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D5.1	**Towards a governance model for the European electricity transmission network in 2050**		

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Executive Summary

1. Introduction

The final deliverable of Work Package 5 ("WP5") provides a detailed and comprehensive analysis regarding the future governance of the European transmission network with a crossborder impact. The deliverable extensively addresses the two formulated objectives of WP5:

- To propose a set of key regulatory principles, referred to as "options", to be considered when determining the appropriate governance framework for the electricity transmission networks of 2050;
- To develop a policy roadmap for the intermediate period in order to implement the options by 2050.

This Executive Summary provides a high-level overview of the approach, methodology and key findings of WP5.

2. Overall approach and scope

The overall approach consists of several steps in order to identify, analyse and compare a set of relevant experiences from around the world regarding the governance of national and transnational infrastructures. These experiences have served as a source of inspiration to propose a set of key regulatory options for the governance of the cross-border European electricity transmission networks up to 2050. A summary of the WP5 steps is described below and illustrated in Figure 1.

- First, a selection of approaches to the governance of national and transnational infrastructures ("**Governance Models**") has been made, taking into account current experiences from around the world.
- Second, a list of main regulatory topics relevant to this study ("**Building Blocks**") has been identified, allowing for a systematic description and like-for-like comparison of the selected governance models.
- Next, a set of criteria ("**Assessment Criteria**") to assess the performance of each Governance Model has been determined for each Building Block.
- Fourth, based on the corresponding Assessment Criteria, the best-performing Governance Models have been identified for each Building Block.
- Finally, the most promising regulatory features of the best-performing Governance Models for each Building Block have been combined, where appropriate, with some of the relevant features of other Governance Models, in order to propose a set of key regulatory principles ("**Options**") to be considered for a potential future application in Europe.

These steps are described below in more detail, with a particular focus on Step 5, leading to the key outcomes of the analysis.

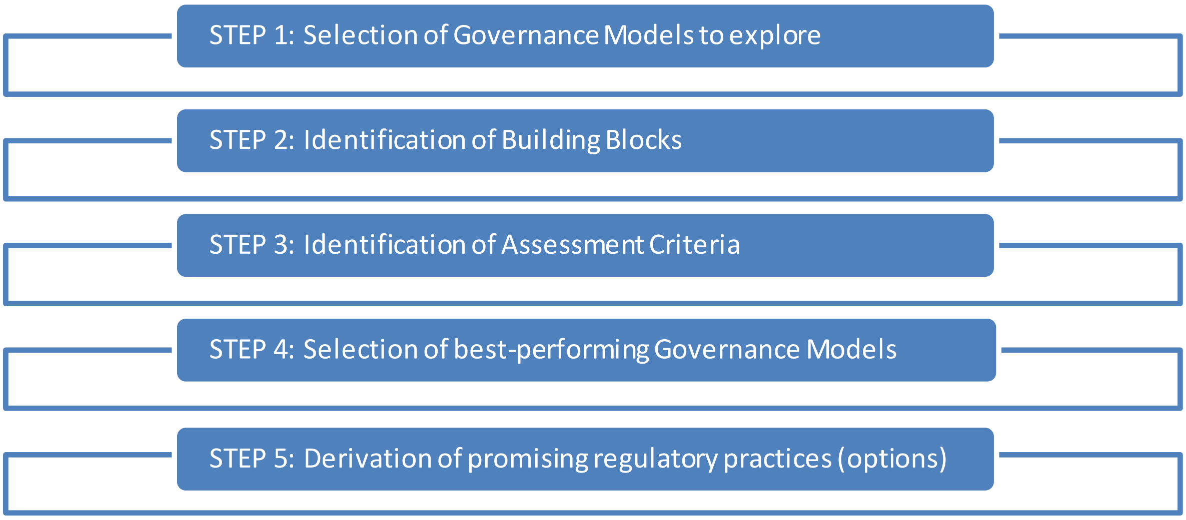

Figure 1: Overview of five main steps

3. Eleven Governance Models to explore

Eleven existing Governance Models have been analysed in order to identify promising regulatory practices for the future governance of the European transmission networks towards 2050. This selection represents a broad geographical and sectorial spread, including non-electricity examples, as well as several specific case-studies. At the early stage of analysis, a number of at first sight interesting models, such as Russia, China or the Middle-East, have been discarded from further investigation. These models do not comprise advanced regulatory elements which would seem applicable to a European context, or have features that are already somehow represented by one of the selected models. The selected Governance Models are summarised in the table below:

European electricity experiences	**Non-European electricity experiences**	**Generic electricity case studies**	**Non-electricity experiences**
1. Germany	4. USA RTO regions	8. "Small & local" case studies	10. Gas sector
2. Great Britain	5. Central America	9. Merchant case studies	11. Non-Energy (aviation, water, telecom) case studies
3. Nordic countries	6. Argentina		
	7. Brazil		

Table 1: Selected Governance Models

Out of the eleven analysed Governance Models, three of them correspond to approaches currently in place in Europe. German and British approaches to the governance of transmission networks relate to systems that are currently fully integrated in most regards. The Nordic model corresponds to a region which consists of several independent systems, but represents a long tradition of close cooperation. Promising elements from those national systems are investigated with regard to their application in a broader European setting.

Four other models depict approaches in the power sectors of North and South America (USA, Brazil, Argentina and Central America), representing different approaches for planning and operational integration. The USA approach is based on a Regional Transmission Operator (RTO) managing the operation of the market and the system in a single region, and focuses mainly on aspects where federal electricity regulation or guidelines apply. It also considers some specific elements of regulation in the PJM region. Central America represents another region where substantial effort has been made to better integrate network expansion and system operation activities. On the other hand, the Brazilian and Argentinean Governance Models are applied in fully integrated systems that function as a single one.

Two models focus on generic case studies that could be applied in a variety of areas in the world. The first one concerns the organization of the functioning of systems based on distributed energy resources, which have a local scope. The second one is a specific model dedicated to the undertaking and operation of merchant investments, for which regulation largely differs from that conventionally applied to transmission and system operation activities.

Finally, two infrastructure models have been taken from outside the electricity sector, i.e. the gas sector and a combination of other network industries, such as aviation, water and telecom.

The final document highlights the merits of focusing on existing approaches, since it allows lessons to be learnt from past experiences in order to identify advantages and disadvantages of each approach. However, this methodology also exhibits shortcomings, namely, that experience with current regulatory regimes may not always be the best proxy for the future and that practices from other jurisdictions may not be "per se" automatically applicable to a European setting. In any case, the e-Highway2050 WP5 did not include an extensive cost-benefit analysis resulting in added value for society of the implementation of each option in Europe.

3.1. Five Building Blocks and their challenges

In order to streamline the analysis and follow a structured and consistent approach throughout WP5, a set of key regulatory topics of particular relevance to this study has been identified. These topics, referred to as "Building Blocks", reflect the main areas for which a potential evolution or adaptation of the existing regulatory and governance frameworks might be appropriate in 2050 and beyond. These Building Blocks are:

- **Transmission network expansion design**

This concerns the process of identifying, proposing, selecting and approving transmission network investments with a cross-border impact.

- **Ownership of new transmission capacity with a cross-border impact**

This relates to asset responsibility and concerns the identification of parties owning and constructing new transmission capacity with a cross-border impact. This Building Block is closely linked to the financing of the investments.

- **Financing of the investments**

This deals with the provision of funds to support the construction of approved grid developments and replacements and concerns the identification of (in)direct parties contributing to the funding of such investments.

- **Allocation of the cost of grid development**

This concerns the process of allocating the investment and operational costs of new transmission capacity with a cross-border impact, including the criteria applied to determine the contribution of each party to the recovery of the regulated cost of assets.

- **Technical and Market Operation of transmission networks and related system services**

Although this topic is less related to the regulation of transmission network development, it has been included in this study to avoid leaving out some important operational aspects.

For each of these Building Blocks, specific challenges for the 2050 horizon can be identified. These are a complement to the overall challenge, i.e. to be able to realise the grid architectures computed in the project for the 2050 time horizon, which in any scenario implies an increased need for transmission grids.

As for the **BB Design**, large amounts of reinforcements to transmission networks in Europe are expected to be needed by 2050. Further efficiency in the planning and execution of grid expansions and reinforcements can contribute to cope with this increased level of network projects in order to timely identify the necessary reinforcements to be undertaken. In a context where power exchanges among countries shall increase substantially, efficiency can be increased if the following conditions are met: firstly, undertaken grid development activities are defined to take full advantage of their potential benefits in the several national systems; secondly, network development decisions fully take into account interdependencies existing among benefits produced by several investments undertaken in all European countries; thirdly, such investment decisions are made taking into account several scenarios that may unfold in the future and their probabilities of occurrence; and, lastly, some coordination of generation and transmission investments takes place.

Furthermore, there is a need to increase the public acceptance of transmission networks and to reduce long permitting processes currently affecting these projects, which is leading to some priority projects being delayed for long periods of time. The non-mandatory nature of pan-European investment plans and the interaction between European and national decision-making levels are surely part of the reasons for the long permitting processes.

Regarding the **BB Ownership**, in the majority of European cases, ownership of the transmission networks is currently in the hands of a single entity, namely, the TSO, with a limited number of exceptions (in which assets owned by a TSO may coexist with a few assets owned by third parties). This “European TSO model”, with one certified entity owning the vast majority of transmission network in a precisely defined region or Member State entails some challenges, which are listed below, in order to successfully persist in the future.

There are for example large differences among incentives and rules to determine revenues applied to regulated network investments across systems in Europe. This results in conditions for the construction of certain types of assets, or those conditions applied within certain countries, being more favourable than conditions affecting other types of assets or countries. Furthermore, efficient schemes of coordination between TSOs and potential private network owners regarding the construction, operation and maintenance of these assets would need to be developed and applied for future scenarios where these might co-exist. Lastly, regulatory frameworks might need to be adapted to ensure that TSOs are able to undertake efficient investments, i.e. at an efficient cost, within existing budget and time constraints.

The above mentioned challenges are closely related to those regarding the **BB Financing**. However, some additional challenges can be identified for this BB. Firstly, the lack of appropriate mechanisms to attract diversified financing sources, which could increase the cost of transmission system investments and may delay their deployment. Secondly, heterogeneous technology risk evaluation methods could impede the development of a common risk management of cross-border transmission investment projects. It is observed that regulatory instability and the lack of legalized long-term commitment, in particular, strongly increase the investment risk of transmission assets that have an asset lifetime of decades. Finally, a lack of mechanisms to differentiate the financing cost for each of the different phases of the transmission network projects might increase the overall financing cost over the long lifespan of the asset.

For the **BB Cost allocation**, two main challenges are identified up to 2050. First of all, because of the limited controllability of electricity flows and the increasing European electricity network interconnectivity, associated costs and benefits of reinforcements will be spread out over several countries, not only the investing countries. Investment and cost allocation decisions should therefore duly take into account positive and negative impacts on all affected countries.

Furthermore, the higher complexity of electricity systems characterized by higher shares of RES, more variable electricity demand (electric vehicles, heat pumps), and wider range of network technologies, e.g. application of DC technology, implies a higher diversity of costs and benefits that network users impose on the system in a variety of situations. Since network charging structures currently often take a typical average situation as their starting point, an increasing gap between the charges paid by network users and the actual costs they cause on the network may be observed. This may result in an increased lack of incentives for generators and loads to make an optimal use of the network from a societal perspective.

The **BB Market and Technical Operation** is firstly challenged by the fact that current transmission capacity allocation at European level considers zones that mainly corresponds to national systems. This zonal pricing approach does not take into account network bottlenecks within Member States resulting in inefficiencies related to re-dispatch costs. Furthermore, it fails to provide correct investment signals based on prices which reflect available transmission capacity. Secondly, regional market coupling remains limited to day-ahead markets, though the increasing share of intermittent energy resources requires well-functioning markets closer to real-time in order to adequately deal with prediction errors of wind and photovoltaic power generation. Thirdly, power systems seem to lack a clear and supra-national (regionally defined) generation adequacy objective, while current capacity market development trend towards a patchwork of mechanisms, not sufficiently taking into account developments in neighbouring countries. Fourthly, the integration of sustainable technologies is driven by means of national integration policies and market mechanisms, which do not always minimize their system integration costs, or maximize their benefit to the system. Finally, due to the increasing variability of cross-border flows, increased efforts shall be needed to ensure regional cooperation and coordination of mechanisms to achieve an efficient and reliable operation of the electricity system.

3.2. Assessment Criteria and Governance Model evaluation

In order to perform an objective and systematic evaluation of the investigated Governance Models, a set of Assessment Criteria has been defined for each Building Block. The Assessment Criteria allow to identify which regulatory features of the analysed Governance Models contribute the most towards meeting the following policy objectives:

- **Sustainability;**
- **Competitiveness;**
- **Security of Supply;**
- **Socio-political acceptability;**
- **Effectiveness.**

For each Building Block and for each of the above objectives, a set of Assessment Criteria has been determined to rank the performance of each Governance Model. These criteria relate, among others, to the allocation of roles and responsibilities, the interactions and coordination among the different stakeholders and their interdependences, the complexity, the perception of risks, the efficiency, the stability, the fit with a European context, the implementability, etc. This assessment has been done by favouring elements that promote further coordination and European integration.

For the assessment, each of the five objectives has been given a different weight in the analysis, depending on the considered scenario. Indeed, not all objectives are equally important when assessing the performance of a Building Block in the context of a scenario. Sustainability is for instance less of an objective in the scenario "Large fossil fuel with CCS and nuclear" than it is in the "100% RES" scenario. In addition, regulation related to a certain BB can have a different importance from regulation for another BB for achieving a certain objective. For instance, regulation for the BB Operation (related to adequacy analysis amongst others) is more relevant for the objective Security of Supply, than is the BB financing.

Eventhough the analysis has integrated scenario-specific considerations, the same Governance Model (or combination of Governance Models) has been identified as best to tackle the challenges for 2050 in all scenarios. Therefore, in the next section, a number of regulatory options for 2050 are put forward, independently of the scenario that is followed for the development of the transmission network.

3.3. Regulatory options and roadmap towards 2050

Whereas the analysis conducted under the previous steps provides interesting insights for the e-Highway2050 project, the main focus and input for further diffusion relates to the key outcomes of the analysis. It is to be underlined that each of the proposed policy options for 2050 entails certain advantages and disadvantages, which are described in the final document, and that it is up to policy makers to make the appropriate evaluation of these prior to their implementation. For this executive summary, several options are combined in a reduced number of principles. Each underlying aspect is however further detailed in the final document.

Furthermore, a roadmap with intermediate steps towards 2050 has been elaborated, of which some of the main steps are included here. These steps are to be seen as "complements" to currently ongoing initiatives, such as the elaboration and implementation of the network codes. In this executive summary, these steps are combined per time period. In the final document, these are grouped per option.

Building Block Design: Towards a more coordinated grid planning

For the BB Design, a general trend towards more coordination is put forward for the 2050 timeframe. The ongoing evolution towards a more top-down European planning approach, whilst at the same time ensuring that the bottom-up and national elements remain a key part of the planning process, is to be further supported. Two regulatory principles are proposed:

1. *The expansion of the cross-border transmission grid in Europe shall be coordinated centrally following a combined top-down and bottom-up approach, taking into account the needs and requirements of the countries involved through close cooperation with the national TSOs. If possible, uncertainty about the future evolution and operation of the system should be adequately represented.*

The current approach adopted for grid planning at European level has already been evolving from a purely bottom-up process at national level towards a more European shared approach. Eventhough continued efforts will be necessary to increase public acceptance of electricity transmission, this evolution towards a more coordinated, European-wide grid expansion planning process, interacting with national ones, is considered as the efficient way to correctly and timely identify main grid bottlenecks and related infrastructure projects.

While doing so, benefits of all potential cross-border transmission investments in the European system need to be taken into account jointly, together with their costs, to determine which network expansions and grid reinforcements to undertake. This top-down approach shall be applied in combination with a bottom up one, so as to keep into due account the knowledge of the regional or national networks, and the specifics of the grid and the needed investments, in order to ensure the safe functioning of local systems and the compatibility of regional and local expansion plans. Adequately representing uncertainty involves considering a set of future scenarios and operational situations that are representative of all those that may occur in the planning time frame, as well as the probability of occurrence of these scenarios and snapshots.

This should lead to a better integration of those network investments with a cross-border impact as well as to the appropriate consideration of benefits that are contingent on the joint realization of several projects. In addition, integrating the knowledge of local networks in the planning process should ensure that selected investments are feasible and fit for purpose.

2. *Cross-border investment proposals should be assessed and approved centrally, by European institutions with executive powers, in accordance with Member States, while respecting national authorization procedures.*

European institutions should be looking after the interest of the largest possible scale of stakeholders in the European system. A harmonised European-wide process for the assessment and approval of cross-border reinforcements is to coexist with national authorization procedures and the approval by national regulatory authorities, which should nevertheless find the way to accommodate reinforcements identified as necessary from a European perspective. This scheme could be combined with European wide stakeholder consultations to increase the level of involvement of local entities.

This policy option ensures that common European interests are best taken into account within the network planning process, and ensures that a more harmonised set of investment approval rules is applied to all European cross-border projects.

Finally, considering that merchant cross-border investments by private promoters are already allowed in European grid development, investments by associations of network users should be allowed by 2050 too. However, these should only be allowed if they are not detrimental to the functioning of the system or the market and if they complement, rather than interfere with, optimal investment decisions made by relevant planning authorities.

Building Block Design – roadmap for the future

In order to implement the above-mentioned policy options by 2050, a series of possible intermediate steps is proposed. Many of these have a different timing, or are dependent on the implementation of preliminary steps. Therefore, most actions have a sequential order. A selection of these steps is listed below:

Short term (up to 2020):

- ENTSO-E should further look into improving its CBA indicators, measurement tools and data collection processes in order to enhance the quality and reliability of the overall assessment and comparison of project impacts.

Mid term (up to 2030):

- In the cases where third-party ownership were to be considered, EU regulatory authorities should set clear, transparent and fair rules and procedures on the conditions that (private) investments should fulfil to ensure minimum distortions to the system.
- ENTSO-E should try to monetise, as much as possible, all project impacts in an objective way. This applies in particular to the Value of Lost Load ("VOLL") indicator for the impact on Security of Supply by developing and applying a harmonised European VOLL methodology.

Long term (up to 2050)

- The process of assessing and approving all proposed investment projects – proposed by both ENTSO-E members and third parties – should be conducted by an independent regulatory authority, in order to guarantee that this process is taking place in a clear, transparent and fair way.
- ENTSO-E could, in consultation with ACER and NRAs, provide EU-wide, long-term (20-25 year) coordinating signals including indicative cross-border network charges based on available insights and advanced scenario modelling work.

Building Block Ownership: Towards an efficient scheme of network construction and ownership

With regards to the BB Ownership, it needs to be ensured that an efficient degree of coordination is maintained between TSOs and potential third-party transmission asset owners in those circumstances and scenarios where these two types of asset owners co-exist. Going forward, there should be no blunt evolution towards favouring a more diversified set of asset owners as a way of ensuring that investments are forthcoming. In fact, most of the ownership challenges identified for the time-horizon 2050 are most effectively tackled within the current ownership structures by ensuring appropriate regulatory and financial conditions for investment, as also stipulated in the BB on Financing. However, in order to ensure that regulatory conditions are such that cost efficient investments are achieved, and an effective coordination of asset-related activities (such as maintenance) and system operation is preserved, some principles specific to the BB Ownership are proposed:

1. *As a base case, network construction auctions for regulated cross-border assets shall be conducted by TSOs to determine which company should construct the asset and provide the related installation services. The winning tender of these auctions (bid) shall be used to compute the allowed revenue of asset owners, i.e. the local TSOs*.

Both the allowed investment costs and the rate of return for these investments shall be approved by regulatory authorities and be subject to oversight at European level. Only if local TSOs are not able to deliver the required investments within a pre-specified time for reasons within their control, auctions open to TSOs and reliable third parties, may take place to allocate the ownership of assets. If there is insufficient competition, ownership of the asset should, by default, be allocated to the local TSO; ensuring in all cases that an adequate remuneration is provided.

The rationale behind network construction auctions is that, by promoting competition amongst potential providers of equipment and installation services, a more efficient pricing and deployment of investments would be enabled, leading to benefits to society as a whole. This provision builds upon current European regulation, which already foresees the possibility of organizing tenders when TSOs are not able to timely deliver a Project of Common Interest.

2. *Economies of scale in grid development are to be encouraged.*

In those cases where third-party private partners are allowed to own network assets, regulatory authorities should monitor the financing and operating capabilities of these entities to ensure an appropriate development, operation and maintenance of their transmission assets, equivalent to the TSOs. Fostering the internationalization and increase of scale of private network onwers should enhance these capabilities. Given that the internationalization and merge of private owners may decrease however the level of competition among these and TSOs in transmission auctions, this should be monitored by regulatory authorities.

Building Block Financing: Towards continuously improved financing conditions

Two main aspects contribute to the success of financing the projected 2050 transmission network: the availability of diversified sources of financing and the determination of a risk commensurate return which ensures efficient investment signals. Therefore the following two principles are put forward:

1. *The role of the public authorities as investment enabler should be strengthened by setting up stable, long-term oriented regulation, and by promoting assistance to create innovative financing tools for attracting diverse financing sources at low cost.*

In order for the required investment needs to materialise by 2050, and to mobilize corresponding finance means, it is fundamental to create a fair and stable regulation that provides long-term regulatory commitment to investors. Long-term commitment spurs investors' confidence by removing unnecessary regulatory risk for transmission network investments with an asset lifetime of several decades. Such regulatory settings could provide financing obligations to pay investor revenues at the European level and foresee in a prolongation of regulatory periods. The role of public authorities as a long-term investment enabler is to be strengthened by providing innovative financing mechanisms. The Project Bond Initiative (PBI) established by the EC-EIB task force to stimulate capital market financing in infrastructure with credit guarantees from the infrastructure investment bank has yielded positive pilot experience.

2. *Improved risk management tools should bring down the cost of transmission network investments. This includes a common risk evaluation for cross-border projects and a common risk management tool. In addition, a separate cost of capital determination mechanism could be used for low risk assets within the regulated asset base.*

In order to promote an active risk management scheme, a first step for facilitating investments is to have better risk recognition, which can be achieved by a common technology risk evaluation platform. This platform should facilitate knowledge pooling through transparency, i.e. all parties are able to use the same data for cost and benefit calculations in bilateral cross-border projects.

A key objective of risk management schemes is to enable better pricing of such risk in order to incentivize an optimal rate of return that achieves cost efficiency and generates adequate investment signals. The currently implemented single average return on all asset types and investment phases does not differentiate between risk components and can obscure efficient investment signals. Therefore, active risk management measures are proposed to address risk by rate adders and a separate set of returns for regulated asset bases.

A general recognition of the capital investment phase of a project, i.e. planning and construction, is that it involves greater risk than the other phases of the project. This is due to the exogenous risks such as permit delays and risk arising from the deployment of novel technology. Thus, the case-by-case rate adder approach implemented in the USA, represents a potentially interesting approach to attract new investment in the short term and provides risk compensation for the planning and construction phase. This mechanism allows a rate of return adjusted by the regulator according to its assessment of risk levels for cross-regional projects.

For the regulated asset base (RAB), which represents the value of efficient investment incurred in the past, a strong and explicit regulatory guarantee for its value should be provided initially in order to alleviate potential regulatory expropriation. With a strong regulatory guarantee to ensure investors stable revenue for RAB, the risk level involved is inherently lower than the planning phases. Therefore, for low risk assets included in the regulated asset base, a separate rate of return could be designed by the regulatory authorities to reflect their low risk nature.

Building Block Financing & Ownership – roadmap for the future

As stipulated above, the proposed options for the BBs Ownership and Financing are closely related. Hence, when considering the intermediate steps that could be taken up to 2050 to implement these options, the two building blocks have been considered together. Contrary to those regulatory changes related to the implementation of options for most of the other BB's, these do not need to occur following a certain order. All the required regulatory developments related to both BB's can be applied as from today. However, these developments are differentiated by time horizon because all of them will presumably not take place within the same time horizon. A selection of these steps is listed below:

Short term (up to 2020):

- TSOs should, as a base case, tender the procurement of transmission asset equipment and the related installation services to reliable suppliers (as is currently already being done in some systems).
- In those cases where third-party ownership were to be considered for 2050, regulators may analyse the increase in transaction and coordination costs that would likely arise from any potential separation of asset-related activities, such as maintenance, (responsibility of the asset owner) from system operation ones (responsibility of the system operator).
- National regulators should consider including priority premiums to incentivise high-risk investments. These may be add-ons or supplements on top of the regulated rate of return.
- National regulators should ensure that there is no time lag between the undertaking of new cross-border projects and their remuneration period, i.e. the regulation should provide remuneration for the depreciation of assets and operational expenditures as soon as these new assets are in service.

Mid term (up to 2030):

- Regulators should use the results of network construction auctions conducted by TSOs as an input to determine the allowed revenues for regulated cross-border investments. Cost-based revenues so computed should be combined with incentive regulation mechanisms.
- Policy makers could provide financial long term guarantees to lower the financing costs and attract low risk and low remuneration investors.
- Regulators should modulate the rate of return using return-adders to stimulate investments according to the time phase of these assets.

Long term (up to 2050):

- Regulators should ensure that regulated tariffs are long-term stable and forward-looking, and that they cover TSOs' long-term cost of capital, enabling them to finance the necessary unprecedented levels of investment without damage to their long-term sustainability.
- TSOs should continue to optimize operation and maintenance costs, ensuring maximum possible coordination between these activities, and optimizing the joint operation of merchant and regulated lines.
- Regulators should develop stable, forward-looking and long term regulatory frameworks, extended regulation periods and guarantees in stability of regulation.
- Regulators should ensure stable and investor-attractive rates of return and ensure these are high enough to make current and future high investment needs financeable and reflect the asset owners' actual cost of capital.

Building Block Cost allocation: Towards an appropriate and fair cost allocation of network investments

In order to meet the identified 2050 challenges for this BB, an evolution towards a more appropriate and fair cost allocation of network investments is put forward. This entails many different aspects and can be summarised in the following two main principles:

1. *Cost allocation of grid reinforcements and flexibility deployed for grid purposes should be coordinated once feasibility studies indicate positive results.*

Given that costs and benefits of network investments will be increasingly spread out over several countries, further coordinated cost allocation of grid reinforcements is foreseen for projects having a cross-border impact, as this is today applied to a limited extent for Projects of Common Interest only. To this aim, a unique, robust and binding methodology should be developed for cross-border cost allocation ("CBCA"). In the short term, and as long as there is no sufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to affected countries, multilateral CBCAs should not be applied as the base case and only be applied in exceptional cases. In the long term, multilateral cross-border cost allocation agreements should be applied on a wider scale, if a(n updated) feasibility study indicates positive results.

Likewise, flexibility measures such as storage and demand response that are deployed as an alternative to network reinforcements may increase available cross-border network capacity, but other countries may not pay for their share in the benefits, giving rise to underinvestment in grid flexibility measures. Therefore, if a CBA indicates that effects of deployment of flexibility measures in the grid on benefiting, but non-contributing countries, are substantial, cost allocation of grid flexibility measures costs should be coordinated across Europe.

2. *Network costs should be allocated as far as possible by applying the beneficiary pays principle. Cost components that cannot be indisputably allocated to a specific country or (group of) stakeholder(s), should however be socialized.*

In order to deal with the higher complexity and interconnection of the European electricity network, it would be economically most efficient to allocate network costs by applying, as far as possible, the “beneficiary pays” principle, i.e. those stakeholders who benefit from an investment should pay for the associated costs. Eventhough this might be difficult to implement, this would provide efficient economic signals to all network users, including both generators and loads. In addition, network charging should not distort short-term market signals, hence network charges should be power-based or lump-sum rather than energy-based. At the same time, certain cost components should be socialized, i.e. reliability network costs and those cost components that cannot be indisputably allocated to a specific (group of) stakeholder(s).

In scenarios where renewable energies (“RES”) are a mainstream technology, RES should be subject to efficient network signals for network investment and operation. Concerning network investments, cost allocation should stimulate joint optimization of generation and network development. Regarding network operation, RES network costs should no longer be socialized through priority access or dispatch, but allocated to RES facilities to the same extent as to other generation sources.

Building Block Cost allocation – roadmap for the future

In order to achieve the above mentioned policy options, a series of possible intermediate steps is proposed. Many of these have a different timing or are dependent on the implementation of other preliminary steps. Therefore, most actions have a sequential order. A selection of these steps is listed below:

Short term (up to 2020):

- Regulators should maintain a significance threshold for the cases in which multilateral cost allocation is applied in order to prevent participation of marginally affected countries in the decision making process.
- Project promoters and regulators should ensure proper involvement of stakeholders throughout the cost allocation adjustment process to improve its acceptability.
- Project promoters and regulators may analyse the impact of national constraints or critical infrastructures on neighbouring countries in more detail as a first step to contain the effects of parallel/loop flows on cost allocation by appropriate policy measures.
- Policy makers should consider removing the upper limit for average Use-of-System (UoS) power-based charges for generators in EU Regulation No 838/2010 in order to overcome the lock-in effect impeding introduction of G-charges in Member States.

Mid term (up to 2030):

- When policy makers, regulators, and TSOs pay more attention to the beneficiary pays principle, they should make due allowance for the robustness of future network benefits in cost allocation.

- Policy makers and regulators should strive for consensus on the implementation of minimum reliability standards as advocated by the BB technical & market operation, as it allows for convergence of the VOLL estimates, and therefore grid reliability costs across Member States, enabling coordinated cross-border allocation of reliability network costs.
- Project promoters and regulators should analyse whether cross-border free-riding effects of deployment of flexibility for congestion management are likely and non-marginal, resulting in underinvestment in flexibility measures. If this is the case, CBCA of these specific flexibility measures should be coordinated by regulators across Europe.
- Policy makers should stress the advantages of sharing cost and benefits of flexibility measures for grid purposes across borders for reducing total system costs both for Europe as a whole and for individual member states.
- In scenario's where RES-E is mainstream, policy makers should no longer exempt RES-E from paying for the network costs incurred to the system, including the possibility for socialization of RES-related network costs by priority access/dispatch in article 16 of Directive 2009/28/EC. Additionally, priority access/dispatch may be assessed in the framework of EC state aid legislation.
- To prevent strong redistribution effects between stakeholder groups, regulators should provide sufficient time for gradual shifts from energy-based towards power-based or lump-sum network charging.

Long term (up to 2050):

- Policy makers and regulators should prevent opportunism and gaming of countries by application of standardized multilateral cost allocation procedures, provided a feasibility study for the introduction of standardized multilateral cost allocation yields a positive result.
- Regulators should take into account the fact that locations for production or consumption that are remote from a national perspective can be advantageous from a cross-border perspective and the other way around. In this case, policy makers should issue EC guidelines for locational differentiation of network charging.
- Policy makers should account for restrictions for network users, including existing generators, to react to locationally differentiated network charging, amongst others for reasons of spatial policy and equity.
- TSOs may mitigate difficulties of the determination of individual contributions (of groups) of network users to network costs by improving network monitoring and controllability, given the technological progress achieved.

Building Block Technical & Market operation: Towards a more coordinated system operation

Although the aspects of this BB are not directly related to the core topic of the E-Highways2050 project, which is focussed on the development of cross-border transmission grids, and the realisation of the projected grid architectures by 2050, relevant operational topics are included regarding the operation of the grid. These aspects not only impact the operation of the transmission assets, but also the investment decisions as these have an effect on the costs and benefits of network infrastructure.

Given the focus of the project, options and the corresponding roadmap are formulated in a more general way, compared to the other BBs. The options which are put forward are thus by no means an exhaustive list, but relate only to the most important aspects of operation which have been identified in the process of this study to overcome the identified 2050 challenges. In that respect, a well-functioning market and technical operation design should entail three key aspects: (1) efficient transmission capacity utilization; (2) integrated market operation and (3) strong cooperation of security management. This is translated into the following three main principles:

1. *It should be further assessed whether a system of Locational Marginal Pricing (LMP) could increase efficiency of transmission capacity allocation in the European electricity system. As long as zonal transmission capacity allocation is pursued however, bidding zones should be configured in an adaptive way which corresponds with network bottlenecks.*

Efficient pricing of network capacity requires locational pricing signals, which accurately price congestion allocating it to specific locations and paths. The benefit of implementing LMP is to incentivise short-term economic efficiency and to signal the long term need for transmission investments. However, LMP results in price spikes during capacity scarcity, and it increases the risk of price volatility for network users. Therefore, the implementation of locational marginal pricing is often accompanied by risk hedging instruments, such as financial transmission rights (FTR). However, it has to be recognized that the nodal market design is not in line with the current market design embedded in the European network guidelines which are based on a zonal approach. Therefore, the nodal design, which seems the best solution from a theoretical point of view, faces several barriers towards its practical implementation in the European context.

Alternatively, if zonal pricing is pursued, bidding zone configurations should correctly include the relevant transmission network constraints that allow more efficient market operation and reduce re-dispatch costs. Dynamic or adaptive bidding zone configurations that better deal with varying system conditions over time, e.g. seasonal, weekly or daily, should be considered.

2. *Regional energy market integration should be pursued in all time frames, incl. on the day-ahead, intra-day and balancing market. Variable renewable generation requires well-designed balancing markets, as well as a well-defined adequacy objective. Market design should allow old and new technologies to compete to provide energy, ancillary services and capacity to the system.*

Further market integration revolves around four layers. First and foremost, there is a clear need to complete the internal energy market. Long-term, day-ahead, intra-day and closer to balancing market integration should be continued to optimize complementing resources over broader geographical areas in order to smoothen the variability of renewable energy resources.

Secondly, in particular for scenarios with higher renewable energy integration, closer coordination between energy and ancillary service markets should be allowed. On the one hand, a central co-optimization of the energy and reserve market bids such as in PJM could create efficiency gains by means of an optimal scheduling and dispatch of resources. On the other hand, assigning the costs of reserve capacity as much as possible to these responsible market actors gives them the incentive to optimize their market positions, and to operate flexible assets in function of the market needs.

Thirdly, well-defined adequacy objectives can be determined by scarcity pricing mechanisms in the energy market, including capacity remuneration mechanisms, or alternatively, by means of flexibility options such as energy storage or demand response. Coordination of these mechanisms and options among member states could reduce social costs to meet predefined adequacy levels.

Lastly, creating a level playing field for all technologies is essential to arrive at a cost efficient energy mix in the long term. This should be achieved by removing barriers and incentivising competition among all technologies that offers flexibility to synchronize generation and demand. With the deployment of more intelligent smart grid technology, transaction cost of data collection that enables direct interaction with small scale consumers or through aggregators is significantly reduced and a much more active role of them in markets is enabled.

3. *Interconnected power systems with high share of intermittent renewable generation require regional security monitoring and control mechanisms closer to real-time, and over larger geographical areas. Regional approaches to define reliability should be considered.*

Security cooperation allows TSOs to better deal with the increasing variability and uncertainty of power flows through the interconnected system following the integration of variable renewable generation. In addition to the security cooperation mechanisms already established today (i.e. Coreso, TSC), further enhanced information exchange and harmonization of procedures should be foreseen, for example by means of common tools, data and processes among TSOs over larger geographical areas and during extended time horizons. This gives insight in the system operational conditions and provides system-wide solutions in case of emergency, as well as coordinated control of transmission system components. Furthermore, a minimum level of harmonized reliability criteria could be determined whilst allowing stricter national values.

Building Block Technical & Market operation – roadmap for the future

In order to achieve the policy options for the BB Technical & Market operation, several intermediate steps are proposed in the final document. These are built up in a sequential manner, starting with a number of steps that can be taken as of today. For each option, the intermediate steps are described in the final document. Here some of the main ones are put forward per time period:

Short term (up to 2020):

- European market design can, on the basis of expert stakeholder knowledge, be further harmonized by having European policy making bodies identifying a range of requirements needed to meet this scope.
- Market entry for RES, flexible loads, aggregators and electricity storage units should be facilitated and all these actors should bear the relevant costs related to network usage, so as to have fully cost reflective electricity prices.
- Coordinated capacity calculations, system adequacy and outage planning coordination should be agreed at regional levels through multilateral discussions between policy makers, on the basis of feedback given by stakeholders, and clearly stated in agreements.
- The integration of the demand side into intraday and balancing markets should be stimulated by creating a regulatory framework with incentives for new market actors (e.g. DSR) while, at the same time, taking into due account the need to at least share the costs borne by TSOs for system balancing. Future pan-European electricity markets should be further analysed so as to determine, also on the basis of expert stakeholder knowledge, if it will be based on the Energy Only principle or should include some form of capacity remuneration.

Mid term (up to 2030):

- All the EU TSOs should have put in place adequate control mechanisms to ensure secure real-time operation of the balancing units and the power system, and these mechanisms should be monitored by NRAs.
- Should capacity markets evolve to become part of the future pan-European electricity market, then policy makers and regulators will have to consider existing procedures at national level as basis for identifying aspects that can be harmonised. Cross-border aspects should in any case be taken into account in an early stage when developping CRM's.
- The expected increases of electricity prices (price spikes) in future systems based on the energy only principle, should be supported by policy makers and regulators.

Long term (up to 2050):

- In order to ensure that cost-reflective intraday pricing bids incentivize market actors to optimize their positions so as to allow more efficient dispatch choices to TSOs, regulators should effectively monitor market power.
- In order to improve the integration of RES to provide energy, ancillary services and capacity to the system, strategic R&D collaborations within Europe could be created to facilitate innovation schemes and roadmaps through cooperation with R&D partners and industrial policy makers.

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List of abbreviations

AS	Ancillary services
BB	Building Block
BNetzA	Bundesnetzagentur (German regulator)
CAPEX	Capital Expenditure
CRIE	Comisión Reginal de la Interconexión Eléctrica – Regional regulatotry Authority in Central America
CNSE	Cost of Non-Served Energy
DSO	Distribution System Operator
EIB	European Investment Bank
EOR	Ente Operador de la Red – Regional SO in central America
ETYS	Electricity Ten Year Statement
EU	European Union
FERC	Federal Enegy Regulatory Commission
GDP	Grid Development Plan
GM	Governance Model
HVDC	High Voltage Direct Current
ICRP	Incremental Cost Related Pricing
IEM	Internal Energy Market
IGCC	International Grid Control Cooperation platform
ISO	Independent System Operator
ITC	Inter-TSO compensation
LMP	Locational Marginal Pricing
LRMC	Long-Run Marginal Cost
MER	Mercado de Electricidad Regional - regional market in Central America
NETSO	National Electricity Transmission System Operator
NGET	National Grid Electricity Transmission plc
NTC	Net Transfer Capacity
OFTO	Offshore Transmission Owner
OPF	Optimal Power Flow
OTC	Over The Counter
PBCE	Project Bond Credit Enhancement
PINT	Put IN one at the Time
PJM	Pensylvania, New Jersey, and Maryland Interconnection
PTDF	Power Transfer Distribution Factor
RAV	Regulatet Aset Value
RIIO	Revenue = Incentives + Innovation + Outputs
RTO	Regional Transmission Organization
SO	System Operator
STC	System Operator-Transmission Owner Code
STCPs	STC Procedures
TGM	Target Governance Model
TO	Transmission Owner
TOOT	Take Out One at the Time
TOTEX	Total Expenditures
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VOLL	Value Of Lossed Load
WACC	Weighted Average Cost of Capital
WP	Work Package

1. Introduction

1.1. Context and objective

The e-Highway 2050 project aims to forecast energy scenarios and to identify the required transmission grid architectures towards the year 2050. Based on the starting situation, and the required development towards 2050, the grid architectures necessary to secure and optimize energy supply are analysed. After defining the target situation in 2050, a backcasting approach is used to suggest a possible pan-European modular development plan from the year 2020. As part of the analyses, a detailed technology review is made to determine suitable transmission and storage technologies for these structures and to identify requirements for research and development in technologies.

However, deploying the optimal network architectures in any given scenario and efficiently organizing the functioning of the resulting European system may also require modifications to the governance framework of cross-border electricity transmission grids[1]. The institutional design of this should facilitate the coordination of all parties involved in it at European level, which should jointly pursue the increase of the overall system welfare. This calls for having efficient economic signals that are also perceived as fair, since this shall drive stakeholders' decisions in the short term, i.e. operation, and the long term, i.e. system development.

Consequently, in order to realise the projected grid architectures by 2050, changes are also likely to be required in the European regulatory framework. This is due to the fact that the system and market context and network reinforcement needs may influence the most relevant challenges faced in each case, and, therefore, the relevance of the several aspects of transmission regulation.

Given the changes to be introduced in regulation applied to the transmission activity, WP5, focussing on governance, has two main objectives within the project. Firstly, target governance models for the 2050 grid architectures are to be defined. These shall comprise main features, or principles, of regulation to be implemented by 2050. Target governance models shall be defined by comparing and analysing feasible options based on lessons learnt from different experiences regarding the governance of transnational infrastructures. Secondly, an initial policy proposal and a roadmap for implementing these target governance models from 2020 to 2050 are developed. In that respect are the intermediate steps for the roadmap towards 2050 as discussed in this study, considered as the initial policy proposal. Both objectives are addressed in this report, which builds further on the Milestone 5.1 document "*Study of governance options and selection of the most promising ones*", which has been submitted to the project coordinator in the beginning of the summer of 2015.

1 When discussing the 'EU cross-border transmission network' in this document, the focus is on 'physical' EU cross-border projects, but also on national projects with a significant cross-border impact (following Regulation EC 347/2013). Projects with solely a national impact are not part of this analysis.

In order to better reflect the content, approach and focus of this study, a slight modification has been brought to the title of Deliverable 5.1. Whereas it initial was *"Roadmap for implementing the target governance model and an initial policy proposal"*, the more appropriate title "*Towards a governance model for the European electricity transmission network in 2050"* is finally used to label the Deliverable 5.1.

The Deliverable "*Towards a governance model for the crossborder European electricity transmission network in 2050"* comprises 10 chapters, which are shortly introduced below.

This Chapter 1 introduces the entire report and provides already more insight into the main features of the analysis conducted, the steps followed and their scope. As from the outset, it is important to highlight that the approach followed is one whereby regulatory options for improvement of the current framework for a 2050 horizon are proposed, based on promising regulatory principles that have been drawn from existing governance models, applied in other relevant systems in the world. In other words, no synthetic schemes for the regulation of the transmission and other related activities have been taken as inputs for the analysis. Chapter 2 describes those main regulatory models that have been taken as a source of inspiration for the identification of most promising policy options to be further investigated. Chapter 3 discusses the methodology implemented to carry out the analysis of regulatory models explored and derive promising regulatory principles and schemes adapted to each situation. Chapter 4 consequently presents the results of the preliminary assessment of those models. Finally, Chapters 5-10 present the results of the analysis and provides an overview of the regulatory options dealing respectively with design, ownership, financing, cost allocation and operation as main regulatory topics that have been researched. In these chapters, more background is provided on the functioning of the options, its advantages and disadvantages, as well as the governance model from which it has been derived from. These chapters also include a trajectory towards 2050, with an overview of intermediate steps and hurdles to overcome. Some key WP5 concepts are visualised in the Figure 1 below.

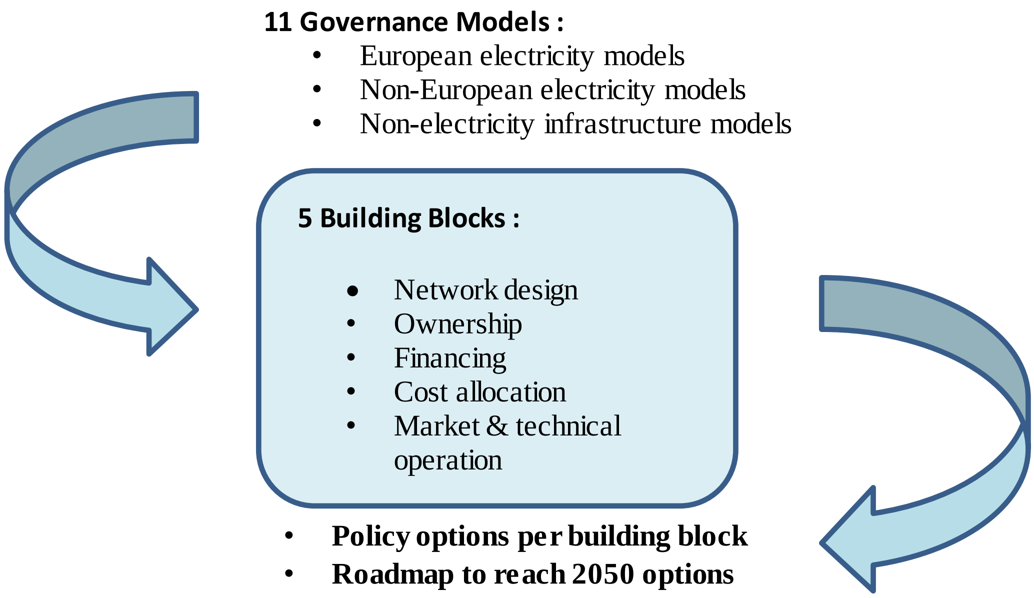

Figure 1: Key WP5 concepts

1.2. Governance Model Assessment approach

The analysis of this study aims to investigate and compare a set of representative experiences regarding the governance of transnational electricity infrastructures with the objective to identify possible interesting options for their application in Europe by 2050. In order to reach this objective, five steps have been followed, which are shortly detailed below and summarised in Figure 2.

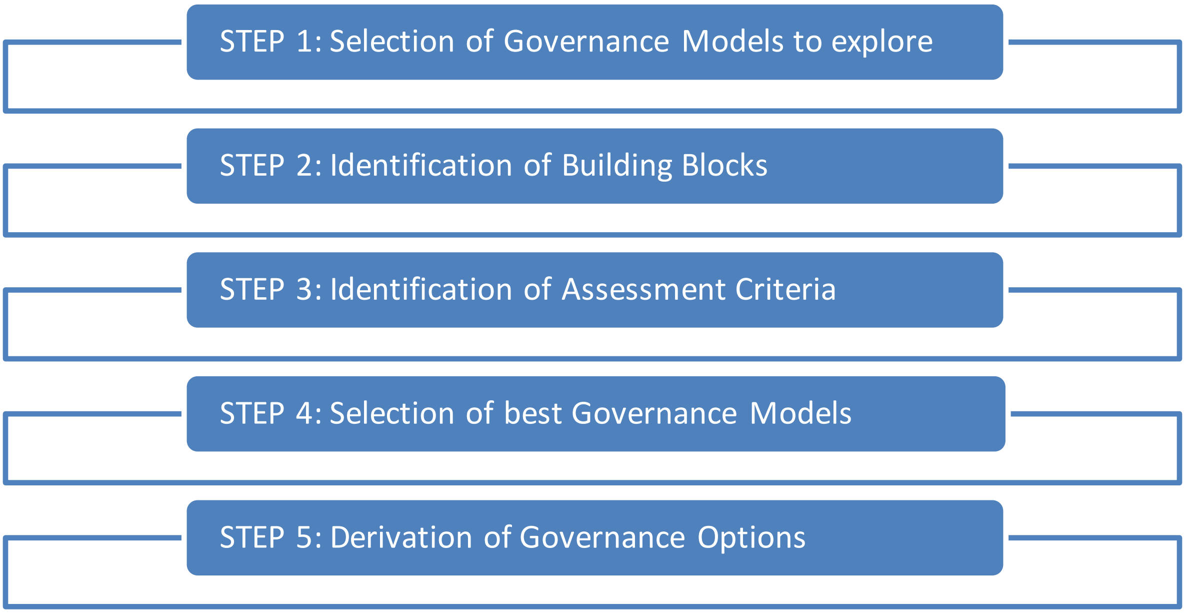

Figure 2: Governance Model Assessment Approach

In in a first step, a selection has been made of Governance Models (GM), i.e. existing schemes for the governance of transnational infrastructures to investigate as best practices.

In a second step, these governance models are consequently analysed in a structured way, which requires defining a set of Building Blocks (BBs), or main regulatory areas of relevance for this study. Five BBs have been retained: design, ownership, financing, cost allocation and operation of cross-border transmission networks.

In a third step, for each BB, a set of Assessment Criteria to assess the performance of the governance models are identified. The criteria defined are related to Policy Objectives to be achieved such as competitiveness, sustainability, security of supply, effectiveness and socio-political acceptability. In other words, these assessment criteria contain the aspects that regulation must comply with. For each objective to achieve, or criterion to comply with, sub-criteria, or partial objectives related to several BBs, are defined.

In a fourth step, criteria are subsequently applied to assess the performance of the governance models explored in order to select the best performing GM(s) per scenario and related grid architecture. This selection processes may render results that are specific to a scenario or grid architecture due to the varying levels of importance of policy objectives across scenarios and the varying levels of importance of regulation in BBs to achieve these objectives.

In a final step, interesting regulatory options are derived from these best practices and described further to consider for a European context. The options which are put forward in this study are by no means to be seen as a unique, nor exhaustive list. These options are rather the result of a best-practice analysis, focussing on some specific topics that have emerged from the research work.

1.3. Selection of Governance Models

On the basis of the available knowledge of the regulatory experts from the different partners involved in WP5, and following an external public consultation in the summer of 2013, a shortlist of 11 existing GMs have been proposed to explore in the scope of this study in order to identify regulatory promising practices (Table 1). This set was confirmed and supported by the public consultation and has been retained.

In the framework of this research & development project, the choice of GMs has been made to ensure a certain geographical spread, to look also into non-electricity sectors, and to take some specific case studies into consideration to discover potential promising elements. Other GMs, besides the ones retained, mainly relate to growing economies, such as Russia, China and the Middle East. However, these models have been discarded after a short exploration as most of them do not comprise advanced regulatory elements which seemed applicable in a European context. At the same time, those promising elements they do include, are rather a translation of elements already implemented in more advanced regulatory models that have been retained for the analysis.

A brief attention has also been paid towards governance models of offshore grids. However, it was concluded that not enough mature lessons could be extracted from these models at the start of the analysis in 2013, due to the fact that relevant regulation for this is still in the process of development. The table with the 11 retained models is presented below.

European electricity experiences	**Non-European electricity experiences**	**Generic electricity case studies**	**Non-electricity experiences**
1. Germany	4. USA RTO regions	8. Small and local case studies	10. Gas sector
2. Great Britain	5. Central America	9. Merchant case studies	11. Non-Energy case studies
3. Nordic countries	6. Argentina		
	7. Brazil		

Table 1: Selected governance models for the analysis of WP5 of the e-Highways 2050 project

Three of the GMs considered include promising elements while being implemented within Europe. The German and Great Britain GMs are applied in systems that are fully integrated in many aspects, while some coordination among areas takes place within them in other aspects. On the other hand, the Nordic GM is applied to a region comprising several independent systems that have a long tradition of cooperation.

Non-European GMs within the power sector are selected from the Northern and Southern American continent, namely USA, Brazil, Argentina and Central America. These four models provide different examples of the integration of planning and operation. The USA GM refers to RTO regions, and focuses mainly on aspects where federal electricity regulation, or guidelines, apply. Besides, some specific elements of regulation in the PJM region is considered. Furthermore, the Central American GM represents a region where relevant progress has been made in the integration of network expansion and operation processes. And finally, the Brazilian and Argentinean GMs are applied in fully integrated systems that function as a single one, but have some salient features in the regulation of the transmission activity which deserve further analysis.

There are two GMs focused on generic case studies that may be applied in a wide variety of areas in the world. The first one concerns the organization of the functioning of systems based on distributed energy resources, which have a local scope. This includes specific practices applied in Europe and the USA. Secondly, a specific GM is dedicated to the undertaking and operation of merchant investments, as regulation applied largely differs from the original regulation of the transmission and system operation activities.

Two GMs are taken from outside the electricity sector. The gas sector has been explored because of the elements of its functioning that are common to the electricity sector. Lastly, a GM is dedicated to relevant regulatory practices with potential application to the electricity sector being in place in other network industries, such as railways, telecommunications, water and aviation.

All these Governance Models are described into more detail in chapter 2 of this study. In order to have similar descriptions, focussing on the same regulatory aspects, a scoping has to be made for the study. In that respect, a list of 5 regulatory topics has been defined, as described in the next section.

1.4. Selection of Building Blocks

The characterization of a GM includes the identification of the institutions involved in each main area of the functioning of the electricity system as well as the identification of the roles of these institutions and the interactions between them. In the context of this analysis, main areas of the functioning of the system related to the transmission network are referred to as Building Blocks. Two different layers are considered when defining the features of a governance model regarding each BB defined:

- general description of the processes related to this BB, focusing specifically on the allocation of roles within these processes, and
- description of interactions among institutions and actors taking place in the undertaking of these processes.

Five BBs have been defined as groups of regulatory issues, related to the institutional approach towards the development and operation of the transmission grid (Table 2). These are the design ownership, financing, and cost allocation of the transmission network as well as those aspects of the operation of the system and the market where this network plays a relevant role. Also this list of regulatory focus has been publically consulted in the summer of 2013 and confirmed by participating stakeholders as a complete set to address the main issues at stake.

For each BB, challenges faced in order to achieve a satisfactory functioning of the European electricity system in the long term have also been identified. Successfully addressing these challenges is likely to require changing regulatory practices that are common in Europe. These challenges for 2050 are described in the chapters 5-9, when focussing on a specific Building Block per chapter. The categorization of relevant regulatory issues into a reduced set of building blocks allows to link also assessment criteria, and regulatory options to these building blocks, which makes the assessment to be carried out better structured, more systematic, and easily extendable to other regulatory schemes. This building block approach will hence by applied throughout the entire study.

The GMs have been assessed for their application in a regional context such as the EU. Therefore special attention is devoted to aspects of coordination in order to identify interesting aspects related to the interaction between several national or local aspects in combination with more regional/European ones. More details on the content of the 5 Building Blocks is summarised in the table below. The results of the analysis for each Building Block is addressed in the BB specific chapters 5 to 10.

Design	Ownership	Financing	Cost Allocation	Technical & MarketOperation
Concerns the process of identifying, proposing, selecting and approving (incl. permitting of) cross-border transmission network investments.	Concerns the asset responsibility and the identification of parties owning new cross-border assets.	Concerns the provision of funds to support the construction of approved reinforcements and the identification of (in)direct parties contributing to the funding of network reinforcements.	Concerns the process of allocating the investment and operational costs of new assets and the criteria applied to determine the contribution of each party to the recovery of the regulated cost of assets.	Concern mainly the scheduling and dispatch of the available generation, demand, storage, balancing and system security aspects.

Table 2: Building Blocks of a Governance Model

Finally, it is to be noted that in the context of the analysis in the WP5, the focus of the assessment is mainly on those aspects of system functioning which have their impact predominantly on transmission grid development. Therefore eventhough the aspects of collaboration between Transmission System Operators and Distribution System Operators is a relevant topic, this has not been included in the scope of this analysis and are thus not treated in the BB on Network Design nor Technical and Market Operation. For the latter however, eventhough these elements do not directly relate to transmission grid development, these do impact the investment decision as these have an effect on the costs and benefits of network infrastructure. Therefore this Building block is included, but the description of the options for 2050 shall remain at a higher level of detail than the other BB’s.

1.5. Criteria, Aspects and Objectives

In order for GMs to be assessed in a detailed manner, assessment criteria have been identified to determine the level of performance of the former regarding their ability to achieve a multiplicity of objectives and sub-objectives. Given that the assessment of GMs and identification of best regulatory practices is carried out separately for each BB, specific criteria are defined for each BB individually. Assessment criteria defined for each BB are classified according to the main energy policy objectives they relate to. These coincide with the three key European energy policy objectives, i.e. Sustainability, Competitiveness, and Security of Supply, complemented with two objectives related to the easiness of the implementation of regulation: Socio-political acceptability and Effectiveness (Table 3).

Competitiveness	Security of Supply	Sustainability	Social and polical acceptance	Effectiveness
•Facilitation of transmission network developments •Facilitation of operational efficiency	•Incentives for reinforcements increasing reliaibility •Incentives to enhance operational reliability •Incentives for coordination	•Facilitation of RES integration •Facilitation of energy efficiency and demand response	•Fit into the current context •Level of autonomy of local institutions •Fairness	•Complexity •Risk •Decision making power concentration •Facilitation of coordination

Table 3: Objectives for Building Block Assessment

Assessment criteria are described by formulating specific questions on the aspects of the functioning of the system they relate to. Including these questions serves the purpose of clarifying the meaning and scope of each criteria, and aspects considered within it. In the assessment of the 11 GMs explored, these questions have been used to guide the analysis. A full overview of the detailed elements on which a building block is assessed per objective is provided in Appendix 1. The overall methodology and the results of the preliminary assessment are described in chapter 3 and 4 respectively.

Finally, it is acknowledged that the analysis leading towards the possible lessons ("options") for Europe did not include an extensive cost-benefit analysis resulting in added value for society, of the implementation of each option in Europe.

2. Description of the Governance Models

As discussed in the introduction, 11 Governance Models have been selected as best-practice input to identify interesting transmission regulation aspects to apply in (a wider) European context. This chapter provides a brief summary of the full descriptions that have been developed in the scope of this study. These descriptions are structured along the identified Building Blocks and include the information that is relevant to carry out the assessment of each GM according to the assessment criteria. Each GM is also introduced with a short description of its distinctive interesting features.

Before going into the details of each GM description, four considerations are made.

- First, for some of the explored GMs, not all aspects of regulation have been described due to the lack of relevant information. These elements are obviously not taken into account for the analysis as the impact is considered as limited, as it is assumed that if there is no relevant available information, it is assumed to also not be a key promising aspect of regulation to investigate further.
- Secondly, as for the GMs that aren't directly related to the power sector, only those pieces of regulation that is deemed to be applicable to electricity transmission systems is described.
- Thirdly, a brief complementary analysis has been conducted for the Chinese, Russian and Middle-Eastern governance model, in order to provide some guidence on the reasons why these systems have not been withheld for further investigation (and thus not being part of the 11 retained GMs). This is described in the Box1.1 below.
- Finally, it is to be noted that all descriptions of GMs have been drafted in the year 2014. Since then, some changes may have taken place in the applied regulation in some countries. These changes have not been taken into account for this analysis.

Box 1.1. Chinese, Russian and Middle East Governance Model

1. Power supply in the Chinese system is not organized as a market. The Chinese system relies on a predefined allocation of power supply to generators, not guided by cost efficiency concepts. Thus, system and market operation are not advanced enough to draw useful lessons for Europe. Additionally, system and network expansion is not properly integrated at national level. Thus, coordination schemes for network expansion and operation are still very limited in their reach. Lastly, cost causality is not applied to the computation of energy and transmission charges, which involves that network cost and benefit allocation is very primitive, as well (Kahrl et al, 2011).
2. In Russia, the integration, or coordination level, achieved in system and networtk planning is still quite limited. Significant bottlenecks exist in the transmission grid, limiting the efficiency of the energy dispatch. Capacity markets have been implemented in Russia. However, these are acknowledged to be only a transitional solution plagued with problems related to their lack of transparency and competitiveness. By contrast, the energy dispatch applied is the result of a full-fledged Optimal Power Flow ("OPF") considering all kinds of network constraints and resulting in nodal locational marginal prices. This scheme, which is quite evolved compared to that in most systems, is already in place for a longer time period in some of the GMs already retained in the list (p.e. the US RTO regions, or Central America). At the same time, these systems do not exhibit the limitations that characterize the Russian regulation (IEA, 2013).
3. Eventhough a regional market has been created in the Middle East, comprising several Arab countries, the level of coordination of the expansion planning and the operation of generation and the network is very limited. Thus, very limited amounts of cross-border transmission capacity have been built since the creation of the market. Besides, the supply of electricity in most of the national systems in the region is organized in the form of vertically integrated utilities (ESMAP, 2013).
4. European offshore grid regulation is still at early phase of development, and therefore not taken as a separate GM. Alhtough three guiding principles are examined on today's offshore grid topology types and examples are given for each principle (THINK, 2014). The first planning principle indicates proactive offshore grid planning which takes into account future generators to be connected. Regulation in German offshore grid gives positive experience in implementation. Secondly, competition principles could be realized by tendering construction, ownership and maintenance of the offshore network. UK offshore wind regulation scheme adopts a tender procedure to grant 20 year offshore transmission license to the winner of the bids and yield interesting insights for introducing competition. Thirdly, the beneficiaries pays principle sends efficient signal for cost sharing to the generators according to their demand for connection service. Sweden provides pilot example in experimenting the third principle by making wind farms responsible for building and paying for grid connection to them.

2.1. European electricity experiences

2.1.1. Germany

The German system comprises four control areas, operated by four different TSOs. TSOs have some autonomy within their areas, but mechanisms are in place to ensure cooperation on network development and system operation. There is an independent energy regulator that is cross-sectoral supervising also other utility sectors (Bundesnetzagentur, BNetzA). This is a fully liberalized market with a strong level of integration.

Design

There are four TSOs in Germany, i.e. 50Hertz, Amprion, TenneT TSO and TransnetBW, which have the common task governed by the Energy Industry Act (EnWG Sec. 12a-d) to create a grid development plan for the expansion of the transmission grid for the next ten years. This must be delivered annually and submitted to the federal regulator, i.e. BNetzA. Firstly, the scenario framework has to be created and to be approved by the regulator. The scenario framework is representing probable developments in energy consumption and generation, and their regional distribution in three scenarios and forms the basis of the grid development plan. Furthermore, it embodies the objectives of the Federal Government. The grid development plan identifies all measures for the next 10 years which are necessary for optimising, enhancing and expanding the grid to meet the requirements.

The BNetzA will check the revised draft of the GDP and resubmit it together with an environmental report for consultation. In addition, it also takes into account the result of the involvement by the public and the authorities when confirming the GDP. The confirmed GDP is the basis for the draft of the Federal Requirement Plan, to be issued, at least, every three years, including the reinforcements, and grid developments, toundertake inmediately. The Federal Requirement Plan Act (Bundesbedarfsplangesetz, BBPlG) is agreed by the German parliament and defines the most important measures concerning optimising, enhancing and expanding the transmission grid.

Ownership

Liberalisation of the German electricity market took place in 1998, and is fully liberalised and opened to competition. Today, the four TSOs are legally unbundled, and 50Hertz Transmission, as well as Tennet TSO, are entirely ownership unbundled. In the four control areas the System Operator is also the owner of the local transmission grid. Tennet is not only acting as a TSO in Germany (in charge of one control area) but also in the Netherlands (single, dominant, TSO). The German transmission grid is owned by the four TSOs which each are responsible for their own control area.

Financing

The regulator has to approve investment measures for expansion and restructuring investments in the transmission grid, provided that these investments are necessary for (1) the stability of the overall system, (2) for inclusion in the national or international grid, or (3) for expansion of the power supply system.

The CAPEX rising out of approved investment measures can be considered in the revenue cap as yearly adjustment. Financing is done through international finance instruments which are offered in the financial markets. The national law allows a privileged interest rate, i.e. more or less nominal 9% in April 2015, for equity not exceeding a 40% share of the total capital.

Cost allocation

The cost of new transmission infrastructure, together with that of other regulated transmission assets, is socialized to stakeholders in the system. No mechanism of locational differentiation of transmission charges is considered in the German system.

The current tariff regulation mechanism is a revenue-cap regulation regime. According to this, network tariffs are defined in order to generate a predefined revenue cap as determined by the regulatory authority BNetzA for each TSO and for each calendar year per regulatory period (each regulatory period lasts five years). The network operators are not allowed to exceed their individually determined revenue caps with the network tariffs invoiced to their network users in the respective calendar year. The revenue caps are fixed for the entire regulatory period, but can nevertheless be adjusted in specific cases provided for in the ARegV.

The BNetzA determines the revenue cap on the basis of incurred or budgeted costs for the regulated activities and by considering the individual efficiency of the specific network operator. Therefore, the revenue caps may vary from year to year. The costs relating to the regulated activities include the allowed return on equity, as well as the predicted values of various cost categories, divided in those which the grid companies by definition can influence (“incentivized costs”) and those which they cannot influence (“non-incentivized costs”). Tariffs are public and are not subject to negotiation with customers (some exceptions apply for customers to agree on individual tariffs). The BNetzA has to approve such individual tariffs.

Within the regulatory procedure, the BNetzA sets caps for revenues for grid operators based on benchmarking and individual cost basis of the operator and adjusted for the inflation and general efficiency factor. Thus, differences between productivity and price evolution of grid operators and the domestic economy are compared and adjusted accordingly. As a result of the mechanism, an improvement of the profit margins for grid operators can only be achieved by lowering costs and improving the capital cost structure over the time of the different regulatory periods.

Market and System Operation

In compliance with the energy act, network operators are obliged to operate, maintain and expand the network system adjusted to the current needs of the market as long as such extension is economically reasonable. These obligations can require reasonable investments in the network, e.g. for expansion measures. Additionally, the energy act provides for detailed cooperation and information duties.

TSOs are responsible, together with main system users, to implement those measures leading achieving a safe and reliable energy supply, i.e. they are co-responsible for the security of electricity supply. Finally, due to their responsibility for the security of the energy supply, transmission system operators are also obliged to cooperate with other German and European TSOs and DSOs they are connected to.

Network operators must grant regulated third party access to their network on an economically reasonable, non-discriminatory, and transparent basis. Access is granted by allowing network users – downstream network operators, final consumers, energy suppliers and power plants – the usage of the network, e.g. supplying electricity to final consumers. Network operators are obliged to connect final consumers, neighbouring and downstream networks, power lines as well as power plants to their network also on an economically reasonable, non-discriminatory and transparent basis. In this case, connection means the physical linkage to the network. Network operators may only refuse connection to their network if the connection would be unfeasible or unreasonable for economic or technical reasons. A specific connection regime applies regarding the connection of offshore wind parks.

The minute reserve, or tertiary balancing energy, required by the four TSOs is procured via a joint tender since 2006. For this purpose, the TSOs common internet platform www.regelleistung.net is available. A common tender for the procurement of primary and secondary control reserve was introduced one year later on 1st December 2007 and is also processed via www.regelleistung.net.

The German TSOs are striving for an international expansion of Grid Control Cooperation. The objective of the IGCC is to optimise the use of secondary control reserves in the associated control areas, allowing substantially lower balancing expenses through a more coordinated approach. Five transmission system operators from Germany's neighbouring countries already participate (in the year 2014) in the grid control cooperation initiative, along with the four German TSOs.

2.1.2. Great Britain

Regulation in Great Britain exhibits some relevant distinct features that make it a paradigmatic case. Network expansion planning and operation takes place at Great Britain level, i.e. centrally. However, several Transmission Companies (Transco's) exist, owning the transmission grid, though the most relevant one, National Grid, is also the system operator. Thus, a hybrid scheme exists potentially rasing concerns about discrimination among companies that may reproduce in the rest of Europe when considering several types of network owners.

National Grid is a TSO subject to a performance-based remuneration scheme, which makes it an active TSO deciding over reinforcements being undertaken, under the price control of the regulator (based on efficient TOTEX). There is a single, national Energy regulator, Ofgem, which is independent of any other entity. A large part of electricity trade is negotiated bilaterally which coexists with Power Exchanges where energy is traded centrally.

Design

National Grid, the National Electricity Transmission System Operator (NETSO), is responsible for network development and planning of the Great Britain onshore transmission system. Each year, National Grid builds the relevant future scenarios based on UK Future Energy Scenarios, and publishes them for further stakeholder involvement. A major output of the network development policy process is the Electricity Ten Year Statement (ETYS), which is published annually (Strbac et al., 2013).

Transmission network development in Great Britain features extensive stakeholder engagement. Stakeholder involvement is included in the scenario preparation, grid planning and final approval phases. The network development plan, as well as the stakeholder engagement, is included in the transmission owner business plan and submitted to the regulator Ofgem for approval prior to the price control period. The business plan is assessed by Ofgem to determine the efficient cost of delivery for the price control period.

For offshore networks, a tender based regulation is applied to grant the license for a specific offshore transmission network. An Offshore Transmission Owner (OFTO), which wins the competitive tender organized by Ofgem, owns the related transmission assets for a period of 20 years, including the bidded revenue streams. The OFTO bidding party can neither be onshore transmission owners or offshore generators. There are two possible offshore transmission network construction models, namely generator-build and OFTO build. Under the generator-build model, generators design the network, obtain consents, procure, construct and commission the network. Under OFTO build model, generators undertake design and obtain consents for network while the OFTO constructs the network. In both cases, the OFTO is responsible for financing, ownership, operation and maintenance of the offshore transmission network.

All interconnectors in GB are required to be HVDC to allow control of power flow, since the GB system is not synchronized to continental Europe. The merchant approach is currently adopted by the regulator to develop interconnectors. Therefore, the network design and planning are performed on a case-by-case basis by the merchant interconnector developers.

Ownership

The onshore transmission network in Great Britain is owned and maintained by three licensed Transmission Owners (TOs), and operated by one single System Operator (SO). National Grid has the ownership license for the transmission network of England and Wales. Scottish Power Transmission Limited plc and Scottish Hydro Electricity Transmission plc have the ownership licenses of the Scottish transmission networks. The whole GB transmission system is operated by National Grid Electricity Transmission plc (NGET).

The high-level relationship between the National Electricity Transmission System Operator (NETSO) as system operator and TOs is defined by the System Operator-Transmission Owner Code (STC). It is supported by a number of procedures (STC Procedures or STCPs) that set out in greater detail the roles, responsibilities, obligations and rights of the NETSO and the TOs.

Financing

Typical channels of finance from internal equity and debt are present in Great Britain. Additionally, as National Grid is a company listed on the stock market, equity could be injected from shareholders. In addition, corporate bonds are issued to attract debt investors.

Regulation based upon RIIO (Revenue= Incentives + Innovation + Outputs) is applied for investment remuneration. Key financial parameters are designed separately for transmission owner and system operator by the regulator Ofgem. The cost of equity during first period of RIIO is set at 7% for both TO and SO. Cost of debt is indexed to long term government bonds.

The remuneration of total expenditure, TOTEX, is split into fast and slow money for both TO and SO, which allows incentives set to target their different responsibilities and financial profiles. Fast money refers to the amount that could be recovered in the current year. Slow money is the amount that is added to the regulated asset value (RAV), considered to compute the return on the RAV, taking into account depreciation, that is perceived by investors.

Cost allocation

Transmission costs are allocated via a flow-based method and a postage stamp peak demand charge to recover any costs not recovered through the flow-based method. The flow-based method is similar to long-run marginal cost (LRMC) in that the relative contributions of flows are multiplied by the replacement cost of the line to arrive at the cost responsibility for the line when they are at their maximum on the line or asset. Counter-flows are recognized in the methodology and it is possible that generators face negative charges, paid for providing counter-flow).

Both generators and load pay a fraction of the costs of lines. Generators in London, which are located in the load center and loads in the north are most likely to face negative charges, while loads in the south and generators in the north are most likely to face the highest positive charges. Remaining transmission costs that are not covered by the flow-based method are recovered through coincident peak charges to all users of the system based on the three highest peak hours from the previous year. The power market does not use locational energy pricing so there are no marginal loss or congestion surpluses to be used to recover costs. The cost responsibility between generation and load is pre-determined at 27% to generation and 73% to the load.

Contrary to what occurs in other markets, EE and DR costs are being accounted explicitly within the UK system.

Market and System operation

British Electricity Trading and Transmission Arrangements (BETTA) that set out a single GB-wide set of arrangements for trading energy and for access to and use of the GB transmission system started to take effect from the year 2005. GB trading arrangements include: long term bilateral contract, power exchange, balancing mechanism and imbalance settlement.

Long term contract

No official price exists under such markets since bilateral agreement takes place between buyers and sellers. However, there is general information about Over The Counter (OTC) contracts available in order to help market participants fine tune their positions close to delivery time (i.e information from the day-ahead and intra-day market). The long-term bilateral contracts are organized in the following forms: long-term negotiated contracts, forward trading and future trading.

Power Exchange

The power exchange APX Power UK offers an anonymous market place for integrated trading, clearing and notification. The APX Power UK Auction is a day-ahead auction, where bids are submitted anonymously and market price is cleared for each hour of the following day. The APX Power UK Spot Market is used for balancing and trading purposes. A competing power exchange N2EX was launched in 2010 by Nord Pool Spot and NASDAQ OMX Commodities, offering three short-term products, similar to its competitor: day-ahead auction, prompt market and spot (or intra-day) market.

Balancing market

The Balancing and Settlement Code (BSC) contains the governance arrangements for electricity balancing and settlement in Great Britain. National Grid is subject to the license condition to control frequency according to 'Electricity supply regulations', which is of nominal system frequency of 50 Hz. Three types of frequency responses are provided: mandatory frequency response (MFR), frequency control by demand management (FCDM) and firm frequency response (FFR).

In addition to the frequency control, National Grid diposes of reserve services to deal with unforeseen demand or generation variations. Three types are categorized on an increasing timescale: short-term operating reserve, fast reserve and balancing mechanism start up. Balancing service providers could use bids and offers to provide balancing service actions for a certain settlement period, which reflects the willingness of the provider to increase generation level or reduce demand level.

BSC Parties are requierd to be 'in imbalance' and the 'energy imbalances', i.e. the amounts of energy generated or consumed and not covered by contracts, have, in effect, been bought or sold from or to the National Grid Transmission System. Two 'cash-out' prices, also known as 'energy imbalance prices', are calculated for each half hour trading period and are used to settle these differences. These are called the System Buy Price (SBP) and the System Sell Price (SSP).

2.1.3. Nordic countries

The Nordic region contains different countries, each with its own national authorities and entities. National authorities, like TSOs, have executive powers over local matters, like the approval of reinforcements. At the same time, integration efforts have taken place in the last two decades leading to the development of an integrated electricity market, comprising both long- and short-term market arrangements. However, arrangements made in these two regards at regional level are not of compulsory implementation, leading to a source of tension between the national and regional administrative levels.

Design

The process of cross-border transmission network expansion starts with one of the involved TSOs identifying a need and initiating a common study. The result of the study is used to assess the need of the investment, and in some cases allocation of investment cost between the TSOs. The investment decision is taken separately by the contributing TSOs. Therefore, project funding is a national decision. There is no pan-Nordic institution to enforce the network investment decision. The time between initiating a common study and reach commissioning for a cross-border investment might be 7, 10 or 15 years. The lead time depends on the scope of the investment and on political or public requests.

A common Nordic investment assessment is usually carried out when assessing cross-border investments, while for national transmission network design each TSO carries out national studies. A prerequisite for such financing is that the investment would otherwise not have been implemented and that benefits accrue to countries other than in which the investment is carried out. The main investment assessment criterion is socio-economic and market utility. In addition accessibility and reliability are part of the assessment. However, reliability costs are not being considered as drivers of investments.

Since the benefits of one investment highly depends on which other investments are carried out in the Nordic area, long term investment planning, including national investments, is done in cooperation between the TSOs, based on longer term scenario's (p.e. 2030).

Ownership

The ownership of the cross-border connection is divided equally between the connecting TSOs. The ownership does not depend on the share of the investment cost coverage. National investments that are co-founded by other TSOs are fully owned by the TSO in whose system the investments are made. The national TSOs are the transmission system asset owners as well as the operators.

Maintenance of cross border connections is carried out in cooperation between the owners. For cross-border overhead lines, each TSO covers the cost of maintenance carried out within the national borders. For sea cables, the cost of all maintenance is equally divided between the connecting TSOs.

Operation and balance responsibility of the cross border investments are decided by the connecting TSOs. There are currently different systems in use for different connections. Regardless of methodology, the cost of the losses of the interconnection is divided equally between the connected TSOs.

Financing

Each of the participating TSOs funds its share of a cross-border investment. Funding is provided through the investment budgets of the TSO. It is not possible for investors or stakeholders to invest in a specific cross-border project.

Since the cross-border investments are financed via the TSO investment budgets, the projects do not need to be approved by the creditor. In practice, the TSOs do not compete with other infrastructure on investment money. Instead, the cross-border projects compete with national investment needs within the TSO budgets. The national regulation framework of the involved TSOs determines financial risks of the investments for each TSO. The inclusion of new investment into national asset base is not homogeneous in Nordic countries.

Cost allocation

The starting point of the cost allocation of cross-border network in Nordic region is that each TSO finances the investment within its system borders. As an exception, investment costs can be allocated according to the expected socio-economic benefits of each TSO. Environmental revenues are not being considered explicitly when allocating grid costs.

For evaluation of ENTSO-E related project, such as the Ten-Year Network Development Plan (TYNDP), Nordic TSOs follow the ENTSO-E guideline for cost benefit analysis of grid development. Some of the Nordic TSOs evaluate the national investments based on the entire Nordic region, which has been recommended by the Nordic Council, while others limit the assessment to include its own system.

Congestions on cross border connections between the Nordic countries are managed ex-ante by market splitting. Any congestion revenue is divided equally between the connected TSOs. Investments are often made to increase cross border trade and thus serve to decrease price differences and congestion revenue.

Market and system operation

Long term market

The long term market is strictly financial and does not involve physical delivery. Financial products are traded on Nasdaq OMX. Products can be traded up to ten years prior to delivery. In addition to the financial market, long term bilateral agreement that includes physical delivery can be made. For such agreements, buy and sell must be in the same bidding area (since it is not possible to reserve capacity between bidding areas).

Power exchange

There is a common Nordic power exchange for day-ahead and intra-day trade as well as a common regulating power market. The Nordic market is implicit; transmission rights are not traded separately. The total volume (Nordic area) traded at Nord Pool Spot was in 2012 323 TWh, which is approximately 84 % of the total Nordic electricity consumption. Hourly settlement is applied.

The price calculation of the power exchange is iterated so that the capacity between the high price area and the low price area is utilized to the maximum. The trading capacity is calculated by use of Net Transfer capacity (NTC). All available capacity is given to the day-ahead market. Capacity cannot be reserved or traded separately and nothing is kept for balancing power. If capacity is still available after the day-ahead market is closed, it is given to the intra-day market. If capacity is still available after the intra-day market is closed, it is used for balancing power and reserves. The day-ahead and intra-day market in Nordic area is integrated with the rest of Europe through market coupling.

Regulation market

The secondary manual control, which is the regulation used to restore the limited frequency normal operation reserve used to maintain frequency between 49,9 and 51,1 Hz, is traded on the regulating power market (RPM). On RPM, marginal pricing is applied and given no congestions, the price is the same in the entire Nordic area. All Nordic bids are evaluated together and during the operating hour the best priced bids are activated.

Decisions to activate resources in the secondary reserve are taken in cooperation between Statnett and Svenska Kraftnät. After settling for an activated volume, Energinet.dk and Fingrid are informed. Each TSO has the responsibility to activate the resources within their area. If the connections to an area are at risk of being overloaded, that area will be treated separately from the rest of the system. If balancing is needed, only resources in that area will be activated and the RPM price will be set separately from that in other areas.

Regarding the procurement and settlement of imbalancing markets, all producers and suppliers of electricity must either be a BRP or have an agreement with a BRP. The BRP has the responsible to balance production, trade and consumption for the production or load within its portfolio. Production imbalances are priced according to a two price system. That is, production imbalances that improve the system balance are priced with day-ahead price, while production imbalance that impairs the system balance is priced according to regulation price. It is not possible for the balance responsible to profit from the imbalance in a two price system.

Consumption imbalances are priced according to a one price system. That is, consumption imbalances are priced according to regulation price whether it improves or impairs the system.

2.2. Non-European electricity experiences

2.2.1. USA

Within the USA, two administrative systems exist: a federal one, with authority over inter-state commerce and all aspects of it; and a State one, with authority over all issues that are specific to an individual State, from retail transactions to the construction of generation facilities and most transmission ones. Arrangements affecting interstate electricity commerce must comply with some guidelines provided at the federal level by the Federal Energy Regulatory Commission (FERC), i.e. the federal regulator, while those affecting the intrastate trading of electricity and sitting of facilities must be approved by the States.

Three main interconnections exist in the USA: Eastern, Western, and Texas. Each Interconnection has a synchronous operation internally, while its operation is not synchronous with that of the other two. For operation and planning purposes, the electricity system in the USA is organized in several regions. Each region is an area within the electricity system that has achieved a high level of integration for operation and planning purposes. Regions comprise part of the territory of one or several States. The supply of electricity within some regions is organized thorugh a market, while in others it is not yet. In any case, the planning of the expansion of the transmission grid within each region is integrated and in the hands of a Regional Planing Authority.

Transmission development, ownership, financing, transmission cost and benefit allocation and energy market arrangements are developed independently by the competent authorities within each of these regions. There are two types of regions: i) those where a market has been created, which are managed by Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs); and ii) those where electricity is supplied exclusively by vertically integrated utilities and no market exists.

Design

Transmission network reinforcements in the US may be promoted as regulated lines or as private lines. Private investments may be undertaken by merchant promoters earning congestion rents or through a participant funded mechanism whereby rates to be paid for the use of lines are negotiated between promoters and future users (FERC, 2012).

Regulated investments are the result of a network expansion planning process that takes place independently within each of a series of transmission planning regions. Planning regions belong to one of the three interconnection systems existing in the US and Canada: the Eastern Interconnection System, the Western Interconnection System, and the Interconnection System of the Electric Reliability Council of Texas (ERCOT). Each interconnection system includes all those generators and loads that are synchronously connected among themselves and connected through DC transmission links to the rest of generators and loads in the US and Canada systems.

The expansion plan within a planning region is conducted by the central regional planning entity, the RTO. When building the regional network expansion plan, the planning authority must consider proposals by consumers and generation companies and private promoters. The regional network expansion plan must pursue the achievement of policy objectives of an economic, reliability or environmental nature. Within environmental ones, the integration of predefined amounts of RES generation has an especial importance. There is a mandate by FERC directing planning authorities in neighboring regions to consider expansion projects serving the interest of more than one region. However, there is no procedure established, nor a mandate, to build cross-regional network expansion plans. Thus, coordination across regions in the planning of the development of the grid is limited.

Lines promoted either as regulated investments or as private ones must be approved by authorities corresponding to several administrative levels. Thus, the network expansion plan concerning an RTO region must be approved by the RTO board of directors. Besides, entities responsible for the construction of lines must get approvals from state siting agencies, state and federal environmental agencies, state and federal land owners and land managers, private land owners, etc. Besides, parties may file complaints with FERC if the network expansion planning process is not in line with guidelines provided by FERC or if it is perceived to be unjust, not reasonable or unduly discriminatory. Federal authorities have the right to prevent private transmission developers to go ahead with their projects if they believe that the size of these projects is too small due to anticompetitive or unduly discriminatory behavior, see (FERC, 2013). Recently, however, there have been some court rulings preventing State authorities from blocking the construction of lines aimed at achieving the integration of renewable generation within an RTO. There have been significant disputes over the interpretation of prevalent law, like the 2005 Energy Policy Act, and 2009 American Recovery and Reinvestment Act, among others, (US, 2005; US, 2009).

If regulated investments are finally approved, they must be built by specialized Transmission Companies. These may win in an auction the right to build, operate and maintain a new asset or, alternatively, be assigned these functions by the RTO board of directors if investments take place within an RTO region. In many cases, Transmission Companies designated to build a line are those owning the grid in that area within the region. All Transcos must hold a transmission license, which proves that they comply with certain requirements regarding their technical and financial ability to undertake the construction, operation and maintenance of transmission assets.

Ownership

Network ownership and operation in the US are generally unbundled in those regions where an organized market exists (ISO model) but may be bundled in the remaining areas. The transmission network within each network expansion planning region may be owned by a multiplicity of Transmission Companies. In most areas where a market exists, the operation of the transmission systems is in the hands of specific transmission system operators, including Public Utility Transmission Providers, RTOs, and ISOs, at inter-State level. In areas where markets have not been deployed yet, the transmission system is normally operated by the same entity that owns the lines. However, even in these cases, network operation is subject to a set of rules called the Open Access Transmission Tariff, see (FERC, 1996). Both Transcos and Transmission System Operators generally are private companies, although the operators are subject to strict regulation applying to the development of their activities. Transcos are not obliged to be part of an RTO.

Financing

In the US, both specialized Transmission Companies undertaking regulated network investments and private promoters normally make use of their own resources to finance the construction of reinforcements. Thus, they mainly rely on private debt (debt issued by these institutions) and, to a lower extent, equity. Besides, there is a limited amount of Federal funds made available for strategic regulated investments, normally of an inter-State nature. Public funds are provided through a variety of financing instruments.

There are a number of measures that facilitate the financing of transmission investments. Talking about regulated investments, their remuneration is largely set at the time the construction, operation and maintenance of new assets is commissioned. Remuneration may result from an auction where companies bid to win the right to build new assets. Alternatively, it may be administratively determined in the case of Transmission Companies that hold the exclusive transmission license for an area where a new asset is to be built. In both cases, the resulting remuneration of investments is expected to include a reasonable rate of return and a guarantee of payment. These should facilitate the collection of funds by the relevant Transcos.

In the case of privately promoted investments, authorities have made available several alternative remuneration frameworks for promoters, ranging from earning the congestion rents, or revenues from the sale of congestion rights, of the corresponding investments, to the negotiation of access tariffs to be paid by future users of these assets. This should allow private promoters to better match the remuneration scheme adopted to their financing needs.

However, the complex and lengthy authorization process that network investments, especially those of an inter-State nature, must go through could pose significant risks on revenues to be perceived by Transcos, and therefore by investors. The process of obtaining the required permits may significantly delay, or even block, the construction and entry into operation of assets, and therefore also affect revenues and financing conditions offered to companies. This process should be streamlined if financing conditions affecting large network reinforcements, like those needed to integrate remote RES generation, are to be attractive.

Cost allocation

Energy pricing schemes applied in the several regions defined within the USA system (nodal pricing in many, zonal pricing in some) condition prices applied in each part of the network, and therefore the allocation of the benefits produced by network reinforcements to stakeholders in the system (generators and consumers). In the case of private network investments, promoters of these investments may earn congestion rents, or instead access tariffs negotiated with future users of the corresponding lines. Then, by definition, a part of the benefits created by merchant assets is being allocated to their owner.

The allocation of the cost of network assets is also dependent on the nature of the corresponding investments. Costs of private investments are born by the project promoter, or owner of these assets, which may sell their capacity in advance to pay at least part of this cost. In the case of regulated investments, when talking about cross-border, i.e. cross-State ones, regulation enacted by FERC requires the cost of these investments to be allocated based on the benefits from them expected to be perceived by parties (lump sum), see (FERC, 2012). When applied to reliability driven investments removing a constraint violation, this may involve the allocation of the costs to those consumers or generators causing this constraint violation in the first place, as it occurs in Pennsylvania, New Jersey, and Maryland RTO (PJM). Or otherwise application of the cost causality principle may imply a sort of socialization of costs of reliability reinforcements that are deemed to benefit a large set of network users under specific situations (emergency ones, for example).

In practice, this has led regional authorities to propose/implement mechanisms based on some proxy of benefits, like the allocation of all costs to consumers or generators connecting in a node or area when talking about connection facilities; or the allocation of costs according to flow-based mechanisms (thus deeming network use as a proxy to benefits, where network use is measured in different ways). Cost allocation schemes should be developed and approved by existing planning regions, but these schemes do not need to be applied over a larger area than the corresponding region. Different regions may apply different cost allocation schemes and, within each region, different types of assets may also be subject to different schemes.

However, benefits produced by investments may be perceived by consumers and generators in several regions. This is especially clear for interregional reinforcements to be sited in several regions. The allocation of the cost of any transmission asset among several regions should be agreed by these regions and be based on the application of a common inter-regional cost allocation procedure, at least in the case of inter-regional new transmission assets. If a region cannot decide on a cost allocation scheme to be applied to regulated investments, FERC is allowed to set one.

Market and System Operation

Allocation of responsibilities

Federal authorities do not have authority regarding the organization of markets. They can only issue guidelines in this regard. However, they have authority over the allocation of transmission capacity in interstate commerce. Strict reliability rules are set by a central body, the North American Electric reliability Corporation (NERC). The operation of the market and the system is managed centrally in RTO regions and locally by vertically integrated utilities in regions where a market does not exist.

Congestion management

FERC though their Standard Market Design, see (FERC, 2002) issued some guidelines on the management of congestion including the organization of network constrained balancing markets, day-ahead and real time markets. Energy is supposed to be valued using nodal prices (Locational marginal Prices). Consumers and generators were supposed to be allowed to acquire Fin ancial Transmission Rights (FTRs) allowing them to hedge in the long term against the volatility in the price of transmission capacity. These guidelines have been implemented by some regional markets.

Besides, FERC has set some minimum requirements to be complied with by congestion management methods in the short and long term, see (FERC, 1996) and (FERC, 2007). In the long term, consumers and generators should be allowed to acquire firm point-to-point transmission service. If there is scarce transmission capacity, the SO can redispatch requests for firm service or allocating conditional service that can be curtailed. In both cases, the SO should set a value for the transmission service to be paid by those receiving this service. This price can be negotiated between the SO and network users or be computed based on the incremental cost of redispatch (system cost of rejecting some transmission service requests). In the short term, redispatch is to be applied on a least cost basis to avoid load curtailment. The cost of redispatch is to be paid by affected SOs proportionally to the load each one serves.

Loose provisions on coordinated congestion management across regions exist at federal level. Neighboring regions are advised by FERC to coordinate congestion management mechanisms applied. Some regions, like PJM and the Mid-West ISO (MISO), have already implemented mechanisms, while others have not.

Balancing and other ancillary services

FERC in its order 890 defines a settlement procedure for imbalances that aims to encourage market operators to accurately estimate their output, by pricing deviations higher than incremental costs, while providing intermittent generators with certain exemptions from imbalance prices. Both generating and non-generating units can provide other Ancillary Services.

Security of supply mechanisms

Currently, there is no main mandate in place at federal level regarding the implementation of security of supply mechanisms. However, some of the regions within the US, like the RTO of Pennsylvania, New Jersey and Maryland (PJM), have developed and implemented pioneering long term mechanisms driving the installation of generation capacity at a regional level. These encourage consumers and generators to install and have available firm generation capacity.

Participation of demand in markets

In the USA, market based demand response refers to the demand response participation that can set the market clearing price, rather than only be reactive to market signals. The resources are dispatched by the system operator, which in RTO regions is the same as the Market Operator. In some electricity markets under FERC regulation, three types of market based demand response service provision are observed: capacity resources, energy resources, and reserve resources as ancillary services (Hurley et al., 2013). In other words, demand can contribute to system security in the long term by providing firm capacity (ability to reduce consumption below its base load level if needed); it can also contribute energy in markets either explicity by participating as any other party or indirectly trough suppliers; and can contribute flexibility in close to real time markets.

2.2.2. Central-America

The regional electricity market of Central America comprises six countries: El Salvador, Guatemala, Honduras, Nicaragua, Costa Rica and Panama. This regional market is superimposed on the arrangements made at national level in the six countries in the region to organize the local supply of electricity in them. However, transactions in the regional market do not replace, but complement, those transactions arranged through the national supply schemes. Some minimal regulatory harmonization among the countries in the region is necessary because of the very different level of development that local markets have achieved. Thus, in some countries, there is a national market properly speaking, where suppliers compete to serve the local load, while others mostly maintain the characteristics of a vertically integrated structure and traditional cost of service regulation. For information on the organization of the regional market and transmission arrangements, see (PHB-HAGLER/SYNEX, 2000), (CRIE, 2005 a), (CRIE, 2005 b), CRIE (2012 a), (CRIE, 2012 b).

There are several regional institutions related to the functioning of the regional market. A regulatory body of regional scope, the CRIE (for Comisión Regional de la Interconexión Eléctrica, in Spanish), is in charge of developing and supervising the implementation of the regulation that applies to the electricity commerce taking place at a regional level. The CRIE must design and apply any preventive or corrective rule that is necessary to guarantee that the regional market works properly. There is also a regional SO, MO, and planner: the EOR (Enter Operador de la Red, in Spanish). The EOR has a mandate to preserve the reliability and safe functioning of the system and therefore also the regional grid.

Design

The regional grid comprises all those network assets that are used by regional transactions, either arranged in the long term or the short term. Thus, it does not include all transmission assets in all countries. It plays a similar role to the Horizontal network in the IEM of the EU. The expansion of the regional transmission grid must be planned and managed by regional entities and authorities.

The EOR is concerned with the planning of the expansion of the regional grid. This institution has its own legal entity and is manged by a governing body comprising two representatives of each national system in the region named by the corresponding government and representative of the market stakeholders (generators and demands) that are renewed every 5 years. This entity must produce a long-term expansion plan for a time horizon of 10 years and a mid-term expansion plan for a time horizon of 5 years. Both must be updated annually and sent to the regional regulatory authority, CRIE, for their approval. Every network reinforcement to the regional transmission grid must, in principle, be subject to the approval of the CRIE, including those initially planned by national authorities. Then, the EOR, besides planning the expansion of the regional transmission grid, must also assess the investment proposals by consumers or generation companies and countries in the region to advice the regional authority on their approval. The maintenance of the grid is planned by the EOR in cooperation with national SO.

Reinforcements to the regional transmission grid may be classified as regulated, or promoted by central planning authorities, or non-regulated, or promoted by private parties and national planning authorities. This classification of reinforcements is specific to this region and quite different from those adopted in other parts of the world, like the IEM of the EU. Regulated reinforcements are remunerated according to pre-established rules based on the results of competitive tenders organized to allocate their construction, operation and maintenance. Non-regulated reinforcements, in principle, earn non-regulated revenues, i.e. revenues corresponding to these lines resulting from the market operation in the region. However, they could also earn some regulated revenues.

Regulated reinforcements comprise those included in the regional expansion plan that are benefiting a multiplicity of consumers and generation companies and countries. Those reinforcements to the regional transmission grid that are part of the regional transmission expansion plan but are benefiting a low number of generators or consumers (three or less consumers and generation companies receive more than 80% of the benefits of the line) or a single country shall be built, operated and maintained as non-regulated reinforcements. Additionally, all those reinforcements to the regional grid promoted by private parties or national systems that are not part of the regional expansion plan shall be promoted as non-regulated reinforcements, as well.

Non-regulated regional investments shall be approved by regional authorities as long as they are not detrimental to the functioning of the system. However, the CRIE may request promoters of network investments carried out as non-regulated regional ones to modify the features of these reinforcements to adapt them to the needs of the region.

Before computing the regional network expansion plan, countries must provide the EOR with their best estimates possible of the future evolution of demand and generation in their systems and national network expansion plans. These are taken as inputs in the regional transmission network expansion planning process. When selecting and approving network reinforcements, the EOR and

CRIE must consider benefits of an economic or reliability nature, but not environmental ones. Scenarios considered in the expansion planning process must represent the different possible futures. Plans must be robust against these scenarios.

Ownership

Separate schemes are applied to regulate the ownership of regulated and non-regulated reinforcements to the regional transmission grid. Non-regulated reinforcements may be owned by those private parties promoting them, including consumers and generation companies and merchant promoters, or by those parties appointed by national regulatory authorities in the case of reinforcements promoted by national systems.

The construction (and initial ownership) of regulated reinforcements is allocated through a competitive tendering process. However, a project company has been created to develop what is deemed to be the backbone of the regional transmission grid, which is called the SIEPAC line. This project company is called EPR. EPR is owned by a set of transmission companies and electric utilities that are active in the region. For a list of the stakeholders of the EPR, see (EPR, 2013).

Therefore, facilities of the regional transmission network are not owned by the entity in charge of operating the regional system and market and planning the expansion of the grid (EOR). Regional transmission facilities may be owned by several types of entities; private transmission companies, national transmission companies, which sometimes are also System Operators, consumers and generation companies willing to invest in a transmission line that would mainly benefit them, and merchant promoters willing to make a benefit out of the commercial exploitation of these lines.

Financing

Separate schemes are employed to finance the development of regulated and non-regulated reinforcements. Generally speaking, regulated reinforcements are financed by those parties winning in auctions the right to construct, operate and maintain the corresponding assets. These are, normally, independent private transmission companies, or national transmission companies, which may also be national SOs. Besides this, a project company, the EPR, has been created to build, own and operate the SIEPAC line. All these companies mainly use debt to finance the construction of these assets. Thus, for the most part of the budget of the SIEPAC line, the EPR has signed loans with several international financial institutions like the Inter-American Development Bank (BID) and the Central-American Bank for Economic Integration (BCIE). Besides, the EPR has signed some other loans backed by the financial guarantees provided by some of the EPR stakeholders and EPR itself. However, the process of obtaining funds from loans for the construction of regulated assets has been a very lengthy one, which has delayed the process of development of the regional grid.

Thus, all those reinforcements that are suitable for their construction by private parties as non-regulated assets are expected to be promoted in this way. Non-regulated lines that are deemed to benefit a reduced set of consumers or generation companies or systems are left for their financing as non-regulated investments through a participant funding scheme. Then, main users (beneficiaries) of these assets are expected to promote them, contribute to their financing and pay part of their cost. Additionally, there may be other approved reinforcements that are not overlapping with regulated ones but are deemed by private parties to produce significant congestion rents in the regional dispatch. These should be owned and financed by private promoters wishing to make a profit from the operation of the former (merchant lines). Promoters of non-regulated investments may resort both to debt and equity to finance these projects. Equity may be more relevant in big projects involving the construction of large generation plants and the associated transmission facilities. These large projects may be undertaken under a project company scheme.

Cost allocation

Remuneration of regional transmission investments

Consumers and generation companies promoting non-regulated regional network investments are earning the operation benefits produced by these new assets. Besides, all promoters of these assets earn the congestion rents resulting from market operation that correspond to these assets, or the revenues from the sale of transmission rights over the capacity of these assets.

However, owners (promoters) of non-regulated assets may request a regulated payment from regional regulatory authorities (CRIE). This is higher, the larger the fraction of the benefits produced by the line that are perceived by a large number of consumers and generation companies, and the larger the cost of the line. In this case, market revenues of line owners shall be reduced accordingly. The "allowed" regulated revenue of non-regulated lines shall be computed based on standard unit costs or those resulting from the international tender of the construction of these assets.

Revenues of the owners of regulated assets whose construction is assigned through an auction amount to the annual canon bid by the auction winner in return for constructing, operating and maintaining these assets. This annual canon is received throughout the repayment period. After the repayment period, owners receive a reduced annual canon established according to administrative procedures and aimed at covering the management, operation and maintenance costs plus the expected cost of complying with availability requirements for the corresponding asset. Lack of compliance with security/reliability rules in the expansion and operation of the system may result in penalties faced by market operators and consumers and generation companies.

Allowed regulated revenues of transmission assets, including connection lines, are recovered from two sources:

- Variable Transmission Revenues (VTR), corresponding to congestion rents of this line in the market, or revenues from the sale of transmission rights over its capacity.
- The application of Network Usage Charges to those consumers and generation companies deemed to be making use of the regional transmission grid. These charges must allow the system to collect the regulated revenue of lines less the VTR, which is called IR. Network Usage Charges are of two types:
    - Tolls: tolls must collect that part of the IR of lines corresponding to the used fraction of their capacity. Tolls are charged 50% to loads and 50% to generators. The total amount of the regulated revenues of a line to be recovered from tolls is allocated to power injections and withdrawals in each country proportionally to the aggregated incremental impact of the latter on the flow in this line. Then, flows attributable to balanced power injections in each country are tracked down to individual power injections and

withdrawals to determine the responsibility of the latter. Flows attributable to power unbalances in countries are allocated to these unbalances proportionally to their size.
- Complementary Charges (CCs): these must collect the fraction of the IR of each line corresponding to the unused capacity of the line. The method applied to compute CCs is very similar to that applied to compute Tolls. One main difference is that, while tolls are paid always 50% by load and 50% by generators, CCs applied on power unbalances are paid fully by loads.

Snapshots representing the historical use made of the grid are employed to calculate how much power injections and withdrawals are using transmission lines. No priority is provided to RES generation in the allocation of the cost of the grid, or rights over its use.

Market and System Operation

Market Operation

Due to the fact that the regional market does not replace but complements national markets, the interface between the two kinds of markets is central to the successful implementation of the regional market, MER (Mercado de Electricidad regional, in Spanish). The next paragraphs describe how the coupling between both markets takes place.

Consumers and generation companies may make one-sided bids (unbalance transactions) in national or regional markets or may sign long or short term bilateral contracts with other agent(s). A regional day-ahead market, where the majority of power injections and withdrawals are negotiated, is followed by a real time one, where changes to the former are computed.

As a result of regional markets, a single price is computed for every node of the regional grid. This represents the marginal cost of supplying an extra amount of power in this node, i.e. the corresponding nodal price. All power injections and withdrawals in each node that are dispatched in the regional market are priced at the corresponding nodal price. As a result of this, a net amount to be paid by each national system is computed. National authorities allocate this total amount to generation and load in their systems as they deem appropriate. Thus, individual power injections and withdrawals may not be earning or paying, respectively, the corresponding nodal price. In any case, regional authorities advice national ones not to discriminate between national and regional transactions regarding prices applied to them.

Transmission capacity can be contracted in the long term buying physical or financial transmission rights.

Ancillary services and System Operation

Ancillary services are provided by consumers and generation companies in the region as compulsory minimum services. Consumers and generation companies are not remunerated for providing them. Compliance with security criteria must be guaranteed for N-1 conditions and even under multiple contingencies. These reliability criteria are administratively defined.

Security of supply

Regional authorities must work to preserve system security both in the short and the long term. The regional system operator produces indicative expansion plans for generation and transmission. Transmission lines deemed to be necessary are constructed as regulated lines. However, no capacity payments or other generation adequacy regulatory instrument is applied at regional level (some are applied at national one).

2.2.3. Argentina

Regulation in place in Argentina is very specific to this system. Since the liberalization of the electricity sector in the 90's took place with the aim to increase the efficiency of the syste m as a result of the introduction of market forces, some regulatory developments have put this system at the forefront of the regulation of the transmisison activity. Thus, several approaches for the promotion of the develoment of the grid coexist, some of which are specific to the Argentinean system. At the same time, there are several entities owning part of the transmisison grid, the most important of which is Transener. The operation of the system and the market is in the hands of an ISO type of entity, CAMMESA. There is a national Elecricity Regulator (ENRE), with links to the national government, but regional governments have authority over some aspects of the organization the system.

Design

The transmission system in Argentina has been separated (unbundled) from power generation and distribution, privatised, and subdivided into two systems:

- The national high-voltage transmission system (STEEAT), which operates at 500kV and transports electricity between the regions administratively defined in the country (political divisions). Since 1993, this system is operated by the private company Transener.
- The regional sub-transmission system (STEEDT), which operates at 132/220kV and connects generators, distributors and large users within the same region. This system is operated by six private companies.

Transmission systems are operated under long-term (95-years) concessions for monopoly service supply within a certain area or grid. These concessions are awarded by a process of competitive bidding and subject to management performance contracts that are renewed and rebidded every 10 years (except for the first period, which lasts 15 years).

In contrast to the rather conventional regulation of existing transmission systems, the governance of new transmission facilities ('expansions') followed a rather different approach. More specifically, at the initial reforms of the early 1990s, four methods were put in place to decide about grid expansions. In brief, these methods include:

- *Minor Expansions*, i.e. new grid facilities under $ 2 million in the national transmission system or under $ 1 million in the regional sub-transmission networks;

- *Contracts between Parties*, i.e. an agreement on a grid expansion between one or few users and the transmission company;
- *Private Use*, i.e. the ability of the Secretary of Energy to authorise a generator, distributor or large user to construct and operate a new transmission line at its own cost and for its own private use;
- *Public Contest*, i.e. a major grid expansion that involves many parties and that requires a vote of users followed by a competitive tender.

The most important and innovative approach – which aroused a lot of international interest and debate – was the Public Contest (PC) method. The key feature of this method is that the decision on the undertaking of a transmission expansion is given to the users (or 'beneficiaries') themselves – who also pay for the expansion – rather than to the transmission company, the system operator, the regulator or the government.

Ownership

Transmission is fully privatised and unbundled from power generation and distribution. The national high-voltage system is owned and operated by the private company Transener, while the regional sub-transmission system is also owned and operated by private companies (each with exclusive monopoly rights in their regional concession area), except those major expansions under the PC method that have been granted to other, more competitive companies. All transmission companies are presently controlled by local investors. A transmission company, any of its controlled companies, or its controlling entity cannot be owner, majority shareholder or the controlling company of a generation company or a distribution company. In turn, a generation or distribution company, any of its controlled companies or its controlling company cannot own, be a majority shareholder or the controlling entity of a transmission company.

At the end of each performance period (see above) the government is assumed to call for a public tender for the sale of the majority stake of class A shares (51% of total company shares). The incumbent has a slight advantage in this tender, as all competing bids have to be compared to its own statement about the value of the company (submitted in a closed envelope before the bidding date). If none of the offers exceeds the incumbent reference price, the concession rights do not change hands. Otherwise, the group offering the highest bid pays this value to the incumbent and obtains the concession rights.

At the end of the 95-year period the government changes the legal status of the company to a new public corporation, and offers its shares in an international public tender. All parties receive equal treatment and the proceeds of the sale are used to reimburse the last concessionaire.

Financing

Transmission investments in Argentina is financed upfront from a variety of sources, including:

- *External assistance*. Over the past decade, international development institutions such as the Inter-American Development Bank (IDB) or the Andean Development Corporation (CAF) have provided assistance to finance transmission investment projects in Argentina.

- *Private funding*. This source of funding includes both equity and debt finance from different private parties, depending on the method of transmission expansion. Under the (voluntary) Contract between Parties method, expansion is financed (partly) by the few, directly interested parties themselves and/or an (independent) transmission company or operator. Under the Public Contest method, an expansion is usually financed by the company or consortium that wins the tender. In addition, starting from 2001, the above-mentioned methods were complemented by allowing other private parties ('investors') to participate in the financing of expansions by acquiring so-called 'Financial Transmission Rights' in proportion to the extent to which they finance the cost of the expansion.
- *Public funding*. Transmission expansions, notably those proposed in the Federal Transmission Plan, have also been financed through public funds such as the Federal Transmission Funds (FFTEF) or the Financial Trust for Investment in Transmission in the province of Buenos Aires (FITBA). These funds result from the proceeds of special 'aggregate tariffs', surcharges or 'stamps' on transmission charges at the federal and/or provincial levels. In addition, transmission expansions have been financed by the allocation of funds from the federal budget.
- *Salex funding*. In August 1994, the Secretary of Energy specified that future congestion revenues from nodal price differences should be put into so-called Salex Funds, one Fund for each of seven transmission corridors. These funds could be used to defray (up to 70% of the) initial construction costs as well as subsequent fees of transmission expansions.

Cost allocation

Regulation of the transmission system in Argentina makes a distinction between existing and new facilities (expansions). For existing installations, the remuneration scheme of the transmission operator is based on both price and quality incentive regulation (derived from the UK's RPI-X price control system). In brief, for the national transmission operator, Transener, the main components of the regulated remuneration scheme regarding its existing capacity include:

- *Line losses*. For each line, revenue from line losses is calculated as the difference between quantities transported, evaluated at nodal prices for each of the two nodes involved.
- *Line reliability*. Reliability of the line, also referred to as network quality of supply, is paid through the spatial difference between the remuneration that buyers pay for active power reserves and what sellers receive for this concept.
- *Access charges*. Access (or connection) charges are unit charges for each connection point within the grid that cover the operating and maintenance costs of existing equipment needed to connect users of the grid. These charges are distributed among the users that are connected, according to their pro-rated share of the maximum total power at the point of connection. The regulation of these charges follows an RPI-X regime, where the efficiency adjustment factor is set by the National Electricity Regulator (ENRE) but cannot exceed 1% per annum.
- *Complementary charges*. Complementary charges have two components. The first one is the so-called transmission capacity charge, which is also subject to RPI-X regulation, in the same fashion as access charges. The second component of complementary charges is the difference between realized and estimated charges for line losses and line reliability (as mentioned above).

For new transmission facilities under the Public Contest method - in particular during the amortisation period of these facilities – the annual transmission charge to cover the construction, operation and maintenance costs of the expansion is set through competitive bidding and shared by all beneficiaries identified by means of the Area of Influence method. After the amortisation period, however, charges for operation and maintenance of the installation basically follow the remuneration regime for existing facilities.

Market and system operation

Both System Operation and Market operation roles are played by the same entity, CAMMESA. Incumbent transmission companies, such as Transener, are primarily responsible for the operation and maintenance of their network, but not for the planning or expansion of the system. While having exclusive monopoly rights within their concession area, they are obliged to provide open, non-discriminating access to all third parties at regulated tariffs. If capacity constraints arise, transmission companies cannot discriminate through rationing devices since the independent System Operator, CAMMESA, decides which generators are called upon, based on an unconstrained dispatch merit list that sorts producers by their fuel costs and guarantees access priority to the lowest-cost generators.

In the spot market, load dispatch and hourly electricity prices are determined by the Wholesale Energy Market Operator (CAMMESA), who is also the System operator, based on hourly demand forecasts and the short-run marginal costs (SRMC) of the generator that clears the market in each area in an efficient cost-based merit order dispatch. The reference point for determining the spot market price is the Ezeiza 500 kV node, i.e. the system load centre located near Buenos Aires. In each of the other nodes on the grid, the electricity price takes into account the cost of power transmission to or from this reference 'market' node.

When a line is congested – i.e., there is a transmission constraint – CAMMESA determines a so-called 'local price' in the constrained generation node as well as the spot clearing price in the reference market node (Ezeiza), based on the most efficient merit order dispatch in each node.

All dispatched generators receive the (local/nodal) spot price, supplemented by a capacity charge (to support generation investment). The nodal factor is calculated by taking into account technical losses and restrictions in the transmission system. The capacity charge is only paid to generators when they are actually producing and not for availability of capacity as such.

For regulated energy consumers – which include all residential consumers, small commercial and small industrial consumers – the regulated electricity tariff is a fixed, stable price, but can be adjusted every three months. The basis of this tariff is the seasonal electricity price, which is set every six months by the Secretary of Energy, which is part of the Argentinean national government and have some competences over the functioning of the system. The final prices for regulated customers are a combination of the seasonal electricity price, a capacity charge and transmission and distribution value added charges.

Finally, besides regulated electricity consumers, there are also free or non-captive end-users in Argentina's power market. These are mainly large users who are entitled to purchase their electricity consumption directly from generators or traders through bilateral contracts, at freely negotiated prices.

2.2.4. Brazil

Brazil is the largest power system in Latin-America. It is an hydro dominated system, where hydro generation contributes 70% of capacity and 90% of electric energy produced. Only 30% of demand is free to choose a supplier. Activities in the sector are carried out as a mixture of central planning and competition. The main regulatory objective is ensuring system security both in the short and the long term.

An independent regulator exists, ANEEL. However, part of the functions of a traditional regulator, like the approval of network reinforcements, are performed by the government. There is also a SO, called ONS, computing the energy dispatch and operation of the system, which is already planned in the medium term. The market operator, CCEE, sets energy prices, settles contracts and conducts energy auctions. The expansion of the system is planned centrally by the competent authority, called EPE, aided by ONS, see (Maurer and Barroso, 2011).

Design

Process of development of the network

The expansion of the grid is centrally planned by the relevant authority, EPE. It is based on the development of generation in the system, which is largely determined by long term energy auctions organized by CCEE. Before auctions take place, generation investors receive an estimate of transmission charges to be paid by new plants in each area of the system. These charges have previously been computed based on an indicative transmission expansion plan produced also by EPE for the following 10 years. In order to produce this plan, EPE considers its best estimates of the future development of generation. Once energy auctions for a period of time have taken place and the development of generation in the system is certain, EPE computes a firm expansion plan for the following 5 years, that is, in turn, updated annually, see (Rudnick et. Al, 2011). Network reinforcements whose construction is scheduled to start in the following year are submitted for approval by the Government, who assess them on an individual basis.

The construction and operation of approved network reinforcements is assigned through auctions organized by ANEEL. The agent submitting the lowest bid for each facility, comprising an annual rent over a certain period, is in charge of building and operating this facility. The construction of reinforcements rarely takes more than 5 years, and in many cases it takes less than 3 overall, from the time the reinforcments is planned. Given that relevant transmission projects are deemed of strategic importance, the process of collection of required permits is very short.

Some of the most relevant generators in the country are owned by the state. Then, possible conflicts of interest might arise when planning the expansion of the network, since EPE is also a public entity.

Transmission planning methodology

Transmission expansion plans computed by EPE are aimed at minimizing the overall cost of expansion of the transmission network and operation of the system. As explained, generation considered when defining network expansion plans corresponds to the existing generators plus new generation developments resulting from, the so-called, new energy auctions plus strategic new generation projects of common interest, mainly hydro ones, which are deemed to be needed in the time horizon of the study.

Therefore, indicative expansion plans are the result of a centralized, cost-minimizing, planning process where reliability constraints, like N-1 ones, are taken into account. The planning methodology takes into account several possible scenarios developing in the future and computes dynamic robust expansion plans where short-term reinforcements are common to all scenarios and reinforcements computed for the long term are specific to each scenario, see (Barroso et. Al, 2007).

Ownership

New transmission facilities that need to be built are auctioned. Companies competing for being assigned the construction and operation of facilities are private national and international ones. However, auctions only started taking place in 1998 to drive down the cost of development of the grid. Before, the grid was owned by national and State public companies. Nowadays, more than 40 private transmission companies own some assets in Brazil representing in overall terms more than 40% of the grid. Competition among transmission companies in auctions has driven prices paid for the construction, operation and maintenance of new assets down. Nowadays, there are lines for which prices are below 50% of the maximum price established by authorities.

Thus, the regulation of network ownership follows an ISO model, whereby new facilities are owned by private companies that are separate from the SO, ONS, and the network planner, EPE, which are public companies. Network maintenance actions are carried out by transmission companies but are planned by the SO, ONS.

Financing

Transmission companies' risks are very limited, since revenues are preset to the bid made by these entities when winning the auction for the construction, operation, and maintenance of the corresponding assets, see (Barroso et. al, 2007). Counterparties are creditworthy, i.c. the Brazilian state. Besides, the construction of relevant transmission infrastructures is deemed a national priority, which involves that times for obtaining the required permits are short. The only relevant risks that investors are subject to, are those associated with delays in the construction times of these infrastructures and other problems affecting the availability of assets once they have entered into operation. Besides, there is a national development bank, the BNDES, which is very active in the financing of these infrastructures.

All this results in debt issued in very favorable conditions being the main source of funds for private transmission companies, some of which are being created after winning in an auction the ownership of their first assets. Given that the remuneration of projects is still attractive, previous earnings made by these companies almost complete their financing needs. Equity financing is significantly smaller in most of these companies.

Cost allocation

Revenues of transmission owners are set at the time they win in an auction the right to construct, operate and maintain assets. Winners in these auctions earn the bid they have made, which comprises an annual rent for each of the 30 years of the concession period. During the first 15 years of the contract, the transmission owners earn a constant annual rent that is only increased annually according to inflation rates. In the second 15 years of the contract, annual rents are halved. Besides, some efficiency incentives exist related to the time of entry into operation of assets and their availability. Transmission companies must pay penalties if they do not comply with the date of entry into operation agreed for a facility. Besides, they may earn extra revenues or pay penalties depending on whether the level of availability of their assets is above or below a reference one established, respectively, see (Barroso et. Al, 2007).

Then, revenues of transmission companies are not linked to the market revenues made by their assets, or the benefits they produce. Congestion revenues corresponding to transmission assets are not employed to reduce the level of regulated transmission charges. Instead they are paid to hydro plants having signed cross-zone supply contracts (contracts where the points of injection and delivery are in different price zones).

Two separate methods are used to allocate the cost of the used and unused fraction of transmission assets. The cost of the used fraction of assets is allocated to consumers and generation companies proportionally to the average incremental use they are deemed to make of these assets. The Aumann-Shapley method is used for this, see (Junqueira et al., 2007), and (Dietrich et al., 2008). Locational charges computed in this way are modified to achieve a 50%/50% split of charges between generation and demand in the system. The cost of the unused fraction of the grid is levied on consumers through postage-stamp charges. Transmission charges applied are structured as capacity ones, i.e. they are defined as charges per unit of installed capacity of generators or peak load of demand.

Transmission charges paid by conventional generators in each area of the system are computed based on the best estimates of authorities of the future development of demand and generation. The level of these charges is set for the first ten years of operation of new conventional generators before new energy auctions involving these generators take place. Therefore, the actual pattern of generation, and demand in the system may differ from those assumed when computing charges paid by these generators. The difference between revenues collected from these charges and network costs caused by these generators is absorbed by demand, whose charges are modified as needed to complete the recovery of the cost of the network. On the other hand, before the construction of new renewable generators is decided in auctions, these are only provided with an estimate of transmission charges to be paid by them in each area. Actual charges levied on them are only computed once auctions have taken place and the real distribution of generation in the system, as well as other conditions applying in reality, are known.

Market and System Operation

Security of supply: energy auctions

Due to the large amount of generation capacity installed in the Brazilian system, mainly hydro, potential supply problems are not related to the lack of generation capacity but to the lack of available energy during dry periods of time. Generation adequacy is achieved through a system whereby all load in the system needs to be contracted in advance of real time. Load in the system must prove to be 100% covered by energy supply contracts. Penalties are applied by the regulator if this is not met. For captive consumers, their Distribution companies must contract their energy consumption at energy auctions. Non-captive consumers decide whom to contract their energy supply with.

New energy auctions, where potential generation investors bid for long term contracts (15 to 30 year long), and existing energy auctions, where load enters into contracts with a duration from a few months to eight years with existing generation, are organized to supply part of the load served by distribution companies, as well as the load of all those other eligible (large) consumers willing to participate. Contracts granted in new energy auctions are for the delivery of energy to start 3 or 5 years after the celebration of the auction. The government may call auctions for new energy supplied by specific generation technologies whose development and deployment is part of Brazil´s energy policy.

All contracts signed by a generator are financial and must be backed by Firm Energy Certificates (FECs), which are issued by the Ministry of Energy and provided to generators each year. Therefore, energy sold by a generator through long term contracts cannot exceed the number of FECs it has been granted. FECs correspond to the sustained energy production of a generator each year when connected to the grid. Contracts granted can have the format of a standard financial forward contract, where generators earn an energy price for their FECs, or instead be energy call options, where an amount is stipulated to be paid for the availability of generation capacity (annual capacity payment) and energy supply is paid at another also stipulated price (related to declared variable operation costs). Given that supply contracts are financial instruments, they do not affect the energy dispatch.

Short term energy market

In the short run, generation and transmission capacity are centrally and jointly dispatched aiming to minimize total operation costs. Consumers and generation companies do not submit bids for this. Instead, their operation costs are estimated and considered by the ONS when computing the dispatch. The full nodal transmission grid is considered when computing the network constrained energy dispatch. Thus, nodal prices are computed in the dispatch, one corresponding to each node of the grid. However, for settlement purposes, four price zones are defined in the country. Then, only congestion affecting power exchanges among zones, as well as inter-zonal losses, are considered when computing prices applied on generators and consumers. A single price is applied within each zone. Existing price zones are North, North-East, South, and South-East and Centre-West. Congestion revenues result from the application of zonal prices, see (Porrua et. Al, 2005), and are earned by hydro plants having signed cross-zone supply contracts. A re-dispatch is run to solve infeasibilities resulting from the dispatch. The net cost of re-dispatch is recovered from consumers through the application of system services charges.

Hydrothermal coordination models are used to compute the optimal network constrained economic dispatch while optimizing the use of water across the relevant time horizon for the corresponding reservoirs. Uncertainty is represented in these models through multistage, stochastic, trees.

Ancillary services provision

A single TSO, ONS, exists within the system. Ancillary Services (AASS) available within the Brazilian system include the provision of reactive energy by generation units required to act as a synchronous compensator, the Automatic Generation Control (AGC), the black start service, and special protection systems. Regarding balancing services, regulation reserves of different activation times are provisioned by the SO to be able to face potential imbalances. All these are managed by ONS. No regional coordination exists in the provision of AASS, which is managed at national level. Power exchanges with the neighboring systems are also monitored and controlled by the ONS in order to stick to scheduled exchanges. All transmission facilities are subject to technical rules and grid procedures designed by the regulator ANEEL.

There is no regulated reserve market in place in Brazil. The System Operator, ONS, mandates each generator in the system to provide a certain amount of reserves. The provision of reserves is not remunerated. Only the cost of investments carried out in order to be able to provide this and other AASS is reimbursed. Then, generators mobilizing regulation reserves are paid the net amount of energy they are producing at market prices. These payments are settled monthly.

2.3. Generic electricity case studies

2.3.1. Merchant GM

Merchant investments can be described as 'market-driven' investments. This network investment model provides an alternative means to attract investments in addition to regulated investments, where the allowed revenue for transmission network is based on rate of return set by investment regulation such as cost based or performance based. In some cases, merchant investments are used to bridge non-coordinated regulatory regimes between different countries. The attributes of the merchant transmission investment model are decentralized ownership and a market-based revenue mechanism (Joskow and Tirole, 2005). Merchat investments are allowed and taking place in several of the GMs annalyzed here, like the USA, the Central American one, and in some specific cases in Europe.

Design

Within the European System, transmission project promoters can apply for exemptions from regulated transmission pricing and access. These exemptions are to be granted by European regulatory authorities, either national or European ones. In the USA, federal authorities (FERC) can authorize mechant projects, as well as the negotiation of access tariffs charged by the project developed to perspective users (substituting congestion rents earned by the owner otherwise). I both cases, authorization of these projects takes place on a case-by-case basis, provided these projects complain with a set of conditions.2

Ownership

There are three merchant transmission ownership models. Firstly, in the TSO ownership model, two neighbouring countries TSOs, interconnected by the merchant transmission project, are the natural candidates to invest. However, this ownership model presents a long debated potential conflict of interest between regulated and non-regulated activities. In Europe, it is mandatory to create a separate project company for merchant transmission investment in order to be exempted under European regulation.

Secondly, in the generator ownership model, the ownership structure entails the presence of dominant generators at the two ends of the merchant interconnector. A new line in general increases competition in the market by providing more interconnection capacity. However, if the line is owned by a dominant generator, the market concentration of dominant generators might rise.

Thirdly, the independent developer model refers to merchant transmission project invested and built by a third party that is not related with incumbent generators or TSOs more commonly adopted in the U.S. This model provides the alternative ownership solution to avoid the potential problems from the TSO and generator ownership structures.

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[2] According to European regulation, DC interconnectors and in exceptional cases also AC interconnectors can apply for exemption for a limited time period from regulation (Regulation 714/2009 and Directive 2000/72/EC), see (EC, 2009 b), and (EC, 2009 a) concerning third party access, use of congestion rent, unbundling and transmission network tariff. The process starts with an exemption request submitted by the investor to the relevant national regulated agencies (NRAs). The involved NRAs have to cooperate and jointly decide for the grant of exemption, or delegate the decision to the Agency for the Cooperation of Energy Regulators (ACER). The NRAs, and in some cases other national institutions, have jurisdiction over exemption granting and can impose additional conditions. In the case where agreement could not be reached between involved NRAs, ACER may decide on their behalf. Once the national decision is taken, it is subject to EC review. European commission retains the right to approve the exempti on or request modification or withdraw the decision. This check by the European Commission provides an additional instrument of European coordination with respect to merchant interconnectors.

In the USA, the Federal Energy Regulatory Commission (FERC) is entitled to approve merchant projects adopting a case-by-case approach and to negotiate their tariff rate. Merchant transmission developer could first allocate a portion of network capacity through anchor customer presubscription. An anchor customer is a generation company that signs contract for the merchant line capacity and agrees to share part of the network development cost. The merchant transmission project developers could engage in an open solicitation of interest to potential customers by issuing a broad notice including transmission developer points of contract and pertinent project dates, as well as sufficient project’s technical specifications and contract information.

Financing

In many systems where merchant investments are possible, including the EU and Central American ones, business models concerning merchant investment can be identified in two different types:

- Firstly, fully unregulated merchant projects, which run entirely on commercial basis[3] and whose revenues exclusively rely on market mechanisms. For these projects, the most common financing approach is project financing with corporate guarantees. Again, financing is channelled via a separate project company. Usually, the shareholders provide guarantees for the lenders to support the project.
- Secondly, projects with a mix of merchant and regulated elements. In this case revenues are determined not only by the congestion rent of the interconnector, but also by the conditions set by local regulatory authorities. For projects with a mix of merchant and regulated elements, the most common approach is corporate finance channelled to a project company. Although project finance is possible through the creation of a separate project company, the money is usually injected from the TSO to the project company.

Unregulated merchant transmission investment generates revenue based on the projected price differences in the markets of the two connected nodes or areas. In the long term, prices in the two areas are volatile and subject to uncertainties. Therefore, merchant transmission investments are exposed to a higher revenue risk than regulated investments. Sometimes, price regulation elements are included in the merchant investment authorization to protect customers from the implications deriving from the merchant developer's right to earn potentially very high congestion revenues. For example, a cap on the upside revenue is set for the BritNed interconnector (while missing a floor on the downside, so that only the investors are exposed to asymmetric risk) in Europe. Furthermore, merchant projects revenue flows are subject to the risk deriving from parallel regulated line that could be built in the future. Consequently, higher share of expensive equity are required and, compared to regulated investment, the cost of capital usually results higher.

Cost allocation

In general, the traditional price regulation does not apply on merchant transmission investments. The revenues of merchant transmission network are generated from the users of the interconnector capacity, rather than directly from captive customers who are subject to transmission tariff schemes. The tariff scheme used for regulated investment is not relevant in merchant transmission context.

Technical and Market Operation

In general, the merchant interconnection market is organized by auctions or long-term contracts. There are two types of auctions: explicit and implicit auctions. Explicit auctions take place in cases where the interconnection transmission capacity is auctioned on a separate and independent marketplace in respect to where electrical energy is auctioned. Explicit auctions are a simple method

[3] In Europe these include market and regulated elements with specific exemption of Regulation 714/2009, see (EC, 2009 b).

to handling the capacity auctioned on the interconnections in Europe. The capacity is normally auctioned in portions through annual, quarterly, monthly and daily auctions. In case of implicit auctions, the transmission capacity is integrated in the marketplace where electrical energy is auctioned. This is typically applied in day-ahead markets where the transmission capacity between price areas (bidding zone) is integrated as a constraint in the day-ahead pricing mechanism when matching demand and supply. This means that the resulting prices per area reflect both the cost of energy in each internal price area, as well as the cost of congestion.

Long-term contracts can be organized by open season or open solicitation. In an open season, merchant transmission investors sell capacity prior to the network construction through competitive auction process that is deemed transparent and fair by the regulator. Winners of the bid are rewarded with long-term contract. The open season has two phases. In the first phase, network developer assesses the capacity needs of market. In the second phase, capacity contract is signed with the participants who offer best bids. The open solicitation method is now adopted by FERC to stimulate merchant transmission investment in the USA. Through the open solicitation of interest, a subset of customers can be identified by the developer. In open solicitation, a broad notice should be issued to ensure that all potential and interested customers are informed of the proposed project, and including pertinent project dates, contract details, and sufficient technical specifications to inform interested customers about the nature of the project. Also a criteria approved by regulator could be adopted to select potential customers.

2.3.2. Small and local case studies

In the small and local governance model, four case studies from different markets are selected to reflect the potential interactions of the local distribution system with the transmission system. Focus is put on the technical and market operation of distributed energy resources, and in particular demand response, in view of maintaining the system balance (therefore the structure of part 3.3.2 is not similar to previous formats). In the paradigm where the distribution network is becoming increasingly important with the integration of more generation, consumption and storage, the relation and information exchange between DSO and TSO becomes more complex and relevant.

Danish Controller Pilot Project

The Danish cell controller pilot project was developed by the Danish TSO Energinet.dk from the year 2005 to 2011 and deployed in a pilot study region (Energinet.dk, 2011). The project not only demonstrated the capability to maintain system reliability with distributed generation resources connected to the distribution grid and power flow applications, but also recognized the role of coordinated control of local assets as a single large power plant i.e. a virtual power plant which could provide ancillary service at select location within distribution system.

The 60kV distribution grid behind the 150/60kV transformer is defined as an autonomous cell with a fully automated cell controller. This controller realizes fast data communication to all distributed combined heat and power plants, wind turbines, transformers and load feeders within the cell area. In general, cell controller covers a range of functionalities: measuring and monitoring of load and production, taking control actions on generators, load feeders and main power circuit breakers.

High level capability in general deals with islanding the cell and providing active power balancing services to the transmission service operator. The potential market operation services involved in the high level capabilities are i) the TSO to dispatch assets for kW/kAR control across the primary interconnect and ii) presents the BRP operator with a list of assets from which groupings can be selected for inclusion in day-ahead, power balancing, and primary regulation market.

Low level capabilities are defined in four levels. The functions deployed in level 3, Cell Controller, are system wide control including voltage control, import/export control, spinning reserves, mode management and network topology module, which implement and coordinate all the high-level functions. The substation controller in Level 2 manages communication to individual interface controllers and acts as data aggregator towards the cell controller. The interface controller in level 1 abstracts away the particular user interface of the asset controller and allows the cell controller to operate with a limited set of object classes without the need to implement interfaces to any possible asset controller. On the lowest control level 0, local asset controls takes pl ace. Level 0 provides a set of basic functionalities.

Belgian TSO – Tertiary reserves Dynamic Profile

The R3 Dynamic Profile is designed by Elia System Operator (Belgian TSO) to allow distributed energy resources (DER) to participate in tertiary reserve, which is going to be implemented as a pilot project from 2014 (Elia, 2013).

The salient feature of R3 Dynamic Reserve is that it allows grid users to the distribution grid and transmission grids to provide tertiary service, through a third party aggregator or as grid users directly. Activation will be called upon in an “all or nothing” modus or the comple te volume will always be required. The contracted volume needs to be fully ready within 15 minutes of the activation. R3 Dynamic Profile is a capacity-fee only product, so there is no fee paid for activation. Elia pays the supplier per MW per hour for the year the capacity is made available. In imbalance settlement, the perimeter of BRP is not corrected with the effectively activated energy.

Prequalification for grid stability is performed by DSO and TSO to give status of the access points. The access points that endanger grid stability will not be allowed to participate in tendering.

Great Britain- Demand Side Balancing Reserve (DSBR)

Demand Side Balancing Reserve (DSBR) is designed by National Grid to provide additional support to the transmission system operator for balancing the transmission system against a background of tightening capacity margins (National Grid, 2013). The potential participants are non-domestic consumers with the ability to reduce or shift demand and owners of small embedded/on-site generation accruing to a supplier’s consumption account for minimum an hour. The service provision is only called upon during winter period.

The designed scheme is a price-based service, in which no obligation is introduced for responding or penalties for not responding. Price signal acts as the only incentive for service delivery. The DSBR can be provided by non-domestic consumers directly or through third parties such as suppliers, aggregators or other intermediaries. In order to incentivize the participation of intermediaries, it is proposed to involve suppliers and aggregators tendering who provide large volumes of DSBR an administrative fee.

The capability to provide generation increase or demand reduction by DSBR participants should be declared against a baseline for at least an hour between 4pm and 8 pm on non-holiday weekdays from the month November to February. The proposed minimum demand reduction capability of individual DSBR units is 1 MW. Tender process is proposed to procure DSBR, similar to other balancing services.

Demand Response Experience in the USA

In the USA, market based demand response refers to the demand response participation that can set market clearing price, rather than only reactive to market signals. The resources are dispatched by the system operator. In some electricity market under FERC regulation, three types of market based demand response service provision are observed: capacity resources, energy resource, and reserve resource as ancillary service (Hurley et al., 2013).

In its role for capacity resource, demand response service providers need to ensure the capability of reducing load in the timeframe between within 30 minutes to two hours, and receive capacity payment. Demand response participation in forward capacity markets are developed by some regional system operator to procure sufficient capacity from generation resource to ensure system reliability. A special case resource program was set up as a demand capacity product by the New York ISO (NYISO), which allows demand response providers, who aggregate many retail customers, to qualify as capacity resource in the program.

As energy resource, demand response providers may bid directly into day-ahead or real time market to be dispatched for economic reason. The energy market price is paid to service providers. There are two types of demand response participation in energy market as energy resources. The primary means is for individual or aggregated customers to reduce load during high energy price periods. The supplementary means is through increasing load during low price hours.

Demand response that is able to be shed in 30 minutes or less can participate in ancillary service provision. In general, traditional dispatchable demand response resources are suited to provide non-spinning reserves, which require 30 minute response time.

A load resource program was developed as a spinning reserve by ERCOT. It could be activated by an automatic frequency trip directly by ERCOT. In its Emergency Interruptible Load Service program, demand responses which include distributed generation that can export to the grid are contracted by ERCOT at fixed price through a solicitation held by ERCOT.

New types of demand response are increasingly providing regulation and load following functions. VCharge is a pilot demand response provider of frequency regulation, which aggregated 250 electric thermal storage heaters. VCharge acts as a “Virtual Power Plant” that buys energy during low price hours and provides ancillary service such as frequency regulation to the transmission system operator. VCharge provides up to 600 kW of balancing service to PJM with a 2 second responding time to the area control.

2.4. Non-electricity sector experiences

2.4.1. Gas sector

Gas is a utility similar in its nature to electricity. However, it exhibits some relevant differential features, the most important of which is that, contrary to what happens with electricity, gas can be stored. The regulation of gas systems varies significantly from one region to another. While there are regions where the provision of gas is liberalized, i.e. markets exist, like in the USA, or parts of Europe; in others the supply of gas is organized in a fully regulated, centralized way through vertically integrated utilities which, in many cases, are controlled by national or local governments. This analysis and description focuses on the current situation in Europe, which in many aspects is quite advanced compared to that in other regions.

Design

In Europe, the cross-border expansion planning process in gas network is similar to electricity transmission. Priority infrastructure goals are set on European level and translated into development plans by means of TSO federation ENTSO-G Regulation No 347/2013). The different characteristics that distinguish gas network design from electricity are threefold. Firstly, international gas projects usually involve more than two partners resulting in higher complexity compared to electricity. This is explained by the limited opportunities for gas production in Europe. Secondly, gas projects usually seem to be deployed faster, due to its underground nature and therefore less public opposition. Finally, gas transmission congestions are currently more of a cross-border issue than a national one.

The coordinating parties for the European gas transmission system are: European Commission (EC), Agency for the Cooperation of Energy Regulation (ACER) and European Network Transmission System Operators for Gas (ENTSO-G), Council of European Energy Regulators (CEER), National regulatory authorities (NRA) and national transmission system operators (TSO).

The nature of planning procedures for gas and electricity transmission expansion is similar. The planning procedure can be divided in three main parts:

- Identification: project promoters which can be TSOs, merchant investors or a group of TSOs and merchant investors, identify the need for a new connection. The objective for the new connection can be security of supply, as well as purely economic.
- Proposal: the identified expansion is proposed to the National Regulating Authority (NRA). In case that the expansion spans over several countries, it is proposed to the according NRAs.
- Approval: in the approval phase the social and environmental impacts of the proposed connections are assessed by the NRAs.

Ownership

Similar to electricity, three ownership models coexist in EU member states: ISO, ITSO (also FOU, Full Ownership Unbundling) and LTSO (also ITO, Independent Transmission Operator) (Politt, 2011).

Independent Transmission System Operator (ITSO)

In this structure, there is one company responsible for both ownership and operation of the transmission grid, which is completely separated from supply or production activities. ITSO model offers the institutional advantage that allows fair competition among suppliers and coordination in long term planning and investment decisions between the transmission operator and system owner segments of the business. The disadvantage can be the political resistance against allowing complete ownership unbundling of transmission assets, and difficulty in conducting inter-regional coordination. In Europe, this model is implemented in countries such as Denmark (Energinet), Belgium (Fluxys), Great Britain (NG Gas).

Independent System Operator (ISO)

Transmission networks remain under the ownership of energy groups, but the operation and control are transferred to an independent operator. There is a clear distinction between the organisation that is responsible for operating the transmission grid and those that own and maintain it. The ISO model has two main advantages. Similar to the ITSO model, it would remove incentives for network operators to favour their affiliated suppliers. Secondly, a single ISO could manage the network of multiple transmission owners. They could also remedy the inter-TSO coordination problems. In Europe, ISO model is chosen in countries such as Ireland (Gaslink), The Netherlands (GTS), Sweden (Svenka Kraftnet).

Legally-unbundled Transmission System Operator (LTSO)

There is a company responsible for both ownership and operation of the transmission grid. However this company is a subsidiary of a parent company that also holds subsidiaries involved in generation, distribution and/or retail segments. LTSO model is largely opted in Europe, in which gas system operator is to some extent integrated with gas suppliers. For instance, countries such as France (GRTgaz and TIGF), Italy (Snam Rete Gas), Norway (Nowega), Hungary (FGSZ) and Czech (Net4gas) have applied this model.

Although unbundling process and system operator/owner relation in gas and electricity sector exhibit similar patterns and ownership structures, electricity sector in the EU has progressed further moving towards fully unbundled ITSO and ISO models.

Ownership of Storage

Gas storage also follows Third Party Access (TPA) regulation, but Member States have the liberty to choose the type of TPA on gas storage capacity. Regulated TPA or negotiated TPA can be opted, as long as non-discriminatory access to gas storage capacity is ensured. In the regulated case, the gas storage users pay a regulated tariff for gas storage services. In the negotiated case, the tariffs are negotiated between the storage operator and the customer. For example, most EU member states (p.e0 France, Germany, the Netherlands) adopted negotiated TPA, whereas for Belgium regulated TPA is applied. In some cases, such as in Denmark and France for TIGF, storage is still controlled by the TSO.

Financing

Sources of financing

The same attributes are observed in terms of financing means in electricity and gas sectors. Similar to electricity transmission network, regulated investment is the dominant business model for the gas network. Regulated investment usually takes corporate financing. Merchant investment is adopted for specific interconnections. It often uses project financing with corporate guarantees.

Electricity and gas sector share the same sources of financing. Credit ratings from TSOs in Europe in electricity and gas sectors are mostly in the investment grade range, which enables TSOs to borrow at a favourable condition. For both the electricity and gas investments, there are clear incentives to follow the European guidelines for infrastructure expansion via the different funding mechanisms to facilitate financing or apply direct grant funding.

Differences between financing in electricity and gas network are found in leverage level and cost of capital. For some gas TSOs, located in market with overcapacity, a lower leverage level is observed. As far as cost of capital is concerned, electricity sector has a lower cost of equity than the gas sector. The (CEER, 2013) (add in Bibliography) shows that in Europe in 2012, the real cost of equity for electricity sector is between 3% and 8%, and between 1% and almost 9% for the gas sector.

Cost Allocation

Network tariff schemes

There are two models applied for a TPA to the gas transmission network (Ruester, et al. 2012):

- Point-to-point model: this model limits the booking of transmission capacity to specified combinations of entry and exit points (linked contract path from entry to exit points called 'the contract path'). It restricts the flexibility of network users in the use of their capacities. As a result, liquidity may be reduced in the market. The point-to-point model shows analogy with bilateral contracts in electricity which results in a contracted path network pricing.
- Entry-exit model: in this model, gas can be injected at the entry points and made available for off-take at exit points on a fully independent basis. Network users are able to book (contract) entry and exit capacities independently. A 'full entry-exit model' has a virtual trading point (VP) that facilitates trade of gas between network users. The entry-exit model is equivalent to pool based electricity markets where generating units and loads are able to subscribe for injection and off-take capacity independently.

Regulation (EC) 715/2009 specifies that gas transmission system operators should have a decoupled entry-exit system in place, with the objective of creating an open internal market for natural gas in Europe, promoting competition and serving the objective of non-discriminatory network access, see (EC, 2009 c). Several member states use an adapted model of the entry-exit model.

The gas sector is currently evolving towards the exit-entry model with explicit auctions for cross-border capacity. Besides, there are also countries that still have the point-to-point network access model. Often two different network access models are used within a single country, such as applying an entry-exit system for domestic transmission but a point-to-point for cross-border trade. This arrangement does not only reduce liquidity in both markets but may also discriminate against foreign network users by creating barriers to entry.

Market and System Operation

The safe and continuous operation of the pipeline system comes down to keeping the pipeline-pressure levels or the line-pack levels within safe operational limits of the pipeline system. The most important aspects of the technical operation of gas networks with respect to regulation are balancing and congestion management. These issues are closely coupled with the operation of storage and line-pack flexibility (Keyaerts, 2012).

The total gas trading amounts to one third more than total gas demand in the EU. Over The Counter (OTC) trading on gas hubs constitute most of gas trading, although the market liquidity is low. A churn rate, which expresses the ratio of traded quantities over physical quantities consumed in the area served by the hub, of 15 is associated with a liquid market.

Exchange based trading, on the contrary, accounts for less than 10% of the trading of gas. The wholesale market encompasses the spot market, forward market and the futures market. Today, gas is exchanged on APXNL, APX ZEE, APX UK, Powernext, EEX and Endex (futures only) platforms. Most platforms emerged only few years ago and are still not widely used.

Capacity allocation and congestion management

Congestion in gas markets commonly occurs on interconnection, storage capacity and LNG facilities. To deal with congestion, the existing approach in many countries is to allocate at least a part of the capacity by auctions and pro-rata access, in parallel to long-term capacity reservations. The same approach is taken for storage capacity. Unlike electricity, explicit auctioning remains in use for contracting annual and monthly capacity with harmonized rules in different regions. However, available capacity in gas transmission was found limited due to network congestion created by capacity hoarding, as a consequence of pre-liberalisation legacy contracts and ineffective congestion management practices.

On 24 August 2011, the European Commission adopted rules to reduce congestion in European gas transmission pipelines. The rules will amend the existing Annex to the Gas Regulation (EC) no. 715/2009. ENTSO-G is finalising the Network Code on Capacity Allocation in order to facilitate more efficient capacity allocation to achieve the single gas market.

To ensure efficient allocation of interconnection capacity, the draft network code specifies that auctions will be the default mechanism for allocating firm and interruptible capacity services for each time interval. In addition, the network code also specifies the use of standard capacity products on yearly, quarterly, monthly, daily and within-day. Furthermore, the network code proposes a translation of explicit capacity allocation rights into “sophisticated products”, which reflect system operation practices or market needs.

To solve above mentioned contractual congestion, better congestion management instruments are being suggested in the network code: capacity increase by oversubscription and buy-back arrangements, firm day-ahead use-it-or-lose-it (UIOLI) clauses, long-term UIOLI. Furthermore, interruptible capacity can be sold after all firm capacity is allocated. Although this does not offer the same guarantees as firm capacity, at many interconnectors interruptible capacity proves as reliable as firm capacity. Finally, the creation of a secondary market in transmission capacity is suggested, where companies that have spare capacity can offer it to other market participants.

2.4.2. Non-energy case studies

In the non-energy governance model, relevant characteristics from the aviation, telecommunication and water industry are investigated towards their relevance for electricity transmission network regulation. The aviation sector embraces relevant experiences on international collaboration in terms of air traffic management, route planning that resembles electricity network design and its market-based improvement to grant slots for scheduling flight landing or departure that can be related to market operation in electricity sector. The water industry contains interesting experiences in ownership and financing of infrastructure. The telecom interconnection is a relevant from a cost allocation perspective.

Aviation

The aviation sector holds two building blocks which can be of particular interest for the electricity sector, i.e. design and market operation. Information is used from reports of the (European Commission, 2013) and (Eurocontrol, 2011).

Network Design

In the aviation industry, three main groups of actors can be distinguished: the aircraft manufacturing industry, airlines and airports. Further important stakeholders are the air traffic control, which is heavily regulated by the regulatory governmental bodies. Air traffic control is the main investigated topic, since it is evolving from a national to an international level playing field, and therefore interesting to look into those alterations from an electricity sector perspective.

The international regulation is carried out by ICAO, the International Civil Aviation Organization which promotes the safe and orderly development of international civil aviation throughout the world. It sets standards and regulations necessary for aviation safety, security, efficiency and regularity, as well as for aviation environmental protection. The organization serves as the forum for cooperation in all fields of civil aviation among its 191 Member States. In Europe, Eurocontrol is the organization to promote safety of air navigation for the 41 Member States.

A common practice to divide the sky for air traffic management in Europe is to divide by national boundaries. The key to improve the performance of air traffic management is to divide the functional blocks of sky according to traffic flows for improving efficiency of airspace utilization. Therefore, two Single European Sky packages which coordinate design, management and regulation of airspace in Europe were passed by European commission. Eurocontrol contributes to draft the rules for Single European Sky regulation, assist Member States to exercise their regulatory functions and identify the need for new regulations.

In terms of route planning, the European Route Network Design Function is set up to achieve an improvement plan for the virtual network where airspace design principles are taken into account. The key factors the plan has to take into consideration are: safe and efficient operation of air traffic, environmental impact, capacity, flexibility and responsiveness. These design principles are utilized to establish an efficient configuration of airspace structures, to present and forecast of traffic demand, the connectivity between the terminals, the possibility to operate along user require d routes, the development of free route airspace and the selection among multiple routes. The plan shall rely on a cooperative decision making process, in which all member states remain responsible for the development, approval and establishment of the airspace structures. Next to the achievement of the improvement plan, another main objective of Eurocontrol is to ensure interconnectivity and interoperability of the route network with all regions, as well the regions under the responsibility of Eurocontrol as worldwide interconnectivity.

Market Operation

In European aviation there is a shortage of 'slots'. A slot is the right that grants the owner to schedule a landing or departure during a specific time period. Most airports are operating at full capacity. In the European Union, slots are granted on a 'grandfathered' basis, they are allocated to the airlines that have been using them historically. These allocated slots can be traded in some countries on a secondary market, i.e slottrade.aero. The existing system impedes competition but there is a strong pressure from incumbents to maintain this system. The current congestion problems may result from malfunctioning allocation of these slots, causing an airport to unnecessarily expand operation. A market for these slots could be beneficial for competition and welfare.

The European Commission has led an investigation concerning different new policies in granting slots. The opted policy doesn't change the administrative nature of the current policy but does add a number of improvements, including market-based improvements. Firstly, the definition of 'new entrant' had to be broadened. Secondly, the slot allocation process has to be made more transparent and the slot coordinator more independent. Thirdly, the slot allocation process has to be compliant with the reform of the European air traffic management system. Finally, the 'grandfathered' basis of slots has to be amended and the late return of slots to the pool has to be discouraged.

Telecommunication

The telecom sector has some features on cost allocation which provide insights for electricity transmission, in particular concerning the management of the interconnection among grids. The costs of interconnection have traditionally been recovered from the party making the call, this on the assumption that the calling party is the cost-causer (CRA, 2012). Therefore the practice of the calling party pays predates the establishment of state or federal regulation. When the traffic is balanced, the party that receives a call pays for receiving the call. In the case when traffic is not balanced, the carrier on which the majority of traffic originated has made payments to the terminating carrier.

Ideally, interconnection payment schemes in the telecommunications industry should be based on market forces and reflect the fact that the benefits of phone calls are not evenly distributed between callers and receivers. They should also capture the positive network externalities associated with the Calling Party Network Pays principle so as not to encourage the underutilization of telecommunications services. They should impose capacity charges that reflect traffic sensitive costs instead of using fixed end-user charges to recover termination costs. This is similar to the challenges of electricity transmission.

Water

The water sector in the USA contains two features in ownership and financing which are relevant for electricity transmission (Finger and Künneke, 2011). Already facing financing challenges today, the U.S water industry has developed some novel financing tools which could shed light for future transmission network investment.

Ownership

The production and transportation network of water industry are bundled and water utility is a natural monopoly. Around 90% of the water networks around the world are therefore publicly owned and operated. The most important exception in Europe is the water industry in England and Wales, where full privatization is accomplished. In the water industry in the USA, municipal ownership is the predominant structure, while private or investor owned water utilities account for 15% of the total water sale revenues.

Financing

Some issues in the water utility industry financing resemble that of the electricity sector, such as the increasing need for new investment and constrained government budget, in particular for countries with high share of public ownership. Therefore innovative financing practices are under development to target these problems and these might be relevant to investigate in the light of the electricity sector.

Given the fact that water utilities in the USA are predominantly municipality owned, municipal bonds have been a primary source of financing means. Though water utilities have maintained high bond ratings, there are critical conditions that impose challenges for future financial conditions.

First, due to government budget constraints and high municipal deficit, the availability of such bond in the future is put into question. Secondly, revenues of water utilities are highly dependent on the sales of water volumes. Water conservation, which might reduce the water consumption levels, represents a risk for the water utilities' earning prospects. Some innovative financing tools are therefore under development in the USA to meet the new investment need (EY, 2013):

- Special subsidized bonds issued by federal government such as Build America Bonds
- Private activity bonds by or on behalf of government at local or state level for private user project financing
- Financing from infrastructure equity fund
- Loans from federal government that target water utilities

3. Methodology for the assessment of governance models and identification of promissing elements

In order to meet the objective to identify the most promising elements from the 11 described governance models, an objective evaluation of these models is conducted. This chapter describes the theoretical methodology which has been used for this purpose and has been presented and discussed on the WP5 public workshop in May 2014. The results of the analysis are described in further chapters, i.e. the preliminary assessment results in chapter 4 and the final results per BB in the chapters 5 to 9.

3.1. Consideration of objectives to be achieved by the Governance Models

Several building blocks have been indentified comprising relevant regulatatory aspects related to the transmission grid development, as stipulated in the introduction. The assessment of GMs and identification of promising options has been carried out according to these BBs in such a way as to assess the ability of a GM and its BBs to achieve a predefined set of objectives. Five objectives have been defined as those which a target governance model should pursue. These include the three key European policy objectives: **Sustainability, Competitiveness and Security of Supply**, together with two additional objectives: **Socio-political acceptability** and **Effectiveness**.

These same objectives are considered when assessing each BB within a GM. However, the relative importance of achieving an objective when assessing the performance of a BB within a GM may be deemed to vary across scenarios and BBs. Firstly, the importance of achieving an objective varies across the scenarios developed in the project (WP1). Indeed, not all objectives are equally important when assessing the performance of a BB in the context of a scenario. Cost efficiency may for instance be less of an objective in a small and local scenario, in contrast to a big and global scenario. Secondly, regulation within some BBs is more relevant than that within other BBs for the achievement of certain objectives. This results in two facts:

- The performance of regulation within each BB regarding the achievement of each objective (partial performance of each BB in a GM with respect to each objective) has a specific weight when assessing the overall performance of this BB. This weight may be different from that assigned to the performance of this same BB regarding the achievement of other objectives;
- Differentiated weights per scenario are assigned to the performance of a BB within a GM with respect to the several objectives.

As such, the partial performances in a scenario of each BB in a GM with respect to the several objectives may be weighted in to compute the overall performance of regulation of this GM for this BB and scenario.

Lastly, the performance levels of this GM for BBs are combined into a single performance level assigned to the entire governance model. The computation of the performance level of each GM with respect to individual BBs allows one to build a synthetic, or hybrid, best performing GM for each scenario, where regulation corresponding to different BBs may come from different existing GMs amongst the ones explored. Several points are clarified in the following sections.

3.2. Preliminary assessment

In the preliminary assesment, entire best performing GMs are identified. Each of the eleven explored governance models is assessed per building block. By combining the grades assigned to the level of performance of each GM for the several BBs, an overall performance level can be assigned to this GM. However, given that GMs are assessed for each of their BBs separately, new combinations of best performing BBs from different GMs can be theoretically assembled towards a best performing "hybrid" GM. Within the preliminary assessment, there are three separate analyses conducted.

3.2.1. Robust, scenario independent selection of a GM

Firstly, the assessment is conducted to identify the most robust, scenario independent, GM. This analysis aims to identify the most robust target GM, meaning the best performing governance model overall, regardless of the scenario considered. In order to identify this governance model, three steps are consequenty executed.

First, each individual BB, from each GM, is assessed according to its contribution to the achievement of the five objectives defined. This results in an assessment of the performance of each GM per objective, per building block. This step is repeated for each of the five defined objectives per BB.

Secondly, the overall performance of a GM regarding each BB is obtained by averaging the five scores obtained for the five defined objectives. This involves that weights assigned to the performance of the BB within the GM considered for all objectives are all the same. This process is repeated for the five BBs, which results in the assessment of the performance of each GM for each of the five BBs.

Finally, by averaging the performance levels assigned to a GM regarding all BBs, an overall assessment of the performance of each GM is made. The schematical overview of the steps taken in this assessment is displayed in Figure 3 below.

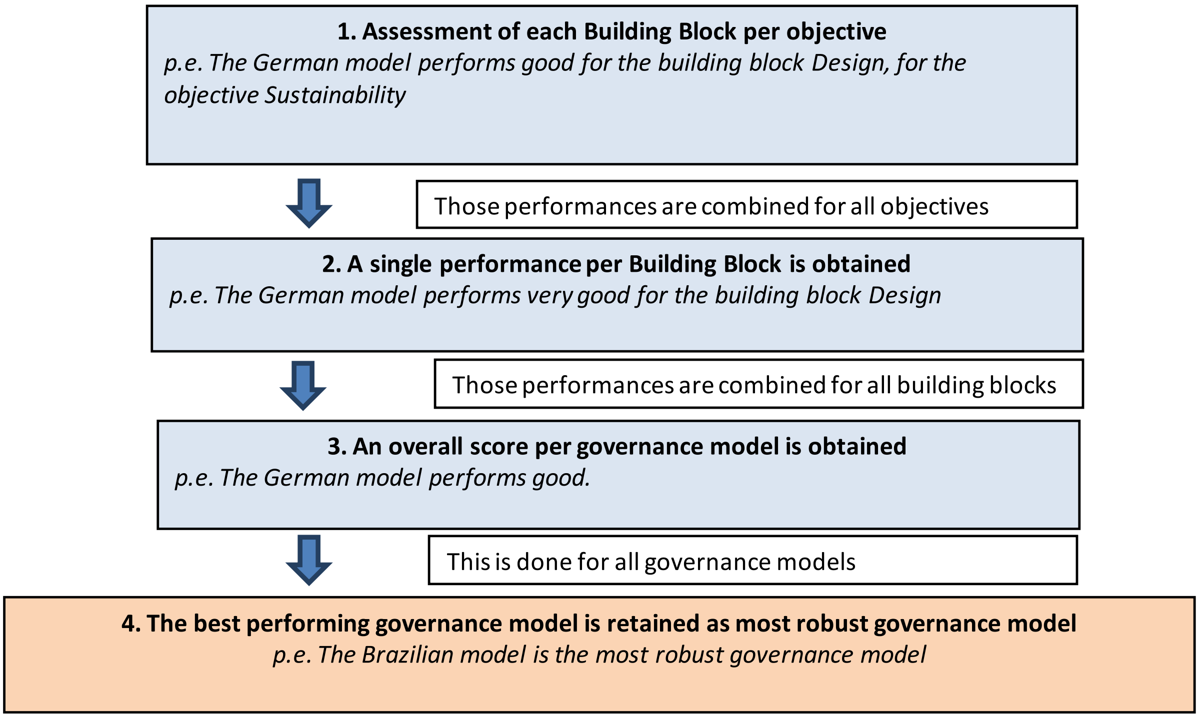

Figure 3: Schematic representation of the preliminary assessment process for the identification of the most robust GM

3.2.2. Robust, scenario dependent, selection of a GM

Alternatively, the assessment process can be applied considering a specific weight for the performance of each GM in achieving each of the objectives defined within each BB. This second analysis is carried out in order to arrive at a best performing GM for each of the WP1 scenarios amongst the existing GMs explored. The process to be followed in this case is depicted in Figure and build further on figure 3 from section 3.2.1.

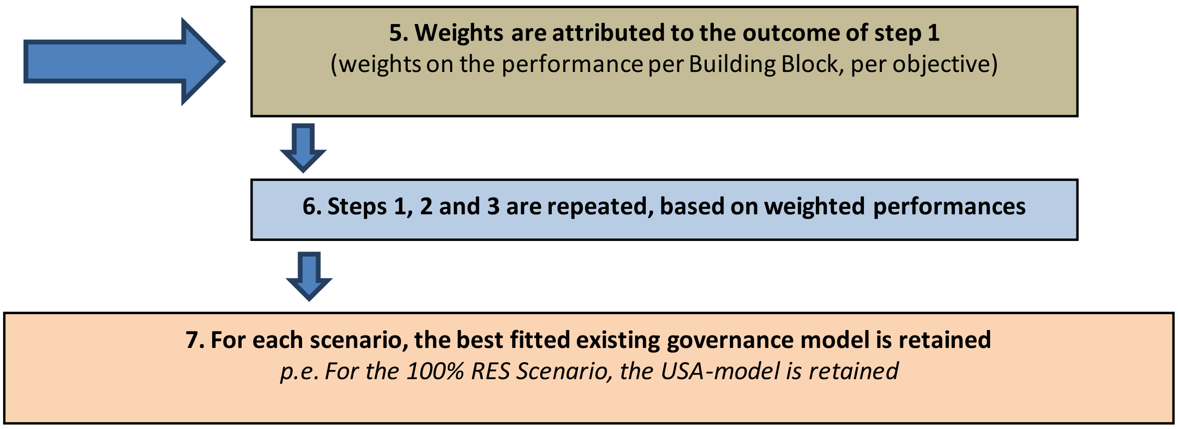

Figure 4: schematic representation of the preliminary assessment process for the identification of the most appropriate GM in each scenario

The assessment of the performance of GMs in specific scenarios, according to weights given to partial assessment levels of BBs in these GMs with respect to their contribution to the achievement of objectives, obviously requires the computation of the aforementioned weights. This is discussed in the following paragraphs.

Computation of weighting factors for the performance levels of BBs in a GM with respect to individual objectives

In order to compute the specific weight assigned to the assessment made of GMs regarding their contribution to the achievement of each of the objectives defined for each BB (result of step 1 mentioned above), two factors are considered:

- the importance of achieving each objective within a specific WP1 scenario;
- the importance of regulation within each BB to achieving each objective.

The first factor is determined according to Table 4, which attributes a level of importance to the achievement of each objective in each scenario. Only the importance of objectives competitiveness and sustainability varies across scenarios.

WP1 Scenarios / Objectives	Big and market	Large fossil fuel with CCS and nuclear	Large scale RES and no emissions	100% RES	Small and local
Competitiveness	HIGH (1)	HIGH (1)	HIGH (1)	MEDIUM (2)	LOW (3)
Security of Supply (4)	HIGH	HIGH	HIGH	HIGH	HIGH
Sustainability	MEDIUM (5)	MEDIUM (5)	HIGH (6)	VERY HIGH (6)	VERY HIGH (6)
Socio/political acceptability (7)	MEDIUM	MEDIUM	MEDIUM	MEDIUM	MEDIUM
Effectiveness (8)	MEDIUM	MEDIUM	MEDIUM	MEDIUM	MEDIUM

Table 4: Level of importance of the objectives in the different scenarios

Next, the rationale behind the allocation of levels of importance to objectives in scenarios is provided. Main decisions made in the allocation of importances to objectives, as displayed in Table 4, have been labelled with a number between brackets in this table. Reasons considered in each decision are identified in the list below by the corresponding number and are derived from the information resulting from WP1 of the project.

1) These three scenarios are focused on market solutions
2) Competitiveness is relevant in the '100% RES' scenario but less than in others because the economic efficiency of the system is deemed in the former less relevant than the environmental/ sustainability objective.
3) The competitiveness is a low priority in the 'Small and local' scenario because coordinated market solutions do not exist. Instead, each area deploys its own local solutions. More efficient solutions available in other areas to achieve load supply are ignored.

4) Security of supply is always a high system priority, as established in high policy principles.
5) In the ‘Big and market’, and ‘Large fossil fuel with CCS and nuclear’ scenarios, non-renewable energy generation, potentially harmful for the environment (nuclear, shale gas and CCS) is prioritized over RES generation.
6) Sustainability has a very high level of importance in the 100% RES and the “small and local” scenarios. In these, the minimization of the environmental impact of power system operation become the highest priority. Thus, environmental risks related to technologies like nuclear, shale gas and CCS are avoided and green solutions are preferred over the former. The importance of this objective in the ‘Large scale RES and no emissions’ scenario is high, since environmentally friendly solutions are prioritized in it. However, contrary to what happens in the ‘small and local’ and ‘100% RES’ scenarios, the importance of Sustainability in the ‘Large scale RES and no emissions’ scenario is not higher than that of other objectives like Competitiveness.
7) Socio/political acceptability has the same importance in all scenarios, since this objective relates mainly to the fit with the current EU context and the level of autonomy of institutions, which are aspects that are always very important in the short term, but are considered more flexible on the long term (i.c. 2050).
8) The relevance of the effectiveness of regulation in place, or ability of authorities to make it work swiftly, is also independent of the scenario taken into account. It relates to aspects like the complexity of regulation, its transparency, and its fairness. This objective has been given a medium level of importance because most, but not all, of the barriers to the ability to implement swiftly a mehod can be overcome with the passing of time.

Together with the importance of achieving each objective within a specific scenario, the importance of regulation within each BB to achieving each objective is to be considered to compute the relevance of partial assessments of a BB in a GM with respect to objectives. The reason why this second weighting factor is considered is the belief that not all BBs contribute to the same extent to the achievement of each objective. It is the purpose of the analysis discussed here to identify those BBs that are central to reaching certain objectives, since this should be emphasised in the assessment of GMs.

This second importance factor may be specific to each scenario, as well, since the relevance of electricity transmission varies across scenarios. In the scenarios “Large scale RES and no emissions”, “100% RES” and “Big and market”, transmission regulation is deemed to be very relevant, since in these scenarios power exchanges are expected to be large. On the other hand, in scenarios “Large fossil fuel with CCS and nuclear” and “Small and local” power exchanges are significantly smaller. Then, both network reinforcement and market coordination needs are expected to be lower as well. However, while in the scenario “Large fossil fuel with CCS and nuclear“ exchanges are expected to be non-negligible, since nuclear and efficient fossil fuel generation may not be 100% evenly distributed in the system, in scenario “Small and local” exchange flows can be expected to be even lower. Thus, the relative importance of transmission regulation may be lowest in the later scenario and a bit higher in the large fossil fuel generation one. The assumption on the importance of transmisison regulation in each scenario was made prior to the delivery of grid architectures per scenario by WP2 of the E-Highway2050 project[4]. However, WP2 results have been considered when setting the

[4] WP2 activities encountered some delays and in order for the WP5 to be able to progress, some assumptions had to be made 5.

priority, or importance, of the retained governance options for 2050 with respect to the deployment of the final grid architectures computed for each scenario. This is carried out through the analysis described in chapter 4.3.3.

The relevance of regulation releted to the several BBs for the achievement of objectives in scenarios “Large scale RES and no emissions”, “100% RES” and “Big and market” (see explanation later for the remaining other two scenario’s) is determined in Table 5.

Building Block / Objective	Network Design (1)	Network Ownership (2,3,4)	Financing (5,6,7)	Cost Allocation (8)	Market and Technical Operation (9)
Competitiveness	Very relevant	Medium	Medium	Relevant	Very relevant
Security of Supply	Relevant	Medium	Low relevance	Relevant	Very relevant
Sustainability	Very relevant	Medium	Low relevance	Very relevant	Very relevant
Socio/political acceptability	Very relevant	Very relevant	Medium	Very relevant	Very relevant
Effectiveness	Very relevant	Low relevance	Medium	Very relevant	Relevant

Table 5: Description of the relevance of BBs for the achievement of regulatory objectives

Next paragraphs provide the reasons for assigning a certain relevance level to regulation within each BB for the achievement of each objective in the three scenarios where larger power exchanges are expected to take place. The relevance of regulation in each BB across scenarios is discussed separately:

1) The BB Network Design is considered always relevant or very relevant to the achievement of policy objectives. This is because, both the allocation of responsibilities in the decision making process leading to the construction of new lines, and the types of benefits considered when deciding on the proposal, or the approval, of each network reinforcement, will significantly condition the set of new lines finally built, and therefore the development of the grid.
2) The BB Ownership is deemed to have a medium level of importance in achieving all three main energy policy objectives (energy policy pillars) of the European Union. Traditionally, main network ownership regulatory options implemented as the prevalent ones in real-life systems, like having network ownership integrated with SO (TSO model), or having network ownership in the hands of fully independent transmission companies (ISO model), have been compatible with the construction of required network reinforcements, though some of them have not promoted cost-efficiency. In a context where network reinforcements to underatake were limited, whether lines were built or not under the TSO and ISO ownership schemes traditionally depended on other issues than the network ownership scheme implemented, like the remuneration scheme

applied to network reinforcements, or the type of benefits considered when identifying required reinforcements. Other network ownership options that do not provide strong enough incentives to achieve the construction of some relevant lines, like having (associations of) market agents as owners (and payers) of transmission lines, or leaving the ownership of new lines in the hands of merchant promoters, correspond, in reality, to options that have also to do with the BB Network Design (allocation of responsibilities in the network development decision making process). Implementing these last options as stand-alone ones could, of course, put at risk the construction of required new lines.

3) However, the relevance of the network ownership scheme for achieving a sufficient development of the network should not be disregarded in a future context, where network reinforcement needs are expected to increase substantially.
4) In contrast to other objectives, whose achievement is not so intimately linked to the choice made of a network ownership scheme among typical ones, the level of importance of the BB Network Ownership for achieving the Socio/political acceptance of transmission regulation is very high. Having network ownership and deregulated activities unbundled is required by one main principle advocated by the European Commission and Parliament. This principle is implemented through several pieces of European legislation, including the 3rd package.
5) Financing should always be available for those network reinforcements that are needed to preserve system security or integrate large enough amounts of RES generation to comply with environmental objectives, since these are highest priority objectives. If financing is not available for all required reinforcements due to the large amount of them needed, projects aimed at increasing competition in the system are most likely to be affected by the scarcity of funds.
6) In the future, the public budget of some European countries may be under stress due to a drecrease in the birth rate and the level of competitiveness of these economies. Then, those financing schemes and systems, largely relying on the State, may be deemed as socio-politically unnaceptable, and therefore should be avoided.
7) Some financing schemes relying on the coordination among a multiplicity of stakeholders may be difficult to implement and should, therefore, be avoided as well.
8) The allocation of the cost of required reinforcements will significantly condition the final approval of these in a system like the European one, where executive decisions on the construction of lines are made at Member State level currently, and will most probably require some kind of coordination among European and national network development processes even in the long term future. Countries will not facilitate the construction of new lines, and they may even block it, if they feel that they are paying a relevant part of the costs of these lines while not benefiting substantially (to a similar extent) from their existence. Thus, the network cost allocation method employed will critically condition the development of the grid at regional level, because the benefits of these lines are generally perceived by several countries or systems, and not just one.
9) The BB Market and Technical Operation is very relevant to achieve energy policy objectives, since aspects of it like the energy pricing regime applied, or the congestion management scheme (process of allocation of transmission capacity) have a clear impact on the economic efficiency of the market outcome, driving both investments and operation decisions by market agents in Europe. Other system and market related aspects like the generation capacity remuneration schemes in place will condition the deployment of the required generation acting as a back-up of RES generation to ensure adequate system security levels. RES support schemes will, of course, condition the deployment of RES generation and the efficiency of this process. And, lastly, the level of geographical or temporal differentiation of energy prices within European countries

(from the application of nodal or zonal pricing schemes) may raise strong opposition in these countries, because it may be perceived as discriminatory when affecting generators, and especially, consumers.

In line with arguments provided above on the relative level of importance of electricity transmisison in each scenario, for the scenario "Large fossil fuel with CCS and nuclear", the importance of transmission regulation related to each BB in achieving each objective is deemed to be one level lower than the importance assigned to it in Table 5 (p.e. very relevant in Table 5 becomes relevant in this scenario). The same applies for the scenario "Small and local", but this time assuming a reduction in the importance of transmission regulation of two levels.

In order to compute a single weight of the assessment of a BB in a GM with respect to each objective, taking into account both the relevance of objectives and that of BBs for achieving them, Table 4 and Table 5 are combined into Table 6. The final column of this table provides the unique relative, qualitative, weights to be given to the initial assessment of BBs with respect to objectives (result of step 1 as discussed above). For carrying out the assessment process, qualitative weights will be translated into quantitative ones in the following way: very large = 1, large = 0,75; medium = 0,5; low=0,25 and no weight =0.

Importance of objective in scenario (from table 4)	Importance of BB for objective (from table 5)	Weight of the assessment of the BB w.r.t the objective when assessing the BB
VERY HIGH	Very relevant	Very large
VERY HIGH	Relevant	Very large
VERY HIGH	Medium	Large
VERY HIGH	Low relevance	No weight
HIGH	Very relevant	very large
HIGH	Relevant	Large
HIGH	Medium	Medium
HIGH	Low relevance	No weight
MEDIUM	Very relevant	large
MEDIUM	Relevant	Medium
MEDIUM	Medium	Low
MEDIUM	Low relevance	No weight
LOW	Very relevant	Low
LOW	Relevant	Low
LOW	Medium	low
LOW	Low relevance	No weight

Table 6: Overall weight of the assessment of a BB with respect to each objective

3.2.3. Hybrid, scenario dependent GM

A final analysis involves using results from the assessment of GMs per BB and scenario to identify the best performing GM, regarding each BB, in each scenario, and, based on this, derive the best theoretical combination of BBs from the considered GMs per scenario. This is visiualised in Figure , which builds further on figures 3 and 4 out of earlier sections.

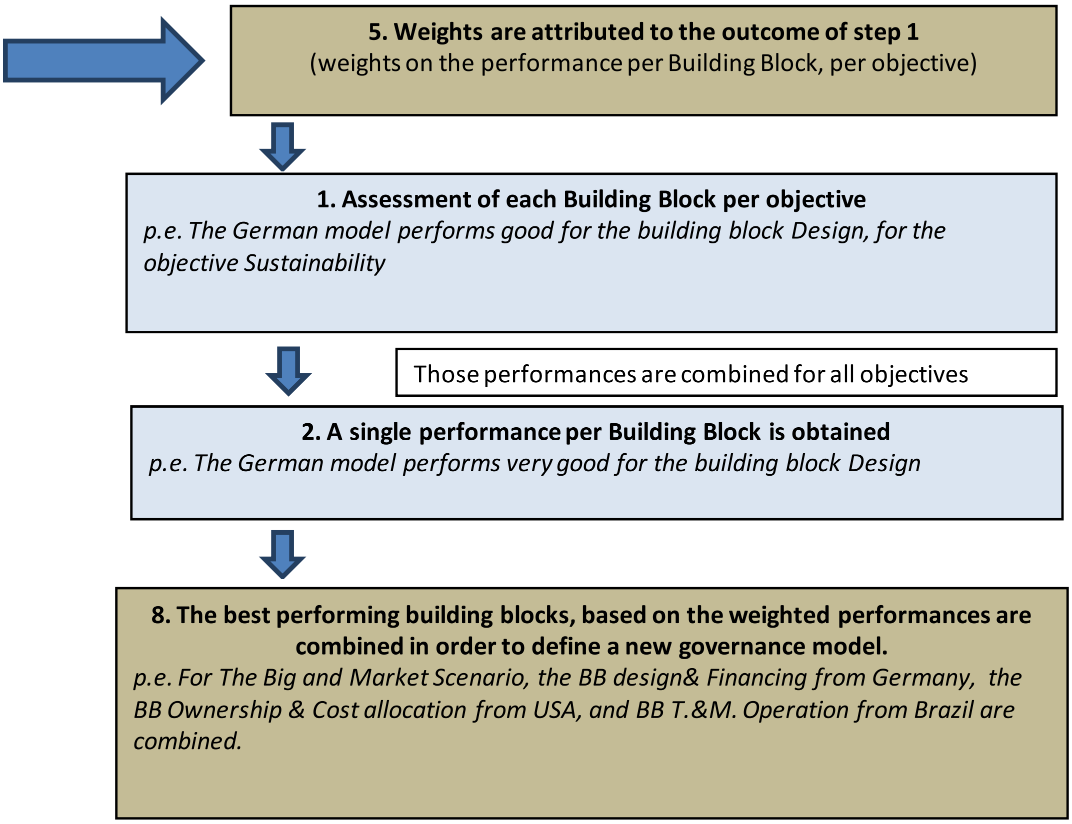

Figure 5: Schematic representation of the preliminary assessment process of GMs to compute a synthetic, best-performing one by combining best perfoming BBs from all GMs.

3.3. Fine-tuning and derivation of options

After the preliminary assessment, a second group of important steps in the assessment framework are performed prior to arriving at the most promising regulatory options for 2050. These steps concern the refinement of regulation retained as most promising within each BB (coming from a specific GM), the consistency check of promising regulatory practices defined for the several BBs, which may initially come from several GMs, and the resulting final retention of governance options. Finally, also the prioritisation of retained options for each grid architecture per scenario is described.

3.3.1. Refinement of the regulatory setting applicable for each BB

Three steps are taken to refine the regulatory setting for each building block. First, the selected best performing model from the initially explored eleven governance models, and the regulatory context where it is applied, are examined in detail. The main interesting elements are extracted to define a policy option for Europe.

In the second step, the rest of governance models are examined, with a special attention to second and third best performing governance models, looking for promising elements in them that can complement regulation in the best performing model. Complementary elements where the best performing model does not score high according to assessment criteria are identified.

In the last step, identified interesting experiences (or regulatory options) from the first two steps, also taking into consideration their applicability in the European context, are combined to make the final regulatory settings proposed as interesting for each building block.

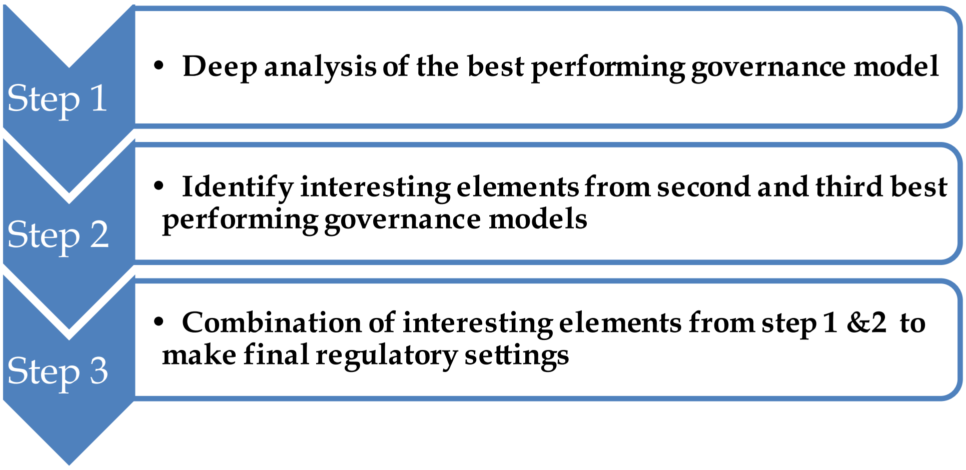

Figure 6: Refinement of regulatory settings applied for each BB

3.3.2. Consistency check during the derivation of the final set of options

The objective of the consistency check is to ensure that policy options derived for all building blocks are a coherent set. Thus, when in the following chapters concrete options for 2050 are proposed, there should be always a reflection on the implementability in a European setting and its coherency with other proposed options. This check should be performed for at least two aspects. First, on the repartition of roles and responsabilities among national institutions on the one hand, and more central ones (regional/European institutions) on the other hand. Secondly, given that regulatory options could be proposed from several models (regulated, tender based and merchant investment), the compatibility of these different models and the joint application of them should also be looked into.

Coordination of central institution responsibilities

Firstly, challenges have been identified related to the coordination of the main roles of more central versus national institutions. For instance, this reflection should identify the interlinks among the several policy options made related to how cross-border transmission network projects should be planned, permitted and financed in a more coordinated framework at European level. Then, the feasibility of these links should be assessed.

Compatibility of business models

At least three business models have been analysed for the development of the cross-border grid in 2050: the regulated one, which should be the main way to promote the construction of new lines, the merchant investment type, and the model based on the initiative by associations of network users (future beneficiaries) of these lines. Whenever options for 2050 are proposed from several of these business models, it should be investigated if the combination of these can still efficiently be put into practice.

3.3.3. Adaptation/prioritization of options for each scenario and resulting grid architecture

Possible options derived on best practices to apply may be deemed generally valid for a 2050 horizon, regardless of the scenario and grid architecture considered, in the understanding that best practices to increase the efficiency of an actitivy and its effectiveness in achieving the defined objectives should always be considered advisable. However, the specific features of each scenario, and the related defined grid architecture for it, may condition the relative importance of options for policy change. Therefore, a prioritisation of options per grid architecture is performed since, given the final grid architectures as input, not all proposed options in the chapters 5-9 could be equally valid in each scenario.

Note, however, that already in the context of the preliminary assessment of governance models, a first scenario-dependency element is already considered. Based on the definition and characterization made of scenarios within WP1, the level of importance that electricity transmission and its regulation, as a whole, has on the development and operation of the system in each scenario has been determined according to the expected level of power exchanges in this scenario.

Once the overall set of possible regulatory options for 2050 has been identified, a scenario-dependent importance level can be given to each promising policy option (or per group of options) in the context of each of the five determined e-Highways2050 scenarios and resulting grid architectures. Factors used for this exercise in the workpackage 5 in order to determine the importance of regulatory options for each scenario and grid architecture, are related to those considered in the preliminary assessment of GMs, i.e. the importance of transmission regulation in each scenario. However, the prioritization of options per grid architecture conducted for the prioritisation purpose makes use of relevant information on the operation of the system and the impact on it of reinforcements that has been available since optimal grid architectures per scenario have been computed.

Regulation related to the organization of the expansion of the grid (design), the ownership, cost allocation and financing of the resulting network reinforcements can be deemed relevant to the extent that these reinforcements are relevant for the system functioning as well. The importance of undertaking some reinforcements directly depends on the net benefits these reinformcents may produce for the system. Therefore, it can be concluded that the importance of regulatory options proposed for BBs Network Design, Ownership, Cost Allocation and Financing is positively correlated with the overall net benefits to be produced by the network to be built. Therefore, the combination of options per BB is looked into in this section, rather than every single option individually.

However, determining the value of energy for consumers, which is needed to quantify the system benefits produced by grid reinforcements, is highly controversial. Therefore, a range of possible levels is considered for the economic value that consumers put on electric energy. In other words, a range of values is considered for the cost for the system of not providing electric energy required by consumers.

On the basis of information from WP2 of the e-Highways2050 project (i.c. deliverable 2.3), the cost of non-served energy, CNSE, has been deemed to reasonably lie between 1 and 10k€/MWh. Considering a level for the CNSE of 1k€/MWh, the benefits and investment costs associated with the network architectures computed for the several scenarios are provided in Table 7 (as drawn from D2.3).

	Large scale RES	100% RES	Big and market	Fossil and nuclear	Small and local
Total annual benefits [b€]	102	90	33	18	15
Range of investment costs [b€]	[14-21]	[14-20]	[8-13]	[7-12]	[7-11]
Net annual benefits [b€]	[81-88]	[70-76]	[20-25]	[6-11]	[4-8]

Table 7: Net benefits of grid architectures for each scenario, low value of the CNSE

Then, even when policy options drawn are relevant for all scenarios, those proposed for the aforementioned BBs would be most important in the 'Large scale RES' scenario, and least important in the 'Small and local' scenario. In between, the importance of policy options would be decreasing for the '100% RES', 'Big and market', and 'Fossil and nuclear' scenarios.

On the other hand, if a level for the CNSE of 10k€/MWh is considered, the benefits and investment costs associated with the network architectures computed for the several scenarios would amount to figures provided in Table 8.

	Large scale RES	100% RES	Big and market	Fossil and nuclear	Small and local
Total annual benefits [b€]	309	549	132	81	60
Range of investment costs [b€]	[14-21]	[14-20]	[8-13]	[7-12]	[7-11]
Net annual benefits [b€]	[288-295]	[529-535]	[119-124]	[69-74]	[49-53]

Table 8: Net benefits of grid architectures for each scenario, high value of the CNSE

Then, for a value of the CNSE of 10k€/MWh, policy options proposed for the aforementioned BBs would be most important in the '100% RES' scenario, and least important in the 'Small and local' scenario. In between, the importance of policy options would be decreasing for the 'Large scale RES', 'Big and market', and 'Fossil and nuclear' scenarios.

Thus, it is concluded that options would be most relevant for the 'Large scale RES' and '100% RES' scenarios, with the relative importance of recommendations between the two depending on the value assumed for the CNSE, while these recommendations would be least relevant for the 'Small and local' scenario, closely followed by the 'Fossil and nuclear' one. The level of importance of recommendations for the 'Big and market' scenario would be medium. This is fully in line with the level of network investments to be undertaken in the several scenarios.

Regulation related to the T&M Operation of the system at a European (international level) is mainly focused on achieving a high level of integration of national markets. Then, the importance of this regulation in a specific scenario, or for the resulting grid architecture, should be higher, the higher the benefits to be obtained from power exchanges occurring among countries. However, within the project, an estimate of the benefits resulting from power exchanges has not been computed. Therefore, a proxy to this is used. The importance of regulatory options proposed for the BB T&M Operation is deemed to be largely proportional to the aggregate level of the absolute value of net exports from countries in each scenario (again, all options are taken together, in stead of the options individually). The magnitude of aggregate net imports or exports all over Europe is to be computed in net terms for the overall year, since hourly values for power exchanges are not available within the dataset made available at project level.

Based on power exchanges computed within WP2 of the project, overall levels of energy imbalances in Europe throughout the target year amount to figures in Table 9.

	Large scale RES	100% RES	Big and market	Fossil and nuclear	Small and local
Total Imbalance [TWh Annual]	1511,92	1101,47	749,62	863,69	316,62

Table 9: Overall energy imbalances of countries at European level for each scenario

Then, for BB T&M Operation, also policy options proposed would be most relevant to implement in the 'Large scale RES' scenario, followed by the '100% RES' one. The level of importance of these options in the 'Big and market' and 'Fossil and nuclear' scenarios would be medium; while this would be lowest in the 'Small and local' one.

In conclusion, it is stated that on the basis of a short analysis, based on available information from other WP's of the e-Highway2050 project, a tentative is made to stress the importance of implementing the proposed regulatory options for 2050 of this study. On the basis of this, the level of importance of options for all BBs follow a similar pattern across scenarios, except for the 'Fossil and nuclear' scenario, for which the importance is higher in relative terms for options related to the BB T&M Operation than for options associated with the rest of BBs. A part from that scenario, the relative importance for all options combined would be (from high to low): 'Large scale RES' - '100% RES' - 'Big and market' & 'Fossil and nuclear' - 'Small and local'.

4. Preliminary assessment

In this chapter 4, the results are presented of the preliminary assessment by applying the methodology as described in the previous chapter. It is recalled that the objective of this assessment is to select a reduced number of GMs for further, deeper, analysis.

The subchapters below focus on the analysis of the current status of the different models per building block. An exception is made for the specific case studies, which cannot be assessed in each case on all building blocks, as these are only of relevance for some specific building blocks. Therefore, the case study preliminary assessment has been done separately and ad-hoc. The results are described at the end of the chapter and their promising elements are taken further in future work as complements to the more general regulatory schemes in place in GMs explored.

In order to provide the reader with a short and easy to understand overview, only the most relevant elements of the assessment are discussed below. In particular the elements that have led to a positive performance are discussed for the GM that has obtained a good overall performance result. The discussion deals thus with the main elements, which relates to a certain objective, which has received a positive performance score. As indicated before, the full list of assessment criteria used is provided in annex 1.

For a visual overview of the analysis results, summary tables have been included in the sections below. On the basis of the assessment performed during the project, a performance level has been attributed to each GM for each BB. The colour code used in these tables correspond to a certain performance, i.e. blue, green, yellow, and red colours indicate outstanding, satisfactory, insufficient, and poor performance, respectively. A white colour codes means this objective was of no relevance in the GM analysed or the GM did not contain any relevant aspects to analyse for that objective.

The best combination of BBs resulting from this preliminary assessment provides the starting point for the in-depth analysis in Chapters 5-9, where this retained combination of BBs is explored further in order to derive the most promising elements to put forward as policy options for 2050.

4.1. Network Design

On the basis of the assessment performed for this study, the Central American GM has been considered as the most interesting concerning the socially efficient grid development. It provides the means to achieve a sufficient development of the grid, while avoiding economic incentives for the planner to promote unnecessary investments. There are means to achieve the construction of reliability lines, because achieving a high level of reliability is a high policy objective. Decisions to build new lines can be easily implemented due to the concentration of executive power in the hands of the regional regulator. Besides, regulation in place is largely coherent with principles established in the IEM of the EU. The only major drawback of this model is the fact that the construction of lines for the integration of RES generation may not be enforced because this is not a policy objective at regional level.

The German, Brazil, UK, and USA GMs contain also interesting aspects. The German model ensures the construction of all lines whose benefits of any kind exceed their costs, since the TSO's and regulatory authorities have as their main objective the maximization of the social welfare through the development of the network considering all kinds of benefits: economic, reliability, and environmental ones. Regulation in place in Germany should be effective in getting approved lines built and is obviously in line with IEM principles. However, even when subject to some efficiency incentives, entities planning the expansion of the grid, being also grid owners, may perceive incentives to build lines whose benefits are not larger than costs in order to increase the asset base and, therefore, their remuneration.

Whereas in Brazil the development of the network includes all lines whose economic and reliability benefits exceed costs, relevant investments may not be undertaken in the USA and the UK. This is due to the lack of coordination among regions in the case of the USA. In the UK, efficiency incentives that the TSO's and asset owner are subject to, do not consider some benefits produced by network investments, like those associated with the increase in power exports to third countries. This has led to a situation where a large part of interconnectors are built as merchant investments. However, network investments to increase the environmental sustainability of the system receive a stronger support in the USA and the UK than in Brazil.

The regulation in place in the USA for these aspects would be acceptable for institutions in the EU because it is in line with main principles applied in the IEM, as both in the US and the EU, the subsidiarity principle applies to the approval of local reinforcements. On the other hand, the regulation in place in Brazil and the UK is less in line with IEM principles.

As for the concentration of decision making power, investments approved according to regulation in place in Brazil and the UK should be more effectively implemented, since decision making power is concentrated in few hands. In contrast, regulation in the US makes it more difficult to achieve the construction of all those lines promoted at regional level due to the definition of several levels of decision making (national, regional, state and local).

Finally, the development of the grid in the UK, USA, Brazil and German GM have scored well on aspects related to the safe operation of the system

Network Design	CA	DE	BR	US	AR	UK	NO	GAS
Competitiveness								
Security of supply								
Sustainability								
Socio-political acceptability								
Effectiveness								
Total								

Table 10: Summary assessment of all GMs regarding the features of network design regulation

4.2. Ownership

Brazil, Germany and the UK are the GMs that seem the most interesting to explore further following the preliminary analysis. The Brazilian GM, where independent transmission companies build, own and operate the reinforcements decided by the network planner, and approved by the central regulator, achieves the construction of required reinforcements while not providing economic incentives to build non-socially optimal new assets. At the same time, network maintenance actions are planned by the SO, thus achieving a high-enough level of coordination between SO and network maintenance. Besides, there is a mandate to achieve economic efficiency, security of supply and environmental objectives. Lastly, regulation concerning new investments, which establishes the separation of ownership from SO, is in line with EU regulatory principles.

In Germany, the TSO, as network owner, is expected to build all efficient reinforcements, because it has a mandate to do so. However, regulatory authorities have to verify the economic efficiency of reinforcements in order to avoid the undertaking of non-needed ones. Besides, there is a mandate to achieve the economic efficiency of the system and security of supply objectives through the development of the grid. There is also a mandate to integrate RES generation, and some economic incentives to build EE and DR related infrastructure. This regulation is obviously in line with EU principles.

In the UK, authorities aim to strike a balance between incentives addressed to the network owner and planner to invest in required new assets and incentives not to build inefficient ones. Incentives of the first type include the pass-through of the efficient cost of part of assets, the mandate to comply with network codes on security of supply, and economic incentives related to RES integration, and the deployment of EE and DR. This should contribute to the achievement of adequate levels of investment in new transmission assets for economic, security of supply, and environmental reasons. Incentives to avoid inefficient investments involve the application of revenue cap schemes. This regulation is also in line with EU principles.

The USA and Central American GMs are similar to the Brazilian one as far as network ownership regulation is concerned. However, the USA one seems a bit less interesting, as coordination between network maintenance and SO is limited. This is due to the fact that both activities are performed by different entities (the System Operator and the network owner, which do not coincide) and the SO is not planning maintenance actions as in Brazil. The Central American model seems also less interesting than the Brazilian one because environmental objectives do not exist in this market, which makes the construction by network owners of the corresponding investments more difficult.

Finally, the Nordic GM is similar to the UK one, but, as in the Non-energy case study and Central American model, environmental objectives are not pursued in it. The Argentinean GM enforces the construction of enough lines to achieve a high enough level of security of supply. Besides, it is compliant with EU ownership regulation. However, network investments decided are not the most efficient ones, since proper Cost Benefit Analyses (CBA) at the whole system level are not always conducted when deciding on investments. Additionally, environmentally driven investments are not promoted because the reduction of emissions is not a high level policy objective.

Network Ownership	CA	DE	BR	US	AR	UK	NO	GAS
Competitiveness								
Security of supply								
Sustainability								
Socio-political acceptability.								
Total								

Table 11: Summary assessment of all GMs regarding the features of ownership regulation

4.3. Financing

Germany is the GM that seems the most interesting for further analysis following the preliminary assesment, as it exhibits distinct features related to the three main financing aspects: sources of financing available, risks and cost of capital, and financing facilitation mechanisms available, which include the European ones. Entities undertaking investments, in general the TSOs, have diversified their financing sources. On the debt side, all four TSOs have acquired credit ratings in order to issue corporate bonds. On the equity side, external equity such as that provided by infrastructure funds and pension funds has been introduced as project financing for those TSOs that undertake offshore wind park connections.

Concerning the risk and cost of capital, Germany features a relatively high rate of return on network investments. However, there lies ex-post investment risk in the German transmission network investment regulation. In the initial one or two regulatory periods, investment costs for expansion and restructuring projects approved by the regulator, BNetzA, can be entirely passed through to consumers. Afterwards, the regulator can perform a benchmarking exercise to set incentives on the sunk investment costs by applying an efficiency factor on them. There are two main implications of this. On the one hand, anticipatory investments are included in the regulated asset base for projects approved by the regulator, thus providing a safe exit for capital expenditures in the building phase. This gives investors a guarantee that remuneration will include large up-front transmission network investment costs incurred, plus a reasonable return on them. On the other hand, given that investors cannot manage costs incurred in the past, which are irreversible, the application of an efficiency factor on past investment expenditures could be perceived as an uncontrollable risk for investors. Therefore, higher risk premiums might need to be paid to compensate for such risks, which would lead to deadweight welfare losses.

European financing facilitation mechanisms include EU mechanisms for cooperation and coordination in the financing of regional investments, such as TEN-E schemes implemented for cross-border transmission grid investments, i.e. grid expansions that have a cross-border impact.

In Great Britain, a new regulatory regime named RIIO (Revenue = Incentives + Innovation + Outputs) has been implemented. This aims to provide long term value of money for new investments making use of incentives. Key financial parameters of this scheme are designed separately for the transmission owner and the system operator by the regulator, Ofgem. This allows the cost of capital to reflect distinct functions and cost components for TO and SO. Novel elements included in the new regulatory framework include: i) a prolonged regulatory period that represents long term regulatory commitment; and ii) a mid-term review that allows the regulator to timely adjust remuneration to new market conditions.

In the Central America and Brazil GMs, there is also a pass-through of network investment costs under the framework of auctions for the allocation of the ownership (construction, operation, and maintenance) of new assets and the computation of their allowed revenues. This provides investors with some degree of certainty over the recovery of their costs. Besides, financing instruments are quite diverse, including both public and private financing sources. Within private ones, the network owner has the possibility to issue debt or equity to obtain funds, thanks to the pay-back guarantee provided by allowed revenues. However, entities undertaking network investments, the Transcos, are small and, therefore, have limited financing capabilities. In the USA, transmission network regulation is in general of a rate of return type. In order to facilitate interstate transmission network investments, specific financing mechanisms for these projects, like rate adders, exist.

Financing	C.A.	DE	BR	US	AR	UK	NO	GAS	ME
Competitiveness									
Sustainability									
Socio-political acceptability									
Effectiveness									
Total									

Table 12: Summary assessment of all GMs regarding the features of financing regulation

4.4. Cost allocation

The USA GM results from the preliminary assessment as the most interesting for further exploration for the BB cost allocation. This is because network cost allocation in this GM is judged as most efficient from an economic, reliability, and environmental point of view, at least according to principles defined in federal regulation. Regulation enacted by the federal regulator, FERC, requires the cost of network investments to be allocated based on the benefits from them expected to be perceived by stakeholders (FERC, 2012). This principle applies to all types of investments deployed within each region. The cost of network facilities crossing several regions should also be allocated to agents following a common cost allocation scheme based on benefits. However, the cost of new assets located within a region that are affecting several regions may not always be allocated to agents in all these regions following such an efficient approach. This is because an agreement must first be reached among all these regions on how to allocate the cost of these new assets at regional level. This agreement may not be fully efficient. Besides, even when the fraction of the cost of these lines to be paid by each region should be allocated to local stakeholders according to a method based on benefits, different regions may apply different cost allocation schemes. This may result in the allocation made of the cost of lines within a region that affect others not being coherent across regions. The cost allocation scheme applied in the USA is however compatible with current practice in the IEM, since it respects the subsidiarity principle.

The cost allocation mechanism in Brazil is also judged efficient from all points of view, and it would be easy to implement from a practical point of view, since decision making power is centralized and thus only few decision levels are involved. However, this makes it difficult to be accepted in the IEM, since national authorities may lose their executive power.

The cost allocation scheme in place in Central America is efficient for transmission investments of an economic or environmental nature. However, contrary to what occurs for the USA model, this is not the case for reliability lines. The cost of the latter is allocated to countries based on the use made of these reliability lines under normal conditions. This is not in line with the cost causality principle. The use of reliability lines by countries (or stakeholders within them) under normal conditions is not representative of the benefits that countries, or stakeholders, are obtaining from these lines. Benefits from reliability lines are only perceived by stakeholders under contingency conditions. Besides, these benefits are distributed evenly across large groups of stakeholders, instead of according to the use made of these lines by stakeholders or countries. This is a scheme that would however also be easy to implement from a practical point of view as, like the Brazilian one, it considers a centralization of decisions on cost allocation. However, there is a risk that national authorities in Europe oppose the application of the Central American scheme. Given that it involves a high level of centralization, it does not allow network cost allocation decisions to be made at the lowest governance level. Then, unless it is convincingly argued that achieving high enough levels of efficiency and fairness in network cost allocation requires shifting decision making power to a higher governance level, local authorities may claim that this allocation scheme is not respecting the subsidiarity principle.

The schemes in the UK, the Nordic system and Argentina are similarly evaluated. The Nordic GM provides a socially efficient allocation of the cost of economic and reliability lines only if TSOs agree to cooperate. Environmental benefits are not being considered appropriately when allocating the cost of lines producing them. The allocation method applied is compatible with the IEM legislation, but seems not to be effective in achieving agreements on the allocation of the cost of regional lines. The UK GM seems inefficient in allocating the cost of economic and environmentally driven lines, though it provides a reasonable allocation of the cost of reliability investments. It is easy to implement from a practical point of view, once approved, because it is a centralized decision making scheme. However, as argued above for the Central American scheme, it may be difficult to accept in continental Europe. As in the case of the UK, the cost allocation scheme in Argentina seems not to be efficient for economic lines and environmentally driven ones in a meshed system, like the EU one. This is so even when cost allocation in this scheme is affected by the use made of clean technologies. It is also a centralized scheme, with its advantages and drawbacks in the European context.

Net. Cost Allocation	C.A.	DE	BR	US	AR	UK	NO	GAS
Competitiveness								
Security of supply								
Sustainability								
Socio-political acceptability								
Effectiveness								
Total								

Table 13: Summary assessment of all GMs regarding the features of cost allocation regulation

4.5. Technical and market operation

The USA model seems also the most interesting to explore further in all scenarios, except the 'Small and Local' one (see infra), as it achieves an efficient system and market operation at regional level. Besides, system and market operation rules favour the integration of sustainable technologies and the deployment of adequate amounts of firm generation. The nodal pricing scheme implemented in the USA model provides an efficient form to reflect the value of scarce transmission network capacity in the energy price in times of congestion. Energy and reserve provision in several RTO regions are co-optimized to some extent by a single entity, the ISO. This co-optimization mechanism creates additional efficiency gains compared to sequential optimization conducted in Europe. Furthermore, the existing centralized market place provides the flexibility to enhance the interchangeability of the two products, which is of high importance in high renewable scenarios. Another interesting feature in the balancing market design in the USA is that direct reserve procurement responsibilities are assigned to those who cause imbalances. This reduces the need for socializing reserve procurement costs. However, relying on bilateral or multilateral cooperation among regions for operation planning, as in the USA GM, would not provide any certainty of achieving an efficient dispatch in the IEM. Given the focus on RES integration, DSM and EE for the small and local scenario, and less on overall and well integrated central aspects, the USA model is not retained as most interesting for this scenario. In this regard, the German GM retains more promising elements.

This German GMs provides regulation favouring the deployment of all clean technologies in order to increase the renewable share in the energy mix. This model relies on strong cooperation, like between TSOs and between regulator and market operator, which drive the development and operation of the system and market, as well as the development of various support mechanisms including priority access and dispatch for renewable generation. These mechanisms, however, can distort competition taking place among technologies to arrive at an economically efficient energy supply. Lastly, the allocation made of transmission capacity can be deemed efficient to some extent, involving the implicit allocation of interconnection capacity among regions. On the other hand, the German model might not result in the most efficient energy price signals, due to the application of uniform prices in the whole country.

The Argentinean GM also reveals interesting aspects, because it involves the application of nodal pricing, which provides efficient price signals and transmission capacity allocation. However, the Argentinean GM does not provide enough incentives for the integration of clean technologies. Besides, the application of this pricing scheme would be difficult to approve in the IEM. In contrast, the Nordic GM would be easy to implement in other systems in the IEM, since it relies on the subsidiarity principle and areas considered in technical and market operation do not change along time. Besides, this model should achieve a safe and secure operation of the system, also in the long term. The zonal pricing scheme applied in the Nordic system, based on market splitting and implicit capacity allocation, is a step forward compared to uniform pricing, but still not fully efficient, since pre-defined congestion and bidding areas are considered in this region.

The GM in Central America results in an efficient market and system operation at regional level, making use of nodal pricing. However, final prices applied locally depend on national authorities. The use of firm transmission capacity products should facilitate the exchange of firm generation capacity at regional level. Its level of acceptance in the IEM could also be high because, as aforementioned, it relies on the subsidiarity principle. However, because of this, its effectiveness in achieving an efficient system operation at EU level would be limited. This would depend on the willingness of EU member States to efficiently apply regional nodal prices. Ancillary services are provided by consumers and generation companies in the Central American region as compulsory services. Besides, this model does not comprise specific generation adequacy mechanisms at regional level that aim to attract new firm generation and it is not facilitating the integration of clean technologies.

This is similar to the GM is Brazil. It provides more than enough means to achieve a safe and secure system operation in the short and long term, such as strict reliability criteria and SoS mechanisms. It includes some relevant incentives for the integration of RES generation in the development and operation of the system, like the organization of some long term RES generation auctions. However, market operation relies on zones that are predefined, within which congestion may occur, and losses are not considered. Finally, its effectiveness is medium because some of the system operation and development processes applied are very complex, like the centralized scheme of hydro-thermal coordination ruling the operation of the system. The scheme for planning the operation of the system in the long to medium term is inspired by some very specific features of this system, like the large abundance of hydro resources, which are not shared by the EU.

Lastly, the UK GM provides strong incentives for the integration of RES generation and the application of EE and DR measures, since it is based on centralized processes. Furthermore, this model includes mechanisms to preserve the safe operation of the system. However, these may not be enough, even when having very recently implemented a long term SoS scheme.

T&M Operation	C.A.	DE	BR	US	AR	UK	NO
Competitiveness							
Security of supply							
Sustainability							
Socio-political acceptability							
Effectiveness							
Total							

Table 14: Summary assessment of all GMs regarding the features of technical & market operation regulation

4.6. Specific case studies considered

Lastly, the situation of some regulatory case studies that can potentially be implemented in specific circumstances is discussed. The analysis has been done on a more qualitative basis, as to identify complements for entire regulatory systems as discussed in previous sections. Therefore, no scoring tables are included in this part.

The three investigated case studies are: (1) the merchant scheme, currently implemented in some systems as a complement to the regulated one, (2) the regulatory scheme applied in other, non-energy sectors, and (3) the regulation specifically developed to organize the functioning of distributed energy systems. The following paragraphs discuss the merits of each of these schemes separately.

4.6.1. Merchant case study

The merchant scheme is considered in regulation applied in a large number of regions in the world, but, normally, only as a complement to regulated investments. It provides an additional way to promote the construction of network reinforcements that is purely market driven. This scheme is only valid to achieve the construction of reinforcements with a high market value. These are normally new lines or interconnectors which are expected to be severely congested, and which should render significant congestion rents to owners if the pricing mechanism applied allows congestion to be reflected in price differences between both ends of the new assets. Additionally, for investment projects whose benefits are going to be earned by few agents, promoters could, if allowed by regulation, negotiate access charges to be applied on these agents for the use of these facilities. However, most required investments of a reliability or environmental nature, as well as a large part of required investments of an economic one, would not be promoted under the merchant scheme.

Investments promoted in a merchant framework are expected to be smaller in size than the socially optimal ones, since the latter would probably result in market revenues that are significantly smaller than the maximum ones that can be achieved, and may even fall short of recovering investment costs. A negotiation process between promoters and authorities may take place to increase the social value of the resulting reinforcements. The effect that regulated investments may have on merchant revenues should be considered by promoters before undertaking investments, since regulated reinforcements should not be halted over the economic life of merchant assets.

On the other hand, given that these investments are driven by revenues from their commercial exploitation, no waste of funds should take place in carrying them out. Besides, merchant owners are separated from System Operators and planners. Thus, no conflict of interest should exist between network ownership and planning or system operation. Another positive aspect of this scheme is that it could allow some coordination between generation and transmission expansion to take place. This coordination is evident for those merchant investments whose promoters are negotiating with potential new generation or demand charges to be paid by the latter to access the transmission capacity of these projects.

Cost allocation of these reinforcements is partially driven by the distribution of the benefits they create. In the case of projects earning congestion rents, network users implicitly paying these rents are the generation on the exporting side and demand on the importing one. These are the same agents benefiting from the construction of these projects. However, the overall cost implicitly paid by each network user is not proportional to the benefits this user is getting from the line.

In the case of merchant projects whose promoters are negotiating access charges with future users, the alignment of cost allocation with future benefit distribution is clear. Agents willing to pay to access the new transmission capacity will be those for which the construction of this capacity has a highest value. However, this scheme will only be applicable to those projects whose beneficiaries are few. Otherwise, benefits of individual agents will not be large enough for beneficiaries to be willing to negotiate paying a charge for the use of the line. Given that the allocation of the cost of merchant lines is being driven by the results of the market (prices and quantities of energy negotiated in it), coordination among systems in the cost allocation of merchant assets is taking place through the coordination of the dispatch in these systems.

Based on the ownership structure of the network in those systems where merchant investments play a relevant role, one can conclude that the merchant ownership scheme is normally resulting in a large number of network owners of a small size. This increases financing costs for owners. Promoters of these projects can normally access only private financing, with some exceptions like project companies owned by TSOs. Besides, no especial financing schemes exist for these projects, normally. Risk management schemes are in this case limited to the negotiation of access charges in the long term in those cases where this is allowed and possible, and hybrid schemes like the possibility to turn a merchant project into a regulated one after some time of operation. Thus, overall financing conditions are not favourable.

4.6.2. Non-energy case study

This case study includes sectors like water transport and distribution, the railway industry, freight transport, or the telecommunication industry. In many of sectors considered, the regulatory scheme applied is usually a fully regulated one, whereby the owner and promoter of infrastructure investments coincide and cost of service regulation is applied to these. Infrastructure owners are normally very large entities which may be a monopolist or a large market player competing with others in the supply segment. Strong regulators exist that decide, and supervise, the development of infrastructure and system operation. In some sectors, like water distribution and the railway industry in many countries, vertical integration occurs.

Then, incentives exist to build all required infrastructure reinforcements so that supply is guaranteed. Besides, strong coordination exists between infrastructure planning, maintenance, and system operation. Where vertical integration occurs and supply is monopolistic, full coordination between infrastructure development and operation and supply to final consumers is achieved. Lastly, the financing capabilities of network owners tend to be very large.

On the other hand, some “waste of public funds” may take place in infrastructure project selection and undertaking, given the potential incentives that exist for promoters and regulator to build more infrastructure capacity than needed in order to increase the reliability of the system and revenues. Supply may be inefficient if there is a monopoly in this, or the incumbent is not subject to strict regulatory control.

4.6.3. Small and local case study

The small and local case study provides interesting tools to deal with ancillary services provision by distributed energy resources, from generation to demand, and even local storage. It can thus be positively assessed as a facilitator of the integration of distributed resources in both short term markets and long term ones, like those organizing the provision of firm capacity. This will most probably be necessary in the future operation of the system and markets in RES-dominated scenarios.

However, distributed schemes will need to be integrated into centralized markets and schemes for the development of the network, which need to consider resources available at a wider scale. Otherwise, the efficiency, and even the reliability, of the power system would be negatively affected. Thus, this scheme shall be considered a complement to centralized processes that will, in most cases, provide additional resources to be considered in these processes. The relevance of processes dealing with the aggregation of distributed resources, normally under a market framework, will be highest in the "Small and local" scenario, and lower in scenarios where centralized solutions are predominantly adopted.

4.7. Summary of the preliminary assessment results

As a result of the preliminary assessment of the GMs explored, one GM is identified as the most interesting for further investigation for each of the five scenarios considered and for each BB. The importance given to objectives related to each of the BBs varies across scenarios. Thus, for any BB, different models may rank highest in different scenarios. A scenario-independent assessment of GMs for each BB has also been made assuming that the achievement of all objectives is equally important in all scenarios and every BB is equally relevant for the achievement of any objective. Best performing GMs for each BB and scenario, as well for the scenario independent assessment made, are identified in table 34.

	Scenario independent	***Big and market***	***Large fossil fuel***	***Large scale RES***	***100% RES***	***Small and local***
Network Design	C. America	C. America	C. America	C. America	C. America	C. America
Ownership	Brazil	Brazil	Brazil	Brazil	Brazil	Brazil
Financing	Germany	Germany	Germany	Germany	Germany	Germany
C&B allocation	USA (PJM)	USA (PJM)	USA (PJM)	USA (PJM)	USA (PJM)	USA (PJM)
T&M operation	USA (PJM)	USA (PJM)	USA (PJM)	USA (PJM)	USA (PJM)	Germany

Table 15: Best performing GM for each scenario and BB according to the preliminary assessment made

Regardless of the scenario considered (except for the Small and local scenario), a certain GM is identified as the best performing one as far as the functioning of the system related to each BB is concerned. Eventhough scenario-dependent aspects are included in the assessment, this result might not be a complete surprise. In the end, from a theoretical point of view, regulation related to a BB that is efficient and effective in the achievement of objectives could be so under any set of circumstances (scenarios). Elements of regulation are, therefore, positive or negative in all scenarios. Then, the models mainly containing positive elements perform well in all scenarios. Differences in the performance level among the best, second best and third best models are often however not very large, albeit not to be neglected. To visualise this, the table below provides an overview of the three best performing GMs per BB.

	Design	*Ownership*	*Financing*	*Cost Allocation*	*T&M Operation*
1st model	C. America	Brazil	Germany	USA	USA (PJM)
2nd model	Germany	USA (PJM)	Nordic	Brazil	Germany
3rd model	Brazil	Germany	UK	C. America	Argentina

Table 16: Three best performing GMs per BB for the scenario independent assessment

Therefore, much attention is to be given to the combination of elements from several GMs to define the best regulation possible. In the following chapters, each BB is discussed further in detail, with a special focus on these three best performing governance models, prior to identify a set of possible regulatory options for implementation in a European setting by 2050.

5. Network design

5.1. Introduction

The organization of the expansion of the grid within a regional market such as the European one is central to achieving a satisfactory functioning of this market. However, achieving a satisfactory development of the cross-border European grid is proving to be challenging. Regulation currently in place has p.e. not always led to the undertaking of all the needed network reinforcements on time. New regulatory principles to improve the situation towards 2050 and their implementation must thus, in any case, achieve a sufficient development of the European grid (i.c. the proposed grid architectures of the WP2) on time, at the lowest cost possible, i.e. a development of the grid which is efficient from an economic point of view, and that, at the same time, complies with technical requirements. Three different types of reinforcements are identified for the development of the grid: a) reinforcements of economic type, which achieve a reduction in system costs; b) reinforcements of a reliability nature, which contribute to preserve the safe system operation; and c) reinforcements with an environmental focus, which should serve the integration of renewable generation.

Next, section 5.2 discusses the challenges and key aspects regarding the EU cross-border network design in order to reach the deployment of the projected 2050 grid architectures. Subsequently, section 5.3 discusses the identified policy options to address these challenges, including a discussion of the current status in the EU regarding these network design options, the advantages and disadvantages of each policy option, as well as possible intermediate measures to overcome the disadvantages (= hurdles). Finally, Section 5.4 outlines briefly a least-regret policy roadmap to achieve the identified policy options and measures.

5.2. Challenges and key aspects for the projected EU 2050 grid architectures

Challenges

Regardless of the scenario considered, large amounts of reinforcements to transmission networks in Europe are expected to be needed by the year 2050. Undertaking these reinforcements must however be made compatible with spending a limited amount of resources on the development of the grid. This is so because electricity tariff increases are likely to face strong opposition from large industrial end-users and other retail power consumers. Besides, regulators have a clear focus of keeping tariff increases limited.

Given this, efficiency in the planning and execution of grid reinforcements must be maximized. Maximizing the efficiency of network development, in a context where power exchanges among countries shall increase substantially[5], can however only be achieved if the following conditions are met:

- reinforcements undertaken are defined to take full advantage of potential benefits produced in several national systems;
- network expansion decisions fully take into account interdependencies existing among benefits produced by investments taking place in several countries.

This challenge is tackled through regulatory option 1 discussed below.

Challenges faced when pursuing a satisfactory and sufficient development of the European network concern the need to reduce long permitting processes currently affecting some cross-border reinforcements having been identified as most necessary. This has led to a situation where some priority projects are stranded for long periods of time, sometimes exceeding 20 years. There could be many reasons for permitting processes currently being too long, out of which the non-mandatory nature of pan-European investment plans and the difficult interaction between European and national decision making levels are, surely, some of the main ones. There could, however, also be other reasons, p.e. there are no limits to the opposition possibilities of stakeholders in any step of the permitting process; there are no binding deadlines for legal authorities to decide and close this permitting process; and because of the long and necessary environmental impact assessments to be performed. This challenge is addressed in regulatory option 2 discussed below.

Identifying network reinforcements needed normally requires having a detailed knowledge of the grid and the operational situation in the relevant area of the system. Thus, local stakeholders in an area may also be in a good position to identify some required local network reinforcements. Besides, network users benefiting from these potential reinforcements may be even willing to directly pay for them, instead of waiting for these reinforcements to be identified as necessary in a central planning process. The advisability to have local stakeholders participating in the promotion of the expansion of the grid is taken care of in regulatory option 3. The impact this option might have on ownership aspects is further elaborated in the chapter on Ownership.

Current network expansion planning practices within each country in Europe largely involve the separate assessment of individual projects. These projects aim to solve some specific limitations of the system (either of a reliability type, or some specific congestion, or the lack of ability to integrate RES generation to be installed in a certain area). The benefits of individual projects could be better assessed in conjunction with other projects, definitely those having a possible impact on one another, as benefits reaped from reinforcements are normally contingent on several others being undertaken.

Besides, the expected benefits of projects are normally computed neglecting the probability of occurrence of the several possible future scenarios identified. Then, reinforcement decisions made may be over-conditioned by highly unlikely scenarios while most probable scenarios are not given a

[5] Exchanges are likely to increase due to the installation of large amounts of RES generation in specific locations and the increasing level of integration of national systems.

large enough weight in the decision making process. Regulatory option 4 is concerned with the joint consideration of all possible reinforcements and the treatment of long-term uncertainty in the expansion planning algorithm.

Finally, generation in many national systems is not paying network charges, or paying a very low charge, while it is responsible for a non-negligible part of the costs incurred in the development of the network. What is more, in those systems where generators pay a transmission charge, no information is provided to generators on the expected evolution of these charges, nor on the expected evolution of electricity prices. As a result of this, large amounts of generation are located in parts of the system where they create large network reinforcement needs, or where such reinforcements are not possible. Alternative locations for generators where these investments would be more efficient from a system point of view, once network investment costs are factored in, are overlooked by generation companies. This point is also further elaborated under the BB Cost Allocation, but in the context of the Building Block Design, the overall limited coordination of transmission and generation investments is investigated and a possible role for generation-transmission investment coordinating signals is proposed in option 5.

Key aspects

An important aspect of network planning concerns the methodologies applied to identify, propose and approve network investments. These will condition the features of investment projects, such as their geographical location, timing, and technical characteristics, such as their voltage level. Avoiding overinvestments, which are negatively impacting cost-efficiency, and underinvestments, which are impacting reliability, requires accurately estimating costs and benefits, as well as efficiently dealing with uncertainty in the expansion planning process.

As network investments take place in a European context, it is important to achieve a high level of coordination among the different systems and actors involved in the selection of network reinforcements. It is important that the right incentives and conditions are provided for achieving the cost-efficient construction of the required reinforcements. Additionally, the ability of potential beneficiaries to propose and promote the construction of grid reinforcements should be confirmed and preserved. Stakeholders may promote the construction of some new assets if strong enough incentives are perceived by them and they are allowed to do so. This depends, among other things, on the nature of the entity proposing reinforcements and the nature of the entity approving them.

5.3. Possible policy options to reach the projected EU 2050 grid architectures

In this section the several options identified for 2050 are further described and detailed by providing an additional explanation, insight of the governance model used as inspiration, some benefits and disadvantages of the option and, finally, possible intermediate measures to overcome the hurdles to implement this option by 2050. Given the complexity and overarching character of this building block in particular, a general overview of the process of the development of the grid, put forward by this study, is explained and visualised in annex 2 as additional support.

5.3.1. Option 1

The expansion of the cross-border transmission grid in Europe should be computed centrally following a top down approach, taking into account the needs and requirements of the countries involved through close cooperation with the national TSOs. Then, all benefits from all perspectives of all the potential cross-border transmission investments in the European system need to be taken into account jointly, together with their costs, to determine which reinforcements to undertake. This top-down approach shall be applied in combination with a bottom up one to consider the available knowledge of the regional and national networks and their requirements, the specifics of the grid, and the investments needed locally.

Explanation

The expansion planning process affecting the European cross-border grid should be run centrally considering jointly benefits of all types produced by all proposed projects, i.e. following a top-down approach. As such, at a central level, the amount of new transmission capacity needed in each corridor and the timeframe for the deployment of this capacity would be determined. Reinforcement proposals resulting from this central planning process should be computed considering the specificities of regional and national networks, as well as the local investments needed in these. Besides, the compatibility of cross-border reinforcement proposals with the safe functioning of local systems and local network expansion plans should be checked by local authorities. Thus, this top-down approach should be combined with a bottom-up one.

Governance model inspiration

Centralized network expansion planning by authorities is the scheme for the expansion of the grid applied in a large part of the existing national systems in the world as well as in several of those explored within the project, such as Brazil. Also in Europe, following the TYNDP approach as described below, there is an evolution towards a more top-down planning approach in combination with a bottom-up one. A further inspiration for the implementation of coordinated network expansion planning in a regional market is the Central American regional market, where the construction of relevant reinforcements of a cross-border nature is being planned by a central regional planner, the EOR, and approved by the central regional regulator, the CRIE. Coordinated planning is finally also being applied within RTO regions in the USA.

Description of current status

Since the late 1990s, the EU has adopted several legal and regulatory packages in order to establish an Internal Energy Market (IEM). The third and last package dates from 2009. For electricity, the package includes (i) Directive 2009/72/EC concerning common rules for the internal market in electricity (EU, 2009a), (ii) Regulation (EC) No 713/2009 establishing an Agency for the Cooperation of Energy Regulators (EU, 2009b), and (iii) Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity (EU, 2009c).

A major requirement of Regulation 714/2009 is that the European Network of Transmission System Operators for Electricity (ENTSO-E) shall adopt and publish a non-binding, community-wide Ten-Year Network Development Plan (TYNDP) every two years. This plan shall include the modelling of the integrated network, scenario development, a European generation adequacy outlook and an assessment of the resilience of the system.

In addition, as part of its Energy Infrastructure Package (EIP), the EC has released more recently Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure (EU, 2013a). This regulation sets out a new framework for infrastructure planning and project implementation for the period up to 2020 and beyond. It identifies the trans-European energy infrastructure priorities which need to be implemented by 2020 in order to meet the EU's energy and climate policy objectives, sets rules to identify projects of common interest (PCIs) necessary to implement those priorities, and lays down measures in the field of the granting of permits, public involvement and regulation to speed up and facilitate the implementation of those projects, including criteria for the eligibility of such projects for EU financial assistance through the Connecting Europe Facility (CEF). 6

Ten-Year Network Development Plan (TYNDP): purpose and evolution

The Ten-Year Network Development Plan (TYNDP) is a biennial package developed and published by ENTSO-E. It provides an overview of the transmission expansion plans that are identified as necessary to ensure that the transmission grid facilitates the achievement of EU energy policy goals, in particular to maintain security of supply, mitigate climate change and facilitate the development of the internal energy market (IEM).

The first (pilot) TYNDP was published by ENTSO-E on a voluntary basis in spring 2010, in anticipation of Directive 72/2009 and Regulation 714/2009. The 2012 release built on this experience and the feedback received from stakeholders, proposing the first draft of a systematic Cost Benefit Analysis (CBA). For the preparation of the 2014 release, ENTSO-E decided to anticipate the implementation of Regulation 347/2013.

For the TYNDP 2014, ENTSO-E has improved the study tools and process to speed up and strengthen data collection, model calibration, consistency checks and the merging of pan-European and regional results. So, the TYNDP is a continuously evolving process including new features and improvements. The 2016 release of the TYNDP is expected to include some additional features, such as an increased level of transparency of the TYNDP, new guidelines for the inclusion of projects in the TYNDP, and a full implementation of the enhanced CBA methodology as approved by the EC on 4 February 2015.[7]

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[6] The Connecting Europe Facility (CEF) is established separately in Regulation (EU) No 1316/2013, which determines the conditions, methods and procedures for providing EU financial assistance to trans-European networks in order to support projects of common interest (PCIs; see EU, 2013c).

[7] For details and other changes of the TYNDP 2016, see the website of the ENTSO-E: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/ten%20year%20network%20development%20plan%202016/Pages/default.aspx

TYNDP 2014: process

Figure 7 provides an overview of the TYNDP 2014 process as implemented over the period 2012-2014. The major elements of this process include:

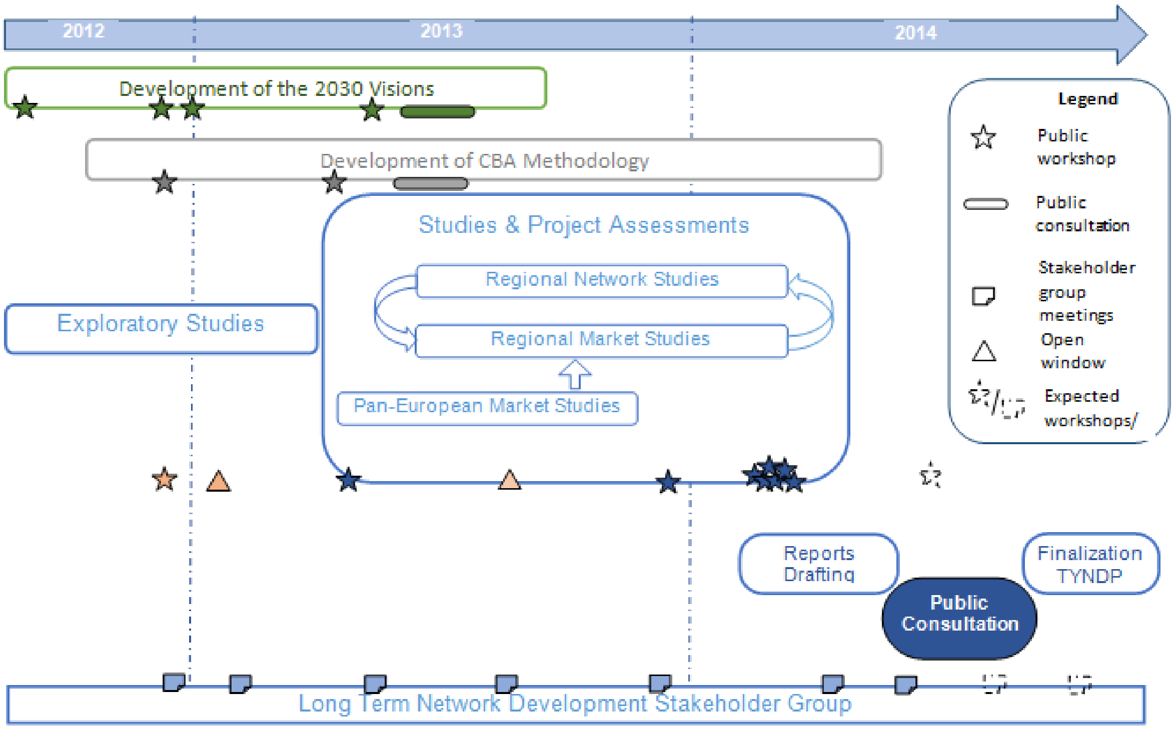

Figure 7: Overview of the TYNDP 2014 process. Source: ENTSO-E (2014a).

- *Development of the 2030 Visions.* As part of the TYNDP 2014, ENTSO-E has constructed four distinct scenarios of the European electricity system in 2030, known as the 2030 Visions. These visions are designed along two axes: (i) reaching the EU's commitment to reduce greenhouse gas emissions set out in the 2050 Energy Roadmap, and (ii) the degree of European integration required to achieve the EU objectives. Vision 1 ('Slow Progress') and Vision 3 ('Green Transition') are bottom-up scenarios that are jointly derived from the input data provided by individual TSOs. Vision 2 ('Money Rules') and Vision 4 ('Green Revolution') are top-down scenarios constructed so that the EU energy policy goals are achieved (ENTSO-E, 2013b).[8]
- *Development of the CBA methodology.* As part of the TYNDP 2014, ENTSO-E has further developed the methodology for the Cost Benefit Analysis (CBA) of the investment projects included in the TYNDP 2014. The CBA describes the common principles and procedures, including network and market modelling methodologies, to be used when identifying

[8] These visions are not directly used by TSOs. National planners construct their own scenarios derived from EU scenarios. As a consequence, the scope and methodology differ between national TYNDPs. These heterogeneous national TYNDPs are a basis for discussion on regional TYNDPs.

transmission projects and for measuring each of the cost and benefit indicators in a multi-criteria analysis (for further details, see ENTSO-E, 2014a).

- *Undertaking of several studies and project assessments.* For each scenario ('Vision'), market and network studies have been conducted at the pan-European/regional level in order to assess the size, robustness and other characteristics of network investment needs (including electricity transmission and storage needs). In addition, proposed projects to address these needs have been assessed by means of CBA indicators such as project costs, socio-economic welfare, network adequacy, environmental impacts, network resilience and RES integration.
- *Stakeholders involvement and public consultation.* Over the period 2012-2014, ENTSO-E has organised several exchanges with stakeholders and public interest groups regarding the TYNDP 2014, including (ENTSO-E, 2014a):
    - Several dedicated public workshops and stakeholder consultations, organized by ENTSO-E and its members on the construction of the scenarios, the preparation of the CBA methodology and the production of the first results and project assessments;
    - A '*Long-Term Network Development Stakeholders Group*', gathering 15 members, designed to debate and finalise the methodology improvements, either regarding the TYNDP itself or grid development more generally (ENTSO-E, 2013a);
    - Dedicated bilateral meetings, especially with DG Energy, ACER and market players also contributed interesting inputs by sharing concerns, jointly developing more and more harmonised methodologies and agreeing on the expected outcomes of the process. In practice, notably the European Commission and ACER exert major influence and actually set major conditions regarding the TYNDP process.

TYNDP: project portfolio

In line with Regulations (EC) 714/2009 and 347/2013, the ENTSO-E TYNDP includes a full comprehensive list of transmission and storage projects of pan-European significance. In order to reach this comprehensive list, ENTSO-E opens for each TYNDP a dedicated application window during which promoters can apply for their projects to be included in the community-wide TYNDP.

A candidate project is accepted for inclusion in the TYNDP 2014 if all the technical and legal requirements are respected as set in the EC *Guidelines on equal treatment and transparency criteria to be applied by ENTSO-E when developing its TYNDP as set out in Annex III 2(5) of Regulation (EU) No 347/2013*.[9] The process for the acceptance, inclusion and assessment of projects in the TYNDP starts with the application and collection of the projects, by a public consultation on the candidate list of projects. At the end of the consultation, ENTSO-E will publish the list of accepted projects for inclusion and assessment in the TYNDP framework.

Projects of pan-European significance can be promoted by ENTSO-E members – i.e. licensed transmission system operators (TSOs) of ENTSO-E Member States – as well as by the so-called 'third

[9] A first draft of these guidelines was published in February 2015 (see EC, 2015). A final version is expected later this year.

parties', such as TSOs not within ENTSO-E, promoters in a non-regulated environment or promoters of electricity storage projects.[10]

TYNDP: projects of common interest (PCIs)

Regulation (EU) 347/2013 sets the governance regime for the so-called 'Projects of Common Interest' (PCIs). PCIs are in fact a subset of the projects of pan-European relevance included in the TYNDP. According to Regulation 347/2013, a major condition for electricity and storage projects to apply for the PCI status and process is that they are included in the latest available TYNDP as projects of pan-European relevance. Actually, Regulation 347/2013 mandates the TYNDP as the sole basis for identifying, selecting and assessing PCIs. However, the selection and assessment process for projects to gain inclusion in the list of PCIs is more restrictive and separate from that of being included in the TYNDP. In addition, this process is followed subsequently to the derivation of the TYNDP and is the primary responsibility of the EC. Moreover, if successful, it results in certain benefits for PCIs compared to other, non-PCI, projects of pan-European relevance (see below).

In addition to being included in the TYNDP, a PCI has to meet the following general criteria (EU, 2013a):

a) the project is necessary for at least one of the energy infrastructure priority corridors and areas listed in Annex I of Regulation 347/2013;
b) the potential overall benefits of the project – assessed according to the respective specific PCI criteria mentioned below – outweigh its costs, including those taking place in the longer term; and
c) the project meets any of the following criteria:

    i. involves at least two Member States by directly crossing the border of two or more Member States;
    ii. is located on the territory of one Member State and has a significant cross-border impact as set out in Annex IV.1 of Regulation 347/2013;
    iii. crosses the border of at least one Member State and a European Economic Area country.

Moreover, each specific category of energy infrastructure projects has to meet certain specific criteria to qualify for the PCI status. For electricity transmission and storage projects falling under the energy infrastructure categories set out in Annex II.1(a) to (d) of Regulation 347/2013, the project is to contribute significantly to at least one of the following specific objectives:

a) market integration, inter alia through lifting the isolation of at least one Member State, reducing energy infrastructure bottlenecks, and enhancing competition and system flexibility;

[10] For details on different categories of project promoters, as well as on the set of legal criteria and other conditions to apply for project inclusion in the TYNDP, see EC (2015).

b) sustainability, inter alia through the integration of renewable energy into the grid and the transmission of renewable generation to major consumption centres and storage sites;
c) security of supply, inter alia through interoperability, appropriate connections and secure and reliable system operation.

The selection of PCIs is conducted in a two stage process involving two levels of decision making (EU, 2013a):

1. *The regional level.* To help decide which projects qualify as PCIs, the EC relies on Regional Groups for each of the twelve energy infrastructure priority corridors and areas mentioned in Annex I of Regulation 347/2013. For electricity, each Group is composed of representatives of the Member States, national regulatory authorities, TSOs, as well as the EC, ACER and ENTSO-E. Project promoters submit their project proposals to the relevant Regional Group. The decision-making body of each Group adopts a regional list of proposed PCIs and submits it to the EC.
2. *The EU level.* Based on the regional lists, the EC takes the final decision on the EU-wide list of PCIs. The EC is set to publish a list of PCIs every two years. The first PCI list was released in 2013, including almost 250 PCIs. The majority of these projects are in the field of electricity, prevalently transmission lines, fourteen storage projects and two smart grid projects (EC, 2013a and 2013b).

Once selected on the EU-wide list of PCIs, the projects concerned have certain advantages over others, notably (EC, 2013a):

- Accelerated planning and permit granting procedures, including a binding three-and-a-half-years' time limit for the granting of a permit, and the selection of a single national authority to deal with, when it comes to the obtaining of permits ('one-stop shop');
- Improved regulatory treatment, including appropriate incentives for higher-risk investment projects;
- The possibility of receiving financial support under the Connecting Europe Facility (CEF).

Being selected 'Project of Common Interest', however, is no guarantee for EU financial support. In particular, to be considered for grants for construction works, a PCI has to meet several conditions. Notably, it has to be proved that the project is commercially not viable, while meeting the specific criteria on the social benefits produced regarding market integration, sustainability or security of supply (EC, 2013a and 2013c).

Advantages and disadvantages

Advantages	Disadvantages
A top-down expansion planning process is best placed to integrate big corridor projects with impacts on a multitude of countries. Besides, it overcomes the possible disadvantages of an uncoordinated process involving bottom-up planning.	A top-down planning process could face opposition from national and local regulators as they may lose part of their authority, power and influence.
A top-down planning approach ensures best the elaboration of a European integrated grid planning, analyzing the impacts of all projects on each other. This is necessary, as	NIMBY complaints may be more common for investments approved centrally at European level.

benefits produced by some investments will be contingent on the construction of other reinforcements.	
Integrating the knowledge of local grids and systems into cross-border expansion planning ensures that the most fit-for-purpose investment decisions are made. The interaction between the European cross-border network expansion planning and regional/local planning processes enhances the opportunity to take into account local specificities, acceptance requirements and constraints.	The needed interaction between central and local network expansion planning may increase the complexity of the whole process.
	Looking after system security, entities involved in the planning of the expansion of the cross-border grid may probably be encouraged to undertake more reliability investments than needed.

Hurdles for the implementation and measures to overcome these

Implementing the option 1 might face the following hurdles:

- *Opposition of current planning authorities,* including national planners and regulatory authorities, as they might be reluctant to loose part of their planning authority, power and influence, notably with regard to those planning and investment decisions that affect their core interests.
- *Rising NIMBY complaints,* as some of the network reinforcements approved may face strong opposition from local authorities and communities, which may not be willing to have a new line crossing their territory that is approved by an external, central authority but does not meet – or even harms – their local interests.
- *The needed interaction between central and local network expansion planning may increase the complexity of the whole process.* Running a central planning process identifying, assessing and proposing cross-border reinforcements needed all over Europe requires that there is, at a central level, a detailed technical knowledge of the grid and the system operation, as well as the potential investment needs, in each country or region. Moreover, assessing and comparing all proposed projects jointly at a central level by means of a common CBA methodology makes the planning process rather burdensome from a computational perspective.
- *Looking after system security, entities involved in the planning of the expansion of the cross-border grid may probably be encouraged to undertake more reliability investments than needed.* This disadvantage could however be limited with appropriate regulatory oversight and bearing in mind that some security margins should be considered in the perspective of a secure and safe operation of the transmission grid.

In order to overcome these hurdles, the following intermediate steps towards 2050 can be proposed:

- To reduce the opposition from national planning authorities, they should be closely involved in the (central) planning process of identifying, assessing, proposing, approving and implementing projects of pan-European significance in their jurisdiction. In addition, awareness campaigns could be set up to show the benefits of these projects for the European community as a whole, including the respective Member States involved. These campaigns should also stress the fact that the central planning process only refers to projects of pan-EU or regional significance and not to other transmission projects (which are left to the discretion of the respective national planning authorities).

- Rising NIMBY complaints from local authorities and communities can be reduced or avoided by (i) more stakeholder involvement in investment decisions, (ii) having a fair allocation of costs and benefits of reinforcements, (iii) applying subsidies to compensate for extra costs related to socio-economic benefits of stakeholders which are not embedded in the electricity market (e.g. environmental costs), (iv) the payment of compensations to local communities negatively affected, or (v) organizing campaigns showing the benefits of the projects.
- To address the complexity of the combined top-down and bottom-up planning process, the central planning process should rely on a close cooperation and coordination with national planning authorities (i.e. notably TSOs). Moreover, over time, the central planning should gradually improve (i) its capacity to collect and process the data and address other information needs, (ii) its knowledge and expertise on the European power transmission system and potential investment needs, and (iii) its tools and methods for assessing and comparing all proposed projects jointly at a central level by means of a common CBA methodology.
- In order to reduce the risk of undertaking more reliability investments than needed, proposed projects should be assessed and approved by independent regulatory authorities based on a social cost-benefit analysis.

5.3.2. Option 2

Investment proposals resulting from the coordinated expansion planning process should be assessed and approved by European institutions with executive powers, in accordance with Member States, looking after the interest of the largest possible share of stakeholders in the European system, taking into account local needs.

Explanation

The coordinated expansion plan computed at European level should be considered a constraint that needs to be complied with by national network expansion plans considering the execution of specific investment projects. In other words, within the scheme proposed here, the pan-European coordinated process for the assessment and approval of cross-border reinforcements is to coexist with national authorization procedures, which should nevertheless find the way to accommodate reinforcements identified as necessary from a European perspective. In order to provide a higher level of involvement of local stakeholders in the network development process, competent European regulatory bodies, namely ACER, should organize an open stakeholder consultation when assessing proposed reinforcements.

Governance model inspiration

Similarly to option 1, providing central regulatory bodies with executive powers over the authorization of the construction of reinforcements proposed by planning authorities is currently a feature of schemes for the expansion of the grid in a large number of systems in the world, p.e in the Brazilian system. A further clear inspiration for the implementation of a central body with executive powers over network expansion authorization in a regional, or multinational, context is the Central American regional market. However, contrary to what occurs for cross-border reinforcements in

Central America, the pan-European permit granting process is to coexist with national authorization procedures.

Providing a large level of involvement of stakeholders is a pillar of the network development process in the UK, allowing final reinforcements made to have a higher level of acceptance, and also in the Argentinian model, where stakeholders are closely involved through the public contest method.

Description of current status

The current central (EU) regulatory authority for energy issues is the Agency for the Cooperation of Energy Regulators (ACER), established by EC Regulation No 713/2009. According to this regulation, the main ACER duties related to network planning in general and the TYNDP in particular are:

- To provide opinion on the contribution of the TYNDP to the objectives set by Regulation (EC) 714/2009. ACER provides opinion and recommendations to ENTSO-E, the European Parliament, the European Council and the European Commission where it considers that the draft TYNDP (i) does not contribute to achieving the non-discrimination of stakeholders in energy market/grid access, or to achieving effective competition and a high enough level of efficiency of the energy market, or (ii) does not contribute to a sufficient level of cross-border interconnection open to third-parties, or (iii) does not comply with the provisions of the third IEM package.
- To assess the consistency of the community-wide TYNDP and national plans. If ACER identifies inconsistencies, it recommends amending the national plan or the Community-wide TYNDP as appropriate.
- To monitor the implementation of the TYNDP. If ACER identifies inconsistencies between the Community-wide TYNDP and its implementation, it investigates the reasons and makes recommendations to TSOs, NRAs and other competent bodies, with a view to implementing the investments.

In addition, ACER is allocated some tasks under Regulation (EU) 347/2013, notably with regard to the Projects of Common Interest (PCIs), including:

- Participation in the activities of Regional Groups for electricity priority corridors and areas;
- Contribution, if necessary, to the assessment of projects proposed by National Regulatory Authorities and provision of support to ensure cross-regional consistency;
- Providing its opinion on the draft regional lists of proposed PCIs;
- Monitoring the implementation of PCIs (a report is submitted to the Regional Groups on an annual basis).

The current role of ACER in the field of EU cross-border transmission network planning is thus largely restricted to providing opinion on the TYNDP and the list of PCIs, monitoring the implementation of the (non-binding) TYNDP, assessing the consistency of the TYNDP and national plans, and making recommendations if it identifies inconsistencies between these plans and the TYNDP. Although ACER has some influence on the planning process of cross-border reinforcements, it does not actually assess and approve proposed projects, let alone it has real executive powers in this field.

Advantages and disadvantages

Advantages	Disadvantages
Once investments are approved, the planning scheme should be agile in achieving the construction of new lines, as National, one-stop, planning processes should commit to central decisions. If central decisions are made as binding, the process of obtaining the local permits should be expedited.	A top-down, central EU project assessment and approval process could face opposition from national regulators as they (may fear to) loose regulatory power.
More harmonization and uniformity in investment approval processes could be achieved if all cross-border projects are approved centrally.	NIMBY complaints may be more common for investments approved centrally.
European interests are best assessed at European level, rather than by a multitude of national authorities.	A central assessment and approval process may become quite complex, requiring local project data and expertise.
The role to be played by central regulatory bodies related to the approval of investments could be easily adapted to the conditions applying in each system or region.	Looking after system adequacy, European regulators would be encouraged to approve more reliability investments than needed.
This scheme would allow aligning at European level the requirements considered for project approval. At the same time, it could take into account the existing heterogeneity of geographic conditions and population density.	

Hurdles and measures to overcome these

In order to implement option 2 by 2050, similar hurdles as discussed for option 1, as included in the table of disadvantages above, will need to be overcome.

In order to reduce the above-mentioned hurdles, similar policy measures as under policy option 1 are thus proposed. Regarding EU/national regulators, these measures might include in particular:

- To reduce the possible opposition from national regulators, they should be closely involved in the central assessment and approval process of projects of pan-European significance affecting their jurisdictions.
- In order to reduce the risk of undertaking more reliability investments than needed, proposed projects should be assessed and approved by independent regulatory authorities based on a social cost-benefit analysis.

5.3.3. Option 3

Considering that merchant cross-border investments by private promoters are allowed, also investments by associations of network users should be allowed.

Explanation

This would come as an additional way to promote network investments, i.e. investments promoted by network users would not be replacing regulated cross-border investments planned in a coordinated way. The latter should have priority over investments by merchant entrepreneurs and those by associations of network users. Before allowing private network investments to take place, additional and special checks are to be installed in order to ensure these investments comply with the following conditions (see EU Regulation 714/2009):

- They should not be detrimental to the functioning of the system, or the market;
- They should complement regulated investments to be undertaken, rather than interfering with optimal investment decisions made by planning and regulatory authorities. The local TSO(s) should not be interested in undertaking, or able to undertake, these investments within a certain period of time.
- These checks should be run by regulatory authorities, whose approval is needed to go ahead with private investments, as for any other network investment.

Governance model inspiration

Regulated network expansion schemes are the main way to organize the development of the transmission grid in most power systems in the world, including the vast majority of cases explored in the project, such as Brazil, Germany or the RTO regions in the USA. In some of these systems, regulated investments coexist with merchant ones. This is the case of the regional market in Central America, regional markets (RTO regions) in the USA, Brazil, and Europe, where European legislation considers the existence of this type of investments, for which promoters can, under certain conditions, negotiate access with prospective users.

Additionally, there are some countries where investments by associations of network users are possible. A paradigmatic case of this is the Public Contest method applied in Argentina. In this system, after a quasi-judicial process where stakeholders can provide arguments in favor or against the undertaking of a network reinforcement, if the project is approved, network users promoting it are entitled to (part of) the ownership rights of the project together with the obligation to pay the corresponding fraction of its construction, operation and maintenance cost. Network investments by network users are also allowed in the Central American regional market, where many of these reinforcements are associated with the connection of a new agent to the main regional grid.

Description of current status

In the current TYNDP process, private promoters are allowed to propose merchant investment projects (provided these projects meet the conditions for third party access laid down in EU Regulation 714/2009). In the TYNDP process, merchant projects are treated as a subset of the so-called 'third party' projects, i.e. projects promoted by non-ENTSO-E members. Within the ENTSO-E TYNDP process, projects promoted by third parties – including merchant projects – basically follow the same application, assessment and approval procedures, and have to meet the same criteria as projects proposed by ENTSO-E members. If a proposed merchant project is not approved ('non-eligible'), ENTSO-E shall provide adequate justification to the respective promoter, underlying the reasons for which the project is considered non-eligible. In this case, the promoter has the possibility to file a request for review by letter, which has to be addressed by ENTSO-E no later than one month after receiving the official letter (ENTSO-E, 2013c).

Advantages and disadvantages

Advantages	Disadvantages
Merchant projects and those promoted by associations of users could concern needed reinforcements that authorities have failed to identify.	Disputes over whether some investments should be carried out as regulated ones, or as investments at risk by private promoters, may occur. Disputes may also concern the capacity, technology, and other features of new projects that are approved as investments at risk.
Associations of network users could have complementary or cheaper access to funds used to undertake some specific reinforcements benefiting them, since market benefits of these projects obtained by users could be used as collateral.	Merchant promoters and associations of network users could aim to promote those projects that are most attractive, because their market value is high or are easy to finance and build, and leave less attractive ones to be built as regulated reinforcements.
Investments by merchant promoters and associations of users could expedite the construction of those new assets whose beneficiaries are few.	It is not clear to what extent, and how, the merchant investor's long term revenues should be protected if both tender-based coordinated planning and merchant-based decentralized planning should be implemented.
Allowing private agents to build new assets that they are willing to pay, provided they meet the conditions above, would make the development of the grid and that of the system more dynamic in taking advantage of new market opportunities.	

Hurdles and measures to overcome these

The main hurdles regarding policy option 3 include:

- Merchant promoters may not be familiar with the ENTSO-E TYNDP application, assessment and approval procedures. Besides, these merchant promoters may have some uncertainty about whether their projects will be assessed fairly and equally to projects proposed by ENTSO-E.
- Disputes over whether some investments should be carried out as regulated ones, or as investments at risk by private promoters, may occur. Disputes may also concern the capacity, technology, or other features of new projects that are approved as merchant investments.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed:

- Setting clear and transparent rules regarding the ENTSO-E TYNDP application, assessment and approval procedures, which should be fairly and equally applied to all projects proposed by either ENTSO-E members or third parties (including merchant promoters). Moreover, if a proposed merchant project is not approved, the promoter should have the possibility to file a request for review by an independent authority, e.g. ACER, rather than by ENTSO-E itself. In the long run, the whole process of assessing and approving all proposed projects – by both ENTSO-E members and third parties – should be conducted by an independent regulatory authority, in order to guarantee a clear, transparent and fair process.

- In addition, clear, transparent and fair rules and procedures should be set on the features that these (private) investments should have. For instance, in AC networks preference should be given to regulated investments, as it is hard to control (the impacts of investments on) network flows in these networks. In DC connections, merchant investments could play a role, notably in those cases where too little regulated investments are realised.
- In order to ensure that the merchant investor's long term revenue is protected if both tender based coordinated planning and merchant based decentralized planning should be implemented, the USA approach (i.e. an open season approach to allow the merchant transmission investor to sign a contract with potential users of merchant facilities before these are built) could be considered.

5.3.4. Option 4

The top-down planning methodology applied should jointly identify all reinforcements to be made of the cross-border grid in Europe, taking into account all possible future scenarios and operation conditions, with the aim to maximize social welfare of Europe as a whole.

Explanation

In order to maximize the overall social welfare of the European system, all types of benefits (i.e. economic, reliability and environmental ones), both positive and negative in sign, resulting from regulated reinforcements would need to be considered in the project proposal and approval phases. Besides, all projects should be jointly considered regardless of the country or system where they are to be built. This is needed to take account of all benefits from reinforcements, which in many cases are contingent on the undertaking of other reinforcements.

At the same time, investment decisions made should be robust against a multiplicity of possible future scenarios (the minimization of the maximum cost of regret could be applied to ensure this, for example). Thus, representative scenarios should be jointly considered in the network expansion planning algorithm. Operation situations considered should be representative of all those that may occur in reality throughout the target year in the planning horizon.

Governance model inspiration

Several scenarios are being jointly considered in the Central American planning algorithm. However, they are just taken into account to minimize the maximum regret possible resulting from the deployment of the expansion plan being computed. Apart from that, algorithms being applied in other systems to compute network reinforcements largely neglect uncertainty and part of the benefits caused by investment projects, or take them into account in an overly simplified way.

Description of current status

In the current (2014) TYNDP process, all investment projects are assessed by ENTSO-E's Regional Groups using a common cost-benefit analysis (CBA) methodology against the background of four ENTSO-E 2030 Visions. These Visions are descriptions of four extreme future scenarios, built on the interaction of economic parameters, such as economic growth or fuel prices, that drive decisions on investments in electricity generation and demand.

The 2030 Visions are developed by ENTSO-E in collaboration with stakeholders through various workshops and public consultations. The Visions are contrasted in order to cover every possible development foreseen by stakeholders. The Visions are neither predictions nor forecasts about the future, but rather selected possible 'extreme' outcomes of the future, so that the actual pathway realized in the future falls with a high level of certainty in the range described by the Visions (ENTSO-E, 2014a and 2014d).

The four contrasted vision scenarios are used for project assessment in the 2030 horizon. Individual transmission projects are assessed with regard to their impacts (i.e. costs and benefits) under each of the four extreme sets of conditions (ENTSO-E, 2014d). In order to conduct these project assessments, ENTSO-E has developed a common CBA methodology, which has been applied on a voluntary pilot basis to the majority of impacts of all approved projects included in the 2014 TYNDP process. For the 2016 TYNDP process, the CBA methodology is compulsory and will be applied fully to all impacts and all projects considered.

The CBA methodology outlines the common principles and procedures, including network and market modelling methodologies, to measure each of the indicators for the costs, benefits and other (social, environmental) impacts of each project in a multi-criteria setting. The benefits considered include (positive or negative) impacts on security of supply, socio-economic welfare, RES integration, thermal losses in the power system, CO_2 emissions, technical resilience and flexibility. The indicators for the environmental and social consequences refer to the project impacts on protected areas and (local) populations in urbanized areas, respectively (ENTSO-E, 2013d).

While some indicators – notably for project costs and socio-economic welfare – are monetized, i.e. expressed in monetary units (Euros), other indicators are measured in physical units (e.g. in MWhs). This is certainly true for the impact on security of supply, RES integration, technical flexibility and resilience, as well as for the social and environmental impacts. As a result, the CBA outcomes cannot be directly compared or added up into a single value. Consequently, ENTSO-E does not explicitly rank assessed projects in the TYNDP but simply presents the outcomes in terms of a multi-criteria assessment (without weighing the scores obtained by projects for the several criteria).

In the current arrangements, it is at the discretion of each stakeholder – or each Regional Group of stakeholders – to provide weights to the criteria according to their own objectives, and eventually rank the projects. Under different circumstances, different criteria may be more important than the remaining ones for a given stakeholder. This may affect the overall assessment, ranking and selection of the respective projects (ENTSO-E, 2014d).

Although, in theory, it would be possible to monetize the impact of a transmission project on security of supply considering the value of lost load (VoLL), at present this is not done.[11] The reason is that ENTSO-E wishes to base its cost benefit analyses on economic parameters established by international bodies or on methodologies approved by international institutions. Hence, CO_2 values and fuel costs are based on values published by the IEA. Although the Council of European Energy Regulators (CEER) has published a methodology to compute national VoLL figures, this methodology has only been applied in a few European countries. Therefore, national VoLL values are not available in every country. Besides, VoLL figures that are available have not been set with comparable methodologies. ENTSO-E will only be able to monetise amounts of loss of load being computed when a methodology for this has been applied throughout Europe in a homogenous way (ENTSO-E, 2013e).

Currently, ENTSO-E systematically quantifies the decrease in loss of load expectancy achieved by each TYNDP project (in MWh). This allows comparing the contribution of projects to security of supply on a consistent basis. If they wish, EU Regional Groups may choose to give a weight to security of supply when assessing, comparing or selecting project options (ENTSO-E, 2013e).

In order to assess jointly the projects included in the TYNDP in a consistent way, one needs a baseline or reference network. In the current TYNDP project assessment process, the reference network is the existing network plus all main identified TYNDP developments, allowing the application of the so-called '*Take Out One at the Time*' (TOOT) approach. Hence, the reference network will represent the target capacity, taking into account the investment needs identified through market studies. The TOOT approach involves excluding investment projects from the forecasted network structure, on a one-by-one basis, and evaluating the project impacts on the several dimensions considered by comparing the system benefits in each of these dimensions with and without the examined network reinforcement (ENTSO-E, 2013d and 2014a).

The TOOT method provides an estimation of the costs and benefits produced by each project, as if it was the last to be commissioned. In fact, the TOOT method evaluates each new project in the context set by the construction of the whole forecasted network. This analysis immediately appreciates every benefit brought by each investment item when this is complementing other reinforcements, disregarding the order of the remaining investments in the plan but assuming that the concerned project is undertaken in the last place. All benefits are considered in a precautionary way. In fact, each evaluated project is considered into an already developed environment, in which all programmed projects are present. Hence, this method allows analyses and evaluations at TYNDP level considering the whole TYNDP vision (ENTSO-E, 2013d).[12]

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[11] The implications of not including the VoLL approach in the CBA methodology for the issue of cost allocation among stakeholders is discussed in Chapter 9.

[12] An alternative approach is the so-called '*Put IN one at the Time*' (PINT) methodology. This approach considers each new investment on the *given* network structure one-by-one and evaluates the project impacts with and without the network reinforcement. The PINT methodology is recommended for individual project assessments outside the TYNDP process, whereas the TOOT methodology is recommended for cost-benefit analysis of a transmission plan such as the TYNDP (ENTSO-E, 2013d).

Advantages and disadvantages

Advantages	Disadvantages
All kinds of benefits produced by lines must be considered to maximize the overall social welfare in Europe.	Could make the planning process more burdensome from a computational point of view.
Benefits produced by combinations of projects are best identified when considering all reinforcements jointly.	Ideally, joint maximization of all benefits requires explicitly monetizing them to be able to compare benefits of different kinds. However, monetizing all kinds of benefits is difficult and complex.
Making robust expansion decisions requires considering jointly most relevant possible future scenarios.	

Hurdles and measures to overcome these

The top-down planning methodology as proposed under policy option 4 faces the following hurdles:

- Considering all types of costs and benefits produced by reinforcements in the network expansion planning process certainly makes this process more complex. The same applies when considering jointly the impacts on system operation of all reinforcements approved. All this will make the network expansion planning for a large system like the European one more burdensome from a computational perspective.
- The proposed assessment approach addresses some current shortcomings, which may however be hard to overcome. In brief these shortcomings include:

  1. In addition to the benefits included in the current CBA approach, there are also other benefits such as the benefits of competition due to a network investment. As these benefits are more difficult to model, they are presently not explicitly taken into account.
  2. Due to a lack of data and/or appropriate measurement tools, some CBA indicators are computed in a rather simple way, or assessed by simplified methodologies. This may question, or complicate, the overall assessment of a project, as well as the comparability of the impacts of a certain kind of several competing projects.
  3. The impacts assessed by the current CBA approach are not, or cannot be, expressed objectively in the same (monetary) unit. This further complicates the overall assessment and comparability of project impacts.

Some of the shortcomings of the current methodology mentioned above may, to some extent, be overcome by intermediate measures, but this could make the planning process even more burdensome from a computational perspective. Hence, there is a trade-off to be made between improving the process, on the one hand, and not increasing substantially its complexitiy, on the other hand.

Should the process be further improved, e.g. by improving the modelling tools and expertise, the following aspects could be considered:

- Improve CBA indicators, measurement tools and available data collection processes in order to enhance the quality and reliability of the overall assessment and comparison of project impacts.
- Try to monetise as far as reasonably possible all project impacts in an objective way. This applies in particular to the VOLL indicator for the impact on security of supply by developing and applying a common VOLL methodology throughout Europe in a homogenous way.
- Set minimum conditions (or constraints) for those CBA indicators that are hard to monetise in an objective way. This will enhance and facilitate the comparability of the impacts of (competing) projects meeting these minimum conditions. However, for some impacts – e.g. on biodiversity – it may be hard to set (objective) minimum standards that are widely accepted.
- Set clear, transparent and widely accepted assessment procedures for those CBA indicators that are hard to monetise in an objective way and for which it is hard to set (objective) minimum conditions.
- Set a proper methodology for the assessment of the incremental benefits of a project when implemented in combination with others. Limitations, or drawbacks, of the TOOT methodology could be overcome.
- Develop a stochastic approach to jointly deal with benefits in all scenarios of projects in order to select the optimal ones in the expansion planning process. Alternatively, a methodology should be developed to identify those reinforcements that are robust against (almost) any scenario.

5.3.5. Option 5

The coordination between generation and network investments should be strengthened. Coordinating signals like indicative network charges or energy prices could be used for this.

Explanation

Coordination between generation and transmission investments could be achieved by sending information to potential new generators on the network charges they are expected to pay depending on their location.[13] These indicative/compulsory network charges would be computed at the moment in time when the decision on the installation of these generators is made, and should be based on the most accurate information available by then on the future development of the network and the system in general. Additionally, an estimate of future energy prices per zone or area in the system could also be provided by planning authorities, power exchanges or independent research institutes.

Governance model inspiration

The Brazilian system has served as inspiration for the proposal to implement signals coordinating generation and transmission expansion. In the Brazilian system, transmission charges paid by new conventional generators to be installed in each area of the system are computed based on the best estimates by authorities of the future development of demand and generation in this system. The

[13] Some specific issues related to the coordination between generation and transmission investments are discussed in more detail in either Chapter 9 (BB Cost Allocation) or Chapter 10 (BB Technical and Market Operation).

level of these charges is set for the first ten years of operation of new conventional generators. A large part of new conventional generators are installed as a result of long term new energy auctions being called by authorities, where these new generators are allocated the production of a certain amount of energy over a certain amount of time at a certain price. However, network charges to be paid by generators in each area are computed before these auctions take place, in order for generation companies to be able to take network costs they are facing in each area into account when bidding to get a long term new energy contract. Therefore, the actual pattern of generation, and demand in the system may differ from those assumed when computing charges paid by these generators. The difference between revenues collected from these charges and network costs caused by these generators is absorbed by demand, whose charges are modified as needed to complete the recovery of the cost of the network.

On the other hand, before the construction of new renewable generators is decided in auctions, these generators are only provided with an estimate of transmission charges to be paid by them in each area. Actual charges levied on them are only computed once auctions have taken place and the real distribution of generation in the system, as well as other conditions applying in reality, are known. In this case, transmission charges guiding the investment decisions of these generators are indicative.

Description of current status

At present, there is little to no coordination between the development of electricity generation and transmission investments in the EU. In many EU countries, national regulators oblige network operators to connect new generators to the grid, to give generators access to the grid and to transport the electricity of these generators under all situations and at all locations and, if necessary, they even have to reinforce the network to meet this obligation. This approach is usually called the 'transmission-follows-generation approach' and is based on the assumption that the network is a big copper plate with unlimited capacity.

EU regulation in this field, however, seems to go less far. Article 32, part 2, of Directive 2009/72/2009 states that: "The transmission or distribution system operator may refuse access where it lacks the necessary capacity." In addition, this Article states that: "Duly substantiated reasons must be given for such refusal….based on objective and technically and economically justified criteria", that "the system user who has been refused access can make use of a dispute settlement procedure" and that "the transmission or distribution system operator provides relevant information on measures that would be necessary to reinforce the network."

In addition, Article 16, part 2 (b), of Directive 2009/28/EC states that: "Member States shall also provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources". Therefore, in the EU regulation, unconditional connection and access to the grid seems to be restricted to electricity generation from renewable energy sources.

Moreover, at present, there is generally little room in the EU to allocate to (RES) producers the full network costs they are causing, and/or to apply locationally differentiated network tariffs. This is due to national EU regulation to warrant national producers from international competition or to stimulate electricity generation from renewable resources. In general, setting (location specific) network tariffs is still the competence of the Member States. EU Regulation No 714/2009, however, provides some guidelines for locational signals when setting the rules on harmonised network tariff structures (EU, 2009c). Up to now, however, these rules refer only to setting a limit to the *average* network tariffs charged to producers and, therefore, provide only some room for the variation of location specific network charges around the average tariff level set as a maximum for producers (ECN and SEO, 2013). Moreover, national governments do not always use this room for the reasons mentioned above.

Advantages and disadvantages

Advantages	**Disadvantages**
Relevant system cost savings could be achieved by considering transmission costs in generation investment decisions.	In many EU countries there is little regulatory room for differentiating locationally network tariffs and allocating to (RES) producers the full network costs they cause.
	Locationally differentiated network charges and electricity prices have to be known before the generation investment decision is made. Thus, a much larger amount of information would need to be released on the expected future system operation.
	Regulatory and political authorities may oppose the application of efficient network charges and prices on (certain types of) generators to protect them from competition and increase local power production from certain technologies (local coal, RES technologies, etc.).

Hurdles and measures to overcome these

When implementing policy option 5 for 2050, the following hurdles can be foreseen:

- In many EU countries, there is little regulatory room for differentiating locationally network tariffs and allocating to (RES) producers the full network costs they cause (rather than to consumers).
- Even if there is some room (created) for full network cost allocation to those agents responsible for these costs and locational tariff differentiation, Member States may be hesitant to use and extend this room for reasons of protecting national producers from international competition or stimulating electricity generation from renewable resources.
- In order to be effective, locationally differentiated network charges and electricity prices have to be known before the generation investment decision is made, ideally for the whole life time of the investment, but at least for the first years of operation that have the largest impact on investments decisions. This implies that a much larger amount of information would need to be released on the expected future system operation. Moreover, the signals to coordinate generation and transmission investments could be non-definite charges (or electricity prices), which would weaken them, since agents could not largely rely on these charges or prices computed if they are to be changed afterwards. Alternatively, charges or prices could be definite ones. However, these would not coincide with real network costs imposed afterwards by each

new generator, or the true value of power produced by it. This would create some losses of economic efficiency that would, in any case, be admissible.

In order to overcome these hurdles, the following intermediate steps towards implementing this option for 2050 could be proposed:

- Member States could agree on some EU-wide, binding rules on setting locationally differentiated network tariffs and allocating the full network costs to different types of network users responsible for them, including RES generators.
- Subsequently, ENTSO-E, in consultation with ACER and NRA's, could provide EU-wide, medium to long-term, coordinating signals on indicative, non-definite, network charges based on current insights and advanced scenario modelling work.

5.4. Least-regret policy proposal and roadmap towards 2050

Table 17 below presents a summary overview of the options for 2050 for the BB Network Design, including possible intermediate measures towards implementing these options, the main stakeholders responsible for these measures, as well as an indicative timing. Concerning timing, three time periods are distinguished, i.e. 2016-2020 (short term), 2020-2030 (medium term) and 2030-2050 (long term). The combination of short term measures can be considered as a least-regret initial policy proposal.

For some intermediate measures, early and timely implementation is favored, i.e. in the period up to 2020, as they are relatively easy to implement while improving the process of pan-European network planning in the short term. For instance, in the period up to 2020, EU regulatory authorities (EC, ACER) should set clear, transparent and fair rules and procedures on the conditions that private investments should meet to be approved.

However, other intermediate measures may be more difficult or time-consuming to implement and, hence, may require a longer time horizon for implementation. Examples include the setting of locationally differentiated network tariffs and the allocation of full network costs to the different types of network users responsible for them, including RES generators. Also, as the TYNDP methodology and the latest list of PCIs have already been approved, improvements in the methodology (p.e. trying to monetise as many impacts of projects as possible) are suggested for a 2030 horizon, rather than the 2020 one.

All these intermediate steps and final options for 2050 are considered as robust against the several scenarios and associated grid architectures considered. However, as indicated in section 3.3.3, it should be kept in mind that policy measures are more urgent to implement when policy makers strive for the fast realization of scenarios with a large share of renewable electricity and a larger demand for the transport of energy over electricity networks, such as the large scale RES and 100% RES scenarios.

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing 2016-2020	2020-2030	2030-2050
1. The expansion of the cross-border transmission grid in Europe should be computed centrally following a top down approach, taking into account the needs and requirements of the countries involved through close cooperation with the national TSOs. Then, all benefits, from all perspectives, of all the potential cross-border transmission investments in the European system need to be taken into account jointly, together with their costs, to determine which reinforcements to undertake. This top-down approach shall be applied in combination with a bottom up one to consider the available knowledge of the regional and national networks and requirements, the specifics of the grid and the investments needed locally.	• **National planning authorities (TSOs)** should be closely involved in the (central) planning process of identifying, assessing, proposing, approving and implementing projects of pan-European significance.			
	• **EU central planning authorities** should set up awareness campaigns to show the benefits of pan-European projects for the European community as a whole, including the respective Member States involved.			
	• **National and EU central planning authorities** should take measures to reduce or avoid NIMBY complaints by local authorities and communities by enhancing local acceptance, in particular by (i) more local stakeholder involvement starting from an early stage, (ii) fair allocation of costs and benefits of reinforcements, possibly including the payment of compensations to local communities, and (iii) organizing awareness campaigns showing the benefits of the project for the wider community as a whole.			
	• **The central network planning** process should rely on a close cooperation and coordination with national planning authorities in order to address the rising data and knowledge needs at the central planning level.			
2. Investment proposals resulting from the coordinated expansion planning process should be assessed and approved by European institutions, with executive powers, looking after the interest of the largest possible share of stakeholders in the European system.	• T**he central planning authority** should gradually improve (i) its capacity to collect and process the data and address other information needs, (ii) its knowledge and expertise on the European power transmission system and potential investment needs, and (iii) its tools and methods for assessing and comparing all proposed projects jointly at a central level by means of a common CBA methodology.			

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing 2016-2020	2020-2030	2030-2050
3. Considering that merchant cross-border investments by private promoters are allowed, also investments by associations of network users should be allowed.	• **ENTSO-E** should further upgrade clear and transparent rules applied in the TYNDP application, assessment and approval procedures. Rules should be fairly and equally applied to projects proposed by either ENTSO-E members or third parties (including merchant promoters).			
	• In the case that a proposed merchant project is not approved, the promoter should have the possibility to file a request for review by **an independent authority, e.g. ACER**.			
	• In the long run, the whole process of assessing and approving projects – proposed by both ENTSO-E members and third parties – should be conducted by **an independent regulatory authority,** in order to guarantee a clear, transparent and fair process.			
	• **EU regulatory authorities (EC, ACER)** should set clear, transparent and fair rules and procedures on the features these (private) investments should have.			
4. The top-down planning methodology applied should jointly identify all reinforcements to be made of the cross-border grid in Europe, taking into account all possible future scenarios and operation conditions, with the aim to maximize social welfare of Europe as a whole.	• **ENTSO-E** should look into its modelling tools and expertise so that other benefits, such as the benefit of competition, can be included in the CBA approach.			
	• In addition, **ENTSO-E** should look into the further improvement of CBA indicators, measurement tools, and available data collection processes, in order to enhance the quality and reliability of the overall assessment and comparison of project impacts.			
	• **ENTSO-E** should try to monetise as many impacts as possible in an objective way. This applies in particular to the VoLL indicator for the assessment of the impact on security of supply of projects. This should be achieved by developing and applying a common VoLL methodology throughout Europe in a homogenous way.			

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing 2016-2020	2020-2030	2030-2050
	• **ENTSO-E** should set minimum conditions (or constraints) for those CBA indicators that are hard to monetise in an objective way. This will enhance and facilitate the comparison of the impacts of (competing) projects meeting these minimum requirements.			
	• **ENTSO-E** should set clear, transparent and widely accepted procedures for the assessment of those CBA indicators that are hard to monetise in an objective way and for which it is hard to set (objective) minimum conditions.			
	• **ENTSO-E and ACER** should set a proper methodology for the assessment of the incremental benefits of a project when implemented in combination with others. Limitations, or drawbacks, of the TOOT methodology could be overcome.			
	• **ENTSO-E and ACER** should develop a stochastic approach to jointly deal with benefits in all scenarios of projects in order to select the optimal ones in the expansion planning process. Alternatively, a methodology should be developed to identify those reinforcements that are robust against (almost) any scenario.			
5. The coordination between generation and network investments should be strengthened. Coordinating signals like indicative network charges or energy prices could be used for this.	• **EU policy makers (EC, European Parliament, Member States)** should agree on some EU-wide, binding rules on setting locationally differentiated network tariffs and allocating full network costs to different types of network users responsible for them, including RES generators.			
	• Subsequently, ENTSO-E could in consultation with ACER and NRAs provide EU-wide, medium to long-term coordinating signals on indicative, non-definite, network charges, based on available insights and advanced scenario modelling work.			

Table 17: Policy roadmap for BB Network Design

6. Ownership

6.1. Introduction

Different approaches have been taken in different global jurisdictions regarding the ownership of the electricity transmission networks. These approaches vary in terms of the identity of the asset owner, the remuneration perceived for the asset, and the process through which ownership has been obtained. In most European countries, transmission system operators ("TSOs") are the owners of the vast majority of the transmission network. In addition, TSOs in Europe are responsible for operating the transmission system and planning the expansion of the grid. Approaches taken in other jurisdictions feature the existence of independent transmission companies (often referred to as TransCo's), who own and operate specific transmission assets within the grid, but have no further responsibilities. Other approaches allow private stakeholders such as merchant investors or associations of network users to own electricity transmission assets directly.

To ensure that energy and climate policy objectives are met by 2050, regulation of network ownership should be guided by some important principles. First, it is important that governance frameworks ensure that socially optimum decisions are taken at European level with respect to the selection of required investments (newly built lines plus reinforcements to existing lines). At the same time, governance frameworks should ensure that the required investment takes place at the lowest possible cost, to maximize social welfare. Finally, governance frameworks should ensure efficient coordination between system operation and asset-related activities (including asset maintenance), to avoid risks to system security and potential welfare losses. These guiding principles need to be taken into account when evaluating the merits of any potential ownership scheme.

Next, section 6.2 discusses the challenges and key aspects regarding network ownership issues in order to reach the deployment of the projected 2050 grid architectures. Subsequently, section 6.3 discusses the identified policy options to address these challenges, including a discussion of the current status in the EU regarding these ownership options, the advantages and disadvantages of each policy option, as well as possible intermediate measures to overcome the disadvantages (= hurdles). Finally, in 6.4 reference is made to section 7.4, which combines a policy roadmap to implement the identified policy options and measures for both the Building Block Ownership and Financing, as these are closely related to each other.

6.2. Challenges and key aspects for the projected 2050 grid architectures

Challenges

Under certain exceptional circumstances, European regulation currently already foresees the possibility of third parties (such as private promoters) planning, undertaking and owning new transmission assets with a cross-border impact. For instance, several cross-border investment projects included in ENTSO-E's Ten Year Network Development Plans[14] ("TYNDP") are being promoted by entities other than the incumbent TSOs. If third party ownership were to be allowed more generally in the future, leading to a "hybridisation" of the European network ownership scheme (with incumbent TSOs coexisting with a larger number of third party owners), then adequate coordination schemes would need to be developed, to ensure an efficient construction, operation and maintenance of the new assets. In addition, responsibilities of the various asset owners, in terms of system security and related tasks, would need to be clearly allocated, to ensure a safe functioning of the system.

There is also the need to ensure that appropriate measures are in place to avoid the potential conflict of interest that may arise if decisions by grid expansion planners (i.e. the TSOs) affect the profitability of their transmission business. At present, many national systems in Europe have implemented measures that successfully limit such conflict, where it so exists, ensuring that only necessary/reasonable/effective investments are undertaken. These measures should be maintained and further follow-up should go forward. A good case study is Germany, where the national grid development plan is developed by the TSOs under the control of the national regulator. The process is as follows. First, the German TSOs develop the so-called "scenario framework", which serves as the basis for market modelling and network calculations. Once finalized, the scenario framework is handed over to the national regulatory authority, who is in charge of approving and publishing the scenario framework, after conducting an extensive stakeholder consultation (i.e. to allow interested parties to bring in their comments and views). On the basis of the approved scenario framework, the TSOs then go on to elaborate a first draft of the national grid development plan, which is then handed over to the regulator. Once again, a stakeholder consultation takes place and the final results of this consultation are made public by the regulator. This process is repeated again for a second draft of the network development plan. The process ends with the final approval on behalf of the regulator of the proposed grid expansion plan. This system of checks and balances, involving stakeholder consultation and requiring regulatory approval, is effective in managing any potential conflict of interest that may exist. It also ensures that socially optimum investment decisions are taken.

Appropriately designed planning procedures, such as those described above, may resolve potential conflicts of interest. However, existing information asymmetry between the regulator and the network planner regarding the needs of the transmission system might still lead to a situation where the former finds it difficult to oppose the construction of reinforcements proposed by planning authorities. This means that the control exerted by the regulator over the development of the grid might be limited. Therefore, further attention needs to devoted to ensure that the right processes are in place in order to prevent the construction of projects that may not always be justified from an economic, reliability, or environmental perspective.

Furthermore, there is a need for harmonisation of the incentive schemes for cross-border investment at European level, to avoid a situation in which investments that are needed from a social welfare perspective are not forthcoming due to a lack of sufficient incentives. At present, there is a wide disparity across Europe in the methodologies applied to determine allowed revenues for new cross-border regulated assets. In some systems, for instance, remuneration of cross-border regulated

[14] TYNDP2014: 22 projects and TYNDP2016: 25 projects

investments is insufficient to reflect the level of incurred costs or the risk profile of the investment. Hence, there is the need for harmonised investment conditions across Europe. Regulators should develop fair, long-term stable and risk-adequate regulatory frameworks, in particular looking ahead to the 2050 future, providing efficient signals for investment. This is further discussed in the next chapter on Financing.

There is also the need to ensure the efficiency of investments, so that they take place at the lowest possible cost to end-users and consumers, keeping system security in check. In this case, conducting network construction auctions, as is currently being done in some European systems, where by incumbent TSOs who will be the future owners of the new transmission assets tender the acquisition of the necessary equipment and the provision of related installation services, can be an effective measure. Competitive mechanisms such as these may assist in determining the level of efficient investment costs and the rate of return to be applied to regulated cross-border investments. At the same time, tenders for the construction of new network assets to be owned by the TSOs could achieve a more economic development of the network, which might free up resources that can be devoted to cover additional investment needs.

To address these challenges, several options have been formulated for the BB Ownership and Financing, of which, in this chapter, the three options regarding ownership are presented. Option 1 relates to competitive mechanisms to be implemented to determine the level of efficient investment costs and the rate of return of regulated cross-border investments. These should increase the efficiency in system operation by achieving a more economic development of the network, and should therefore free resources to be devoted to cover additional investment needs. The application of these schemes should be made compatible with the preservation of system security. This option is also related to the definition of the most appropriate entitity to own future new cross-border assets and how the construction of these could be tendered.

The latter is closely related to option 2, which goes into further detail for situations in which multiple asset owners would be present in the 2050 European future. One of the most significant downsides of so-called "hybrid" transmission ownership schemes (where assets owned by TSOs coexist with a larger number of assets owned by private promoters) is the significant loss of coordination between system operation and asset-related activities that may occur under these schemes, as these activities no longer take place within the same entity. Hence, in the exceptional event that the TSO model were to be abandoned in favour of a more "hybrid" third party ownership model, this could lead to situations where maintenance works undertaken on some assets negatively impact efficiency in system operation, putting the overall system at risk. To address this potential challenge, a second regulatory option has been developed (option 2), highlighting the importance of efficient coordination.

Finally, option 3 adresses the risk that third party investors could be small companies lacking sufficient technical knowledge and financial strength. Therefore, the need for entities of a sufficient size is highlighted to successfully undertake, operate and maintain the new cross-border assets.

Key Aspects

Arrangements affecting the ownership of new cross-border assets must be compatible with EU unbundling requirements for ownership of generation assets to be detached from system operation and planning. Even more difficult to achieve, network ownership should not interfere with the responsibility of the network expansion planner in achieving the construction of needed reinforcements. Related to this, revenues of cross-border transmission asset owners must be appropriately set to reflect the risk profile of investments. This should lead to optimal investment decisions from a societal point of view.

An effective coordination between asset-related activities such as maintenance works and system operation activities is also of crucial importance. The responsibilities and obligations towards the regulatory authorities of the asset owner, in terms of the maintenance of these assets, are to be considered carefully, especially if the owner is not a regulated company such as a TSO. In addition, the mechanisms to be implemented, or conditions to be imposed, to guarantee a level playing field in network development and operation, are also important.

Concentration of network ownership may have a positive impact on network development due to economies of scale considerations in the financing and technical capabilities of owners. Experience shows that, given a certain regulatory framework for a particular infrastructure, the overall cost of capital is usually lower for the corporate finance traditionally used by TSOs than for third party project finance due to economies of scale in financing and grid development. Furthermore, concentration of network ownership within a given geographical region may benefit from the fact that the cost structure of highly-meshed transmission systems exhibits strong increasing returns to scale.

6.3. Possible policy options to reach the projected EU 2050 grid architectures

Prior to going into detail of the three proposed options for 2050, a more general description and background of relevance of these options is provided in the next paragraphs.

It is important to highlight that the proposed options concern network investments of a cross-border nature. Regulation of the ownership of national reinforcements should be left to local authorities only, as these reinforcements have a local impact on the functioning of the system. Out of all potential cross-border investments, the focus of this study is on regulated investments. Network investments promoted by private merchant promoters should be owned by them, or by those independent private parties with a transmission license to whom they sell the particular piece of infrastructure. This is in line with current practice in most, if not all, systems where merchant investments are common, such as Central America or the RTO regions in the USA. An exception to this are some merchant lines in Europe which are owned by project companies created by TSOs. Analogously, cross-border network infrastructures promoted by coalitions of network users that are built as investments at risk should be owned by users in the coalitions. This is the ownership scheme applied to reinforcements promoted through the *Public Contest* method in Argentina.

In any case, system operation, as well as decisions on transmission asset maintenance, should not be left in the hands of stakeholders with interests in deregulated activities (generation, commercialization), even if they would own a part of the aforementioned transmission assets. This is required by EU regulation in order to avoid unfair discrimination in the use that third parties can make of these network assets. Decisions on the management of the capacity of these assets and their operation should be in the hands of System and/or Market Operators (MOs), who are not involved in deregulated activities. This principle has been implemented in most systems in Europe and has been applied to regional infrastructures in Central America.

Internationally speaking, there have been two main approaches to regulating the ownership of cross-border transmission networks. The traditionally more widely implemented scheme is the "TSO Model", which features the existence of a single entity owning the vast majority of the transmission network within a certain system. At the same time, this entity is in charge of network planning and system operation activities. In this case, all regulated cross-border assets that are built within its territory are owned by the TSO. This scheme is in some cases complemented by network construction auctions, by which the TSO tenders the acquisition of transmission network equipment and provision of related installation services to the most efficient third party.

The second approach to transmission network ownership is characterized by the introduction of auctions to allocate the construction, operation, maintenance and ownership of new cross-border assets. Bidders in these ownership auctions may be specialized transmission companies with no ability to influence network expansion planning, or the TSOs themselves. With regards to the former, there may be a single one within each area being the single local transmission license holder, or several ones, competing in auctions to be assigned the ownership of each cross-border transmission asset. In the first case, the license holder must win the transmission license over a certain period of time in the context of an auction.

Across Europe, the dominant ownership scheme for cross-border regulated investments is the TSO scheme. One of its core characteristics is the existence of a single entity owning the vast majority of the transmission network in a precisely defined region or Member State. Each of these entities also acts as a TSO and is, according to European legislation, unbundled from generation and supply activities. TSOs can be publicly or privately owned and are primarily responsible for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity; for operating the system in real-time; for maintaining and developing a secure and efficient transmission system with due regard to the environment under a fair and sustainable economic umbrella; and for contributing to security of supply. These tasks are highly inter-dependent. To ensure the long-term reliability of the system, TSOs are obliged to invest into the renewal, reinforcement and expansion of their grids.

Despite the widespread existence of this TSO model, a few quite limited examples of new entrants (often referred to as third party investors) into the market for transmission services can be observed, namely for cross-border interconnections and the connection of offshore wind farms in the UK. Reasons for this are various. In the case of offshore connections, this reflects political efforts in the UK to develop wind generation offshore and to connect offshore wind farms to the national transmission system. In the case of interconnectors, third party investments are sometimes incentivized by the exemption option in Article 17 of Regulation 714/2009 (EC). According to these rules, new DC interconnections can be exempted from specifically named parts of the regulatory framework, hence providing third parties, directly or indirectly, with additional financial incentives to undertake these reinforcements.

Maintaining the TSO scheme guarantees maximum coordination between network maintenance, on the one hand, and network expansion planning and system operation, on the other hand. Furthermore, when applied in Europe, this scheme has traditionally achieved a sufficient development of the grid within each country. However, a potential conflict of interest may arise between the TSOs' network expansion planning and network ownership activities, whereby TSOs, who are able to influence the outcome of network expansion planning at European level, could do so to favor the construction of those reinforcements that are most profitable, or least difficult to finance, for them as network owners. In addition, it is to be acknowledged that some relevant projects have not been developped under this scheme, or have taken much more time than initially foreseen.

Properly designed grid expansion planning and authorization procedures considering stakeholder participation and having regulatory authorities approving the reinforcements, such as those that are already in place in many European countries, could effectively limit any inefficiencies stemming from this potential misalignment of interests. However, they are unlikely to fully avoid these inefficiencies due to information asymmetry existing between the regulators and network planners.

Apart from the options discussed under the chapter Financing, to ensure the right conditions for network infrastructure development, there is also the possibility to introduce a system of auctions to allocate the ownership of new network assets, whereby the winning bid could be used as an input to determine rates of remuneration. However, such a strategy would imply losing out on the substantial coordination and other benefits achieved under the TSO model. Moreover, its implementation in a European setting would be highly challenging, as this would imply a substantial departure from the status quo also in terms of the current licensing regime. Introduction of widespread ownership auctions would most likely face strong opposition from stakeholders and Member States, rendering this a less effective strategy.

In light of the above, a TSO-based scheme combined with a system of auctions for the acquisition and installation of new transmission network equipment is considered to be the most effective solution to address identified 2050 challenges. Regulatory authorities should monitor the ability of TSOs to deploy the required investments within a predefined time span that is deemed reasonable. Regulatory authorities should also design long-term stable and forward-looking regulatory frameworks allowing incumbent TSOs to undertake the necessary investments without endangering their long-term sustainability, while ensuring their regulatory incentives are designed to encourage efficiency. Only in the exceptional case that incumbent TSOs are not able to deliver the required investments within a pre-specified period of time, for reasons within their control, and assuming that appropriate and forward-looking regulatory frameworks are in place, should authorities consider the implementation of auctions for the allocation of the ownership of new cross-border assets.

In these rare circumstances that ownership auctions are necessary, sufficient coordination between network expansion planning, system operation and maintenance should be guaranteed, to avoid losses to society. This could be achieved by entitling the system operator (TSO) to plan the undertaking of maintenance actions for all assets, including cross-border ones owned by third parties. Additionally, in order to ensure potential new network owners are of a sufficient size to finance the required large reinforcements and exploit economies of scale, the internationalization of Transco's, and even of TSOs, could be fostered. However, this should be made compatible with the need for sufficient competition in ownership auctions, which can be fostered by monitoring the behavior of bidders and setting caps on the prices resulting from the auction. If competition in network ownership auctions is deemed insufficient, ownership of the asset should be by default allocated to the local TSO, ensuring in any case that an attractive remuneration is perceived.

6.3.1. Option 1

By default, regulated cross-border network assets should be owned by incumbent TSOs. TSOs should tender the construction works for the new regulated cross-border assets in order to determine which construction company should build the asset on their behalf. The winning bid at these auctions (tender) shall be used as an input to determine the allowed revenue of asset owners, i.e. the local TSOs. The level of allowed revenues shall be approved by the corresponding national regulatory authorities and subject to oversight at European level. The rate of return on the investment shall be set in accordance with European provisions and those of the national regulator.

Only if local TSOs are not able to deliver the required regulated investments within a pre-specified period of time for reasons within their control, once the regulatory framework has been properly tailored to address the high investment needs facing TSOs, auctions open to TSOs and to reliable third parties should take place to allocate the ownership of assets.

Explanation

In order to ensure the efficiency of investment costs, TSOs who will be the owners of new regulated cross-border assets should tender the acquisition of required transmission asset equipment and provision of corresponding installation services. TSOs should conduct these auctions once the features of the reinforcement to undertake have been fully defined in the network expansion planning stage and permits for the installation of the corresponding assets have been obtained. Payments to the construction companies that win these auctions can be used as an input for the computation of the allowed revenue of the TSOs owning the corresponding network assets. The allowed investment costs and rates of return for regulated cross-border asset owners should, therefore, be computed separately for each project. The allowed investment costs, which should be collected through regulated tariffs, need to be approved by regulatory authorities and subject to oversight at European level, by p.e. ACER, in order to note and keep track of potential differences among Member States and pursue the harmonization of investment incentives.

Only if local TSOs are not able to achieve the undertaking of required investments within the specified time limit due to conditions under their control, and if the conditions prevailing by 2050 require it, assuming appropriate regulatory frameworks are in place, an auction to allocate the ownership of these assets open both to TSOs and reliable third parties (such as Transco's) should take place. Winning bids in this ownership auction should be used as an input to determine the allowed investment costs and rate of return on investments. If competition in the auction for the allocation of the ownership of an asset is deemed insufficient, the local TSO should be named the default owner of this asset. Remuneration conditions applying to this asset should, in this case, be attractive enough for the incumbent party.

Governance model inspiration

The proposed regulatory option has been inspired by several of the analysed governance models. On the one hand, auctions for the acquisition of transmission system equipment and provision of related installation services are already being conducted in some countries in Europe (e.g. France) or foreseen in the regulation (e.g. Spain).

On the other hand, a scheme of auctions for the allocation of the ownership of new cross-border assets, is derived from the ownership auctions currently in place in Central America, Brazil, or RTO regions in the USA. In Brazil p.e. this has resulted in winning bids in the corresponding auctions including large discounts with respect to the maximum allowed revenues administratively set by the regulator. For some new lines, discounts offered were as large as 50% of the maximum allowed revenue set before the auction (Rudnick et. al, 2012; Barroso et al, 2007).

In addition, requiring regulatory approval of allowed investment costs and rates of return resembles some of the features of the so-called “active-TSO” schemes in place in the UK and, to some extent, the Nordic countries.

Description of current status

The Electricity and Gas Directives of the Third Energy Package have introduced a structural separation between transmission system operator activities, and generation, production and supply activities. The purpose of these "unbundling" requirements is to prevent some main possible conflicts of interest and to ensure the independence of transmission system operators regarding the day-to-day operational decisions, and also the strategic investment assessments. In this case, transparency can be guaranteed towards all network users (Ofgem, 2010).

The rules on unbundling are provided in Article 9 of the Electricity and Gas Directives (EC, 2013). It is required that the same person cannot 'control' generation, production and/or supply activities, and at the same time 'control' or exercise 'any right' over a TSO or a transmission system. Additionally, the same person cannot 'control' a TSO or a transmission system, and at the same time 'control' or exercise 'any right' over generation, production and/or supply activities. In this case, three options have been introduced. National regulatory authorities are required to certify transmission system operators as compliant with one of the options available (EC, 2013)-Figure 1.

1) ***Ownership Unbundling (OU)***

This is the default option. This option is intended to split the ownership of commercial generation (production and trade of electricity) assets from regulated network assets.

2) ***Independent System Operator (ISO)***

Member States are also given the opportunity to let the transmission networks remain under the ownership of energy groups; however, their day-to-day operation and control should be transferred to an independent system operator. Investments on the network will be accomplished, not only by the owner’s funding but also by the ISO’s management. The ISO must demonstrate that it can provide the required technical, financial, and human resources to perform these tasks. On the other hand, the rights of transmission ownership are limited, as the owner is required to finance the investments decided by the ISO. In particular, based on Article 13(4) Electricity Directive, each ISO is responsible for granting and managing third-party access, including the collection of access charges, congestion charges, and payments under the inter-TSO compensation mechanism. The ISO is also responsible for operating, maintaining and developing the transmission system and also for network expansion planning, including obtaining the necessary permits for the construction and commissioning of new infrastructure (EC, 2010). The transmission system owner has no responsibility with regards to the granting and managing of third-party access.

On the other hand, the transmission owner has a range of responsibilities as follows (EC, 2010):

- Provide all the relevant cooperation and information concerning the network to the ISO for the fulfilment of its tasks.
- Provide coverage of liability relating to the condition of network assets
- Finance the investments decided by the ISO. If the network owner does not want to finance the investments itself, it has to give its approval to the financing of these investments by any interested party, including the ISO.

The ISO model exists in vertically integrated systems, e.g. Scottish electricity within the UK where the National Grid Company now is the system operator but does not own the transmission assets (Pollitt, 2011), as well as Northern Ireland, Ireland, and Bosnia and Herzegovina.

*3) **Independent Transmission Operator (ITO)**:*

Different countries such as France, Germany, Greece, Luxembourg, Latvia, Austria and Bulgaria have implemented the ITO option (EC, 2014). This is also named legal unbundling. In this case, energy companies retain the ownership of their transmission networks, but the transmission subsidiaries are independent, ring-fenced companies operating under their own name and a stringent regulatory supervision in order to avoid possible losses against market instabilities. This option meets the requirements of the Directive 2009/72/EC-Chapter V, and can involve the effective separation of transmission operation from the rest of the sector while transmission assets remain under the same ownership as generation or retail. In this case, a compliance officer is responsible for monitoring a specific program of relevant measures to avoid the exercise of market power.

The ITO option implies that, although a TSO may be managed independently from the rest of the energy group, it is still owned by the same parent company. France is a particular example of this, where its TSO is still owned by the parent company, EDF, itself still predominantly state-owned. It is arguable that legal unbundling creates conflicts, and that full ownership unbundling would give independent TSOs greater incentives to invest in cross-border electricity interconnections, as the competition it generates in generation and supply sectors in its home country does not affect the TSO's holding company itself.

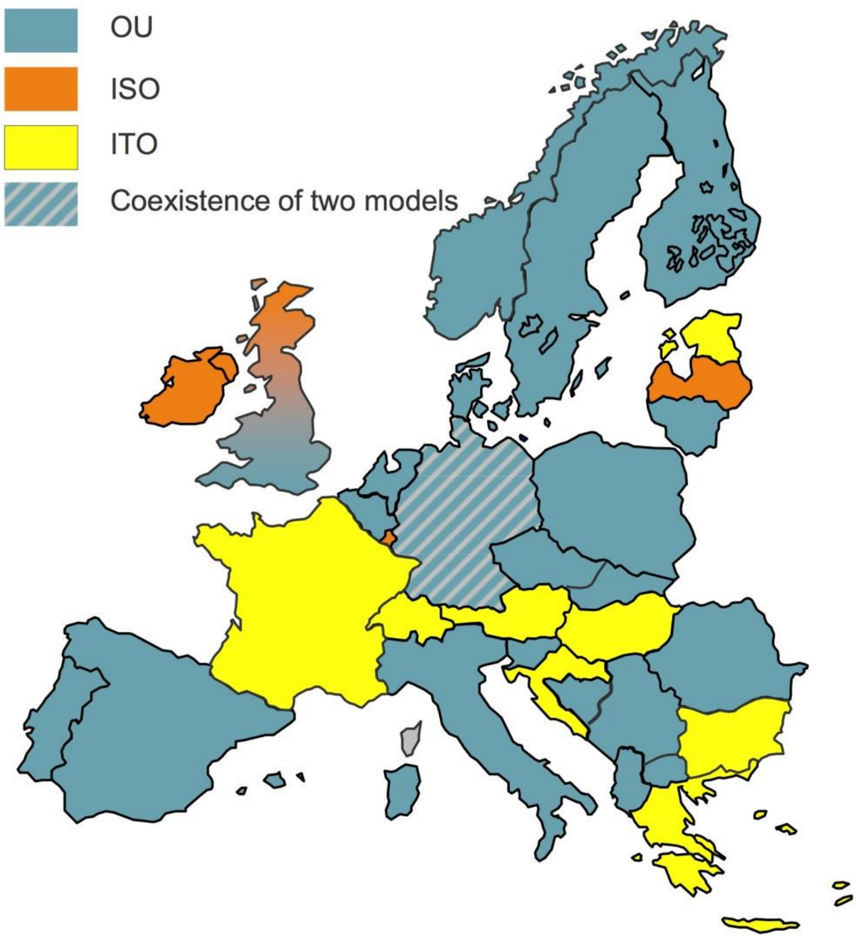

Figure 8: Unbundling within Europe (RTE, 2013)

Regarding interconnectors, there are different regulatory frameworks within Member States, as the regulation of electricity transmission is the responsibility of national regulators within Europe. In the GB system, interconnection is a separately licensable activity from other transmission activities. In this case, entities participating in cross-border transmission cannot apply for a transmission licence other than the interconnector licence and it is not possible to apply the onshore or offshore regulatory arrangements to interconnectors (Ofgem, 2010). In the UK, also separate Offshore Transmission Owners (OFTOs) take responsibility for offshore transmission assets under long-term OFTO licences. Over £2bn have been committed so far to the OFTO asset, suggesting that over £8bn of OFTO projects will come to market by 2020 in order to meet the UK target for renewables (KPMG, 2012).

Regulatory arrangements can differ across Member States. Generally, interconnections within continental Europe are developed by regulated TSOs of both countries involved. Since regulatory practices differ from country to country, regulation of interconnectors requires close engagement between NRAs. Third party project developers will also need to engage with the regulatory authorities in both states. Generally, regulated investments and network reinforcements owned by regulated TSOs are preferred over the merchant investments because of their more efficient size.

This is the result of considering different types of benefits such as reliability benefits, environmental issues ones, etc. (Starbc et al, 2013).

It should be noted that all merchant investments so far in the EU, for example Estlink and BritNed, are financed by holding companies that also own TSOs (Jacottet, 2012). Investors are legally unbundled from the TSOs, but have common ownership. This means that, although the TSO is unbundled to the extent that it is managed independently of commercial parts of the value chain, the TSO is still owned by the same parent company that also owns generation capacity – the ITO model applies.

Advantages and disadvantages

Advantages	**Disadvantages**
Construction auctions held by TSOs for the acquisition of transmission asset equipment and provision of associated installation services ensure that network expansion and reinforcement takes place at an efficient cost to society. Competition amongst potential providers of equipment and installation services fosters efficient pricing and deployment of investments.	Under the proposed scheme, planning and regulatory authorities might still have some incentives to achieve the construction of too many reinforcements in order to increase reliability, or system security, for example.
A "TSO" scheme results in efficient levels of investment costs for already approved reinforcements as well as high innovation and coordination solutions. This is so because, within a given geographical region, the cost structure of highly-meshed transmission systems exhibits strong increasing returns to scale and other natural monopoly characteristics.	Under the current regulatory frameworks, European TSOs still face "financeability challenges" caused by an imbalance between cash inflows provided by regulated tariffs and the cash outflows required to undertake the necessary investments.
Investments made by TSOs should incur lower financing costs than others, as under normal conditions, the overall cost of capital is usually lower for the corporate finance traditionally used by TSOs than for third party project finance. On the one hand, the cost of debt is often lower because lenders often rely on the overall creditworthiness of the investor rather than on the projected cash flows for the project. On the other hand, the cost of equity is usually also lower as the overall risk of transmission companies can be diversified across their entire project portfolio.	Allowing third parties, like Transco's or TSOs other than the incumbent TSO, to own assets that the incumbent TSO is unable to install may create some problems for the system: - Transco's may have smaller capabilities to finance, construct and operate investments than TSOs. - For assets owned by third parties, lack of coordination between system operation and network maintenance may occur, posing threats to system security - The participation of third parties in ownership auctions would face strong opposition from local authorities and TSOs, since this has not been largely implemented in Europe. - Such an option contradicts the objective of having few parties benefitting of scale advantages. The Introduction of new and more parties may lead to higher coordination costs for the system.

A TSO scheme guarantees maximum coordination between transmission ownership and maintenance activities across systems on the one hand, and system operation and grid development planning on the other hand, as these activities fall under the responsibility of the TSO and there is no organisational separation. This leads to a close cooperation between departments instead of interfaces between various companies. This should enhance economic efficiency and reliability in system operation and network development.	Possible discrimination may take place between assets owned by the TSO and those owned by third parties.
A TSO scheme guarantees some level of cooperation in transmission activities. European TSOs benefit from a long tradition of successful cooperation, at various geographical levels (bilateral, regional and pan-European). TSOs are also trusted long-term partners that know each other and share the same core business. This should, again, have a positive impact on system security and efficiency.	
If TSOs owning new cross-border regulated assets are the local ones, the socio-political acceptance of network investments should be higher than under a scheme whereby a relevant fraction of reinforcements is owned by foreign stakeholders. Given their reputation and experience with regards to stakeholder management, and backed by the support of strong regulators/political entities, local TSOs are best placed to overcome challenges related to public resistance to the construction of new transmission lines. Regarding the approval procedures, a single entity (TSO) having a portfolio of projects to realise in one region has a coordinated set of communication activities and can put all its projects into a right context. The TSO model also guarantees that the interested public has only one point of contact (the respective TSO), facilitating visibility, information exchange and communication.	
The existing European regulation already includes provisions to organize tenders when TSOs do not deliver timely a PCI. There is already room within regulation to implement both construction and ownership tenders of cross-border assets.	

Hurdles and measures to overcome these[15]

The list of disadvantages includes the main hurdles to implement this option and, more specifically, those arising when introducing ownership auctions. Below are the three main hurdles listed with some possible intermediate steps to overcome these.

- Planner and regulator could favour overinvestments: The planning and regulatory authorities might still have some incentives to achieve the construction of too many reinforcements in order to increase reliability, or system security.
- Financing costs for third-party investors: Many uncertainties on the actual return for third-party investors, investing at their own risk, and then depending on the congestion revenues, market and impact of regulation on markets, increase the rate of return expected by merchant line investors compared to regulated TSOs. The cost for consumer of merchant lines might be higher.
- Lack of coordination with third party owners: Lack of coordination between the system operator and third party owners can result in higher costs and decreased asset availability. In this case, significant unforeseen events may result in a range of operational risks such as asset failure due to technical reasons, and an unexpected increase in the cost of maintaining and operating the system.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed:

- Expenses on reliability reinforcements should be monitored by independent authorities, by preference European ones, to try to avoid unnecessary ones.
- More transparency should be enforced (i.e. by publishing information on the nature and size of expected benefits of any type resulting from approved network investments) and/or stakeholder consultation and regulatory approval of proposed investments should be required.
- The regulatory authorities must be responsible to ensure that congestion rents are determined by market mechanisms in a non-discriminatory and transparent manner.
- ACER could assist in coordinating agreements between Member States for the construction of new electricity interconnectors, their maintenance, and system operation. Furthermore, third parties owning assets should notify the involved TSOs, and the respective regulatory authorities, of the corresponding Member States.

6.3.2. Option 2

In those very specific cases where the ownership of a transmission asset and the operation of the system are the responsibility of different entities, there needs to be a sufficiently high level of coordination between system operation and network maintenance.

[15] It is arguable that legal unbundling without independence requirements (as in ITO certification) creates conflicts, and that full ownership unbundling would give independent TSOs greater incentives to invest in cross-border electricity interconnections, as the competition it generates in generation and supply sectors in its home country does not affect the TSO's holding company itself.

Explanation

Much of the explanation of this option is included in the description of option 1. The coordination referred to in option 2 could be achieved through the planning of network maintenance actions by the System Operator (SO), even when the implementation of maintenance actions would always remain in the hands of network owners. However, the plan of maintenance actions defined by the SO should be monitored by regulatory authorities in order to ensure that this entity does not unfairly discriminate against assets owned by third parties, by systematically placing maintenance actions for these at times where they are most expensive (certain periods of the day or the year, etc.).

Governance model inspiration

In Brazil, it is the SO who decides on the planning of the maintenance actions of assets it does not own. This seems to have had positive effects on the safety of system operation.

Description of current status

Currently, system operation and network maintenance is highly coordinated for most assets because, in most European countries, both functions are being performed by the same entity, i.e. the local TSOs. However, some merchant lines already exist and some additional ones are being built in some European countries. Coordination between the maintenance of merchant assets (largely interconnectors) and the operation of the system is limited. The planning of maintenance actions is being made in most cases by merchant owners, though these assets must comply with some minimum availability requirements and may be subject to incentives related to this. Besides, some exchange of information between system and market operators and merchant owners exist regarding the expected operation situation of the system in the coming days, weeks or months and how an outage of their merchant facilities could affect it. Merchant owners have an incentive to have their transmission assets available when the network stress in their area is largest, since, by then, market revenues to be made from congestion rents should also be highest.

Advantages and disadvantages

Advantages	**Disadvantages**
The proposed policy option ensures a higher level of coordination between system operation and network maintenance activities, leading to overall efficiency gains.	An even higher level of coordination can be achieved under a TSO scheme, where coordination of these activities takes place naturally within the same entity. The TSO scheme also avoids potential distortions to network maintenance planning, which can occur when third party network owners try to adjust maintenance to suit their needs.
	Having an external company planning the maintenance of their assets, third party investors could suffer organizational stress.

	Discussions may emerge about the party who is ultimately responsible for system security. A clear allocation of responsibilities is crucial in this case, given that a lack of clarity might result in everyone being accountable for certain tasks. This would increase the total costs of the system. In turn, this would lead to a higher rate of return required by investors to provide funding, as this risk will be priced in.

Hurdles and measures to overcome these

The identified hurdles for this option, as indicated in the table above, mainly relate to the need to efficiently operate the grid when there is a coexistence of regulated and merchant lines, and to achieve a coordinated maintenance planning. In order to overcome these hurdles, the following two intermediate steps towards implementing the option for 2050 are proposed:

A. Coexistence rules:
Rules for coexistence of regulated and private assets have to be developed. These should be compatible with the nature and operation regime of both regulated and merchant investments and should be aimed at scheduling and coordinating transmission system outages. These rules should consider the ability to mandate maintenance plans and should also clearly define the roles and responsabilities of all involved, specifically as regards system security.

B. Systematic maintenance planning:
Each party can provide a documented maintenance program ensuring compliance with the system operator standards. These maintenance reports can be reviewed and analysed by the regulatory authorities and agreed by both the transmission owners and system operators. Maintenance and testing of the facilities must be scheduled and coordinated by the system operator to ensure that the reliability and capabilities of the transmission system are preserved.

6.3.3. Option 3

Economies of scale in grid development are to be encouraged.

Explanation

TSOs in Europe have a high level of efficiency in network construction, operation and maintenance. However, in the exceptional circumstances where third parties, like Transco's, are allocated the ownership of new network assets, their financing and operating capabilities should be monitored in order to ensure timely delivery of reinforcements and compliance with quality requirements. This could be achieved by fostering the internationalization of Transco's. However, the level of competition in network ownership auctions should also be monitored. If it is insufficient, the auction should be declared invalid and ownership of the asset should go by default to the local TSO, accompanied with appropriate conditions.

Governance model inspiration

Some RTO regions in the USA have imposed conditions on Transco's financing and operating capabilities to allow them to hold a network owner license. Political authorities in some national systems are fostering the development of multinational, international, TSOs.

Description of current status

As explained under option 1, most of the transmission grid in Europe is developed by local TSOs with proven financing and operating capabilities. Despite this, some TSOs, like Tennet, are undergoing (/have undergone) a process of internationalization. Thus, being the Dutch TSO orginally, now Tennet has also the TSO license for one of the control areas in the German system. The same can be said about the Belgian Transmission System Operator Elia, which has become one group with the German TSO 50Hertz. Besides this, the merge of currently existing TSOs into larger ones at European level is an interesting option being analyzed now by stakeholders in the region. As for merchant owners within Europe, these are not lacking financing capabilities because, for the time being, in most cases these are project companies owned by the corresponding local TSOs of the areas where the merchant asset is going to be installed. Regardless of the need for exploiting economies of scale in grid development, some further current status regarding merchant lines is provided here.

Merchant interconnections differ from regulated interconnections in two key respects. Firstly, merchant investments are not remunerated via regulated tariffs but they are rather built on the hope and assumption of future revenues to be generated by the sale or use of interconnector capacity (the price of which will be determined by the price differential between the interconnected systems). Merchant investors therefore assume a commercial risk. Secondly, merchant interconnections can be developed by parties other than the incumbent TSOs.

Under the typical UK model, National Grid's UK interconnectors earn their revenues by auctioning capacity based on the price differences between markets at both ends of the link and are referred to as merchant interconnectors, e.g. National Grid owns and operates half of the BritNed and IFA interconnectors. BritNed is a 50/50 joint venture with TenneT, the Dutch electricity TSO. National Grid invested £250m into the project. IFA is part of a joint agreement between National Grid Interconnectors Limited and the French TSO, RTE (National Grid 2013).

The investment that would maximize the profits of a merchant investor is typically of a lower capacity than the optimal investment that the regulator would have chosen, as the income of the merchant investor is derived from the congestion rents (CEER, 2004). Specifically, in a meshed grid, merchant investments may be suboptimal, since the congestion rents earned by regulated facilities are affected by merchant ones being built in such a grid. The amount of regulated TSO investments may decrease due to the merchant investments. In general, the socially optimal network investment would reduce too much, from the point of view of investors, the remaining congestion rents. Merchant investments can only contribute to the development of a transmission network in some specific instances, but they cannot be relied on as the main mechanism to develop the network. Additionally, the private revenues from locational price differences are highly uncertain in the course of time; therefore, the private risk related to merchant investment is high. This high risk could be settled by using long-term capacity contracts providing private investors with more certainty on future revenues. However, policy makers do not welcome long-term capacity contracts as they can result in extra hurdles to new entrants.

Additional interconnection capacity being built in parallel with the merchant interconnection would decrease the value of the merchant interconnection, so investors in merchant interconnections would try to prevent the construction of any additional, competing capacity. Then, merchant investment may lead to severe underinvestment relative to the welfare optimum, as the economies of scale involved in such projects may lead to foreclosure of the market by constructing further capacity.

Advantages and disadvantages

Advantages	Disadvantages
Economies of scale and scope can be achieved in many different ways (merging of activities, grouped participation, etc.) and should have a positive impact on total pricing.	A lower number of third party investors may mean a lower level of competition in ownership auctions.
Promoting economies of scale would reduce the number of interfaces between system operation, expansion planning, and network ownership, which should lead to lower risks of error.	
Promoting economies of scale is important because third party investors, such as those existing in some countries like Brazil, do not often have the financial muscle and technical expertise required to operate their assets.	

Hurdles and measures to overcome these

For implementing this option, few hurdles are identified, as economies of scale can be achieved in many different ways, p.e. by ensuring sufficiently large national TSOs, by cross ownerships between European TSOs, by competitive procurements, etc. One hurdle would however be that the more economies of scale are exploited, the more reduced the number of potential third party investors could be, which could lead to an imperfect competition environment in exceptional ownership auctions. This could be overcome by:

- Closely monitoring competition conditions, and
- Establishing caps on prices resulting from these auctions.

6.4. Least-regret policy proposal and roadmap towards 2050

As can be seen, the steps needed to successfully implement the three regulatory options proposed for the BB Ownership by 2050 are closely related to financing. Hence the final regulatory proposal and the roadmap for implementation by 2050 is combined with the proposals for BB Financing (infra, 7.4).

7. Financing

7.1. Introduction

This BB relates to the regulatory aspects for financing transmission network investments, and is structured by means of two aspects: the availability of financing sources and the determination of an appropriate cost of capital. The first aspect deals with the financing means that contribute to grid network investments and how to facilitate a more diversified financing sourcing that match the characteristics of the investments. The second aspect concerns the investment risk in transmission network and its impact on the cost of capital. By proposing appropriate risk management mechanisms, the objective is to arrive at a cost of capital level which not only attracts adequate investments, but also keeps the financing cost and the increase in the consumer's invoice limited.

Next, section 7.2 discusses the challenges and key aspects regarding the financing issues in order to reach the deployment of the projected 2050 grid architectures. Subsequently, section 7.3 discusses the identified policy options to address these challenges, including a discussion of the current status in the EU regarding these financing options, the advantages and disadvantages of each policy option, as well as possible intermediate measures to overcome the disadvantages (= hurdles). Finally, Section 7.4 outlines briefly a least-regret policy roadmap to achieve the identified policy options and measures.

7.2. Challenges and key aspects for the projected EU 2050 grid architectures

Challenges

A major challenge facing TSOs is that the current regulatory frameworks often lead to a significant imbalance between cash inflows provided by historically-based regulated tariffs and the cash outflows required to undertake the necessary investments going forward. Hence, unless these regulatory frameworks are adapted to take into account the substantial capital requirements facing TSOs in years to come, Europe might find itself in a "regret" scenario where investments are not realized and European policy goals are not met in time or not at all.

Facing these increases in the investment needs for the transmission network in all e-Highway2050 scenarios, several other financing challenges for their realisation arise. Limited technical guidance is present from the public authorities to help the transmission network investor establishing new financing mechanisms, and to access the capital market at appropriate financing cost. In particular, for some TSOs in regions with high investment needs, more equity injection or improved capital structure requirements (such as increase of debt ratio in the RAB) are needed to realise the future investment needs. Therefore, the regulatory framework in place should facilitate novel financing means (Option 1 and 4).

The risk management mechanism, and in particular its impact on the cost of capital, is of major importance for transmission network investment regulation. By examining the e-Highway2050 grid architectures and the current regulatory context, three challenges are found to dominate the risk mitigation aspects:

Firstly, the lack of long-term commitment at European level increases the risk perception for cross-border transmission network investors whose assets have a lifetime of several decades. Therefore long-term legislative commitment for investors at European level is required (Option 2).

Secondly, the adoption of new technologies such as HVDC implies that technology specific risks, concerning delivery and cost, are incurred. Heterogeneous risk evaluation methods for cross-border network investment, which are currently in place in the different Member States, impede the development of a common risk management regulatory tool. Moreover, cross-border network investments face higher risk due to the regulatory coordination in different countries. Therefore, a coordinated risk identification mechanism and its management aspects should be targeted (Option 3).

Thirdly, the absence of mechanisms to differentiate the financing cost over the different phases of the transmission network project obscures efficient investment signals and puts upward pressure on the network tariff. In particular, the lack of a liquid investment market for low cost financing sources, such as participation of pension funds to invest in low risk phases of the transmission projects, constrains some cash-strapped network developer to conduct new investments. New financing means are thus required, which lower the financing cost, as for instance a mechanism to mitigate the risk that takes into account different investment phases and asset types (Option 4).

Key aspects

Creating a well-functioning financing structure for transmission investments has two main dimensions, i.e. (1) diversified sources of financing and (2) appropriate risk identification and allocation.

Adequate sources for equity and debt, as well as novel financing tools to promote more private sector involvement, are an important factor in financing transmission investments. To lift the barriers that hinder the contribution of potential investors in the context of the financing gap, new tools should be designed for potential new equity or debt investors whose profile matches the characteristic of transmission network investment.

The risk management mechanism, and in particular its impact on the cost of capital, stands at the center of transmission network investment. The analysis conducted to assess the cost of capital and risk mitigation dimension is a trade-off between two aspects. On the one hand, benefiting the consumers requires driving down the financing cost of network investments. Seen from the investor's side, cost of capital required by the investors needs to be compensated with the risk level they perceive. The key to arrive at an efficient financing of network investment is thus to allocate the risks to stakeholders who can best manage it and provide investors a risk commensurate return.

7.3. Possible policy options to reach the projected EU 2050 grid architectures

In this section the several options identified for 2050 are further described and detailed by providing an additional explanation, insight of the governance model used as inspiration, some benefits and disadvantages of the option and finally possible intermediate measures to overcome the hurdles to implement this option by 2050.

7.3.1. Option 1

The role of the public sector authorities as investment enabler should be strengthened by setting up stable regulation and promoting assistance to create innovative financing tools for attracting diverse financing sources at low cost. This can for instance be achieved by providing financial guarantees for prioritized transmission investment projects to establish high credit rating.

Explanation

In order to realize the investment requirements towards 2050, and mobilize the corresponding financing means, innovative financing mechanisms are to be deployed in order to facilitate access to the capital market, which would achieve lower financing cost of investments. Credit rating enhancing mechanisms and government guarantees based on transparent priority transmission project selection could mitigate the investor risk perception and reduce the financing cost. Furthermore, a tailored transmission network investment facilitation mechanism could differentiate the electricity transmission network better from other infrastructure assets.

Governance model inspiration

In the German financing model, in which the European mechanism to facilitate network investment also applies, the Project Bond Initiative established by the European Commission and European Investment Bank (EC-EIB) provides valuable pilot experience to stimulate capital market financing in infrastructure with credit guarantees from the infrastructure investment bank. For the pilot phase of the project bond initiative, EU budgetary funds of 230 million EUR has been allocated and expected to stimulate up to 4.4 billion EUR investments. In order to mitigate risk for investors, the European Investment Bank provides Project Bond Credit Enhancement (PBCE) instruments to ensure debt service and enhance credit of projects bonds from a typical BBB- rating up to A-. However, a sector specific project bond, targeting transmission network financing, should be considered to embraces the right risk-reward for this type of infrastructure investment.

Description of current status

Currently the role of public authorities is generally as follow:

- The government or local authorities provide authorizations for network investments and manage local opposition.
- The regulator decides and approves investments expenses and decides upon the tariff.

- Financing issues are only on the responsibility of TSOs that need to find debt investors, or in more rare cases, new equity investors. The financial situation of the TSOs is reflected in their credit rating, which has an impact on attracting financial resources and its conditions.
- EIB loans with lower rate are available for some network investment projects.

Advantages and disadvantages

Advantages	Disadvantages
Stimulates private sector involvement in network investments.	Government support could be considered as illegitimate state aid.
Further untangles network investment from government budget constraints in some state-owned TSOs.	Purely private investments may enhance costs as the required private rate-of-return is usually higher than the public rate-of-return.
Lower the cost of financing with public financial guarantees.	For state-owned TSOs, increased private investments weaken the direct control of the government on the network development as majority shareholder.
Assist investors to access long term funding from private sector that match asset life of transmission network.	

Hurdles and measures to overcome these

As many TSOs in Europe currently do not have the government as majority investor, for them there are little hurdles to implement this option. For countries in which this is still the case however, the direct control of governments on the network development could we weakened by introducing more private investments. This shift towards more private, instead of public investments, might also increase the costs, as usually public sector rate-of-return requirements are lower. In any case, a hurdle that must be overcome before implementing this option, is to define in what conditions public sector support is allowed in the light of the European state-aid rules.

These hurdles could be predominantly overcome by developing a clear legal framework about the government financing support for regulated electricity investments.

7.3.2. Option 2

Long term orientated regulatory commitment could be foreseen, e.g. providing revenue payment at EU level and prolonging the regulatory period, to ensure investor safe and stable payment of revenues which provides investor confidence.

Explanation

Providing financing obligations to pay investor revenues at European level and prolonging regulation periods from the current 3-5 years to 5-10 years, could provide investors more confidence for long term oriented transmission investments and reduce the financing cost. For increasing private sector involvement in cross-border network investment, revenue payment guaranteed by law provides explicit protection for investors and lowers financing cost. Fixed long regulation period, in which tariffs are subject to the remuneration settings, might lead to less flexibility to act upon changing investment needs. However in most regulatory systems, investment planning is reviewed each year and there exists adjustment mechanisms inside a regulatory period to cover the actual costs of investments.

Governance model inspiration

This option is inspired from the Great Britain governance model where eight years of regulatory period is applied. A longer regulatory period aligns better with the long life span of transmission network asset and hedges the investor from regulatory expropriation. In addition, in the new regulatory scheme implemented in Great Britain, a mid-term review is also included to adjust the ex-ante investment forecast for the regulator to accommodate unanticipated changes in the investment climate.

Description of current status

Currently the regulation period in Europe is generally from 3 to 5 years, exceptionally 8 years (in GB). There are European systems in which a general regulation framework can be defined by law (p.e.10 years in Germany). TSOs have no visibility beyond the end of the regulation period, or at least the legal regulation framework when it exists. At the same time the technical life time of the investments are from 20 to 80 years, and the accounting or regulated depreciation duration is often about 40 years. This is considered as a risk for investors who have no guarantee to be correctly paid during the regulated depreciation duration, and may be faced with stranded assets, and therefore the consequence is a higher financing cost. This risk is enhanced when there is high uncertainty about the need of investments for the future, and in consequence the risk to decide and achieve unnecessary investments.

Advantages and disadvantages

Advantages	Disadvantages
Providing revenue payment and prolonging regulatory period, with timely indexation or remuneration of efficiently incurred operating cost, reduces the uncertainty for investors.	Flexibility to act upon changing circumstances might be reduced in long regulatory period though mid-term review which helps to timely adjust the remuneration
Transparent and easy to understand regulatory rules with stable payment of revenues in the long term will help to attract institutional investors (who might lack specialized analytical capability to evaluate transmission network investment).	

Hurdles and measures to overcome these

The only hurdle identified to implement this option is to find the right balance for the regulatory period between sufficient visibility or regulation rules for investors on the one hand and the level of uncertainties of the business environment on the other hand. This implies that, a safe rate of return, adapted to market conditions, must be guaranteed to investors for an extended regulation period, while guaranteeing possible adjustments during regulation periods to adequately react on unanticipated changes.

This hurdle can be overcome by foreseeing and well executing mid-term and intermediate reviews in order to timely adjust remuneration according to (market) changes. Furthermore, beyond regulatory periods, a legal regulatory framework based on a methodology that can remain stable for several regulatory periods would be the best way to create an efficient long-term regulatory framework and a predictable and risk adequate remuneration. This could then lead to attracting more equity or debt investors on the long term, as pension funds, at the lowest rate of return possible.

7.3.3. Option 3

A common risk evaluation for cross-border projects should be installed in order to attract new investments and facilitate a common risk management tool. Consequently, coordinated risk management schemes which recognizes risk for different asset types and investment phases, i.e. 'rate adders' for cross-border projects in planning and construction phase could be considered to speed up new investments.

Explanation

A key design aspect of the risk management regulation schemes is to enable better pricing of the risk and to send correct investment signals. Therefore the identification and disaggregation of risks at different project phases and by different asset types is a prerequisite to achieve design of proper incentive schemes with appropriate risk allocation. In the context of cross-border network investments, a common risk evaluation is essential to facilitate coordinated risk management, which avoids ad-hoc regulatory measures due to information gap and institutional incoherence. For instance, a common technology risk evaluation platform which acts as a knowledge pool, i.e. dealing with reliability of new technology and the corresponding delivery risk, facilitates regulation development to address such risks. This is a particular important aspect for novel technologies such as offshore DC cables and substations where few project precedents and regulatory knowledge and experience to handle such investment exist. Exogenous risk for transmission network investor such as delivery risk of new technologies should be clearly identified and separated from the type of controllable risks for better risk allocation. The knowledge could be extracted from such a common risk evaluation platform by starting to use the same values for cost benefit calculation in bilateral cross-border projects.

Governance model inspiration

A common risk management tool is inspired by both literature review and the current challenges in European network financing governance models such as Germany. Increasing deployment of novel technology for offshore wind park connections in the North Sea has yielded lessons and call for better risk management. Lack of technical precedents for novel technologies such as offshore substation, recent construction of offshore wind connection has experienced significant delay and cost overruns. It calls for exchange of knowledge through transparency and best practices to deal with uncertainties in technical issues, supply chain constraints and standardization. Rate adder as a risk management tool is inspired from the USA governance model, where a rate adder approach has been adopted by the federal regulator (FERC). It has stimulated investment by allowing FERC to conduct case-by-case risk assessment for interstate transmission projects.

Description of current status

Currently, a common methodology for cost benefit analysis exists in the TYNDP process, to determine investments forecasts for four visions. The current status of this approach is detailed under option 1 of network Design.

Advantages and disadvantages:

Advantages	Disadvantages
A common risk identification mechanism with high transparency leads to higher market confidence for new investments.	A rate adder for the construction and planning phase might lead to overinvestment.
A separate mechanism to compensate the risk involved in the project CAPEX phase provides incentive to facilitate new investment.	Determination and implementation of rate adder parameter might be subject to the regulator's discretion.
Higher returns to compensate the risk of coordinating multiple jurisdictions for cross-border project provides investment incentives for investors.	High complexity to reach common risk management scheme (i.e additional need to coordinate relevant renewable policies, for instance to compensate foregone revenue for offshore wind farm in case of HVDC network construction delay).

Hurdles and measures to overcome these

This option clearly intends to overcome the current hurdle that some TSOs have in order to find public or private investors, either in equity or debt. This occurs when the remuneration rate is not compliant with the risk related to the regulation framework, and/or if the necessary rise of tariffs is not accepted by the regulatory authority.

Therefore, rate adders on the planning and construction phase can be useful for projects with higher risk, e.g. to address technical, market or regulatory risk. This could however marginally lead to an increase of costs and be decided at the discretion of the regulator.

Therefore, in order to overcome this, clear and objective rules and guidelines should apply for the regulatory authorities to grant such rate adders. When these are granted, consequent support needs to be provided to allow for this increase in costs and to communicate on the total added value for society, which should be larger than the additional cost of the rate adder.

7.3.4. Option 4

In order to attract all investors at low financing cost, and to ensure optimal WACC throughout the lifecycle of the assets, a split cost of capital mechanism that takes into account risks in different investment phases and asset types should be used for the CAPEX and low risk assets in the RAB.

Explanation

Current European transmission financing mechanisms do not differentiate between the financing costs for different phases within a project. Generally, the same level of return is applied for low risk phases (p.e. operational phase) as well as high risk phases (p.e. preparation and construction phase). Therefore, this option proposes to disaggregate the risks associated with different investment phases and assets, in order to identify and price the risks more accurately and provide an optimal WACC throughout the life cycle of assets. In the investment phase, investors face high regulatory uncertainty (i.e permission delay) and market volatility such as cost overruns due to supply chain constraints. In the operational phase, stable revenues for assets included in RAB are paid to investors and the risks associated with maintenance at this phase are relatively low for matured technologies such as overhead lines. The option provide a timely compensating to investors at the high risk planning construction phase of projects, and set a separate rate of return for the low risk assets in the RAB.

Regarding the initial capital investment phases, i.e. planning and construction, a general recognition is that an investor faces greater risk levels, such as permission delay and risk evolved in employment of novel technology. The case-by-case rate adder approach on the CAPEX that are incurred in the planning and construction phase is an interesting tool to attract new investment in the short term. This allows a rate-of-return adjusted by the regulator, according to its assessment of risk levels for cross-regional projects. In particular for companies facing constrained financing condition and high investment needs, this mechanism could reduce possible delays due to financial difficulties, compared with a single cost of capital scheme. Indeed, the latter does not always adequately reward the new investment in the short term. The higher rate of return at the beginning of project also contributes to alleviate the time inconsistency which might lead to regulatory expropriation. However, different rate adder levels granted to different investment cases and the rationality of decisions is arguably subject to discretion by the regulator (as discussed under option 3).

On the other hand, the RAB is designed to determine the value of past investment, calculate depreciation and guarantee investors a return for assets in the operational phase. This widely implemented tool with decades of regulatory experience and reputation provides a unique opportunity to lower the cost of capital and attract new investors with a lower risk preference. Given the low risk nature of this phase, for low risk assets included in the regulated asset base, a separate, in theory lower than a single WACC number averaged for a whole asset life, rate of return could be designed by the regulator to reflect their low risk nature. This is obviously only to be pursued whenever high-risk phases are rewarded with a higher return in order to respect overall sufficient interesting financing conditions.

Transmission network companies can, if required or preferred, create a specific legal entity for low risk assets included in the regulated asset base, such as a subsidiary of TSOs, to attract debt investors and low cost equity investors such as pension fund which requires low risk and low return. A higher debt ratio could be foreseen for such subsidiary given the low risk nature of RAB. This way, given a full regulatory guarantee for the long term and adequate return on CAPEX for new investment, the cost of capital could be lowered for the RAB phase. Furthermore, it opens up the possibility for transmission network companies to find investors whose risk and return requirements match the nature of different project phases or different categories of assets.

Governance model inspiration

The two components put forward; rate adder and a separated cost of capital determination for RAB, have roots in existing regulatory practices. Rate adder as a risk management tool is inspired from the USA governance model, where a rate adder approach has been adopted by the federal regulator (FERC). It has stimulated investment by allowing FERC to conduct case-by-case risk assessment for interstate transmission projects. The rate adder adjusts the investor return to corresponding risk exposure. In contrast, the RAB as a regulatory commitment tool to investors for remuneration of existing assets has accumulated extensive regulatory experience and reputation by decades of implementation in Europe and in other parts of the world. Therefore, a part of the assets included in regulated asset base are perceived as low risk by investors and a separate rate of return could be designed for such assets.

Description of current status

Debt and equity investors are currently generally corporate investors with average risk profile, compliant with equity and debt remuneration of the regulated WACC. There is no differenciation of type or lifecycle of assets for investors, except in specific cases.

Furthermore, TSOs in Europe, whose cash flows are finance their investments generally by means of:

- Self-financing with after tax return on equity and accounting depreciation covered by regulated tariffs that provide cash flows;
- Debt financing on the financial market, or with EIB loans.

With the foreseen high level of investment needs for grid development by 2050, TSOs can encounter difficulties to keep good credit ratings, because the share of debt in the total of liabilities can become too high. In this case, equity injection by current or new shareholders, adaptation of regulatory framework by rate adders or specific incentives, EIB loans at low rate, or grants from the European Commission are the usual solutions to meet the investments challenge. A risk exists that an increased cost of capital due to downgraded credit ratios is not covered by regulated tariffs.

Advantages and disadvantages

Advantages	Disadvantages
Stable revenue from low-risk assets included in the RAB, which has strong regulatory reputation, provides predictability of the rate of return, and therefore attracts external investors looking for low risk and low remuneration.	The possibility to split assets owned by TSOs in separate subsidiaries, to attract specific shareholders profiles for some specific assets categories and the transfer of assets from a subsidiary to another, when the risk associated to

	the asset changes, result in transaction costs.
Split cost of capital reduces the overall financing cost during project life time for a part of the assets.	Determination and implementation of return parameters according to different phases and asset types requires enhanced regulatory flexibility, and might be subject to the regulator's discretion.

Hurdles and measures to overcome these

For this option, the same hurdles and suggested measures apply as for the point that return parameters could be set at the discretion of the competent regulator (see infra option 3).

Furthermore, attention should be paid that whenever this option is implemented, an overall fair and commensurate risk-reward mechanism is ensured, in a stable context with regulatory comfort for the conditions. This is to stress that only low-risk phases can be remunerated less, if high-risk phases are accordingly remunerated higher. This could be overcome by installing objective benchmarks to evaluate the adequate reward levels for the different phases, as complement to the evaluation of the overall remuneration level for the entire project.

7.4. Least-regret policy proposal and roadmap towards 2050

Table 18 below presents a summary overview of the options for 2050 for the BB Financing and Ownership together, including possible intermediate measures towards implementing these options, the main stakeholders responsible for these measures, as well as an indicative timing.

As already indicated in the BB ownership, as this is closely related to the BB Financing, these two BB's are taken together for this section regarding the roadmap. The options in the table below for the BB Ownership are preceded by the letter "O", the financing ones by the letter "F". As for the timing, similar time periods are included in the table as for the other BB's. However, specifically in this case, many of the suggested options could already be implemented prior to 2050. In that respect, the timing is rather to be seen as a duration, meaning by when the options can be achieved (some take longer than others).

Generally stated for the combination of the two aforementioned BB's, the most effective way to address the "financeability challenge" is to design and implement a forward-looking regulatory framework allowing TSOs to undertake the necessary investments without endangering their long-term viability, while ensuring market efficiency. Moving forward, regulatory authorities should actively set up a regulatory framework fostering investments, and thereby enabling TSOs to overcome the investment and the financing challenges they face. This may be achieved by setting network tariffs based on current and future investment needs. Only by creating a fair and adequate investment climate, transmission infrastructure will emerge at full strength and contribute to the desired policy goals.

In particular, and in the short run, the current ownership structures and financing processes, identified as the "base case" should be retained in order to focus on designing the appropriate regulatory framework. The aim is to stimulate the development of planned efficient investments by the regulated incumbent transmission owners, with corporate and balance sheet financing, without endangering their long-term financial sustainability.

Furthermore, TSOs and regulators should cooperate to develop a regulatory framework that is forward looking, with a clear focus on the challenges ahead. It should be recognised that, inside a European general framework, no one-size-fits-all solution exists and that national specificities may require national regulatory frameworks to be different and tailor made. NRAs should be able to select from a "toolkit" of potential regulatory solutions which should involve (1) targeting those solutions that tackle the financeability challenge in general, e.g. locking-in parameters determining returns, (2) finding solutions to give priority to specific projects over others (priority projects are often also higher risk ones), and (3) recognizing a higher level of risk for new technologies or market uncertainties, e.g. through the provision of priority premiums. In the short- to medium-run, TSOs and regulators should further develop this regulatory toolkit and contribute to the design of adequate regulatory frameworks for the future, to finance the high level of investments needed in the future. Active participation from European policy makers could be also considered.

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing		
		2016-2020	2020-2030	2030-2050
O1 Regulated cross-border network investments should be owned by the local TSO(-s) by default. In this case, the TSO is to auction the construction work for these regulated cross-border assets in order to determine which construction company builds the asset for this TSO. The winning bid at these auctions (tender) shall be used to compute the allowed revenue of asset owners, i.e. the local TSOs. The level of allowed revenues so determined shall be approved by the involved national regulatory authorities and subject to oversight at European level. The rate of return on the investment shall be set in accordance with European provisions and those of the national regulator. Only if local TSOs are not able to deliver the required regulated investments within a pre-specified period of time, once the regulatory framework is properly tailored to address currently existing high investment needs, auctions open to TSOs and reliable third parties should take place to allocate the ownership of assets.	**Regulators** should pay more attention to the general principle of regulated tariffs have to cover long-term costs of capital and meet the financeability needs of regulated companies.			
	TSOs must tender all their procurements to external suppliers			
	Regulators must use results of the auctions as an input to determine regulated tariffs, combined with a normative cost of capital and incentive regulation mechanisms			
O2. In those very specific cases where the ownership of a transmission asset and the operation of the system would be ensured by different entities, there needs to be a high level of coordination between system operation and network maintenance.	**Private project promoters and regulators** may analyse the impact on transaction and coordination costs of having separate maintenance by transmission owners and operation of the system by TSOs			
	TSOs should continue to optimize operation and maintenance costs, and optimize system operation for merchant lines			
O3 Economies of scale in grid development are to be encouraged.	**Policy makers** should avoid the multiplication of actors in grid development			

F1. The role of the public authorities as investment enabler should be strengthened by setting up stable regulation, and promoting assistance to create innovative financing tools for attracting diverse financing sources at low cost. This can for instance be achieved by providing financial guarantees for prioritized transmission investment projects to establish high credit rating. F2. Long term orientated regulatory commitment could be foreseen, e.g. providing revenue payment at EU level and prolonging the regulatory period, to ensure investor safe and stable payment of revenues which provides investor confidence.	**Regulators** should develop long term regulation framework, extended regulation periods and guarantees in stability of regulation	
	Policy makers could provide financial long term guarantees to lower the financing costs and attract low risk and low remuneration investors	
F3. A 'common risk evaluation' for cross-border projects should be installed in order to attract new investments and facilitate a 'common risk management' tool. Consequently, coordinated risk management scheme which recognizes risk for different asset types and investment phases, i.e. 'rate adders' for cross-border projects in planning and construction phase could be considered to speed up new investments.	**Policy makers** should recommend a common methodology for Cost Benefits Analysis, in association with TSOs and regulators	
	Regulators should develop rate adders for high risk or priority investments.	
F4. In order to attract all investors at low financing cost, and to ensure optimal WACC throughout the lifecycle of the assets, a split cost of capital mechanism should be used for the CAPEX and low risk assets in the RAB to provide risk commensurate return that takes into account different investment phases and asset types.	**Regulators** should modulate the rate of return according to the time phase of the assets	
	Regulators should remunerate (all types of) assets under construction at least at the same rate as commissioned assets. In addition, regulators could develop objective benchmarks to evaluate the adequate reward levels for the different phases, as complement to the evaluation of the overall remuneration level for the entire project.	

Table 18: Policy roadmap for BB Financing & Ownership

8. Cost allocation

8.1. Introduction

Cost allocation concerns the process of allocating the investment and operational costs of new assets with a significant cross-border impact, including the methods applied to determine the contribution of each party to the recovery of the cost of assets. As a boundary condition, it is assumed that all cost allocation methods allow for full recovery of efficient network costs by TSOs. This Building Block is included as adequate network cost allocation among countries and stakeholders is required to enhance network investments in order to achieve a sustainable, reliable, and affordable European energy system by 2050. Following proper regulatory assessment, total allowed revenues of the project promoter(s), i.e. TSOs and if applicable third party investors[16], are the basis for the cost allocation process. Consequently, this BB does not analyse the determination of TSO remuneration. Instead, this BB focuses both on the cost allocation between countries (i.e. between TSOs) and within countries (with TSOs on the one hand, and producers and consumers on the other hand). This is in line with common practice; network costs of projects influencing several member states are usually divided between countries (through TSOs), with afterwards each TSO recovering these costs from producers and consumers.

Next, section 8.2 discusses the challenges and key aspects regarding cost allocation of the EU cross-border network in order to reach the deployment of the projected 2050 grid architectures. Subsequently, section 8.3 discusses the identified policy options to address these challenges, including a discussion of the current status in the EU regarding these cost allocation options, the advantages and disadvantages of each policy option, as well as possible intermediate measures to overcome the disadvantages (= hurdles). Finally, section 8.4 outlines briefly a least-regret policy roadmap to achieve the identified policy options and measures.

8.2. Challenges and key aspects in for the projected 2050 grid architectures

Challenges

Two main challenges for network cost allocation are identified. Firstly, with the projected grid architectures for 2050, interdependencies between national networks will increase. Therefore there is an increasing need for more cooperation and coordination at the cross-border level in the allocation of the cost of reinforcements and flexibility measures. The realisation of one European-wide internal energy market as well as increasing power exchanges related to weather dependent renewable energy sources located further from load centres require a vast increase in the investments in grid reinforcements (see ENTSO-E, 2014). Because of network effects (parallel or loop flows) of AC lines in meshed grids, costs and benefits of reinforcements across countries ('interconnections') as well as important reinforcements within countries will be spread out over

[16] i.e. merchant investors, associations of beneficiaries or any other private promotor.

many system users belonging to several countries, both hosting and third countries. A multiple GW corridor from UK to Spain for example, as present in several e-Highway2050 grid architectures, will inevitable also impact countries over which this grid reinforcement does not span. If these economic and/or reliability costs and benefits for third countries are substantial, but not taken into account in the cost allocation decision, this will lead to suboptimal decisions about investments in new interconnections. In the case where the investment results in additional costs to a third country, but those costs are not internalized in the decision, free-riding of the project promoter(s) at the expense of the third country takes place. In the case where the investment results in additional benefits to a third country, without coordination in cost allocation, free-riding of the third country or countries happens at the expense of the project promoter(s). The upshot is unfair cost allocation between system users in different countries and too few investments may be realised in comparison to projected needs for 2050 if countries do not, or only partially, pay for the benefits they obtain from new assets outside their borders. Related to this, costs and benefits of flexibility measures such as storage and demand response are gaining importance compared to grid reinforcements. Given the development of the IEM, these costs and benefits are also likely to be spread over countries. Hence, like in the case of investments in grid reinforcements, the challenge is to ensure sufficient investments in flexibility measures by preventing free-riding behaviour in cost allocation.

Secondly, in several scenarios, sustainability targets push the development of low-carbon technologies both on the supply and demand side, resulting in more variable and location-dependent patterns of use of the grid by stakeholders and countries. These more diverse patterns originate from the higher complexity of electricity systems characterized by higher shares of RES-E, more variable electricity demand (electric vehicles, heat pumps), and higher diversity of network technologies (wider application of DC technology), which translates also into a higher diversity of costs and benefits that network users incur. In contrast, the current assessment made of the distribution of benefits and costs from network reinforcements in EU Member States often takes a typical average situation as point of departure. However, such average situations are increasingly unreflective of real costs and benefits incurred by network users, due to the increase in the interconnectedness of the system and the dominance of intermittent generation. Furthermore, energy intensive industries and generators do have to pay little or no network charges at all for reasons of international competition. As a result, the gap between network charges levied on network users and the true costs they cause increases, implying that the application of uniform network charges may be largely contested. Moreover, this results into a lack of incentives to generators and loads for optimal use of the network.

Related to the latter main challenge, RES priority schemes currently implemented in some countries are not allowing network costs to be allocated to those benefiting from network investments. If RES is offered priority in network access or dispatch, this implies that transmission rights are provided for less than their economic value to RES-E. The resulting costs are usually implicitly spread out among mid-merit and peaking plants, as well as consumers. Given that in situations where congestion is relevant, fewer transmission rights are available for non-prioritized generation and demand, and the price paid by the latter for these rights increases. This involves that non-prioritized generation and demand are paying the cost of transmission capacity that they are not benefiting from. In scenarios where RES shares further increase, the amount of RES driven transmission costs that will be socialized will further increase as well. As a result, like other generation, RES receives no incentives from network charging for efficient network behaviour. Furthermore, continuation of RES priority will increase the gap between network charges levied on the remaining non-RES network users and the true network costs they cause.

Key aspects

For mitigating and overcoming these challenges, seven key aspects for network cost allocation are identified;

1. Application of the cost causality or beneficiary pays principle where possible, remaining costs to be socialized;
2. Multilateral coordination in cost allocation of grid reinforcements;
3. Multilateral coordination in cost allocation of grid flexibility measures;
4. Efficient economic signals to all network users: Network charges to be paid by both generation and loads;
5. Efficient economic signals to RES;
6. No distortion of short-term market signals by network charging;
7. Locational differentiation of network charging.

Key aspect 1 is an overarching element from which the other elements are derived, hence this element covers both challenges. Key aspects 2 and 3 specifically addresses challenges 1 and 2, while key elements 4-7 help to overcome challenge 2. For each key aspect a specific policy option for 2050 is identified, thus seven policy options are described below.

In the following, each of the regulatory key principles is elaborated towards possible policy options in the EU context, inspired by best practices in other governance models as well as a gap analysis to compare the 2050 option with the current situation. For identified best practices no extensive cost-benefit analysis of the impacts on different countries is carried out, where costs and benefits could depend on the grid architecture implemented, but instead disadvantages are identified. Finally, intermediate steps towards the implementation of the 2050 option in order to overcome the identified disadvantages of the option are presented.

8.3. Possible policy options to reach the projected EU 2050 grid architectures

Before the elaboration of several specific options, a general overview of main cost allocation methods is provided. Project promoters, supervised by regulators, recover network cost due to investments, operation, and maintenance of the network assets using revenues from two sources:

A. Market-based congestion rents;
B. Regulated or negotiated network charges.

A. **Market-based congestion rents**: Project promoters, both TSOs and third party investors, earn congestion rents from congested lines between areas that are in different bidding areas (zonal/nodal). Earned congestion rents are often used for recovery of network investment costs of TSOs and merchant project promoters.[17] In the case of merchant investors, revenues from congestion rents should compensate for the full network costs, while in the case of regulated TSOs, the congestion rents usually recover only part of the network costs (Pérez-Arriaga *et al.* 1995).[18] In the latter case, congestion rents are currently often divided between project promoters on a 50%-50% basis (EC, 2011).

B. **Regulated or negotiated network charges**: Network costs that are not recovered by congestion rents must be recovered by network charges.[19] Network charges are regulated in case of TSOs, while merchant investors are allowed to charge negotiated charges to network users for their use of lines owned by the former. Generally, project promoters, supervised by regulators, apply three different methods for network charging, which are summarized below (PJM, 2010; Van der Welle, 2014):

- ***Network flows***: Network flows caused by network users are determined (marginally or as average) and network costs are allocated pro rata to each user accordingly. Network costs are allocated to customers as capacity-based, energy-based or fixed charges. Flow-based methodologies are applied to determine the responsibility of network users in the construction of lines.

  The network flow method is applied in Central America and the United Kingdom, amongst others. Network flow methods include the average participation, incremental cost related pricing (ICRP), and areas of influence methods[20]:

  - The *average participation method* assumes that power inflows into a node contribute to the outflows from the node in proportion to the volume of the latter (Olmos & Pérez-Arriaga, 2009). After flows have been traced, the usage of each line is allocated to network users to the extent they caused flows on the node, as a rule 50% by producers and 50% by consumers. This method is applied in Central America, amongst others.
  - The *incremental cost related pricing method* calculates the marginal costs of investment (i.e. long run incremental costs) in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. The marginal costs are estimated,

[17] Alternatively, earned congestion rents can be deployed for hedging of customers against congestion costs (e.g. in the context of financial transmission rights). In that case, they do neither lower negotiated access charges for users of infrastructure of merchant investors nor network charges for users of infrastructure of regulated TSOs.

[18] See also the discussion of complementary charges below. Furthermore, given the high investment levels foreseen in TYNDPs it is likely that current congestion rent levels will be significantly reduced in the coming decades.

[19] Following Article 16 (6) of Regulation 714/2009/EC, some preconditions have to be fulfilled before (part of the) congestion rents can be deployed for reduction of network tariffs.

[20] Besides, transmission cost allocation literature such as EC (2008) mentions other methods such as the marginal participation method, which is however not seen as feasible alternative and hence discarded in this study.

based upon DC power flow changes resulting from a 1 MW injection to the system (National Grid, 2014). This method is applied in the United Kingdom, amongst others.

  - The *area of influence method* identifies the beneficiaries of the transmission expansion and determines their proportion of votes in the public hearing process as well as the proportion in which each beneficiary would have to share the costs of the expansion. Both proportions are based upon the expected network use (line flows) of the expansion over the first two years of its operation. The method is applied in Argentina, amongst others.

- ***Economic beneficiaries***: Network costs are allocated to those users that benefit from the reinforcement. Beneficiaries are identified either by expected changes in production costs, wholesale energy prices, energy expenditures and revenues or Power Transfer Distribution Factors (PTDFs) which provide an indication of the power flows resulting from commercial transactions. Alternatively, cooperative game theory can be deployed either to delimit distributions satisfying minimum criteria of mutual acceptability or to arrive at a unique and feasible distribution of the total gain of cooperation. In the latter case, network costs are allocated in such a way that they allow for stable cooperation of network users. Network costs are finally allocated to customers as capacity-based, energy-based or fixed charges.
  - The beneficiary pays method is (to some extent) applied in the USA, Brazil, Argentina, and the Nordic system. Recently, the beneficiary pays method has been put forward both in the US (FERC, 2012) and in the EU (EC, 2013a; ACER, 2013c). Among the specific economic beneficiaries methodologies are the positive net benefit method, proportional to benefits method, the areas of influence methods, and the Shapley value method based upon game theory:
  - In the case of the *positive net benefit method*, negatively affected stakeholders are compensated by all actors with (substantial) positive net benefits if an integrated infrastructure is advantageous at global level compared to individual offshore wind park connections and interconnections. Stakeholders that obtain highest positive net benefits have to pay the highest compensation to negatively affected stakeholders, and vice versa (ACER, 2013c).
  - The *proportional to benefits method* allocates network costs proportionally to countries' benefits, i.e. every country will have the same benefits-costs ratio. In the Nordic system, this method is applied on a voluntary basis, i.e. agreement between the different countries involved is required.
  - The *area of influence method* has already been explained above. It is a combination of network flow and economic beneficiaries methods.
  - The *Shapley value method* is a solution concept in cooperative game theory. For a coalition of several players, the Shapley value assigns a unique distribution of the total gain generated by this cooperation. A specific method applied to the electricity sector in the Brazilian context is the Aumann-Shapley method (Pérez-Arriaga, 2010), which combines game theory with an assessment of network flows. When it is applied, locational network charges are computed for the used fraction of the grid as the cost of the network assets used by agents according to the Aumann-Shapley theory. This theory states that each agent is responsible for

the average incremental use it makes of the network when joining a great coalition that ends up containing all generators and loads in the system.

- ***Postage stamp***: Network costs are allocated uniformly among network users (often consumers only), either based upon the yearly consumed or produced energy (MWh) independent of system peak and (often) location, or the (simultaneous) contribution of network users to the system peak, independent of location and usage. The postage stamp method is applied for recovery of all networks costs in Germany and gas systems as well as for the recovery of remaining costs which cannot be related to specific stakeholders (e.g. reliability costs) in other regions and countries.

With this general background for the BB Cost allocation, the seven policy options for 2050 for this BB are further described and detailed.

8.3.1. Option 1

Network costs should be allocated as far as possible by applying the beneficiary pays principle. This would ensure a fair allocation of costs to countries and allow for compensation of negatively impacted ones. Reliability network costs and cost components that cannot be indisputably allocated to a specific country or (group of) stakeholder(s) should be socialized, e.g. by adapting the division of congestion rents or by network charging.

Explanation

The cost causality principle states that those who cause more/less costs should pay for more/less costs. The economic beneficiaries, network flow and postage stamp methods discussed above differ to the extent to which they apply this principle. Economic beneficiaries methods by definition are most in line with this principle, since the beneficiary pays principle states that those who benefit from network upgrades should pay for them. Thus, both principles come down to the same: "To the extent a [customer] benefits from the costs of new facilities, it can be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed" (Dennis, 2015).[21] Consequently, in the remainder the cost causality and beneficiary pays principles are treated as synonyms.

The economic beneficiaries' method allows to increase short and long-term system efficiencies towards 2050. Moreover, it is perceived as most fair by many and may thus contribute to increase acceptance of grid reinforcements, and shortening realisation periods. On the other hand, it requires many assumptions to be made about possible future situations; expected beneficiaries have to be identified and future benefits depend on assumptions on future system conditions as summarized in scenarios. Therefore, benefits vary according to the scenario at hand, implying that part of the costs cannot be indisputably allocated to a specific group of stakeholders. This holds also for reliability

[21] Likewise, the lack of proper cost allocation might lead to benefits for some users without bearing them the accompanying costs, resulting in an oversupply of facilities. Since the level of network investments in Europe is generally considered as too low, the focus in the remainder is on undersupply.

costs which due to their public good character benefit all network users, although some network users may be willing to accept lower grid reliability levels in return for a lower energy bill. Moreover, policy makers should recognize that improving cost causality of network costs by deployment of economic beneficiaries' methods may come at the disadvantage of higher complexity and associated higher implementation, transaction and compliance costs as well as possibly lower transparency of network cost allocation. As such they should carefully trade-off advantages and disadvantages of adopting more cost reflective network cost allocation methods against each other.

Network flow methods indirectly estimate and allocate the benefits through network flows, and thus also comply with the principle, although to a lower extent. First, there is no indisputable procedure to measure "physical network utilization", all evaluation methods are questionable, and the economic rationale for network usage methods is weak (Pérez-Arriaga, 2010; Pudjianto, 2014).[22] On the other hand, in meshed AC networks, flow methods are considered as the only possibility to determine costs and benefits in more detail. PJM (2010) also states that 'the international trend is toward the use of location-based or flow-based methods to allocate and recover at least some portion of transmission costs'. In market arrangements that explicitly account for network constraints such as flow-based market coupling in Europe and locational marginal pricing (LMP) in several states of the US, DC load flow analysis is applied to divide scarce network capacity over network users as efficiently as possible. Therefore, although network flow methods score somewhat lower on the criterion cost causality, they seem indispensable for cost allocation in meshed grids as is increasingly the case in Europe. In fact, as seen above, in practice combinations of economic beneficiaries and network flow methods are also applied (Areas of Influence method in Argentina and Aumann-Shapley method in Brazil). Like beneficiary pays methods, network flow methods require sets of assumptions, since normally prospective cost allocation is applied where cost allocation is based upon the expected situation after installation of the network upgrade. Network flow methods thus require forward-looking network studies which are more complex and difficult to understand for stakeholders than economic beneficiaries methods and postage stamp methods (see discussion below). As a result, substantial efforts are required to gather and apply the necessary data for cost allocation, increasing complexity and possibly lowering transparency.

Instead, postage stamp methods are relatively simple and easy to understand, less complex, and may dispose of a higher transparency (depending on the system at hand). Furthermore, the method does implicitly recognize that a public good such as grid reliability is enjoyed by all network users and therefore grid reliability costs should be socialized. Grid reliability is a public good, as it is both non-rivalrous and (partially) non-excludable. It is non-rivalrous as the consumption of reliability by one actor normally does not diminish the reliability for another actor. In most European countries network interruptions with significant effects occur usually only very infrequently during extreme situations. Grid reliability is also largely non-excludable as it is difficult, if not often impossible, to curtail individual network users, especially small users, and frequent curtailment of groups of users would have severe negative consequences for the reputation of the system operator concerned. Therefore, network reinforcements generally promote network reliability of a wide range of network users within a certain geographical area. Consequently, the best cost allocation practice is to spread reliability costs over all network users ('socialization'). To that aim, these costs should be summed up

[22] Pudjianto, D. (2014), Imperial College, private communication. He confirmed that there is no indisputable procedure to measure physical network utilization.

and divided equally across countries. Network costs can be socialized between countries by either adjusting the division of congestion rents or by deploying the inter-TSO compensation (ITC) mechanism (see discussion of option 2). On the other hand, the postage stamp method assumes homogeneous network user categories and therefore neglects the increasing diversity of network users with more diverse production and consumption patterns. However, as indicated before, average situations are often not representative of the huge diversity of network situations in reality. As a result, postage stamp methods are increasingly unreflective of real costs and benefits that network users incur to the system, although these methods do not necessarily fully ignore the cost causality principle since the distinction of different network user categories could reflect some basic ideas about cost reflectivity.

Governance model inspiration

The preferred type of network cost allocation method differs for upgrades performed for economic and reliability reasons.[23] Concerning the allocation of the costs of economic upgrades, the beneficiary pays method by its very nature fulfils the cost causality principle to the highest extent possible and therefore allows best to increase short and long term efficiency of the system by 2050 as well as positively impacting public acceptance leading to possible decreasing of realization periods of grid reinforcements. The beneficiary pays method is currently not yet applied on a wide scale; it is applied in Brazil and Argentina, while in the US and the EU (including the Nordic countries) first attempts are being made. Until now, in the US only clear principles have been issued in federal regulation; a specific beneficiary pays method has not yet been selected.

For proper application in meshed networks, the beneficiary pays method has to be combined with a network flow method for cost allocation. In Central America and the UK, pure network flow methods are applied, while in Brazil and Argentina, combinations of economic beneficiaries and network flow methods are deployed. The methods applied in the UK and Argentina are considered less efficient and reasonable for Europe than those of Central America and Brazil; the former methods are based on marginal network use and a single responding node in the system which makes them less able to capture the impact on network flows in meshed systems than the latter methods that are based on average incremental network use and multiple responding system nodes.

Moreover, specific beneficiary pays methods that compensate negatively affected countries such as the positive net benefit method and Aumann-Shapley methods are preferred above specific methods that do not allow for compensation of negatively affected stakeholders by positively affected stakeholders. Hence, without compensation negatively affected stakeholders may (try to) block the network expansion. The positive net benefit method is applied by ACER for some PCIs, while the Aumann-Shapley method is applied in Brazil.

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[23] Usually, potential network reinforcements are evaluated by application of both market and network models. Market models may be applied to identify network reinforcements that are advantageous from an economic point of view, while network models may be applied to identify network reinforcements that are required from a security perspective. ENTSO-E (2013) applies both models in a loop, but in other jurisdictions the models are sometimes separated with advantageous network reinforcements from economic and security perspective called economic upgrades and reliability upgrades respectively.

Concerning the allocation of the costs of reliability upgrades, cost socialization is favoured. Nearly all governance models socialize reliability network costs over all network users, except for the Central American and Merchant ones. The Central America model allocates the costs of reliability upgrades based on network usage, while the Merchant model does not account for reliability costs at all. When applying cost socialization, several governance models distinguish between network upgrades for reliability and economic reasons respectively (USA, Brazil, Argentina, and UK), whereas other governance models socialize all network costs (Germany, gas). Since only network upgrades for reliability reasons show public good characteristics, the former types of governance models is preferred.

Description of current status

As discussed before, network costs can be divided by economic beneficiaries, network flow, and postage stamp methods between countries, which differ to the extent they deploy the cost causality principle. Within the EU, network costs of economic upgrades are mainly shared between countries through postage stamp methods while network cost of reliability upgrades are usually not shared. Network costs within countries are generally also shared with the postage stamp method, while in some cases (UK, Sweden) network flow methods are deployed. The current status for both the network cost allocation between and within countries is further discussed in the next options.

Advantages and disadvantages

Advantages	Disadvantages
Higher system efficiency both in the short-term and the long-term, decreasing overall system costs.	Many assumptions to be made about possible future situations: uncertainty about exact level of net benefits implies that full costs cannot be indisputably allocated to a specific (group of) stakeholder(s) implying part of the costs to be socialized using the postage stamp method
Perceived as most fair and may thus lead to increasing acceptance and shorten realization periods of grid infrastructures	More complex and/or difficult to understand resulting in higher implementation, transaction and compliance costs
Socialization of reliability network costs allows for adequately taking into account public good aspects.	Socialization does not account for possible need for differentiation of grid reliability services.
	Certain stakeholder groups, especially poorer people, may have to pay larger shares of grid costs, raising equity/fairness issues.

Hurdles and measures to overcome these

Four hurdles may prevent moving from the current governance situation towards the envisaged option for the year 2050.

1. Assumptions need to be made about possible future situations of generation and demand: Future network benefits depend amongst others on countries' expected fuel and CO_2 prices for generators, generation mix, electricity demand, and EU and national energy policy. The number of plausible scenarios towards 2050 and therefore the spectrum of plausible network investments is large, resulting in a large bandwidth of net benefits of new grid infrastructures that should be taken into account in cost allocation. The uncertainty about the exact level of net benefits implies that part of the network costs and therefore part of the compensation payments between countries are not robust. As a result, part of the costs cannot be indisputably and precisely allocated to a specific country. These costs should be socialized i.e. divided equally across countries. Network costs can be socialized between countries either by CBCA or by deploying the ITC mechanism (see infra option 2).
2. The beneficiary pays method is more complex. Therefore it is more difficult to understand than the 50/50 rule, causing higher administrative costs (implementation, transaction and compliance) for project promoters, national regulatory agencies (NRAs), and other stakeholders involved.
3. As long as small network users cannot be curtailed individually and as such each user consumes the same level of grid reliability, it is impossible to allocate network users different grid reliability costs.
4. Stricter application of the cost causality principle might result in levying a larger part of the network costs on poorer people, raising equity/fairness issues. For example, those people may be living in energy inefficient houses that require relatively more energy and therefore network transport.

Given these hurdles, currently a lack of consensus exists about the application of cost allocation methods. However, some intermediate steps towards implementing the option for 2050 are envisaged:

- When policy makers, regulators, and TSOs pay more attention to the beneficiary pays principle, they should make due allowance for the robustness of future network benefits in cost allocation. The part of network costs that cannot be indisputably and precisely allocated to a specific country should be socialized.
- TSOs should allow for innovative differentiation of grid reliability services, not only between economic sectors but also within groups of consumers. E.g. some industrial customers may be willing to opt for interruptible network services in return for a discount on network tariffs. This may reduce the share of reliability network costs that has to be socialized over all network users.
- Project promoters and regulators should ensure proper involvement of stakeholders throughout the cost allocation adjustment process to accommodate equity and fairness considerations in energy pricing and network charging. It will also help to improve understandability, transparency and acceptability of cost allocation by stakeholders.
- Policy makers may mitigate possible negative impacts of more cost reflective energy and network pricing on poorer people by securing minimum social security standards and, if necessary, by implementing complementary social security policy (e.g. subsidies for housing insulation).

8.3.2. Option 2

In order to stimulate regulatory certainty and stability for all projects having a cross-border impact, a unique, robust and binding methodology should be developed for cross-border cost allocation (CBCA). In the short term, and as long as there is not sufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to countries, multilateral CBCAs should only be applied in exceptional cases, rather than as base case. In the long term, multilateral cross-border cost allocation agreements should be applied on a wider scale, if a(n updated) feasibility study indicates positive results.

Explanation

At EU level already some governance efforts are made to prevent free-riding of countries by coordination and thereby to stimulate fair network cost allocation. First of all, the European inter-TSO compensation (ITC) mechanism exists which allows for compensation payments between TSOs for costs incurred as a result of hosting cross-border flows of electricity in each country involved. Secondly, EC (2013a) provides guidelines for trans-European energy infrastructure, and especially for Projects of Common Interest (PCIs) which are prioritized and therefore eligible for cross-border cost allocation, amongst others. As outlined before, the extent of coordination is currently limited; the size of the ITC mechanism fund is limited since its current design does not properly account for the real impacts of cross-border flows, while following EC (2013a) coordination by ACER of cross-border cost allocation (CBCA) is limited to exceptional cases.

It can be expected that with the continuing developments towards a well-functioning internal energy market, coordination by ACER of CBCA will be gradually performed in a larger number of cases. The detailed beneficiary pays type of method that ACER deploys for their coordination efforts is considered as a good starting point, as it would stimulate regulatory certainty and stability for all projects having a cross-border impact and prevents gaming of individual countries. At the same time it should be recognized that this method makes the cost allocation process more complex and should be further developed to increase both its robustness and the consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to countries. Its robustness may be questioned when cost allocation calculations are based upon just one generation and demand scenario, while in practise several generation and demand scenarios are possible. Therefore, the cost allocation decision should adequately account for the bandwidth and uncertainty of net benefits that can be realised, e.g. by taking into account multiple scenarios, a significance threshold for transfer payments between countries, and socialization of costs that cannot be indisputably allocated through CBCA and/or the ITC mechanism. The appropriateness of the method for the computation and allocation of benefits of reinforcements to countries may be contested given the difficulties around the identification of future benefits. Hence, the development and definition of a robust and binding European calculation method for benefits and costs is required. For establishing such a robust calculation method, of course, a feasibility study has to be performed, or existing feasibility studies outside the e-Highway2050 project have to be updated. Besides, if cross-border reliability impacts are identified, some convergence of reliability standards is needed. Also some further developments may be needed to make financial flows consistent with physical flows, thus loop flows should be adequately taken into account. For more details and a further discussion of the ITC mechanism and EU-wide coordination of CBCA, we refer to the description of the current status below.

In the short term, the identified issues may imply that the application of stronger multilateral coordination of CBCA is restricted towards exceptional cases, rather than being the base case. In the long term, it could be imagined that once the need for coordination increases, the benefit items are increasingly being quantified, and other hurdles are mitigated, the allocation of the cost of new lines can be multilaterally coordinated. This holds not only for (selected) PCIs, but for all projects with significant cross-border impacts as identified by TYNDPs. This would help to contain free-riding effects more effectively for two reasons. First, it removes the complexity of the current staged multi-level approach, that only allows for application of the ACER method in case of a request of project promoters or in case of lack of agreement of NRAs. Second, the application of one harmonized cost allocation method removes potential inefficiencies related to the application of a range of different (ad-hoc) cost allocation methods. As a result the achievement of European policy objectives is promoted by increasing system efficiencies, network investments, and social welfare. But as discussed before, this should only be implemented if a feasibility study shows the positives results for this.

Governance model inspiration

The level of coordination of network cost allocation among countries varies between governance models; from little or no coordination, mechanisms based on the voluntary cooperation of countries to regulatory coordinated cost allocation agreements that take into account allocation of costs (or saved costs) to all countries defined within regional markets. Only the Central America and Nordic systems currently show a medium to high level of coordination. In Central America, full coordination of cost allocation of regional network assets seems to take place in the whole region. In the Nordic system, coordination of cost allocation is still an exception rather than a common practise and takes place on a voluntary basis;[24] it is subject to agreement between countries involved. If an agreement is not reached, unfair cost allocation is still possible. Apart from these two systems, all other governance models analysed perform cost allocation at national level only. Concerning the USA, coordination in cost allocation among regions is still almost non-existent, and difficult to achieve, though general federal guidelines (FERC, 2012) are in place. Therefore, the USA is still plagued by market seams issues i.e. issues that relate to incompatible governance on both sides of a border which create transaction costs or externalities. These include incompatibilities between regions concerning transmission scheduling, congestion management, and unscheduled flows (Helman *et al.* 2008).

Description of current status

Concerning the network cost allocation of economic upgrades, until recently both network (investment) costs and congestion rents have been often divided between countries[25] on a 50%-50%

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[24] See chapter 3, description of Nordic Governance Model.

[25] Usually through TSOs as project promoters, since the role of merchant investors is quite limited in the EU.

basis (EU, 2011).[26] This has been changed by EU (2013) which foresees, upon the fulfilment of certain conditions, the application of a beneficiary pays method for EU Projects of Common Interest (PCIs).

PCIs are a selection of projects of ENTSO-E's TYNDP that are prioritized and therefore eligible for cross-border cost allocation, amongst others. A precondition for application of cross-border cost allocation is that at least one project promoter has to request relevant national authorities to apply cross-border cost allocation (article 12 (2) of EU, 2013). Additionally, only if National Regulatory Agencies (NRAs) do not reach agreement on an investment request including cross-border cost allocation within six months, or upon joint request from the NRAs concerned, the decision is referred to ACER (article 12 (6)). ACER specified a cross-border cost allocation (CBCA) method[27] – the positive net benefit method – in order to facilitate a consistent CBCA approach among NRAs and to clarify the details that project promoters have to submit for PCIs that are subject to cross-border cost allocation. Project promoters submit the electricity and gas project proposals for which they want to obtain the status of PCI to the Regional Groups for assessment. Regional Groups consisting of stakeholders at EU level (ENTSO-E, ACER, and the EC) as well as national level (TSOs, NRAs and national ministries) then will evaluate the projects against the general and specific criteria as defined in the Regulation, and summarized and clarified by ACER into the positive net benefit method. Regional Groups provide weights to sustainability, security of supply and affordability.

When the positive net benefit method is applied, negatively affected project promoters are compensated by all actors with (substantial) positive net benefits if an infrastructure is advantageous at global level compared to the situation without the project. Stakeholders that obtain highest positive net benefits have to pay the highest compensation to negatively affected stakeholders, and vice versa (ACER, 2013c). However, ACER (2013c) does not oblige NRAs to consider negative impacts on third i.e. non-hosting countries, although third countries often also will participate in Regional Groups and therefore are likely to be able to internalize negative external effect in the decisions. Moreover, NRAs may decide not to apply the ACER method, but instead agree on a bilateral solution that shares benefits and costs on an equal basis (ACER, 2015). However, the method proposed by ACER could serve as a kind of benchmark; countries or stakeholders that will lose under cost sharing on an equal basis may be inclined to block a bilateral solution and therefore force reference to ACER if they consider that they would have to pay less when ACER would make a cost allocation decision. Finally, EU (2014) seems to indicate that project promoters for requesting grants from the EU to close their financial gap related to positive externalities should apply the CBCA format for PCIs. As opposed to those selected PCIs, TYNDP projects with cross-border impacts but without PCI status seem not yet systematically taking into account the impacts on third countries. This seems not in line with the purpose of EU (2013), although given the limited experience with CBCA it remains to be seen how this exactly works out in practise.

Apart from sharing of interconnector costs (and congestion rents) between countries by CBCAs, a very limited amount of network costs is distributed between countries by another instrument; the

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[26] According to EU (2011), exceptions are cost allocation for the interconnections between Ireland and the UK as well as between France and Luxembourg.

[27] Its application requires information on cost and benefits for different countries; therefore the CBCA is linked to a project specific cost benefit analysis (CBA).

ITC mechanism.[28] The European ITC mechanism allows for compensation payments between TSOs for costs incurred as a result of hosting cross-border flows and concomitant network losses in each country involved. TSOs are compensated for cross-border use of their networks based upon the minimum of physical imports and exports out of the ITC fund, while they must contribute to the fund for their transport over foreign networks based upon net imports or exports. This results into a net payment or receipt. The total amount of payments is equal to the total amount of receipts i.e. it is a zero sum game for TSOs. Table 19 summarizes the main characteristics of CBCA and ITC mechanisms.

	CBCA	**ITC**
Scope	All costs & benefits	Network costs for hosting cross-border flows only (and network losses)
Type of cost allocation method	Largely and increasingly monetary, for meshed grid often combined with network flow method	Network flows
Time of calculation	Ex-ante	Largely ex-post

Table 19: Comparison of main characteristics of CBCA and ITC mechanisms

ACER calculates yearly the amounts of compensations and contributions within the ITC mechanism based upon an ex-post analysis, although payments are partially made in advance. In 2013, the most recent year for which data are publicly available, the compensation payments for the costs of network losses amounted to 145 million euro, while the compensation payments for the availability of cross-border infrastructure is 100 million euro.

Especially the volume of the latter amount is quite limited compared to the total TSO congestion income revenues which according to EU (2011) in 2010 amounted to about 1,300 million euro. As a result, the ITC mechanism plays only a marginal role in investment decisions and associated cost allocation decisions. The restricted volume of compensation payments for the availability of cross-border infrastructures presumably relate to the suboptimal design of the current ITC mechanism, for several reasons.

First of all, methods to settle costs for infrastructure utilization by cross-border flows are characterized by several limitations. One of the limitations is the fact that the current ITC mechanism cannot distinguish between the origin of flows; commercial flows, non-scheduled flows such as loop flows, or flows for mutual TSO support. As a result, transits are allocated towards net flows of both involved countries, implying the latter increase in proportion to the total (absolute) value of net flows to and from all national transmission systems. This increases the contributions of importing countries that are confronted with non-scheduled flows to the ITC fund.

Another restriction is that the method for compensating TSOs for the costs of cross-border flows is based on cross-border transactions. There exists, however, no indisputable method to determine whether these flows are caused by national or international stakeholders. As a result, the cost distribution of a new interconnection will not be in line with the benefit allocation. The party which

[28] The description of the ITC mechanism draws heavily upon ECN (2013).

exports becomes a net payer, while importing actors become a net receiver of the ITC mechanism (see example 3 of Stoilov *et al.* 2011).

Furthermore, the ITC is an ex-post mechanism that does not account for expected costs and benefits of new infrastructure since it is based on realized transit flows in the past. The lack of an assessment of expected costs led to the restriction of the infrastructure part of the ITC fund for hosting cross-border flows to a marginal 100 million euro (i.e. total payments and total compensations). Moreover, EU (2010) required ACER to evaluate the technical and economic assessment of the forward-looking long-run average incremental costs (LRAIC) method that forms the basis for the infrastructure part of the ITC fund. ACER (2013a) found that the LRAIC method is an inappropriate method in this context and ACER (2013b) recommended that 'a new regulatory framework should be developed in relation to ITC' and that 'the current ITC infrastructure compensation should be limited to infrastructures existing at the end of 2015 and the corresponding ITC infrastructure fund should be phased-out'. Consequently, the current impact of the ITC mechanism is deemed marginal and the current mechanism is not likely to be relevant for the 2050 situation. Instead, a mechanism may be implemented that allows for compensation of loop flows.

Concerning reliability costs, cross-border reinforcements usually deliver reliability benefits for a wide range of countries in a meshed grid as the future European power network. Apart from the investing or hosting countries, adjacent third countries also often obtain reliability benefits. If network (and/or market) studies identify reliability impacts that are spread over a geographical area consisting of several countries, this should be acknowledged in cross-border cost allocation in order to prevent free-riding effects. Like for other cost items, reliability costs can be derived from CBAs for grid reinforcements. In this context, ENTSO-E (2015) prescribes to apply a network study to obtain insights in the improvement of expected energy not supplied (EENS) through inclusion of such a project.[29] If EENS is multiplied by the value of lost load (VOLL) this would provide an estimation of the reliability network costs involved, which could then be spread out over all network users. However, given the variability of VOLL estimates, currently no monetization of reliability impacts for Union-wide comparative purposes takes place.

Advantages and disadvantages

Advantages	Disadvantages
Fair allocation of costs to countries by allowing for compensation of negatively impacted countries.	More complex cost allocation process, difficult to achieve full coordination (e.g. to take loop flows adequately into account) which has an impact on the feasibility of the implementation.
Incorporating positive externalities such as improved grid reliability in neighbouring countries in cost allocation decisions may allow for more network investments and better sizing of network investments. Similarly, taking into account negative externalities improves the system efficiency of	Positive or negative effects on third countries are sometimes rather marginal. Involvement of those countries in cost allocation decisions may complicate the decision making process.

[29] Alternatively, regional adequacy assessments may deliver estimations of reliability indicators such as EENS and LOLE. See for instance PLEF (2015).

network investments.	
One robust European calculation method for benefits and costs provides regulatory certainty and stability, and prevents gaming of countries.	In the absence of harmonized reliability standards, the VOLL and average grid reliability costs will differ significantly across countries, impeding cross-border allocation of reliability costs.
	CBCA would imply financial payments from / towards non-hosting countries which are not backed up by assets. Consequently, dilution of the asset base and lower credit rating for TSOs/ project promoters may lead to higher costs for society.

Hurdles and measures to overcome these

Also for this option, four main hurdles can be identified.

1. Currently, neither electricity markets nor the ITC mechanism properly account for loop flows that result from technical network effects of AC lines in meshed grids. As such, part of the costs will not be adequately allocated to the countries involved. Given that free-riding will not be fully resolved, countries that are experiencing loop flows may require that first more extensive solutions are sought, postponing the wider introduction of multilateral coordination.

2. Furthermore, positive or negative effects on third countries are sometimes rather marginal. Involvement of those countries in cost allocation decisions may complicate the decision making process. Even if effects on third countries are substantial, countries may fear the higher complexity of the involvement of more than two countries in cost allocation decisions. Multilateral coordination of cost allocation may also be prevented by lack of trust between countries which may be fuelled by opportunism of countries concerning particular cost allocation decisions.

3. Concerning the multilateral coordination of reliability cost allocation, in the absence of common reliability standards, the value of lost load (VOLL) and therefore average grid reliability costs will differ significantly across countries. As a result, the allocation of reliability costs across countries may be impeded.

4. CBCA would imply financial payments from / towards non-hosting countries which are not backed up by assets. Consequently, dilution of the asset base and lower credit rating for TSOs / project promoters might lead to higher costs for society.[30]

[30] The risk of dilution of the asset base may be modest since;

1. Depending on the country at hand, payments will be (partially or fully) compensated by receipts from other countries. As such risks for creditors are limited. Moreover given the advice to standardize regulatory treatment of CBCAs by coordination, predictability of CBCA may be improved, thus lowering risks for providers of equity and debt.
2. Indeed in the current situation the TSO investment model is fully asset based. In a Smart Grids future one could also imagine a gradual shift towards a (partial) service oriented business model with costs partially remunerated by services and thus not backed up by assets (e.g. likewise the situation in air control, telecom etc.).

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 are proposed:

- Project promoters and regulators may analyse the impact of national constraints or critical infrastructures (e.g. in Germany) on neighbouring countries in more detail as a first step to contain the effects of parallel/loop flows on cost allocation by appropriate policy measures.
- Regulators should introduce/maintain a significance threshold for multilateral cost allocation in order to prevent participation of marginally affected countries in the decision making process.
- Policy makers and regulators should strive for consensus on the implementation of minimum reliability standards as advocated by the BB technical & market operation as it allows for convergence of the value of lost load (VOLL) estimates and therefore grid reliability costs across member states, enabling coordinated cross-border allocation of reliability network costs.
- Policy makers and regulators should prevent opportunism and gaming of countries by application of standardized multilateral cost allocation procedures, provided a feasibility study yields a positive result.
- Dilution of the asset base can be mitigated by ensuring that payments will be sufficiently compensated by receipts and/or, by evolving more towards a (partial) service oriented remuneration with costs partially remunerated by services and thus not backed up by assets (e.g. likewise the situation in air control, telecom etc.).

8.3.3. Option 3

If deployment of flexibility measures such as demand response and storage for congestion management purposes increases available cross-border network capacity, but other countries do not pay for their share in the benefits (i.e. free riding), underinvestment in grid flexibility measures takes place. Therefore, if a CBA indicates that effects of deployment of flexibility measures in the grid on benefiting, but non-paying countries, are substantial, cost allocation of grid flexibility measures costs should be coordinated across Europe.

Explanation

Flexibility measures such as demand response and storage are likely to be deployed in an increasing number of cases for relieving network constraints by congestion management, if technically feasible, thereby (partially) postponing or cancelling more costly network reinforcements. Because of the increasing share of intermittent generation in some scenario's, these flexibility measures will gain importance. Their costs are recovered by network cost allocation to the extent that they are deployed for congestion management, while flexibility that is deployed for market purposes such as for example portfolio optimization is likely to be recovered through energy markets (either directly by capacity or flexibility markets, or indirectly in energy markets through scarcity rents). Therefore, the discussion here is limited to the deployment of flexibility for network purposes.

Likewise the case of network reinforcements discussed within option 2, because of network effects of AC lines in meshed grids also flexibility measures may not only affect the investing country (countries) or network operator(s), but also neighbouring countries or network operators through an increase of cross-border network capacity. Since decisions about deployment of demand response and storage for grid purposes are currently entirely made at the national level, their associated costs and benefits are not yet accounted for in cross-border network investments. However, if such grid flexibility measures are not coordinated across borders, free-riding of countries at the expense of the country investing in flexibility measures may occur. Hence, non-investing countries may benefit from the increase of cross-border capacity by investing countries, while the former are not paying for it. Consequently, grid flexibility measures would be sized smaller than optimal, or in the extreme case may be not profitable at all. For the European system as a whole the upshot would be underinvestment in grid flexibility measures.

In case underinvestment is estimated to be substantial, some coordination of flexibility measures with impacts on the grids across countries is considered to be beneficial. In addition to current measures that ensure the removal of network tariffs that are detrimental to overall efficiency, including energy efficiency of the grid amongst others, one could think of coordinated assessment frameworks for investments in both grid infrastructure and flexibility measures. Assessment frameworks such as social CBAs can deliver the required information to organize the CBCA of flexibility measures in an equal manner as CBCA of network reinforcements.

Governance model inspiration

This option is inspired by option 2 about the CBCA of network reinforcements and the governance model experiences mentioned there.

Description of current status

Demand response costs that are part of network costs are currently only accounted for explicitly in the UK cost allocation method. At the same time some efforts are being made to implement regional / EU-wide product standards for balancing capacity and balancing energy (ENTSO-E, 2014b). Both can be provided by different types of flexibility providers including generators, storage, interconnections, and demand response. Standardisation may help to exchange flexibility products across borders, and thus to achieve cross-border cost allocation. These topics are addressed in the forthcoming Network Code on Electricity Balancing.

Advantages and disadvantages

Advantage	**Disadvantages**
Cross-border cost allocation of grid flexibility measures may prevent free-riding of countries like for conventional network reinforcements.	Uncertainty about size and likelihood of free-riding effects in cross-border flexibility procurement.
	More complex and could thus lead to increased need of efforts.

Hurdles and measures to overcome these

The need for convergence of national policies for stimulation of flexibility provision by demand response and other technologies may not be widely acknowledged, especially when feasibility studies are either lacking or do not prove the existence of free-riding effects in flexibility deployment for congestion management. Continuation of the current situation with national policies to stimulate demand response and energy efficiency may also be preferred in order to more easily achieve national policy objectives and to prevent complexities and the need for additional efforts that may evolve from transnational coordination.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 are proposed:

- Project promoters and regulators should analyse whether cross-border free-riding effects of deployment of flexibility for congestion management are likely and non-marginal, resulting in underinvestment in flexibility measures. If this is the case, CBCA of flexibility measures that relieve network congestion should be coordinated by regulators across Europe. Project promoters and regulators should implement one framework for coordinated cost allocation of both flexibility provision and grid reinforcements rather than separate coordination frameworks for cost allocation of flexibility provision as well as cost allocation of grid reinforcements.
- Policy makers should stress the advantages of sharing cost and benefits of flexibility measures for grid purposes across borders for reducing total system costs both for Europe as a whole and for individual member states.

8.3.4. Option 4

Efficient economic signals to all network users: The beneficiary pays principle should not only be applied between countries but also within countries among stakeholders. Network charges should be paid by both generators and loads.

Explanation

After costs have been divided across countries, they have to be allocated to specific stakeholders, notably generators and consumers. Given that both generators and large consumers such as industrial consumers compete with generators and companies respectively in other member states, amongst others on network costs, the need for coordination of national network charging is acknowledged by EU legislation (Regulation No 838/2010). As the development of the IEM is expected to continue, it seems likely that national network charging will be increasingly coordinated across Europe for achieving a level playing field for generators and industries.

Network costs of project promoters are assumed to be fully recovered by revenues obtained through congestion management ('congestion rents') and network charging. Residual network costs after deduction of congestion rents are recovered by network charges. Network costs are levied upon the network users i.e. generators and loads. Both generators and loads benefit from utilizing the grid, but also incur congestion management, investment and O&M costs on the system, for which they should pay according to the beneficiary pays principle. Congestion management and network charging should provide efficient economic signals to network users so that the operational and investment actions of the latter are not detrimental to overall system efficiency. In the short-term, congestion management should encourage an efficient use of the existing network, while in the long term both congestion management and network charging should induce a cost-effective network development. In order to stimulate efficient network investments and operational network use, the beneficiary pays principle should also be applied within countries among system users. This will also decrease the increasing gap between network charges and true costs levied by network users on the system, due to the increasing diversity of network users. Hence, application of the beneficiary pays principle could assist in mitigating the challenge for policy makers and network operators that uniform network charges are heavily contested by network users. Therefore, network charges should be paid by both generators and loads. Network charges for generators are called G-charges, and charges for consumers are called L-charges. Given the difficulties to determine individual contributions of network users to network costs, it is common practise that costs are approximated for groups of network users.

Governance model inspiration

In Central America, Argentina, and the Nordic governance models, congestion rents are collected to pay part of the grid costs. In the USA and Brazil, (some) congestion rents are obtained but deployed for other purposes: in the USA for hedging of customers against congestion cost, while in Brazil, congestion rents are paid to hydro plants having signed cross-zonal supply contracts (contracts where the points of injection and delivery are in different bidding zones). Finally, in Germany and the UK, no congestion rents are produced since each country is considered as one bidding zone. The situation where congestion rents are used to pay part of the costs of the grids is preferred as it shows the most direct relationship between benefits and cost recovery.[31] Network charges are paid by both generators and load in Brazil, Central America, Argentina, UK, and some countries (Norway and Sweden) in the Nordic system. For the US holds that the largest share of network charges is paid by load, although in some regions generators are responsible for paying some deep network costs, amongst others in PJM (PJM, 2010).

Description of current status

Although both generators and consumers enjoy advantages from the transport of energy (producer and consumer surplus), both within and between countries, only consumers usually have to pay the large majority (or even all) of the investment and O&M costs through network charges. As is shown in Figure 9 below, producers often have to pay either limited network charges or no network charges at all (exceptions being Austria, Great Britain, Ireland, Northern Ireland, Norway, Romania, and Sweden).

	Sharing of network operator charges	
	Generation	**Load**
Austria	43%	57%
Belgium	7%	93%
Bosnia and Herzegovina	0%	100%
Bulgaria	0%	100%
Croatia	0%	100%
Cyprus	0%	100%
Czech Republic	0%	100%
Denmark	5%	95%
Estonia	0%	100%

[31] However, further research into this issue is advised as opinions differ on what is desirable (cf. PJM, 2010).

Finland	18%	82%
France	2%	98%
Germany	0%	100%
Great Britain	TNUoS 27% BSUoS 50%	TNUoS 73% BSUoS 50%
Greece	0% (TUoS and Uplift charges)	100% (TUoS and Uplift charges)
Hungary	0%	100%
Iceland	0%	100%
Ireland	25%	75%
Italy	0%	100%
Latvia	0%	100%
Lithuania	0%	100%
Luxembourg	0%	100%
FYROM	0%	100%
Montenegro	0%	100%
Netherlands	0%	100%
Northern Ireland	25%	75%
Norway	40%	60%
Poland	0%	100%
Portugal	9%	91%
Romania	19%	81%
Serbia	0%	100%
Slovak Rep.	3%	97%
Slovenia	0%	100%
Spain	10%	90%
Sweden	39%	61%
Switzerland	0%	100%

Figure 9: Sharing of network charges over Generation and Load. Source: ENTSO-E (2015), Table 4.1.

Advantages and disadvantages

Advantage	Disadvantage
Higher system efficiency when generators and loads face the network costs they incur to the system, increasing the efficiency of their operational and investment decisions.	Distortion of level playing field between generators if coordination between countries is lacking.

Hurdles and measures to overcome these

Nowadays, countries do not have an incentive to introduce more substantial network charges for generators (G-charges) since this would distort the level playing field of their generators with competing generators of neighbouring countries in electricity market (assuming countries are physically connected). As such there exists a lock-in effect bolstering the current heterogeneous situation across EU member states and preventing the realization of an overall higher level of system efficiency.

In order to overcome this lock-in effect, as a first step, policy makers should consider to remove the upper limit for average Use-of-System power-based charges for producers in EU Regulation No 838/2010. Subsequently, they should provide further guidance to stimulate the introduction of cost reflective G-charges on regional or EU-wide level.

8.3.5. Option 5

In the medium term when RES-E priority access/dispatch is phased-out, concomitant network costs should no longer be socialized, allowing for wider application of the beneficiary pays principle.

Explanation

In the medium term and for scenario's where RES technologies are becoming more mature and obtain considerable market shares, it is envisaged that RES support declines and RES will no longer be treated (partial) separately from the overall regional or EU-wide electricity market, but instead becomes an integral part of it. Also national RES priority schemes that allow for network access and/or dispatch for RES-E at lower costs will then be gradually phased out. Although the abolition of RES network priority schemes may be considered by some as in conflict with the current objective of some member states to stimulate deployment of renewable energy at maximum, this is likely to be outweighed by a substantial increase of system efficiency and network investments in the medium term; it allows public authorities at national, regional or EU-wide level to treat effects of projects with significant cross-border impacts on RES as any other type of costs or benefits, and to replace cost socialization of RES costs by economic beneficiaries cost allocation methods towards 2050.

Governance model inspiration

Central America, Nordic, and gas systems do not provide priority to RES and can therefore be considered as reflective of the future situation without socialization of RES priority costs. On the other hand, RES priority schemes currently shift network costs from RES to non-RES network users in USA, Brazil, Argentina, and UK. The same holds for Germany that provides RES priority but redistributes costs outside network charging by socialization to consumers. If RES is given priority this holds only for the national level, since cross-border network capacity is usually allocated using non-discriminatory market auction algorithms. The absence of RES priority in Central America, Nordic, and gas governance models is deemed as most reflective of the envisaged future European situation.

Description of current status

Priority network access and/or dispatch for RES-E allow for network access and transport for RES-E at lower costs. Often this implies that transmission rights are provided for less than the economic costs to RES-E. These costs are usually implicitly spread out among mid-merit and peaking plants as well as consumers given that in congested situations, fewer transmission rights are available for non-prioritized generation and demand. Currently RES-E is granted priority at national level in the majority of EU Member States: AT, BE, CY, DK, DE, GR, HU, IE, IT, MT, PL, PT, SK, SI and ES (http://www.res-legal.eu/compare-grid-issues/). Although at interconnections non-discriminatory congestion management procedures apply, RES-E network priority may also have impacts on other countries through loop flows. For integrated infrastructures that combine interconnections and connections for offshore wind energy, sometimes priority for the transport of offshore wind energy is foreseen, based upon wind power predictions (e.g. Kriegers Flak). Consequently, network costs of priority network access / dispatch of offshore wind on interconnections are sometimes socialized.

Advantages and disadvantages

Advantage	Disadvantage
Allows for increasing system efficiencies and additional network investments.	Phase out of RES priority access/dispatch schemes may be in conflict with objective of some member states to stimulate deployment of renewable energy.
	Full implementation probably requires a shift of responsibility for generation and energy mixes, including RES, from national to European level, which is in contradiction with the EU Treaty.

Hurdles and measures to overcome these

Also for this option, changes in the treatment of RES network costs from a transnational perspective may be deemed in conflict with national objectives. Moreover, full implementation probably requires a shift of responsibility for generation and energy mixes, including RES, which is currently still a national competency rather than an EU competency. Member States may not allow transfer of competences regarding generation mix to a European level. As a result, priority for RES-E in network access/dispatch may be maintained.

As long as the Member states are the competent authorities for these policy measures, it will be difficult to overcome the hurdles. However, some intermediate steps towards 2050 are proposed:

- For scenarios where RES-E becomes mainstream, it should become part of the IEM like all other generation. Member States have a number of other policy instruments at their disposal to achieve their national objectives (e.g. research grants, innovation subsidies, taxation).
- As a first step, policy makers should consider to remove the possibility for socialization of RES-related network costs by priority access/dispatch in article 16 of Directive 2009/28/EC. If afterwards full implementation of the policy option is still lacking, maintaining priority access/dispatch may be assessed in the framework of EC state aid legislation, since it is difficult to imagine that reasons for priority treatment remain to exist when RES-E becomes mainstream.

8.3.6. Option 6

No distortion of short-term market signals by network charging: Network charges for generators (G) and loads (L) should be power-based or lump-sum rather than energy-based.

Explanation

If G-charges are applied following policy option 4, it is important to prevent the short-term market signals from interfering with generation dispatch and demand response actions through markets. The possibility of interference depends on the type of charges. Basically, three forms of network charges exist; power-based, energy-based, and lump-sum charges. Power-based network charges depend on the capacity connected to the grid or to output under peak conditions (€/MW). Energy-based network charges depend on every unit produced/consumed and/or injected into/withdrawn from the grid (€/MWh). Lump-sum charges are charges that do not depend on capacity connected, and on yearly peak output, unless these are taken into account in the form of an average over a past period of at least five years (ACER, 2014). If energy-based charges are applied to recover infrastructure costs, the recovery of long-term network costs can distort efficient dispatch of power plants in short-term electricity markets by changing the relation between short-term marginal costs of power plants. ACER (2014) therefore considered “that energy-based G-charges shall not be used to recover infrastructure costs” to prevent distortion of the internal market. Likewise generation dispatch, demand response actions in short-term electricity markets can be changed. Therefore, power-based or lump-sum charges are preferred (Olmos & Pérez-Arriaga, 2009; ACER, 2014).

Governance model inspiration

Power-based charges are applied in Brazil and Central-America. PJM (2010) shows that in most regions of the USA, including PJM, costs are allocated based upon peak load or peak generation or demand (MW) rather than energy (MWh).

Description of current status

Network tarification may impact generation dispatch and demand response in short-term electricity markets through energy-based network charges. National network charges thus may distort competition within the internal electricity market, although distortive effects are currently sometimes limited due to transmission bottlenecks. Given the EU-wide network expansion taking place, distortion of the IEM is likely to increase. Currently, energy-related components of transmission tariffs constitute a main part of the overall transmission tariff in many EU member states, see Figure 10.

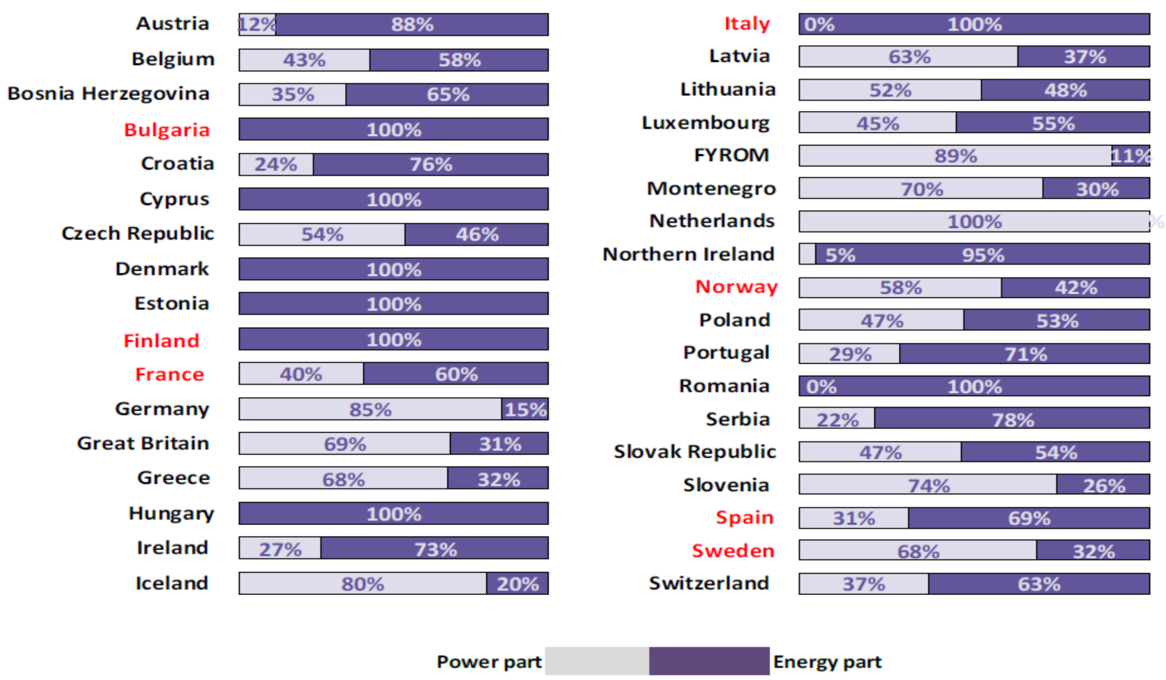

Figure 10: Power and energy related components of the transmission tariffs. - Those countries for which certain elements of the 2015 Unit Transmission Tariffs are estimations are marked in red colour. Source: ENTSO-E (2015), Chart 7.1.

Advantages and disadvantages

Advantage	Disadvantages
Efficient market functioning and grid development.	Redistribution effects between stakeholder groups with high energy production and/or consumption on stakeholder groups with low energy production and/or consumption.
	Flexibility/ may be less stimulated with abolition of energy-based network charges.

Hurdles and measures to overcome these

Introducing capacity or power based network charges instead of energy based network charges will change cost allocation among stakeholder groups within countries (e.g. levying less on network users with high consumption and more on those network users with low consumption) and as such may be at odds with national policy objectives (p.e. energy efficiency).

More theoretically, flexibility provision may be less stimulated in the future if network cost savings are fully remunerated on capacity basis rather than partially or fully on energy basis. In this case, favourable shifts of energy production or consumption decreasing energy losses and congestion are not remunerated by network charges.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 are proposed:

- In order to prevent strong redistribution effects between (groups of) stakeholders, regulators should allow for gradual shifts towards power-based or lump-sum network charging.
- If policy makers implement a restriction on application of energy-based GUoS charges, e.g. by revision of EU Regulation No 838/2010, they should account for potential negative impacts on flexibility provision.

8.3.7. Option 7

Locational network charges should be implemented, so that the true cost that network users incur to the system are reflected in network charges, promoting system efficiency.

Explanation

The level of network costs is clearly shaped by the locations of generation and load. Locational signals provide incentives to market participants to trade-off the effect of their decisions on network costs against possibly higher generation costs (e.g. because of longer transport routes for fuel supply of conventional power plants) or lower revenues (e.g. due to lower wind resources for wind turbines). This allows for system optimization by reducing the total amount of required investments, both generation and network investments, to equal supply with demand. Locational signals can be provided through energy prices (i.e. zonal or nodal pricing) as well as through network charging. This requires the application of cost allocation methods that take into account physical network characteristics ('network flows') in the division of network costs. However, locational signals need to account for limitations in the choice of another location due to spatial policy which may restrict the possibilities to locate near to a network backbone rather than in a remote corner of the network. Besides, if locational network charges are fully determined on national level, integration of small meshed national networks may be a challenge since some locations are likely to be more advantageous from an EU perspective than from a national perspective (e.g. a producer located close to a border), and the other way around.

Governance model inspiration

Locational signals are sent to generation and load in the three best performing governance models for cost allocation (USA, Central America, Brazil). Here the discussion is limited to the locational signals provided by network charging, since zonal versus nodal pricing is discussed in the BB market operation. In PJM, at least part of the costs of both reliability and economic upgrades below 500 kV are shared using the distribution factor contribution to flows on the constrained facility causing the need for the transmission upgrade (PJM, 2010). In Central America, first the Dominant Flow method is used to allocate the use of transmission facilities to power transactions (super-transactions) and subsequently the Average Participations method for allocating the flows corresponding to the regional super-transaction to individual power injections and withdrawals. The latter method determines the contribution of the network users to the flow in each line for every node. In Brazil, computed locational network charges are adjusted in order to arrive at a 50%-50% split between demand and generation of the cost of the used part of the grid. As a consequence, locational signals are deemed less efficient than in the former two governance models mentioned.

All in all, both theory and practises of the three best performing governance models indicate that locational network charges should be implemented to promote system efficiency i.e. the true cost that network users incur to the system are reflected in network charges.

Description of current status

The implementation of new technologies, including low-carbon technologies, may substantially increase the share of network users with non-standard production and consumption patterns. Lack of application of the cost causality principle in network charging may imply that generation investments are done at locations far away from load centres requiring substantial reinforcements of the grids. As a result, average network costs incurred on network users are increasingly unreflective of actual cost of their actions, distorting efficient network development and operation, bearing prohibitively high costs for overall society. Many national network charging methods do not allow for locational differentiation, hence spreading the cost over all network users/consumers. Exceptions are Great Britain, Ireland, Northern Ireland, Norway, Romania, and Sweden), see figure 11. An EU regulation (EU, 2010) reinforces this practice since average Use-of-System charges for producers ("G-charges") are limited to the range of 0-0.5 EUR/MWh.[32] Based upon this Regulation, ACER was entrusted with the evaluation of the range of the annual average transmission charges

[32] Exemptions hold for Denmark, Sweden, Finland (all 0-1.2 EUR/MWh), Ireland, United Kingdom, Northern Ireland (all 0-2.5 EUR/MWh), and Romania (0-2.0 EUR/MWh).

levied upon producers. It considered that for providing appropriate and harmonized locational signals for efficient investments in generation, 'it [is] unnecessary to propose restrictions on cost-reflective power-based G-charges and on lump-sum G-charges'.

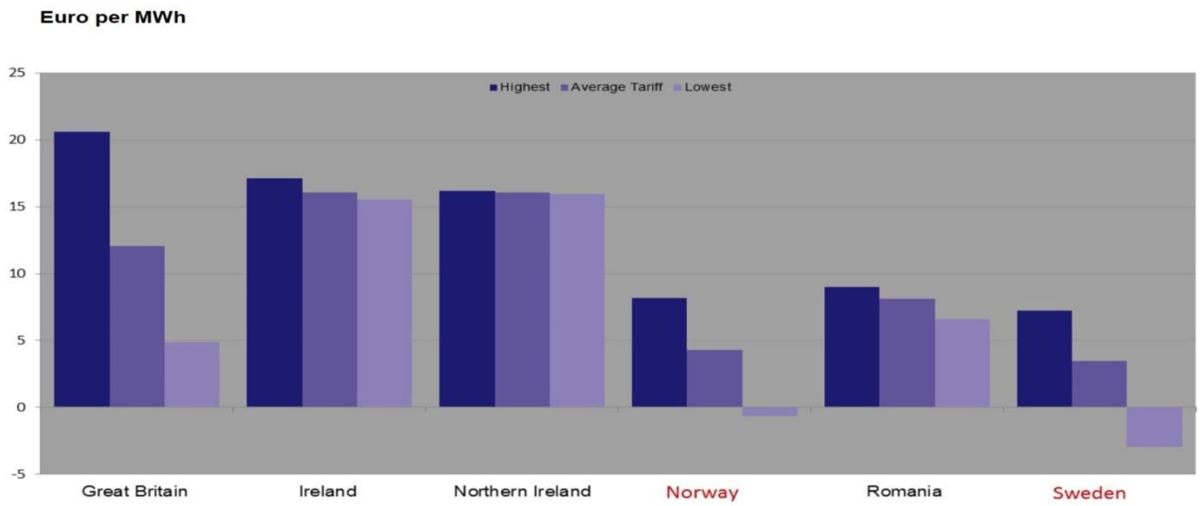

Figure 11: Impact of location on the transmission tariffs - Those countries for which certain elements of the 2015 Unit Transmission Tariffs are estimations are marked in red colour. Source: ENTSO-E (2015), Chart 7.5.

Advantages and disadvantages

Advantage	Disadvantage
Lower system investments needed due to possibilities for system operators to steer system users away from critical network points by influencing their siting decisions.	Locational network tarification may be considered as contradictory to national policy objectives e.g. equal market access for all.
	If locational network charges are fully determined on national level, integration of small meshed national networks may be a challenge.
	Spatial policy may prevent network users from choosing a different location, hence locational differentiation of network charges may be perceived as unfair.
	Difficult to determine individual contribution of network users to (most) network costs, hence costs should be approximated for groups of network users.

Hurdles and measures to overcome these

Likewise other policy options, the introduction of locational network charging may be advantageous from a European perspective, while being in conflict with national policy objectives e.g. the wish to have equal market access for all network users with the same production and consumption levels regardless of their location ('copper plate paradigm'). In addition, national policy makers may question whether the subsidiarity principle is fulfilled, in particular as sometimes locational network charging is not allowed by national laws and regulation.

As a variation to this disadvantage, it may also be the case that locational network charges are fully determined on national level but are not coordinated at the EU level. In this case, integration of small meshed national networks may be a challenge.

Furthermore, differentiation of energy prices and network charges may be considered as unfair since national spatial policy may prevent network users from choosing another siting area and thus to respond to locational charges. This is likely to hold especially for consumers and for existing network users.

Finally, difficulties around determination of individual contributions of network users to network costs prevent full and precise allocation of benefits to specific stakeholders. Actual network usage of an individual network user is affected by locations of generation and demand in the whole grid, and their actual production and consumption respectively. As a result, it is very difficult if not impossible to determine individual contributions of network users.

These are significant hurdles to overcome by 2050, for which some intermediate steps are proposed:

- Regulators should show and recognise that locations for production or consumption that are remotely from a national perspective can be advantageous from a cross-border perspective – and the other way around – and as such the call upon the subsidiarity principle may be generally not justified. If this is shown, EC guidelines for locational differentiation of network charging based upon Articles 14 and 18 of EU Regulation No 714/2009 can be submitted.
- Project promoters and regulators should explain that demand for and supply of energy and derived network services is heavily location dependent and hence that locational network charges make sense. They may refer to other commodities for which pricing also depends on the location e.g. housing, airplane tickets etc.
- Policy makers should account for restrictions due to spatial policy and equity in the design of locational differentiated network charges. Existing network users may be exempted from locational differentiation.
- Project promoters / TSOs may mitigate difficulties around determination of individual contributions (of groups) of network users to network costs by improving network monitoring and controllability given technological progress.

8.4. Least-regret policy proposal and roadmap towards 2050

Table 20 below presents a summary overview of the options for 2050 for the BB Cost Allocation, including possible intermediate measures towards implementing these options, the main stakeholders responsible for these measures, as well as an indicative timing. Concerning timing, three time periods are distinguished, i.e. 2016-2020 (short term), 2020-2030 (medium term) and 2030-2050 (long term). The combination of short term measures can be considered an initial policy proposal.

For several policy measures early implementation is favored, since these measures remove socio-economic and institutional barriers related to cost allocation and thus are essential to achieve a higher social welfare level in general and a higher network investment level in particular. Those measures include reconsidering to remove of the upper limit for Use of System charges for generators in EU legislation, the introduction of a significance threshold (i.e. a certain limit which determines the impact and thus the need for a certain country to be involved) for multilateral cost allocation, and proper involvement of stakeholders in cost allocation processes. Such intermediate steps can qualify as short-term policy measures and should preferably be performed before the year 2020. For some policy measures like the pursuance of multilateral cost allocation agreements over grid infrastructure with a significant effect on third countries, a broader application is foreseen towards 2050; currently the policy measures is only applied in the case that NRAs are not able to achieve timely agreement over PCIs.

At the same time, some intermediate steps may be more complex and/or costly than others and are likely to be partially realized after 2020 for three reasons;

First, some measures are heavily dependent of the maturity of new network, electricity storage and demand response technologies. Without technologies to increase the controllability of network flows, uncertainty in cost allocation in the meshed grids of e.g. continental Europe remains large. Without further development of electricity storage and demand response technologies, flexibility provision may remain prohibitively expensive for many potential providers, decreasing the importance of cross-border cost allocation of flexibility.

Second, some measures require the active involvement of electricity consumers which is not granted beforehand. For instance, larger involvement of consumers in cost allocation procedures may prevent that decisions are achieved timely and swiftly. Besides, procurement of flexibility such as demand response requires the active involvement of electricity consumers and sufficient attention for their preferences and requirements.

Third, some measures require drastic changes of policy and regulation and therefore require a step-by-step approach over longer time periods. These include;

- Wider implementation of the beneficiary pays principle. Wider implementation may be difficult since uncertainty about the exact level of expected net benefits implies that full costs cannot be indisputably allocated to a specific (group of) stakeholder(s).
- Multilateral coordination in cost allocation of grid reinforcements. There is insufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to countries. This lack of consensus relates amongst others to difficulties around the quantification of benefit items, and the large diversity of benefits and costs of potential investments in the context of different scenarios for generation, demand, and storage due to widespread network effects in meshed (AC) grids.
- Introduction of locational incentives. Current generation facilities cannot change their location without high costs and probably need to be compensated for any substantial locational incentive. Furthermore, as long as renewable energy policy remains a national competence, steering towards realisation of EU-wide RES potential with lowest overall system costs seems unlikely.
- Harmonised EU approach in flexibility market design. This requires at least some European coordination of electricity generation, which is currently considered as a national competence. Therefore, harmonisation at EU level is likely to be preceded by a period of convergence of national and regional approaches.

- Larger roles for demand response and storage requires new business models which are heavily dependent on changes in policy and regulation. Promoting demand response often requires time-dependent electricity prices and network charges, while advancing electricity storage necessitates clearer conditions for usage of storage facilities by commercial stakeholders like producers and traders as well as regulated TSOs. Achieving agreement about policy changes as well as implementation of the required changes in legislation is likely to take substantial time.

Finally, it is noted that all these intermediate steps and final options for 2050 are considered as robust for the different scenarios and associated grid architectures. However, as indicated in section 3.3.3, it should be kept in mind that policy measures are more urgent to implement when policy makers strive for fast realization of scenarios with a large share of renewable electricity and a larger demand for the transport of energy over electricity networks, such as the large scale RES and 100% RES scenario.

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing		
		2016-2020	2020-2030	2030-2050
1. Network costs should be allocated as far as possible by applying the beneficiary pays principle. This would ensure a fair allocation of costs to countries and allow for compensation of negatively impacted countries. Reliability network costs and cost components that cannot be indisputably allocated to a specific country or (group of) stakeholder(s) should be socialized, e.g. by adapting the division of congestion rents or by network charging.	When **policy makers, regulators, and TSOs** pay more attention to the beneficiary pays principle, they should make due allowance for the robustness of future network benefits in cost allocation.	↔	↔	↔
	TSOs should allow for innovative differentiation of grid reliability services, not only between economic sectors but also within groups of consumers, reducing the share of reliability network costs that has to be socialized over all network users.		↔	
	Project promoters and regulators should ensure proper involvement of stakeholders throughout the cost allocation adjustment process to improve acceptability of cost allocation by stakeholders.	↔		
	Policy makers may mitigate possible negative impacts of more cost reflective energy and network pricing on les fortunate people by securing minimum social security standards and, if necessary, by implementing complementary social security policy.	↔		
2. Multilateral coordination in cost allocation of grid reinforcements: In order to stimulate regulatory certainty and stability for all projects having a cross-border impact, a unique, robust and binding methodology should be developed for cross-border cost allocation (CBCA). In the short term, and as long as there is not sufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to countries, multilateral CBCAs should only be applied in exceptional cases, rather than as base case. In the long term, multilateral cross-border cost allocation agreements should be applied on a wider	**Project promoters and regulators** may analyse the impact of national constraints or critical infrastructures on neighbouring countries in more detail as a first step to contain the effects of parallel/loop flows on cost allocation by appropriate policy measures.	↔		
	Regulators should introduce/maintain a significance threshold for multilateral cost allocation in order to prevent participation of marginally affected countries in the decision making process.	↔		
	Policy makers and regulators should strive for consensus on the implementation of minimum reliability standards as advocated by the BB technical & market operation as it allows for convergence of the value of lost load (VOLL) estimates and therefore grid reliability costs across member states, enabling coordinated cross-border allocation of reliability network costs.		↔	
	Policy makers and regulators should prevent opportunism and gaming of countries by application of standardized multilateral cost allocation procedures, provided a feasibility study yields a positive result.			↔

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing		
		2016-2020	2020-2030	2030-2050
scale, if a (n updated) feasibility study indicates positive results.				
3. Multilateral coordination in cost allocation of grid flexibility measures: if deployment of flexibility measures such as demand response and storage for congestion management purposes increases available cross-border network capacity, but other countries do not pay for their share in the benefits (i.e. free riding), underinvestment in grid flexibility measures takes place. If a CBA indicates that effects of deployment of flexibility measures in the grid on benefiting, but non-paying countries, are substantial, allocation of flexibility provision costs should be coordinated across Europe.	**Project promoters and regulators** should analyse whether cross-border free-riding effects of deployment of flexibility for congestion management are likely and non-marginal, resulting in underinvestment in flexibility measures. If this is the case, CBCA of these specific flexibility measures should be coordinated by regulators across Europe.			
	Policy makers should stress the advantages of sharing cost and benefits of flexibility measures for grid purposes across borders for reducing total system costs both for Europe as a whole and for individual member states.			
4. Efficient economic signals to all network users: The beneficiary pays principle should not only be applied between countries but also within countries among stakeholders. Network charges should be paid by both generators and loads.	**Policy makers** should consider to remove the upper limit for average Use-of-System power-based charges for generators in EU Regulation No 838/2010 in order to overcome the lock-in effect impeding introduction of G-charges in member states.			
5. Efficient economic signals to RES: In the medium term when RES-E priority access/dispatch is phased-out, concomitant network costs should no longer be socialized, allowing for wider application of the beneficiary pays principle.	In scenarios where RES-E is becoming mainstream, **policy makers** should no longer exempt RES-E from paying for the network costs incurred to the system, including the possibility for socialization of RES-related network costs by priority access/dispatch in article 16 of Directive 2009/28/EC. Additionally, priority access/dispatch may be assessed in the framework of EC state aid legislation.			
6. No distortion of short-term market signals by network charging: Network charges for generators (G) and loads (L) should be power-based or lump-sum rather than energy-based.	If **policy makers** implement a restriction on application of energy-based GUoS charges, e.g. by revision of EU Regulation No 838/2010, they should account for potential negative impacts on flexibility provision.			
	For preventing strong redistribution effects between stakeholder groups, **regulators** should allow for sufficient time for gradual shifts towards power-based or lump-sum network charging.			

Policy option for 2050	Intermediate measures and main stakeholder(s) roles	Timing		
		2016-2020	2020-2030	2030-2050
7. Locational network charges should be implemented, so that the true cost that network users incur to the system are reflected in network charges, promoting system efficiency.	**Regulators** should show that locations for production or consumption that are remotely from a national perspective can be advantageous from a cross-border perspective – and the other way around – and, if this is the case **policy makers** should issue EC guidelines for locational differentiation of network charging based upon Articles 14 and 18 of EU Regulation No 714/2009.			
	Project promoters and regulators should explain that demand for and supply of energy and derived network services is heavily location dependent and hence that locational network charges can make sense.			
	Policy makers should account for restrictions for network users including existing generators to react to locational differentiated network charging, amongst others for reasons of spatial policy and equity.			
	Project promoters / TSOs may mitigate difficulties around determination of individual contributions (of groups) of network users to network costs by improving network monitoring and controllability given technological progress.			

Table 20: Policy roadmap for BB Cost Allocation

9. Technical and Market Operation

9.1. Introduction

The BB operation deals with the scheduling and dispatch of the available generation, demand, storage and network assets. Part of these operational processes concerns the services which are to be provided in order to ensure stable system operation. In addition, most of the aspects discussed in this BB refer to market mechanisms to achieve cost-efficiency. As mentioned in chapter 1 of this study however, many aspects in this BB are not directly related to the core topic of the e-Highways2050 project, which is focussed on the development of cross-border transmission grids and the realisation of the projected grid architectures by 2050. However, some relevant operational topics are included in this section, as these do not only impact the operation of the transmission assets, but also the investment decision as these have an effect on the costs and benefits of network infrastructure.

It seems thus appropriate to highlight some of these aspects, however the options and corresponding roadmap for this BB will be formulated in a more general way, compared to the other BBs. This also applies for the description of the hurdles and measures to overcome these. The options which are put forward are thus by no means an exhaustive list, but relate only to the most important aspects of operation which have been identified in the process of this study.

Next, section 9.2 discusses the challenges and some key aspects regarding the technical and market operation of the European cross-border network in order to reach the deployment of the projected 2050 grid architectures. Subsequently, section 9.3 discusses the identified policy options to address these challenges, including a discussion of the current status in the EU regarding these operational options, the advantages and disadvantages of each policy option, as well as possible intermediate measures to overcome the disadvantages (= hurdles). Finally, section 9.4 outlines briefly a least-regret policy roadmap to achieve the identified policy options and measures.

9.2. Challenges and key aspects in order to reach the projected 2050 grid architectures

Challenges

Firstly, it is a challenge for transmission capacity allocation mechanism to accurately reflect the power flows in the network and the technical constraints imposed by the system. Current transmission capacity allocation mainly corresponds with national borders via a zonal pricing approach, which does not take into account network bottlenecks within member states. This might result in inefficiencies following re-dispatch costs and is expected to become an increasing challenge towards 2050, as market integration, as well as the increasing share of renewable generation, in many scenario's is increasing the power exchanges among interconnected regions, and therefore increasing network congestion. Furthermore, a zonal pricing approach distorts locational signals driving the investments in transmission and generation assets. Therefore, a locational marginal pricing based congestion management could contribute to efficient short term price signals and long term investment signals. This would however imply a fundamental change in the market design of Europe. Therefore, improvements to the current zonal transmission capacity allocation is put forward as an option, by means of increasing the geographical granularity of electricity prices (nodal pricing), or modifications in the current configuration of bidding zones (Option 1).

Secondly, regional market coupling remains limited to day-ahead markets. However, the increasing share of intermittent energy resources towards 2050 requires well-functioning markets which should allow operation closer to real-time. This needs to allow the system to adequately deal with prediction errors of variable generation sources such as wind and photovoltaic power generation. Lack of coordination among systems in intra-day and balancing markets impedes the system to balance efficiently the increasing share of renewable generation. Additionally, power systems seem to lack a clear and regionally defined generation adequacy objective, while there is a current capacity market development trend towards a patchwork of capacity remuneration mechanisms. A suboptimal deployment of these adequacy measures will however result in an increased integration cost of renewable technologies. Furthermore, the integration of sustainable technologies is driven by means of national integration policies and market mechanisms, which do not always optimize system integration costs. Based on the challenges, a further move towards market integration in markets which operate closer to real-time (Option 2), a well-designed balancing market which allow coordination with the energy market (Option 3), while achieving balancing responsibility for market players (Option 4), a well-designed generation adequacy objective (Option 5) and a level playing field for all technologies to participate in markets (Option 6) are proposed.

Finally, the lack of regional cooperation and coordination mechanism to address technical operation could endanger reliable operation due to increasing variability of cross-border flows. Variable and uncertain power flows across wide geographical areas, resulting from the operation of the EU power system, put the reliability of the system at risk. This calls for strong regional cooperation to address technical issues and ensure security of supply (Option 7).

Key Aspects

In order to achieve the European policy goals towards a competitive, sustainable and reliable grid, strong cooperation is required on the operational level. The operational framework should facilitate trade of electricity over the European continent, as well as allowing an efficient operation of the corresponding power flows. Key aspects for the regulatory framework on the technical and market operation of regional network deal with (1) congestion management in the integrated European grid, (2) reinforcing the regional market integration and (3) facilitating strong cooperation of security management. Specific attention is directed towards innovative approaches to integrate renewable generation technologies, while ensuring a competitive framework for all generation technologies, as well storage and demand response.

A first aspect deals with the deployment of market mechanisms that are adequate to strengthen the incentives for market agents to pursue or promote the construction of new lines. This concerns market mechanisms for transmission network pricing and congestion management schemes, providing locational signals, correctly pricing transmission capacity in order to reveal congestion and, therefore, allowing an efficient operation of the system to take place, as well as the construction of new required lines.

The second aspect is the level of regional integration of long-term, day-ahead, intra-day and balancing markets. The increasing shares of renewable generation increase the need to access electrical energy demand and supply in other regions. Renewable generation also increases the importance of balancing markets. It is therefore, important to develop a market which allows an efficient exchange of resources among regions, facilitating the deployment of flexible resources including storage and demand response as well as real-time control of renewable generation, where they are cost competitive. The need of integration affects not only energy markets, but also ancillary service and capacity markets.

A last aspect concerns the need of the regional harmonization of operational rules, as well as the cooperation among systems for security reasons, including the coordination of security measures applied.

9.3. Possible policy options to reach projected EU 2050 grid architectures

In this section the several options identified for 2050 are further described and detailed by providing an additional explanation, insight of the governance model used as inspiration, some benefits and disadvantages of the option and finally possible intermediate measures to overcome the hurdles to implement this option by 2050.

9.3.1. Option 1

A Locational Marginal Pricing (LMP) could increase efficiency of transmission capacity allocation. Financial Transmission Rights (FTR) can be used as a risk hedging instrument to reduce the risk of price volatility.

As long as zonal transmission capacity allocation is pursued however, bidding zones are to be configured in an adaptive way which corresponds to the network bottlenecks and vary with system operating conditions. This should be combined with a flow-based transmission capacity allocation method.

Explanation

Locational Marginal Pricing (LMP) represents a highly efficient form of pricing electrical energy, as well as transmission capacity utilization. Such a transmission pricing scheme aims to incentivize short term economic efficiency and signal the long term investment needs by pricing congestions accurately to specific locations and paths. However, LMP results in price spikes during capacity scarcity, and it increases the risk of price volatility for network users. Therefore, the implementation of locational marginal pricing is often accompanied by risk hedging instruments, such as financial transmission rights. FTRs allow the owner to be remunerated according to the price difference between two zones or two nodes. Therefore, it provides a mechanism for market parties to hedge the risk of congestion charge volatility as a result of locational marginal pricing in the spot market, while giving incentives for long term trade and investment.

It should be further assessed whether a system of Locational Marginal Pricing (LMP) could increase efficiency of transmission capacity allocation in the European electricity system. In any case, it has to be recognized that the nodal market design is not in line with the current market design embedded in the network guidelines which is based on a zonal approach. Therefore, the nodal design, which seems the best solution from a theoretical point of view, faces several barriers towards its practical implementation in the European context.

The current European bidding zone configuration mainly corresponds to national borders (with some exceptions in Germany, Austria, Italy and the Nordic region where internal bidding zones are defined), which, in general, is not necessarily in line with the real network bottlenecks. Furthermore, transmission network integration is likely to change the location of bottlenecks in the European grid. Consequently, bidding zone reconfigurations are useful to properly value the scarcity of available transmission capacity, but need to be complemented with accurate capacity calculation and allocation methods. In particular, the Flow Based Market Coupling is based on a refined representation of the transmission network between bidding zones. This allows to achieve a capacity allocation closer to the physical limits of the transmission grid, particularly when facing meshed grids. As such, the efficiency of power trading can be increased by allocating transmission capacity between the different zones, while ensuring that the physical limits of the grid are respected. In doing so, market coupling narrows price spreads between price zones and increases social welfare for the involved countries.

Governance model inspiration

The Locational Marginal Pricing and financial transmission right option are inspired by the USA governance model. LMP has been implemented by PJM in both day-ahead and real-time market. The day-ahead and real-time markets use the same set of operational parameters for LMP calculation, which means that price consistency is kept between the two markets. Moreover, market participants can bid in PJM auctions for long term, annually and monthly FTR products and trade them bilaterally in the secondary market.

Also the Nordic model, where market splitting is applied in case of congestion, has been used as inspiration, mainly as regards for the bidding zone configuration. In times of congestion, the Nordic region is divided into 13 bidding areas. The bidding areas are based on existing grid constraints and will be reconsidered when the constraints evolve. A similar model is in place in Italy where, in case of congestion, the day ahead electricity market is split in 10 zones and their structure can be periodically reviewed based on the different system conditions.

In Europe, the flow based market coupling for day-ahead market has been already established, in which impact of a part of the network constraints are taken into account in cross-border exchanges when determining the market outcome.

Description of current status

Setting bidding zones requires a set of careful trade-offs. On one hand, it is important to consider the current and future status of the transmission network within and between bidding areas such as system security constraints, structural bottlenecks and typical power flows. In fact, an ideal bidding zone configuration should enhance the operational security, taking into account the present and future capabilities of the transmission network in relation to the present and future expected physical and commercial electricity flows. On the other hand, market aspects also have to be considered carefully. For instance, the larger the bidding zones the greater the liquidity, and thus competition among market participants, within that bidding zone. At the same time, costs sustained by TSOs for keeping the network uncongested within one bidding zone also depend on the size and configuration of all the other related bidding zones.

As for the current European systems for congestion management and transmission capacity allocation, this can be summarized as follows (Neuhoff et al, 2011):

1. National Transmission Capacity Allocation:

In order to deal with the fact that transmission capacity between and within countries is limited, economic congestion management methods are developed to efficiently divide scarce transmission capacities while guaranteeing Security of Supply. Generally, according to the timing when congestion management is performed in respect to energy market clearing process there are two main economic congestion management methods: preventive (implicit) and curative.

The preventive or implicit method requires to take into account some transmission constraints already in the energy trading. It's often based on implicit auctions which allow for energy trading, while concurrently allocating transmission capacities on transmission lines between bidding zones. Once the need for transmission capacity for a certain line is too high, congestion is resolved by splitting the market into two zones, one export zone upstream of the constraint and one import zone downstream of the constraint. The result is a zonal price higher in the importing zone and lower in the exporting zone.

In the case of curative congestion management, transmission constraints are not taken into account in the energy trading (DAM, IDM or Bilateral Trading). Hence the system operator subsequently has to adjust the physical flow between congested regions by countertrading and/or redispatching in order to ensure that transmission capacity limits are respected. Since congestion in this case is resolved in a separate step after gate closure of market trading (DAM and ID market) it is called curative congestion management. These type of methods are often used in combination, to avoid congestion in many cases (Neuhoff et al, 2011). Status in some of the European countries is as below:

- In the UK, the system operator has incentives to re-dispatch at least cost.
- In Spain, there is an automated procedure that uses market bids for re-dispatching.
- In the Netherlands, the operator has been considering a number of alternative congestion mechanisms. However, it has ruled out locational marginal pricing and retained re-dispatching.
- In Germany, four transmission system operators (TSOs) are in charge of managing congestions using curative methods, particularly re-dispatching of power plants. It is important to note that the coordination between different TSOs within a country in managing national congestion would be essential.
- In the Nordic countries, a « hybrid » congestion management method is applied, where re-dispatching is a complement to market splitting ('implicit auction') in several internal bidding zones with potential different zonal prices. In such system energy trading taking place in the wholesale market takes into account transmission limits between bidding zones; however intra-zonal congestions are subsequently relieved by TSO redispatching.

2. International Transmission Capacity Calculation:

Scheduling of transmission across country boundaries is currently treated separately from domestic dispatch, which leads to incomplete information flows on the state of the network and the expected development of demand and generation. This results in underutilization of the network and an increased risk of unexpected emergencies. The traditional approach for allocating transmission capacity between countries in the EU is to calculate first the Available Transfer Capabilities (ATC) for bilateral transactions, and then to auction it off. This approach created initial clarity and a market-based mechanism for allocation and capture of transmission rents for re-investment, but in the meantime, several shortcomings have demonstrated. ATC values are usually defined bilaterally, with temporary limits being defined for flows between one country and two or more of its neighbours. However, constraints affect several countries simultaneously. ATC calculations generally do not consider this interaction, or if they do, they operate conservatively, so that feasibility and therefore security is maintained under various different patterns of generation and demand. (Neuhoff et al, 2011). Moreover it is important to note that the flow base method (FB) has been considered more efficient than ATC method specifically in the highly meshed area such as CWE and CEE. Therefore, the flow-based (FB) method has been developed (and implemented for the DAM), which takes into account the interactions between power flows according to Kirchoff's laws. It is foreseen that FB is implemented in highly meshed areas, while other EU areas might still apply ATC. In this regard, the Guideline for Capacity Allocation and Congestion Management (EC, 2015) allows a smooth path for transition period to FB.

3. International Transmission Capacity Allocation:

Internationally available transmission capacity and its allocation are typically determined long before real-time. Transmission rights acquired in year- or month-ahead markets have to be nominated in the day-ahead time frame, otherwise they are subject to use-it-or-sell-it (UIOSI) or use-it-or-lose-it (UIOLI) provisions that are intended to prevent capacity hoarding. Given the historic generation pattern and the ability to anticipate demand, the day-ahead market is considered as the central market timeframe. Consequently, international transmission capacity allocation is most advanced for close to the day-ahead time frame. For this timeframe, energy and network capacity can already be traded jointly through implicit auctions. Market coupling through implicit auctions has been implemented over large parts of Europe by application of the dedicated price coupling of the regions (PCR) algorithm.

With increasing shares of intermittent energy and continued uncertainty about their output at the day-ahead stage, markets for shorter time frames i.e. intra-day and balancing markets gain importance. These markets offer the possibility for market participants to adjust their commercial positions after the day-ahead stage, given changes in expected (renewable) energy produced and consumed. Positions can be adjusted across border by utilizing cross-border network capacity (either remaining capacity after day-ahead or by trading in the opposite direction of the day-ahead flow). Concerning the intra-day timeframe, despite negotiations lasting for many years, the development of a EU-wide intra-day market is not yet taking off. As a result, the intraday market is still in its infancy and characterised by a multitude of bilateral markets. However, this is expected to change; amongst others, gate closure times are likely to be fully harmonized by 2020. Concerning the balancing timeframe, the Draft Network Code for Electricity Balancing (NC EB) (Entsoe, 2014) aims to move Europe from the current situation in which most balancing is carried out on a national level, to a situation in which larger markets allow the different resources which Europe has available to be used in a more effective way.

Advantages and disadvantages

Advantages	Disadvantages
LMP represents the full short-term cost of electricity at a specific location. This allows revealing network congestion by means of price divergence and provides efficient operation signals.	The nodal market design is not in line with current network guidelines which put forward a zonal market model.
Price differences between locations reveal scarce transmission capacity, providing efficient grid	The nodal market design has strong implication towards the cooperation model between system

development signals.	operators, in fact it could require the creation of one single system operator, or at least a very strong coordination on a information exchange and process level.
Electricity prices will capture the transmission network constraints, which allow more efficient system operation, as well as providing market competition and network investment signals.	Policy makers and stakeholders may be concerned to allow price discrimination among different nodes within a country, as well as increased price volatility.
Bidding zone reconfigurations avoids complexity and transaction costs of implementing locational pricing in unconstrained regions.	Policy makers and stakeholders may be concerned by market power issues, reduced price transparency, and transaction cost.
Dynamic or adaptive reconfigurations allow coordinating markets with changing system conditions over time.	Increasing bidding zones and flow-based transmission capacity allocation approaches may increase complexity of power system operation.
	Bidding zone approach is theoretically less efficient than a nodal pricing approach and will need to be periodically updated in order to reflect new network bottlenecks.
	Bidding zone adaptations result in uncertainty for market players which can impact investment decisions.

Hurdles and measures to overcome these

Evolving towards LMP would imply significant changes for Europe. In order to adopt this policy option there might arise different LMPs with different TSOs in EU. This will lead to the development of significant 'seams' issues, i.e. issues that are defined as barriers that relate to investment, tariff/pricing and the laws that facilitate liquidity. (RE-Shaping, 2011). These 'seams' issues could be an impediment to trade at cross-border level.

Policy makers and third parties may also be concerned to allow price discrimination within a zone between different types of generators. Furthermore, some perceived inequities could be introduced resulting from the implementation of locational marginal pricing. In case of LMP implementation, prices might be more volatile than zonal prices, or that the need for specific locations of delivery could make markets illiquid (RE-Shaping, 2011).

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed:

- To reduce the exercising market power and bring more transparency into the market, European bodies could take up several initiatives that can take a lead in identifying a range of requirements for harmonizing European market design and suggesting a roadmap to achieve those requirements.
- A high level political support can overcome possible hurdles towards implementing locational marginal pricing within Europe.
- An understanding and agreement between the TSOs could be foreseen in order to foster possible integration of regions under the umbrella of the nodal pricing method.
- Incremental development of this option can take place by introducing some intermediate steps i.e. to provide improvements to zonal pricing. The efficiency of bidding zones can be increased by complementing it with accurate capacity calculation and allocation methods.

The complexity of power system operation can be reduced between different zones by allocating transmission capacity while ensuring the physical limits of the grid are respected.

9.3.2. Option 2

Regional energy market integration should be pursued in all time frames, i.e. the long-term, the day-ahead, the intra-day and the balancing market.

Explanation

Market integration offers the advantage of smoothing the variability of renewable energy sources, as well as pooling balancing resources over larger geographical areas. Day-ahead markets are already coupled, allowing implicit allocation of transmission capacity over a large part of the European continent. Herein, demand and supply bids are matched implicitly taking into account cross-border transmission capacity. However, with increasing uncertainty induced by RES, market operation closer to real-time becomes increasingly important, and requires thus a reinforced integration of the intra-day and balancing market.

Governance model inspiration

Market coupling for day-ahead markets as adopted in Europe, which aims at efficient and coordinated cross-border capacity calculation, has provided positive experience to enhance market liquidity and convergent prices. The IGCC mechanism, originated in Germany, and elaborated internationally, allows netting of imbalances between participating countries. Different countries in Europe, e.g. Belgium, allow foreign pooling of reserve capacity.

Description of current status

Market coupling in Europe has a long and extensive history, which is vastly elaborated in many different studies. For the purpose of this study, this is not extensively described here. The successful trend towards market integration in Europe is however underlined, especially for the day-ahead markets. However, today's intra-day and balancing market designs are far from a fully efficient, harmonized integrated market. In the third Energy Package however, the EU laid out a path for further regulatory harmonization, which aims to promote a common energy market (Borggrefe and Neuhoff, 2011).

Advantages and disadvantages

Advantages	Disadvantages
Close to real-time regional markets optimize demand and supply over larger geographical areas. This allows to better deal with the limited predictability of intermittent generation by smoothing locational imbalances.	Operation closer to real-time increases operational complexity, and may interfere with national security measures and margins.
Close to real-time regional markets allow to access cheap balancing power in other regions, optimizing the reservation and activation of balancing power.	

Hurdles and measures to overcome these

The main hurdle of this option is the complex operation close to real-time. Operation closer to real-time complicates the process of cross-zonal balancing management and network security management. The calculation of available capacities for balancing service exchange can become highly complex since the network and resources usage is only partially predictable. At the moment, TSOs determine how much energy can be exchanged before a network security constraint is violated. Neighboring TSOs agree on a common determination process. The issue is to continuously improve the cooperation in order to maximize the available capacity. Due to the dynamics of the market and its operating conditions, the available capacity is also dynamic and becomes firm as a result of the nomination process. This firmness can result in economic risks for TSOs as providers of firmness, affects the available capacity, and implies higher cost of balancing services in different locations of the electricity grid.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed (Borggrefe and Neuhoff, 2011):

1. Integrate the demand side into intraday and balancing markets:
   - Creating incentives and systems that allow the demand side to fully contribute to the available flexibility, which reduces the complexity.
2. Manage the joint provision of power across multiple hours:
   - A broader set of actors can contribute energy in day-ahead and intraday markets and balancing services in the balancing market if they can coordinate sales across adjacent hours (therefore more accurately reflecting technical constraints of power stations like ramp-up rates or start-up costs).
3. Effectively monitor market power, which helps to deal with the complex condition:
   - To ensure that cost-reflective intraday pricing bids gives market actors incentives to optimize their positions so as to allow more efficient dispatch choices to TSOs;
   - To Limit costs for integrating intermittent renewables;
   - To reduce the risk for market participants exposed to intraday adjustments.

9.3.3. Option 3

An efficient use of generation resources requires a strong coordination between energy and operating reserve markets, both on the scheduling and dispatch level. This may entail a central co-optimization of energy and reserve capacity requirements.

Explanation

The European reserve market is partially separated from the energy market. Reserve capacity is procured by the TSO as a single buyer, generally by means of long-term contracts or by competitive bidding on specified market platforms (in recent years a trend towards more short-term auctioning is put forward and implemented). The scheduling of energy and reserve capacity is therefore conducted sequentially, which does not necessarily result in the optimal commitment of resources. Indeed, this approach may lead to a suboptimal scheduling of reserve capacity, resulting in costly overcapacity or even worse, undercapacity.

If a joint optimization for energy and reserve capacity would be conducted by means of centralized optimization process, this would probably result in efficiency gains by avoiding suboptimal utilization of generation and demand resources. These resources would be used for energy or reserve capacity services, depending on where they achieve the highest value. This would mean that energy and reserve capacity bids would be included in one central optimization, and this as well in the scheduling as in the dispatch phase of the optimization.

Governance model inspiration

This option is inspired from the USA model, where energy and reserve markets are co-optimized in a central market platform, operated by the system operator. The energy market is based on a day-ahead and real-time market. In a first phase, the system operator collects all the energy and reserve capacity bids on the day-ahead market, in order to determine the optimal schedule. After several iterations, adapting the optimal schedule to changing market conditions, the optimal dispatch is determined close to real-time. To keep the consistency of price formulation of these two markets, the same market clearing mechanisms are implemented taking into account transmission system constraints.

Description of current status

The market that emerged from the EU energy sector liberalization is predominantly an energy-only model. The energy-only market generation companies' revenues depend only on the electricity they can sell to the market without receiving any additional payment for their installed capacity. With real-time balancing, after gate closure, when all trading ceases among participants, the TSOs sends activation signals to reserve capacity or activates it manually. Furthermore, BRPs exchange imbalances by means of intra-day markets or pooling.

It is important to note that reserves are neither defined nor treated equally in different countries, in the most European countries electricity systems are based on self-dispatch, like UK electricity market, British Electricity Trading and Transmission Arrangements (BETTA) but at the same time some European countries has adopted a central dispatching model to operate the system.

Electricity markets within Europe were initially developed nationally with a lack of, or poor, market integration vision and little cross-border coordination. In this case, there is a variety of different rules and procedures for balancing services and reserves procurement across Europe (EWEA, 2012).

In the Qualified Recommendation of ACER on Electricity Balancing Network Code[33], self-dispatch is considered the primary dispatching model, but other systems are also allowed. In this case, generators alter their output to maintain the balance between generation and served demand. Before real-time, the generators submit bids to the TSO which corresponds with self-schedules of their units. Bids are used by the TSO to dispatch additional generation needed to balance and secure the system in real-time.

Generally, central dispatching models typically occur in electrical systems where the impact of internal grid constraints or the particular shape of the country (long and narrow such as Italy or

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[33] Recommendation of the Agency for the Cooperation of energy Regulators No 03/2015 of 20 July 2015 on the Network Code on Electricity Balancing.

isolated or partially isolated such as Ireland and Italy) have a significant impact on the security of the system. In some countries e.g. Greece, Hungary, Ireland, Italy, Northern Ireland and Poland, there is a need for central dispatch in order to ensure system security and minimize the cost of energy delivery to the end consumer. According to the Supporting Document for the Network Code on Electricity Balancing on 6 August 2014 by ENTSO-E (Entso-e, 2014), it is not expected that the number of TSOs operating central dispatch systems will increase or decrease in the near future.

Advantages and disadvantages

Advantages	Disadvantages
A strong coordination or central co-optimization between dispatching and scheduling allows correct pricing on the energy and reserve markets, while meeting predefined reliability criteria.	Pricing might be less transparent for market participants if the energy and reserve are co-optimized, since it is less traceable when technical constraints such as congestion is added and different time frames are optimized together.
Continuously optimizing and updating energy and reserve markets allows the market to better deal with intermittent generation in the short-term.	Current European market design based on separation of forward energy markets and real-time balancing market results in an institutional barrier to realize co-optimization energy and reserve markets.

Hurdles and measures to overcome these

There are five hurdles identified that needs to be considered in order to be able to implement this option. Taking into account the comments made by EFET in 2014,

1. There will be reduced interaction between producers and consumers directly.
2. There will be reduced independence of the generator in the market. This particular issue regarding reduction in dispatch freedom with increasing importance of the power exchange is also observed in option 1.
3. Providing price incentives to market players might become complex process where it is simple and direct in self-dispatch.
4. There will also be reduced transparency on network management.
5. Pricing might be less transparent and adjustment of prices due to integration of intermittent sources has to be dealt with high importance by employing more rigorous methods

In addition, in the current market mechanism in Europe there is no trend foreseen to a single system, but countries can decide themselves on which regime to implement. There might be valid reasons for systems not to operate a mechanism of self-dispatch, for which then exceptions should be allowed.

In either case, if TSOs were to adopt a central dispatch system, they must be given power to include or address issues on transparency, integration of intermittent sources and better network management in order to overcome some of the hurdles mentioned above. This will enable stronger co-ordination between energy and operating markets. Any special powers that are being assigned for smooth transition to central dispatch system must however be analyzed thoroughly and approved by national energy regulatory authority (NRA).

Market players seeking self-dispatch seems to protect their identity and position and unwillingness to lose the independence of determining their own dispatch position. If so decided and supported by an in-depth analysis, a clear briefing must be circulated explaining the need and possibility why ensuring system security and energy price reduction is better via this mechanism.

9.3.4. Option 4

Increasing balancing requirements should be allocated as much as possible to market parties, by means of a well-designed balancing market, correctly incentivizing to react according to system imbalances.

Explanation

The increasing share of variable RES increases the system need for operating reserve capacity. As this is generally acquired by the system operator, as an ancillary service, this market finds itself in a regulated framework. It is however important to implement efficient sizing of reserve requirements, as overcapacity results in higher costs and undercapacity negatively impacts reliability. In European systems, the system operator, ensures system security by means of minimum reserve requirements that are contracted from market parties representing flexible resources in their portfolio or that are procured simultaneously with congestion management and balancing energy procurement by means of an integrated process (typically in central dispatch systems as discussed in the option 3). An alternative approach may be based on assigning reserve capacity obligations to market players based on their portfolio. This can be achieved by means of own production, or purchased in a reserve market.

In order to keep the regulated ancillary service market limited and remunerate reserve provision based on the actual use, it is important that the reserve market framework incentivises market parties, or balancing responsible parties, as much as possible to maintain resources belonging to their portfolio in balance. This is preferably done by means of a cost-reflective approach allocating the reserve costs to the measured imbalance volume of market parties. The success of a direct reserve obligation on market parties depends on the organization of a highly liquid centralized energy and reserve market, in order to send efficient short-term price signal for market parties to react upon.

On the other hand, one should note that rare and extremely high prices could create risks for some (smaller) parties in case adequate hedging (financial) products are not available or easily accessible. It is to be noted however, that this implies public/political acceptance of wholesale price spikes, increasing volatility and geographically different prices (also within a country) as an efficient market outcome.

However, in general, an evolution towards more market sensibilization and responsabilization should be pursued in order to incentivize market participants to contribute and solving the system scarcities for which they are responsible. Requirements related to energy supply can be efficiently translated into imbalance prices or capacity obligations placed on balancing responsible parties, which are financially responsible for the imbalances of resources belonging to their perimeters.

Governance model inspiration

Direct reserve obligations to market parties are implemented in the USA. The seven ISOs/RTOs in the USA require Load Serving Entities (LSEs) that are responsible of serving loads to schedule reserve capacity on day-ahead basis. The required capacity is expressed as a proportion of their demand, and can be procured by means of withholding reserve capacity on own generation, demand or storage resources, or buy the capacity on the reserve market, by means of bilateral trading, or organized markets. The potential efficiency gains lays not in the sizing of the reserve capacity requirements, which is set by TSO and Regulator, but in the allocation of the reserve capacity, avoiding the set-up of procurement mechanisms by the TSO.

The imbalance settlement in the USA is based on real-time prices following an economic dispatch of available resources for energy and reserve capacity. This provides a cost-reflective price for up- and downward regulation, incentivizing market parties to keep resources belonging to their portfolio in balance to avoid imbalance price risks. In the EU, the imbalance tariffs are also usually cost-reflective, determined by means of an economic dispatch of the reserve capacity.

Description of current status

The procurement of different reserve services as well as their settlement can be referred to as balancing. Settlement takes place on one hand with the market participants providing reserves. On the other hand, the costs made by the TSOs to maintain the balance are recovered from the parties deviating from their profile submitted in day-ahead, as such causing imbalances and creating the need for reserves.

Depending on the state of the system, an imbalance charge is imposed per Imbalance Settlement Period on the BRPs that are not in balance. This defines the Imbalance Settlement which is a core element of Balancing Markets. Typically, it aims at recovering the costs of balancing the system and includes incentives for the market participants to reduce imbalances – e.g. with references to the wholesale market design – while transferring the financial risk of imbalances to BRPs. Regarding pricing method for balancing energy, the NC EB describes marginal pricing as the preferred methodology. In the marginal pricing scheme it is possible to apply a single or dual pricing mechanism, the choice of which is could depend on the length of the Imbalance Settlement Period and to the kind of balancing incentives to be provided to Balance Responsible Parties (ENTSO-E (2014), Supporting Document for the Network Code on Electricity Balancing, 6 August).

Participating in the provision of some ancillary services is not possible for some types of renewable and distributed generators unless they are able to modify their active or reactive power output according to the system requirements. At the moment, many renewable and distributed generators are not controllable and thus do not participate in AS markets. This should be overcome in the future as TSOs will need to accommodate a large amount of reserves when compared with a similar sized system without intermittent generation. For every additional GW of intermittent sources 0.25 GW to 0.3 GW additional reserve is required and maintained in Germany, Spain and Portugal (Eurelectric, 2012).

Advantages and disadvantages

Advantages	Disadvantages
A mechanism where the reserve requirements are imposed to the energy market limits the direct costs of system operators.	Pursuing a cost reflective imbalance settlement, in conjunction of market parties that react upon real-time market expectations, may create increased system imbalance risks or volatile prices.
A centralized allocation of reserve capacity avoids overcommitment of generation due to a double reservation by means of system operator and market.	A central dispatch system as discussed under option 3 might be difficult to harmonise with a system based on self-dispatching of market parties upon real time market expectations as proposed in this option 4.
Cost-based imbalance settlement can provide incentives to market players to react upon real-time market expectations to take positions in favour of the system imbalance.	

Hurdles and measures to overcome these

Cross-border reserve capacity procurement is only gradually starting to be developed and integrated in the European markets. These deserve further attention and focus towards 2050 so as to achieve complete and well-designed balancing markets.

In addition to ongoing work related to the Network code on balancing in particular, the following intermediate steps could be proposed to overcome the hurdles:

- The contractual and organisational framework regarding the procurement of reserve capacity has to include rules introduced by policy makers, which must be applicable to different kinds of providers in different countries. In this case, it is also essential to facilitate the market entry of new providers of balancing energy from e.g. RES, flexible loads and electricity storage units, and meet the changing system requirements. Furthermore, technical and organisational solutions must be developed to permit coordination of increased provision of balancing energy via decentralised energy systems.
- For all TSOs and providers there must be control mechanisms established at a comparable level by means of monitoring to ensure a secure real-time operation of the units and the power system.
- An operating reserve capacity trading platform is to be developed to ensure a highly liquid short term cross border reserve market.

9.3.5. Option 5

Electricity markets should contain a well-defined regional adequacy objective. Capacity remuneration mechanisms, if required, should be market-based, indiscriminative towards technology, and deployed in a regionally integrated way.

Explanation

Market actors in deregulated power systems need incentives to invest in generation capacity to meet demand at a certain reliability level. Currently, the discussion is held if capacity remuneration mechanisms (CRMs) are needed to complement the existing energy and ancillary service markets, in order to ensure generation adequacy. The experiences with measures to ensure adequacy in the USA during the past decade has been looked into, in specific PJM and ERCOT, and in particular factors that contribute to a market design which delivers competition between different technologies and attract resources to contribute to generation adequacy. If it would be decided that capacity remuneration mechanisms are needed in Europe, in addition to the energy-only market, they need to evolve towards a market-based mechanism. Despite different technology and cost characteristics of either existing or new capacity, resources that contribute to the same level of reserve margin requirement at the same evaluation period should be awarded the same capacity payment.

In any case, a well-defined rolling resource adequacy objective with consideration of the special and intertemporal aspects is required which enables locational based scarcity pricing in different market designs, either as a long-term forward capacity market or a short-term energy market with high price caps.

Setting up different and non-homogeneous capacity mechanisms in the various Member States would lead to inefficiency, while a harmonized capacity market in Europe would offer the advantage of reducing costs to maintain a harmonized level of security of supply. Furthermore, the market design should be non-discriminative towards generation technologies as well as flexibility approach such as demand response products, which can also contribute to adequacy. Efficiency factors for the different technologies could however be foreseen.

It is to be noted that the topic of CRMs is intensively debated at European level at the moment of writing this study (see infra. Current Status). Since there are many other studies and documentation dealing specifically with this topic, this study does not intend to investigate this topic into much detail nor to provide guidance on whether CRMs should be integrated in the future European Market Design. Its focus is only on providing some best practice experience, mainly from the USA model, for the case CRMs should be part of the future market design.

Governance model inspiration

In PJM, a capacity market is deployed, based on a capacity obligation. Its implementation shows a rolling adequacy assessment with more accurate information on the near term. Generation adequacy is integrated into a market-based capacity mechanism which addresses locational reliability challenges, while allowing the participation of storage and demand response. In other markets, such as ERCOT, energy-only markets with higher price caps are implemented, sometimes complemented by market purchase of operating reserve capacity, which implicitly includes some kind of capacity instruments. Other experiences from the researched models such as the UK and the Nordic countries have been considered as to new to draw already lessons from.

Description of current status

There is a growing concern in EU Member States that with increasing shares of electricity from variable RES, electricity markets will not be able to deliver sufficient capacity to meet electricity demand continuously and securely in the future. CRMs have been introduced in some Member States in order to provide additional incentives to investors and ensure that a sufficient amount of capacity is available.

The current fragmented status implies however a pragmatic step-wise evolution towards solutions ensuring the compatibility of the different capacity mechanisms, in particular for the development of cross border participation. There could be however some benefits in providing such a European framework setting out common principles (instead of price rules, in order to leave flexibility for the implementation so that country specific elements can be taken into account) to evolve towards compatible capacity market designs, allowing for fully coordinated solutions.

Here again, a clarification of the governance framework for security of supply is needed, to ensure that the subsidiarity principle and Member States competences are consistent with the IEM and the Target Model. It is important to ensure that national decisions remain consistent with the integrated market and are coordinated at least at a regional level. At the same it remains crucial to bear in mind the problem to be solved by such mechanism and to realize that problems could differ as well (e.g. adequacy in hydro-based and thermal systems could require different solutions).

Five different CRMs have been presented in (ACER 2013). They can be classified according to whether they are volume-based or price-based. Volume-based CRMs can be further grouped in targeted and market-wide categories, as illustrated in Figure 12.

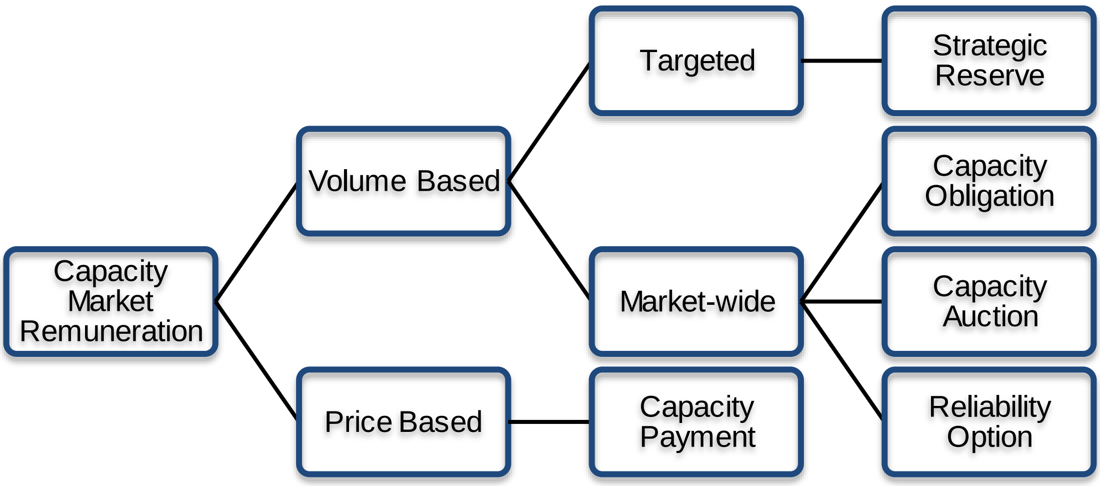

Figure 12: Volume and Price based CRMs

According to Figure 13, at present, a large number of MSs have different approaches for national generation adequacy policy. Finland, Greece, Ireland and Northern Ireland, Italy, Portugal, Spain and Sweden have already implemented a CRM with different diversities. A number of other MSs including Belgium, Denmark, France, Germany and Great Britain are considering implementing a CRM (ACER, 2013).

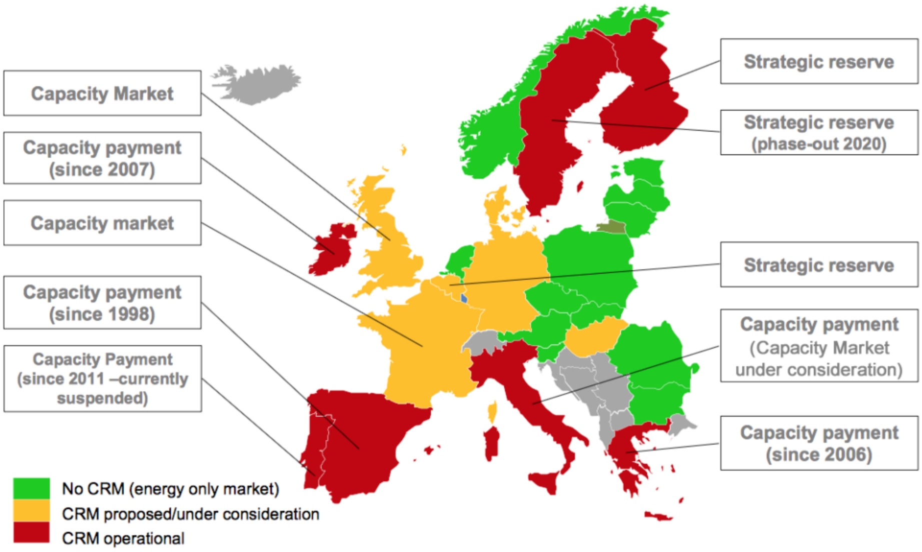

Figure 13: CRMs at Different EU MS (ACER 2013)

It is important to note that CRMs are mainly aiming to tackle adequacy issues, but they can also consider other aspects, such as flexibility and reduction of price volatility. Table 21, illustrates general overview of considerations for CRMs in different countries (ACER 2013).

	Belgium	Finland	France	Germany	Greece	Great Britain	Hungary	Ireland	Italy	Portugal	Spain	Sweden
Adequacy	□	□	□	□	□	□	□	□	□	□	□	□
Flexibility											□	
Reduced Risk								□	□	□	□	

Table 21: Different CRMs Approaches

Advantages and disadvantages

Advantages	Disadvantages
Coordination of CRMs between Member States allow to reduce the total resource needs to meet predefined adequacy levels.	Regional coordination of adequacy measures may develop at a slower pace than necessary to tackle the most urgent problems.
Coordination of CRMs roll-out allows achieving cost-efficiency gains over Europe, as installed capacity in one Member State impacts the entire European market.	Relevant national specificities that must be taken into account might hinder European harmonisation.
Possibility for new technologies such as Demand Response and storage to contribute to adequacy.	As many national electricity wholesale markets are highly interconnected, CRMs may distort cross-border trading.
	Harmonisation will remain very difficult as long as Member State are responsible for security of supply and the national energy mixes.

Hurdles and measures to overcome these

The main hurdle regarding this policy option is the distortion of cross-border trading and adequacy measures, in combination with the repartition of roles and responsibilities at Member State level.

CRMs may act as a hurdle to trade if they are designed without considering the cross-border trading. As different European countries adapt different types of CRMs, harmonization is the key issue for the future and there is no uniform approach towards capacity markets. In this case, coordination of adequacy measures both at regional and pan-European levels, may not be implemented in time.

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed:

1. Harmonizing national capacity markets: Each Member State has different approaches in addressing adequacy issues, also considering that several countries have already implemented a CRM while others are in the process of introducing them. In this case, it would be challenging to propose a harmonised design for a capacity market throughout Europe in both short and medium-term to meet the needs of different countries. In this case, policy makers and regulators should consider a harmonization procedure at national capacity market level as it is a key step towards future pan-European electricity market. It is also important to note that the harmonization should be developed incrementally at both regional and pan-European levels. This while taking into account the above mentioned aspect of repartition of roles and responsibilities.
2. Correctly remunerate all capacity: Cross-border participation to capacity mechanisms should retain the integrity of the Internal Energy Market and be consistent with the electricity Target Model in all market timeframes. In this case, capacity mechanisms should remunerate all capacities based on to their contribution to adequacy, in order to provide efficient investment signals, with a market based pricing to avoid any arbitrary cost to the end-users energy bill. Therefore, project promotors and policy makers should correctly evaluate limitations of cross-border capacity in the short-term, especially during scarcity events.

9.3.6. Option 6

Electricity market integration policies for sustainable technologies should allow generation, demand and storage technologies to compete regionally to provide energy services, ancillary services and capacity services to the system. Innovative, market-oriented solutions facilitated by smart grid technologies, should be incorporated in network operation

Explanation

A market design, even if it includes supporting schemes, should strive for an active market participation of renewable energy, and other sustainable technologies. This means RES should react as much as possible to price signals, similar to conventional generation technologies. Renewable generation, demand response and storage technologies should be able to expand their operation towards ancillary services and capacity services. Therefore, the supporting schemes for renewable energy, or other technologies, should not distort an efficient operation of the system so that these technologies can fully participate into the markets. Furthermore, renewable energy sources should be responsible for their imbalances, sending correct market signals to all technologies in order to reduce the overall system cost for balancing.

With the deployment of more intelligent smart grid technologies, the transaction cost of data collection that enables direct, or through aggregators, interaction with small scale customers is significantly reduced and a much more active role of customer participation in the market is enabled. Therefore, a more market based approach to integrate the flexibility from prosumers and

DSM into the traditional grid operation sphere, such as trading capacities, should be further investigated. In addition, the roll out of smart metering systems can also enable market-based reliability values that reflect customer preferences.

Governance model inspiration

In the Nordic system, as well as in a lot of European countries, renewable generation, such as wind power, is contributing increasingly more to higher imbalance price volatility, as a result of the more difficult prediction of expected generation. Some of the measures to overcome this, is to obviously develop well-functioning provision tools and making the results public, but also by means of creating well-functioning intra-day markets to allow market parties to optimize their portfolio so as to reduce their expected imbalances and real-time markets, to manage efficiently remaining imbalances. In the USA, several markets allow demand response to bid in the energy, ancillary service and capacity markets, without discrimination compared to conventional generation technologies. Various case studies show the potential of demand response to develop local generation systems.

Description of current status

Predominantly electricity generation from RES has increased and led to a change in the composition of European generation mixes. The largest impact on competition, however, can be attributed to the increasing share of subsidized generation from renewable resources. These market participants will reduce the market shares of the conventional sources of generation, which have been traditionally used to deliver flexibility and ancillary services to the system.

Support mechanisms for electricity production from RES vary between member states. These are not detailed in the framework of the project, but what is relevant is that these different support schemes have induced major inefficiencies if viewed from a European perspective. Most importantly, since all support schemes only support renewable energies within their own national territory massive gains from trade and from market integration are predictable. These gains from trade could easily result, as climate and weather conditions vary heavily across and even within member states. However, since almost all RES support schemes (with the particular exception of Sweden and Norway) are based on national frontiers so that only domestic production is supported, these benefits are foregone, resulting in according inefficiencies (Bockers et al. 2013).

Advantages and disadvantages

Advantages	Disadvantages
An active market participation of sustainable technologies avoids cross-subsidies and providing efficient incentives to contribute to the system balance	An active market participation may expose new sustainable technologies to additional costs and risks which may block as an entry barrier, and limit further innovations.
A more uniform market design allows sustainable technologies to compete, and provide their services where they are valued most, and increase cost-efficiency of system operation.	Alternatively, technology-supporting mechanisms may over-facilitate market entry of new technologies.
A market based approach to integrate the flexibility from prosumers and DSM reflects customer preferences more accurately.	

Hurdles and measures to overcome these

A possible hurdle to implement this option is that technology-supporting mechanisms may over-facilitate market entry of these new technologies. This can result in market inefficiencies and additional challenges for system operators to manage grid security and stability. Based on the European perspective, new technologies may create negative price signals in the market, as there will be a different level playing field in member states depending on the RES technology and geographical area. The coordination between MS in order to improve the integration of national balancing markets which could also make all the RES data available to improve the transparency regarding the cost of imbalances is a great challenge. (EFET, 2014).

In order to overcome these hurdles, the following intermediate steps towards implementing the option for 2050 could be proposed:

- Creation of strategic R&D collaborations within Europe to facilitate innovation schemes and roadmaps through cooperation with R&D and industrial policies for renewables, storage, and energy efficiency products which may improve the integration of RES that can provide energy, ancillary service and capacity to the system. An easily accessible method should be adopted in the market where the new RES technologies will ensure the overall system cost reduction and introduce upstream competition in ancillary services market, imbalance reduction and storage enhancement. Therefore further harmonization of subsidies and supporting schemes must be reviewed for renewable energy producers to create level playing field with other market participants. (EFET, 2014).
- Should new supporting mechanisms be foreseen for new technologies, these should be set at a flexible level in order to evolve gradually over time following the penetration into the market of these technologies.

9.3.7. Option 7

Interconnected power systems with high shares of intermittent renewable generation require regional security monitoring and control mechanisms closer to real-time, and over larger geographical areas. Regional approaches to define reliability should be present, including economic objectives.

Explanation

Security cooperation among TSOs allows to better deal with the increasing variability and uncertainty of power flows through the interconnected system, following the integration of variable renewable generation. This allows to provide insight in the system operational conditions, and optimal solution in emergency cases. Hence, enhancing information exchange and harmonization of procedures among TSOs should be pursued to handle security issues. Such security cooperation, is already conducted by means of regional security coordination initiatives (RSCIs), which have been developed proactively by TSOs to provide coordination services, particularly in cross-border network security analysis. These RSCIs play an increasingly important support role for operators in the control centres to ensure optimal utilisation of the infrastructure. Therefore, RSCIs are an integral part of the operational planning processes of TSOs, maximising the efficiency of coordination between them. As a matter of fact, RSCIs perform analyses that otherwise TSOs would have to perform individually, resulting in suboptimal solutions on the regional level.

However, the current RSCIs do not cover yet all the European ENTSO-E systems, implying only partial geographical coverage (about 75% of EU population). There would be added value in ensuring that all systems can count on the support of a RSCI, which is to assist the TSOs in ensuring security of supply at a regional level on a timeframe from a few days ahead until close to real-time. As getting closer to real-time, the decision making window decreases, the opportunities for decision support also decreases, implying that the full decision making responsibility remains with the TSOs. However, RSCIs should continuously review their processes to improve the support to the TSOs' decision making in system management amid the constraints.

Governance model inspiration

This option is inspired from the European experiences with Regional Security Coordination Center Initiatives (RSCIs). These organizations, such as CORESO and TSC, enhance information exchange and harmonization of procedures among TSOs to handle security issues.

Description of current status

The harmonized reliability and secure cooperation of the European electricity system requires organizational structures at regional and pan-European level. Currently, there are different European initiatives with this objective, such as Coreso and TSC.

1. Coreso

Coreso was established as a regional initiative to enhance operation security. The main goal of it is to prevent any blackout by recognizing the risks and coordinating a range of necessary remedial actions. Coreso's aims to contribute to the following objectives:

- Facilitating the European electricity market
- Operational security of the electricity system with the integration of large-scale RES

Coreso plays a major role in both CWE and CSE regions by providing an annual review regarding key figures on security coordination activities between TSOs:

- Monitoring physical flows at national borders and reporting the status of the key transmission grid conditions
- Providing stress level figures for the next day for both CWE and CSE

Coreso has developed tools to obtain and analyze various incoming data and also compare the results with previous predictions and share this information with other TSOs. In this case it is essential to consider two-day-ahead, day-ahead and intra-day congestion forecasts for the market analysis using an IT platform.

2 Day ahead: Merging single two-day ahead files provided by each TSO every day can create the Day 2 Ahead Congestion Forecast (D2CF). In February 2014, the D-2 capacity calculation process on the Italian border started, and currently, the Coreso is involved in the D-2 capacity calculation project for the CSE area. The process will then grow-up with the final goal to have the allocation of 24 capacities based on the calculation of 2 timestamps each day at 3h30 and 10h30 (Coreso, 2015).

- *Day ahead*: It is essential to collect unique security analysis data of the European grid on a day-ahead basis every hour. In this case, TSOs can submit their Day Ahead Congestion Forecasting (DACF) files. The security analysis performed by Coreso simulates the tripping of any 380-kV/220-kV line or generator connected to the grid in areas of interest and under observation. This comprehensive analysis is processed for 24 timestamps for the CWE and CEE regions, as well as for the CSE region in the short term - currently only two timestamps for peak and off-peak. Therefore, Coreso can identify the constraints for the following day and detecting remedial actions
- *Intra-day*: From October 2013, TSOs submit their Intraday Congestion Forecast Files (IDCFs) to perform the analysis close to real time (Coreso, 2015). The security analyses are automatically conducted every 15 minutes on snapshot files, simulating faults on each 380-kV line, main 220-kV lines, main generation unit or busbars in strategic substations. After merging these files to generate a full description of the grid for Western Europe, Coreso send them to the TSOs twice a day. Additionally, intraday capacity is calculated in the CWE and CSE areas. These studies are performed half a day ahead of the planned exchange though a special tool called DADS (Data Acquisition and Display System) based on a Data Historian.

2. <u>Transmission System Operator Security Cooperation (TSC):</u>

More than 10 TSOs in central Europe are currently involved in the TSC. This regional initiative was launched in December 2008 to raise regional European cooperation for system security in the countries concerned and in the pan-European level. TSC includes a new cooperation tools for control centers, and a common IT platform for data exchange and (N-1) security assessment, called Common Cooperation Platform (CTDS) in order to achieve a high security standard for the pan-European power system. The CTDS serves as the basis for all subsequent grid security calculations such as N-1 contingency assessment accessible to all member TSOs.

In 2009, TSC launched the TSO Real-time Awareness and Alarm System (RAAS), which provides a global view of the status of the electricity system in all TSC-control centers. Therefore, RAAS serves now as reference for the establishment of a common European Awareness System among the TSOs of ENTSO-E. Additionally, TSC introduced the Central Service Providing Entity (CSPE) in 2013. The CSPE can provide high and faster coordination for real-time awareness and alarming purposes.

Additionally, TSOs of Serbia, Bosnia Herzegovina and Montenegro have set up South-East Europe's first Regional Security Cooperation Initiative (RSCI) in April 2015. RSCI offer regional coordination services and provide TSOs with an overview of electricity flows at European regional level. This can result in mitigating security issues arising from large-scale, regional power flows (Entso-e, 2014).

Advantages and disadvantages

Advantages	Disadvantages
Information on the operational conditions, as well as common control, of the regional system allow TSOs to take into account the system impacts of other control zones when taking operational decisions. This allows increased reliability and cost-efficiency on regional level.	Transfer of responsibilities to several parties.

Regionally identified reliability criteria based on economic objectives result in cost-efficient reliability levels on the regional levels.	Operational responsibility over larger geographical region may lead to practical complexities such as the unclear definition and allocation of those responsibilities.

Hurdles and measures to overcome these

Ensuring that the RSCIs cover the entire European electricity market will be a challenge, as differences needs to be addressed in market developments across EU countries Therefore, a step-by-step approach leading to a Europe-wide coverage is required. The major hurdle that can be foreseen is that roles and responsibilities of involved stakeholders will evolve as discussions on system adequacy progress. It should be made clear as from the outset which entities take on which roles.

In order to overcome this a range of multilateral political discussions and agreement at regional level, starting from the early stages of implementing national policies, can be implemented to define clear principles on the degree of coordinated capacity calculations, system adequacy, and also outage planning coordination. This would be beneficial to the TSOs at both regional level and European level to perform the security analysis and identifying appropriate remedial actions to manage those risks within timeframes that the RSCI will cover. It is also important to note that a near term solution to solving the problem of larger geographical areas complexity is that all TSOs should be part of a RSCI.

9.4. Least-regret policy proposal and roadmap

Regarding the BB of Technical & Market operation, 7 policy options have been proposed. For these policy options, several intermediate steps have been determined to be taken by stakeholders, as displayed in table 22 below. For a number of these, early implementation is expected as they identify a range of prerequisite requirements, such as regulatory structures to introduce incentive schemes, facilitate market entry for new market participants, and solving the complexity problem of larger geographical areas. These policy measures are considered as short-term policy measures and need to be completed by 2020. Other policy options may be more challenging to implement or depend on the outcome of these short-term measures. These policy measures are categorized as medium term (2020-2030) and long-term (2030-2050), such as effectively monitor market power, control mechanisms, and strategic R&D collaborations within Europe.

All these intermediate steps and final options for 2050 are considered as robust for the different scenarios and associated grid architectures. However, as indicated in section 3.3.3, it should be kept in mind that policy measures are more urgent to implement when policy makers strive for fast realization of scenarios with a large share of renewable electricity and a larger demand for the transport of energy over electricity networks, such as the large scale RES and 100% RES scenario.

Policy option for 2050	Intermediate measure and main stakeholder roles	Timing: Up to 2020	Up to 2030	Up to 2050
1b. A Locational Marginal Pricing (LMP) could increase efficiency of transmission capacity allocation. Financial Transmission Rights (FTR) can be used as a risk hedging instrument to reduce the risk of price volatility.	**European policy making bodies** can take a lead, on the basis of stakeholder knowledge, in identifying a range of requirements for harmonizing European market design to reduce the exercising market power and bring more transparency into the market.			
1a As long as zonal transmission capacity allocation is pursued, bidding zones are to be configured in an adaptive way which corresponds to the network bottlenecks and vary with system operating conditions. This should be combined with a flow-based transmission capacity allocation method.	Coordinated capacity calculations, system adequacy and outage planning coordination should be agreed at regional levels through multilateral discussions between **policy makers**, on the basis of feedback given by stakeholders, and clearly stated in agreements			
	Policy makers and Regulators can reduce the complexity of power system operation between different zones by allocating transmission capacity while ensuring the physical limits of the grid are respected.			
	An understanding and agreement between the **TSOs** must take place which leads to possible integration of regions under the umbrella of single nodal pricing.			
2. Regional energy market integration should be pursued in all time frames (e.g. long-term, day-ahead, intraday and closer to real-time).	**Policy makers** and regulators are required stimulate the integration of the demand side into intraday and balancing markets by creating incentives and systems that allow the demand side to fully contribute to the available flexibility.			
	All TSOs need to work together to manage the joint provision of power across multiple hours.			
	Regulators should effectively monitor market power to ensure that cost-reflective intraday pricing bids gives market actors incentives to optimize their positions so as to allow more efficient dispatch choices to TSOs.			
3. An efficient use of generation resources requires a strong coordination between energy and operating reserves markets, both on the scheduling and dispatch level. Ideally, this may entail a central co-optimization of energy and reserve requirements	If **TSOs** were to further develop a central dispatch system, they must be given power to include or address issues on transparency, integration of intermittent sources and better network management.			

	Any special powers that are being assigned for smooth transition to central dispatch system must be analysed thoroughly and approved by **national energy regulatory authority** (NRA).	
4. Increasing balancing requirements should be allocated as much as possible to market parties, by means of a well-designed balancing market, correctly incentivizing to react according to system imbalances.	Market entry for **RES, flexible loads, aggregators and electricity storage units** should be facilitated and all these actors should bear the relevant costs related to network usage, so as to have fully cost reflective electricity prices.	
	Regulators must ensure that all the EU TSOs should have put in place adequate control mechanisms to ensure secure real-time operation of the balancing units and the power system.	
	Policy makers should develop an operating reserve capacity trading platform to ensure a highly liquid short term reserve market issues are addressed.	
	The contractual and organisational framework regarding procurement of reserve capacity has to include rules introduced by **policy makers**, which must be applicable to different kinds of providers in different countries in line with European legislation such as network codes.	
5. Electricity markets should contain a well-defined resource adequacy objective. Capacity markets, when required, should be market-based, and deployed in a way compatible with the European-wide energy market.	**Government bodies (Regulators)** must ensure that capacity mechanisms should remunerate all participants based on contribution in order to provide efficient investment signals, with a market based pricing system to avoid arbitrary costs to customers.	
	Future pan-European electricity markets should be further analysed by **policy makers, and regulators**, so as to determine, also on the basis of expert stakeholder knowledge, if it will be based on the Energy Only principle or should include some form of capacity remuneration.	
	Should capacity markets evolve to become part of the future pan-European electricity market, then **policy makers and**	

	regulators will have to consider existing procedures at national level as basis for identifying aspects that can be harmonised. Should, on the other hand future systems be based on the energy only principle, then the expected increases of electricity prices (price spikes) supported by **policy makers and regulators**. Cross-border aspects should in any case be taken into account in an early stage when developping CRM's.	
6. Electricity market integration policies for sustainable technologies should allow generation, demand and storage technologies to compete regionally to provide energy, ancillary service and capacity to the system. Innovative market-oriented solution to integrate flexibility, based on smart grid technologies, should be incorporated in grid operation scheme.	In order to improve the integration of RES to provide energy, ancillary services and capacity to the system, strategic R&D collaborations within Europe could be created by **policy makers and R&D partners** to facilitate innovation schemes and roadmaps through cooperation with R&D partners and industrial policy makers.	
	Policy makers and Regulators should develop an easily accessible method that can be adopted in the market where the new RES technologies will ensure the overall system cost reduction and introduce upstream competition.	
	Should new supporting mechanisms be foreseen for new technologies, **Politicians and Regulators** should set these at a flexible level in order to evolve gradually over time following the penetration into the market of these technologies.	
7. Interconnected power systems with high share of intermittent renewable generation require regional security monitoring and control mechanisms closer to real-time, and over larger geographical areas. Regional approaches to define reliability should be present, including economic objectives.	**Politicians and Policy makers** must participate in a range of multilateral political discussions which must lead to policy agreements at regional levels that can be implemented to clearly define coordinated capacity calculations, system adequacy, and also outage planning coordination. This would be beneficial to the TSOs at both regional and European level to performing security analysis and identifying appropriate remedial actions to manage those risks within timeframe that the RSCI will cover	
	All **TSOs** should be part of a RSCI.	

Table 22: Policy roadmap for BB Technical and market Operation

Annex 1: Assessment criteria

As annex 1, the overview of the entire set of assessment criteria and related questions is provided, which have been considered in the assessment of the 11 GMs in the study.

Network Design

Competitiveness

- Development of the transmission network
  - Incentives and conditions for achieving the construction of required reinforcements (avoiding underinvestment situations). Sub-criteria relevant for this BB are:
    - Ability of potential beneficiaries of network investments to propose and promote the construction of these investments: ➔ Do market agents (generators, consumers) that may benefit from the construction of reinforcements have an active role in their promotion?
    - Sufficiency of incentives perceived by relevant stakeholders in the network expansion process to pursue those investments required, i.e. those with large positive net social benefits: this depends on the role assigned to each entity in the process of development of the system network and coordination among roles assigned in different areas. A distinction can be made between incentives perceived by private promoters (merchant investors), TSOs and those perceived by regulatory authorities:

      Sufficiency of incentives perceived by potential private promoters (merchant investors and market agents that may promote the construction of lines) to pursue the construction of required investments: Participant funding allowed by the institutional setting is a way to try to align the benefits of a private promoter with those of the system (the whole set of generators and consumers). By negotiating access rates, the private network promoter may extract from agents those rents needed to build efficient lines. A remuneration scheme whereby revenues of the owner amount to the corresponding congestion rents is likely to result in required investments that would significantly reduce existing congestion rents not being undertaken (promoted by potential investors) ➔ Are private promoters able to sign contracts for access to the capacity of potential new lines with market agents that shall benefit from these investments? Are regulatory authorities able to modify features of projects promoted by private investors before approving these projects?

      Sufficiency of incentives perceived by the SO, which is in charge of formulating expansion plans and helping regulatory authorities to assess private investment projects, to promote required reinforcements ➔ Are economic drivers considered by the SO when determining which reinforcements to propose? Must they propose the construction of individual assets (lines, transformers, etc.) or whole reinforcement projects that have some entity themselves?, Must they propose individual investment projects or comprehensive expansion plans that may account for synergies among projects? Are incentives for TSOs foreseen aimed at encouraging them to promote or approve network investments mainly benefiting market actors in other zones than those where they are based (are coordination schemes strong enough)? In other words, is there a framework foreseen for TSOs to analyze and take into account cross-border effects of potential investments? Are investment premiums foreseen for critical/difficult/crossborder/special interest projects?

Sufficiency of incentives perceived by Regulatory Authorities to pursue efficient network reinforcements that are economically driven ➔ Do Regulatory Authorities consider the economic benefits brought about by new lines as one of the reasons for approving the construction of regulated reinforcements? Is the government interfering with the powers of Regulatory Authorities to approve the construction of proposed reinforcements? Do Regulatory Authorities carry out a proper techno-economic assessment (e.g. SCBA) of promoter's (SO's or other's) proposals to check their advisability? Are competent authoriti es taking into account the interest of market agents not residing in the control area of the SO they regulate? Is there a framework for discussion/interaction between different competent regulatory agencies?

- Type of benefits considered in the cost-benefit analysis (regulatory test) carried out to propose/decide the construction of lines: all those benefits resulting from the construction of a transmission asset should be considered when determining whether its construction is beneficial. ➔ Are economic efficiency, competition, and sustainability benefits (probably after being monetized) considered in the planning of the expansion of the grid by the SO/Regulator or, instead, investment decisions of the latter are only driven by the need to ensure the safe functioning of the system (Security of Supply)? If several types of benefits are considered, which weights are given to each of the relevant aspects of system functioning?
- Consideration of uncertainty in the network expansion planning process: are the different possible scenarios considered in the expansion planning process by the SO, including different hypothesis on the duration of the process of obtaining permits and building new lines, and the outcome of possible appeals on the construction of lines?

- Incentives and conditions for network development cost reduction. Criteria relevant here are:
  - Avoiding overinvestment resulting from perverse incentives: if the SO happens to be the owner of lines and subject to 'cost of service' remuneration, as well as when the SO and/or the Regulator have got a mandate to avoid reliability problems, some checks and balances should be in place to prevent

overinvestment caused by the incentive for these institutions to avoid reliability problems at any cost or increase the regulated asset base. ➔ Are revenues of network development promoters (TSOs, market agents, private promoters) mainly conditioned by the size of network investments?; Do network investment promoters or authorities have a single/predominant mandate to avoid relaibility problems at any cost? Does an independent Regulatory Authority make the final ivestment decisions?

- Avoiding overinvestment resulting from the inappropriate consideration of uncertainty in network expansion planning ➔ Are network investments specific to each possible different future scenario that may develop or they are robust solutions aimed at addressing problems in all possible scenarios?
- Cost efficiency in the construction of lines ➔ Are the approved regulated investments (non merchant lines) subject to any kind of competitive auction for their construction, operation and maintenance? Is, otherwise, benchmarking applied to limit the remuneration of lines, or any other measure to keep within reasonable limits the cost for the system of constructing new lines? Is a level playing field achieved in this regards between regulated and merchant investments?

- Incentives and conditions for achieving the coordination of generation and transmission expansion

  Level of coordination of the development of generation and transmission: increasing the level of coordination should result in a more efficient development and operation of the system. Possible coordination schemes include the provision of information by the SO on the expected level of prices and congestion in each zone, and the signing of contracts with (usually new) generators for the construction of transmission capacity ➔ Is locational information on expected future congestion and prices provided by the SO? Are Open Seasons of transmission capacity organized?

- Incentives and conditions for achieving a certain quality level in the construction of network reinforcements.

  Incentives for increasing the quality of the service of constructing new network assets: A proper network design will not only require efficient investments to be undertaken at the lowest cost possible, but also that the reduction in construction cost is not detrimental to the quality of the material employed in the construction, the quality in the design of the project, or the timely delivery of network reinforcements, and therefore that it does not result in an increase in maintenance costs, a reduction of the useful life of the assets, or an increase in operation costs due to unavailability of these assets while being built ➔ Do penalizations or incentives related to the availability of the transmission network assets exists for the life of the asset?

- System Operation
    - Efficiency in the operation and maintenance of the network → is the owner of lines encouraged to undertake investment and maintenance tasks (p.e. because his revenues increase with the level of availability of the transmission assets it owns)?

Security of Supply

- Development of the transmission network: Since reliability driven investments are more complex to identify (usually the benefits associated with them are difficult to monetize and are spread among many agents) and a proper network design should include them, it is necessary to assess whether the GM appropriately considers them or may lead to underinvestment or overinvestment in this kind of reinforcements → Do the entities in charge of promoting/approving the construction of reinforcements have a prevalent mandate to preserve system security? If not, how is the Security of Supply ensured? Are entities in charge of promoting/approving reliability reinforcements active at national or regional level?
    - Underinvestment in reliability reinforcements → Do they have incentives to promote these lines? Is the remuneration of these entities subject to some relevant penalization for the lack of compliance with security/reliability standards?
    - Overinvestment in reliability reinforcements: If 'cost of service' remuneration applies to reliability investments by the SO, then the benefits of this entity increase with the amount of investments. Besides, if there are penalties associated with a low reliability level, the economic incentive to build these lines is even bigger → Are the benefits of TSOs/regulatory authorities (profits, level of reputation, reduction of penalties faced by its staff or the institution as a whole) increasing with the construction of these reinforcements?

Sustainability

- Integration of RES generation:
    - Development of the grid (avoiding over/underinvestment problems) → does the party in charge of promoting the construction of new lines have a mandate or some natural incentives to achieve RES integration objectives or environmental objectives in general? And the party approving these reinforcements? Is this party active at national or regional level?
- Energy efficiency and demand response and Storage:
    - Development of the grid (avoiding over/underinvestment problems) The deployment of Smart Meters and DR related equipment, including telecommunications, should facilitate the achievement of DR and energy efficiency objectives. If System and Market Operators are active at regional level, the coordination of the deployment of DR and energy efficiency technologies within the region will be most efficient. → Does the party in charge of promoting the construction of new lines, and/or that approving their construction, have some mandate or natural incentives to reduce network development and system operation costs through DR, flexible grid access/connection, and energy

efficiency, or to achieve DR, or energy efficiency objectives? Are parties responsible for SO and MO active at national or regional level?

Socio/political acceptability

- Fit with the current context → is the allocation of tasks in the network development approach in line with current practice in Europe? Is the allocation of tasks in the network development approach consistent with main basic governance principles present in Europe regarding unbundling of ownership of Generation and Transmission or that of Transmission Ownership from System Operation and prevalence of regulated network investments?
- Level of autonomy of local institutions → are institutions with power over network development and operation local or regional? Can local entities influence these processes?
- Fairness → does the allocation of roles in network expansion allows all reinforcement options to be considered in the process on equal terms?

Effectiveness

- Transparency: this will avoid concerns and claims about unfair discrimination. → are the methods applied transparent?
- Complexity → Are processes involved in the expansion of the grid and system operation activities difficult to understand for entities participating in these processes including Regulatory Authorities?
- Risks → Is there a risk that a lack of agreement among relevant stakeholders results in required/beneficial reinforcements not being undertaken? Could this lack of agreement/cooperation affect system/market operation?
- Concentration of decision making power: this may affect, among other things, the length of the period required to get permits needed. → Is the agreement of a large number of parties required to undertake network investments or integrate system operation? Is there a limit to the length of the period required to obtain a definite answer to the requests for obtaining the permits?
- Facilitation of coordination. For example, integration of expansion planning and System Operation makes coordination of both easier → does the allocation of roles in the expansion and operation of the system enables parties to cooperate constructively in the development of these activities?

Ownership

Competitiveness

- Development of the transmission network
  - Incentives and conditions for achieving the construction of required reinforcements (avoiding underinvestment situations). Sub-criteria relevant for this BB are:

    Sufficiency of benefits from reinforcements perceived by stakeholders to undertake required reinforcements: Under any paradigm of ownership of the network, the unbundling between generation and system operation activities should be in place, as well as between consumers and the SO, so as to avoid system operation to be carried out so as to favor some agents at the expense of the rest. Additionally, different schemes result in different levels of incentives for the construction of required reinforcements according to the extent to which network promoters' interests in them are aligned with the interests of the system.

    Sufficiency of the benefits of the owner of required reinforcements for him to promote them ➔ which constraints exist to the ownership of transmission assets? Is there unbundling in place between transmission and generation activities?; Is the SO also the owner of new lines being built? , and, in this case, is its remuneration of a 'cost of service' type or of a 'revenue cap' (incentive based) one? Are, the generators the owners of lines?; or are the owned by consumers?; are network assets owned, on the contrary, by private merchant promoters? Is in this case the remuneration of merchant promoters based on the corresponding congestion rents or of a 'participant funding' type?; are lines built as regulated assets but assigned afterwards to private Transmission Companies?

  - Incentives and conditions for network development cost reduction
    Avoiding overinvestment related to the choice of reinforcements to undertake: a passive TSO tends to incur in over-investment, while an active one, network users, merchant investors and transcos as owners and promoters of new lines avoid overinvestment. ➔ which constraints exist about the ownership of network assets? Which control measures exist to avoid unnecessary investments if the SO is the owner of lines but and it is a passive one?

    Cost efficiency in the construction of lines: If the remuneration of the entity building new transmission assets is proportional to the costs it incurs, it has no incentive to keeping these costs low. Besides, it is probably more cost efficient if one instead of several parties own and built the system transmission network ➔ do the benefits of the owner of a line increase when reducing the costs incurred in the construction of this line? Are there any control checks to avoid excessive construction costs if there is a passive TSO? How many entities are involved in the construction of a line and its maintenance?

- Operation of the system

  Efficiency in the operation and maintenance of the network. Having the System Operation and Ownership of the network in the same hands allow a better coordination of System Operation and the operation and maintenance of assets, which are the responsibility of the transmission owner. What is more, coordination of the maintenance if in the hands of several entities (TOs) will be more difficult and less efficient than if there is a single TO. Lastly, learning and knowledge creation resulting from the operation and maintenance of the grid are larger when there is a single owner of the grid than when there are several owners. ➔ Does the ownership of the network allow an easy coordination of the operation of the system and the operation and maintenance of transmission assets? In other words, may the party in charge of deciding on the maintenance and operation of lines (network owner) have problems of coordination with the system operator? Does the TO bear the impact that his decisions on the maintenance/operation of lines has on system operation costs? How many entities own a part of the grid?

Security of Supply

- Development of the transmission network
  - Construction of reliability reinforcements ➔ Unless the SO is also the TO and subject to 'cost of service' remuneration, it will need extra incentives to promote the construction of reliability lines. ➔ Is a passive SO the owner of the grid?

Sustainability

- Integration of RES
  - Development of the grid (avoiding over/underinvestment problems): unless the SO is the TO and subject to 'cost of service' remuneration, it will only care about the installation of RES related grid assets if it has a mandate and some incentives for this. ➔ Is a passive SO the owner of the grid? Is there a mandate to integrate RES generation?
  - Energy efficiency, demand response, and storage/Development of the grid (avoiding over/underinvestment problems): Unless the SO is the TO and subject to 'cost of service' remuneration, it will need extra incentives to promote the installation of demand response, energy efficiency, and storage facilities ➔ Is a passive SO the owner of the grid? Is there a mandate to achieve EE, DR and storage integration objectives?

Socio/political acceptability

- Fit with the current context: in the EU, SO unbundling from generation and demand is in place and TO and SO must be increasingly unbundled as well. ➔ Is the ownership regime for the Governance Model compatible with current EU regulation?

Financing

Competitiveness

- Development of the transmission network
  - **Provision of incentives for achieving a sufficient development of the network**

    Diversity of financing sources: is there sufficient variety of available financing sources to finance new transmission investments (e.g. corporate bonds, commercial bank loans, grants from public sector, internal equity (cash flow from system operators' own operations) and external equity (e.g. from the free float in national stock exchange)? Are there special favorable financing mechanisms in place that encourage transmission investments (e.g. international, regional and national financing institutions with favorable conditions such as low interest rate and long maturities)?

    Facilitation mechanisms to reduce financing risks: are there adequate mechanisms to reduce financing risks (e.g., improved regulatory conditions such as rate of return/equity adders and public grants, guaranteed return on investment (e.g. through tariffs…)? Are there mechanisms available to cover political risk such as expropriation (e.g. risk political risk mitigation institution to provide insurance against political instability or expropriation)? Is there proper regulation design to mitigate the long term scenario risk or bankability risk?

    Adequate cost of capital level: is there credit rating of the network company (average credit rating in case several network operators are active in a governance model) to provide appropriate signals investments in the transmission system?

    Incentives for financing of grid reinforcements: are there sufficient incentives given to finance reinforcements of the transmission system since grid investments are in competition for financing with other actions of system owners and other infrastructures? Is there proper cost pass through design under a cost based (rate of return) scheme or incentive based scheme (price-cap or revenue cap) to reduce risk for investors? Under the cost based scheme, is there an obligation for the investor to expand the network? Does the timing of investment efficiency check incentivize the investor (e.g. ex-post investment efficiency check could lead to higher risk since network investment is sunk)? Is CAPEX subject to an ex-post investment efficiency test? Does the design of price control period provide sufficient incentive to reduce investment risk?

Socio/political acceptance

- Fit of the governance model with the current context: is the financing framework in line with the current practices in Europe? Is the financing framework necessary/possible in European context?

Effectiveness:

- Facilitation of coordination…: does the financing framework provide incentives for cooperation between different market parties? Does the financing framework provide incentives for cooperation between different countries? Is the financing framework based on international coordination? Is there a regional coordination for strategic projects being eligible for favourable financing conditions (e.g. projects of common interest)? Is there mechanism to attract local participation for financing the network investment?

Cost & Benefit Allocation

Competitiveness

- Development of the transmission network
    - Avoidance of regulatory intervention/coordination problems

      Coordination problems among those entities participating in the decision on which network reinforcements to build and hence influencing the distribution of costs and benefits may prevent the construction of some of them. Coordination problems relevant for cost & benefit allocation may take place among; a) several TSOs, b) TSO-market agents and regulatory authorities.

      Which entities (national as well as international) are participating in the cost and benefit allocation decision in the governance model (e.g. TSOs, regulators, governments, market agents)? Please describe briefly their responsibilities.

      Coordination among several TSOs. In case of bilateral network expansion and cost allocation agreements, due to the low controllability of AC network flows either free riding of third countries may take place at expense of the project promoters or free riding by project promoters may negatively affect a third country. In the first situation, positive external effects on third countries are not internalized in the cost allocation decision, while in the second situation negative external effects are not internalized in that decision. Hence, effects on third countries should be taken into account within multilateral cost allocation agreements in the European context (see also Article 12 of Regulation No. 347/2013 EC). Does the governance model distribute network costs among several systems and hence include a possible scheme for side compensations (payments) of negatively (positively) affected third countries by the construction of network reinforcements?
    - Avoidance of possible gaming or market failures

      Coordination among TSO-market agents and regulatory authorities. If expected net benefits of a network investment by project promoters are positive, they will propose this network investment. However, social net benefits of a network investment maybe larger (smaller) than private net benefits of a network investment because of positive (negative) external effects of the network investment. Positive external effects include effects on security of supply and markets such as lower possibilities for exercising market power, and enabling of better sharing of cheap power and balancing resources and hence lower investments in generation capacity. Negative external effects may originate from loop flows which may affect the capacity of existing lines negatively. For achieving an economic efficient network development from a societal point of view, private net benefits should be aligned with the social net benefits of the new infrastructure. If this is the case, cost and benefit allocation should be based on the distribution of social net benefits identified. Do the network promoters/TSOs internalize external benefits and costs of cross-border network reinforcements for market agents in their cost allocation decisions?

- Efficiency of allocation of the costs of reinforcements

There exist two broad principles for cost allocation by network tarification: beneficiary pays and cost socialization. The beneficiary pays principle allocates costs to actors that benefit of the network reinforcement, based on the idea that the parties using the new facility are causing the costs on that facility. With cost socialization costs are allocated, often evenly, to all parties without regard to whether some parties being allocated costs are beneficiaries of the project. For those investments that are identified for economic reasons, application of the beneficiary pays principle -as far as possible- is preferred for ensuring economic efficiency of the transmission network. Cost and benefit allocation of reliability investments will be discussed separately under criteria related to system security below.

To which extent is the beneficiary pays principle applied by the network tarification method of the governance model? To which extent is the cost socialization principle applied? Which type of network cost allocation method is applied in the governance model for recovery of network reinforcements that affect more than one country?

Besides, coordination among systems, or areas, in a region regarding the allocation of costs should take place for it to be efficient. To which extent are network costs recovered by national and international/regional schemes (such as inter-TSO compensation scheme in Europe) respectively? If international/regional schemes are in place, does the scheme include a mechanism for the recovery of network costs for 'third' countries (countries which are impacted by a interconnection which is not crossing their territory)?

If beneficiaries of the construction of new lines are not being assigned a fraction of the costs of these new lines that is in proportion to the benefits they are receiving, they may pursue the construction of these lines even when they are not socially justified (social costs are larger than social benefits).

Is the allocation of the cost of new lines driving beneficiaries of inefficient network investments to promote their construction?

- Provision of incentives for achieving an efficient operation of the system

Market operation and therefore energy dispatch results in allocation of benefits (derived from prices) and costs (such as fuel costs, O&M costs, other operational costs) over market agents i.e. producers and consumers.

Network constraints may influence the results of energy dispatch in different ways depending on the model applied for allocation of benefits of network reinforcements through market operation. Congestion management methods may either influence the energy dispatch directly as consequences of network constraints result in different energy prices on zonal or nodal level before gate closure (implicit and explicit auctions), or energy prices may be corrected for congestion after gate closure of energy markets (which is usually the case for countertrading and redispatching).

How does the cross-border congestion management approach applied in the governance model influence the electricity price formation and hence the efficient operation of the system? Do they result in congestion rents contributing to the recovery of part of the cost of the network? Costs and benefits are allocated using assumptions about system operation after construction of the network investment. Is the allocation of costs and benefits permanently based on the situation before network reinforcement or regularly updated following the network reinforcement?

Network users require a certain amount of network capacity to be connected and to make use of the system. They should take into account the network costs that the system will incur as a result of their decision to install a new generation or consumption facility in a certain node in their investment. These network cost depend on the operation profile of the generation or consumption facility. Hence, one can conclude that the level of the transmission tariff to be paid by a new generator should depend on the production profile that the generator is deemed to have. There is a similar need for the level of transmission tariff to be paid by a consumer to depend on its expected consumption profile. Given that the production and consumption profiles of market agents depend on the market operation design, this will condition the allocation of the cost of the grid.

Do producers (including RES-E) and consumers in your governance model have to pay network tariffs? Which part of the network costs is allocated to producers and consumers (loads) respectively? You may limit yourself to average situations for producers and consumers. Are some groups of producers and consumers (e.g. RES-E or energy-intensive industry) (partly) exempted from paying network tariffs? Which kind of charges do they have to pay (connection charges, Use of System charges, both)? Do these charges cover the network costs up to the grid connection point ('shallow charges') or include network costs beyond the grid connection point ('deep charges')?

Security of Supply

All those aspects common to the development and operation of any kind of network asset have already been considered under "Criteria related to the impact on economic efficiency of the development of the transmission network". Here only those aspects specifically related to reliability projects are considered. Because of rules for guaranteeing security of supply (such as the N-1 reliability criterion) additional network investments are required on top of the economic optimum. Since those reliability investments accrue to all users of the power systems and it is very difficult to attribute costs to specific (groups of) network users, their network investment costs are usually socialized.

- **Incentives for the construction of reliability reinforcements**

  This criterion should be assessed from the perspective of the construction of regional network reinforcements only. Are reliability benefits among those considered when allocating the costs of lines in general? Are the costs of reliability network investments socialized?

- **Coordination incentives**

  What type of coordination is foreseen for cost and benefit allocation of investments in cross-border reliability reinforcements between involved actors? Do national actors (e.g. regulators) play a role in this cost and benefit allocation for subsidiarity reasons? Or is C&B allocation in the region carried out centrally?

Sustainability

This set of criteria concerns the incentives to achieve GHG emission reduction and other environmental objectives. One aspect of a governance model is whether concerning environmental criteria there is an EU lead or a national lead in the cost and benefit allocation of measures promoting the sustainability of the power systems in the governance model. Assessment criteria considered here relate to the main tools that can be adopted to achieve these objectives:

- **Integration of RES generation**

  This concerns the creation of incentives to facilitate the installation of RES based generation and increase its power production. In order to stimulate the penetration of RES in the power system, some countries do grant RES generation priority in network access or priority in dispatch over other generators. These priority regimes should affect the allocation of costs and benefits of network reinforcements and network operation over stakeholders.
  Which stakeholders bear the costs of priority in network access, or priority in the dispatch of RES, over other generators? Conventional generators, consumers, others? If conventional generators are bearing the cost of giving priority to RES generation, are they compensated for this? Is the change in the benefits obtained by agents from network assets caused by the application of RES generation priority schemes being considered in the allocation of the cost of these assets?

- **Energy efficiency, demand response and storage**

  This concerns incentives to deploy measures increasing the responsiveness of consumers to system conditions and encouraging them to reduce the amount of energy consumed when carrying out their activities. Those measures may be an alternative to network reinforcements as well as conventional operational network measures. The allocation of costs and benefits of these measures over stakeholders is our main point of interest here. Are the costs of EE, DR, and storage measures allocated proportionally to benefits obtained from them?

Institutional / socio-political acceptability

These criteria concern those aspects of a governance model that may create opposition to its implementation by authorities, entities and/or market agents in the region or system. Criteria considered are related to the main causes of the existence of public resistance to this model.

- **Fit of the governance model with the existing context**

  This criterion is related to the conformity of the governance model to the market, network and operation structures and allocation of responsibilities currently existing in Europe or those that may easily exist. Is the allocation of tasks and criteria applied in the cost and benefit allocation approach in line with current practice in Europe?
- **Level of autonomy of national/local institutions**

  Governance models that require a high level of integration, or centralized decision making processes, may enter into conflict with the principle of subsidiarity and therefore may be difficult to accept. Does the model require allocation of network costs as well as congestion rents to be decided (or computed based on a common method) centrally?
- **Fairness**

  Have there been any concerns raised by stakeholders about the fairness of the C&B allocation method?

Effectiveness

This set of criteria is related to the level of facilitation of the different decision making processes caused by the implementation of a governance model, i.e. to whether decision making processes are streamlined or not due to the implementation of a model. Aspects, or criteria, including within this set are:

- **Complexity**

  Are there any complaints about the understandability of the cost & benefit allocation part of the model by stakeholders?
- **Risks**

  Which are the major potential risks (regulatory, financial, political, other) that may give rise to malfunctioning or hamper implementation of the cross border cost & benefit allocation method of the governance model? Does the governance model foresee a backup authority that decides if no agreement is reached?
- **Facilitation of coordination of the activity of the different entities involved in the European Market**

  Does the governance model facilitate collaboration between stakeholders concerning cost & benefit allocation? Who takes the final decision on cost allocation (involved TSOs & regulators in common, involved national ministries/institutions in common, regional institution)?

Technical & Market Operation

Competitiveness

- Transmission network development
    - **Incentives and conditions to build required reinforcements**: regulatory framework and market rules may affect, i.e. weakening or strengthening, the current incentives to build or reinforce the transmission grid. This may concern the incentives mechanisms established by the NRAs.

      Market framework driving grid reinforcements and constraints: are market rules adequate to strengthen the incentives for market agents to pursue or promote the construction of new lines? Are there energy pricing schemes (e.g. nodal pricing, zonal pricing), and congestion management mechanisms (e.g. transmission capacity sales) providing market agents with incentives to pursue or promote the construction of new lines?

      Mechanisms ensuring efficient use of cross-border transmission capacity: are the capacity calculation methodologies efficient for using of cross-border capacity? Are there efficient methods for allocating cross-border capacity (e.g. implicit auctioning) on different time scales (e.g. intra-day)?

      Mechanisms ensuring efficient use of local transmission capacity: are there flexible grid connection schemes? Are there incentives available to promote energy efficiency? Are there incentives to implement new flexibility sources for local balancing (e.g. demand response)?

- Operation system efficiency
    - **Market operation efficiency, influencing network aspects**

      Regulation of access to the network (provision of capacity reserve): are there priority access schemes for certain uses (e.g. which have installed first in this node), for scarce connection capacity? are there flexible grid connection schemes?

      Efficiency of congestion management: Is the locational signal included in the pricing scheme (e.g. uniform, zonal or nodal pricing)? Is congestion managed with mechanisms which increase the operational efficiency (e.g. use-it or lose- it clause, use-it or sell-it clause, or secondary market)

      Efficiency of capacity allocation: is the interconnection capacity allocated by means of market driven mechanisms (e.g. explicit auctioning, implicit auctioning 'market coupling', first-come-first-served or pro-rata allocation)? Is interconnection capacity periodically updated when approaching real-time operation (e.g. yearly, quarterly, monthly, day-ahead or intra-day)? Is the cross-border capacity calculation method properly representing the available physical capacity (e.g. flow based approach)?

      Incentives and means for participation of demand in energy markets: is the demand-side properly remunerated to participate in energy markets?

Efficiency of ancillary service provision: For each ancillary service (Frequency control, voltage control, spinning reserve, standing reserve, black start capability, remote automatic generation control, grid loss compensation, emergency control actions): is the procurement market-based (e.g. mandatory provision without payment, mandatory provision with remuneration, tender or ancillary market)? Is the ancillary service procurement periodically updated when approaching real time operation (e.g. yearly, monthly, day-ahead or hour-ahead)? Is the remuneration compensating the costs of providing ancillary services? Are new service providers incentivized to participate in the provision of these services (demand-response, storage or RES)?

Efficiency of balancing mechanism: is the balancing responsibility and balancing costs adequately transferred to the market (balancing responsibility renewable generation, cost-reflecting tariffs)? Is there balancing market providing incentives to re-balance market positions real-time (e.g. real-time information, intra-day markets)? Are incentives available to facilitate flexibility from new providers (e.g. decentralized storage, RES, demand-response). Is the balancing designed to provide sufficient economic signals for market players by reactive or proactive participation?

- **Network operation and maintenance efficiency**

  Incentives able to optimize operation and maintenance decisions: is the operator incentivized by the OPEX regulation to improve efficiency of operation and maintenance (cost-based or incentive-based)? Are incentives in place to achieve an appropriate trade-off between the level of availability of transmission assets and the costs of achieving this level? Are system loss reduction incentives in place (based on threshold or based on the optimality)?

- **Coordination efficiency**

  Level of coordination between capacity allocation and congestion management mechanisms: are the procedures for cross-border capacity allocation and congestion management adequately harmonized in the region? Do TSOs have support from international agencies for capacity allocation mechanisms (e.g. CASC, CAO)? Is there coordination of decision-making or monitoring dealing with cross-border flows (e.g. Coreso)? Are the domestic congestion management mechanisms coordinated with cross-border congestion management approach? Are there harmonized ancillary service products standard within regions? Can ancillary services be contracted outside the control zone?

Security of Supply

- Incentives to build reinforcements aimed to enhance the system reliability
  - Security standards impacts on incentive for system reliability: does the adopted security standard provide enough incentives for network reinforcement from security perspective?
- Incentives for increasing system security at the operational level
  - Incentive schemes encouraging the installation and availability of generation capacity: is there a capacity market on top of energy only market? Does the generation capacity installation scheme by the NRA or market provide incentives

for system security? Are there incentive schemes in place that encourages the availability of generation capacity?

- Coordination incentives
    - Regional security coordination level: is system security properly coordinated on a regional basis (Regional cross-border coordination or national level in case there are several control areas in a country with monitoring or coordination responsibilities)?
    - Regional harmonization of operational procedures: Is there a regional harmonization of operational rules, and is the harmonization of regional operational procedures binding (Regional cross-border coordination or national level in case there are several control areas within a country)?

Sustainability

- RES integration
    - Grid development facilitating RES integration
        - RES grid connection incentive: are grid connection mechanisms facilitating RES integration (e.g. non-discriminatory or priority connection)?
    - System and market operation to increase RES integration
        - Degree of electricity market participation of renewable energy: are support mechanisms incentivizing for renewable participation in the market (e.g. priority dispatch and feed-in tariffs)
        - Degree of RES participation in ancillary service: are RES incentivized to participate in ancillary services (e.g. TSO connected RES, DSO connected RES)? Are RES incentivized to participate in balancing service (e.g. with compensation of green certificate)?
    - Network Operation
        - Is the unavailability of RES integration lines (lines used to integrate RES generation into the system) heavily penalized?)
    - Energy efficiency and demand response
        - System and market operation to increase the level of these measures

          Degree of time differentiation (e.g. time of use, critical peak pricing and real-time pricing) of energy pricing schemes applied to customers: are there incentives to activate customer participation? Are market players incentivized to offer flexible supplier contracts?

          Demand response mechanism participation to ancillary services at TSO/DSO level: are there incentives to activate demand-response for ancillary service provision?

Socio/political acceptance

- Fit with the current context: is the market and operation framework in line with the current practice in Europe?

- Level of autonomy of local institutions: are the institutions dealing with the market and operational issues regional? Can local entities influence or modify regional decision processes and implementations? Do these regional institutions have sufficient independence?
- Facilitation of coordination: is there market integration (e.g long term market, day-ahead or intra-day market) with neighboring countries? Does the market and operation framework provide incentives for corporation between different market parties? Does the market and operation framework provide incentives for corporation between different countries? Is the market and operation based on international coordination?
- Fairness: Is there discrimination in the market among different players (for example, RES and conventional)?

Effectiveness

- Complexity: are system operation processes complex to manage?
- Risks: is there a risk that a lack of agreement among relevant results in efficient and secured system operation not being undertaken? Could this lack of agreement/cooperation affect system/market operation?
- Decision making power concentration: is the agreement of a large number of parties required to undertake integrated system operation? Is the decision making power extremely decentralized or strongly concentrated?
- Facilitation of coordination: Are the market and operation procedures providing incentives for cooperation among market agents or countries?

Annex 2: Supporting scheme for the BB Design

Given the complexity and overarching character of the building block network design, a general overview of how the process of the development of the grid could take place, as discussed in this project, is explained in the following paragraphs as support to the descriptions provided in the chapter on Network Design.

Two separate tracks are possible for the construction of new cross-border transmission assets: the main track includes transmission assets being constructed as regulated investments, as resulting from a centralized, coordinated planning process; and a second, complementary, track for exceptional cases, whereby network investments occur due to the initiative of private promoters. As aforementioned, the main, first, track involves the development of the grid through the construction of regulated assets. In this first track, reinforcements promoted should result from a centralized, top-down, network expansion planning process combined with a bottom-up process whereby local TSOs can influence the plan.

Even though there is room in this planning process for the exceptional participation of private parties, the reinforcements promoted in this process would be generally built by the corresponding local TSO. As explained in the BB Ownership, only if the local TSO is not able to undertake these investments for reasons under their control, their ownership could be allocated to the winner of an auction where TSOs and Transmission Companies with a license would compete to get hold of the construction, ownership and maintenance of the corresponding assets. Access to grid assets promoted through this track and built by TSOs would be regulated. Access to those other assets promoted by the central planner and built by private parties would also generally be regulated, but could, instead, be negotiated in specific cases. Having negotiated access to network facilities would not be possible if this confers market power to their owner, or if these assets are built and owned by an association of users not comprising all those that could potentially use them.

The second track for the promotion of new cross-border assets concerns network reinforcements promoted by private parties, which would also be assessed and approved centrally at European level if they are of a cross-border nature (going to be used by agents located in systems different from that where they would be built). Investments promoted through this track should be approved if they result in an increase in the aggregated net system operation revenues of market agents in Europe and they do not overlap, or interfere, with reinforcements proposed by planning authorities (either European or local).[34] Reinforcements promoted by private parties that are approved should be subject to regulated access if they confer market power to the operator of these assets, while access to these reinforcements could be negotiated by their owners and agents willing to use them otherwise.

[34] If merchant investments cause reinforcements on the regulated network, the costs of these should be deducted from the net increase in system operation revenues brought about by the former to determine if these investments should be approved.

The sequence of decisions that could drive the development of transmission grid reinforcements both as regulated ones and as private investments is visualised in the flow diagrams below.

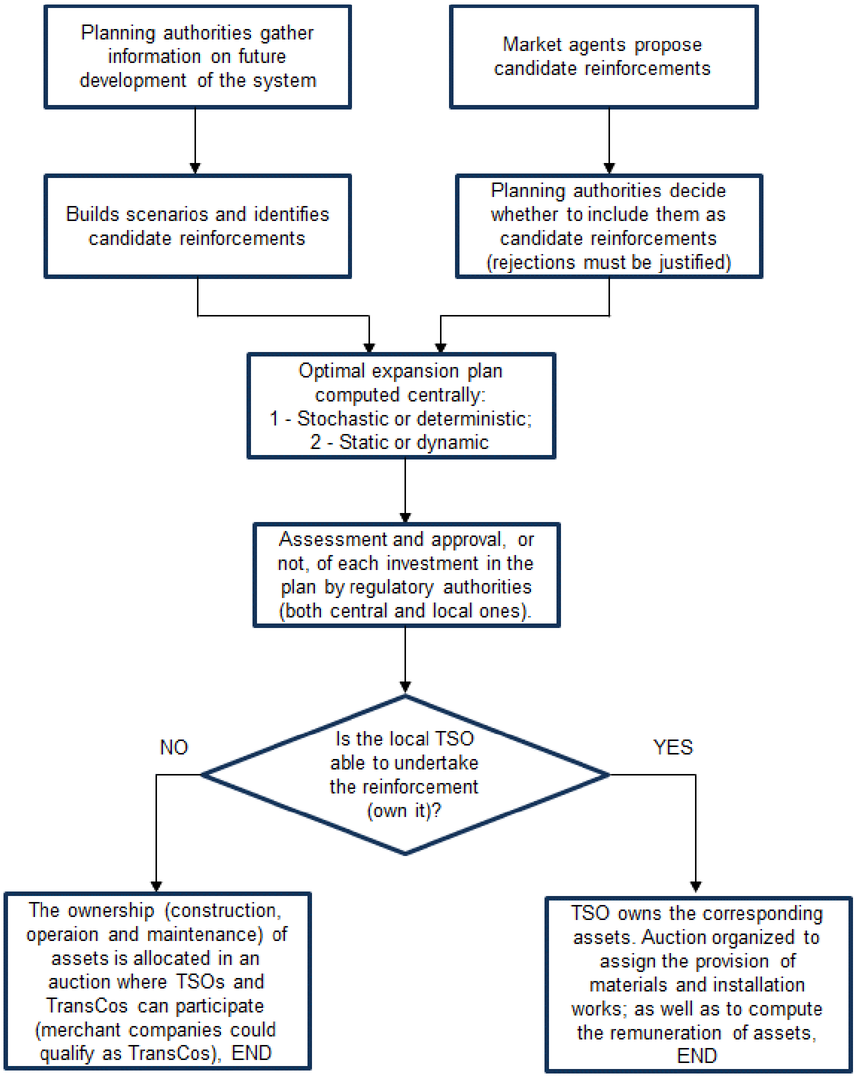

Figure 14: Flow diagram showing the process of development of regulated reinforcements (majority of cases)

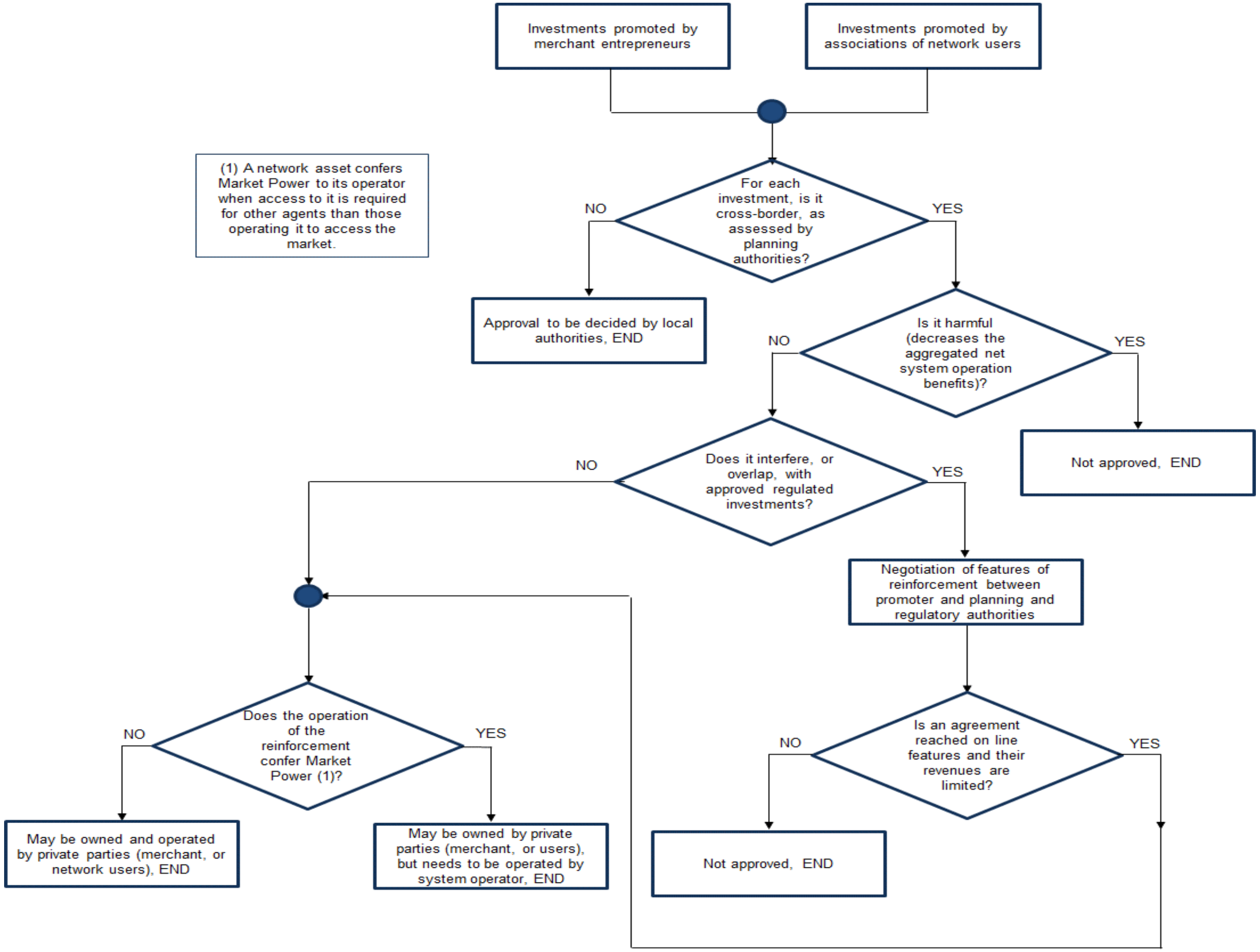

Figure 15: Flow diagram showing the process of development of reinforcements by private promoters (exceptional cases)

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