (PV), allows customers to reduce or eliminate the need to draw electricity from the gird. Additionally, excess electricity produced from these systems may be sold back to the utility or into the market, depending on the state regulatory regime. No residential and very few commercial DG resources implicate the voltages or wattages at the transmission level.[25]

Residential generation is closely related to the feed in tariff (FiT), a mechanism used at the state level to consumer self generation. A FiT is a set price for a particular source of renewable energy, and of particular importance, for DG. The FiT is usually allocated to the generation for a set term of purchase, typically long enough to finance the energy source infrastructure, such as solar panels. A FiT aims to incentivize smaller scale projects and is typically not robust enough to incentivize larger, commercially scaled projects with higher installation and operation costs (such as wind farms, which primarily benefit from state RPS programs). As such, a FiT seeks to incentivize renewables at a more local level, typically through DG. Also of importance to the localized or distribution level is the smart meter; FiT is being deployed for residential consumer use in ever larger numbers. As the penetration of smart meters (and other AMI) increases, utilities will have greater ability to engage in dynamic pricing and demand response initiatives.

The EPAct 2005 mandated RTOs to include customer options for net metering. This regulatory action spurred a large state response and most states now offer net metering opportunities. The concept of net metering is closely related to FiTs and DG. Net metering allows customers to install renewable generation "behind the meter," or to generate their own small-scale commercial or residential renewable power. Rather than relying on a utility to purchase renewable energy, net metering programs create a financial incentive to install renewable energy locally. The incentive exists when the residential or small-scale commercial generation is sufficient to offset entirely the retail customer's bill. Further, when the generation is more than sufficient, the meter "spins backwards" thus generating a credit—which is where the FiT comes into play. The credit is applied against the customer's utility bill. Net metering usually requires a separate meter to track the local generation of power. Group net metering is available in certain jurisdictions (including Vermont) and allows small-scale commercial or residential users to benefit from local renewable generation without having to invest or be directly connected to the generation infrastructure.

4.2 Europe

4.2.1 Operating and Oversight Organizations

The European power system consists of five major synchronous areas: Continental, Nordic, Great Britain, Ireland, and Baltic (see Figure 15). Some HVDC links connect the synchronous areas and they are used for commercial and security[26] support reasons.

[25] Especially considering that many state laws restrict the size of such distributed generation resources, and retain authority to deny connection to the local grid.

[26] In the power system terminology, security refers to as the capability of the system to withstand disturbances, such as short circuits or the loss of a generating unit, without impacting the continuity of the power supply to the customers.

ENTSO-E, the body of TSOs at the European level, includes 41 TSOs from 34 countries, as noted earlier. Through its activities – grid codes, working groups – it aims to support security of operation by harmonization of operating rules and cooperation among TSOs, as well as talk with the EC and the European regulators grouped in the CEER organization. In the actual European legal framework, however, each TSO bears the responsibility of system reliability in its own control area.

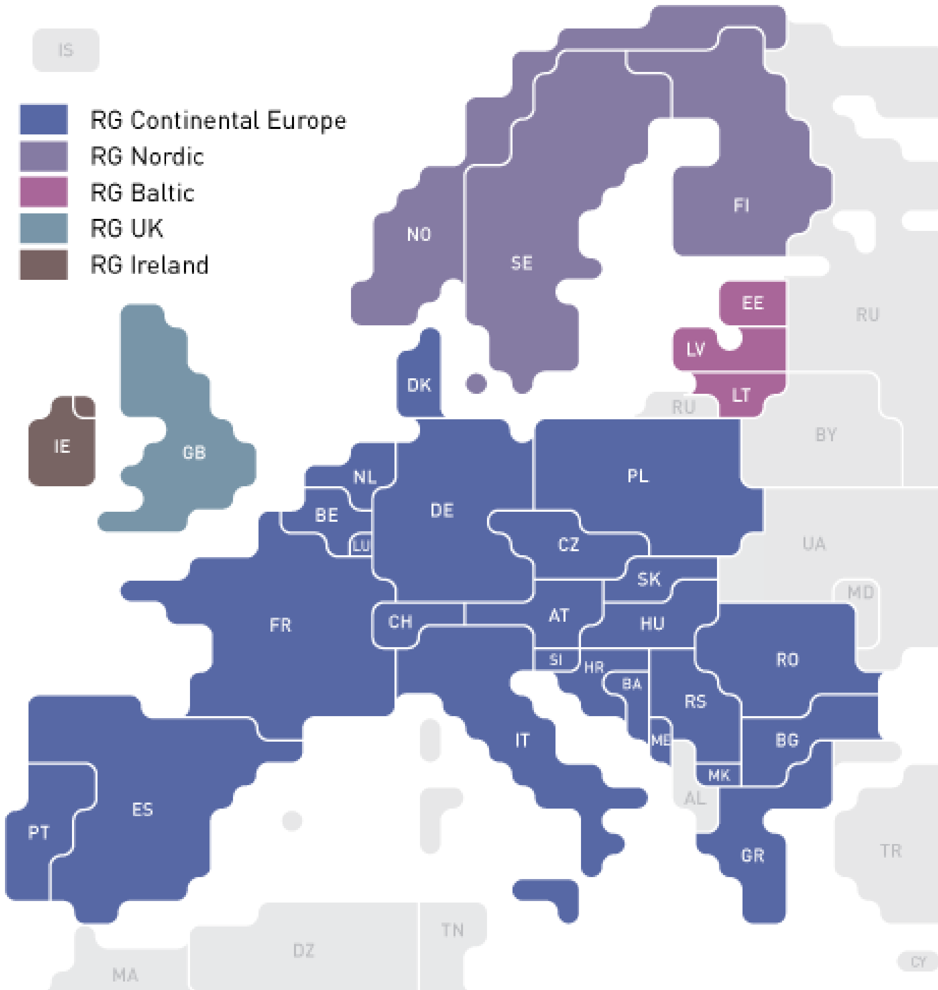


Figure 15. Synchronous areas in Europe (ENTSO-E)

Specific bi- or multi-lateral agreements may hold for security procedures and control actions. In the continental interconnected system, security is determined by the Operation Handbook. As far as the Nordic countries are concerned, a specific Agreement is in force.[27]

The current status of security management strategy at the European level is represented by ENTSO-E Network Code on Operational Security (amended version submitted to ACER, September 2013) [10] in which requirements on frequency and voltage control, short circuit current management, contingency analysis and handling, protection and System

[27] All of these documents are available at the ENTSO-E website www.entsoe.eu.

Protection Schemes, dynamic stability management, data exchange, and operator training are proposed. These rules focus on common operational security principles, pan-European operational security, and coordination of system operation; however, they are still essentially based on the N-1 criterion.

Previously, security of operation has been based on the deterministic N-1 criterion, i.e., the system must be made robust with respect to the loss of any single element. However, blackouts may arise from more complex, multiple events, involving the power and/or the information and communication technology (ICT) layer used for monitoring, control, protection, and defense of the power system. On the other hand, under today's push from the market and renewables, it may be problematic even to meet the conventional N-1 criterion. Hence, there is a need for advanced defense systems and accurate methods and tools for online security analysis and identification of control actions.

As established by the EC [11], one of the crucial objectives for the electricity networks is to identify methods and techniques to manage the security of the power system and to develop and validate advanced control systems and monitoring techniques to improve flexibility and security of the networks. To this aim, research projects are ongoing [12] [13],[28] in order to assess operational security in a deeper way by addressing several challenges such as multiple events, ICT vulnerabilities, risk-based approaches, and grid dimensionality in online analyses.

TSOs strongly need jointly-agreed practical methodologies to assess the operational risk in order to control risks and to guarantee an adequate security level for the interconnected network. A remarkable example of inter-TSO cooperation for supporting operation is CORESO, an independent company set up by several TSOs in Western Europe aiming to help them to enhance the level of security of supply by bringing a wide vision of electricity flows complementary to their national vision. CORESO acts as a Regional Coordination Service Centre providing its shareholders[29] with services of coordination with regard to the forecast and operation of electricity flows. The major objective of CORESO is to avoid large disturbances by intensive studies of the risks and coordination ahead of real-time. Thus, the main service provided by CORESO consists of day-ahead and intraday security analyses and remedial actions coordination management. However, CORESO is able to perform online security analysis every 15 minutes and suggest countermeasures. Responsibility of control actions remains however at TSO level.

Another interesting example of a joint initiative for security of operation is Transmission System Operator Security Cooperation (TSC), involving 13 TSOs from central Europe. [14] Its aim is to help member TSOs to better manage the growing operational needs, especially those related to changes in production allocation until close to real-time, the integration of wind energy, increasing cross-border trading, and increasing electricity transport via multilateral cooperation. This aim is pursued by various organizational and technical actions, e.g., creating a network of experts, developing common procedures and data exchange, performing common

[28] It is worth mentioning also another EU project, named GARPUR, currently at its start, aiming to investigate new operational criteria of large grids with RES.

[29] CORESO shareholders include 50Hertz, Elia, National Grid, RTE, and Terna, representing more than 40% of the EU's population.

training. In particular, the "Common Tool for Data exchange and Security assessments (CTDS)" is a collaboration platform which facilitates grid security calculations.

Some highlights of the emerging issues relevant for operation are briefly mentioned in the following sections.

4.2.2 Security and RES

The penetration of growing amounts of non-dispatchable RES, mainly wind and PV, allows reduction of the consumption share covered by fossil fuel-fired power plants, but introduces a number of criticalities in power system planning and operation. [15] The network must be developed to connect renewable energy production, often located far from the bulk transmission system, and permit access to flexibility resources such as reserve capacity and remote energy storage. As far as operation is concerned, several problems arise at both the local and system levels. RES and more in general DG connected to distribution level may cause local control and protection problems, such as power flow inversion possibly implying protection misoperation, unintended island, voltage deviations from nominal values, local congestion. At the system level, stability and congestion problems may arise. Voltage and short circuit power issues may be exacerbated too, as the smaller number of online conventional generators implies a smaller support to grid voltages under normal and faulty conditions. In particular, frequency stability, from short-term (response to contingencies) to long-term (balancing), is a key issue. As RESs have priority of dispatch in Europe, conventional generation is "displaced" so that the number of conventional units in operation is reduced. Conventional generation is still much needed, however, being increasingly called upon to provide ancillary services rather than bulk energy services. In fact, the high variability of RES generation introduces large excursions in the relevant power injections. Conventional generation must provide higher ramping performances and be available to supply power during periods of low renewable generation. Moreover, the forecast uncertainty of RES generation increases the operating reserve requirements from conventional units for balancing purposes. Overgeneration problems have been experienced in countries with large RES penetration, calling for measures such as the disconnection of RESs and DG.

As far as dynamic phenomena are concerned, since a lot of RESs are connected to the grid through power electronic converters, the inertia of the system (traditionally assured by the synchronous machines of conventional generators) decreases, thus leading to more severe frequency transients unless specific controls are introduced in the converters. In addition, renewable power plants are operated in most countries with no upward margin in order not to "waste" the primary energy resource; thus, they do not contribute to primary regulation to counteract underfrequencies. As far as downward regulation is concerned, grid codes often pose less demanding requirements than conventional units. Overall, online contingency reserve decreases. [16, 17, 18] High penetration of DG may impact security at the system level as well. The presence of DG may substantially affect the effectiveness of load shedding schemes that were designed when DG was negligible. In addition, the settings of under/overfrequency relays of DG are, or have been, until recently, very strict in many countries. This may lead to the tripping of DG in cases of system disturbances, especially in countries with large penetration of PV units in distribution networks like Germany and Italy (where the limits were, respectively, +200 mHz and ±300 mHz) which have recently introduced new connection requirements for new or already existing plants. [19] Operation issues related to PV systems have been recently addressed by the European TSOs. [20]

Germany and Italy have undertaken large programs to retrofit the majority of their existing non-compliant units, which should be completed by end-2014. As pointed out by ENTSO-E, in case of maximum power production of dispersed units and until the on-going retrofit programs are complete, the frequency gradient after massive disconnection of DG is so high that the first step of underfrequency load shedding is not sufficient to prevent frequency collapse. On the other hand, the penetration of RES sin the other countries is not negligible and additional retrofit programs in other European countries are needed to avoid reaching the critical condition of load shedding activation in cases of plausible disturbances.

4.2.3 Challenges and Ongoing Research Programs

The major challenges of transmission system operation in Europe are due to the extension of the electricity market and the integration of large amounts of renewables, in particular wind and PV, and DG. Due to market arrangements and renewable generation, the interconnections between areas are exploited at their security limits. Moreover, diversity and volatility of operating conditions lead to difficulties for the operators in understanding the actual security margins and deciding timely, appropriate actions. Jurisdictional issues may also prevent optimal decisions from being implemented.

The technology and control strategies of DG inherently modify the dynamics of the power system, possibly causing stability problems. Conventional generators are still required to provide the necessary reserve and control features (both power and voltage). DG control and protection settings are additional issues that may impact the system. Overall, increased TSO/DSO coordination is needed, with changes on both the technical and regulatory sides. Widespread disturbances similar to, or worse than, the one that affected the continental European interconnected system in 2006 might occur.

Advancements in transmission technologies and ICT allow for enhanced tools for system control and monitoring. Power flow control devices and systems, such as phase shifting transformers (PST) and HVDC, effectively support security of operation. However, the complexity of system behavior is increasing, as is the need for inter-TSO coordination. Wide area measurement systems (WAMS), conveying in real-time the phasor measurements by phasor measurement units (PMUs), have been installed in several European countries and already provide support in security monitoring and in other important tasks such as maneuvering in stressed situations. On the other hand, enhanced analysis tools able to assess online the security of the whole system and the need for control actions are increasingly needed. With the increasing penetration of ICT systems in power system operation, cyber security concerns also increase, demonstrating the need for adoption of standard protocols for communication. To prevent attacks, more severe security policies are being set in place although several issues remain open.

The ongoing EU co-funded iTESLA project, based on a large consortium of European TSOs supported by IT companies, research centers, and universities [13] aims at developing new concepts, methods, and an open interoperable platform to assess security limits of the pan-European system and to quantify the distance between an operating point and its nearest security boundary. Security assessment accounts for the forecast uncertainties over different time horizons, with the ultimate objective of determining if preventive actions are needed (in which case they must be activated in due advance) or less costly corrective actions are sufficient in case of contingency occurrence.

In the AFTER project, relying on TSOs' perspective integrated with research institutes and academia, [12] consideration is given to the fact that electric power systems are vulnerable to different threats, including from accidents, natural disasters, and deliberate acts of sabotage. The resilience of the integrated power and ICT system with respect to failures, caused by different kinds of threats, must be assessed. Equipment failures and/or subsystem malfunctions, natural events and disasters, negligence of the operators, malicious behavior such as deliberate acts of sabotage, and criminal activity must be taken into account. All of these threats may result in multiple contingencies leading to extensive loss of electricity supply. Within the AFTER research project, the need for a three-fold step forward in security assessment approaches has been identified:

(1) Expressing security of supply in terms of risk, considering in particular how to manage wide area disturbances caused by multiple contingencies as an integration of conventional deterministic approaches to security (based on the N-1 criterion) and convey a better insight into the risk.

(2) A more integrated modeling of the power and ICT subsystems to be considered in security assessment tools to evaluate the effects of their interdependencies on electricity supply.[30]

(3) An extension of contingency analysis considering all types of hazards/threats, i.e., natural events, technical failures, human/operational errors and deliberate acts (e.g. sabotage), thus providing a more complete analysis of the causes for loss of supply.

A preliminary investigation of statistical yearbooks [21], as well as of the final reports of recent blackouts, helped identify the main causes of service and infrastructure disruptions, which led to a proposed classification of the significant threats. Figure 16 summarizes the contributions as percentages of the total number of events to the disturbances in the UCTE (now Continental Europe—CE area within ENTSO-E) grid during 2008.

[30] Several examples from recent blackouts support this statement, e.g., the out-of-service of (both primary and backup) SCADA servers at FirstEnergy during the Northeast U.S. blackout in 2003 caused a loss of observability of the power system and a subsequent delay in deploying suitable corrective actions, which worsened the power system operation in the following minutes. Malfunction of protection systems due to wrong settings, inadequate logics, and failures in actuators or measurement devices can delay the clearance of a fault or cause inadvertent tripping, reducing the stability of the power system, as demonstrated by the 2006 European blackout. [30] Wrong settings in defense systems can also jeopardize the effectiveness of these measures in counteracting system disruption.

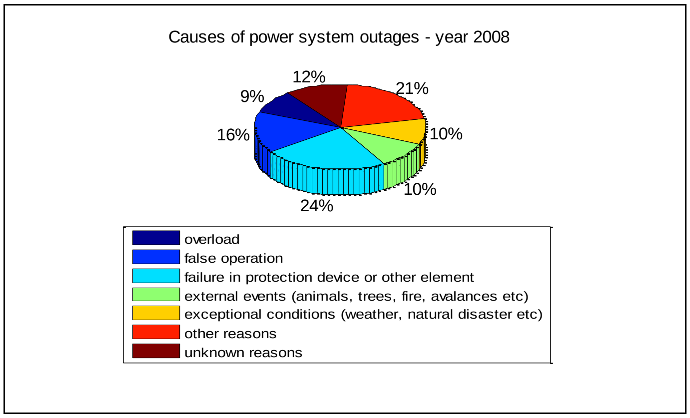


Figure 16. Statistical analysis of the electric transmission faults in the UCTE Continental Europe (CE) area during 2008.

Along these lines, in view of supporting common categories for incident classification, ENTSO-E published an Incidents Classification Scale (ICS) methodology [22] including four levels of disturbance severity. The objective is to facilitate the identification of the causes and most important sources of disturbance.

As far as the causes of disturbances are concerned, a classification of the threats for both ICT components and power components was proposed in the AFTER project, which emphasizes the distinction between natural and man-related threats. Another dimension of the classification distinguishes between internal and external threats, respectively coming from inside or outside the boundaries of the system under study (including power and ICT components). Moreover, man-related actions can be intentional or not. Table 1 shows the classification of some threats to the power and ICT components. ICT threats may affect either the physical infrastructure or the logical level. This classification may provide the basis for more detailed reporting of the causes of disturbance events and identify the need for preventive countermeasures.

Another important security issue in the synchronous grids of Europe is the deterministic frequency deviations from the setpoint, occurring around the change of the hour. This phenomenon has been recognized as a consequence of the market design, as the generators change their scheduled output in steps every hour and keep their output practically constant until the next hour, whereas the consumption changes only gradually. This fact endangers security of operation as it implies a reduction of power reserves to face sudden power imbalances, e.g., the loss of generators. A solution has been proposed, consisting of splitting the market period into quarters of hours instead of full hours. [23] This solution is currently under investigation; its implementation would impact the market structure.

Table 1. Examples of power and ICT threats

Power component threats	***External*** (Exogenous)	***Internal*** (Endogenous)
Natural	Lightning, fires, ice/snow storms, floods, solar storms	Component faults, strained operating conditions
Man-related	Unintentional damage by operating a crane; Sabotage, terrorism, outsider errors	Employee errors Malicious actions by unfaithful employees
ICT threats (Physical or Logical)	***External*** (Exogenous)	***Internal*** (Endogenous)
Natural	Ice and snow, floods, fire and high temperature, solar storm	ICT component internal faults Data overflow
Man-related	Hacker, sabotage, malicious outsider	SW bugs Employee errors Malicious actions by unfaithful employees

4.2.4 Recommendations

Regarding operation issues and transmission technologies, reference should be made to the discussion paper "Smarter & Stronger Power Transmission: Review of feasible technologies for enhanced capacity and flexibility" prepared by Annex 6 Tasks 3-4. [24] As far as the impact of policy, planning and regulatory issues on operation is concerned, it can be stressed that actions should be taken along these lines:

- Accomplish or deploy retrofitting programs of DG.
- Foster increased coordination between TSOs and DSOs in distribution system monitoring and control by deploying distribution smart grid programs.
- Develop the regulatory and technical framework for smart distribution grids, in order to allow participation of DG in system services and remote control.
- Deploy market mechanisms in order to guarantee availability of sufficient conventional generation in the new paradigm of large RES penetration for use as balancing services (i.e., make such services profitable, develop capacity market strategies).
- Foster technological development aimed to improve the performances of conventional generation in the new paradigm (e.g., higher ramping rate, reduced minimum output power).
- Enhance the portfolio of flexibility resources, by setting proper frameworks allowing, for example, load contribution to security provision (industrial or possibly

distributed loads, referred to as demand-side participation) and utilization of pumped storage[31] for system services.

4.3 References

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[3] Federal Energy Regulatory Commission, “Order 890, Preventing Undue Discrimination and Preference in Transmission Service,” http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

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[31] Storage through other forms such as Compressed Air Energy Storage (CAES) and batteries are also increasingly noted for their potential to provide services at system level.

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5 Transmission Expansion Planning

5.1 United States

Transmission expansion in the U.S. is accomplished through a variety of mechanisms and to address various issues such as congestion and reliability. Understanding and managing congestion is an integral component of transmission expansion. For example, in the Northeastern part of the U.S., transmission congestion can cause unwanted price increases and reliability concerns. To begin to better address the congestion problems in the U.S., Congress amended the FPA through the EPAct 2005 to require the DOE to conduct a national electricity congestion study and, further, to designate geographic areas of national interest, concern, or importance as national interest electric transmission corridors (see Section 3.1.4 and the discussion below). [1]

Following is a description of current planning practices, a summary of some of the major expansion initiatives, and a brief discussion of some of the tools being developed to facilitate effective transmission expansion while incorporating emerging technologies and addressing challenges facing the industry.

5.1.1 Transmission Planning

Transmission planning in the U.S. has focused on investment for reliability with recent efforts to identify efficient and cost-effective transmission expansion options. While transmission investment is done by utilities and transmission companies, planning occurs on various levels and through several planning activities. A series of FERC orders, beginning with Order 890 in 2007, have prompted a shift toward more transparent and inclusive planning processes, which are also becoming increasingly regional and interregional in scope. The FERC, who exercises jurisdiction over wholesale tariffs and rates, has begun exerting influence over planning as a way to ensure that transmission infrastructure is in place to allow for efficient operation of the grid, and that rates are just and reasonable.

Other drivers of the expanded use of regional and interregional planning process include recognition of regional and national transmission congestion and integration of new variable resources. Congress, through the EPAct 2005, and the FERC have both identified a need to reduce regional and interregional congestion; strategically planning transmission is one way to potentially accommodate or alleviate congestion.[32] Additionally, the need to accommodate variable energy resources into the grid in a coordinated and reliable way through cooperation lends itself to regional planning because of the large amounts of transmission infrastructure usually required for such projects.

[32] Other ways to address congestion include resource investment, demand-side programs, distributed generation, or operational changes. In some cases it is not economically-attractive to reduce or remove transmission congestion because alleviating the congestion is judged to be more expensive than not.

Reliance on regional planning also reflects the criticism that the U.S grid is highly balkanized. [2] This is not just an operational observation, but also a reality that reflects reliability and security concerns. A disjointed grid is much less able to deal with significant disruptions than is a coordinated and integrated electricity delivery system. The chosen approach to begin to deal with this weakness is the coordinated planning and expansion of interstate transmission projects. The more that systems can work with other systems across seams in a holistic way, the more secure and stable the whole North American grid will be.

One of the most recent and comprehensive interregional transmission planning initiatives is the DOE-sponsored IWTP project (noted above). The objective of the project, funded under the ARRA,[33] "is to [help] strengthen the capabilities for long-term analysis and planning in the three interconnections serving the lower 48 [states]."[34] The DOE awarded grants to five organizations to establish open, coordinated, and transparent planning processes in each of the three U.S. interconnections. The awards have two objectives: (1) for industry and transmission planners to address the actual physical requirements of the current and future system and (2) for state-level authorities, including utility and environmental regulators, among others, to address interconnection priorities and planning processes. The organizations were directed to develop 20-year transmission plans.

Each interconnection planning body is comprised of and engages stakeholders, but approaches the planning process in different ways. The Eastern Interconnection is represented by both the Eastern Interconnection Planning Collaborative (EIPC) and the Eastern Interconnection States Planning Council (EISPC). The EIPC comprises and represents industry and asset owners in the Eastern Interconnection and is conducting the technical analysis behind the long-term transmission expansion modeling. The EISPC comprises and engages with the state-level authorities, regulators, and interested organizations to provide input and guidance, particularly with respect to state and federal policy, to the planning process.

In the Western Interconnection, the Western Electricity Coordinating Council (WECC) and the Western Governors Association (WGA) received the industry- and state-based awards, respectively. Again, the two organizations generally represent the differentiation of the award between industry and asset owners, and states and other representative organizations; however, there was some coordination between the awardees. The ERCOT was the sole awardee for its interconnection, conducting activities to support both the industry and state award objectives..

The IWTP process addressed prospective needs of the respective interconnections, but do not result in firm plans or investment decisions. It is important to remember, however, that the participants of these organizations are often the same as those who are actually engaging in the physical expansion of the system. These organizations, conceptually and financially under the IWTP, are mechanisms by which interregional and national transmission needs might be approached and eventually addressed. The actual authority to effectuate this commonly

[33] As discussed above, the ARRA is legislation that effectively implemented President Barack Obama's 2009 stimulus package to help rejuvenate the U.S. economy.
[34] The IWTP is administered pursuant to Title IV of the ARRA, through the DOE Office of Electricity Delivery and Energy Reliability. See http://energy.gov/oe/information-center/recovery-act/recovery-act-interconnection-transmission-planning.

agreed upon process, as implemented within each interconnection, is still widely disparate and shared among many smaller parties and organizations.

Another example of interregional planning, the Northeast Coordinated System Plan, is a tool used to identify and alleviate areas of congestion and to identify reliability concerns and increase the over-all reliability, security and resiliency of the grid across PJM, NYISO, and ISO-NE, specifically. [3] The congestion and reliability analyses of this process, while distinct from one another, was done for the purpose of planning and expanding the transmission system. Ideally, transmission system expansion enhances reliability, relieves congestion where it exists, and increases the overall security of the system. Planning is the blueprint by which stakeholders achieve the purposes of transmission system expansion.

Similarly, while the IWTP is an important analytical process to explore potential future needs of the grid, the outcomes of the planning activities are not the mechanisms used to accomplish transmission expansion, but may inform expansion decisions. To this end, each region engages in their own planning process to evaluate and prioritize expansion projects. This can be accomplished by utilities in vertically integrated regions, or by market operators in regional markets, such as ISO-NE, PJM, or MISO. Transmission planning may align along state and ISO boundaries, as in the case of CAISO, ERCOT, and NYISO. For example, CAISO engages its stakeholders and participants through an annually published transmission plan, which includes appropriate transmission planning standards and infrastructure requirements for the ISO balancing authority. NYISO, which operates only within the state of New York, conducts transmission planning according to its comprehensive intra-state system planning process.

There are a variety of tools and methods used for transmission planning. Some, such as software packages developed and supported by GE and Siemens, are used widely by industry participants; others are in preliminary phases or research and development. The DOE is supporting the development and maintenance of several optimization tools. One of which, referred to as the SuperOPF along with the underlying MATPOWER package, is an open-source power system simulation and optimization tool used widely in the power systems field, especially in academia. This project has developed new tools that attempt to efficiently allocate and appropriately price the various products necessary for electricity markets to function reliably and efficiently.

The unifying themes running through the various SuperOPF-based tools include the simultaneous, explicit modeling of multiple system states, where each state has a full set of optimal power flow (OPF) variables, constraints, and costs; a stochastic or weighted cost across the various states; and, additional variables, costs, and constraints that tie these states together. The data needs of the SuperOPF are significant, and the need to accurately and appropriately represent the stochastic nature of inputs is paramount in its applicability. [4,5] Other research is focusing on the co-optimization of generation and transmission expansion. [6,7] These decisions are modeled in two stages: the first well before real-time operations and the second when regulatory and system conditions are clearer. This research indicates that stochastic modeling may reveal the most efficient transmission expansion for a variety of potential futures, none of which may be optimal in any single potential modeled future.

5.1.2 Transmission Expansion

Transmission expansion is a natural outgrowth of the transmission planning process. The planning process may be seen as the analytical framework by which the actual physical expansion of the transmission network within a given grid. As discussed above, planning activities often inform the prioritization of transmission projects. Analyzing the physical needs of the system requires consideration of a vast amount of variables that affect the physical and technological makeup of the respective grid components. Expansion decisions must keep the grid operating securely and reliably. This function is often at odds with public opinion, and projects can face public challenge.[35] For example, many transmission projects implicate a large number of interested stakeholders, from private equity investors, to operators, to state and federal regulatory bodies to local community and "grass roots" organizations.

The ability to make decisions regarding actual expansion and build out of generation and transmission infrastructure needs lies with the asset owners themselves. Generally, asset owners cannot be forced to expand or build. Planners make proposals that identify needs. These proposals must obtain a variety of local, state, and federal approvals before construction can begin. The permitting processes for new lines can be complex and take many years. Some have identified lack of coordination, particularly among federal agencies, as one reason for the long permitting timelines. In response to these criticisms, the President created the interagency Rapid Response Team for Transmission that aims to increase coordination among federal agencies responsible for permitting transmission project, including those on federal land. [8]

Technological improvements and innovation may give planners and grid operators new options for expanding grid capabilities without making large, expensive investments in new transmission projects. Dynamic line rating systems and improved sensing and communication technologies may allow for more efficient use of existing transmission infrastructure, delaying or obviating the need for new investment. [9]

5.1.3 Regulatory and Planning Authorities

At the federal level, the FERC has jurisdiction over the sale of electric energy at wholesale in interstate commerce while states retain jurisdiction at the retail level. [10] The FERC also has jurisdiction over "all facilities used for [] transmission or sale of electric generation," but not over facilities (1) used for the generation of electric energy, (2) used in local distribution, or (3) for the transmission of electric energy consumed wholly by the transmitter. [10]

With respect to system reliability, FERC (and NERC) have an affirmative duty to ensure the reliability of the bulk power system. As noted earlier, NERC has been designated the electric reliability organization for North America and is responsible for developing and

[35] An example of the importance of engaging interested stakeholders is the social phenomenon known as NIMBY-ism, or "not in my back yard" opposition to transmission (or generation) infrastructure. Residential or rural communities are sensitive to changes in the physical environment associated with electricity production and transmission.

enforcing reliability standards, annually assessing seasonal and long-term reliability; and, monitoring the bulk power system.

The associated land use and environmental implications of projects requiring federal authorizations are handled by various federal agencies across the government according to their respective areas of expertise and congressional mandates. These agencies include, for example, the U.S. Department of Interior, which manages federally owned lands; the U.S. Army Corp of Engineers which has jurisdiction over wetlands; and the EPA. Further, review of a proposed transmission project by any federal permitting authority will likely trigger the requirements under the NEPA, e.g., an evaluation of the potential environmental impacts and project alternatives, and the NHPA. As noted earlier, the results from a NEPA nor NHPA review are not deciding factors, but inform a permitting agency's decision. Similarly, proposed transmission projects generally must also seek authorizations from state agencies.

Investment in transmission projects can vary by jurisdiction. For example, in vertically integrated regions, utilities are the primary entities that plan and invest in transmission expansion. In some regions, transmission-only companies own and operate the transmission network separately from the incumbent utility. In these cases, the transmission company would invest in and build new transmission.

In regions with organized electricity markets, the RTO or ISO plays a role in the transmission planning and expansion for its respective service area. It may do so according to its own objectives and stakeholder input, provided it complies with FERC and NERC requirements and receives the required permits from the federal and state agencies with jurisdiction over the project. The ISO/RTO engages in transmission expansion according to analysis of transmission needs and proposed changes to the transmission system and develops plans and forecasts for the region's future transmission and energy needs. Basically, these organizations make expansion decisions according to the outcomes of their planning processes. Additionally, the ISO or RTO coordinates maintenance of generation facilities across the bulk power system.

The introduction of electricity markets, together with increasing interregional trade and the integration of renewables, has made transmission expansion planning more complicated. Uncertainty about fuel prices, the location, amount, type of new generation, and electricity demand means that transmission investments today may later be regretted as being the wrong type, the wrong amount, or in the wrong location. Traditional deterministic planning methods cannot value the optionality and flexibility associated with particular investments as compared to alternatives whose consequences may be irreversible. Policy models that can simulate interregional additions of transfer capability and generation investment, as well as operation response, implicitly assume that market players have perfect foresight and consistent beliefs over the entire time horizon and that they must commit irreversibly to a particular expansion path today. The resulting projections of transmission investment may be quite different from what investors will do in the face of pervasive economic, technological, and policy uncertainty, particularly if some of the alternative expansion paths allow investors to revise their choices in the future when the value of present uncertainties become better known.

5.1.4 Outcomes, Challenges and Opportunities

Transmission expansion planning in the U.S. consists of a variety of formal and informal regional and interregional processes. Planning authorities (ISO/RTOs, utilities, transmission companies) invest in and build transmission. Regional and interregional planning processes offer forums for wider collaboration and communication, with the goal of increasing the efficiency of transmission investment (e.g., addressing local and regional issues with the most efficient set of projects). The DOE-funded IWTP activities created new opportunities for stakeholders within interconnections to develop relationships, focus on long-term planning issues (including policy and environmental concerns), and develop new tools and processes.

Maturation of electricity markets and integration of renewables has made transmission expansion planning more technically and institutionally complex. Other challenges include long permitting timeframes and public opposition to new infrastructure development.

Deployment of new smart grid technologies may increase capabilities of existing systems and delay or obviate the need for new investment. Research and development of new planning software and methods is being supported by the DOE. Further, more robust coordination among stakeholders results in better understanding of new technologies, tools, techniques, and options. The IWTP process and other regional and interregional planning processes can help improve coordination and communication among diverse stakeholders.

5.2 Europe

The transmission expansion planning process is a complex task in which the network planners need to handle several uncertainties and risk situations. In the past, before the electricity market liberalization, in a centrally managed power system the vertically integrated operator could control the whole power system. The transmission network was then expanded with the aim to minimize both generation and transmission costs, while meeting static and dynamic technical constraints to ensure a secure and economically efficient operation.

In the current liberalized environment, the TSO plans the expansion of its network by minimizing transmission costs (investment and operation), overcoming bottlenecks, and pursuing maximum social welfare, when requested by specific regulation, while meeting static and dynamic technical constraints to ensure a secure and economically efficient operation. Socio-environmental constraints must also be increasingly considered in the planning process. [11,12]

5.2.1 Transmission Planning Process and Challenges

Some important criticalities make the task of a TSO at the same time crucial and very delicate. In fact, changes in future system conditions significantly affect benefits of transmission expansion. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or overestimate the true benefit of the project and may lead to less than optimal decision-making. For this reason, transmission planners need to fully capture all impacts a project may have, examining a wide range of possible system conditions. Furthermore, it generally takes much longer to get a new transmission project approved and built than similar procedures for new generation facilities.

Therefore, the development of the transmission system always lags behind the development of generation. This can only be considered by using different scenarios.

The transmission planning process with its basic scheme and stages can be recalled as depicted in Figure 17. [13] The first stage of planning concerns the power system projection (scenarios) over the analyzed timeframe in terms of those elements that may impact the transmission system evolution over years of observation. Such elements regard the projected trends of load demand, import/export, and production (phasing in and out, respectively, new and old generation), which also depend on economic, market, policy, and regulatory drivers (such as the EU 2020 targets). The development of system scenarios, related to the targeted time horizon, provides the boundary conditions for planning transmission expansion. In fact, within the frame of the developed scenarios for the specific area under study, transmission planners need to check whether their related network in unchanged conditions (without any expansion, the "do nothing" alternative) is still reliable (i.e., secure and adequate). They assess the resilience of the system in different possible situations, e.g., high/low load, changing generation dispatch patterns, adverse climatic conditions, and contingencies. This analysis is carried out by applying static and dynamic reliability/security analysis methods, which take into account the so-called N-1 criterion. The application of the N-1 criterion is a general transmission management practice. It requires that, in the presence of a single contingency (i.e., an outage of a single network component like line, cable, transformer, generator, or controlling device), parameters like power flows, voltage, and current amplitudes regarding the different network elements are all within the respective operational security limits. The contingency analysis includes transient, dynamic, and steady-state stability checks for both frequency and voltage conditions. In some specific cases, more severe contingencies than those applied by the N-1 criterion can be considered by transmission planners, e.g., situations of double contingency (when applying N-2 security criterion), multiple contingencies, or loss of busbar(s). Provided these planning criteria are met, then the network can be considered secure and does not generally need an expansion to accommodate the evolution scenarios. On the other hand, if the security analysis regarding the unchanged network within the developed scenarios is not satisfied, a transmission reinforcement action must be addressed by the planners. To address a specific problem in the system, different system expansion solutions may be available ranging from upgrading/uprating the existing assets to building new ones. The available options span from using conventional technologies such as HVAC overhead lines, transformers, and cables to implementing more innovative devices.

After identifying a first, broad group of possible reinforcement solutions that address a specific issue in the system, transmission planners need to carry out a cost-benefit analysis of the different options. The aim is to compare and rank them to select the most feasible option(s). The cost-benefit analysis of the expansion alternatives comprises a techno-economic assessment of each option; the benefits provided by every option need to be carefully and quantitatively evaluated against their respective investment and operating costs. Today, this analysis needs to include environmental and social issues as well, considering the crucial role that such aspects play towards the expansion of a transmission system. In the past, a socio-environmental assessment was a further (even optional) stage in the transmission planning process. Currently, it is paramount to consider socio-environmental aspects for a more complete and systematic cost-benefit analysis. In some cases, environmental constraints and social opposition have required the transmission planners to reconsider the rank of the investigated alternatives. Subsequent steps of the process include the submission of the selected transmission expansion plan(s) related to top-ranked option(s) to the respective decision-makers (such as the competent ministries and/or regulatory authorities) for their approval. This stage is then followed by implementation of the authorization procedures at all levels (national, regional, and local) as required by their respective laws. In Figure 17, the approach to the cost-benefit analysis proposed by REALISEGRID is provided. [14]

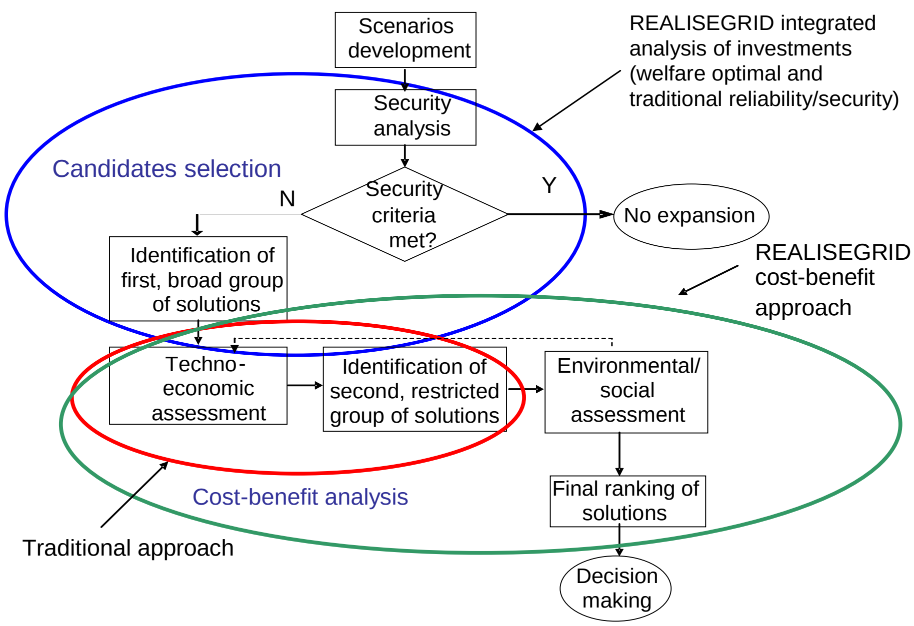

Figure 17. Basic scheme of the transmission planning process [13,14]

5.2.2 Transmission Planning Practices in Europe

A review of the transmission planning practices in Europe [12] and the previous work done within ENARD Annex IV highlight the European TSOs' two main objectives when planning the development of their grid: (1) maximizing system reliability and security of supply and (2) fostering the market to allow an efficient use of generation, thereby minimizing the total costs for the system. This is mostly achieved by connecting new (conventional and renewable) generating units to the networks and/or increasing transmission capacity to allow the most efficient use of generation based on national and European energy and economic objectives.

For a selected number of European countries, the objectives of transmission planning and development are described below [12]:

Scandinavian countries. All parts of the power system shall be designed so that the electric power consumption will be met at the lowest cost. This means that the power system shall be planned, built, and operated so that sufficient transmission capacity will be available for utilizing the generation capacity and meeting the needs of the consumers in the most economical way. The long-term economic design of the grid aims to balance between costs of investments and costs of maintenance, operation, and supply interruptions, given the environmental demands and other limitations.

France. The mission of the transmission network development is to guarantee that a grid covers the national territory in a rational fashion and respects the environment, while interconnected to the networks of the bordering countries, and that there is a non-discriminatory connection and access of the users to the network. The TSO ensures the balance of power flows on the network, as well as the system security, safety, and efficiency by taking into account the technical constraints.

Ireland. The primary aim of transmission planning is the maintenance of the integrity of the bulk transmission system for any eventuality. The adequacy and security of supply to any particular load or area is secondary to this primary aim. The technical considerations are continually mitigated by economic issues and all other significant factors brought up by the various stakeholders.

Italy. By developing the transmission grid, the TSO aims at the security, reliability, efficiency, continuity of supply of the electrical energy system as well as at the cost reduction of transmission and supplies. This objective is pursued through suitable planning of the network development, aimed at reaching an appropriate level of quality of the transmission service and reduction of possible grid congestion, while complying with environmental and landscape law restrictions.

As has been described above, the TSOs rely on scenarios of forecasted consumption, generation development, and power exchanges evolution. For each scenario, they have to take into account the stochastic aspects of various phenomena, e.g., load varies on the basis of human activity and weather conditions, generating units may produce or not, depending also upon external factors such as wind or hydro conditions and forced outages, and behavior and bidding strategies of the different market players may directly impact the scenarios.

Figure 18 provides a first comparison of key planning practice elements in some European countries. Features, such as the network planning timeframe, the utilization of deterministic and probabilistic criteria, and consideration of market issues, are quantitatively and qualitatively compared for some European country systems in Figure 18. [12]

It is evident that the ten-year horizon is the most adopted by European TSOs. This is also the case for Belgium, where probabilistic elements in grid planning have been inserted over the years in the national development plan [15], and for Germany, where the four TSOs first prepared in 2012 a joint network development plan mainly based on a ten-year time horizon (from 2012) to be updated every year, while also looking at a twenty-year scenario in the long-term. [16] The ten-year timeline applies also at a pan-European level, as seen for the quoted ENTSO-E's TYNDPs. [11,17]

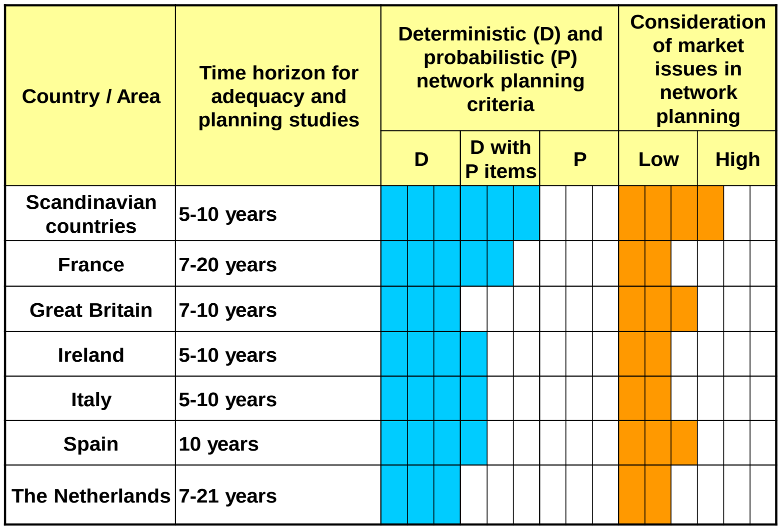

Figure 18. Key features of planning practices in some European countries [12][36]

The comparison in Figure 18 also shows that existing transmission planning methods commonly make use of a worst-case scenario approach in which the two main drivers are load and generation. With the increased uncertainty and the many assumptions necessary for the analysis, the need to capture more combinations of load, (renewable) generation and international exchange is becoming essential for more robust planning under a variety of possible scenarios. In this sense, probabilistic planning approaches, which could help get a more complete picture of the evolution of the system, are not yet fully exploited or need further improvements. In some cases, they mainly aim to complement deterministic analyses, upon which the planning decisions are primarily based. [12]

For what concerns cost-benefit analyses and market value in the European planning practice, most TSOs, taking also into account the aspects of environmental safeguard, evaluate and rank from the techno-economic point of view the several possible alternatives stemming from the planning analyses and which, as a necessary pre-condition, fulfill the priority target of realizing a secure transmission grid. In Italy, for example, the various alternatives are evaluated by comparing the estimated investment costs of each option with the related benefits in terms of reducing overall system costs (including production, transmission and distribution costs that are passed on to the end users of the national electricity system). These cost-benefit evaluations take into account, where possible, costs of grid congestion, foreseeable trends in the electricity market, the possibility of increasing the level of imports/exports with other countries, network losses, and risks of not supplying the end users. The benefit attached to the energy unlocked by a new electric transmission line represents one of the most important gains deriving from transmission expansion. [14]

In the experience of Scandinavian countries, it is difficult to quantify the costs and benefits in a better-functioning market. However, it is quite obvious that the energy market will become more robust and efficient when investments are made to remove congestion.

[36] In the Netherlands, the planning horizon of 21 years was used for the strategic Vision2030 document (it is usually seven years). In Ireland, a 15–20 year timeframe is set for a limited set of studies (like GRID25)). [12]

Such investments should be based on socio-economic analyses to ensure that the benefits are higher than the costs. After the investments, the prices will be more stable, at least in the short term.

Transmission investments will also help to mitigate the possible exercise of market power, which leads to socio-economic losses. There is a clear link between transmission capacity and the potential exercise of market power. Sufficient transmission capacity contributes to enlarging the market and possibly reducing the risk of abusing market power. [12]

5.2.3 Transmission Investment Cost-Benefit Analyses

Given the high costs of investments and the long lifetime of the transmission assets, it is crucial to make the right decision at the right time (cf. ENARD Annex IV report). However, the future evolution is uncertain, and public opposition rarely halts any transmission expansion project.

In-depth cost-benefit analysis approaches must be developed in order to identify the need for expansion in a consistent way and to evaluate the risks associated with different alternatives (including that of doing nothing), in terms of reliability and operational costs. Comprehensive cost-benefit analyses, accounting for a wide range of benefits and costs, can also reduce the issue of public acceptance while identifying the projects that are of “real” relevance for the European energy policies.

Of course, transmission planning is performed under many uncertainties regarding the location and amount of future generation (depending on energy scenarios and incentive schemes), as well as generation/demand patterns that may lead to highly diverse power flows. Accordingly, the possibilities of performing probabilistic analyses must be improved in order to consider these features in cost-benefit analyses. Simulation tools and data models should be able to deal with large systems and consider a wide range of possible operating scenarios. This is necessary to properly identify the system-wide benefits of transmission investments and thereby avoid sub-optimal solutions.

Costs and benefits of the different transmission development options should be identified. The possible transmission development alternatives must be evaluated to provide the best decision basis for policy makers, regulators, and local communities. This should consider different grid topologies and expansion solutions, including transmission line paths (e.g., cell concepts vs. supergrids), alternative technologies (e.g., AC vs. DC, overhead vs. cable) and devices (e.g., building new lines vs. installing power flow control devices, flexible alternating currents transmission system(FACTS) devices, etc.). The impact of high-capacity installations on operational security and system stability should be accounted for even in this stage, defining proper countermeasures and operational strategies. New technologies should be tested on pilots to reduce the risk of unexpected pitfalls as much as possible. Technology aspects are recalled more in depth in the discussion paper of ISGAN Annex 6 Tasks 3-4 [18] and in the next section.

The issue with cost-benefit analyses is their complexity. Hypotheses regarding scenarios and economic parameters may strongly affect the results. Moreover, some costs or benefits (e.g., related to public acceptance, security of supply) may be difficult to quantify in economic terms. A lot of effort is being pursued around this topic. ENTSO-E is pursuing a comprehensive multi-criterion methodology to be agreed upon within European countries, as a new version of the multi-criteria assessment methodology first issued in 2011.

The main goals of this methodology are [19]:

(a) System-wide cost-benefit analysis, allowing an assessment of all TYNDP projects in a homogenous way, and

(b) Assessment of candidate Projects of Common Interest (PCIs) which contribute to market integration, sustainability and security of supply; when approving cost allocation, and for PCIs, the results of cost-benefit analysis could be considered if at least one project promoter requests the relevant national authorities to apply cross border cost allocation.

The ENTSO-E cost-benefit analysis methodology has undergone a consultation stage through September 15, 2013. The overall proposed approach is depicted in Figure 19.

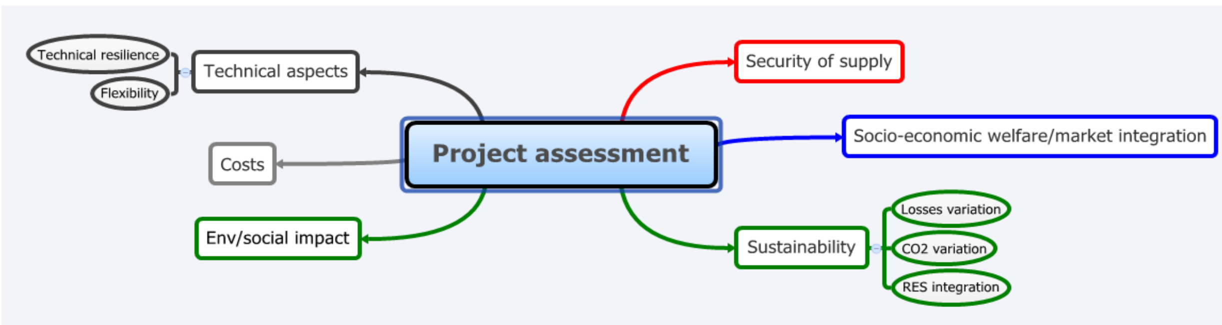

Figure 19. Cost-Benefit Analysis of grid development projects in the ENTSO-E methodology

The EU research project REALISEGRID investigated cost-benefit analysis methodologies. Some highlights are reported in the following sections. [22]

5.2.3.1 Benefits

Within the cost-benefit analysis, it is crucial to quantitatively assess the possible benefits[37] provided by transmission expansion. This task, especially in a liberalized power system, generally represents a rather complex stage as the evaluation strongly depends on the viewpoint taken for each considered benefit. Manifold aspects in which a new infrastructure can affect the system have to be considered. These benefits can be grouped into several categories: system reliability improvement, quality and security increase, system losses reduction, market benefits, avoidance/postponement of investments, more efficient reserve management and frequency regulation, environmental sustainability benefits, and improved coordination of transmission and distribution grids. However, only some of these items are quantitatively significant and can be measured by means of single indicators.

[37] It is crucial that the different benefits are not overlapping so as to avoid double-counting when they are summed.

An evaluation of the economic impact of reliability increase can be carried out by multiplying the expected energy not supplied (EENS) value , by an estimation of the value of lost load (VOLL).

The market benefits provided by transmission expansion can be summarized by two concomitant effects: (1) the decrease of potential for exercising market power by dominant players (strategic effect) and (2) the replacement of local inefficient generation by cheaper imported power due to the removal of existing transmission bottlenecks (substitution effect). Both effects can be measured by the social welfare, defined as the sum of generators and consumers surplus. [13] When planning the utilization of fast power flow controllers such as FACTS devices and HVDC, an additional benefit could arise from the system controllability increase enabled by these technologies. This effect translates into an increased substitution effect and is measured by the social welfare.

The environmental sustainability benefits by transmission expansion include a better exploitation of a diversified generation mix (including RES generation), CO_2, NO_x, and SO_2 emissions savings, a reduction of conventional generation external costs (externalities), and a reduction of fossil fuel consumption and costs. Transmission upgrades may bring some additional environmental benefits in terms of land use reduction, visual impact abatement, and decrease of the electromagnetic field with respect to an existing situation. [13,20]

Other benefits, which, in the future, may gain higher consideration, relate to the improved interaction of transmission and distribution grids within systems experiencing high shares of DG and/or even evolving toward smart grid schemes. A transmission reinforcement plan may prevent more complex reinforcements of the distribution networks. However, the evaluation of this benefit implies a manifold process and is currently being further investigated. [21]

In general, the quantification of the different benefits, each one measured by the corresponding key indicator, requires an appropriate power system and market simulation tool. REMARK, the tool developed within REALISEGRID [22], considers the real network situation in which the variability of RES generation as well as the reliability of each element in the grid are both accounted for toward social welfare maximization. [14]

5.2.3.2 Costs

Capital expenditures for transmission system assets are highly dependent on different parameters, e.g., equipment type, rating and operating voltage, technology maturity, local environmental constraints, population density, geographical characteristics of the installation area, and costs of material, manpower, and rights-of-way. In general, environmental constraints increase costs and implementation time, e.g., for overhead lines, while technological advances in manufacturing usually reduce costs. This is the case for power electronics components, for example. Another aspect that plays a role in the determination of transmission assets costs (especially for innovative technologies) is that equipment prices continuously change due to a dynamic world market. Costs of European transmission assets are then influenced and driven by external factors. In order to take into account all these factors, Table 2 reports up-to-date (average) ranges for the costs of different 400 kV transmission components in continental Europe. [13,23,24]

In Table 2, the lower limit (min) refers to installation costs in continental European countries with low labor costs, while the upper limit (max) refers to installation costs in European countries with high labor costs. Costs for overhead lines refer to the base case, where the installation of overhead lines over flat landscape and in sparsely populated areas is considered. Costs for installations over hilly and averagely populated land as well as over mountains or densely populated areas are to be taken into account by a surcharge of +20% and +50%, respectively. In the case of underground cross-linked polyethylene extruded cables and gas insulated lines, the cost component related to the installation expenses can drastically influence the final investment cost, depending on installation location, type of terrain and other local conditions. [13,23,24]

Table 2. Average capital costs (range) of transmission assets [13,23,24]

Cost of components	Rating	Min	Max	Unit
HVAC OHL (single circuit)	1500 MVA	400	700	kEUR/km
HVAC OHL (double circuit)	3000 MVA	500	1000	kEUR/km
HVAC underground XLPE cable (single circuit)	1000 MVA	1000	3000	kEUR/km
HVAC underground XLPE cable (double circuit)	2000 MVA	2000	5000	kEUR/km
HVAC GIL (double circuit)	2000 MVA	4000	7000	kEUR/km
HVDC OHL bipolar	1000 MW	300	700	kEUR/km
HVDC underground XLPE cable (pair)	1000 MW	700	2000	kEUR/km
VSC converter terminal (bipolar)	1000 MW	75000	125000	kEUR
CSC converter terminal (bipolar)	1000 MW	70000	110000	kEUR

Note: OHL – overhead lines; XLPE – cross-lined polyethylene extruded cables; GIL – gas insulated lines

5.2.3.3 Ranking Approach

The aim of a full-fledged cost-benefit analysis is to provide a criterion to co-evaluate the effects of each benefit weighing them together to provide one single ranking value. This value represents the degree of optimality of a single expansion project. In this way, different alternatives can be compared and the highest ranked is the most suitable to be financed and realized. In fact, creating a merit order (ranking) between alternative reinforcements means mapping the different evaluations of the benefits of each single infrastructure into one mono-dimensional space. According to the theory of multi-criteria analysis [13], a weighed sum is performed by adding up the value of each benefit and subtracting investment costs to this amount. In order to take into account the long lifetime horizon of the entire investment cycle (authorization time, building time, amortization time following the operation start of the new infrastructure), the net present value approach has to be applied. The weights associated to each single benefit mimic the importance associated to it by network planners. [13,20]

5.2.4 Towards the European "Electricity Highway"

In addition to RES becoming increasingly available, new and variable generation sources are expected to be developed further away from major consumption sites. Thus, electricity must be transported over longer and longer distances and across national borders to be delivered where consumption needs arise. A Pan-European network is required to enable integration of TSOs and benefit from the different behaviors of consumption and generation to use the wind energy from North-Western Europe, the solar energy from Southern Europe, and the biomass from Eastern Europe (see Figure 20). Such a long-distance and meshed transmission network at the Pan-European level introduces the opportunity of an innovative concept of the "Electricity Highway System." [25]

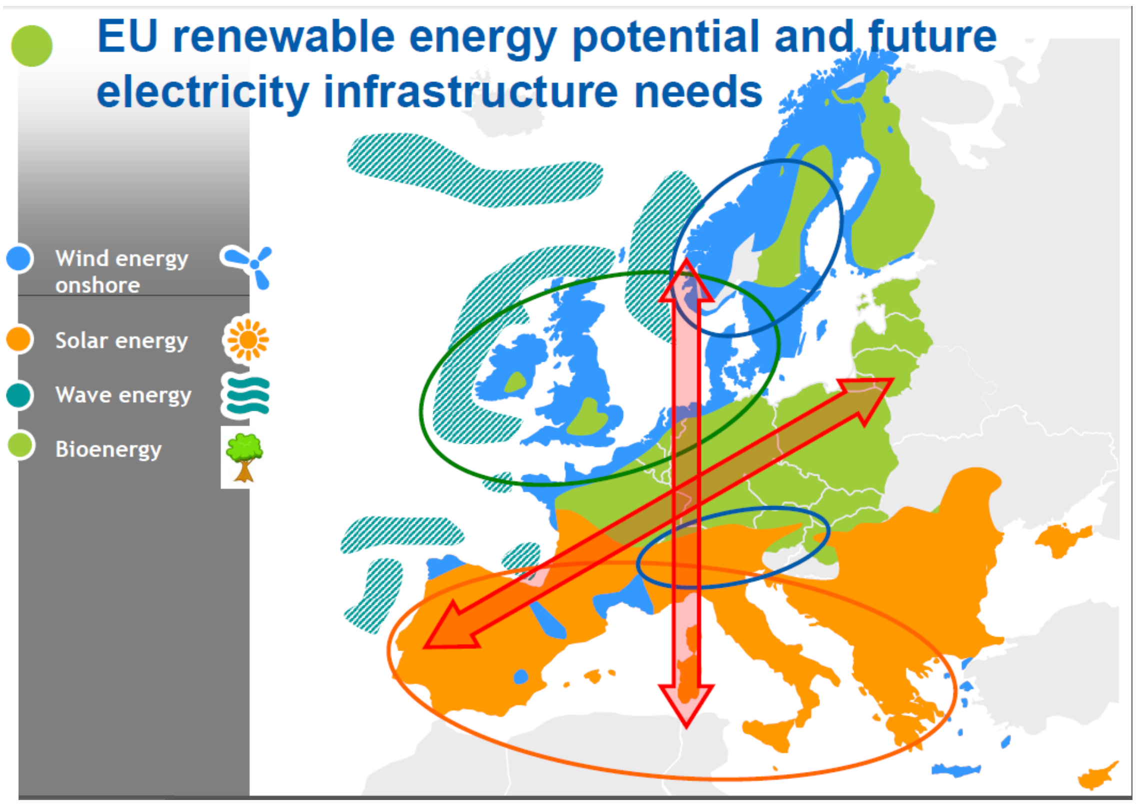

Figure 20. RES potential vs. infrastructure needs in Europe [26]

Following the "Modular Development Plan on pan-European Electricity Highways System 2050" [27] elaborated by the ENTSO-E, a consortium of 28 partners, involving a wide spectrum of stakeholders like TSOs, research institutions, universities, manufacturers, companies, and non-governmental organizations from all over Europe, launched in September 2012 the project e-Highway2050 [21], co-funded by the EC. The overarching goal of the e-Highway2050 project is to develop the foundations of a modular and robust expansion of the pan-European electricity highway system network capable of meeting European needs for electricity transmission between 2020 and 2050, to be in line with the European energy policy, which aims at not only integrating massive amounts of RES, but also at completing the internal electricity market and safeguarding the security of supply. [25] Figure 21 and Figure 22 schematically show the potential evolution of the transmission network system structure from today's (Figure 21) to a future electricity highway system-based structure (Figure 22).

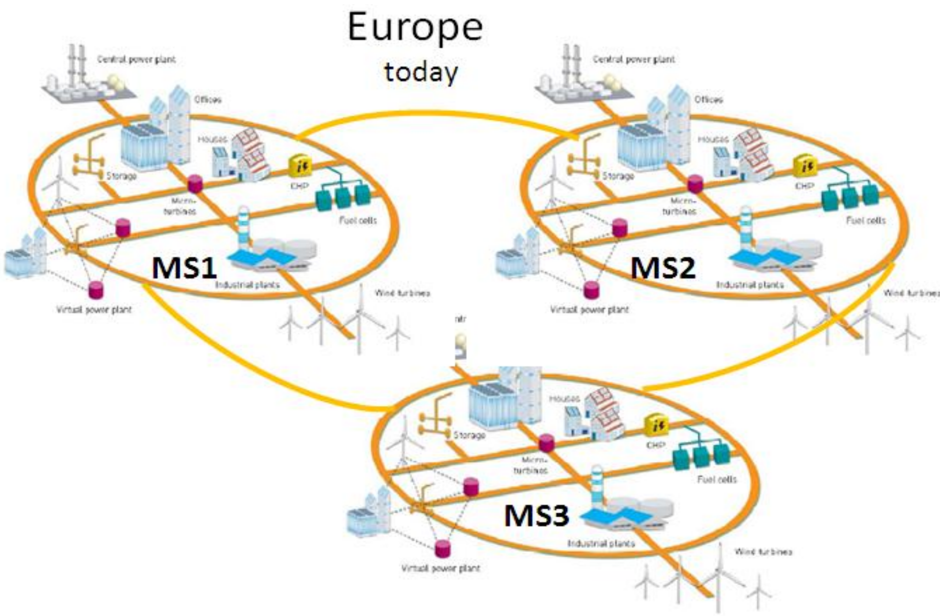

Figure 21. Basic structure of today's transmission system in Europe

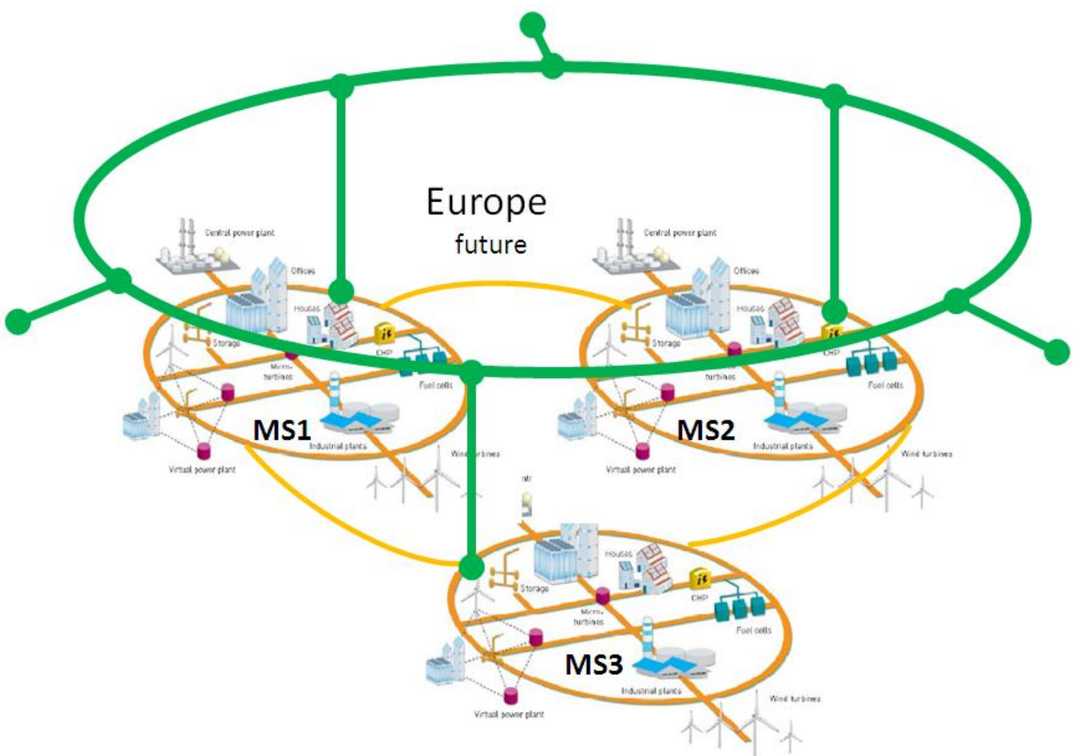

Figure 22. Basic structure of future transmission system in Europe

The project addresses recurrent and crucial issues in the discussion on the future European power system, as it includes among its objectives:

- To frame the scope of a 2050 transmission infrastructure development plan including boundary conditions.
- To detail candidate grid architectures able to meet the challenges of electricity markets by 2050.
- To validate a portfolio of technologies that will have a direct or indirect impact on the grid architecture studies.
- To detail modular development plans from 2020 to 2050, based on new grid architectures that will be able to overcome potential operational and/or non-technical barriers .
- To study the governance issues raised by the candidate grid architectures and establish a target governance model.
- To perform socio-economic analyses of the candidate grid architectures based on a multi-criteria/cost-benefit analysis.
- To establish a stakeholder framework and involve stakeholder groups at all stages of the scenario-based planning process.
- To validate an enhanced long-term planning methodology able to circumvent the limitations of existing approaches.
- To support the work flow between the single work packages and evaluate and disseminate the project results.

Concerning the development of long-term planning approaches, at the European level, the five following steps will be implemented within the project (Figure 23):

(1) Energy generation and consumption scenarios. An approach to design different long-term energy generation, exchange and consumption scenarios, based on macro-economic data, is developed and applied. The energy adequacy between generation, exchange, and consumption is ensured at the European level irrespective of the scenario studied.
(2) Power localization scenarios. Power localization scenarios, using the assumptions about the generation mix exchanges and consumption by area, are developed. Stochastic inputs (such as renewable generation, uncontrollable consumption, or failure modes of generation units) with their temporal and spatial correlations are simulated. Power adequacy between generation, exchanges, and consumption should be ensured probabilistically.
(3) Simulation of load flows with potential overloads and/or weak points. Market and network simulation techniques are applied to identify feasible and efficient pan-European grid architectures under each of the scenarios chosen above by 2050.
(4) Viable grid architecture option. A verification that the grid architecture options selected alleviate critical issues focusing on overload problems and possible voltage and/or stability problems for a given level of system reliability is performed. In return, this must allow some of the successful architectures to become part of the final modular development plan between 2020 and 2050.

(5) Implementation of the retained architecture. The development of implementation routes from 2020 to 2050 is proposed on the basis of cost-benefit analyses, appropriate wider socio-economic considerations, and grid governance models able to address issues such as cross-border power flows.

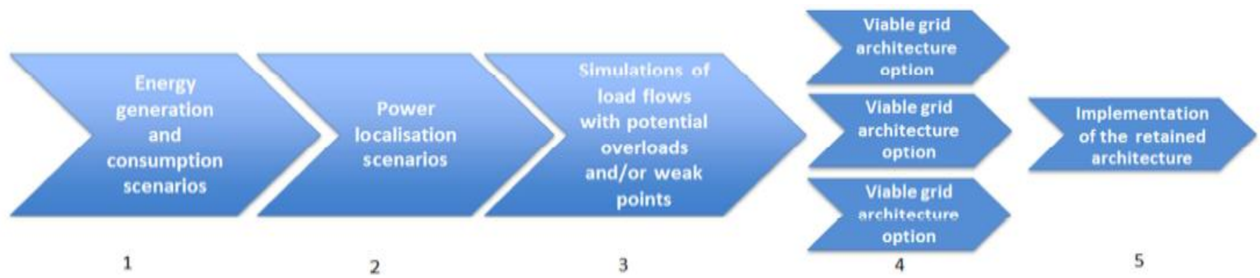

Figure 23. Schematic representation of the five steps for long-term planning in the e-Highway2050 approach

This scenario-based, top-down innovative planning methodology considers the whole electricity supply chain, taking into account all the relevant technical/technological, economic/financial and regulatory/socio-political dimensions needed to develop efficient, yet sustainable, grid architecture options that will meet future energy supply requirements.

A crucial activity within the project relates to the development of a new multi-criteria/cost-benefit methodology for comparing transmission investments by assessing the socio-economic impact on the basis of costs, risks, and benefits for society and stakeholders.

This new methodology is to be applied to analyze the pan-European grid architectures for each scenario elaborated within the project with the aim to rank them according to the above-mentioned cost-benefit assessment while incorporating the impact of the governance models. Particular attention is devoted to the technical-economic opportunity to deploy extra-high voltage highways to facilitate the integration of RES generation in Europe.

5.2.4.1 HVDC Grids

The topic of HVDC grids is of special relevance in Europe, mainly as a requirement stemming from the projects for the large-scale exploitation of the offshore wind resources in the Northern Europe seas. In fact, AC transmission over long distances is not feasible unless reactive compensation devices are put in place at space interval magnitudes of 10 km. Previously, HVDC transmission had been realized only in point-to-point configuration (with very few exceptions of three-terminal links), due to technological and operational issues such as the impossibility to selectively isolate faulted DC branches without interrupting the entire DC system, and the control complexity of multi-terminal links. However, HVDC technology is advancing at a fast pace, and the day of multi-terminal, possibly meshed HVDC grids may be approaching, allowing higher reliability with respect to outages as well as greater flexibility of operation. Details on HVDC technology are reported in the Task 3-4 discussion paper. The open challenges on HVDC grids are not limited to the technical side, but involve, for example, regulatory and jurisdictional topics as also pointed out in the ENARD Annex IV report.

HVDC grids are of interest not only for offshore transmission, but also for their potential to form the backbone of the European supergrid. One of the most important initiatives dealing with the HVDC grids in Europe is the North Seas Countries Offshore Grid Initiative (NSCOGI), established in 2010 by a Memorandum of Understanding signed by ten countries, the EU Commission, ACER, ENTSO-E, and national regulatory authorities. The ten countries involved are Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, Norway, Sweden, and the UK.

Among its initial findings, NSCOGI identified that the radial and the meshed variants result in similar initial investment costs (both in the order of 30bn€) and market benefits on the basis of the assumptions made. The similarity in results can be explained by the relatively small volume of offshore renewable energy assumed to be installed between 2020 and 2030 in this scenario. However, the slight difference in net annual costs suggests a preference for adopting a meshed approach to grid design by 2030 (with the meshed approach being some 77 M€ p.a. less expensive than the radial approach). This difference arises from the introduction of relatively few meshed assets, but only represents a small percentage of the total costs.

Initial work on a sensitivity analysis, including a more ambitious offshore renewable deployment, resulted in more complex and integrated offshore grids. New offshore grid configurations with offshore renewable energy projects grouped together and connected to more than one country pose regulatory and market challenges, as potentially does the interaction of different renewable support schemes.

The TWENTIES project investigated economic drivers and technical aspects for the HVDC grid. In particular, a prototype DC circuit breaker was developed, and R&D was conducted on control strategies of HVDC and wind farms to keep overall system stability and provide ancillary services to the bulk AC grid by exploiting HVDC converter and offshore wind farm capabilities.

Given the growth in HVDC link installation and HVDC grid perspectives, ENTSO-E has drafted a Network Code on HVDC Connections to specify requirements for long-distance DC connections, links between different synchronous areas, and DC-connected Power Park Modules, such as offshore wind farms.

5.2.5 Integrating Technologies in the Planning Process

5.2.5.1 Recall on Technological Opportunities

As mentioned above, the development of RESs and the expansion of the European market required to reinforce the transmission system, eliminating bottlenecks to allow higher power transfer over long distances and greater flexibility of operation. However, due to public opposition to new infrastructures, solutions must be found, that are efficient and with low environmental and visual impact. To this aim, in addition to conventional HVAC technologies, like overhead lines, substations, transformers, reactors, capacitors, protection, etc., transmission technologies may include innovative devices like:

- Cross-Linked Polyethylene (XLPE) underground HVAC cables;
- Gas Insulated Lines (GILs);
- High Temperature (HT)/High Temperature Low Sag (HTLS) Conductor-based overhead lines (OHLs);

- High Temperature Superconducting Cables (HTSCs);
- Innovative-design HVAC OHLs;
- Extra HVDC (EHVAC) OHLs;
- Fault Current Limiters (FCLs);
- Phase Shifting Transformers (PSTs);
- HVDC[38] OHLs/cables;
- FACTS devices[39];
- Wide Area Monitoring/Control/Protection Systems (WAMSs/WACSs/WAPSs);
- Dynamic Line Rating (DLR)/ Real Time Thermal Rating (RTTR)-controlled OHLs/cables.

Details on the technologies are reported in the discussion paper of ISGAN Annex 6 Tasks 3-4. [18] In the following, some considerations are presented concerning the development trends of main technologies in Europe [13]:

(1) In a context of public opposition toward more OHLs and lengthy permit procedures, the following technology development trends are recorded:
    (a) Several technologies, not having control features, like XLPE underground cables, and innovative OHLs with HT conductors and based on new tower designs, are ready to respond to network expansion needs, while GILs might be available for specific applications in a mid-long term horizon.
    (b) HTSCs, even though promising, are still a controversial topic for which real life transmission applications would probably occur, but not before 2030.
(2) Concerning technologies having control features, several applications already exist outside Europe (lately in countries like China) and in some regions of Europe. Large-scale experiments are also underway in Europe and scheduled for the coming years to validate at full scale critical HVDC components, PSTs, and dedicated FACTS configurations, combined with DLR/RTTR-based systems and WAMSs towards RES integration. Their replication will be decided on a case-by-case basis, based on coordinated investment between TSOs to encourage cross-border optimization on technical and economic standpoints.
(3) Introducing technologies like FACTS, HVDC, and DLR/RTTR systems will inevitably make the dynamic operations of the pan-European transmission system more complex. Transients and network instabilities will be considered in future short-term operational planning of the electricity systems, requiring increased numerical

[38] HVDC systems can be further distinguished in devices based on line-commutated current source converter (CSC - HVDC) and on self-commutated voltage source converter) (VSC-HVDC).

[39] FACTS devices can be further distinguished in shunt, series and combined FACTS elements. Among shunt controllers the main devices are the Static VAR Compensator (SVC) and the Static Synchronous Compensator (STATCOM). The series controllers category includes devices such as the Thyristor Controlled Series Capacitor (TCSC) and the Static Synchronous Series Compensator (SSSC). Devices such as the Thyristor Controlled Phase Shifting Transformer (TCPST), the Interline Power Flow Controller (IPFC), the Dynamic Flow Controller (DFC), and the Unified Power Flow Controller (UPFC) belong to the category of combined FACTS controllers.

simulations of coupled power systems; their complexity will continue to grow to assess system security beyond the borders of each TSO control area.

(4) The indirectly impacting technologies should ease TSOs' operations in the next 20 years:
   (a) Smart metering at the distribution level allows monitoring capabilities of the low voltage network. It can be coupled with smarter substations to provide TSOs with increased observability of DGs and consumption, which in turn will serve implementing demand response approaches to manage peak load efficiently.
   (b) Massive electricity (centralized and decentralized) storage can take into account the change of the design paradigm of electric systems and make wind and solar electricity be produced at times where there is not enough consumption needs. Electricity storage facilities can be optimally located close to generation centers. Large-scale demonstrations are needed by 2020 to prepare a massive development of electricity storage systems that would have benefits for the whole electric system (peak management, balancing and even system services).
(5) The wealth of technologies available or under development opens new options for future transmission network architectures, including the ones needed to link offshore wind farms (offshore grids).

In summary, in the short- to mid-term (up to 2020) horizon, these transmission technologies may emerge: HVAC XLPE cables, VSC-HVDC, FACTS (static VAR compensator (SVC) and static synchronous compensator (STATCON), also with storage), HTC/HTLS, DLR/RTTR-monitored OHLs/cables, WAMSs/PMUs, and innovative design-HVAC OHLs. In the mid- to long-term (after 2020) horizon, these transmission technologies may emerge: multi-terminal VSC-HVDC, FACTS (static synchronous series compensator (SSSC), thyristor controlled phase shifting transformer (TCPST), unified power flow controller (UPFC)), FCL, GIL (after 2025), and HTSC (after 2030).

5.2.5.2 Introducing Technological Options in the Planning Pprocess

This subsection presents the approach of an ongoing European research project, named GridTech [28], aimed to conduct a fully integrated assessment of new grid-impacting technologies and their implementation into the future European electricity system (in a 2020, 2030, and 2050 timeframe). This will allow comparing different technological options towards the exploitation of the full potential of future electricity production from RESs, with the lowest possible total electricity system cost. Within the project, the analysis is preliminarily devoted to the most promising and innovative technologies that directly or indirectly impact on the transmission system. Two general categories of technologies to be investigated can be distinguished: (1) technologies directly impacting on the transmission system and (2) technologies indirectly impacting on the transmission system.

The first category includes technologies that are generally planned/operated by TSOs; the use of these technologies is then generally in the hands of TSOs. Transmission grid technologies (TGT) belong to the first category.

In addition to conventional HVAC (High Voltage Alternating Current) technologies, like overhead lines (OHLs), substations, transformers, reactors, capacitors, protection etc., TGT may include innovative devices like:

- Cross-Linked Polyethylene (XLPE) underground HVAC cables;
- Gas Insulated Lines (GILs);
- High Temperature (HT)/High Temperature Low Sag (HTLS) Conductor-based overhead lines (OHLs);
- High Temperature Superconducting Cables (HTSCs);
- Innovative-design HVAC OHLs;
- Extra HVDC (EHVAC) OHLs;
- Fault Current Limiters (FCLs);
- Phase Shifting Transformers (PSTs);
- HVDC[40] OHLs/cables;
- FACTS devices[41];
- Wide Area Monitoring/Control/Protection Systems (WAMSs/WACSs/WAPSs);
- Dynamic Line Rating (DLR)/ Real Time Thermal Rating (RTTR)-controlled OHLs/cables.

Particular focus is on the most mature and promising of these transmission technologies (starting from PST, HVDC, FACTS, WAMSs, and DLR/RTTR-devices) towards RES integration in the European system.

The second category includes technologies that are generally not planned/operated by TSOs; the use of these technologies is not in the hands of TSOs. Electricity generation technologies (including variable RES-E), energy storage technologies, and demand-side technologies belong to the second category.

Integration of renewable and distributed energy resources—encompassing large scale at the transmission level, medium scale at the distribution level, and small scale on commercial or residential building—can present challenges for the dispatchability and controllability of variable RES and for operation of the electricity system. Energy storage systems can alleviate such problems by decoupling the generation and delivery of energy. Smart grids can help through automated control of generation and demand (in addition to other forms of demand response) to ensure balancing of supply and demand.

In addition to conventional electricity generation technologies, like thermal, nuclear and hydroelectric power plants, innovative electricity generation technologies (variable RES) may

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[41] FACTS devices can be further distinguished in shunt, series and combined FACTS elements. Among shunt controllers the main devices are the Static VAR Compensator (SVC) and the Static Synchronous Compensator (STATCOM). The series controllers category includes devices such as the Thyristor Controlled Series Capacitor (TCSC) and the Static Synchronous Series Compensator (SSSC). Devices such as the Thyristor Controlled Phase Shifting Transformer (TCPST), the Interline Power Flow Controller (IPFC), the Dynamic Flow Controller (DFC), and the Unified Power Flow Controller (UPFC) belong to the category of combined FACTS controllers.

include offshore and onshore wind power plants/farms, PV power plants, concentrated solar power (CSP) plants.

Energy storage technologies may include pumped hydroelectric energy storage (PHES), compressed air energy storage (CAES), flywheel energy storage (FES), superconducting magnetic energy storage (SMES), sodium-sulphur (Na-S) batteries, flow batteries, supercapacitors/ultracapacitors, and lithium (Li)-ion batteries.

Demand side technologies may include smart meters, efficient lighting, smart appliances, electric vehicles (EVs), plug-in hybrid electric vehicles (PHEVs), and ICT.

DSM can be considered as the application of a series of measures stimulating demand response and load peak shaving/shift.

The specific focus is on the future integration of the different technologies into the European power system and their behavioral characteristics, also in terms of improved flexibility and controllability.

Within the 2020, 2030, and 2050 time horizons, it is crucial to assess where, when, and to what extent innovative technologies could effectively contribute to the further development of the European transmission grid, also toward potential supergrid (electricity highways) architectures [26], fostering the integration of an ever-increasing penetration of RES generation and boosting the creation of a pan-European electricity market, while maintaining a secure, competitive, and sustainable electricity supply.

Toward this aim, after the build-up of the 2020, 2030, and 2050 scenarios, the GridTech approach features a cost-benefit analysis of the implementation of the innovative technologies into the European electricity system. This requires the set-up of a consistent and tailor-made analysis methodology (based on technology cost, benefits, and reciprocal weighing) qualified to meet the objectives in the scenario analyses. In particular, for each target year and scenario, the methodology is based on the evaluation of the different benefits to the European power system provided by the innovative technologies comparing the case implementing the assessed technology with respect to a base case without it.

The verification of the cost-benefit analysis is based on technology cost calculation, on the one hand; on the other hand, it is based on sophisticated European electricity system modeling (top-down level) as well as target-country-specific case study analyses (bottom-up level. For the top-down level, a pan-European system analysis is carried out by modeling the whole European power system (EU30+ region) for the 2020, 2030 and 2050 time horizons. This is performed using a zonal approach.

For the bottom-up level, taking the outcomes of the pan-European analysis into account as boundary conditions, for 2020, 2030 and 2050 scenario timeframes, GridTech also focuses on seven target countries: Austria, Bulgaria, Germany, Ireland, Italy, Netherlands, Spain (see Figure 24). The analyses on these countries are based on grid detailed approaches. These countries, with their differences and strategies, can be representative of the existing and future European electricity systems. In fact, although large-scale RES integration significantly depends on the specific characteristics of the electricity system in each country (like mix and flexibility of power plant portfolio and transmission interconnection capacities to neighboring market zones), the fundamental challenges are common to the other European countries.

Figure 24. The seven target countries of GridTech analyses

A cost-benefit analysis related to the role of innovative grid-impacting technologies in the European system towards its further development is then carried out as a trade-off analysis based on different indicators (such as the net present value and the benefit-to-cost ratio).

The project is currently ongoing and is expected to contribute to:

- Assess the non-technical barriers for transmission expansion and market compatible renewable electricity integration in Europe.
- Develop a robust cost-benefit analysis methodology on investments in most suitable new technologies fostering large-scale renewable electricity and storage integration into the European transmission grid.
- Apply and verify the cost-benefit methodology for investments in the European transmission grid on a national and continental level.
- Achieve a common understanding among key target actors on best practice criteria for the implementation of new technologies fostering large-scale renewable electricity and storage integration.
- Deliver tailor-made recommendations and action plans, taking into account the legal, regulatory, and market framework.

5.2.6 Outcomes and Challenges

Europe is undergoing deep changes in its electricity supply system, attributable to the large variable RES penetration, nuclear phase-out, and paradigm shift of conventional generator utilization, from covering base load to balancing RESs and load variations. This change requires huge investments in the transmission system as well as new methods to evaluate the right investments. The choice of investments is made more complex by a wider range of available technological solutions, by the uncertainty in the evolution of generation, and by the variability of operating conditions introduced by RESs and the European market implementation. To this aim, increasingly comprehensive cost-benefit analyses are needed, and market mechanisms should be considered more in-depth in the transmission planning process. Moreover, greater coordination among TSOs is required in order to achieve a truly optimized transmission expansion. ENTSO-E efforts are along these lines, although much work still has to be done to achieve fully coordinated planning.

Advanced technologies, as mentioned above, makes it possible to optimize usage of existing assets and provide temporary solutions to increase system transfer capacities, thus coping with siting/permitting delays which become the bottleneck for connecting new generation to the grid. On the other hand, there is often a lack of direct incentives to motivate TSOs to deploy such solutions. This suggests that regulation and market structures should be revised/developed to better align costs and benefits. Moreover, pilot projects should be supported in order to reduce as much as possible the risk of unexpected pitfalls. A special role in terms of market impact and grid operation is played by energy storage, which should be more accurately modeled in transmission grid planning.

Finally, planning of the future transmission grid should take into account the role of smart grids and ICT, in terms of impact (e.g., prosumers, electric vehicles), services (including demand response), and (cyber) security issues. In particular, the role of service-based markets in transmission grid planning should be given due emphasis.

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6 Market Structure and Operation

6.1 United States

The following section provides an overview of U.S. markets that govern the transmission of electricity—from generator to transmission facility to end user—and the mechanisms that operate to provide structure and predictability to these markets. It describes some distinct types of markets and presents a simplified view of the relationship between the entities and markets, focusing on the "seams." Understanding the operation and functioning of electricity markets is a prerequisite to understanding how transmission planning may change to accommodate new ownership structures and operational paradigms.

In the U.S., electricity markets are both complex and diverse. There is no national electricity market, but a patchwork of different markets and other arrangements and a variety of types of planning and operational paradigms in different regions. One way to understand the systems are to think about the functions of the system and what kind of entity can be responsible for each (see Figure 25).[42]

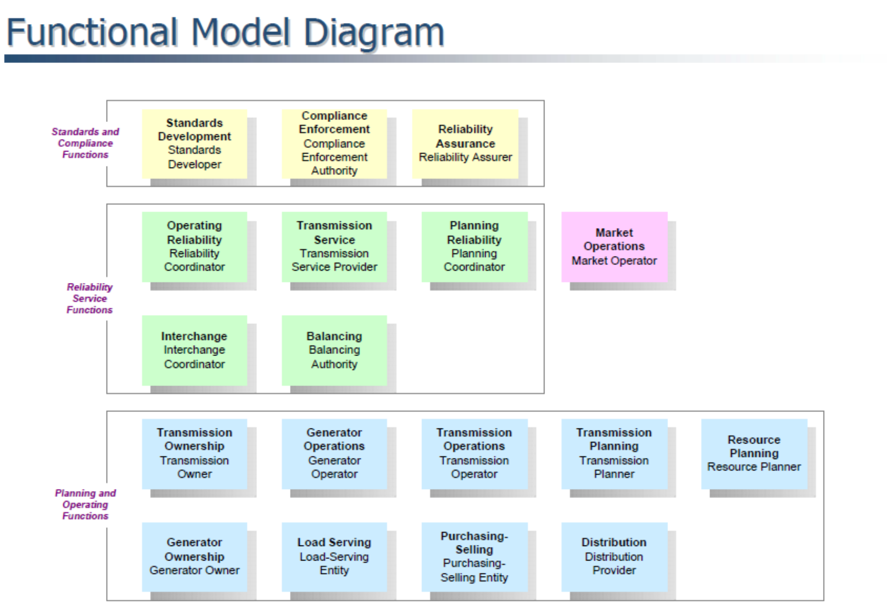


Figure 25. NERC Functional Reliability Model

6.1.1 Market Functions and Participants

There are several distinct functions: generation of electricity, transmission of this electricity over the bulk power system, distribution of electricity to retail voltage levels/customers, and metering and billing. A variety of entities generate electricity,

[42] To facilitate this process, NERC has defined 18 functional reliability functions and obligations that are described in the model description published at http://www.nerc.com/files/functional_model_v5_final_2009dec1.pdf.

distinguished by ownership structure: investor-owned utilities are publically held companies owned by shareholders but closely regulated by the state(s); independent power producers are public or private entities owning generators and selling electricity into a wholesale market; co-generators are public or private industrial facilities selling power into the wholesale market under federally mandated conditions; municipal and cooperatives are privately owned and governed by their members; and, federal PMAs and authorities are part of the federal government. Power produced by these entities is transported over a common transmission network that is often owned by others. Investor-owned utilities and federal PMAs own and operate transmission, but there are also independent transmission companies, RTOs, municipalities, and cooperatives that perform these functions. Responsibility for delivery of power to end user (distribution delivery) lies with investor-owned utilities, municipals and cooperatives, federal entities, and independent distribution companies. Distribution companies, municipalities, cooperatives, investor-owned utilities, or power marketers may provide metering and billing services. Power marketers are relatively new entities that generate, purchase, or otherwise obtain power to supply to customers through a variety of mechanisms, including internal operations, power purchase agreements, bilateral trades, and centralized markets. Supply of a single customer may involve all of these entities, or various subsets. There is no standard model or combination of actors, mechanisms, or ownership structure that typifies U.S. electricity generation and delivery. A single entity may provide one or many of these functionalities.

The U.S. has three electrically independent interconnections (as noted earlier): the Eastern Interconnection, the Western Interconnection, and the ERCOT Interconnection. In the Eastern and Western Interconnections, investor-owned utilities serve roughly 60% of retail sales, but comprise only 6% of entities that deliver power to customers (distribution). Municipals, cooperatives, and other local and state entities serve about 30% of sales but comprise 90% of distribution. [1]

6.1.2 Centralized Market Structures

As mentioned earlier, one-third of the U.S. operates under non-RTO/ISO market structures, notably the West (excluding California) and the Southeast. These more traditional market structures operate under vertically integrated utilities, a mechanism under which the same corporate or government entity provides all of the services described for an area, e.g., generation or purchase of power, transmission, distribution, billing, and metering.

There are five centralized electricity markets in the Eastern Interconnection, characterized by the existence of RTOs and ISOs, centrally cleared market prices and various forward and real-time market settlements.[43] The Western Interconnection has only one centralized market (CAISO). (See Figure 10, page 34.)

Despite the range of institutional configurations, there is some consistency in jurisdictional issues. States have jurisdiction over rates charged for retail power and for siting of infrastructure, including transmission. The FERC has jurisdiction over the rates charged for

[43] ISO-NE, NYISO, PJM, MISO, SPP.

using the bulk transmission system (wholesale markets) in the Eastern and Western Interconnections. Power authorities such as Bonneville and SWAPA are not subject to FERC rate jurisdiction because they are part of DOE. Additionally, state governmental entities, such as municipal and cooperative electricity providers, are usually not subject to FERC rate jurisdiction. The ERCOT is the sole system and market operator in the ERCOT Interconnection, and is not subject to FERC rate jurisdiction because it does not engage in interstate trade. All operators of bulk transmission facilities in the U.S. are subject to FERC reliability jurisdiction with the exception of Alaska and Hawaii, and abide by NERC reliability rules. For convenience, we refer to "FERC-jurisdictional" to indicate entities operating under the FERC's rate jurisdiction.

All FERC-jurisdictional utilities and transmission owners/operators are subject to open access requirements. The FERC's open access rule, Order 888, requires public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. Entities that are not FERC-jurisdictional may choose to abide by open access rules as well to take advantage of reciprocal system usage (e.g., if municipally-owned or cooperatively-owned utilities allow others to use their transmission, they can also use others' systems). But following open access rules does not require implementing a centralized, formal electricity market. A transmission owner can comply with open access requirements by publicly posting transmission availability and rates and accepting reservations from independent power providers.

Regional centralized electricity market rules and operation are influenced by a variety of factors, included federal statutes, federal regulations (such as FERC Orders), RTO/ISO guidance, stakeholder input, NERC reliability standards, state PUC advice, and the forces of the competitive markets themselves. Centralized electricity markets are often designed by RTOs or ISOs with input from industry stakeholders, and market rules subject to FERC approval. Sometimes, such as in NYISO and CAISO, the state and ISO jurisdictional boundaries align, and sometimes the market is enveloped by a single state such as ERCOT within Texas. In such market designs, the PUC has a much larger influence on market rules. In Texas, FERC has no jurisdiction over the market design, and the state PUC holds authority over market rules and tariffs. Other electricity markets in the U.S., such as PJM, MISO, and ISO-NE, span multiples states and other jurisdictional boundaries.

Centralized electricity markets engage a variety of participants and stakeholders, including the following:

- The market operator, an ISO or RTO
- Power generators, e.g., investor-owned utilities, independent power producers, and other power marketers
- Load serving entities, which typically procure generation to meet its load obligations, including traditional utilities, unregulated municipal or cooperatively owned utilities, and less conventional power marketing organizations in retail deregulated jurisdictions
- Transmission owners that may or may not be the same as the entities that own generation resources or serve load.

There is a wide variety in ownership structures and relationships between all these entities across different markets. The business model of the entity is usually determined by how they engage the market.

In general, the trade and transportation of wholesale electricity is regulated or governed by the federal government, while retail sale of electricity is regulated by state-level regulatory authorities. The FERC approves transmission tariffs, but states regulate consumer tariffs. For instance, it is the state's decision to allow consumers choice of supplier, or restrict them to a monopoly service area provider. For this discussion, it is sufficient to understand that retail competition is managed at a state level and implementation may vary from jurisdiction to jurisdiction.

Four distinct types of markets are most common to U.S. centralized markets:

(1) Capacity markets
(2) Energy markets
(3) Ancillary service markets
(4) Transmission capacity markets.

Capacity markets are created to ensure sufficient generation capacity is available for future years by incentivizing generation capacity with guaranteed revenue streams. In the U.S., Capacity markets are utilized in many, but not all, centralized markets. Central market operators utilize these markets to procure existing and potential future capacity to cover forecasted load levels one or many years out at administratively determined reliability levels. Generators whose capacity is procured are required to participate in energy markets for the years procured. Many market jurisdictions are instituting capacity markets that include deliverability restrictions. Typically, they identify capacity regions where capacity must be procured to cover some or all of the local demand. Prices of cleared capacity between these regions should differ.

All centralized markets in the U.S. have energy markets. In an energy market, suppliers submit energy bids to the system operator, which then stacks the bids by price, lowest to highest, to determine the energy dispatch needed to service load. The generator that sets the clearing price is called the "marginal unit." Each generator that bids below the clearing price is selected and is paid the clearing price. It is important to understand that all resources except the marginal unit(s) are paid more than their bid, presumably providing revenue over their cost of operation to compensate for fixed costs such as investment and profit. Energy-only market proponents assert that, in the absence of bid-caps, this revenue is sufficient to incentivize new investment and cover fixed-costs, making capacity markets unnecessary.

One complicating feature of electricity systems is the limits on transporting electricity. Electricity flows through the transmission network according to laws of physics. Without specialized equipment (i.e., new investment or smart grid technologies), it is impossible to control the path it takes. Physical characteristics of the transmission network, including thermal or reactive limits on how much electricity can flow over a line, often limit the amount of power that can be moved between locations. These limitations are referred to as congestion.

Most centralized markets for energy use locational electricity pricing in the wholesale market to help manage congestion. This system, known as locational marginal pricing, prices electricity at each location in the system based on the bidding of generation deliverable to that point while taking into account the physical limitations of the transmission system.[44] Thus, the market clearing prices can be different for different locations in the network within a single market, and each generator is paid the market clearing price—the locational marginal price—at their particular location. Without transmission congestion the price of wholesale electricity across an entire market will be the same in all locations, and all generation will be paid the same price.[45] The cost of energy losses, which also varies by location, may be included in the locational marginal price. When losses are included in the locational marginal price, the load pays the costs of congestion and losses in its wholesale purchase of power.

In most centralized markets in the U.S., there are two energy markets: a day-ahead and a real-time market. This is known as a two-settlement system. In day-ahead markets, generators bid or offer their available capacity into an auction, usually by hour. Day-ahead markets are purely financial, with implications for real-time: any accepted offer will be financially settled in the day-ahead timeframe, but in real-time they must either deliver electricity or buy back their position. In real-time markets, the generation is dispatched, and paid the difference from the day-ahead dispatch to meet demand as needed. These markets operate in tandem with one another: in the day-ahead time frame the majority of needed power is arranged, but because precisely predicting demand in the day-ahead timeframe is not possible, the fine-tuning of matching demand with generation is accomplished in the real-time market. The day-ahead market is cleared for each hour for the subsequent day, and the transactions are financial. Most real-time markets are cleared every five minutes, but billing and accounting is normally performed on longer timeframes.

Ancillary services markets are also generally operated by an ISO or RTO. Ancillary services are defined for most markets by the FERC and the NERC.[46] The major services include, but are not limited to, the following:

- The regulation market provides for continuous balancing of load and generation.[47]

[44] In NYISO, locational marginal price is referred to as locational-based marginal price. The concept is the same as locational marginal price in other markets, thus the term “locational marginal price” will be used to refer to this pricing concept in all markets.

[45] Prices can vary between locations because of electricity losses as well even in the absence of transmission congestion.

[46] In Order 888, the FERC defined six generic types of ancillary services and indicated that customer loads should have opportunities to participate in these markets as part of its overall goal to facilitate more competitive markets. The ancillary services listed include: (1) scheduling, system control, and dispatch; (2) voltage control; (3) regulation and frequency response; (4) energy imbalance; (5) operating reserves-spinning reserves; and, (6) operating reserve-supplemental reserve. See Heffner, Goldman, Kirby & Kintner-Meyer, “Loads Providing Ancillary Services: Review of International Experience,” (Washington, DC: U.S. Department of Energy, May 2007), available at http://certs.lbl.gov/pdf/62701.pdf.

[47] One example is an energy storage project that is selling up to 3 MW of frequency regulation to PJM 's grid. In addition to frequency regulation, the system provides demand management services to a local utility during specified peak power periods. These services provide up to 1 MW for 1-4 hours. This project will serve as a model for the implementation of energy storage technologies on a much a broader scale, which will enable the transition to a smart grid. For additional information, see http://energy.gov/sites/prod/files/East%20Penn.pdf.

- The reserve market ensures enough resource capacity is available to bring generation and load back in balance after the loss of generation.[48]
- Black start service, which is a cost-based (meaning offered at that cost of what it takes to provide the service, rather than allowing the market to dictate what the service would trade for) provides for the availability of a generating unit that can start and synchronize to the system without having an outside source of AC power.
- Reactive services, which are also cost-based, maintain transmission voltages within acceptable limits.

6.1.3 Financial Implications of Various Market Practices

In market constructs, the ISO/RTO typically acts as the entity that provides scheduling services, system control, and dispatch services. These services include operating, managing, and maintaining transmission equipment, and sending operating signals to generators. Different market designs, however, may create new business units to provide some of these services. In the ERCOT, for instance, scheduling services are provided by a new market construct called a qualified scheduling entity (QSE). The ISO deals with the QSE, and the QSE deals with generators, distribution companies, load aggregators, and power marketers. The ISO/RTO normally recovers administrative costs with a regulatory-approved adder to the market price of the traded electricity for providing services.

The practice of hedging against transmission constraints has created an important market product for trading transmission capacity, referred to as financial transmission rights (FTRs).[49] The market for FTRs operates in parallel with the two settlement markets and can have significant financial implications. In places where there is ample or sufficient transmission infrastructure, such rights are not as essential as in markets where there can be significant constraints. For example, in the NYISO region, there can be significant congestion in the more heavily populated southeast corner, including New York City and Long Island. FTRs are contract-based financial instruments that entitle the holder to revenue from (income), or make liable for (costs) the differences in day-ahead congestion price between two locations. Any qualified entity, not just generators or load serving entities, can purchase FTRs in annual, monthly, and other auctions, and all holders are paid the day-ahead congestion price independent of participation in the energy markets.

These financial instruments allow load and generation entities to hedge the cost of electric delivery (congestion) well ahead of time and limit their risk exposure to congestion price volatility. Allowing financial and speculative purchase of these instruments greatly increases their liquidity and makes the overall market more efficient.

Interstate markets, tariffs, and rates for the transmission of electrical energy are approved by the FERC. The FERC has exclusive jurisdiction over approving transmission rates

[48] There are several levels of reserves, depending on the status of the resource providing it. For example, spinning reserves come from generators that are operating already; non-spinning reserves are from generators that need to be turned on to produce power.
[49] These are called transmission congestion contracts in the NYISO and congestion revenue rights (CRRs) in ERCOT. In this discussion paper, all transmission hedging products will be referred to as FTRs.

for interstate commerce. Ancillary service rates are normally proposed by the ISO/RTO, and reviewed by FERC staff. How a rate is set will depend on the characteristics of the market, and to what extent the ancillary services are needed or utilized. In centralized energy markets, ancillary services are often procured in day-ahead auctions, and the quantity procured determined by a reliability analysis.

Transmission transactions cost are implicit in the locational marginal prices. RTOs rely on centralized dispatch to decide how transmission capacity is utilized, and locational marginal pricing to optimize both transmission costs and if included in the dispatch, the cost of transmission losses across the system. Transactions are priced at the differential between locational marginal price at the origin and destination of the power. As part of this equation, transmission limitations are automatically rolled into the pricing through the congestion component of the locational marginal price.

It should be recognized that transmission congestion rents do not typically accrue to the transmission owners. These revenues are the property of the owners of FTRs, usually purchased at annual, monthly, or other auction periods. Transmission owners are compensated through separate mechanisms, normally charging loads. In the ERCOT, for instance, load serving entities are charged for transmission based on their average load on the grid at the three peak hours of the year. This methodology simultaneously collects revenue for transmission providers and incents load management during peak periods.

6.1.4 Non-Centralized Market Structures

In regions that do not operate centralized markets, transmission rates often differ depending on where the power originates from and where it is being delivered. Three basic rate structures govern transmission transactions: postage stamp, license plate, and pancaked rates [2]:

- Postage stamp rates operate by spreading costs among all end users in a given planning region. This is a fixed cost-per-unit of energy within the given region, no matter where the power originates or is delivered, or the distance the electrons travel. Postage stamp rates may also have a local adder.
- License plate rates allocate existing transmission costs to the customers who benefit from the transmission. Like postage stamp rates, transmission transactions within a region are subject to a single rate, but each customer pays a rate based on the local cost of transmission within their particular service territory in the region. This is also known as zonal pricing.
- Pancaked rates apply multiple rates to transmission transactions that cross more than one region. This means that inter-regional transactions would pay multiple rates to each respective transmission owner, as opposed to postage stamp or license plate rate that are fixed. Pancake rates may also include a local adder or boarder rates, which can increase the cost and complexity for inter-region transmission transactions.

6.1.5 Financing Transmission Projects

How a transmission owner finances infrastructure improvements depends on the characteristics of the project. Three typical funding mechanisms exist today.

A regulated project is compensated under formula rates derived by a fixed method. Regulated projects socialize the cost across rate-payers within an area/RTO, and so are necessarily regional. In most regions, charges are updated annually and the input data is provided from public sources. The recalculation of fixed charges is done pursuant to a set of regimented rules or protocols. Because of the predictability of this type of cost recovery, regulated projects provide an efficient process to compensate transmission providers while avoiding a full-blown rate case. ISOs and RTOs are often central to the review/approval process approved by states for this process.

The second, a participant funded project, usually involves a joint venture between similarly interested private parties who finance development and construction. This type of project usually involves parties that will use the transmission capacity developed. This guaranteed market is essential to the cost recovery.

The third is the merchant project, a close relative of the participant funded project. Under this mechanism, developers are not necessarily direct users of the transmission capacity. While those paying the rates (and therefore providing the cost recovery) will be only those using it, the developer either builds around an anchor tenant or into a ready market, normally with contracts already in place or with the capacity fully subscribed. There is normally no regulated tariff for this type of project, and the merchant/developer recovers costs directly from those that use the project.

Controlling costs appropriately for power flow across jurisdictional seams depends on agreements between regions and markets and market designs, ensuring that power flows reliably across the seams from one region to another, is a function of the operation of the transmission system.

6.1.6 The Role of RTOs/ISOs

The RTOs/ISOs are important players in the electricity system in the U.S. because of their power to shape and operate markets across large portions of the country among a diverse set of fuel sources dealing with a variety of geographic and institutional issues. While RTOs and ISOs are not legislative or rule making bodies, they implement legislation and rules, such as the mandate for an open access transmission system.

RTOs are useful in helping "reduce technical inefficiencies caused when different utilities operate different portions of the grid independently…." [2] The FERC has encouraged the management of RTOs by ISOs. [2] Both organizations engage in the design and operation of electricity markets. Still, there are some differences between an ISO and an RTO. One of the primary differences is that (despite the name of the organization in some cases, e.g., ISO-NE) an

RTO operates interstate, while an ISO tends to operate intrastate (for example, CAISO vs. PJM). Further, a RTO must be granted FERC approval to operate as a RTO by meeting explicit criteria.[50]

6.2 Europe

European energy policy has been based on three "pillars," namely increasing the generation from renewable energy and reducing CO_2 emissions (sustainability), guaranteeing security of energy supply (security), and integrating the European electricity market (competitiveness). [3]

As far as the integration of the European electricity market is concerned, the conclusions published by the European Council (4 February 2011) feature two ambitious targets: (1) completion of the internal energy market by 2014 and (2) no member state is electrically isolated from the rest of the EU by 2015.

Indeed, the complete integration of national electricity markets into an internal energy market is an important benefit for the entire system, provided it is accompanied with a gradual harmonization of regulation of national markets. In fact, the result is increasing competition (higher market liquidity) due to higher trans-national flows, causing a general increase of the social welfare.

6.2.1 Day-Ahead Market Coupling

The integration of different national electricity markets towards the European objective of a single internal energy market [4], to be completed by 2014, is clearly a benefit for the whole system, bringing more actors into the playing field, thus increasing cross-border competition and improving the social welfare of the coupled markets. Within this context, cross-border transmission capacity, with development in Europe still far from reaching an optimal level [5], needs to be allocated in the most efficient way. To this aim, the European regulation in force [6] states that "network congestion problems shall be addressed with non-discriminatory market-based solutions," that is, by means of either explicit or implicit auctions.

6.2.1.1 Transmission Capacity Allocation Mechanisms

Explicit auction has been the most widely used way of allocating transmission capacity in Europe. Each TSO sets the free capacity ex ante, and this capacity is allocated by an auction. Bids are sorted according to their price, and they are accepted until no free capacity remains. In this way, capacity is allocated apart from the energy to be transmitted, whose allocation is carried out either through bilateral contracts or in another dedicated auction in a power exchange. On the contrary, in an implicit auction, the allocation of both capacity and energy occurs at the same time as a result of the clearing of the market, which sets prices and quantities in such a way as to make the optimal use of the available transmission capacity. In

[50] These characteristics include the requirement that the transmission organization maintain independence from market participants, have regional scope and maintain and ensure short term reliability. Additionally, the FERC mandated that the organizations have minimum functionality, including importantly, operation of the OASIS system and tariff design and administration. The full text of the order is available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/2000A.pdf.

this case, the price of transmission capacity, when congestion occurs, is the difference between the energy prices at the ends of the congested interconnectors.

In the day-ahead timeframe, due to its greater efficiency, the implicit auction has been selected by ACER as the target mechanism to be implemented in Europe. [7] The implementation of the implicit auction in a multinational electricity market (where each country is considered a market zone) can be done through two main different approaches: (1) market splitting and (2) market coupling. With market splitting, a single central power exchange clears the market, setting quantities, zonal prices (that differ in case of congestion), and cross-border flows by applying uniform matching rules. This solution clearly requires a high level of integration among the involved national markets. With market coupling, the different national power exchanges coordinate themselves through a coupling algorithm that is run by a central body, but they retain the pricing authority and may have different matching rules.

6.2.1.2 Market Coupling Approaches

There are two types of market coupling: volume coupling and price coupling. With volume coupling, the central algorithm calculates cross-border flows that are used by the national power exchanges to clear the local markets and to set the prices. Volume coupling can be either "loose" or "tight," according to the amount of difference between the central and the local matching algorithms and to the completeness of market data provided to the central algorithm. The looser the coupling is, the more flows may occur adversely (i.e., flows from a high price zone to a low price one) between the coupled markets, and the less price convergence takes place and the lower is the gain in social welfare. Volume coupling is therefore considered as a step towards a greater integration of markets through price coupling, where the central algorithm fully implements the matching rules of the coupled markets and is provided with all the necessary market data. It therefore calculates both cross-border flows and zonal prices (as well as other possible results, e.g. the list of selected block bids). The national power exchanges use this information to calculate the program of each market player.

Price coupling is the preferred method for the implementation of the internal energy market. In fact, ACER states that capacity allocation in the day-ahead market should be implemented "on the basis of implicit auctions via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, based on the marginal pricing principle." [7] There are several advantages of a price coupling solution over a conventional explicit auction for transmission capacity with a subsequent energy trading:

- It simplifies the access to the market, requiring bidding only on the power exchange for energy.
- It reduces the risks for market players, since they don't need to buy transmission capacity before knowing its real value that will be set in the energy market.
- Transmission capacity is fully used, even when the sign of the zonal price difference is uncertain in advance; moreover, a full netting of opposite transactions is accomplished and no capacity withholding can be carried out.
- The uncertainty about the final use of transmission capacity is therefore reduced; in this way, the involved TSOs could reduce security margins and make available a larger amount of transmission capacity, and even more when a "flow-based" market

coupling is implemented, where detailed grid modelling is used to calculate more precisely the power flows and better account for network security constraints. [8]

- The allocation of transmission capacity is non-transaction based; it is fairly allocated to the transactions that value it most.
- In case of congestion, it provides a correct price signal; the value of transmission capacity is the difference of the prices of the connected zones.
- When no congestion occurs, zonal prices fully converge, as required by a single integrated internal energy market.

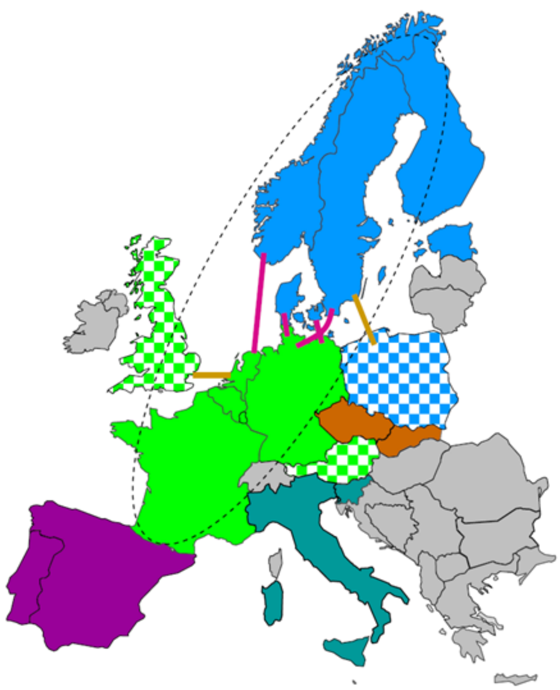
6.2.1.3 Examples of Coupled Markets

Currently, several electricity markets are already coupled in Europe, either through market splitting or through market coupling (Figure 26). Market splitting is the solution implemented by the Nord Pool Spot power exchange (see www.nordpoolspot.com) to integrate the markets of Norway, Sweden, Finland, Denmark, and Estonia. Similarly, the MIBEL market integrates via market splitting the electricity markets of Spain and Portugal, with the power exchange managed by OMI (see www.omie.es). As for price coupling, the largest initiative is the Central Western Europe (CWE) market, including France, Belgium, the Netherlands, Luxembourg, and Germany, managed by EPEX Spot, APX-Endex, and Belpex (see www.epexspot.com/en/marketcoupling/documentation_cwe). Price coupling is active also between Italy and Slovenia (see www.mercatoelettrico.org/It/Mercati/MercatoElettrico/MC_QuadroNormativo.aspx) and is jointly managed by the Italian (GME) and by the Slovenian (Borzen) market operators. Moreover, the CWE and the Nord Pool Spot markets have been coupled through a "tight" volume coupling (interim tight volume coupling), managed by EMCC (see www.marketcoupling.com). The outcomes of the aforementioned initiatives are generally considered positive in terms of increase of price convergence between the interconnected zones (e.g., see References [9] and [10]). All these initiatives are first steps towards a more general objective known as "price coupling of regions ," a project announced by Nord Pool Spot, EPEX Spot, APXEndex, Belpex, OMI, and GME, with the aim of implementing a single price coupling across the Nordic, Central West, and Southern European regions and to provide the basis for an effective European power market. The project will address the implementation of a common price coupling solution in a geographical area, which initially shall cover Portugal, Spain, Italy, Belgium, the Netherlands, Great Britain, France, Germany, Austria, Switzerland, Denmark, Norway, Sweden, Finland, and the Baltics, including the price coupling on the SwePol-link to Poland. More than 80% of the European power consumption takes place in this area. The initiative is open to other power exchanges and market areas on equal terms.

A hot topic is how the market integration, to be accomplished by 2014, should be implemented, the problem of the "target model." ENTSO-E has developed a Network Code on Capacity Allocation and Congestion Management (CACM) as a step in implementing a "target model" for the design of European electricity markets. The network code on CACM aims to establish methods for allocating capacity in day-ahead and intra-day timescales and to define mechanisms of capacity calculation across zones. The expected benefits are in terms of higher market efficiency, hence reduced costs in view of a pan-European market. The CACM is currently at the EC for evaluation, after ACER recommendations and subsequent remarks by ENTSO-E.

Similarly, a Network Code on Forward Capacity Allocation (FCA) has been drafted by ENTSO-E and underwent a consultation process. The objective is to develop pan-European markets in all timescales from markets for securing capacity several years ahead of real time, to day ahead, intra-day, and real time balancing markets. All these efforts are aimed at providing harmonized market rules leading to more efficient management of the market process taking into account the technical requirements, especially the needs posed by variable RES.

The implementation of the integrated market is a challenge from the algorithmic and computational viewpoints. To the extent individual countries want to preserve in the overall computational framework the peculiarities of their own electricity markets, the overall solution may not exist or it may take too much time to be computed compared to the timeline imposed by the market process. Hence, a trade-off must be found between the needs of standardization at the European level and the needs of each individual market. Figure 27 shows an example of functional architecture for the market integration.



REGIONAL IMPLICIT AUCTIONS		
	CWE	Price coupling
	Austria	Price coupled to GE/CWE (no congestion)
	BritNed	GB price coupled to NL/CWE
	Nordic + Estonia	Price coupling, also Poland via Swepol
	ITVC	Volume coupling CWE - Nordic
	Italy - Slovenia	Price coupling
	Mibel	Price coupling
	Czech - Slovak	Price coupling

Figure 26. Current status of market integration [11]

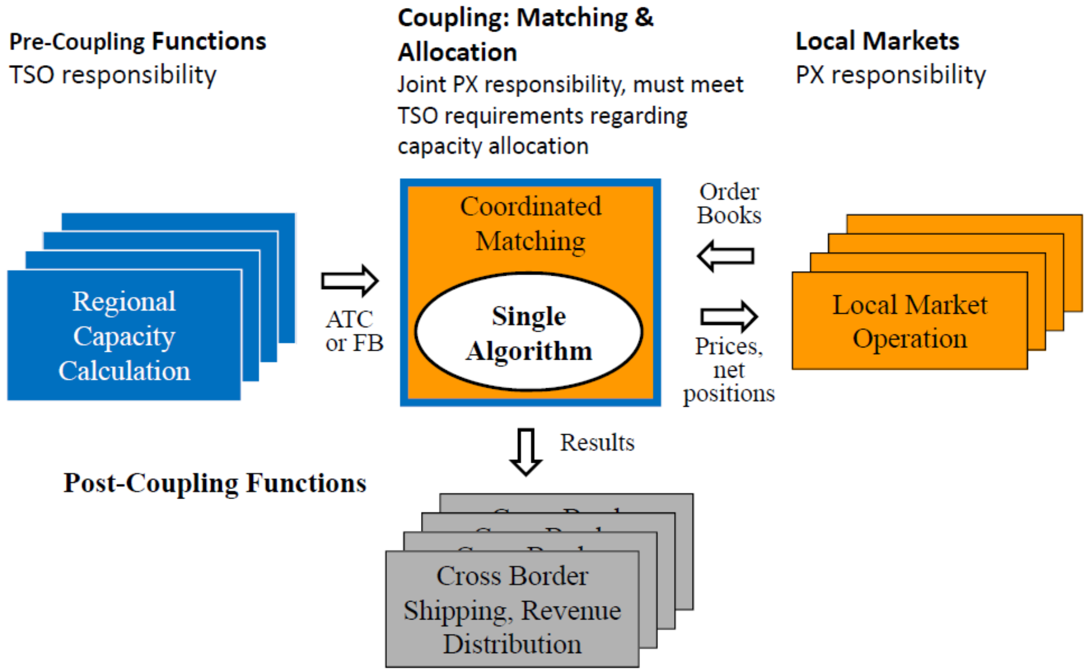


Figure 27. Overview of Day Ahead Solution Functional Blocks [11]

6.2.2 Pan-European Balancing Market

Until now, the main impact studies and the most noteworthy regulatory efforts have been focused on the integration of the national day-ahead market through the progressive enlargement of the market coupling. It is important to notice that also the integration of electricity markets closer to real time, the most critical for the proper functioning of the system, is an important goal to achieve at a pan-European level.

The 3rd Energy Package [12] clearly "moves" in this direction and boosts the development of an Integrated European balancing mechanism. In this context, ENTSO-E has proposed a network code on balancing. [13,14]

In light of this, the ACER published [15,16,17] a specific framework guideline relating to reserve and balancing markets issues. The ACER view is that active demand response will play a significant role in a future integrated balancing market, allowing the participation into the balancing market of virtual power plants and DG.

Moreover, the result of a study by ENTSO-E [18] "highlights the great diversity of arrangements that exist for ancillary services and imbalance charges across Europe - which will be one of the biggest challenges when designing balancing schemes."

Following this path, the eBADGE project [19] (a European co-funded project under the 7th Framework Programme), aims at studying possible mechanisms of a pan-European market for reserves and balancing that are also able to incorporate the role of virtual power plants and which optimizes the allocation of the transnational transmission network. In total, four different market architectures for national and cross-border electricity balancing are analyzed, two benchmarking models representing a “national minimum” as well as a multilateral maximum and two intermediate models respectively, as described here.[51]

6.2.2.1 National Market Based TSO Balancing Model (Benchmark for Minimum)

This market model corresponds to a typical status-quo, in which balancing service providers send their bids to their own national platform, and two independent merit order lists are built for upwards and downwards regulations (with a tendering period in which the bids for balancing reserves should be provided—that can be a day, one calendar week or month—and a reserved generation capacity within the control zone of a TSO defined according to the relevant provisions).

Thus, no bids are exchanged between different nations and the balancing management is done independently by each nation.

6.2.2.2 Bilateral/Multilateral Market Based TSO-TSO Balancing Model Without Common Merit Order (“Surplus Exchange”)

In such a market, the TSOs involved exchange only balancing energy bids and the procurement of balancing reserves is carried out separately by each TSO. In this way, the amount of the balancing reserves needed in each control zone is defined by the relevant provisions. More precisely, the energy exchange among the TSOs is not based on balancing reserve-sharing, which means that a reservation of cross-border transfer capacity is not needed.

This approach is a further extension of the previously described national approach in more steps; in particular:

- In a first step, the same procedure is carried out as described in the previous model (national procurement of balancing energy).
- In a second step, it is considered the possibility to exchange surplus balancing energy bids between different TSOs. This second step is conducted by sorting the surplus balancing energy bids in an international platform and re-allocating the surplus bids in national merit-order for balancing energy. This results in a second national procurement of balancing energy.

In general, the application of the surplus model will result in a balancing energy flow between the offering TSOs and the requesting TSOs. However, there implies neither a further direct connection/link between a single balancing service provider and a TSO beyond the one already existing at national level nor between a single balance service provider (BSP) and the multi-lateral/international platform.

In case of more than two TSOs involved in the multilateral approach, there might be an iterative set of further clearings of surplus balancing energy bids after the second step in order

[51] The project will develop, in particular, a pilot simulator for the region encompassing Italy, Austria, and Slovenia where different implementation details of a would-be transnational exchange of balancing resources will be analyzed as well as the ICT needs for its implementation. Methodology and approach are designed to allow a gradual extension to wider regions of Europe. The simulator will be implemented in a “cloud” environment allowing a distributed participation to the experiment from the three countries studied.

not to lose any of “low/cheap” energy bids in this process among many TSOs. There are different possibilities to re-allocate the various balancing energy bids of the multilateral/international platform to the different TSO for balancing energy activation:

(1) The first solution could be to use a “ranking-principle” that re-allocates the surplus bids to those TSOs that could benefit from one of these bids[52] (compared to the initial situation of the purely national merit-order).

The key question here is, how to allocate the different multilateral/international bids, notably the most attractive to the different involved TSOs “courting” them:

- *Ranking principle 1*: the TSO with the higher percentage of imbalance in real-time gets access to the most attractive existing bids in platform.
- *Ranking principle 2*: each of the TSOs involved gets a specific amount of the existing bids within the common multilateral/international platform. For example, a percentage sharing of bids again can be determined according to the percentage of imbalance in real-time of the involved TSOs.

The finalization of the entire process after the second national procurement of balancing energy, however, can have also the disadvantage of some “cheap” balancing energy bids still getting lost. Therefore, in the following second approach, the process shown above is further elaborated to mitigate this particular problem/inefficiency which could occur (from the total system efficiency point-of-view).

(2) This second approach aims at not losing any cheap bids until the last TSO has finalized its national procurement of balancing energy (based on a merit-order list containing own national balancing energy bids from the first national procurement and forwarded surplus bids).

This means that the first approach presented above needs to be further developed and not finished after the second national procurement because there could “appear” a new surplus bid of a TSO after the second national procurement of balancing energy (due to flattening of the merit-order of this TSO as a result of the insertion of forwarded bid(s) from the multilateral/international platform) having a lower price level than other forwarded balancing energy bid(s) to other TSOs after the first national procurement.

[52] To benefit is in the sense to get access to a lower balancing energy bid and “inserting” it into the initial national merit order list. This process will flatten the initial national merit-order list of those TSO benefiting from this step. Note, if the TSO having cleared with the lowest price in the first step in the national clearing can’t improve its result in subsequent steps, this TSO is already “finished.”

Therefore, after the second national procurement of balancing energy, again, several available surplus balancing energy bids of all still involved TSOs must be forwarded again to a multilateral/international balancing platform. Thus, the allocation of these balancing energy bids goes into a next round. From the total system efficiency's point-of-view, this is an improvement in comparison to the previous approach.

The disadvantage, however, is that more than two national procurements are needed. Moreover, this process might be too complicated and inconvenient in order to be considered for practical implementation.

(3) This third approach also builds upon further steps after a national procurement of balancing energy in a first step. The procedure is in subsequent manner as follows:
   (a) Identification of TSO with lowest clearing balancing energy price in the first national procurement. This TSO is already "finished" and cannot change the result in subsequent steps.
   (b) The surplus balancing energy bids have been taken from this TSO with the lowest clearing and been provided to the TSO with the next cheapest clearing price after the first national procurement of balancing energy.
   (c) This TSO receives the surplus balancing energy bids and integrates them in its initial national merit-order list and procures again.
   (d) The surplus balancing energy bids have been taken after this procurement from the second TSO (being finished after step 3) and been provided to the TSO with the next cheapest clearing price after the first national procurement.
   (e) Repetition of procedure until the last TSO is "finished."

   The advantage of this third approach is that the allocation of the surplus balancing energy bids is very clear and transparent. It is a sequential approach based on clear and transparent ranking. The reallocation of balancing energy bids to the involved TSOs is at least done after two national clearings for each one.

In any case, it has to be noticed that only a harmonization of the surplus energy bids on the international platform would be sufficient for an appropriate exchanging of surplus bids between the TSOs, whereby a harmonization of the different national approaches in terms of procurement of balancing energy and national imbalance products could result in greater total system efficiency.

6.2.2.3 Bilateral/Multilateral Market-Based TSO-TSO Balancing Model with Common Merit Order and Unshared Bids

This model can be interpreted as an intermediate step next to the final "target model" and deliver valuable experience before implementing the target model. The challenge of the model with unshared bids, however, is to find criteria (or a set of criteria) determining those balancing energy bids need not to be shared among the TSOs.

As mentioned in the last market architecture, the involved TSOs exchange only balancing energy bids between each other and the procurement of balancing reserves obtains in each TSO, separately. Therefore, a cross-border exchange of balancing energy bids is feasible only if sufficient cross-border transfer capacity is available. In this case, the TSOs forward the national balancing energy bids to an international platform; more precisely, the BSPs will not be able to set their balancing energy bids directly into the international platform.

Thus, after a national procurement of balancing energy, the amount of "shared" balancing energy bids are forwarded immediately to a platform to build the multilateral/international common merit-order list where, among others, also the cheapest bids of several of the TSOs are shared. Therefore, in addition to individual national platforms a multilateral/international platform is also needed for balancing energy bids for both upward and downward regulation.

6.2.2.4 TSO-TSO Balancing Model with Common Merit Order and Without Unshared Bids (Benchmark for Maximum; Final Target Model)

A further development of the previous TSO-TSO model with common merit-order and unshared bids finally results in a system where several bids of the BSPs have to be shared on an international platform. As described in previous market model, the collection of balancing energy bids is conducted by the incumbent TSO. The TSO will directly forward all the collected balancing energy bids to the international platform, in which a clearing is performed.

In case of activation of balancing energy, there is a balancing energy flow between the offering BSPs (physically connected to an associated TSO) and a requesting TSO. It has to be noticed that an entire harmonization and standardization in terms of different national parameters and products (e.g., gate closure) is necessary.

6.2.3 Capacity Market

In the monopolistic electricity industry, the generation undergoes a planning process, like transmission, aimed to guarantee adequate generation capacity over the next years. In liberalized markets, the new generation, as well as the typologies of electric generation, are left to the initiative of investors. An issue then arises whether investors will build adequate generation capacity, that is, for the amount needed to cover the demand, and featuring enough technological diversity in order to provide a balanced portfolio under the primary energy source and operation flexibility viewpoints.

The EC states the problem as follows:

- The topic of effective policies for ensuring generation adequacy in electricity markets has become an increasingly visible topic in the policy discussion.
- One element of the discussion is the need to ensure that new flexible resources are delivered to complement wind and solar power generation in particular.
- The other element of the discussion is the need to ensure sufficient capacity is available to meet demand on the system at times of highest system stress. [20]

The issue is how to achieve such objectives. To this aim, suitable capacity remuneration mechanisms need to be set up. A significant description of possible options is reported in

Reference [21]. Several contributions were provided by EURELECTRIC [22], ENTSO-E [23], CEER [24]; however, the topic is still pending.

6.2.4 Outcomes and Challenges

The European market is undergoing an integration process. However, the way the process is implemented will definitely impact the efficiency of the resulting market and also the flexibility of grid operation. The real challenges regard the regulatory harmonization of both day ahead and balancing markets and implementation from the methodological and ICT standpoint. In fact, the algorithmic and computational requirements posed by the integrated market problem accounting for all specific rules are very demanding. A certain risk exists; therefore, the resulting dispatch is far from optimal. At least in the initial stages of the new market operation, efficiency may be reduced.

More challenges regard the need for increased transmission and distribution collaboration. This is fundamental to foster decentralized electricity markets and end-user involvement through smart grids. It is suggested that transmission, distribution, and markets be looked at together, from an overall system perspective, technically and economically. Major issues need to be addressed, including how to tackle capacity needs, how to deal with incentives to drive the load and embedded generation to respond to local congestion, possibly within a zonal pricing market philosophy, and how to incentivize providers of energy storage (electric, thermal, industrial) to support primary energy balancing needs.

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7 Summary

The purpose of this discussion paper is to examine the policies and regulations that govern the transmission system as well as the expansion, planning and operation, and markets for the U.S. and European electricity systems. This discussion paper looked at how these policies and regulations have changed over time to accommodate new developments in the operation, planning and market areas of each region's electricity system.

The changing dynamics of electricity systems around the world are creating new challenges to operating, planning and expanding these systems. This discussion paper also presented several technical and institutional opportunities that are available to overcome the challenges such as integrating large amounts of renewable energy while maintaining reliability and security.

TRANSMISSION OPERATION AND MANAGEMENT

Grid operation and management can be complicated by a variety of factors, including diverse resources and complex ownership or jurisdictional structures. Understanding how these resources interact with the electric grid and the potential implications is critical. The U.S. and Europe have a number of technical and institutional opportunities they are exploring to help manage the complexity of the grid and maintain reliability.

Table 3. Summary of Transmission Operation and Management

	United States	Europe
Decision-makers	• Multi-layered, complex system-wide task that requires multiple organizations • Transmission system is managed across a variety of industry standards that vary according to jurisdiction • The local distribution owner is responsible for the operation and maintenance	• European Network of Transmission System Operators for Electricity includes 41 TSOs from 34 countries
Challenges	• Operating a diverse set of resources and operational strategies often add complexity to the grid and reveals seams issues • Lack of wide area visualization	• Increasing complexity of system behavior – including integration of DG and renewables – that can inherently modify the dynamics of the power system possibly causing stability problems • Algorithmic and computational requirements posed by an integrated market
Technical Opportunities	• Deployment and networking of PMUs • Deployment of smart grid technologies	• Enhanced analysis tools to assess online security of the system
Institutional Opportunities	• More robust coordination among stakeholders to better understand the potential implications of new technologies, tools, techniques • Multi-area coordination efforts to address seams issues	• Increased TSO and DSO coordination • Increased inter-TSO coordination

TRANSMISSION EXPANSION PLANNING

Transmission planning and expansion efforts in the U.S. and Europe involve complex and time-consuming issues. Some of these issues include planning a reliable system, the cost allocation of infrastructure and social and environmental impacts. The U.S. and Europe are exploring several opportunities to help alleviate these issues.

Table 4. Summary of Transmission Planning and Expansion

	United States	**Europe**
Decision-makers	• ISOs/RTOs, utilities have planning authority • State PUCs are the primary regulatory bodies that govern transmission siting and the retail electricity market • FERC (through Orders 890 and 1000) engages in the planning processes • Other government bodies play important roles (e.g., the EPA, state environmental offices, etc.)	• European Network of Transmission System Operators for Electricity includes 41 TSOs from 34 countries • TSO has sole responsibility to plan expansion of its network while minimizing transmission costs and ensure reliable and efficient economic operation
Challenges	• Maturation of electricity markets and the integration of renewables has made transmission expansion planning more complicated and introduced more decision-makers into the process • Public opposition to new infrastructure	• Environmental constraints and social opposition • Generation sources farther away from major consumption sites; electricity must be transmitted over longer distances
Technical Opportunities	• Deployment of smart grid technologies to enhance performance of existing infrastructure • The DOE is supporting the development of and research using planning tools (e.g., SuperOPF)	• Integration of tools and techniques to evaluate whether a “do-nothing” approach will affect reliability and security
Institutional Opportunities	• More robust coordination among stakeholders to better understand the potential implications of new technologies, tools, techniques • IWTP and other regional planning processes	• Pan European network to enable integration of TSOs and benefit from the different behaviors of consumption and generation – e-Highway 2050 • Comprehensive cost benefit analyses

MARKET STRUCTURE AND OPERATIONS

Electricity markets are designed and operated through a variety of mechanisms depending on regional market structures and agreements. There are challenges with market structure and operations that the U.S. and Europe are attempting to overcome by capitalizing on technical and institutional opportunities.

Table 5. Summary of Market Structure and Operations

	United States	Europe
Decision-makers	• The FERC has regulatory jurisdiction over the wholesale electricity market (approve market rules) • State PUCs are the primary regulatory bodies that govern transmission siting and the retail electricity market • Balancing authorities responsible for balancing generation and load in their region • ISO/RTOs develop rules for and operate markets	• European Council develops targets and goals for European countries and electricity system operators • TSOs, ENTSO-E, creating new pan-European market • ACER
Challenges	• Operational seams exist between regions; variation in methods available for achieving efficient and reliable power system operations	• Implementation of the integrated European market presents algorithmic and computational challenges • Harmonization of day-ahead and balancing markets
Opportunities (Technical)	• Improved data processing and communication, through PMU networks, energy management systems and other smart technology, to improve knowledge of physical and financial status of grid operations	• Development of appropriate computational methods and algorithms to represent unique aspects of each countries' market
Opportunities (Institutional)	• Incremental changes to wholesale tariffs to encourage behavior that supports efficiency and reliability • Creation of "RTO-like" operations (e.g., energy imbalance markets) in non-market areas to increase flexibility and aid renewables integration • Cooperation between regions to address seams issues	• Implementation of implicit auction which allocates transmission and energy simultaneously • "Market coupling" to address seams issues

FUTURE TOPIC AREAS

As a result of this paper's assessment of policies and regulation, transmission expansion planning, and market analysis for the U.S. and Europe, several areas for expanded discussion were identified:

- Cybersecurity policies and technologies, and their implementation
- Transmission planning technologies and their utility (e.g., energy storage, smart grid technologies)
- Implications of demand-side resources and related policies and regulation on transmission expansion planning
- Expanded discussion of European legal framework and ENTSO-E legal mandates

- General discussion of how transmission and distribution collaboration is increasingly important to foster decentralized electricity markets and end-user participation (e.g., through the use of smart grid technologies)

These topics may be discussed in more details in a future follow-on effort to this discussion paper. Additionally, similar assessments of additional countries may also be incorporated.

CHALLENGES

The changing dynamics of electricity systems around the world are creating new challenges for planning, operating and expanding these systems. Overcoming challenges in the coming decades, such as the ones listed below, requires a systematic, holistic, integrated approach that considers technologies, policies and markets.

- Accomplishing or deploying retrofitting programs of DG
- Coordinating between TSOs and DSOs in distribution system monitoring and control
- Developing the regulatory and technical framework for smart distribution grids
- Deploying market mechanisms in order to guarantee availability of sufficient conventional generation
- Fostering technological development
- Enhancing the portfolio of flexibility resources

FINAL REMARKS

ISGAN Annex 6 is working to establish a long-term vision for the development of smarter electricity systems. Flexibility, visibility, and understanding of grid operations are important characteristics of this vision that enable deployment of technologies to modernize the electric grid system and address the challenges listed above. Several activities are needed to help achieve this long-term vision:

- For transmission planning more coordination and cooperation among all stakeholders and national and international entities are needed to help align policy making, technology development and markets and operations.
- Technologies and institutional changes can help to alleviate liberalization and higher renewable energy system utilization, increased cross-border flows, congestion and uncertainties for planning.
- Technologies should be better incorporated into the transmission planning process.
- Development of clear guidelines, procedures, and tools can help manage the complex nature of transmission planning.

8 Appendices

8.1 Acronyms and Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AMI	advanced metering infrastructure
ARRA	American Reinvestment and Recovery Act of 2009
ATC	available transfer capacity
BSP	balance service provider
CAISO	California Independent System Operator
DG	distributed generation
DLR	dynamic line rating
DOE	U.S. Department of Energy
DSM	demand-side management
DSO	distribution system operator
EC	European Commission
EHVDC	extra high voltage direct current
EIPC	Eastern Interconnection Planning Collaborative
EISA	Energy Independence and Security Act of 2007
EISPC	Eastern Interconnection States Planning Council
ENTSO-E	European Network of Transmission System Operators for Electricity
EPA	U.S. Environmental Protection Agency
EPAct 1992	Energy Policy Act of 1992
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
EU	European Union
FACTS	flexible alternating current transmission system
FCL	fault current limiter
FERC	Federal Energy Regulatory Commission
FiT	feed in tariff
FPA	Federal Power Act
FTR	financial transmission right
GIL	gas insulated line
HT	high temperature
HTLS	high temperature low sag
HTSC	high temperature superconducting cable
HVDC	high voltage direct current
ICT	information & communication technology
ISO	independent system operator
ISO-NE	Independent System Operator of New England
ITO	independent transmission operator
IWTP	Interconnection Wide Transmission Planning
MISO	Midcontinent Independent System Operator

NEPA	National Environmental Policy Act of 1969
NERC	North American Electric Reliability Corporation
NHPA	National Historic Preservation Act
NYISO	New York Independent System Operator
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OE	DOE Office of Electricity Delivery and Energy Reliability
OHL	overhead line
PJM	Pennsylvania-New Jersey-Maryland Regional Transmission Organization
PMA	Power Marketing Administration
PST	phase shifting transformer
PUC	public utility commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act of 1978
PV	photovoltaic
REC	renewable energy/electricity credit
RES	renewable energy source
RPS	renewable portfolio standard
RTO	regional transmission operator
RTTR	real-time thermal rating
SPP	Southwest Power Pool
TEN-E	Trans-European Energy Network
TSO	transmission system operator
TYNDP	Ten Year Network Development Plan
U.S.	United States
WACS	wide area control system
WAMS	wide area measurement (or monitoring) system
WAPS	wide area power system
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
XLPE	cross-linked polyethelene

8.2 United States – Additional Information and Resources

8.2.1 Statutes and Regulations

8.2.1.1 Clean Air Act (CAA)

Authority 42 USC §§ 7401-7671q

Agency Responsible EPA

The EPA (www.epa.gov) regulates and tracks a number of air pollution sources related to the grid under the Clean Air Act (amended in 1970 and 1990), including but not limited to, mercury and other air toxics, greenhouse gases, ozone, NO_x and SO_x, and other emissions from generators. Additionally, the EPA tracks SF_6 emissions from transmission lines as part of its annual air emissions inventory.

8.2.1.2 Clean Water Act (CWA)

Authority 33 USC §§ 1351 et seq.
Agency Responsible EPA

The EPA (www.epa.gov) regulates and tracks a number of water-related impacts related to the grid under the Clean Water Act, including, but not limited to cooling water intake structures, thermal discharges, groundwater management, total maximum daily loads of identified water pollutants.

8.2.1.3 Resource Conservation & Recovery Act (RCRA)

Authority 42 USC §§ 6901 et seq.
40 CFR 260 et seq.
Agency Responsible EPA

The EPA (www.epa.gov) regulates and tracks the storage, transport and treatment of hazardous waste. The EPA's authority includes the establishment of a cradle-to-grave regulatory hazardous waste management program. The EPA is currently considering regulation of coal ash residuals (see www.epa.gov/coalashrule**).**

8.2.1.4 Federal Power Act (FPA)

Authority 16 USC §§ 791 et seq
Agency Responsible DOE
FERC

The Federal Power Act dissolved the Federal Power Commission and transferred its authorities to the DOE and the FERC. The FPA was amended subsequently, including by the EPAct 2005.

8.2.1.5 Public Utility Regulatory Policies Act of 1978 (PURPA)

(including impacts of EPAct 2005)
Authority 16 USC §§ 2601-2645
16 USC § 824a-3
Agency Responsible DOE
FERC

The Public Utility Regulatory Policies Act required utilities to purchase generated power from qualifying facilities (QFs) rather than generate new power; it was a jump-start for renewables and cogeneration. The EPAct 2005 terminated utilities' obligation to purchase energy and capacity from QFs (16 USC § 824a-3).

8.2.1.6 Energy Policy Act of 2005 (EPAct 2005)

Authority 42 USC §§ 15811 et seq.
Agency Responsible DOE
FERC

While the Energy Policy Act of 2005 included authorities for numerous federal agencies, the primary energy-related authorities were granted to the DOE and the FERC. One significant aspect of the EPAct 2005 addresses reliability; the EPAct 2005 authorized creation of a self-regulatory electric reliability organization spanning North America with FERC oversight for the U.S. jurisdictions.

8.2.1.7 Energy Independence and Security Act of 2007 (EISA)

Authority Pub.L. 110-140

Agency Responsible DOE
FERC

The Energy Independence and Security Act was enacted to move the U.S. toward greater energy independence and security; to increase the production of clean renewable fuels, to protect consumers; to increase the efficiency of products, buildings, and vehicles; to promote research on and deploy greenhouse gas capture and storage options; and to improve the energy performance of the federal government, and for other purposes. The DOE received research direction in numerous technology and efficiency areas. Additionally, the EISA directed the FERC to "institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets." Other federal agencies also received authority under the EISA.

8.2.2 Federal Energy Regulatory Commission Orders

Date Issued	Order Number	Title
May 17, 2012	Order No. 1000-A	Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Order on Rehearing & Clarification)
Oct 20, 2011	Order No. 755	Frequency Regulation Compensation in Organized Wholesale Power Markets (Final Rule)
July 21, 2011 (effective Oct 11, 2011)	Order No. 1000	Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Final Rule)
Feb 16, 2007	Order No. 890	Preventing Undue Discrimination and Preference in Transmission Service (Final Rule)
Dec 20, 1999	Order No. 2000	Establishment of Regional Transmission Organizations proposals (Final Rule)

Date Issued	Order Number	Title
April 24, 1996	Order No. 888	Transmission Open Access. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Final Rule)
April 24, 1996	Order No. 889	OASIS: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct (Final Rule)

Additional FERC orders may be found on the FERC website: http://www.ferc.gov/legal/maj-ord-reg.asp.

8.2.3 International Regulatory Trade – Canada, United States, Mexico

Table 6. International Regulatory Trade - General information

	CANADA	UNITED STATES	MEXICO
Responsible Authority	**National Energy Board (NEB)**	**Department of Energy (DOE)**	**Energy Regulatory Commission (CRE)**
Legislation	***National Energy Board Act*** The *National Energy Board Act* was initially promulgated in 1959, and later amended. Significant changes were introduced following the implementation of the *Canadian Electricity Policy (1988)*. The NEB also has responsibilities under the *Canadian Environmental Assessment Act* (CEA Act), which came into effect in 1995.	***Executive Order 10485 and Federal Power Act*** Regulation of international transmission lines began in 1939 and was established by Executive Order rather than law. In 1953, Executive Order 10485 delegated the authority for Presidential permits to the Federal Power Commission; in 1978, Executive Order 12038 transferred the authority to the Secretary of Energy. The Federal Power Act, section 202(e), establishes DOE's electricity export authority.	***Public Electricity Service Act*** The *Public Electricity Service Act* was published in 1975, and it established exclusive Federal responsibility over the electricity industry. However, it was amended in 1992, in order to allow private participation under certain generation categories. ***Energy Regulatory Commission Act*** The Energy Regulatory Commission Act (CRE Act) was issued in 1995. The CRE Act transformed the CRE's role to that of an empowered, independent regulator with technical and operational autonomy and provided the CRE with a legislative mandate to regulate the activities in the electricity and gas industries.

	CANADA	UNITED STATES	MEXICO
Regulated Activities	Construction and operation (and abandonment) of international powerlines (IPLs). Electricity exports.	Construction, operation, maintenance, and connection of electric transmission facilities at the U.S. international border. Electricity exports.	Construction and operation of private generation plants under the self-supply, cogeneration, Independent Power Producer (IPP), small production and import/export category. Any private party may apply for a generation permit under the above mentioned categories. However, the Comision Federal de Electricidad (CFE) will be in charge of the planning of IPP[53] projects and conduct an international bidding process. An IPP generation permit will be granted subject to the awarding of the above-mentioned bidding process.
Procedure			
Application	An application is filed with the NEB containing information specified in the NEB's Electricity Regulations. Prospective applicants may arrange pre-application meetings with the NEB to discuss procedural and general, non-substantive matters. The NEB's Memorandum of Guidance dated August 26, 1998, and Guidelines to Filing Requirements dated February 22, 1995, provide information on the application process and filing requirements. These documents are available at www.neb-one.gc.ca (under Publications (Links to Acts and Regulations).	Applications for Presidential permits and electricity export authorizations are filed with DOE's Office of Electricity Delivery and Energy Reliability in accordance with DOE's regulations at 10 CFR 205.300. Applicants for Presidential permits may request pre-application meetings with DOE to discuss filing requirements. Export authorization applicants do not generally require pre-application meetings.	The applicant must be aware of the types of permit that CRE may grant and the requirements that the Law and the Regulations specify. The applicant must file an application form requesting a generation or an import permit. Before filing the documentation, the applicant may participate in meetings with CRE officers to resolve any doubts regarding filling in the application form or the additional documents required. The permit request procedure is specified in the Public Electricity Service Ruling Act and at CRE's website: www.cre.gob.mx/English/publications/booklets/folleto%207/doc7-dis.html

[53] An IPP is a private generation category permitted by the Public Electricity Service Act. This category consists of a power plant built and operated by a private party with an installed capacity larger than 30 MW. The producer will sign a Power Purchase Agreement with CFE to sell on an exclusive basis all the power plant capacity and the associated energy. These projects will be awarded through a bidding process carried out by CFE.

	CANADA	UNITED STATES	MEXICO
Public Notification	Coincident with the filing of the application to the NEB, the applicant is required to publish notification of its application in the Canada Gazette and, in some cases, local newspapers.	DOE places a notice of each application in the *Federal Register* usually within 2 weeks of receipt of the application that begins a 30-day public comment period. Interested parties may comment, protest the application, or request status as an intervener. The application can be viewed on the program website after the public notice appears.	There is no public notification requirement.

Table 7. International Power Lines

	CANADA	UNITED STATES	MEXICO
Legislative Requirement	The NEB Act states that no person shall construct or operate a section or part of an international power line except under and in accordance with a permit or certificate issued by the Board (section 58.1).	*Executive Order (EO) 10485* established that no person shall construct, operate, maintain, or connect an electric transmission line at the borders of United States without a permit from the Federal Power Commission. In 1978, EO 12038 transferred authority to issue permits for new international transmission facilities to the Secretary of Energy.	The Public Electricity Service Act does not establish the need of a permit to construct, operate, or maintain an International Transmission Line (IPL). If CFE constructs or operates the IPL, there is no need for such organism to obtain a CRE permit. In the other hand, if a private party is interested in building and/or operating an IPL, they will have to comply with the Official Mexican Standards (NOMs), and in the case that private party should be interconnected with the National Electric System, it will require a contract with CFE.
Criteria	The NEB must take into account the effect of the powerline on provinces other than those through which the powerline is to pass, which may include adverse effects on the power systems of those provinces. The NEB must take into account the impact of the construction or operation on the environment. This may require the applicant to prepare a screening report, or a Comprehensive Study Report (CSR) pursuant to the CEA Act, or a report undertaken pursuant to provincial regulation. A CSR would normally be required for an IPL greater than 345 kV and longer than 75 km in length on a new right-of-way. The CSR must be	The proposed international transmission facilities must not adversely impact the reliability of the U.S. electric power supply system. DOE must identify the environmental impacts of the project using the National Environmental Policy Act of 1969 (NEPA). Three levels of environmental review are available under NEPA. DOE exercises its discretion, case-by-case, based primarily on project size and location, in determining the appropriate level of environmental review. DOE must obtain concurrence from the Departments of State and Defense prior to issuance of	The applicant will have to comply with the environmental and municipal regulations. Additionally, if the applicant will use the National Electric System, they will have to sign an interconnection contract, which will establish the terms and conditions to use the power grid. The permit holders shall use generated electricity for their own supply and the surplus energy may be sold to CFE. According to the General Law of Environmental Balance and Protection, any party interested in building an International Transmission Line must submit an Environmental Impact Assessment and a Risk Analysis of

	CANADA	UNITED STATES	MEXICO
	prepared and provided to the Minister of the Environment, for his or her decision, before the NEB can take a course of action with respect to the applied-for project. The NEB must take into account other considerations as specified in the Board's Electricity Regulations.	new or amended permits. If there is disagreement among the agencies, the decision is referred to the President of the United States.	the project to the Environment and Natural Resources Ministry (SEMARNAT). The SEMARNAT will review all the information provided, and if it complies with the requirements established in the General Law of Environmental Balance and Protection, an environmental impact license and a risk license will be granted. Regarding the municipal regulation, the applicant must obtain a land use license, and in case, a construction license, whenever this authorization will not damage other authorities by crossing its jurisdiction. This procedure will depend on the municipal authorities.
Procedure			
Application	An application is filed with the Board containing information specified in the Board's Electricity Regulations. The Board's Memorandum of Guidance dated August 26, 1998, and Guidelines to Filing requirements dated February 22, 1995, provide information on the application process and filing requirements. These documents are available at www.neb-one.gc.ca (under "Publications" (Links to Acts and Regulations). There are no application fees. The NEB recovers its costs from electricity exporters on a *pro rata* basis.	Applications for Presidential permits and electricity export authorizations are filed with DOE's Office of Electricity Delivery and Energy Reliability in accordance with DOE's regulations at 10 CFR 205.300. Applicants for Presidential permits may request pre-application meetings with DOE to discuss filing requirements. Export authorization applicants do not generally require pre-application meetings. The applicant is responsible for the cost of the preparation of environmental assessments or environmental impact statements required by NEPA.	If the IPL is built by a private party, an export/import permit will be required. The procedure will be the same for an export/import permit. If the line is built by CFE it will not require any permit from the CRE, it will only have to comply with the environmental and municipal requirements. CFE will be responsible for all the reliability analysis. The applicant party must pay an export/import permit fee of $68,001 Mexican pesos as permit rights.[54]
Public Notification	Coincident with the filing of the application with the NEB, the applicant must publish a Notice of	Within 2 weeks of receipt of the application, DOE places a notice in the *Federal Register*	There is no public notification requirement except in the case of permit termination, renewal or

[54] Approximately U.S.$6,719 (exchange dollar rate from November 29, 2002, issued by Mexican National Bank, Official Federation Gazette $10.1193 (pesos/U.S.). The fee established in the Fee Federal Law has a semestral adjusment.

	CANADA	UNITED STATES	MEXICO
	Application and Directions on Procedure (NOA/DOP) in the Canada Gazette and local newspapers. Prior to the filing, the applicant must provide early public notification (EPN) to explain the project and the potential environmental and socio-economic effects and to allow an opportunity for public comments and questions.	announcing the start of a 30-day public comment period. During this period, interested parties may submit comments, protest the application or request to intervene in the proceeding.	expiry.
Additional Filing Information	After reviewing the application, the Board and other interested parties may request additional information to complete the record.	Each Presidential permit project is unique and may have properties that preclude submission of standard information. After an application is submitted, DOE may request additional information from the applicant.	If the permit application is not complete and if additional information is required, the CRE could notify the applicant to submit any additional information required.
Authorization/ Issuance	The Board issues a permit to construct and operate an IPL, if it is satisfied that the information provided conforms with its requirements and all concerns have been addressed. The permit normally includes terms and conditions to be fulfilled by the applicant respecting matters prescribed by the Electricity Regulations. If, after consideration of the relevant factors, the Board believes the application raises concerns, it may recommend to the Governor in Council (GIC) that a public hearing be held. If the Board approves the application after the public hearing it issues a certificate, subject to GIC approval.	DOE issues a Presidential permit only after fulfilling the NEPA and electric reliability criteria and obtaining State and Defense Department concurrences. Presidential permits may contain conditions determined by DOE (i.e., environmental mitigation measures) or, based on technical studies, DOE may apply very specific conditions regarding transfer limits during certain operating conditions. These technical limits are usually the same limits established by the regional reliability councils and/or independent system operators.	The CRE issues a permit to export and import electricity provided that the information conforms with all legal requirements.
Timing	From the date the application is filed (and public notification is given), interested parties have 30 days to review it, in order to provide comments and ask for additional information. The applicant has 15 days to respond to any submissions. Interested parties then have 10 days to assess and comment on the responses. The Board may then issue a permit or make a recommendation to the GIC that the application be designated for a public hearing. Additional time	Applications requiring an environmental impact statement, the highest level of environmental review, could take between 15 and 24 months to complete. Applications requiring an environmental assessment usually can be completed within 6 months. DOE has identified types of projects that experience has shown do not normally have a negative environmental impact. Proposed IPL projects, within one	After the CRE receives all the information submitted by the applicant, the CRE will ask CFE's opinion, which they will have 30 working days period to submit. This opinion will have regard to the availability of wheeling and back-up services that the applicant may require and, if applicable, the delivery of surplus energy to CFE. Once the CRE receives the public utilities' opinion, CRE will have a 20 working days period to publish

	CANADA	UNITED STATES	MEXICO
	would be required in the case where a public hearing is held.	of these groups, can be completed within 60 days of submission of final electric reliability studies. (NEPA "Categorical Exclusion")	the permit resolution. If there are any comments from the CRE or the public utilities, the applicant will have 10 working days to submit any corrections to the permit application. Finally the CRE has a 20 working days period to issue the permit resolution.
Maximum Term for IPL Authorizations	NEB issues a permit or certificate without term limits. The NEB may revoke or suspend a permit or certificate: on application to the NEB, or by consent of the holder of the permit or certificate; or if the holder has not complied with a term or condition of the permit or certificate. The NEB must approve the abandonment of the operation of an IPL.	Presidential permits are issued without term limits; permits are not transferable or assignable. If facility ownership changes, a joint application by both parties is required. Although it has not occurred, permits may be modified or revoked without notice by the President of the United States, or by the Secretary of Energy after public notice.	Permit issuance without time limit except for the IPP permits that last 30 years. However, permits may be revoked, according to the Public Service Electricity Ruling Act, if the permit holder doesn't comply with its obligations established in article 90 of the Public Service Electricity Ruling Act or if it transfers the permit right to another party in a different way than that established in the regulation.

8.3 ISGAN Annex 6 Workshop: Key Topics of Policy and Regulation, Planning, and Market

The following tables synthesize significant issues as identified during the inaugural ISGAN Annex 6 workshop held in Milan, June, 18–19, 2012.

Table 8. Task 1 – Impact on Policy & Regulation – Smart Grids

Issues	Conclusions/Recommendations	T	D	PRIO
Scope of the SG	• Awareness that smart grid development is *part* of the solution to the RES integration and the other strategic objectives, it does not address *all* of the problems	X	X	1
Flexibility	• RES require *flexibility* to a degree that was not needed in the past: (1) Provide policy & regulation framework for the development/deployment of flexibility resources (e.g. load management, VPP, conventional generation availability…). However, load response ("*n*egawatt") may be less reliable than generation capacity. (2) Define meaningful flexibility indices. • Current regulatory systems were fit for the "old" power systems. A *revolutionary* approach is needed for energy and flexibility market (flexibility includes capacity) design. For instance, "base load" power plants is a concept which belongs to the "old" structure and should be overcome • Face issue of "stranded costs" in conventional generation: RES displace conventional generation, hence risk of shutting down conventional power plants due to decreased profitability of the energy service. However, conventional are still necessary	X	X	1

Issues	Conclusions/Recommendations	T	D	PRIO
	to compensate for the RES variability. Pay for capacity service instead, to avoid risk of conventional generation adequacy problems in the long run.			
Proper regulation and stimulation of Smart Grids T&D projects	• The remuneration framework is crucial to promote Smart Grids (including storage) projects. At D level, the ongoing Italian experience (see slides by the Italian regulator) for a framework moving from an *input-based* towards an *output-based remuneration scheme* can represent an important reference case. At T level, the experiences in Asia (China, South Korea) with a state-based pricing have provided their effectiveness to guarantee investments (this is however different from the European situation).	X	X	1
Interoperability standardisation	• This touches upon different levels, technologies, stakeholders. Top priority is to make software/hardware devices of different manufacturers able to work together, as well as to streamline control and ICT means across different operators and stakeholders, such as at TSO-TSO, TSO-DSO, DSO-DSO, TSO-DG operator, DSO-DG operator levels	X	X	1
Cost allocation, Cost vs. value	• Splitting the Smart Grids projects costs among the different users in a clear way can facilitate investments. • Costs are more apparent than benefits: hence, look at the value more than the cost. Point out that the electric system serves the whole society. *Electricity does more than serve the market*. The price of any good is affected by electricity price. In particular electricity supports the employment, country development etc. • “Who pays” and “what is the benefit for the general public” are issues to clarify • Stress that delaying projects has a cost (example: wind generation of Gotland island cut due to inadequate transmission development)	X	X	1-2
Authorisation and permit processes	• This concerns mostly Europe and US: without T&D expansion in a reasonable time, Smart Grids projects cannot be properly implemented. Harmonising and streamlining procedures with accelerated patterns (see proposals in the EC Energy Infrastructure Package) have to be put in place. • See item above (cost of delaying projects) • Siting issues make investment costs unpredictable, which may discourage investors	X	X	1
Mismatch between generation (RES) and T&D investments	• Continuous monitoring and precise specification of grid connection requests and harmonisation of grid connection rules represent important countermeasures.	X	X	1
Incentives	• Harmonisation of incentives over wide areas, for steadier development of RES. Overall, a stable regulatory framework is needed for T&D investments			

Table 9. Task 2 – Integration of RES in T&D Systems – market mechanisms and tools

Issues	Conclusions/Recommendations	T	D	PRIO
Transmission development needs	• Large penetration of variable renewables requires to address not only local, but also wide-area issues. Example: large variations of wind production may occur, hence transmission is needed to allow for largely different power flow patterns over wide areas. Moreover, lack of wind production may occur over large areas and for long periods (e.g. 10-12 days), hence need for conventional	X		1

Issues	Conclusions/Recommendations	T	D	PRIO
	capacity. PV development adds to variability. Address these issues in transmission planning • Within the evaluation of grid expansion alternatives, putting "grid" against "ICT" is not a good approach (transmission must be replaced in any case, e.g. due to ageing)			
Integration/Interaction of T and D planning to cope with DG and RES variability	• A tighter coordination of TSO and DSO is more and more needed, especially in Europe and US, where unbundling is mostly in place: an interesting case is given by the Cell Pilot Project in Denmark where TSO closely controls a microgrid (Cell of D network managed by DSO), directly interacting with the DG operator; in other cases the TSO has a wider observability of the system (Spain) or it directly operates assets down to HV (Italy) or MV (France). In Asia (China, South Korea), T and D are operated by a vertically integrated utility: a top-down approach gives priority to planning T before D. • In the current situation in Europe two choices are possible: local compensation in D or management within T of the "reverse" flow from D. The right choice should be the one that minimizes system costs, compatibly with the characteristics of the deployed technologies (e.g. limitations dictated by the storage technologies). • In some cases (Austria) the D network has no bottlenecks due to the abundance of generation; in some others (Norway and Austria-Kärnten) new hydro resources cannot be connected to the network due to transmission limitations. Each case should be examined per se. • There is a regulatory problem due to the different solutions adopted in the different countries (in particular, in Europe). A harmonization process is needed with the aim to foster the creation of a true unified market. The tools have to be standardized as well and the keyword is interoperability. • There is a risk of competition between T and D investments, typically carried out by different companies. Expensive investments Smart Grid apparatuses in D can sometimes be avoided by investing in T. However, here essential is the role of the regulator, which fixes the goals for investments by means of the set-up of the remuneration schemes. • Need for in-depth evaluation of the *system* impacts of RES at D levels, and of the resulting system planning and operation requirements • The liberalised market forbids to talk about coordinated T&D planning *investment*, as different entities are involved. *Interaction* is ok instead. "Build bridges" on T&D planning and operation	X	X	1
Ownership of storage devices	• Most European countries (Italy is an exception, at least for batteries) don't allow TSOs to own storage devices but open it to private competition, in particular among the GenCos. There are pros and cons: the contemporary ownership of storage and generation make it possible to exercise strategic behaviours (under-usage of storage for keeping peak prices high), so it should be not admitted by the regulators. • If storage were regarded as a system service, the	X	X	2

Issues	Conclusions/Recommendations	T	D	PRIO
	perspective would be different (cf. reactive compensation devices)			
Possible participation to the wholesale and reserve markets of Virtual Power Plants (VPPs: DG + storage+RES generation)	• Local constraints on D networks could make it difficult or less profitable for the system, but this is not technically impossible (wherever a bottleneck arises, two different market zones can be individuated). • The "scattered" nature of VPPs can make it difficult to directly interact with the markets (e.g.: needed ICT infrastructure). The intermediate figure of an aggregator could be necessary. • The needed amount of data to be exchanged between the market clearing office and the bidders as well as the time horizon (how much ahead wrt real time: gate closure issue) have to be accounted for to establish whether direct participation is possible and/or envisageable. • The robustness of the resulting system has to be considered as well (in case of the break up of one or several communication lines, "plan B" has to be considered involving reliable thermal generation in order to ensure the real time dispatching).	X	X	2
Participation of RES and storage in ancillary services (f/V regulation, system restoration, etc.)	• Possible if technically feasible and economically justifiable. • Remuneration schemes have to be set-up (in many European countries some ancillary services are compulsory and not paid). • It could also be useful to pre-contract capacity availability than waiting for real time bids.		X	3
Increase of cross-border bulk power transport capacity	• This issue has been highlighted both in Asia (where the main limitation is related to the lack of regulation harmonisation) and in Europe (where often the main hurdles are the complication of authorisation procedures and the social-environmental constraints)	X		1
Offshore power grids market mechanisms/organisation	• The harmonisation of grid codes is an absolute priority for establishing the North Seas offshore grids in Europe	X		1
Planning tools extension	• New technologies (like HVDC at T level and FACTS at T&D level) shall be properly modelled and integrated in respective T and D planning tools • Converting existing AC to DC lines is an option to be considered in the tools for transmission planning cost-benefit analysis • Compare "grid vs. ICT" developments (although it may not be an appropriate comparison as recalled in the table of Task 1)	X	X	1
Flexibility requirements evaluation	• Account for flexibility resources in the transmission development and market tools. • Determine the amount of "flexibility" required as a function of the RES penetration • Develop methods to quantify the actual need for conventional generation capacity, the costs associated to different market schemes, and the costs of not having enough generation (cf. item *"Stranded costs" in conventional generation* in the Policy table)			