European Commission

Study supporting the Impact Assessment concerning Transmission Tariffs and Congestion Income Policies

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SUMMARY

Assessment of policy options on transmission tariffs

In addition to the current policy regime on transmission tariffs ('Option 0 – Baseline'), five alternative policy options have been identified and assessed under the following headings:

1. ACER G-Charge opinion of April 2014 i.e. replacing energy-based G-charges by capacity-based or lump-sum G-charges;
2. Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity;
3. Location-based charging;
4. Harmonised charges related to ancillary services (AS), losses, and grid connection;
5. Harmonised G:L split (harmonised percentage split between generators and consumers for transmission costs).

The overall evaluation and conclusions regarding these alternative policy options are summarised below.

1. ACER G-Charge opinion of April 2014

G-charges are defined as transmission charges levied upon producers by Use-of-System (UoS) charges. Replacing existing energy-based G-charges by capacity based or lump sum G-charges increases economic efficiency of generation dispatch and investment decisions as well as overall competition between generators. Given the current G-charges levels across Member States (MS), a limited effect on dispatch and investment decisions of generators in those countries that would have to change their G-charges can be observed. In addition, our quantitative modelling analysis also shows that dispatch and investment decisions of generators in countries that currently either have no energy-based G-charges or only non-energy based G-charges are also indirectly affected.

Concerning G-charge monitoring efforts, according to Regulation (EC) No 838/2010, the current upper limits to G-charges of part B of the Regulation have to be converted from energy to capacity based or lump sum G-charges. It is unlikely though that ACER and/or EC has to actively intervene in order to prevent that G-charges exceed the upper limits of the Regulation, since cross-border competition between generators induces regulatory competition between MS and thus serves as an implicit upper limit to all types of G-charges, preventing larger divergence of G-charges with the EU.

This policy option does not mean that G-charges will be set to their optimal long run cost-reflective level i.e. the level that stimulates generators and consumers to take investment and siting decisions that minimize overall system costs.[1] Rather it is likely that the G-charges of the largest MS in Continental Europe are becoming the benchmark, and therefore national policy goals of some MS rather than the EU policy goals. In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), this option should be considered as only one aspect of any future work towards more harmonisation.

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1 System costs are here defined as the sum of generation, network and societal costs.

2. Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity

A long-term trajectory with procedural obligations to develop a common set of principles for cost reflectivity will increase the efficiency of dispatch and investment decisions by generators, will remove distortions and improve the level playing field for generators across Europe. A common set of principles will also lead to a higher predictability and certainty with respect to the expected tariff development, and may contribute to more flexible power supply by properly rewarding flexibility. Despite the fact that national tariff differences are only one of the drivers of current distortions of dispatch and/or investment decisions between Member States, the focus on cost reflectivity of transmission signals is key in order to prevent that negative spillover effects from national network charging policies occur in an increasingly European system which is highly interconnected. Given that the need for harmonisation of tariff principles will evolve further over time, some first set of harmonisation measures e.g. transparency measures such as unequivocal obligations to TSOs and NRAs for common cost allocation methods, data gathering and reporting should be pursued in the short-term while more advanced measures such as for instance regulatory accounting guidelines for the treatment of network depreciation policies and ITC costs should be prepared for the long-term.

3. Location-based charging

The implementation of differentiated capacity based G-charges per area or per generator will have a positive impact on the efficiency of the electricity system, as it will induce more efficient siting decisions, in particular of conventional generators. Also the optimal siting of RES installations can be positively affected. While only effective in a mid-term perspective, it will positively affect the long term system efficiency. An EU wide implementation would however be complex and challenging, in particular in EU regions with a highly meshed and interconnected system and a decentralised and diversified power production park, with a large share of intermittent renewables. Location based capacity related G-charges are an adequate option in an electricity system, where areas with a structural deficit or overcapacity can be easily determined, and where power flows between areas with a predominant direction. Although this option offers some major benefits (positive impact on the long term system efficiency, higher cost-reflectiveness) and can be an effective measure to steer investments in the right direction in certain areas of Europe, a mandatory EU wide implementation is not considered as a preferred option to support the move to a more decentralised and RES based electricity system at the moment, mainly due to the complexity of its implementation.

4. Harmonised charges related to ancillary services (AS), losses, and grid connection

The implementation of a more harmonised approach towards procurement and charging principles for ancillary services would be an effective measure to create a more liquid and cross-border market for ancillary services and to increase the cost-reflectiveness and transparency of the related tariffs and the overall system efficiency. As the current divergences between MS are also distorting cross-border competition, the option to harmonise the procurement and charging principles would improve the level playing field for generators. A harmonisation of the major charging principles is hence recommended, but a full harmonisation of the tariff structures and charges is not appropriate, due to the fact that the optimal cost components and levels are different depending on the specificities of the national systems.

The current diversity in charging methodologies and cost levels for grid losses within Europe clearly shows that MS are differently interpreting the tariff principles of cost reflectiveness, non-discrimination and transparency. The current charging approach leads to a competition handicap for generators in some MS, thereby distorting competition in the internal market. Although generators are causing part of the costs for grid losses, they are in most MS exempted from a specific contribution. The option to harmonise at EU level the procurement and charging principles would improve the cost-reflectiveness and contribute to restoring a level playing field for generators; it could, depending on the concrete approach, also have positive economic and environmental impacts.

The connection cost charging approaches are in the EU also quite diverging. In order to avoid market distortions and to offer adequate and cost-reflective signals for siting decisions, a deep charging methodology could be an appropriate basis for harmonisation. However, given the potential risk for discrimination and distortion of generator decisions and the need to facilitate the transition to a more decentralised low carbon electricity supply, a shallow charging methodology based on capacity and distance related averaged and regulated standard tariffs should also not be excluded as an appropriate basis for harmonisation at EU level: depending on the design, it can (to a certain extent) be cost-reflective, highly predictable, non-discriminatory and offer a (limited) locational signal to generators. Such a harmonized methodology should equally apply to all installations, independently of the voltage level of the grid they are connected to and independently of the generation technology.

5. Harmonised G:L split percentage

This policy option – to have a uniform ratio between generators and consumers for transmission costs – would allow not only equal network tariff structures but also some harmonisation across Europe concerning the absolute network tariff levels, while respecting differences in network topology, geographical differences etc. between countries. On the positive side, apart from contributing to a higher system efficiency, the option also helps to establish a level playing field for competition between generators and to achieve higher transparency for network users. On the negative side, harmonisation of the G:L split percentage for all Member States requires coordinated action by EC or ACER and consequently increases administrative burden and raises questions about the proportionality of the option. One may argue that coordinated action is needed to internalize negative (and positive) external effects of national transmission tariffs on other EU Member States and the EU internal market for electricity. However, whether or not the policy option is proportional depends also on the size of the distortion, which we were not able to identify due to the lack of data and difficulties in disentangling the reasons behind the distortion, amongst others G-charges. Given the other factors that currently distort investment decisions of generators, proportionality of the option could be doubted. Furthermore, the option should be considered as an additional step when other options such as option 1 and 2 have been realised. As such it is a medium term option. On the other hand, the option could be considered as proportional from a precautionary perspective i.e. to prevent that already existing competition distortions due to variation in G:L percentage splits across Europe are amplified in a situation with continuation of current policies.

Conclusions and recommendations

The table below summarizes our assessment, which is more extensively discussed above, and allows for a comparison amongst the different policy options.

Table 1 Scoring of transmission tariff policy options on impact assessment criteria

	Economic				Social	Environ-mental	Propor-tionality
	Efficiency	Compe-titiveness	Admini-strative burden	Trans-parency			
Option 1	**0/+**	**0/+**	**0/-**	**0/+**	**0**	**0**	**+**
Option 2	**+**	**+**	**-**	**++**	**0/-**	**0/+**	**0/+**
Option 3	**+**	**0/+**	**-**	**+**	**0**	**0/+**	**0/+**
Option 4A	**0/+**	**0/+**	**-**	**+**	**0/-**	**0/+**	**0/-**
Option 4B	**0/+**	**0/+**	**-**	**+**	**0/-**	**0/+**	**0/-**
Option 4C	**0/+**	**0/+**	**0/-**	**+**	**0/-**	**0/+**	**0**
Option 5	**0/+**	**+**	**-**	**+**	**0/-**	**0/+**	**-**

On the basis of this study, the following main conclusions and recommendations are provided:

First of all, diverging tariff systems can have a negative impact on competition between generators from different Member States, thereby creating obstacles to the internal electricity market. However, it is quite difficult to prove this in a quantitative way due to modelling difficulties and –most important- the lack of data. Modelling difficulties relate mainly to the complexity of the issue at hand with many variables impacting generators dispatch and investment decisions. The lack of data to quantify the policy options implied that we were only able to model policy option 1. Network tariff data is very heterogeneous at Member State level, and only summarized for a few types of generators and loads at European level to a limited extent. Available reports do provide little insights in underlying assumptions, parameters, and calculations.

Although distortions on cross-border competition due to G-charges *currently* are limited, we deem it likely that distortive effects of variation of G-charges on competition and overall system efficiency will increase in the (near) future for two reasons. First, the increase of transmission capacity between and within countries means that higher transmission costs are expected in the coming years and decades. Second, the progress that is expected in creating common internal electricity markets given the EC CACM guideline and proposed Energy Union legislation implies that cross-border competition will further increase, making variation of G-charges a more prominent factor in dispatch and siting decisions of generators. On the other hand, in a future where differences in national generation policies remain and national capacity mechanisms are more widely introduced distortions of generator decisions due to G-charges could still be overpowered by other factors such as market price differentials and differences of taxes and levies. All in all, differences in G-charges may contribute to the cumulative competition distortion effect and tackling them can make a difference, even if the effect would be small if they were to be tackled alone.

Several policy options analysed contribute to overcome this competition distortion by stimulating better cost reflectiveness and transparency of network charges, and realisation of a cross-border level playing field for generators.

Overall, policy option 2, a long-term trajectory with procedural obligations to develop a common set of principles for cost reflectivity, is deemed to be proportional as well as most beneficial for European generators and citizens. This option has the potential to increase system efficiency, competitiveness, and transparency, and focuses on infrastructure costs which make up for the largest part of TSO costs. In this respect, we also confirm the message of other studies (amongst others CEPA, 2015) that the EC should first focus on harmonisation of G-charge principles (cost reflectivity versus transparency, capacity versus energy based G charges) rather than on variation in G-charge levels which may result either from artificial, policy-related differences between countries or structural differences between countries such as network topology and geographical differences. At the same time, the administrative burden of option 2 is surmountable, and the option can be implemented in a flexible, stepwise manner by either an electricity transmission tariff guideline or network code. Given that the need for harmonisation of tariff principles will evolve further over time, some first set of harmonisation measures e.g. transparency measures such as unequivocal obligations to TSOs and NRAs for common cost allocation methods, data gathering and reporting should be pursued in the short-term while more advanced measures such as for instance regulatory accounting guidelines for the treatment of network depreciation policies and ITC costs could be prepared for the long-term.

Option 3 undoubtedly offers substantial economic benefits and may be an appropriate means to provide the right investment siting signals in cases of lasting mismatch of demand and supply in a country. However, due to its challenges around optimal delineation of the different transmission tariff zones and large impacts on regulatory and administrative processes, an alternative such as a review of the bidding zones might be more proportional and effective options.

Option 4C could be considered proportional and beneficial as it prevents unfair cross-border competition between generators with potentially countries shifting substantial costs from G-charges (‘use-of-system’ charges) which are subject to EC Regulation No 838/2010 to connection charges which are currently explicitly excluded from harmonisation efforts. The option could be implemented by an electricity transmission tariff guideline or network code. However, a common approach to setting principles for more long-term harmonisation (Option 2) may also mitigate the risks outlined above.

The positive effects of option 1 suggested by economic theory were not very much supported by our quantitative analysis, which indicated that option 1 has tiny effects on decreasing cross-border competition distortion. Nonetheless, given the expectation that variation in G-charges will increase in the future, this option does not require additional policy intervention but rather limited adjustment of EC Regulation 838/2010, and hence could be deemed proportional.

Likewise option 2, options 4A and 4B have the potential to increase system efficiency, generator competitiveness and transparency, although the shares of ancillary services and grid losses in overall TSO costs are much more limited than network infrastructure costs. Furthermore, impacts on cross-border competition are likely to remain limited due to structural differences between Member States concerning ancillary services and losses which cause variation in network costs and therefore tariff levels, and that are not resolved by these specific policy measures.

Option 5 is considered to be disproportional in the current situation to reach the objectives. On the one hand, option 5 helps to establish a level playing field for competition between generators, to achieve higher transparency for network users, and to realize higher system efficiency by more optimal G-charge levels. However, on the other hand, this option requires substantial administrative efforts by NRAs, TSOs and

ACER, is not flexible and, taking into account the currently limited competition distortion effects of variation of G-charges, a bit too drastic at the moment.

Finally, it should be noted that time-of-use components of transmission tariffs have not been considered in this study. Given the need for flexibilisation of the electricity system, such tariffs could become an increasingly effective option and could form an important component of any future analysis or study on this topic. In addition, as suggestion for further work it is advised to take a broader approach and to develop a consistent network tarification approach which besides flexible generation also stimulates flexible demand in order to minimize overall system costs. For enabling such future quantitative studies on transmission tarification with an European scope it is key that MS practices are reported for a range of different types of generators and loads in a more systematic and coherent way. Such reports should not only include final network tariffs but also provide insights in underlying assumptions, parameters, and calculations.

ASSESSMENT OF CURRENT SITUATION ON CONGESTION INCOME SPENDING

The current situation with regard to the spending of congestion revenues in the EU is stipulated by Regulation (EC) No 714/2009 on conditions for access to the network for cross border exchanges in electricity. The main objective of Article 16(6) of this regulation is that congestion rents are used primarily to cover the costs of redispatching, counter trading and other operational measures to guarantee the actual availability of allocated interconnection capacity, or to maintain or increase interconnection capacity in a social optimal way. In addition, if this aim is met, it is allowed to include congestion rents in the tariff base – i.e. to actually reduce network tariffs – or to save them on a separate account (for future spending on interconnection capacity or reducing transmission tariffs).

Spending of congestion revenues in 2011-2015

According to data from ENTSO-E, the total amount of TSO net revenues from congestion management on interconnections over the period 2011-2015 varied from about € 1.2 billion in 2011 to € 2.6 billion in 2015. A major share of these revenues accrues to only a limited number of ENTSO-E Member States. Furthermore, the spending of congestion revenues varies widely among ENTSO-E Member States.

During the period 2011-2015, an average annual amount of approximately € 1840 million of congestion rents by all ENTSO-E Member States was used as follows:

- € 340 million was spent on capacity guarantees (19%),
- € 570 on capacity investments (31%),
- € 680 million on reducing transmission tariffs (37%), and
- € 250 million saved on a separate account (14%).

This implies that, by changing the rules on using congestion rents, the amount spent on enhancing interconnection capacity can increase by, on average, some € 680 million per annum as a maximum, in particular if the option to use these rents on reducing network tariffs is no longer allowed under any condition.

Although some aggregated data on the spending of congestion rents are available, much detail to interpret this spending is lacking. For instance, as far as data on spending congestion revenues on new interconnection investments are available, it is not clear which costs of which link(s) have been covered by this spending. Therefore, in general, more transparency on congestion income spending (and applied accounting rules) is desirable and even necessary to assess (options to enhance) the performance of current policies and practices on congestion income spending.

Additional interconnection investments are needed but investments are lagging

There is still a strong demand for further investments in interconnection capacity. ENTSO-E has provided an estimate of the total investment costs needed for additional interconnection capacity for pan-European projects (with a positive contribution to social welfare) which amounts up to 150 billion euro in the period up to 2030.

Nonetheless, investments are lagging, for a number of reasons. The impact of a lack of interconnection capacity is that the European electricity system operates less efficiently, that network users pay too much for their electricity and, overall, that energy security and social welfare are lower than optimal.

Financial assistance to facilitate interconnection investments

In addition to using (earmarked) congestion rents and/or other revenues from the regulated (tariff) asset base to cover investments and other costs in interconnections, the EU has introduced a number of supporting financing and funding tools in order to facilitate investments in energy infrastructure, including:

- The *Connecting Europe Facility (CEF)*. CEF is an EU initiative, established under Regulation (EU) No 1316/2013, in order to provide financial assistance to investments in trans-European networks in the transport, energy and telecommunication sectors.
- The *European Fund for Strategic Investments (EFSI)*. Early 2015, the Commission proposed the creation of EFSI in order to provide financial instruments to significantly improve EU investment projects' access to long-term financing.
- The *European Structural and Investment Funds (ESIF)*. From 2014 to 2020, € 50 billion of co-financing (€ 630 billion including national co-financing) will become available as ESIF support in order to strengthen EU economic structures and reduce development disparities across regions.

Congestion rents as a source of funding interconnections

A policy option regarding congestion revenues would be to severely restrict spending of these revenues on other purposes than guaranteeing, maintaining or increasing interconnection capacity, and earmark these resources for funding new investments in interconnection capacity. When carrying out new investments, a fair burden-sharing is important as benefits of new interconnection investments between the countries and stakeholders involved are not necessarily aligned with the costs. The basic dilemma is that interconnection investments may e.g. result in a reduction of the price difference between countries involved, the interconnection value – not only for the new capacity but for all capacity between the countries involved – will be reduced since the price difference between these countries will be lower (as a result of the additional investment).

While the new link will lead to an increase in social welfare (due to the higher efficiency of electricity generation serving consumers' demand), but the high price country will mainly benefit from an increase of consumer surplus whereas the low price country will benefit from an increase of producer surplus. For NRAs involved, especially in countries where NRAs are charged with promoting low energy tariffs for electricity consumers, approving a link which will (on average) lead to higher electricity prices for their consumers, it may be difficult to positively defend the investment decision in additional interconnection capacity. Only for projects of common interest the so-called cross-border cost allocation addresses these questions, but for non-projects of common interest, a solution needs to be found in NRA negotiations.

Another possible approach to mitigate the issue is to ring fence the congestion revenues. Strong ring fencing of congestion revenues may help as TSOs/NRAs will become indifferent with respect to the amount of the congestion revenues. When these revenues can no longer contribute to the tariff base (and thus be considered as a source of revenue for the TSO), any decrease of these revenues will no longer financially impact the TSOs.

Monitoring and assessing regulation on congestion income spending

In the current situation, TSOs report on the use of their congestion revenues to the NRAs. Due to a lack of information and transparency, however, it is not clear to which extent the rules are being applied in accordance with the provisions of Article 16(6) of EC Regulation No 714/2009, which aim at maximizing interconnections for an optimal social welfare. In particular, it is not clear how the TSOs decide on the use of congestion revenues for guaranteeing, maintaining or increasing interconnection capacity. In addition, it is not clear whether and how the NRAs check (i) that TSOs have used congestion revenues efficiently for guaranteeing, maintaining or increasing interconnection capacity, and (ii) that the rest of the revenues cannot be efficiently used for these purposes. Therefore, besides policy options for changing the rules on spending congestion revenues, there seems to be need for enhancing the transparency regarding the compliance and enforcement of these rules.

Congestion revenues shall preferably be used to fund the costs of interconnection investments. In general, the final decision to approve the costs of interconnection investments and how to use congestion rents lies with the NRAs. NRAs, however, have to serve several social (national) objectives, including to strike a balance between protecting consumers against high tariffs and ensuring a stable and secure network. So, they look critically to the costs of new interconnection investments and may be inclined to use congestion income primarily for serving (short-term) national interests, including controlling transmission tariffs for consumers, in particular when the reserve (internal account) of remaining congestion rents is already significant and there are no short-term opportunities to invest in interconnection projects that have a clear positive national (social) outcome. Moreover, although NRAs are independent, in practice NRAs may feel pressure from national policy makers and/or TSOs to use congestion rents for serving particular national (short-term) interests.

Hence, leaving the decision to use congestion revenues to fund the costs of interconnection investments solely at NRAs' discretion, may prevent investments in interconnection capacity, notably for those projects that serve (long-term) regional or EU-wide interests – in particular the projects of common interests (PCIs) – but for which (short-term) national benefits are less clear. Therefore, improving the rules on spending congestion revenues will ensure that an adequate amount of congestion revenues are spent on enhancing interconnection capacity, including investments in projects of regional or EU-wide interests.

1 INTRODUCTION

Background and rationale of the study
For achieving the internal energy market, maintaining security of supply and integrating electricity from renewable energy sources, several legislative acts and guidelines have been issued in the fields of market design and network regulation in the past two decades. These also determine the incentives for market participants and revenue frameworks for regulated actors such as TSOs. The Energy Union Strategy highlights that, despite progress, "the current market design does not lead to sufficient investments, market concentration and weak competition remain an issue and the European energy landscape is still too fragmented." EC (2015a). One reason for the weak competition is that spillover effects of national network charging policies on the cross-border level playing field for competition of generators are often not taken into account. One reason for the lack of sufficient network investments that are quite valuable for Europe's internal electricity markets is the predominantly national financing of those investments, which does not acknowledge that the realization of congestion income depends on all other trading transactions across Europe.

Consequently, the Commission stresses the importance to continue implementation of existing measures following the Third Energy Package (amongst others binding network codes in the form of European Regulations). Moreover the Commission is striving 'to provide a new integrated, cooperative, and more effective and relevant framework for common EU energy and climate policies providing to the European consumers – households and businesses – secure, affordable, competitive and sustainable energy.' As part of this strategy, the Commission will develop initiatives, including the energy market design initiative (EC, 2015b).

Objectives and scope of the study
The consortium has been tasked to perform a study about transmission tariffs and congestion income, in order to support the Commission in their overall impact assessment exercise concerning the energy market design initiative.

The objective of the first part about transmission tariffs is to detail and where possible quantify different policy options to overcome potential distortions of competition between generators and generation technologies resulting from heterogeneous network charging regimes in different Member States.

The objective of the second part about congestion income revenues is to present a factual summary and assessment of the current situation on the spending of these revenues.

Structure of current report
After this introduction, the topics transmission tariffs and congestion income will be discussed consecutively in Part 1 and Part 2 of this report. More specifically, Chapter 2 assesses the current situation in Europe regarding transmission tariffs, in order to provide a baseline for Chapter 3 which elaborates upon the alternative policy options. Chapter 4 provides a partially qualitative and partially quantitative impact assessment of the policy options. Subsequently, in part 2 of this report, Chapter 5 presents a factual summary and assessment of the current situation on the spending of congestion income.

PART I: TRANSMISSION TARIFFS

2 ASSESSMENT OF CURRENT SITUATION AND ANALYSIS OF KEY DISTORTIONS OF TRANSMISSION TARIFF POLICIES (BASELINE)

2.1 Assessment of current situation

The current situation is the result of established transmission tariff policies, and serves as the baseline to which the policy options of Chapter 3 are assessed. Choices made in the past that impact today's situation are being discussed for the following three successive steps of transmission tariff policies:

1. Cost categories included in allowed revenues and recovered by transmission tariffs;
2. Allocation of transmission costs to production and consumption (Generation: Load split);
3. Allocation of costs to specific network users (energy based and capacity-based tariffs, connection and Use-of-System (UoS) charges, uniform versus time-of-use and/or locational differentiated charges).

Cost categories recovered by transmission tariffs

Because of the fact that transmission networks are very capital-intensive transmission costs consist mainly of infrastructure costs (capital expenditures i.e. CAPEX), and only a limited amount of costs for system operation, congestion management, and compensation of grid losses (mainly operational expenditures i.e. OPEX).

Table 2 below shows broadly whether and, if yes, how different cost categories are included in the transmission tariffs (G and/or L) of each Member State.[2] Costs for congestion management are included in the category system services, while connection costs are not included. Costs for losses and system or ancillary services are in most countries included in transmission tariffs (either in an overall tariff or separate tariffs for losses and/or ancillary services), and in other countries recovered through the electricity market. Costs of grid losses are recovered by electricity markets in Belgium, Great Britain, Greece, Ireland, Italy, Portugal, Slovakia, Spain and Switzerland,[3] while the same holds for costs of ancillary services for Greece, Portugal, Slovakia, Slovenia, Spain and Switzerland.[4] Methodologies to levy transmission costs for system services, losses, and establishing new connections on users are further discussed in Chapter 3 under option 4.

[2] The text below is based upon Table 4.1 of ENTSO-E (2016). In case of conflicts between information provided by Tables 4.1 and 5.1 of ENTSO-E (2016) respectively, it has been assumed that Table 4.1 prevails as this table is most in line with information from other sources.

[3] Italy and Slovakia are only mentioned by CEPA (2015), but not by ENTSO-E (2016).

[4] Greece, Slovakia and Slovenia are only mentioned by CEPA (2015), but not by ENTSO-E (2016).

Table 2 Network costs included in unit transmission tariffs

	Infrastructure				System services									
	OPEX (except system-services,losses and ITC)	Depre-ciation	Return on capital invested	ITC	Primary reserve	Secondary reserve	Tertiary reserve	Congestion management (internal)	Congestion management (cross border)	Black -Start	Voltage Control Reactive Power	System Balancing	Losses	Other
Austria	C	C	C	B/C	N	C	N	C	B/C	C	C	N	C	C
Belgium	C	C	C	B/C	C	C/B	C/B	C	C/B	C	C	N	C (estimated)	C
Bosnia & Herzegovina	C	C	C	B/C	C	C	C	N	B/C	C	N	C	C	N
Bulgaria	C	C	C	C/B	C	C	N	N	B/C	C	C	N	C	C
Croatia	C	C	C	N	N	C	C	C	C	C	C	C/B	C	C
Cyprus	C	C	C	N	C	C	C	N	N	C	C	N	C	N
Czech Rep.	C	C	C	C/B	C	C	C	C	C	C	C	C/B	C	N
Denmark	C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)	C (estimated)	C (estimated)	C/B (estimated)	B/C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)	C (estimated)
Estonia	C	C	C	B/C	N	N	C	N	C	N	C	N	C	C
Finland	C	C	C	C	N	N	C	C	C	C	C	N	C	C
France	C	C	C	C	C	C	N	C	N	C	C	N	C	C
Germany	C/B	C	C	C/B	C	C	C	C	C	C	C	N	C	C
Great Britain	C	C	C	C/B	C	C	C	C	C	C	C	C	N	C
Greece	C	C	C	C/B	C (estimated)	C (estimated)	N	N	B/C	C (estimated)	N	N	C (estimated)	C
Hungary	C	C	C	C	C	C	C	C	B/C	C	C	B/C	C	N
Iceland	C	C	C	N	C	C	C	N	N	C	C	C	C	N
Ireland	C	C	C	C	C	C	C	C	C	C	C	N	C	N
Italy	C	C	C	N	C	C	C	B/C	B/C	C	C	C	C (estimated)	C (estimated)
Latvia	C	C	C	B/C	C	C	C	N	C	N	C	N	C	N
Lithuania	C/B	C	C	C/B	N	C	C	N	N	C	C/B	B/C	C	N
Luxembourg	C	C	C	C	C	C	C	C	C	C	C	C	C	C
FYROM	C	C	C	B/C	N	C	C	N	B/C	C	C	B/C	C	N
Montenegro	C	C	C	B/C	N	C	C	N	B/C	N	N	C	C	C
Netherlands	C	C	C	B/C	C	C	C	C	B/C	C	C	B/C	C	N
Northern Ireland	C	C	C	C	C	C	C	C	C	C	C	N	C	N
Norway	C	C	C	C	C	C	C	C/B	B/C	C	C	N	C	N
Poland	C	C	C	N	C	C	C	C	N	C	C	C	C	C
Portugal	C	C	C	C/B	N	C/B (estimated)	N	N	B/C	N	N	N	C (estimated)	C
Romania	C (estimated)	C (estimated)	C (estimated)	C/B (estimated)	N	C (estimated)	C (estimated)	C (estimated)	N	N	C (estimated)	N	C (estimated)	C (estimated)
Serbia	C	C	C	C/B	C	C	C	C	C/B	C	C	C	C	C
Slovak Rep	C	C	C	C/B	C	C	C	C	N	C	C	N	C	N
Slovenia	C/B	C/B	C/B	C/B	N	C	C	C	C/B	C	C	N	N	C
Spain	C	C	C	C	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C
Sweden	C	C	C	B/C	C	N	N	N	N	C	C	N	C	N
Switzerland	C	C	C	B/C	C	C	C	C	B/C	C	C	C	C	C

Source: ENTSO-E (2016), Table 5.1.

The letters in this table indicate the following:

- C if a given cost item is included in the calculation of transmission tariff.
- C/B (B/C) if for a given activity there are both costs and benefits/revenues, the costs (benefits) are higher than benefits (costs), and the costs (benefits) increase (decrease) the transmission tariff.
- N if a given cost is not considered in the calculation of the transmission tariff.
- C or C/B or B/C marked as "estimated" indicate that the cost item is not invoiced by the TSO and estimated values are provided for comparability purposes.

Allocation of transmission costs to production and consumption

Table 3 shows that in some countries transmission costs currently are entirely recovered from consumption (apart from connection costs), while in other countries they are recovered both from generators and consumers. The table provides the sharing for the unit transmission tariff i.e. a tariff that is calculated for a specific base case with connection of producers and consumers to the extra high voltage (EHV) network, and for consumers a maximum power demand of 40 MW (10 MW) when connected to the EHV network (lower voltage levels) as well as a utilization time of 5,000 hours.

Table 3 Generation: Load splits for the Unit Transmission Tariffs of EU Member States and Norway and Switzerland

	Sharing of transmission charges	
	Generation	**Load**
Austria	43%	57%
Belgium	7%	93%
Bulgaria	0%	100%
Croatia	0%	100%
Cyprus	0%	100%
Czech Republic	0%	100%
Denmark	3%	97%
Estonia	0%	100%
Finland	19%	81%
France	2%	98%
Germany	0%	100%
Great Britain	23%	77%
Greece	0%	100%
Hungary	0%	100%
Ireland	25%	75%
Italy	0%	100%
Latvia	0%	100%
Lithuania	0%	100%
Luxembourg	0%	100%
Netherlands	0%	100%
Northern Ireland	25%	75%
Norway	38%	62%
Poland	0%	100%
Portugal	8%	92%
Romania	8%	92%
Slovakia	3%	97%
Slovenia	0%	100%
Spain	5%	95%
Sweden	41%	59%
Switzerland	0%	100%

Source: ENTSO-E (2016), Overview of Transmission Tariffs in Europe: Synthesis 2015, June 2016. Note that these values include (connection) infrastructure, ancillary services, losses and other charges not directly related to TSO activities.

Since absolute transmission cost levels differ between Member States a higher (lower) percentage does not automatically imply that generators or consumers are levied higher (lower) transmission costs. It is assumed that these percentages, and therefore the Generation:Load (G:L) splits do not change in the baseline.

In the current situation the share of costs allocated to generators by network tariffs for generators (G-charges) is to some extent affected by the legal provisions in EC (2010)[5]. Generally, they provide upper limits to average G-charges (0.5 €/MWh for most countries; 1.2 €/MWh for Denmark, Sweden, and Finland; 2.0 €/MWh for Romania; and 2.5 €/MWh for Ireland, United Kingdom, and Northern Ireland). However, some charges paid by generators (for ancillary services, system losses, and physical assets required for (upgrade of) connection to the system) are excluded from the calculation of the annual average G-charges, and therefore are unrestricted by the EC (2010) provisions.

Allocation of costs to specific network users

Transmission costs can be allocated by energy-based and capacity-based tariffs, through connection and UoS charges, and by uniform tariffs for a whole country or bidding zone or differentiated to time-of-use and/or location of the network users.

Energy-based and capacity-based transmission tariffs

Network costs can be recovered by either energy or capacity based transmission tariffs. Energy based transmission tariffs are expressed in €/MWh, while capacity or power-based transmission tariffs are denominated in €/MW. Energy-based charges are best suited to allocate operational costs such as costs of losses and congestion, while capacity based charges are generally preferred to allocate network investment costs. Figure 1 below shows the allocation of transmission costs by energy and power components in case of the unit transmission tariffs. The variation between countries exhibits not only differences in cost structures, technical characteristics and geographical differences but also the diversity of policies across Member States which results from a different emphasis laid on several policy objectives (cost reflectivity, cost recovery, predictability, equity considerations etc.). This may impact the level playing field of generators.

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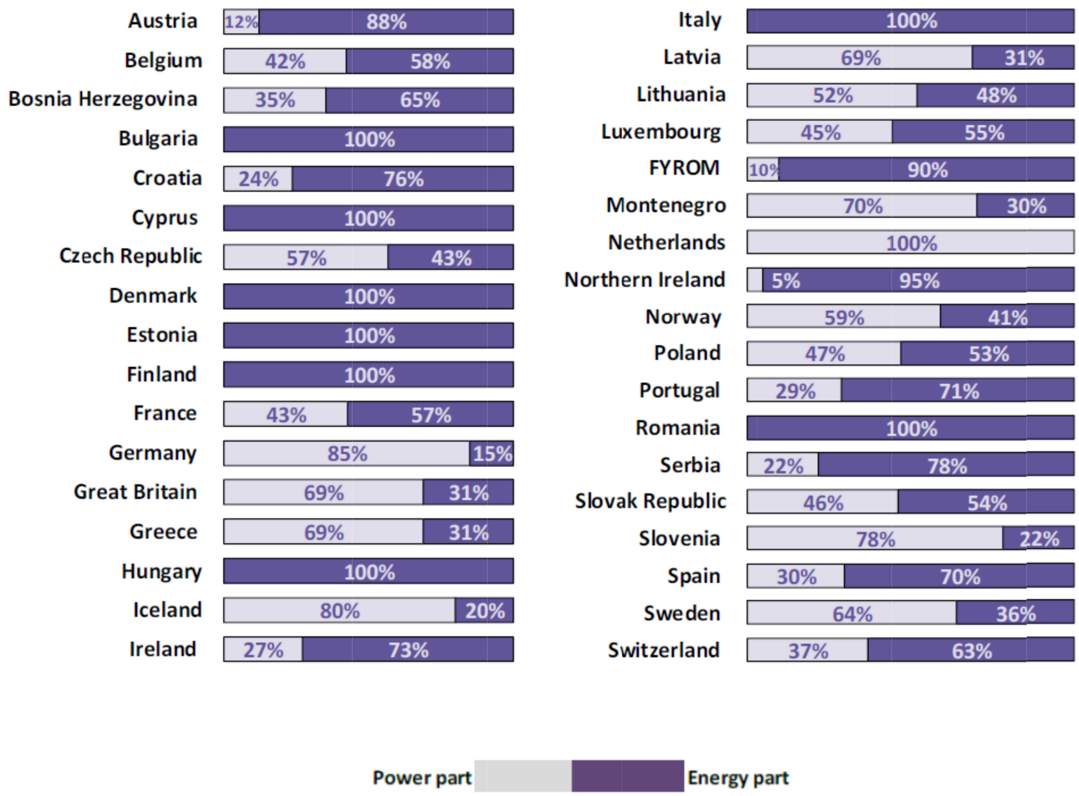
5 EC (2010), Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, OJ L 250: 5-11.

Figure 1 Energy-based and capacity/power-based components of the Unit Transmission Tariff



Source: Chart 7.1 of ENTSO-E (2016). Note that these values include connection infrastructure, ancillary services and losses, but exclude charges not directly related to TSO activities.

Connection and Use-of-System charges

Up to now we discussed the UoS charges. However, network costs are also partially recovered by connection charges. Connection charging policies differ across the EU; in some Member States all costs related to the grid connection are socialized via the grid user tariffs, while in other countries either shallow or deep connection charges are levied on network users. If all costs are socialized via the UoS charges, no specific costs are charged to the connecting power plant or load unit, and thus the so-called super-shallow methodology is applied. In case of the shallow connection regime, grid users only pay for the specific infrastructure (line/cable and other related equipment) necessary to connect their installation to the grid. Costs related to grid reinforcements and/or extensions are socialized via the UoS charges. In case of the deep connection regime, the grid users pay both the costs for the specific infrastructure to connect their installation to the grid as well as the grid investments to reinforce and/or extend the grid beyond the grid connection point.

According to the overview published by ENTSO-E (Appendix 7 in ENTSO-E, 2015), most TSOs currently apply a shallow approach, which is either based on the actual costs of the connection (e.g. Belgium, Germany, Hungary, Luxembourg, Slovak Republic,…), on a standard tariff (Austria, Czech Republic, Finland, the Netherlands, …) or on the actual costs related to a connection to a fictitious point that can be closer than the effective physical connection (Denmark). Only a minority of MS applies a deep methodology (Croatia, Estonia, Latvia, Lithuania, and Sweden).

This diversity of connection charging approaches implies that in countries with a deep connection regime a larger part of the costs is recovered by connection charges, lowering the part of the costs to be recovered by UoS charges from generation and loads. This may impact the level playing field for generators across different European markets.

Uniform tariffs versus tariffs differentiated to time-of-use and/or location

At the moment most EU Member States apply uniform transmission tariffs for the whole country or bidding zone, while some countries provide additional economic signals by differentiating tariffs according to the location within the country or bidding zone, or the time-of-use of the network for electricity generation. We will consecutively discuss locational and time-of-use signals.

Locational signals via transmission charges: status quo

Within a market/bidding zone, locational signals can be provided either through electricity market prices (either by zonal or nodal pricing) or through location differentiated network tariffs. In the context of this study locational signals via market prices are not considered.

Transmission tariff structures in Europe currently include locational elements in only 5 Member States: GB, Ireland, Norway, Sweden and Romania.

The exact method of applying locational signals differs between countries although, at least in the case of GB, Norway and Sweden, locational signals reflect a distinct pattern of generation and demand location – i.e. long transmission distances between generation areas located in the north of the country and demand centres located in the south. In Sweden, for example, G-charges decrease linearly with latitude (from north to south) while load charges increase with latitude (from south to north).

In Romania, the country is split into seven generation areas and eight load areas with charges reflecting surplus and deficit areas. The generation tariff includes a component to cover the short-term marginal costs related to grid losses and congestion and a second component that is based on installed capacity to recover network operating and infrastructure costs.

GB has in April 2016 introduced changes to the incremental cost method it uses to set locational transmission tariffs for load and generation, in order to take account of changing patterns of use of the network mainly due to the development of intermittent RES.

Time-of-Use signals via transmission charges

Transmission investments are usually dimensioned on peak demand for network capacity. Time-of-Use (ToU) signals are provided to reduce this need for transmission investments. In Belgium, Croatia, Estonia, Finland, France, Greece, Norway, Portugal, Slovenia and Spain, TSOs provide ToU signals to network users (ENTSO-E, 2016).[6] The types of ToU signals differ between Member States, countries differentiate signals according to time-of-day i.e. day/night, season i.e. summer/winter, or simultaneity of production with peak demand i.e. peak/mid-peak/off-peak (CEPA, 2015). The number of time differentiated charges also differs; Croatia, Estonia, Finland, Greece, Norway, Portugal apply either one or two time differentiations, while Belgium, France, Slovenia

6 Updated overview of transmission tariffs in 2015.

and Spain apply three or more time differentiations (ENTSO-E, 2016).[7] The potential benefits of this type of charging has not been analysed further in this study but given the transition to a more flexible and decentralised electricity system, this could form an important component of future analysis in this area.

2.2 Previous analyses concerning potential distortions of cross-border competition due to variation of G-charges

The variation of transmission tariffs across EU member states due to choices made around cost categories recovered by transmission tariffs, G:L split, and around allocation of costs to specific network users (e.g. energy-based versus capacity-based tariffs) as described above may give rise to cross-border market distortions. These are all indicators that distortions due to G-charges may occur. In fact, every measure which actually or potentially reduces cross-border trade constitutes a market distortion under EU law.[8]

However, whether or not public intervention is beneficial is another question. This depends both on the significance of the distortion and on the information available for adequate public intervention, the administrative/compliance cost involved, and the extent to which other European and national policy objectives are affected. This section will further elaborate upon the significance of the distortion. The cost involved with policy measures as well as its proportionality is the focus of next chapters, which elaborate upon the policy measures and provide an assessment of their impacts respectively.

Concerning the significance of the distortion, in practise the variation of G-charges is one of several factors that influence cross-border competition between generators, both with respect to operational decisions in the short term and investment decisions in the long term (CEPA, 2015).[9] For both types of decisions, generators will basically compare total expected revenues with total expected costs. Assuming that generators face international competition given the realization of an European internal electricity market and thus compete across borders,[10] in case of a significant difference in *net* expected revenues for generators, either for potential dispatch or siting decisions, the level playing field for generators can be said to be significantly distorted. This may be the result of one factor causing a distortion, or several factors that coincide with each other. In the opposite case that the difference in net expected revenues for generators in different countries or bidding zones is insignificant, the level playing field for generators is insignificantly influenced. Both ACER (2014), which calls it the total cost approach, and CEPA (2015) apply essentially this approach for their analyses.

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[7] Ibid., Table 4.1.

[8] ECJ, Judgment of the Court of 11 July 1974. Procureur du Roi v Benoît and Gustave Dassonville. Reference for a preliminary ruling: Tribunal de première instance de Bruxelles - Belgium. Case 8-74. ECLI:EU:C:1974:82.

[9] Two types of markets for generators can be distinguished; a short term market for making operational decisions (whether or not the unit should run), and a long term market for investment decisions. Although both markets are related, they each have their own price. Generators will produce when short term marginal prices exceed or are equal to short term marginal costs. Generators will invest when long term marginal benefits are at least equal to long term marginal costs of capacity additions. Long term marginal prices reflect not only operational costs but also fixed costs i.e. investment costs. By definition fixed costs are not reflected in short term marginal prices as it takes time for actors to realise new investments, hence fixed costs are only included in long term marginal prices.

[10] This assumption will be discussed below.

Given this approach, CEPA (2015) searched for case studies with a significant distortion due to generator tariffs. Specifically for generation dispatch decisions they evaluated situations in the 4M day-ahead market coupling region (i.e. four countries in Central Europe; Czech Republic, Slovakia, Hungary and Romania), and the CWE day-ahead market coupling region (Belgium, France, Germany, Luxembourg, Netherlands). In the case of the 4M DAM coupling region they do not find a significant effect due to generator tariffs. In the case of the CWE region the dispatch of a hypothetical CCGT in Belgium would be influenced by the energy-based charge that is in place in Belgium but not in the Netherlands. Without the current energy based ancillary services charge a CCGT would run around 5% more hours in Belgium. Because a simple dispatch model was deployed, CEPA was not able to identify price effects, and therefore to assess the monetary significance of the effect.

Likewise for operational decisions of generators, CEPA mentions the Nordic region as a region with a potential significant distortion of generation investment decisions due to generator tariffs. They find that the Nordic region is on the one hand closely integrated, while on the other hand countries apply heterogeneous G-charges and as such the Nordic region fulfils many of the conditions outlined above. However, CEPA concludes that it was not able through its own work 'to determine whether current structural differences in transmission tariffs across the Nordic region have created harmful investment distortions', although it recognizes that the Nordic region 'demonstrates how the risks of distortions from the absence of tariff structure harmonisation … could increase across Europe, as further physical interconnection and steps towards market integration occur'.

At the same time CEPA seems to suggest that these results cannot be generalized as they conclude that 'Since the differences in capacity payments and renewable subsidies tends to be higher than differences in generation tariffs, it is likely that at least currently these distortions are more significant than any distortions that would be caused by the lack of transmission tariff structure harmonisation.' This situation may become different in the future. On the one hand distortions due to transmission tariffs then may become more important due to the increase of interconnection capacity and further market integration efforts. On the other hand in a scenario when existing differences in national generation policies remain and national capacity remuneration mechanisms are implemented, these distortions may still outweigh distortions due to transmission tariffs.

2.3 Additional quantitative analysis

Since the preceding quantitative analyses turned out to be partially inconclusive, we performed an additional quantitative economic analysis with the COMPETES market model in order to compare a fictitious reference case without G-charges with the current situation with different G-charges per country (policy option 0). COMPETES is a power optimization and economic dispatch model that seeks to minimize the total power system costs of the European power market whilst accounting for the technical constraints of the generation units, the transmission constraints between European countries as well as the transmission capacity expansion and the generation capacity expansion for conventional technologies, given the policy-driven (i.e. exogenously determined) installation and generation of electricity from renewable sources such as solar PV, wind energy or water power. The model is applied to calculate the least cost generation and transmission allocation for both cases under a future scenario of the year 2030. The model also calculates the optimal conventional generation capacity and cross-border transmission capacity investments in Europe. For more information about the COMPETES model and the assumptions taken, please refer to Annex A. The energy-based G-tariffs (Euro/MWh) are included in the model as an additional cost to the short run marginal cost (SRMC) of generators. This means that the supply curve is shifted upwards in countries with an energy-based transmission tariff. The capacity-based transmission tariffs (Euro/MW) are included in the model as a fixed cost of new and existing generation capacity and, therefore, they increase the long run marginal cost (LRMC) of new generation capacity. Implementation of non-harmonized tariffs in EU countries may distort the competition and affect the location of generation and transmission investments, resulting in less efficient investment and generation decisions and, consequently, in welfare losses. Therefore, comparison of option 0 with the reference case can indicate the level of distortion due to implementing these tariffs.

In the current situation, some countries (i.e., Spain, Finland, France, Portugal, Denmark and Norway) have implemented an energy-based G-tariff whereas some other countries (i.e., Ireland, Sweden, Slovakia and the UK) have implemented a capacity-based G-tariff. Table 4 presents the impact of option 0 (compared to the reference case) on generation investments, power generation, import/export flows and average electricity prices in European countries, whereas Table 5 presents the impact of option 0 on producer surplus, TSO surplus, consumer payments, system costs and total tariff costs in European countries.

The results can be summarized as follows:

- *Generation capacity and investments:* The capacity-based G-charges result in additional fixed costs for both the existing and new generation capacity. Therefore, they affect the amount and location of new generation investments as well as the decommissioning of existing units in countries with such charges. Since the existing generation capacity and the renewable capacity assumed for the background scenario are sufficient to cover the peak demand in these countries, additional generation investments are not needed in the reference case. Therefore, the direct impact of a capacity-based G-charge on generation investments is not observed for this scenario. However, the countries with a capacity-based G-charge are affected mostly through decommissioning of their existing peak generation (e.g., gas turbines). In particular, the peak units which run a few hours a year cannot cover their fixed (operational and maintenance) costs anymore and, therefore, they are decommissioned. Among the countries with a capacity-based transmission tariff, the largest amount of decommissioning of conventional power plants is observed in the UK (2.2 GW of peak capacity) followed by Ireland (0.4 GW) and Slovakia (0.2 GW).

- *Wholesale electricity prices:* Both energy and capacity-based G-charges result in increased wholesale electricity prices in most EU countries either directly or indirectly via tariff-induced changes in power imports/exports:
    - The energy-based G-charges increase electricity prices via an upward shift of the marginal cost curve of generation in the countries applying these charges. This decreases the competitiveness of generation in these countries. Hence, they increase their imports from neighbouring countries with lower generation costs. As a result, total generation in countries applying energy-based G-charges decreases and their net power imports increases. For instance, Spain increases its power imports from France but exports more electricity to Portugal (which has also implemented an energy-based tariff). In addition, countries without a G-based tariff that export to countries with a G-based tariff are also affected by higher domestic electricity prices.
    - The decommissioning of peak capacity in countries with a capacity-based G-charge results in an increase in peak prices in these countries. In addition, other countries (without a G-charge) exporting to these countries during peak hours are also affected by increased electricity peak prices.

- *Impacts on producers, consumers, and TSOs:* As a consequence of the increase in electricity prices, the producer surpluses and consumer payments increase in most European countries. Producers are better off due to higher prices in these countries while consumers are worse off due to the resulting higher consumer payments (i.e. lower consumer surpluses in the countries concerned). This indicates that most of the

G-charges are passed on to consumers via increased electricity prices. The TSO surplus increases as well in most of the countries due to increases in cross-border flows, congestion rents and/or G-based transmission charges.

- *Indirect impact on other countries via tariff-induced changes in import/exports of electricity:* As a result of increased imports from countries implementing an energy-based transmission tariff, there is an indirect effect on other countries due to tariff-induced changes in power imports/exports. The largest increase in net imports in option 0 is observed in Spain, in particular from France. As a result of the increased exports from France to Spain, the exports from France to other neighbouring countries decrease. On the other hand, the exports from Germany to France and other North-West EU countries increase whereas its exports to central and eastern Europe decrease. This results in more coal-based capacity investments and power generation in Italy and some countries in eastern Europe (e.g. Poland).

Overall, total annual system costs (i.e. annual operational expenditures plus the annualised costs of generation and transmission investment) increase by € 3 million per year in option 0 compared to the reference case. This is very small compared to the absolute cost of € 71 billion per year in all European countries. However, the total tariff revenues from G-charges in all countries sum up to € 666 million per year, implying that redistribution effects across individual countries are more significant. Effects differ clearly from country to country and border to border.

We believe that the limited distortive effects of variation of G-charges on cross-border competition of generators are at least partially due to the following factors;

- Current G-charge levels are generally quite low (energy-based G-charges are on average about 0.5 €/MWh), and only half of the countries currently applies G-charges in the sense of EU Regulation No 838/2010. If G-charge levels would be higher and/or the number of countries applying G-charges larger, effects would also be larger.
- Network congestion is already causing larger price differences between countries, overpowering small differences in G-charges across countries. Also other factors such as differences in fuel supply costs, national capacity mechanisms, taxes and levies, ability to relatively flexible allocate its capital and resources between potential countries and bidding zones drive dispatch and investment decisions of generators and may overpower effects of variation in G-charges.
- Since the optimal levels of G-charges are not known[11], distortions have not been compared with a situation with G-charges set at their optimal levels i.e. inducing minimization of overall European system costs in the long run but rather with a situation without G-charges.
- The COMPETES model assumes that renewable energy is fully policy driven i.e. exogenous and not determined by modelling. Hence, the G-charges do not affect decisions of investors in renewables and therefore subsidy levels, implying that part of the impacts are not captured by the model. A different assumption would be that RES is affected by different G-charge policies of countries. However, this is also not realistic, since RES generally still operates outside markets.
- G-charges are in practise levied by national specific and very detailed rules that often determine the G-charges for different types of producers. As holds for all electricity market models, very detailed policy rules cannot be captured in quantitative analyses, hence we had to refrain to one average G-charge for all types of producers.

[11] Modelling of the optimal level of G-charges is an additional challenging task, which was not foreseen and falls outside the scope of the project.

- The model does not take into account the distortive effects of L charges on investment and operational decisions of consumers. Therefore it is a partial analysis.

Although distortions on cross-border competition due to G-charges *currently* are limited, we deem it likely, that distortive effects of variation of G-charges on competition and overall system efficiency will increase in the (near) future for two reasons. First, the increase of transmission capacity between and within countries means that higher transmission costs are expected in the coming years and decades. If network costs are not levied on generators this will increase system inefficiencies as generators are not incentivised to take into account system/network costs in their generation decisions. Besides, the progress that is expected in creating common internal electricity markets for different time frames (i.e. from year-ahead future markets to real-time balancing markets) given the EC CACM guideline and other legislation implies that cross-border competition will further increase, making variation of G-charges a more prominent factor in dispatch and siting decisions of generators. On the other hand, in a future where differences in national generation policies remain and national capacity mechanisms are more widely introduced distortions of generator decisions due to G-charges could still be overpowered by other factors such as market price differentials and differences of taxes and levies. Furthermore, in the absence of new policy measures, implicit regulatory convergence on low G-charge levels implies that competition distortions of G-charge policies will remain limited as well.

As a conclusion, differences in G-charges may contribute to the cumulative competition distortion effect and tackling them can make a difference, even if the effect would be small if they were to be tackled alone. At the same time, limited coordination of national G-charges is more likely to result in long term system inefficiencies with detrimental effects on European citizens rather than competition distortion effects for generators.

Table 4 Impact of option 0 (compared to the reference case) on generation investments, power generation, import/export flows and average electricity prices in European countries

	Energy tariff	Capacity tariff	Generation Investments	Generation	Net imports /exports	Average Prices	ΔGeneration Investments	ΔGeneration	ΔNet imports /exports	ΔAverage Prices
	Euro/MWh	Euro/MW	MW	TWh	TWh	Euro/MWh	MW	TWh	TWh	Euro/MWh
BE	0	0	0	36	57	61	0	0.04	-0.05	1.29
CZ	0	0	1956	94	-20	56	-327	-2.35	2.34	0.01
DK	0.4	0	0	15	1	59	0	-0.11	0.11	1.36
DKW	0.4	0	0	27	-4	59	0	-0.14	0.14	1.36
FI	0.9	0	0	98	-7	58	0	-0.18	0.18	1.37
FR	0.19	0	0	567	-121	61	0	-0.03	0.03	1.63
DE	0	0	0	565	-9	59	0	0.12	-0.17	1.33
IE	0	7041	0	31	7	63	0	0.18	-0.18	1.44
IT	0	0	4543	294	60	60	200	1.79	-1.80	0.00
NL	0	0	0	127	-6	59	0	-0.02	0.02	1.29
PL	0	0	4503	199	-25	56	487	3.15	-3.14	0.04
PT	0.5	0	0	38	19	61	0	-0.69	0.69	0.29
SK	0	2700	0	38	-7	52	0	-0.02	0.02	-0.05
ES	0.5	0	0	288	28	61	0	-2.44	2.46	0.29
SE	0	3913	0	179	-32	59	0	0.02	-0.02	1.42
UK	0	8560	0	265	65	64	0	0.53	-0.53	1.54
CH	0	0	0	55	14	60	0	0.00	0.00	0.07
NO	1.04	0	0	135	-4	59	0	-0.10	0.10	1.43
BLK[a]	0	0	0	358	-23	54	0	0.02	-0.02	-0.01
BLT[b]	0	0	0	30	2	57	0	0.01	-0.01	0.20
AT	0	0	0	70	4	58	0	0.18	-0.16	0.08

a) BLK = Balkan countries
b) BLT = Baltic countries

Table 5 Impact of option 0 (compared to the reference case) on producer surplus, TSO surplus, consumer payments, system costs and total tariff costs in European countries

	Producer Surplus	TSO Surplus	Consumer Payments	System Costs	Tariff Costs	ΔProducer Surplus	ΔTSO Surplus	ΔConsumer Payments[a]	ΔSystem Cost	ΔTariff Cost	ΔSocial Welfare
	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro
BE	1290	61	5725	990	0	73	0	120	3	0	-48
CZ	2447	64	4103	2767	0	1	13	1	-127	0	13
DK	391	7	920	493	2	20	2	21	-6	2	1
DKW	1015	28	1381	515	2	16	2	32	-8	2	-14
FI	4051	48	5333	1561	44	67	48	125	-7	44	-10
FR	28435	391	27411	5430	80	578	137	729	-2	80	-14
DE	18890	205	32914	13657	0	549	81	740	9	0	-110
IE	1162	50	2448	837	42	16	42	56	11	42	3
IT	8579	111	21118	9199	0	2	9	0	106	0	10
NL	4177	44	7157	2602	0	129	0	155	-1	0	-26
PL	4343	52	9712	6702	0	2	13	6	174	0	8
PT	1735	4	3432	622	4	6	4	16	-42	4	-6
SK	1513	52	1634	460	12	-14	12	-2	-1	12	0
ES	12498	224	19242	5194	66	14	111	91	-144	66	33
SE	8608	59	8636	1717	31	160	35	208	1	31	-13
UK	8938	510	21122	7752	382	45	382	507	30	382	-80
CH	3082	77	4133	257	0	5	23	5	0	0	23
NO	7899	36	7810	153	0	199	0	188	-6	0	10
BLK	10472	116	18177	9038	0	-4	1	-4	2	0	1
BLT	1139	12	1820	602	0	8	7	6	0	0	8
AT	3152	113	4300	1014	0	7	42	6	11	0	43
Total	133815	2266	208527	71563	666	1877	964	3008	3	666	-166

a) A change in consumers payments is the opposite of a change in consumers surplus

3 ELABORATION OF TRANSMISSION TARIFF POLICY OPTIONS

3.1 Overview of the policy options

In addition to the current policy regime on transmission tariffs ('Option 0 – Baseline' , as outlined in the previous chapter), five alternative policy options are identified for a detailed impact assessment (see next chapter). These alternative policy options are discussed briefly below under the following headings:

1. ACER G-Charge opinion of April 2014: replacing energy-based by capacity-based or lump-sum G-charges;
2. Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity;
3. Location-based charging;
4. Harmonised charges related to AS, losses, and grid connection;
5. Harmonised G:L split.

3.2 Option 1 – ACER G-charge opinion of April 2014: Replacing energy-based by capacity-based or lump-sum G-charges

As set out in the ACER opinion, this option would, principally, prohibit the transmission charges that can be levied upon producers based on energy injected, and replacing these by either capacity-based or lump sum transmission charges on producers. Please note that for those countries affected the G:L split is kept the same, and other countries that currently levy only capacity-based and/or lump sum transmission charges on generators (i.e. IE, NI, SE, SK, and UK) would also not be affected by this option. Following Regulation (EC) No 838/2010, transmission charges which are used for recovering the costs of system losses or costs relating to ancillary services remain excluded from harmonization; hence countries which are levying energy-based transmission charges on producers for these cost items are not affected.

Selection of this option is likely to have a number of implications. First of all, when grid infrastructure costs are no longer recovered through energy-based transmission charges, distortion of short-term market decisions cannot longer take place. Secondly, prohibiting the transmission charges that can be levied upon producers based on energy injected also means that the current upper limits to G-charges of part B of Regulation (EC) No 838/2010 have to be converted from energy to capacity based or lump sum G-charges.[12] It is unlikely though that ACER and/or EC has to actively intervene in order to prevent that G-charges exceed the upper limits of the Regulation, since cross-border competition between generators induces regulatory convergence between MS and thus serves as an implicit upper limit to all types of G-charges.

Given the efforts made to establish the Energy Union and more specifically the internal electricity market, structural congestion is likely to decrease while cross-border competition between generators is likely to further increase, preventing large divergence of G-charges within the EU, notably within meshed areas. Given the expected decrease of structural congestions and further increase of price convergence, if in some Member

[12] Article 2 of part B of Regulation No 838/2010 does not distinguish between transmission tariffs to different types of G-charges, but instead considers the total annual income received by TSOs from transmission tariffs. In practice this would mean that the denominator of the calculation formula of G-charges should be converted from MWh of total annual energy injected in the transmission grid to total MW of capacity connected to the transmission grid.

States a significant G charge would be in place while this in other countries not being the case, generators would site new plants in (neighbouring) countries with significantly lower G-charges. In order to prevent this happening, Member states are inclined to protect the generators situated in their countries by not introducing significant G-charges (especially for peak power plants as this would affect national generation adequacy) , and thus the level of G-charges is to some extent disciplined by cross-border competition between generators. Some experiences are supporting this; for instance in the Netherlands, G-charges in place (covering 25% of total transmission costs) were abolished in 2004 in order to lift the competitive disadvantage for Dutch generators connected to transmission networks. In Belgium, recently a provision has been added in legislation for adaptation of G-charges, obliging the NRA to take into account the impact of adaptation of G-charges on the level playing field of generators. Presumably at least in other countries with equal or higher shares of electricity interconnection capacity in installed electricity generation capacity (see section 5 of the report) the impact of G-charges on the level playing field of generators is also an important policy consideration.[13]

Furthermore, some careful choices need to be made in the design of capacity-based G-charges. These charges should be tuned to the actual situations that are stressful for the network. In case capacity-based G-charges are time independent and based upon the maximum yearly capacity connected to the grid, or the maximum (yearly or monthly) production during system peak demand conditions, G-charges levels may be suboptimal because they do not provide an incentive to prevent stressful grid situations with abundant power supply (the notorious windy and sunny Sunday morning with low power demand). Hence, G-charges should be differentiated to excess and shortage situations e.g. by carefully defining system peaks and lowering G-charges for those generators that operate outside those peaks.

Also the choice between capacity-based and/or lump sum transmission charges for generators deserves attention. Some stakeholders prefer energy-based or lump sum transmission charges since capacity-based charges may be detrimental to investments in peak power plants and RES-E with low load factors (see e.g. THEMA (2015)[14]). In case energy based G-charges are replaced by lump sum G-charges, it depends on the design of these tariffs whether or not generation investments are affected. If lump sum G-charges are differentiated according to the load factors of generation technologies, generation investment costs do not change, and therefore the generators' investment decisions. Instead, if lump sum G-charges are not differentiated according to the load factors of generation technologies or energy-based charges are replaced by capacity-based G-charges this would result in higher G-charges for those plants with lower load factors. On the other hand, the network is dimensioned on the peak demand for network capacity, hence capacity-based G-charges would be considered as optimal, and energy-based G-charges as implicitly subsidising power plants with low load factors. Moreover, a technology specific approach to G-charges would be contradictory towards the principle of technology neutrality which is considered to be a core principle in electricity policy to ensure that regulation does not stifle technological developments or that regulators are not tasked with picking winners. At the same time, one could imagine a gradual move from energy-based to capacity-based charges in order to prevent large redistribution effects between different types of generators at once.

[13] Unfortunately, reporting on network tariffs is scarce and often only done nationally in national languages, in different types of publications. Hence, we did not find relevant information on policy considerations in other countries.

[14] THEMA (2015), Harmonisation of generator tariffs in the Nordics and the EU, report commissioned by Fortum, Skelleftea Kraft, Statkraft and Vattenfall, Report 2014-43, January 2015.

Having said that, please note that this policy option does neither mean that G-charges will be implemented nor that they will be set to their optimal long run cost-reflective level i.e. the level that stimulates generators and consumers to take investment and siting decisions that minimize overall system costs, which is the sum of generation, network, and societal costs. Rather it is likely that the G-charges of the largest MS in Continental Europe are becoming the benchmark, and therefore national policy goals of some MS rather than the EU policy goals. In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), therefore this option should be considered as only one aspect of potential future coordination or harmonisation.

3.3 Option 2 – Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity

This option would set out a path that should be followed in order to create a set of principles to govern the arrangements for transmission charging. The cost reflectivity principle seems the core principle to achieve a level playing field for generators across Europe and is therefore the main principle that will be discussed. Potential trade-offs with other principles such as cost recovery and tariff predictability will be highlighted in the discussion. This would allow either the EC or ACER to provide guidance for progressive harmonisation of transmission tariffs as envisaged by article 18 (2) of EU (2009), which states that 'Guidelines may also determine appropriate rules leading to a progressive harmonisation of the underlying principles for the setting of charges applied to producers and consumers (load) under national tariff systems, including the reflection of the inter-transmission system operator compensation mechanism in national network charges and the provision of appropriate and efficient locational signals, in accordance with the principles set out in Article 14 [Charges for access to the network] …'.[15]

The development of cost reflectivity principles for transmission charging is a challenging task because of physical and economic reasons. A physical reason is that electricity is a flow and behaves according to Kirchhoff laws i.e. an energy flow fans out over all possible routes, which prevent the definition of an equivocal transport route. Furthermore, when two market transactions cause counter flows in the network, the effective physical network load will be less than each of the flows separately, implying that the network effect of a transaction is influenced by transactions of many other market participants. Both physical principles heavily complicate a system of network tarification. An economic reason are market failures such as economies of scale of network reinforcements and oversizing of the network to ensure reliability, implying that transmission systems that would be solely based on marginal costs do not fully recover transmission costs. Hence, in practice marginal pricing signals, through market prices as well as transmission tariffs (e.g. for losses, congestion and ancillary services), are complemented by transmission charges to recover the residual network costs. In this way, full cost recovery of efficient network costs of TSOs is guaranteed. Furthermore, in practise transmission network users do not want to face highly fluctuating tariffs as this makes predictions of their future business conditions burdensome (PJM, 2010).[16] Hence, when developing cost reflective principles for transmission charging EC and ACER should take into account potential impacts on tariff predictability for transmission network users.

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

16 PJM (2010), A Survey of Transmission Cost Allocation Issues, Methods and Practices.

Given these challenges for the development of cost reflectivity principles for transmission charging, let us discuss cost reflectivity for each step of transmission charging policies (cf. Chapter 2):

1. Cost categories included in allowed revenues and recovered by transmission tariffs;
2. Allocation of transmission costs to production and consumption (Generation/Load split);
3. Allocation of costs to specific network users (energy based and capacity-based tariffs, connection and UoS charges, uniform versus time-of-use and/or locational differentiated charges).

Provided that the charging elements of steps 2 and 3 are discussed as part of other policy options,[17] this option is focussed on step 1 i.e. which cost categories should be included in transmission charges. As shown in Section 2.1, a large diversity exists between Member States concerning the costs for infrastructure, system services, and losses taken into account in transmission charging. As a result, transmission charges are affected in at least two ways. First, in some Member States transmission charges do not reflect some cost components of infrastructure costs, system services, and losses. For example in Italy and Poland, inter TSO compensation (ITC) costs are not included in infrastructure costs. Second, transmission charges differ as costs are established using a diverse set of methodologies, e.g. in some countries based upon historic costs, while in others based upon forward looking costs.

For increasing cost reflectivity, options include;

- Prescriptions for network cost items to be included in national transmission tariffs in order to improve comparability between transmission tariffs;
- Regulatory accounting guidelines for the treatment of infrastructure costs components, e.g. for depreciation policies, investment timing, and ITC costs;
- Transparency measures such as unequivocal obligations to TSOs and NRAs for data gathering and consistent reporting regarding;
  - Total allowed revenues
  - Actual network costs incurred to the system by groups of network users
  - Level and structure of transmission tariffs for different user categories as well as the methodology that is used by a TSO to derive transmission tariffs. The current ENTSO-E overview reports only EU-wide results for the so-called unit transmission tariff i.e. for one type of generator, without consistent and comprehensible information about the methodological steps applied to derive the result.

Such options can be enforced by different legal instruments. The most appropriate legal instrument would be a binding legislative document (e.g. regulation), as non-binding documents (guidelines, opinions, and even directives) can still lead to diverging implementation practices and hence suboptimal results from an EU perspective.

[17] Please refer to options 1, 4 and 5. Time-of-Use differentiation of transmission charges is not discussed in this study.

3.4 Option 3 – Location-based transmission charging

This option would introduce an EU wide requirement that transmission charges include a locational element reflecting, in particular, transmission cost differences and constraints within a bidding zone (See Section 2.1).

Status quo in Europe

Transmission tariff structures in Europe currently include locational elements in only 5 Member States: GB, Ireland, Norway, Sweden and Romania.

The exact method of applying locational signals differs between countries although, at least in the case of GB, Norway and Sweden, locational signals reflect a distinct pattern of generation and demand location – i.e. long transmission distances between generation areas located in the north of the country and demand centres located in the south. In Sweden, for example, G-charges decrease linearly with latitude (from north to south) while load charges increase with latitude (from south to north).

In Romania, the country is split into seven generation areas and eight load areas with charges reflecting surplus and deficit areas. The generation tariff includes a component to cover the short-term marginal costs related to grid losses and congestion and a second component that is based on installed capacity to recover network operating and infrastructure costs.

GB has in April 2016 introduced changes to the incremental cost method it uses to set locational transmission tariffs for load and generation, in order to take account of changing patterns of use of the network mainly due to the development of intermittent RES. More detailed information on the British scheme is provided hereafter.

Lessons learned from the experience with location based Transmission Network Use of System (TNUoS) charging scheme in GB

The costs incurred in investing in and maintaining the transmission system are in GB recovered by the TSO from generators (G-charges) and suppliers (L-charges); generators pay at present about 27% of the total charges recovered under the TNUoS charging scheme and suppliers pay the remaining 73%.

The TNUoS charging scheme comprises 2 tariff components applicable to generators, a local tariff and a wider tariff, which comprises a locational element (variable according to which of the 27 zones where the generator is situated) and a residual element. Both conventional and intermittent generators pay the TNUoS charges.

In order to better take account of the actual and expected evolution of the generation fleet and not to hinder the deployment of RES investments, a review of the locational tariff component has been implemented in April 2016, which is, according to the assessment of Ofgem, more cost reflective and better reflects the effective impact of generation on the transmission system. The new investment related pricing methodology should also lead to more stable and transparent tariffs. These are considered as important aspects to reducing barriers to entry and facilitating effective competition.

In the new scheme, the locational element in the tariff has been divided into 2 components: a Peak Security Tariff and a Year Round Tariff. The Peak Security Tariff has to be paid only by conventional generators and is supposed to reflect the fact that grid investment planning decisions are based on the need to ensure that the grid has the capability of transporting sufficient electricity to meet peak demand. As it is supposed that only conventional generators can be relied upon to meet peak demand, the demand security criterion provides that investment decisions are based on the need to ensure that sufficient conventional generation capacity can be conveyed over the transmission system at peak times.

The Year Round Tariff has to be paid by all generators and is supposed to reflect the investment cost incurred by the TSO to avoid system congestion due to injection into the grid. This tariff comprises 2 components: the non-shared component is based on the generating capacity and applies where there is a high concentration (> 50%) of generators in an area that receive low carbon support, while the shared tariff component is based on the average annual load factor and reflects the likelihood that installations with a high load factor cause more grid constraints and hence lead to higher grid investment costs.

RWE Generation UK plc had in July 2014 introduced a claim for judicial review of this tariff change decision, arguing that it would lead to unlawful discrimination as it involves differential treatment of conventional and intermittent generators, while intermittent generation in practice also contributes to meeting peak demand. This claim was in July 2015 dismissed by the High Court.

Ofgem pointed to the regulatory advantages in differentiating charges to broadly reflect the costs that different users place on the system. Charging generators different costs for using the transmission system in different locations (as they have different impacts on the transmission system) leads to a better outcome for consumers in the long term. From a regulatory perspective, Ofgem also found no compelling case to move to a uniform national network charge.[18]

This British experience definitely offers useful input to evaluate a possible EU wide introduction of locational transmission charging, as it illustrates the need to properly design transmission tariffs in order to reflect the changing nature of the electricity system and market and in particular the increased penetration of RES. However, its results cannot be extrapolated as such to other EU regions, due to the specific situation of GB (limited cross-border interconnection capacity, introduction of locational transmission charging before privatisation of electricity generation, structural power flows from north to south). As the electricity generation sector is in Europe meanwhile to a large extent privatised, an EU wide implementation of a similar scheme might provoke judicial proceedings from generators that would have to pay higher charges. Moreover, as the grids are in most EU regions highly meshed and integrated, and power flows becoming less predictable due to the increasing share of intermittent RES, the implementation of locational transmission would be highly complex in most EU Member States. The major impacts of this option are further evaluated in Section 4.1.4.

Possible sub-options for a harmonised implementation of location based transmission charges for generators across Europe

Based on the current practices, the following sub-options could be considered for harmonised implementation across Europe:

- Capacity based fixed (annual lump sum/kW) or time related (different annual rates/kW per period, e.g. peak/off peak, winter/summer,…) transmission charges differentiated per area based on the long term marginal grid cost;
- Capacity based fixed or time related transmission charges differentiated per individual power generation installation based on the long term marginal grid cost;
- Energy based time related charges differentiated per individual installation based on the short term marginal grid cost (mainly grid losses).

18 Debate pack House of Commons (2016), Regional differences in energy network charges.

This third sub-option is further elaborated and evaluated in Section 3.5.2. Locational signals can also be offered via differentiated connection charges; this sub-option is elaborated and evaluated in Section 3.5.3.

In order to avoid distortions, harmonised grid tariff principles and methodologies should equally apply to all generation types (both to RES based and conventional generation) and independently of the grid voltage level they are connected to. This would ensure a level playing field across Europe and avoid competition distortion amongst different generating technologies on the one hand and amongst installations connected to the HV or LV grid on the other hand.

Most grid tariffs are currently determined ex ante (in principle year ahead) in order to offer a high predictability to market participants (and to facilitate market transactions) and TSOs (to cover their actual costs). Variable grid tariffs could be determined day ahead or intraday (e.g. hourly tariffs) in order to reflect the actual cost of grid losses and/or measures to prevent/reduce congestion; such an approach would be more cost reflective and offer more efficient price signals to operators, but it might not offer the required predictability to market operators and its implementation would be highly complex.

Legal provisions at EU level with regard to locational transmission charging

Article 14 of Regulation (EC) 714/2009 explicitly refers to locational transmission charging. It states that charges applied for access to networks "shall be transparent, take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. Those charges shall not be distance-related. Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals."

Pros and cons of locational transmission charging

The "Transmission charging options draft paper" published by Ofgem in 2010 comprises a useful overview of the main arguments for and against locational transmission charging.

Arguments pro:
- It can help to fill the gap by efficiently signalling where there is scarcity or oversupply.
- Locational charging schemes give economic signals about where to site new generation capacity and use existing capacity, and reflect the costs to the transmission network that generators cause.
- A locational charging system is cost reflective, i.e. it reflects the effective costs that system users cause to be incurred for building, developing and maintaining the grid system, and allows to minimise the overall cost to the consumer.
- A locational charging approach is designed to encourage generation close to consumption. It is intended to send signals to generators on where to locate, to minimise the energy losses from transmission over long distances, and helps to ensure the grid network does not become constrained.
- Locational charging is supposed to deliver the most cost effective system. The charging mechanism is not designed to facilitate and encourage renewable energy development and to deliver a broader mix of energy supply. A range of specific incentive mechanisms, such as RES schemes, exist to contribute to this objective.

Arguments against:
- Opponents argue that locational charging would be designed to reflect a generating mix predicated on generation close to centres of demand, and that it would not

encourage the shift to a more mixed and geographically spread energy supply, including a significant renewable energy share, as the largest potential of renewable energy is in general in parts of the territory distant from main demand centres. It can also be considered as a barrier to developing renewable energy generation in peripheral parts of the network.

- Opponents of locational charging also argue that it is failing to achieve the purpose for which it was created, since evidence suggests that locational decisions are mainly taken on other grounds than transmission charging systems. According to different studies, 75 to 80% of the expected investments in 2020-2050 in generation capacity will concern RES based assets, in particular solar and wind energy; the location of these plants is mainly influenced by the availability of suitable sites and favourable meteorological conditions.

Taken together, these arguments suggest that a simplistic locational charging system would perhaps not be wholly fit for purpose to deliver a low carbon energy mix and ensure security of energy supply for the next decades. As the costs of grid development are ultimately borne by consumers, there is a need to ensure that locational signals will reflect the costs of the future system, the changing energy mix and efficiently support the integration of renewables. This may need to include some considerations on load factors and time of use considerations. To ensure that the consumer is protected from unnecessary costs in grid development, a reasonable proportion of the costs should be placed on generators and the development of the grid should be efficient and economic, while facilitating a balanced energy mix, including a significant amount of renewable energy.

Main findings of other studies on locational transmission charges

The Brattle Group assessed in 2007 the option to introduce location based G-charges in the Netherlands.[19] The study concluded that such a scheme would create windfall gains and losses to existing generators. Generators in congested areas that would be faced with higher G-charges would oppose to the new scheme; this resistance could substantially delay the introduction of a locational G-charge, so that this policy would not be an effective solution to mitigate congestion. The Brattle Group referred in this context to the introduction of a zonal losses scheme in the GB market, where resistance from generators has delayed the scheme for 18 years. While the GB market currently does have a system of locational G-charges, these were introduced before privatisation, when the electricity supply industry was state owned. Accordingly, the introduction of locational G-charges in the GB market did at that moment not create winners and losers. Moreover, the UK has limited interconnection with other countries, and therefore less concerns with potential distortion of investment. The experience of the UK shows that the decision to introduce locational signals can provoke litigation that might hinder or delay an effective implementation of the measure. The introduction of stable, long-term signals would entail some system of financial risks and rewards for the TSO, which can be done and may even be interesting as a long term goal, but would be extremely complex to design. The Brattle Group considered that a policy of locational G charges would make sense, but it would require co-ordination with neighbouring countries and a fundamental change in TenneT's regulation. As there was little confidence in the ability of authorities to implement such reforms in time to address the problem of network congestion, the Brattle Group did not recommend introducing location based G-charges in the Netherlands.

[19] The Brattle Group (2007), A review of TenneT's connection policy (in particular Appendix VIII Resistance to locational signals in the GB market). The conclusions of this study of 2007 are still relevant as grid congestion is a highly critical issue in Europe that could be mitigated by locational grid tariff signals.

NERA Economic Consulting and Imperial College London concluded in their 2014 study[20] for RWE npower that efficient locational signals are important in competitive power markets for ensuring that investors make an efficient trade-off between their own costs and the costs of transmission infrastructure, constraints and losses that their presence imposes on the system. One means of sending efficient locational signals to generators is through LMP, whereby energy prices reflect the SRMC of generation and transmission at each node on the network. However, while the efficiency advantages of LMP are well-established in academic literature on electricity market design, at present there is no locational pricing of energy in the British electricity market. In the absence of LMP (or any other form of zonal energy pricing) efficient signals regarding the SRMC of energy can still be conveyed to users through transmission infrastructure charges. If the transmission system is planned optimally, then the SRMC of energy can be approximated by the LRMC of transmission, and signalled through infrastructure charges set to reflect LRMC.

Poyry points in its study for EDF Energy[21] to the need for transmission charges to encourage efficient grid investment, in order to provide value to consumers, especially given the expected future expansion of the grid. Transmission charging arrangements will continue to be a critical driver of efficient transmission investment going forward. This suggests that it is appropriate for some form of variable location-based transmission charges to be retained in order to promote efficient generation investment decisions and consequently grid development. Charging arrangements affect generation investment decisions, but they are only one tool amongst many in this context.

FTI Compass Lexicon has in 2015 assessed the introduction of location based grid charging in France and Europe.[22] The study concludes that a possible review of the bidding zones should be assessed at EU level, but that implementation difficulties and costs should be duly taken into account in the CBA. FTI also recommends a further harmonisation at EU level of the energy based G-charges (in particular by including the grid losses), and suggests to study at EU level the issue of capacity based G-charges, in particular in relation to the capacity remuneration mechanisms. FTI recommends to the French authorities not to integrate the congestion costs into the grid transmission charges, as a variable tariff based on actual congestion costs would be too complex. FTI however suggests to further assess the introduction in France of a variable and geographically different energy based G-charge to cover the grid losses, and finally also recommends to study the possible introduction in France of a capacity and location based tariff component to optimise the location of future investments.

An academic study report (2011) commissioned by the British NRA Ofgem in the context of its Project TransmiT, recommended that all network costs should be allocated to load, rather than the then applicable 27/73% split between generation and load. In the end, costs paid by generators are passed on to consumers in the prices charged by generation unit owners, which can also lead to distortions from the least cost supply of wholesale energy. Together with elimination of locational differentiation, full allocation of these costs to load will considerably simplify the TNUoS system and limit the risk that the transmission charging mechanism reduces the efficiency of the wholesale energy market. Furthermore, this change would bring GB's charging system into closer alignment with those in neighbouring countries, which will help level the playing field in

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[20] NERA and Imperial College (2014), Assessing the cost reflectivity of alternative TNUoS methodologies.

[21] Poyry (2010), Electricity transmission system charging: Theory and international experience.

[22] FTI Compass Lexicon (2015), Analyse des signaux de localisation dans la tarification des réseaux et de leur applicabilité en France et en Europe.

the international competition between GB and non-GB generation.[23] Following this study, Ofgem launched a consultation in December 2011 on this proposal, and decided in May 2012, based on its assessment of the stakeholders' opinions and evidence provided, not to alter the G:L split at that stage, but asked the TSO to keep it under review and make proposals for change as and when necessary through the normal amendment process. Since then, the principle of allocating part of the transmission cost to generators has been maintained but the G:L split has been slightly adapted to 23/77% in 2015.

The current capacity and location based transmission charging system in Sweden has been assessed by Thema Consulting Group.[24] The consultant recommends to consider making generator tariffs uniform regardless of grid and handle the necessary price signals through connection charges, area prices and energy charges based on marginal losses. Thema also concludes that it would be better to move from capacity based generator charges to a lump-sum energy charge, for instance based on historical generation. Thema finally recommends to avoid geographical price signals in the G-component.

Cambridge Economics Policy Associates concludes in its study[25] for Ofgem that the value of locational signals for generator siting decisions is useful in some but perhaps not all cases. As utility systems have evolved from centrally planned and controlled entities to decentralised and often competitive industries, concerns have grown about the use of locational pricing signals for generation. This is in part because, while centralised planning could take into account the full internalised system costs of siting decisions, decentralised planners will, absent other constraints, only take into account externalised costs. While externalising such costs is important, these price signals might in some cases be secondary to other considerations. For example, some generation types are strictly limited by planning rules regarding siting (e.g. nuclear) while others are resource-following (e.g. wind). Even so, while externalising locational costs might not influence choices of site for such generation options, they should play a role in overall project development decisions in the planning stages, and in terms of operational decisions once projects are built.

Several stakeholders and experts consider in general that nodal pricing would be a more effective and efficient option than location based transmission charging to offer adequate locational signals to investors. IEA states in its study[26] that in Europe, nodal pricing would reduce the generation cost by 1.1% to 3.6% (Neuhoff et al, 2011), but that applying nodal pricing across multiple jurisdictions may be a complex and lengthy process. For the time being, market coupling in Europe is a much simpler procedure. Zonal pricing captures some of the benefits of LMP with a simpler definition based on the observation that most network congestion in Europe occurs mainly at the borders between different system operators' areas. Looking forward, increasing shares of variable renewables located far from consumption centres may lead to new grid congestions and increase transmission losses, in particular if network investments lag behind renewable energy deployment. With higher shares of renewables, nodal pricing could bring more cost savings. Indeed, nodal pricing allows differentiating the value of different wind farms according to their impact on network congestion of network losses.

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23 Ross Baldick, James Bushnell, Benjamin F. Hobbs, and Frank A. Wolak (2011), Optimal Charging Arrangements for Energy Transmission.

24 Thema Consulting group (2015), Harmonisation of generator tariffs in the Nordics and the EU.

25 Cambridge Economic Policy Associates (2011), Review of international models of transmission charging arrangements.

26 Manuel Baritaud IEA (2012), Securing power during the transition – Generation investment and operation issues in electricity markets with low-carbon policies.

LMP can also provide locational signals for investment in new renewable generation. In addition, in case of excess supply, LMP would lead to curtail first wind turbines located in nodes at the origin of congestion or higher network losses.

The different studies do not present converging opinions. Most studies point to the need for transmission charges to encourage efficient operational and investment decisions, but some studies conclude that locational transmission charging can be an appropriate measure to reach this objective while others consider a review of the bidding zones and nodal pricing as a more adequate solution. We can conclude that the implementation of locational G-charges across Europe could be an appropriate option from an economic and technical perspective, but it would require a fundamental change in national tariff regulations, and the tariff structures should be properly designed in order to avoid a negative impact on the development of RES based installations and on the cost and availability of back-up or peak capacity which is needed to ensure system and supply security. In a future electricity system with higher shares of decentralised and renewable energy based installations, capacity and flexibility availability at the right place and moment are key to minimise the overall short and long term system costs. Location and capacity based grid tariffs, both for generation and demand, can contribute to reaching this objective, but as the characteristics of the electricity systems are quite different across Europe, a mandatory implementation in all EU Member States of a simplistic location-based transmission grid tariff scheme for generation would require detailed consideration and, on the basis of the different studies at present, is not considered an appropriate option. A comprehensive impact assessment of option 3 "Location-based transmission grid charges" is provided in Section 4.1.4.

3.5 Option 4 - Harmonised charges related to ancillary services, TSO grid losses, and grid connection

Network charges related to ancillary services, TSO grid losses and physical assets required for connection to the system are currently not covered by the G-charges legislation (Regulation 838/2010).

In this section, we will illustrate that the charging principles and modalities that are currently applied by the different regulators and TSOs are largely diverging across Europe, which suggests that the criterion of cost-reflectivity is not consistently interpreted and which leads to distortions amongst power generators that are competing in integrated supranational markets.

We will for each of these items shortly describe and evaluate the current situation, identify the relevant legislation at EU level, summarise the outcome of other studies on this topic and finally propose possible options for harmonisation at EU level. The evaluation of the different sub-options is provided in chapter 4.

3.5.1 Ancillary services: balancing and non-frequency ancillary services

Status quo in Europe

Costs related to balancing services (Frequency Containment reserves and Frequency Restoration reserves) and non-frequency ancillary services (local congestion management, steady stage voltage control, fast reactive current injections, synthetic inertia, short circuit power and black start capability) are recovered either through the electricity market (generators are for instance in some MS legally obliged to make balancing reserves available to TSOs in the framework of their grid access contract) or through the transmission tariffs (G and/or L-charges). In most countries, costs for balancing services are included in the overall transmission grid fee, except in Northern-Ireland, Ireland, Portugal and Switzerland, where TSOs apply specific tariffs for balancing and non-frequency ancillary services. The specific share of system services (charged to load and/or generation) in the overall transmission fees widely differs, from less than 0.5 €/MWh in some Member States (France, Sweden, Norway, etc.) to more than 3 €/MWh in other Member States (Northern-Ireland, Ireland, Spain, Czech Republic, Poland, etc.).[27] As this study focuses on harmonisation of transmission grid charges on generation, we will in the next section mainly focus on the ancillary services' cost that is or could be allocated to power generation.

In most Member States, the costs for balancing reserves and non-frequency ancillary services are recovered via L-charges, while the residual imbalance costs are allocated to the concerned balance responsible parties. Only in a few Member States, generators pay grid charges which comprise a specific contribution for the cost related to balancing services: Austria (2.81 €/MWh in 2015), Belgium (0.9111 €/MWh, which represents 50 % of the overall reservation cost for balancing services), Bulgaria (3.65 €/MWh to be paid only by wind and solar generators to cover the cost for balancing services), Finland (0.17 €/MWh), Ireland (0.3 €/MWh), Northern-Ireland (0.31 €/MWh), Norway (0.21 €/MWh – the costs for procuring balancing services are in Norway divided equally between generation and load) and Sweden (0.087 €/MWh).[28] In Great Britain, the costs incurred by the TSO (NGET) in balancing the transmission system are recovered through Balancing Services Use of System (BSUoS) Charges, which are shared equally between generators and suppliers.

This short overview illustrates the diversity in charging methodologies and cost levels for balancing and non-frequency ancillary services within Europe, which shows that Member States are differently interpreting the principles of cost reflectiveness, non-discrimination and transparency. The current tariff approach leads to competition distortion amongst generators, as for instance generators in Austria and Belgium have to pay a substantial share in the cost for balancing services, while their competitors in most other countries of the same interconnected and integrated wholesale market (CWE) do not have similar charges. National authorities are aware of this concern; in this context, a specific legal provision has recently been included in the Belgian electricity law which obliges the TSO and regulator to ensure that the level of G-charges should not exceed the average level in neighbouring countries.

We also notice that generators have become very sensitive for any impact of changes in charging practices on their competitiveness. For instance in GB, generators have expressed their concern that the disparity in charging arrangements of the balancing costs incurred by the TSO is putting them at a competitive disadvantage relative to other EU generators. For that reason, the British TSO has raised a code modification proposal (CMP201) to remove BSUoS charges from generators, leaving suppliers paying the whole charge. The proposal was intended to level the playing field between generators based in GB and elsewhere in Europe. All parties would still be liable for charges relating to their own imbalance.[29] Ofgem agreed on the fundamental economic principles put forward by this proposal, namely that in an open market, competition is increased if parties trade on an equal basis, and the opportunity of higher profit margins should attract additional investment (provided no other barriers to entry exist), but argued that there are uncertainties in the European market that could affect the impacts – both direction and magnitude – of this proposal. The proposed code modification was hence not adopted.

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[27] Based on chart 7.6. "Components of TSO costs of the Unit Transmission Tariffs" in ENTSO-E Overview of transmission tariffs in Europe, 2016.

[28] ACER, Internal Monitoring Report on Transmission charges paid by the electricity producers, May 2016.

[29] Ofgem - Impact assessment on CMP201 - proposal to remove balancing charges from generators – November 2013.

The diverging current cost recovery approach might also lead to an overall suboptimal operation of the European electricity system, as the related cost is not always charged to the grid users (L or G) that are responsible for it and market parties are hence not adequately incentivized to reduce the need for balancing services, among others by flexible and back-up capacity or demand response.

Relevant provisions in EU legislation regarding balancing and non-frequency ancillary services

There is at present no explicit legal provision at EU level with regard to the methodology for TSOs to recover their costs related to balancing and non-frequency ancillary services. There is only a reference in the EU legislation to the provision of balancing services. Article 37 of the Electricity Directive 2009/72/EC of 13 July 2009 concerning the internal market in electricity, provides that "regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for the provision of balancing services which shall be performed in the most economic manner possible and provide appropriate incentives for network users to balance their input and off-takes. The balancing services shall be provided in a fair and non-discriminatory manner and be based on objective criteria".

To what extent can generators be held responsible for balancing reserve costs?

The cost for balancing services is mainly related to the reservation and activation costs of balancing reserves to keep the electricity system permanently in balance and to be able to restart the system after a black-out ("black start"). Reserve activation costs are in general charged to the concerned balance responsible parties, while the reservation costs are in most MS socialised. However, these costs are in some MS partly charged to generators, based on arguments which are hereafter shortly commented.

The overall Frequency Containment reserve needs are determined by ENTSO-E at European level on the basis of the assumption that two power plants of 1500 MWe connected to the same bus bar can become unexpectedly and simultaneously unavailable. The Frequency Containment reserve that each TSO has to procure is determined by ENTSO-E on the basis of the annual production in its territory. The use of this criterion indicates that there is a link between the balancing reserve needs and generation, and that part of the related cost can hence be allocated to generation.

The capacity needs for the Frequency Restoration reserves and for non-frequency ancillary services such as black start are individually determined by the TSOs.

Frequency Containment and Frequency Restoration reserves are mainly necessary to cope with:

- the unexpected unavailability of power plants due to technical incidents
- the volatile character of generation based on intermittent RES
- deviations between nominated and actual consumption and production patterns
- synchronisation problems of cross-border programs for production increase in one country and production reduction in another country.

Balancing reserve is hence needed to cope with both production and consumption deviations. The respective share for L versus G could be determined on the basis of detailed assumptions and calculations, and the outcome would be different in each Member State depending on the characteristics of its generation and consumption park. Such an approach would be cost-reflective but very complex to implement.

Therefore, some Member States (Belgium[30] and Norway[31]) have opted for a fixed 50/50 split of the reservation cost for balancing services between generation and load, while the activation cost is effectively allocated to the responsible balancing parties that cause the imbalances. A fixed split G/L (e.g. 50/50) or a range could hence be considered as a basis for harmonisation at EU level.

Possible harmonization option

A harmonization initiative could focus on the principles and methodologies to recover the cost for balancing and non-frequency ancillary services: via the wholesale electricity market or via capacity and/or energy based transmission tariffs, via specific tariffs or included in the G- and/or L-charges.

The following principles could be used as a basis for possible harmonisation:

- TSOs could be held responsible in all Member States to procure all necessary balancing and non-frequency ancillary services and to recover the cost for balancing and non-frequency ancillary services via specific transmission tariffs. This implies that countries where the cost of some balancing and non-frequency ancillary services is recovered via the wholesale electricity market, should change their approach in order to have a consistent methodology across Europe.
- TSOs should cover their needs for balancing and non-frequency ancillary services via market based mechanisms, in particular via tenders for balancing reserves, which are open for cross-border participation.
- The related cost for balancing reserves can be shared between generation and load in a simple way (e.g. 50/50) or on the basis of a more elaborated analysis. The actual cost for activation of balancing reserves to cope with residual imbalances should be allocated and charged to the concerned balancing responsible parties.
- Specific tariffs per type of non-frequency ancillary services would be more cost-reflective than one global tariff, but their implementation would be rather complex.

The tariff for balancing and non-frequency ancillary services could be capacity based, energy based or hybrid; from a cost-reflectiveness perspective a hybrid tariff should be preferred.

A comprehensive assessment of this option is provided in section 4.1.5.

3.5.2 TSO grid losses

Status quo in Europe

Grid losses are in most European countries recovered via the L-charges, but in a few countries the related cost is partly or fully charged to generators: Austria (0.45 €/MWh in 2015), Belgium (balancing responsible parties are obliged to inject, depending on the time period, 1.25 or 1.35 % more than their offtake from the grid), Greece (average = 1.08 €/MWh based on zonal Generation Losses Factors), Ireland and Northern-Ireland (1.36 €/MWh), Norway (average = 0.57 €/MWh based on marginal loss rates which are

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30 See CREG decision 8658E-36 on the Elia tariff for the period 2016-2019 - paragraph VII 2.6.1.

31 See ACER Internal Monitoring Report on Transmission charges paid by the electricity producers in 2015, May 2016.

different depending on the location and the time), Romania (0.23 €/MWh) and Sweden (0.40 €/MWh).[32]

This short overview illustrates the diversity in charging methodologies and cost levels for grid losses within Europe, which shows that MS are differently interpreting the tariff principles of cost reflectiveness, non-discrimination and transparency. The current tariff approach leads to competition distortion amongst generators, as similar power plants in different MS are participating in the regional common merit order with differences in variable costs, which are due to the fact that in some MS grid losses are exclusively charged to load while in others they are partly or fully charged to generators.

The currently diverging cost charging practices for grid losses lead to competition distortion amongst power generators that are active in the same integrated regional market. This distortion only occurs in a few MS where losses are (partly) charged to generators while in the large majority of MS grid losses are entirely charged to load. The individual (highest level = 1.36 €/MWh) and overall impact is limited and therefore a harmonisation of the charging principles for grid losses has not yet been considered as a priority. ACER referred for instance to the complexity of harmonizing charges notably for losses, and concluded '… there is no point in harmonizing the charges for these cost categories.' (ACER, 2014).[33] Nevertheless, an initiative at EU level to harmonise this methodology would reduce the current distortions and contribute to a level playing for generators at supra-national level.

Relevant provisions in EU legislation regarding grid losses

At present there is no explicit legal provision at EU level with regard to the methodology for TSOs to recover their costs related to grid losses. There is only a legal provision with regard to the provision of energy needed to cover grid losses. Art 15 § 6 of Directive 2009/72/EC of 13 July 2009 concerning the internal market in electricity stipulates that "Transmission system operators shall procure the energy they use to cover energy losses and reserve capacity in their system according to transparent, non-discriminatory and market based procedures, whenever they have such a function."

Possible harmonization options

A harmonisation initiative could focus on the principles and methodologies to recover the cost for grid losses:

- Grid operators could be held responsible in all MS to recover the grid losses via a specific ToU-tariff, which reflects the impact of the load factor on the losses' level. Such a specific and time differentiated tariff is in principle more transparent and cost-reflective than most currently used mechanisms. This implies that countries where losses are covered via the market, should change their approach.
- Grid operators should procure the energy necessary to cover their grid losses via market based mechanism (according to articles 15§6 and 25§5 of Directive 2009/72/EC). Specific regulation should ensure that grid operators minimise their grid losses and adopt an adequate sourcing strategy (both long term and short term sourcing contracts).
- The cost of the transmission grid losses can be shared between generation and load in a simple way (e.g. 50/50) or on the basis of a more elaborated analysis.

[32] ACER, Internal Monitoring Report on Transmission charges paid by the electricity producers, May 2016.

[33] ACER (2014), Opinion No 09/2014 on the appropriate range of transmission charges paid by electricity producers, 15 April.

The above mentioned allocation mechanism is not location based and does not send locational signals to market agents. If it is deemed useful to implement location based price/cost signals for grid losses, two options can be considered:

- Nodal market pricing (this aspect is out of scope of this study)
- Location based marginal loss tariffs: this mechanism (which is for instance applied in Norway) reflects the physical reality of the system and is a priori more cost-reflective than a charging methodology based on the actual average grid losses. Its implementation is however much more complex.

Main findings of other studies on grid losses charging methodologies

CESI (2003) (an independent Italian based centre of expertise) considers the inclusion of losses in the market clearing algorithm as the most rigorous way to address grid losses. This method also sends clear locational signals. However, this solution is not the most widespread; one reason is that in decentralized markets the market operator doesn't make available a very detailed model of the transmission network. CESI considers that the recovery of losses by using calculated marginal loss factors can also be an accurate method if a sufficient number of representative conditions is available and patterns of generation are relatively stable. With regard to the "simple" mechanisms which are usually applied, such as attributing a fixed share of losses to generators and load (e.g. 50/50) and distributing the whole amount proportionally to the injected/withdrawn energy, CESI does not consider these approaches as an optimal solution as they are not location based and send no locational signals to the market agents.[34] Despite the age of the study, its conclusions are still relevant, as, since its publication, the legal framework and national practices have not substantially changed.

An external working group of the French regulator CRE has extensively assessed different options to cover the energy needs of TSOs related to their grid losses. The group came to the conclusion that, in order to maximise the economic and technical efficiency of the losses' compensation mechanism, this responsibility should be allocated to TSOs. As a substantial part of the losses is predictable at long term, TSOs should cover the corresponding share via long term contracts, in order to stabilise the sourcing cost and avoid negative impacts on the electricity market.[35]

A publication of Ronan Targosz focuses on the effect of the grid tariff system on network efficiency, and argues that the current tariff systems in most countries are not favouring network efficiency. In several European countries, there is a price cap on the network tariff, in which the term for network losses is not included. This means that the cost of network losses can be entirely charged through to the customer. This tariff system produces a strong disincentive for investing in network efficiency. The price cap prevents network operators from accumulating sufficient cash for efficiency investments, while the lack of a price cap on network losses makes such investments completely useless – the network operator does not have to pay for the losses anyway. In some other European countries, maximum values are set for the amount of network losses that can be

[34] CESI (2003), Implementation of short and long term locational signals in the internal electricity market.

[35] CRE (2010), Les dispositifs de couverture des pertes d'énergie des réseaux publics d'électricité.

charged through. This forces network operators to prevent losses from increasing, but it does not yet stimulate them to reduce losses.[36]

The impact of the grid losses' tariff methodology on network efficiency is also addressed in a publication of ICER. The authors conclude that grid losses should be part of the controllable costs of TSOs in order to encourage them to invest in loss reduction equipment. The least cost configuration should be used as a guiding principle for investments. Embedding of least cost configuration can be accomplished through various pathways. In case of cap regulation, the scheme should facilitate investments in efficient equipment, while it should also allow retention of OPEX cost savings related to network loss reduction. However, if suppliers are held responsible to procure network losses, neither these costs nor any retention of cost savings will emerge in the TSO's accounting. Therefore, in that case, explicit loss reduction incentive schemes should be considered to incentivize TSOs to limit their losses, e.g. via recorded reduction in network losses relative to a target.[37]

We can conclude that the studies recommend in general that the cost for grid losses should be recovered in such a way that both grid operators and users are encouraged to reduce losses; the proposed concrete solutions to reach this objective are however slightly different. On the basis of this analysis our recommended option is to make grid operators in all MS responsible to procure energy to cover grid losses via the market (tenders or power exchanges) and to incentivize them to minimise the overall grid losses by adequate regulation on national level (incentives and/or penalties) based on a systematic benchmarking of grid losses on EU level, while grid users should be encouraged to optimise their operational decisions (including their impact on grid losses) by adequate energy based ToU grid tariffs.

A comprehensive impact assessment of the option to harmonize the grid losses' charging methodology is provided in section 4.1.6.

3.5.3 Connection charges

Grid users have to pay network charges to compensate TSOs for the costs they incur as a result of their connection to the grid and their need for transport following electricity offtake from or injection into the grid. While UoS charges are discussed in the sections about the other policy options, in this section we focus on the grid connection charges which have to be paid at the moment that a grid user requires a new physical connection to the network.

Status quo in Europe

The connection costs that grid operators charge to grid users for the physical connection of a power plant or load unit to the grid are currently mainly calculated on the basis of one of the following methodologies :

- Super-shallow : all costs related to the grid connection are socialized via the grid user tariffs, no specific costs are charged to the connecting power plant or load unit.
- Shallow : grid users only pay for the specific infrastructure (line/cable and other related equipment) necessary to connect their installation to the grid connection

[36] Ronan Targosz, Leonardo Energy (2008), Reducing electricity network losses.

[37] ICER, S. Hers, C. Redl and M. Duvoort (2013), Grid Regulation Incentives for Network Loss Reduction.

point. Costs related to grid reinforcements and/or extensions are socialized via the grid user tariffs.

- Deep : grid users pay both the direct (connection infrastructure) and indirect costs (upstream investments to reinforce and/or extend the grid).

According to the overview published by ENTSO-E (Appendix 7 in its 2015 "Overview of transmission tariffs in Europe"), most TSOs currently apply a shallow approach, which is either based on the actual costs of the connection (e.g. Belgium, Germany, Hungary, Luxembourg, Slovak Republic,…), on a standard tariff (Austria, Czech Republic, Finland,…) or on the actual costs related to a connection to a fictitious point that can be closer than the effective physical connection (Denmark). Only a minority of MS applies a deep methodology (Croatia, Estonia, Latvia, Lithuania, and Sweden).

The current diversity in connection charging approaches implies that in countries with a deep connection regime a larger part of the costs is recovered by connection charges, lowering the part of the costs to be recovered by Use-of-System (UoS) charges from generation and load, while in countries with a super-shallow connection methodology all costs related to the grid infrastructure are socialised. This has a limited impact[38] on the level playing field for market operators, as for instance generators in Norway (super-shallow method) and Sweden (deep method) are competing in the same interconnected Nordic market. We will in chapter 4 evaluate the impact of an EU wide harmonised approach to connection charges; offering a level playing field to generators that are competing in integrated markets is a major element in this evaluation.

Relevant provisions in EU legislation regarding connection charges

There is at present no legal provision at EU level that offers a basis for harmonising connection charging methodologies across Europe. The current legal provisions focus on cost-reflectiveness, non-discrimination, transparency and the need to have connection charges that do not hinder the deployment of RES.

Directive 2009/72/EC on the Internal Market for Electricity provides that national regulatory authorities are responsible for "fixing or approving, in accordance with transparent criteria, transmission or distribution tariffs or their methodologies; and for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for: (a) connection and access to national networks, including transmission and distribution tariffs or their methodologies. Those tariffs or methodologies shall allow the necessary investments in the networks to be carried out in a manner allowing those investments to ensure the viability of the networks" (art. 37, 1 and 6). It also mentions that, in carrying out this task "regulatory authorities shall take all reasonable measures in pursuit of the following objectives: … "e) facilitating access to the network for new generation capacity, in particular removing barriers that could prevent access for new market entrants and of electricity from renewable energy sources." (art. 36)

Directive 2009/28/EC on Renewable Energy Sources mentions in its recital 63 that "Electricity producers who want to exploit the potential of energy from renewable sources in the peripheral regions and regions of low population density, should, whenever feasible, benefit from reasonable connection costs in order to ensure that they are not unfairly disadvantaged in comparison to producers situated in more central, more industrialised and more densely populated areas." In article 16 it is mentioned

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[38] The impact is limited as the connection cost represents in most cases a minor share in the overall investment cost of a power plant. According to EWEA (2012) the average share of the connection cost of wind turbines is 5 to 6 % of the overall investment cost (14 % in Bulgaria).

that TSOs and DSOs must "set up and make public standard rules relating to the bearing and sharing of costs of technical adaptations, such as grid connections and grid reinforcements… which are necessary to integrate new producers feeding electricity from renewable energy sources into the interconnected grid. Those rules - as well as the sharing of the related costs - shall be based on objective, transparent and non-discriminatory criteria…".

Possible harmonization options

Increased harmonization in the approach to connection charging conditions and tariffs across Europe would contribute to eliminating distortions which currently exist for similar connections depending both on the MS at hand and the voltage level of the grid (transmission or distribution).

Two harmonization options, i.e. a shallow and a deep charging methodology, can be considered in the context of this study:

- A shallow charging methodology based on capacity and distance related averaged and regulated standard tariffs is cost-reflective to the extent that it concerns connection costs up to the grid connection point (as remaining connection costs beyond the grid connection point are usually socialized to load by UoS charges), highly predictable, transparent (if regulated), non-discriminatory, and could offer a limited locational signal to generators. The modalities should however be properly designed in order to avoid disproportionate cross-subsidies to power generation installations in remote areas; the implementation of distance related averaged and regulated standard connection tariffs per kW is an appropriate solution to mitigate this risk.
- A deep charging methodology based on the actual connection cost is even more cost-reflective, prevents cross-subsidies across power generators, and offers stronger locational signals to prevent siting of production installations at locations that would lead to disproportionately high system costs. However, it is less predictable and less transparent for market parties than the shallow approach. Furthermore, the higher connection cost level and uncertainty could have an impact on the feasibility and cost of reaching the RES-targets, in particular for remote onshore and offshore wind parks. In addition, the deep charging principles should be properly designed in order to avoid discriminatory impacts. If for instance several wind parks are planned in a specific zone, and if the available residual grid capacity in that zone is not sufficient to connect all new capacity, generators can be discriminated if the first one can benefit of a connection at low cost (no need for reinforcement), while the last one has to bear the reinforcement cost. This risk may be (partially) mitigated by more transparency of network operators about the connection costs at different locations in the grid as well as attention by policy makers for the availability of sufficient locations for power generators to connect to the electricity grid. This would allow generators to find a suitable alternative location at acceptable connection costs.

Both options thus have their merits and drawbacks but a deep charging methodology seems the most cost-effective and cost-reflective approach. This study is focusing on transmission tariffs but we suggest that a harmonized methodology should equally apply to all new installations, independently of the voltage level of the grid they are connected to and independently of the generation technology.

Main findings of other studies on connection charging methodologies

EWEA has estimated that the EU average grid connection cost for onshore and offshore wind energy projects is respectively 5.1 and 5.4 % of the total investment costs. EWEA recommends to lower the connection cost for wind projects to an average of 2.5 %;

system operators should contribute to grid connection costs and adapt the connection fee of the investor to the project size.[39]

An ad hoc expert group under the Inogate project has evaluated the European practices regarding grid connection tariffs and considers that, with a deep charging methodology, the TSO will not be able to make a clear distinction between system and connection assets, as it will depend upon the order that they were built and paid for. With a shallow methodology only the cases of shared infrastructure between users would require a specific accounting follow-up. This expert group also analysed the merits and drawbacks of different connection charging policies. A deep connection pricing approach, where the generator has to pay all the connection costs plus the cost related to the extension and reinforcement of the grid, is cost-reflective and provides a good "locational" signal, commonly required for an efficient and reliable transmission grid. The shallow connection pricing policy, where the generator pays only the cost of connection assets, while all reinforcement costs are being shared among networks users, does not provide a locational signal and is less cost-reflective. The hybrid model tends to take advantages from the two previous policies: offering a shallow connection approach in providing a locational signal through a capacity charge. Concerning renewable energy power plants connection, it seems that the shallow connection pricing policy or a hybrid one has to be favoured; all reinforcement costs being shared among users the viability of wind power projects is improved and the connection pricing does not constitute a market entry barrier as the deep connection policy does.[40]

The Brattle Group refers in its study commissioned by the Dutch TSO TenneT41 to an international precedent with deep charging: in the US the FERC policy permits utilities to impose charges based on the incremental costs of network reinforcements, but few utilities do. They prefer to charge shallow costs to avoid potential litigation with grid users. The UK regulator has rejected deep charges as they would discriminate against entrants and deter competition. However cancellation fees apply in UK for new connections; they vary by zone and are higher in congested areas. The Brattle Group concludes that a universal deep connection policy would not be an appropriate solution for the Netherlands. The study however considers higher up-front payments in congested areas as a possible option. The possibility of applying deep charges only in particular (congested) areas in the Netherlands is also examined; the Brattle Group recommends exploring the right for TSOs to refuse connections which would require "unreasonably" high grid investments. In that case, generators should have the ability to overturn the negative TSO decision by offering to pay for the associated reinforcements. This solution should therefore devolve into a policy where a deep connection policy would apply in certain extreme cases.

Céline Hiroux concluded in her study[42] that a shallow connection pricing methodology is in general favoured by countries which tend to support the development of renewable energy. This connection policy accompanies commonly a strong renewable energy policy and a strong support from the government and regulatory authority. Deep connection pricing policy has some advantages for the configuration of the network thanks to the locational signal. The choice between a shallow or deep connection pricing approach

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[39] Ivan Pineda EWEA (2012), Good practices for grid connection: European wind industry perspective.

[40] Ad Hoc Expert Facility under Inogate (date not available), European best practice regarding connection tariffs.

[41] The Brattle Group (2007), A review of TenneT's connections policy.

[42] Céline Hiroux (2005), The integration of wind power into competitive electricity markets: the case of transmission grid connection charges.

therefore depends on the parameter preferred by the regulatory authorities: the more the challenge concerns the renewable energy policy, the more the connection policy will draw nearer to 'shallow' policy. The more the challenge concerns a reliable efficient network, the more the choice will conduce to a deep connection policy.

Richard Knight (Rolls-Royce plc) has made a study in the framework of the Intelligent Energy-Europe program and concludes[43] that the European Commission should recognise that increased consistency and transparency is needed in the approach to generator connection charging across EU MS. Fully transparent connection charging mechanisms and costs should be introduced (and enforced) across all MS. His general view is that where possible connection charging for DG and RES should follow a shallow charging philosophy. However, it is recognised that there are two issues that must be considered: the need of recovery of reinforcement costs (a fixed share could be considered similar to the Apportionment Rules in the UK) and the need for locational signals to discourage the siting of new generators in locations that would adversely affect overall system efficiency.

Despite the age of these reports, their findings are still relevant as they already take into account the impact of connection charges on the development of RES based power generation, and as, since their publication, the regulation and national practices have in this domain not substantially changed. We can conclude that most studies consider a shallow charging methodology as an appropriate option; they point however to the need for accompanying measures that allow to prevent siting of production installations at locations that would lead to disproportionately high grid investment or system costs.

A comprehensive impact assessment of the option to harmonize the connection cost charging methodology is provided in section 4.1.7.

3.6 Option 5 – Harmonised G:L split percentage

Assuming a harmonised definition of cost-reflectivity is achieved following option 2, different interpretations of cost reflectivity cannot longer distort the base for tariff setting i.e. the Regulatory Asset Base (RAB) of TSOs. Furthermore, assuming that energy based tariffs are no longer applied following option 1 (except possibly for ancillary services and losses) and the boundary between connection and UoS charges is settled following option 4, the introduction of a harmonized G:L split percentage can further contribute to achieve a level playing field for the competition between generators in different Member States. It implies that in each Member State the same *proportion* of network cost is recovered from generation and load respectively i.e. an X% from G and a Y% from L. A harmonised G:L split percentage does not impede different absolute tariff levels between countries, which not only result from influencable electricity network policies but also from non-influencable factors such as differences in geographical conditions, distances between generation and load, and other factors. For example, a country with less mountains and short average distances between generation and load can provide network services at lower costs than a country with many mountains and long distances between generation and load. Therefore the former country has a so-called comparative advantage compared to the latter country, which makes it efficient from a social welfare point of view that these cost differences remain reflected in a lower tariff level in the former country compared to the latter. At the same time, it is likely that absolute tariff differences will reduce if network charging policies would converge between Member States.

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43 Richard Knight Rolls-Royce plc (2006), Proposals for a DG Connection charging framework in the EU.

Concerning the desirable percentage of costs which are recovered from generation and load respectively, several considerations can be made. First of all, as a rule of thumb it can be said that half of the transmission costs are imposed by operational and investment decisions of generators and half of the cost by similar decisions of consumers (loads). Second, following Ramsey-Boiteux pricing rules, in order to ensure full recovery of transmission network costs while at the same time limiting any distortion to economic signals for efficient network use provided by marginal cost based tariffs, residual network cost can be allocated inversely proportional to the price elasticity of demand of different network user groups. This implies that customers who are price inelastic are charged a higher price than those who are price elastic (Econ Poyry, 2008; THEMA, 2015; Brattle, 2014).

Given the low price elasticity of consumption compared to generation, this rule results in levying a larger share of the costs on demand and less on generation (some state: all costs to demand, and none to generation). Provided the introduction of both smart metering with accompanying smart home automation and the expected introduction of time variable retail prices linked to wholesale prices, it is likely that the price elasticity of demand will significantly increase, diminishing the need to levy network costs mainly on consumers.[44] Third, ENTSO-E (2015) indicates that the maximum share of network cost currently recovered from generation amounts to about 40% (Austria, Norway, and Sweden). For these three reasons, we suggest to analyse the impact of an EU-wide introduction of a G/L split of 40:60 (i.e. 40% to G and 60% to L) in a quantitative analysis with deployment of a market model, provided that the required data is made available. Additionally, again assuming that the required data is made available, as a sensitivity the option of no G-charges (i.e. 0:100 G/L split) can be analysed.

3.7 Overview of the options

Table 6 presents a concise overview of some key characteristics of the five options with on the horizontal axis the three main building blocks for transmission tariffs (derived from D-Cision *et al.* 2013):

1. Cost categories included in allowed revenues and recovered by transmission tariffs;
2. Allocation of transmission costs to production and consumption (Generation:Load split);
3. Allocation of costs to specific network users (energy based and capacity-based tariffs, connection and UoS charges, uniform versus time-of-use and/or locational differentiated charges).

[44] Alternatively, non-linear pricing can be applied i.e. two-part or three-part tariffs consisting of one or more fixed components and one or more variable components. The fixed charge is meant to recover the fixed costs of transmission, while the volumetric charge recovers the variable costs (costs of congestion and losses) as far as the latter are not recovered by market prices.

Table 6 Overview of transmission tariff policy options

	Cost categories recovered by transmission tariffs	Allocation of transmission costs to G and L	Allocation of costs to specific network users
1. ACER G-charge opinion of April 2014		✓	✓
2. Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity	✓		
3. Location-based charging			✓
4. Harmonised charges for ancillary services, losses, and grid connection			✓
4. Harmonised G:L split		✓	

4 IMPACTS PER TRANSMISSION TARIFF POLICY OPTION

4.1 Assessment

In this section, we will evaluate the transmission tariff policy options on their economic, social and environmental impacts. Economic impacts include the impacts of policy options on short and long term system efficiency, competitiveness amongst generators and generation technologies, administrative burden, and transparency. Social impacts mainly relate to the effects on employment due to changes in the generation mix, since no social impacts on public health and safety as well as social protection and safety are expected. Environmental impacts highlighted include effects from changes in the generation mix on CO_2 and local emissions. Finally, for each option an overall evaluation of the main impacts, including its proportionality, is provided.

4.1.1 Option 0 (current situation)

Economic impacts

Efficiency
No further EU action means that short term market efficiency remains at suboptimal levels since national energy-based network charging policies are allowed and thus may distort electricity price signals and therefore generators' dispatch decisions which are taken in electricity markets. Distortive effects on competition are currently limited though, since current levels of non-harmonised G-charges increase system costs by € 3 million per year, which is tiny compared to estimated total system costs of the European system of € 71 billion per year. Distortive effects on competition may increase in the future though with the increase of transmission capacity and the decrease of price differences when progress is achieved in the creation of an Energy Union.

In the longer term, in order to safeguard the competitive position of their national generators Member States, at least those with a share of electricity interconnection capacity in total generation capacity higher than 10%, are inclined to reduce G-charges as long as neighbouring countries do not introduce G-charges. Therefore, generators do not have to take into account the network costs they incur on the system. Although we were not able to quantify the effects on longer term system efficiencies, based upon economic theory about externalities it is likely that due to the lack of internalisation of network costs by generators in their investment decisions, overall system cost levels will be too high, and consequently the network tariffs for load. When consumers face higher network costs than optimal, they are incentivised to look for possibilities to decrease payments of network charges (e.g. by micro grids, private grid, and investments in off grid solutions such as storage). As a result of this grid defection network costs have to be divided over less users, increasing network charges and providing additional incentives for network users to search for solutions to decrease grid utilisation. Hence, a vicious circle may develop.

Competitiveness
Generally, the differences in G-charges methodologies add complexity and may create artificial barriers to cross-border competition for new entrants and small competitors.

In some Member States generators may benefit from lower G-charges or abolition of these charges and consequently an improvement of their competitive position, while in other countries generators may suffer from higher G-charges or the introduction of these charges.

In case national G-charge policies change, those generators that face relatively lower G-charges compared to neighbouring countries will be able to produce more in the short-term and may expand generation capacity in the long term, while generators that face relatively higher G-charges compared to neighbouring countries will produce less and may need to decommission generation capacity at the margin in the long term.

Administrative burden
Because of continuation of national tariff policies, in the short term no additional administrative burden is foreseen. Both associated administration and enforcement costs for TSOs and NRAs as well as total compliance costs for generators and consumers are likely to remain on the same level, although a cost shift from generators to consumers and vice versa would be possible. However, in the longer term the administrative burden of heterogeneous national network charging policies will increase with deeper market integration.

Transparency
Limited transparency of transmission tariff methodologies. Methodologies are often very complex and published in national language only. Often parts of the steps are not published and known by TSOs (and NRAs) only. Lack of comprehensible overview at EU level.

<u>Social impacts</u>

An autonomous change of national G-charge policies within the boundaries of EU legislation may lead to a different dispatch of power plants, affecting revenues of individual plants and therefore both investments (replacement and expansion) as well as decommissioning decisions of generators. Consequently, employment levels at individual power plants might be affected, although presumably changes are small as overall employment at power plants is limited.

<u>Environmental impacts</u>

Lack of harmonisation of G-charges may shield generators in countries without or with lower G-charges from cross-border competition with generators in other countries that face higher G-charges. This may result in a larger number of power plants being deployed, with slightly higher CO_2 emissions compared to the case that less power plants are running at higher load levels. It may also imply a different fuel mix and therefore an increase or decrease of CO_2 emissions, depending on the combined merit order of the interconnected countries. However, given the low levels of G-charges such impacts are likely to be very small.

A change in the dispatch of power plants due to autonomous changes in national G charge policies may result in a change of the overall fuel mix of a country. This may have either a positive or negative impact on local emissions and hence on the local environment. The negative impact on one EU location is usually compensated by a positive impact at another EU location.

<u>Stakeholders view</u>

In theory the present transmission tariffs provide distortion to the market, but it is according stakeholders questionable whether these distortions can be observed in practice. At least recent studies did not show any urgency. Before applying a cure, what is the diagnosis? Moreover, even if it can be proven that differences in tariffs create distortions, there are other sources of distortions as well, which may have a higher impact.

According to stakeholders, the transmission network will be used more and more as an insurance. The networks do no longer only transmit energy from generation to load, but gradually more intermittent generation is added as well as distributed, active load, so the flows in the grid are changing, which could provide an argument for more capacity based charging.

Evaluation (including effectiveness/proportionality of the option)

The competition distortion effects of differences in G-charges across EU Member States are currently very limited; our quantitative analysis indicates that current levels of non-harmonised G-charges increase system costs by € 3 million euro per year, while total system costs of the European system are estimated to be € 71 billion per year. The competition distortion effects may increase in the future due to the increase of transmission capacity and the decrease of price differences with the creation of an Energy Union.

Furthermore, based upon economic theory about externalities it is likely that the lack of internalisation of network costs by generators in their investment decisions, results in too high system cost levels, and consequently too high L-charges. Besides, the administrative burden of heterogeneous national tariff policies is likely to increase with deeper market integration. Transparency of transmission tariff methodologies is poor and acts as barrier for generators and consumers as well as new entrants and small competitors. Social and environmental impacts seem insignificant.

If network tarification remains to be mainly decided at national level, the envisaged level playing field for competition of generators across the EU will not be achieved. Steps to harmonise the current situation would be pursued on a voluntary basis between different countries. Given the complexity and the need to balance different interests, voluntary cooperation and current EU level rules do not seem sufficient.

4.1.2 Option 1 – ACER G-Charge opinion of April 2014: Replacing energy-based by capacity-based or lump-sum G-charges

Economic impacts

Efficiency and competitiveness
In this option, in six countries energy-based network charges no longer exist but are replaced by capacity-based or lump-sum G-charges. Therefore they do not interfere with short term pricing signals meaning that short term market efficiency is no longer distorted. Consequently, in theory price formation should be more efficient and comparable across Europe. Furthermore, a small gain of longer term market efficiency is expected when energy-based network charges are annulled and replaced by capacity based G-charges, since generators are incentivised to take into account the effects of their investment decisions on the electricity system, while this is not the case with energy-based G charges.[45] The capacity based G-charges increase generators' cost in the six countries that in the baseline applied energy-based G-charges, decreasing the expected net revenues of investment and therefore preventing generation investments at the margin.

We performed a quantitative analysis with the COMPETES model in order to get better insights in the magnitude of the short and long term market efficiency effects of option 1 in practise.[46] [47] In our simulation for those countries that currently do have energy-

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[45] In case of energy based G-charges, the increase of costs when the price of the marginal price setting generator increases with the G-charge is compensated by an increase of revenues because these G-charges are fully transferred in higher power prices.

[46] As explained before, we were not able to model the long term effect compared to the long term optimal situation.

based G-charges in place these charges are replaced by capacity-based G-charges. Energy-based charges in option 0 are thus converted to Euro/MW capacity-based charges based on the 2030 generation and capacity mix of option 0 in each EU country. Table 7 presents the major results for option 0. Table 8 presents the major results for option 1 and compare them with option 0, whereas Table 9 shows similar results for option 1 but now compared to the reference case. The main observations can be summarized as follows:

- *Generation capacity and investments:* Capacity-based G-charge only affect the decommissioning of the existing peak generation (e.g., gas turbines) rather than impacting new generation investments. This is caused by the fact that the existing conventional generation capacity and the (policy-driven) renewable capacity assumed for the background scenario are sufficient to cover peak demand in countries with capacity-based tariffs. Therefore, new generation investments are not needed. Among the countries with a capacity-based transmission tariff, the largest decommissioning of conventional power plants in option 1 (compared to the reference case) is observed in Spain (by 7.1 GW of peak capacity) followed by the UK (2.2 GW), Ireland (0.4 GW), and Slovakia (0.2 GW). The level of decommissioning in these countries in option 1 is similar as in option 0, except for Spain where the level of decommissioning is considerably higher in option 1 (7.1 GW than in option 0 (0 GW).

- *Wholesale electricity prices:* Because of the increase in peak prices in countries which replaced energy-based by capacity-based G-charges, the average electricity prices are still higher compared to the reference case. However, in contrast with option 0 the increase in baseload prices due to energy-based G-charges is not observed in option 1. Therefore, the net impact of increasing average electricity prices in option 1 is slightly less than in option 0.

- *Impacts on producers, consumers and TSOs:* Most of the G-based transmission tariff costs are passed on to consumers via increased prices. In some cases, these tariffs are directly passed on to consumers and increase the consumer payments in countries that implement such tariffs. It may also indirectly affect consumers in neighbouring countries due to increases in exports from these countries to the countries with G-based transmission tariffs. The impacts on producer surplus, TSO surplus, and consumer payments are generally smaller in option 1 than in option 0 due to eliminating the increased electricity price impact of energy-based tariffs in option 1. Hence, social welfare increases in option 1 compared to option 0. Concerning distributional impacts across countries, producer surplus and consumer payments are affected by G-charge payments due to the resulting price impacts in the countries concerned. In countries where a capacity-based tariffs is implemented instead of an energy-based tariff (e.g., Spain and Portugal), both the producer surplus and the consumer payments are lower due to lower electricity price levels.

- *Indirect impact on other countries via tariff-induced changes in import/exports of electricity:* As a result of the implementation of a capacity-based G-charge in Spain, power imports by Spain from neighbouring countries are lower in option 1 compared to option 0. This results in less coal-based capacity investments and generation in Italy in option 1 compared to option 0.

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[47] Due to a lack of data on transmission tariffs across European countries we were not able to model and quantify the impacts of other policy options.

Table 7 Impact of option 0 (compared to the reference case) on generation investments, power generation, import/export flows and average electricity prices in European countries

	Energy tariff	Capacity tariff	Generation Investments	Generation	Net imports /exports	Average Prices	ΔGeneration Investments	ΔGeneration	ΔNet imports /exports	ΔAverage Prices
	Euro/MWh	Euro/MW	MW	TWh	TWh	Euro/MWh	MW	TWh	TWh	Euro/MWh
BE	0	0	0	36	57	61	0	-0.03	0.04	-0.01
CZ	0	0	2011	94	-21	56	55	0.35	-0.34	0.01
DK	0	1084	0	15	1	59	0	0.10	-0.10	-0.04
DKW	0	1621	0	27	-4	59	0	0.14	-0.14	-0.03
FI	0	5754	0	98	-7	58	0	0.17	-0.17	-0.05
FR	0	1206	0	567	-121	61	0	0.01	-0.02	-0.03
DE	0	0	0	564	-9	59	0	-0.21	0.25	-0.03
IE	0	7041	0	31	7	63	0	-0.21	0.21	-0.03
IT	0	0	4378	292	62	60	-165	-1.67	1.69	-0.01
NL	0	0	0	127	-6	59	0	-0.03	0.03	-0.02
PL	0	0	4503	199	-25	56	0	-0.15	0.15	0.01
PT	0	908	0	38	18	61	0	0.64	-0.64	-0.01
SK	0	2700	0	38	-7	52	0	0.00	0.00	-0.04
ES	0	1737	0	291	26	61	0	2.11	-2.10	-0.02
SE	0	3913	0	179	-32	59	0	-0.02	0.02	-0.05
UK	0	8560	0	264	66	64	0	-0.80	0.81	-0.02
CH	0	0	0	55	14	60	0	0.00	0.00	0.06
NO	0	538	0	135	-4	59	0	0.10	-0.10	-0.03
BLK	0	0	0	358	-23	54	0	-0.18	0.18	-0.01
BLT	0	0	0	30	2	57	0	-0.03	0.03	0.02
AT	0	0	0	70	4	58	0	-0.17	0.18	0.04

Table 8 Impact of option 1 (compared to option 0) on producer surplus, TSO surplus, consumer payments, system costs and total tariff costs in European countries

	Producer Surplus	TSO Surplus	Consumer Payments	System Cost	Tariff Cost	ΔProducer Surplus	ΔTSO Surplus	ΔConsumer Payments	ΔSystem Cost	ΔTariff Cost	ΔSocial Welfare
	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro	Meuro
BE	1289	61	5724	989	0	0	0	-1.1	-1	0	1
CZ	2447	64	4104	2786	0	1	0	0.9	20	0	0
DK	391	7	920	498	2	-1	0	-0.6	5	0	0
DKW	1015	28	1380	523	2	-1	0	-0.8	7	0	0
FI	4046	48	5328	1568	44	-4	0	-4.3	7	0	0
FR	28419	377	27398	5432	80	-15	-15	-13.5	2	0	-16
DE	18874	202	32898	13647	0	-16	-3	-16.0	-10	0	-3
IE	1161	50	2447	825	42	0	0	-1.0	-12	0	1
IT	8575	114	21114	9102	0	-4	2	-4.0	-97	0	2
NL	4175	45	7154	2601	0	-2	0	-2.6	-1	0	1
PL	4344	52	9713	6695	0	1	0	1.0	-7	0	0
PT	1742	4	3432	662	4	7	0	-0.4	40	0	8
SK	1512	52	1633	459	12	-2	0	-1.3	0	0	0
ES	12527	196	19237	5310	53	29	-28	-5.5	116	-12	6
SE	8601	59	8630	1716	31	-7	0	-6.6	-1	0	0
UK	8934	511	21114	7706	382	-4	0	-8.2	-47	0	5
CH	3086	77	4137	257	0	3	0	4.0	0	0	0
NO	7896	36	7806	159	0	-4	0	-3.6	6	0	0
BLK	10468	117	18173	9028	0	-4	1	-3.8	-10	0	0
BLT	1140	12	1820	600	0	1	0	0.5	-2	0	0
AT	3156	112	4303	1004	0	4	-1	3.0	-10	0	0
Total	133798	2225	208463	71567	654	-17	-42	-64	4	-12	5

Table 9 Impact of option 1 (compared to the reference case) on physical and monetary electricity system variables in European countries

	ΔGeneration Investments	ΔGeneration	ΔNet imports /exports	ΔAverage Prices	ΔProducer Surplus	ΔTSO Surplus	ΔConsumer Payments	ΔSystem Cost	ΔTariff Cost	ΔSocial Welfare
	MW	TWh	TWh	Euro/MWh	**Meuro**	**Meuro**	**Meuro**	**Meuro**	**Meuro**	**Meuro**
BE	0	0	-0.01	1.28	72	0	119	2	0	-46
CZ	-272	-2	2.00	0.03	2	13	2	-108	0	13
DK	0	0	0.01	1.33	19	2	21	0	2	1
DKW	0	0	0.01	1.33	15	3	31	0	2	-13
FI	0	0	0.01	1.32	62	48	121	0	44	-11
FR	0	0	0.01	1.60	563	122	716	0	80	-30
DE	0	0	0.07	1.31	533	78	724	-2	0	-113
IE	0	0	0.03	1.42	16	42	55	-1	42	4
IT	36	0	-0.11	-0.01	-2	11	-4	9	0	13
NL	0	0	0.05	1.27	128	0	153	-2	0	-25
PL	487	3	-2.99	0.04	2	13	7	167	0	8
PT	0	0	0.05	0.28	13	4	16	-2	4	1
SK	0	0	0.02	-0.09	-15	13	-3	-1	12	1
ES	0	0	0.35	0.27	43	82	86	-28	53	39
SE	0	0	0.00	1.37	153	35	201	0	31	-13
UK	0	0	0.28	1.51	42	382	499	-17	382	-75
CH	0	0	0.00	0.13	8	24	9	0	0	23
NO	0	0	0.01	1.41	195	0	185	0	0	11
BLK	0	0	0.16	-0.02	-8	2	-8	-8	0	1
BLT	0	0	0.02	0.21	9	6	7	-1	0	8
AT	0	0	0.01	0.12	11	41	9	1	0	43
Total					1860	923	2944	7	654	-161

Overall effects are tiny though; social welfare increases by € 5 million compared to an overall social welfare figure of € 345 billion. We think that the limited distortive effects of different types of G-charges on cross-border competition of generators result from the fact that only six countries will have to change their G-charges to capacity-based G-charges. If G-charge levels would become higher in the future and/or the number of countries which has to replace energy-based G-charges by capacity-based G-charges higher, effects would also be larger. Furthermore, the COMPETES model assumes that renewable energy is fully policy driven i.e. exogenous and not determined by modelling. Hence, capacity-based G-charges, like G-charges in general, do not affect decisions of investors in renewables and therefore subsidy levels, implying that for instance impacts of the change of G-charges on renewable generators with low capacity factors are not captured by the model. Despite these factors which could increase the absolute effect of policy option 1, it is likely that overall effects remain (very) small.

Administrative burden
A one-off increase of compliance costs is expected for those countries that should replace energy-based G charges by capacity-based or lump-sum G charges i.e. Denmark, Finland, France, Portugal, Romania, and Spain (ACER, 2014; ENTSO-E, 2015). TSOs (or NRAs) need to adapt G charges, while NRAs need to approve adaptations and might have to propose mitigating measures for those stakeholders (e.g. with low load factors) which are potentially negatively affected. Recurrent costs are on the same level as in the baseline option.

Transparency
The diversity of different national transmission charging methodologies is limited by the removal of energy-based tariffs compared to the base case, which increases transparency somewhat.

<u>Social impacts</u>

Prohibition of energy-based G-charges leads to less competition distortion, more cross-border competition and thus result in a smaller number of power plants being deployed. Consequently, total employment at power generators may slightly diminish, and shifts of employment between power plants may occur, although presumably impacts on employment levels remain limited.

<u>Environmental impacts</u>

The more efficient dispatch of power plants due to implementation of the ACER G-charge opinion results in both dispatch of a lower number of power plants and a change of the overall fuel mix of a country. This may have either a small positive or negative impact on both CO_2 emissions and local emissions. Concerning CO_2 emissions, harmonisation of energy-based G-charges may contribute to more cross-border competition and thus result in a smaller number of power plants deployed, with slightly lower overall CO_2 emissions since power plants on average are able to run on higher load levels. Concerning local emissions, a small negative impact on emissions such as NO_x and PM_{10} of one EU location is usually compensated by a small positive impact at other locations across the EU.

<u>Stakeholders view</u>

Whereas network investments are more related to capacity (peak) than energy, providing a strong argument for G-charges, capacity based charges will function as an additional fixed cost for network users. According to stakeholders, many generators are already unable to recover their fixed cost (and fixed costs do not play a role in the electricity market, which is based on marginal generation costs), so G-charges will be difficult to recover from the revenues – contrary to kWh charges, which are directly included in the market price.

Since more generation is gradually connected to distribution grids, the same principles for charging generation should be applied to these. Furthermore, given the development that gradually more load will play an active role in the market, charging generators and loads should be similar and not provide a cause for market distortion.

Given that G-charges are a form of capacity based charging, stakeholders note that this will create distortions with respect to RES and other units with a low number of load hours. Stakeholders have finally noted that the impact of G-charges on capacity with different load hours will have a dramatic impact on the investments.

Evaluation (including effectiveness/proportionality of the option)

According to our quantitative analysis, replacing energy-based G-charges by capacity-based G-charges (excluding costs for ancillary services, system losses, and connection charges), results in tiny improvements of cross-border competition between generators. Cost reflectivity in the short term will thus marginally improve when energy-based G charges can no longer distort short-term electricity market decisions. Based upon economic theory, cost reflectivity in the long term is expected to remain weak; although the number of countries with non-energy-based G-charges increases, in several Member States generators do not have to pay for network costs they incur on the system, let alone that G-charges will be set to their optimal long run cost-reflective level i.e. the level that stimulates generators and consumers to take investment and siting decisions that minimize overall system costs. Rather it is likely that the suboptimal G-charges of the largest Member States in Continental Europe are becoming the benchmark (and with that their national policy goals rather than the EU policy goals). In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), this option can therefore be considered as only one aspect of potential future coordination or harmonisation.

Besides, impacts on the administrative burden as well as social and environmental impacts are likely to be insignificant.

Finally, some more specific EU-wide requirements to national G-charges are not against the proportionality principle, since coordination is required to prevent negative external effects of national policies on other EU Member States and the size of the public intervention is unlikely to be disproportional since the size of the intervention does not change, only its specificity. This option could be implemented by adapting either Regulation No 838/2010 or alternatively by issuing an electricity transmission tariff guideline/network code (like for gas transmission tariffs). Such a guideline is enabled by article 8 (6)k of Regulation No 714/2009.

4.1.3 Option 2 – Long-term trajectory with procedural obligations to develop common set of principles for cost reflectivity

Economic impacts

Efficiency
A harmonisation of the tariff principles to better reflect grid costs will increase the efficiency of dispatch and investment decisions by generators from a system perspective. Harmonisation of tariff principles will have no major impact on cost recovery of TSOs as the basis for network tarification i.e. total allowed revenues remains unchanged.

Competitiveness of generators

Harmonized tariff principles have several consequences for the competitiveness of generators. First of all, harmonized tariff principles will improve the level playing field for generators, both for dispatch and investment decisions.[48] Besides, it improves the investment climate for power generation by offering higher predictability and certainty with regard to the expected tariff development.

The impact of tariff harmonisation principles on the competitiveness of individual generators can be positive or negative depending on the current situation. E.g. generators with relatively high and low load factors (base load versus peak load and RES generators) maybe differently impacted by changes in transmission charges structures and tariffs.

Administrative burden

The transition from the current national tariff structures to a new approach based on harmonised tarification principles and structures will lead to initial and recurring costs related to implementation of changes by NRAs and TSOs. At the same time, market participants (e.g. generators and suppliers) that are active in multiple Member States may benefit from less heterogeneity in tariff principles and structures and therefore a lower administrative burden.

Depending on the design of the principles and their implementation, the impact on NRAs could be considerable if they were obliged to determine the tariffs on the basis of a commonly decided charging methodology. Although they already manage this at national level, it would require additional efforts for the elaboration and implementation of new tariff principles and possibly but not certainly also tariff structures, the associated data gathering, monitoring and reporting on compliance of new principles, and for resolving unexpected issues.

The impact on TSOs may also be considerable, especially if the new harmonised tariff design would be based on a new cost calculation methodology (e.g. regulatory standard costs instead of actual costs). Likewise NRAs, TSOs are assumed to take part in the elaboration and implementation of new tariff principles and possibly but not certainly also structures and to deliver data reports, increasing their administrative burden.

Transparency

If tariff principles and structures are properly designed and thus do have a material effect on Member States' policies, the diversity of different national charging methodologies will be limited, increasing transparency for network users.

Social impacts

Harmonisation of tariff principles may result in less competition distortion, and therefore change dispatch as well as investment and decommissioning decisions of generators. Consequently, total employment at power generators will change or slightly reduce in line with changes in the generation mix. Redistribution of employment over individual power plants may occur, but is likely to be limited.

[48] In case option 1 has already been implemented no change of dispatch decisions is expected.

Environmental impacts

Harmonisation of transmission tariff principles and structures affects power generation through its impact on cross-border competition, this is likely to have also an impact on CO_2 emissions and local emissions. Concerning CO_2 emissions, harmonisation of tariff principles and structures will in principle lead to less distortive dispatch of generation,[49] a lower number of conventional power plants deployed, and therefore potentially less part loaded operation and lower overall CO_2 emissions. Furthermore, it may have an impact on the fuel mix, see option 1.

Concerning local emissions, given that both generators dispatch and investments change as a result of less competition distortion, depending on the locations of the affected generators, this impact can be either positive or negative.

Stakeholders view

According to stakeholders, the development and transparency of such long-term principles is very important. According to stakeholders especially the application of the cost reflectivity principle should be further investigated. Furthermore, the different cost categories should be clarified with respect to common and shared definitions, categories, etc.

Nonetheless, the stakeholders have noted that tariff harmonization will only make sense when the (national) purposes of the tariff structure are also harmonized. Furthermore, any change in tariff structure is likely to create winners and losers.

An interesting question put forward was who bears any new charges? Typically existing plant are conventional, while many new plants are based on renewable energy. Any change of the regime of charging generators, will also affect the question who will pay most: new plant or old plant?

Finally, stakeholders have noted that although option 1 includes a clear pathway, the implementation of the other options is not too clear.

Evaluation (including effectiveness/proportionality of the option)

This action would substantially contribute to minimising potential competition distortions between technologies and MS by different transmission tariff regimes. In addition, the proposed action would contribute to reaching other objectives such as better cost reflectiveness, cost recovery, and transparency.

EC or ACER could provide guidance for establishing a more consistent interpretation across Europe of principles for transmission tariffs, notably cost reflectivity of G-charges. Guidance may include:

a) Prescriptions for network cost items to be included in national transmission tariffs in order to improve comparability between transmission tariffs;
b) Regulatory accounting guidelines for the treatment of infrastructure costs components, e.g. for depreciation policies, investment timing, and ITC costs;
c) Transparency measures such as unequivocal obligations to TSOs and NRAs for data gathering and consistent reporting regarding total allowed revenues, actual network costs incurred to the system by groups of network users, and level and structure of transmission tariffs for different user categories as well as the methodology that is used by a TSO to derive transmission tariffs. The most appropriate legal instrument

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[49] Unless option 1 has already been implemented.

would be a binding legislative document (e.g. regulation), as non-binding documents (guidelines, opinions, and even directives) can still lead to diverging implementation practices and hence suboptimal results from an EU perspective.

The proposed action should be initiated by ACER, in cooperation with ENTSO-E. The effective realisation of this action will largely depend on the willingness of the NRAs to actively cooperate in this process and to commonly develop and implement a harmonised approach.

The proportionality of the policy option is not easy to assess, since cost reflectivity principles need further definition and elaboration, and choices need to be made including their scope and detail. Hence, quantitative testing of the impacts of these principles on society as a whole and generators, TSOs and NRAs in particular was not yet possible. Generally it can be said that the proportionality depends on the size of the distortion as well as the strength of the procedural obligations to mitigate this distortion. Despite the fact that national tariff differences are only one of the drivers of current distortions of dispatch and/or investment decisions between Member States, a stronger focus on cost reflectivity of transmission signals is key to prevent cumulative effects of a range of small factors including national tariff differences. Probably the need for harmonisation of tariff principles will evolve further over time, implying some basic level of harmonisation should be pursued in the short-term while more advanced measures should be strived for in the long term. At least the basic measures should be considered a no regret option, while more advanced measures require further scrutiny. Likewise for option 1, this option can be implemented by an electricity transmission tariff guideline or network code.

4.1.4 Option 3 (Location-based charging for generators across Europe)

The impact of an EU wide implementation of capacity based fixed (annual lump sum/kW) or time related (different annual rates/kW per period, e.g. peak/off peak, winter/summer,…) transmission G-charges differentiated per area or per generator based on the long term marginal grid cost, is hereafter evaluated.

Economic impacts

Efficiency
Locational capacity based G-charges will in general have a positive impact on the efficiency of the electricity system. The short term impact will be low, as, in the current market design, electricity prices are determined on the basis of the variable cost of the marginal plant in the merit order. As capacity based transmission charges do not change the variable cost and will hence not affect the merit order, they will not influence the short term production mix and prices.
In the medium and long term, locational capacity charges will induce more efficient siting decisions of generators (and consumers), in particular for conventional power plants, but also the siting of RES installations can be positively affected. While only effective in a mid-term perspective, it will positively affect the long term system efficiency. The effective impact will depend on the level of the charges and their modulation.

Competitiveness of generators
The implementation of this option would have an impact on the competitiveness of generators, depending on their location. Generators located in regions with a supply deficit would have to pay lower capacity based transmission tariff fees and would hence improve their competitiveness, while generators located in areas with oversupply would become less competitive. Capacity based charges might also affect the competitiveness of generators, depending on their technology. If G-charges are calculated on the subscribed access or connection capacity, the cost impact in €/MWh will be relatively higher for installations with a low factor (e.g. peak/back-up units, RES based installations). Not properly designed capacity based G-charges might hence in the

medium term lead to reduced availability and higher cost of back-up capacity and affect the feasibility and cost of reaching the RES target. In order to mitigate this risk, capacity based transmission charges should be designed to properly reflect the share of generators in TSO investment costs to meet peak demand on the one hand and to avoid congestion from injection on the other hand.

Administrative burden
The administrative burden is likely to increase for several reasons. First of all, coordinated action is needed for enabling a common, harmonized methodology by EC or ACER. This would require a transmission tariff guideline or network code. For enforcing compliance with a new guideline or network code NRAs or ACER needs to carry out additional monitoring efforts. In case ACER is given this task, it requires that ACER should be given more powers. In addition, TSOs should change their calculation of network tariffs accordingly.

In the sub-option where differentiated capacity based G-charges would be applied per area, the delineation of the zones, which should preferably be determined at supra-national level in order to also take into account structural cross-border power flows, would represent a new administrative task for the TSOs and regulators of the EU Member States where such approach is not yet implemented. The sub-option to determine differentiated location based charges per generator would also result in a new administrative task for NRAs and TSOs in most Member States. This option would hence lead to an administrative burden for both NRAs and TSOs.

Transparency
Option 3 will increase transmission tarification’s transparency as transmission costs will be more transparently charged to generators on the basis of their location and actual impact on the grid costs.

<u>Social impacts</u>

The introduction of differentiated capacity based G-charges will negatively affect the profitability of power plants that are faced with higher transmission charges due to their location and/or technology. This option will hence have an impact on investment and decommissioning decisions of power generators. Consequently, total employment in the power generation sector might slightly decrease, as higher grid tariffs in zones with oversupply might trigger decommissioning of unprofitable power plants, and redistribution of employment over individual power plants may occur. The shift of transmission charges from load to generation will in principle lead to more competitive end-user base-load prices, which might have a positive impact on the employment in the electricity intensive industry.

<u>Environmental impacts</u>

Capacity based G-charges will in the short term not change the merit order and will hence have no short term environmental impacts. They will however affect investments/divestments in generation capacity and will have positive environmental impacts in the medium/long run. The actual overall impact will depend on the level of the charges and their modulation.

Stakeholders view

A stakeholder recalls that, with regard to a possible implementation of locational signals in a whole bidding-zone, a vast majority of NRAs considered in 2013 that the existing heterogeneity of transmission tariffs would not hamper cross-border trade and/or market integration. Therefore the harmonisation at EU level was not considered urgent or relevant to NRAs. Other stakeholders emphasise that markets should offer short term signals to market operators while transmission tariffs should mainly reflect the long term marginal grid cost; they stress that locational signals should be offered by markets, and only if markets fail, it might be appropriate to implement locational signals via transmission tariffs. Another stakeholder refers to the fact that there are multiple theoretically justified options for locational charging based on short run costs (marginal grid losses, congestion costs) or long run costs (incremental grid investment costs); both contribute to a more efficient utilisation of existing infrastructure. Therefore he considers the implementation of harmonised locational charging in all EU Member States as not appropriate as there is "no one size fits all" solution. If a charging scheme for marginal losses and market splitting apply, there is no need for further locational tariff signals.

Evaluation (including effectiveness/proportionality of the option)

The implementation in all EU Member States of differentiated capacity based G-charges per area or per generator would improve the economic efficiency of the electricity system, but would be administratively complex and challenging, in particular to avoid competition distortion between technologies and operators. Moreover, the delineation of the zones should be regularly reviewed in order to reflect the actual situation (supply/demand balance). The implementation of ex-ante determined capacity based zonal transmission tariffs would mainly offer benefits in regions or Member States where power is structurally flowing from one large area to another (e.g. Sweden, UK, Germany). In EU regions or Member States with a highly meshed and interconnected system and a decentralised and diversified power production park, in particular with a high share of intermittent renewables, it might be more difficult to delineate tariff zones on the basis of structural power flows with a predominant direction. Therefore an EU wide mandatory introduction of ex-ante determined differentiated capacity based G-charges per area or per producer would not be a recommended option, also taking into account that it would in the short term not effectively contribute to reduced congestion and higher overall system efficiency. The design of such a tariff system would be rather complex and sensitive and require significant stakeholder engagement, in order to reduce the risk for legal actions from generators that are faced with higher grid charges (see experience in UK). Besides, this option would have a high impact on the way that national regulators/authorities and TSOs determine and calculate grid tariffs.

Although the option of an EU wide implementation of locational tariff signals for generators offers benefits from an economic and technical perspective (positive impact on the long term system efficiency, higher cost-reflectiveness), its effectiveness might not substantially outweigh its drawbacks.

4.1.5 Option 4A (Harmonised charges related to ancillary services)

Harmonised G-tariff structures for balancing and non-frequency ancillary services can be capacity based, energy based or hybrid; the impact of this harmonisation is slightly different depending on the tariff base. The main impacts of introducing harmonised G-charges for ancillary services are hereafter evaluated.

Economic impacts

Efficiency
As this harmonisation option would in principle lead to a more cost reflective and transparent allocation of ancillary services' costs to grid users (generation and load) that are at the basis of the concerned grid services, generators and consumers will be incentivized to contribute to lowering the overall need for balancing reserve and other ancillary services via more flexible demand and supply. The impact on the short-term and long-term overall efficiency of the electricity system will hence be positive, but the effective impact will be low (taking into account the limited share of ancillary services cost in the overall TSO budgets) and depend on the level of the concerned G-charges and the concrete modalities.

A harmonisation of the tariff principles would have no major impact on cost recovery of TSOs as the basis for network tarification i.e. total allowed revenues remains unchanged.

Competitiveness of generators
Harmonized tariff principles for ancillary services would improve the level playing field for generators, both for dispatch (energy based charges) and investment decisions (capacity based charges).

The impact of tariff harmonisation on the competitiveness of individual generators can be positive or negative depending on the current situation and the new charging methodology. E.g. generators with relatively high or low load factors (base load versus peak load and RES generators) maybe differently impacted by changes in transmission charges structures and tariffs. Equally, the competitiveness of power generators versus self-producers, and cost and availability of flexible supply may be affected.

Administrative burden
The administrative burden is likely to increase for several reasons. First of all, coordinated action is needed for enabling a common, harmonized charging methodology by EC or ACER. This would require a transmission tariff guideline or network code. For enforcing compliance with a new guideline or network code NRAs or ACER need to carry out additional monitoring efforts. In case ACER is given this task, it requires that ACER should be given more powers. In addition, TSOs should change their calculation of network tariffs accordingly.

Transparency
This option will offer higher transparency than the current diverging national approaches as a common methodology will be developed and implemented to transparently and specifically charge for ancillary services, rather than including these costs in an overall tariff structure.

Social impacts

The introduction of harmonised G-charging principles to recover part of the costs for ancillary services via generation would lead to a shift of transmission charges from load to generation. Capacity based G-charges would not be transparently passed through to end-users and could slightly increase the competitiveness and hence the employment level of electricity intensive end-users. Capacity based G-charges would negatively affect the profitability of power plants and would hence have an impact on investment and decommissioning decisions of power generators. Consequently, total employment in the power generation sector might slightly decrease, and redistribution of employment over individual power plants may occur. Energy based G-charges would have a very limited impact on employment.

Environmental impacts

Capacity based G-charges for ancillary services will in the short term not change the merit order and will hence have no environmental impacts. They will however affect investments/divestments in generation capacity and will hence have a positive environmental impact in the medium/long run. Their concrete impact will largely depend on the level of the charges and their modulation.

Energy based G-charges affect the merit order, and, if the transmission tariff structures are correctly reflecting the underlying costs that are caused by generators respectively consumers, they will have a positive environmental impact, both in the short and long term.

Stakeholders view

Some stakeholders consider that there is no evidence that harmonisation at EU level of charges for ancillary services would be needed, also given the fact that most EU Member States do not yet have a liquid market for ancillary services. They have also doubts about the added value of an EU wide implementation of separate tariffs to recover the costs of ancillary services, taking into account the administrative burden. Other stakeholders suggest that grid operators should in all MS procure ancillary services via market based mechanisms, and recover the related cost via L-charges only. RES installations should in all MS be allowed to provide ancillary services to grid operators. Finally, a stakeholder argues that, the costs for ancillary services should be recovered through market solutions where possible. Cost reflectivity is an important criterion for ancillary service charging. Sunk costs should be recovered according to the same principles as infrastructure.

Evaluation (including effectiveness/proportionality of the option)

The implementation of a harmonised approach towards procurement and charging principles for ancillary services could be an effective measure to increase system efficiency, the level playing field for generators and the cost-reflectivity of grid tariffs. This option would reduce the autonomy of national regulators, but they would still be responsible for determining the concrete modalities and tariffs and for taking into account the specificities of the different national electricity systems. On the other hand, costs of ancillary services constitute a limited share in overall TSO costs, which are dominated by capital expenditures for network infrastructure grid charges, and therefore network charges.[50] Furthermore, a full harmonisation of the tariff structures and levels is neither feasible nor appropriate, as the cost components are different depending on the specificities of the national systems. Moreover, for some types of ancillary services costs could also be recovered through market solutions rather than network tariffs, hence further discussion is needed about the optimal recovery of cost of ancillary services. For all these reasons, it is quite uncertain whether this option is currently proportional.

50 Although figures in section 3.5.1 indicate that G-charges related to balancing services range from 0 to 2.81 €/MWh (excluding G-charges that are levied upon specific generation technologies only), while current wholesale prices (e.g. average day-ahead prices in CWE region) ranged in 2016 from 29 to 36.6 €/MWh depending on the country. The grid tariff differential of 2.81 €/MWh may be a significant competitive disadvantage for the concerned generators.

4.1.6 Option 4B (Harmonised charges related to network losses)

The harmonisation option would consist of sharing the overall grid losses costs between generation and load either in a simple way (e.g. 50/50) or on the basis of a more elaborated analysis, and to charge the related costs to generators either via a uniform tariff or via a differentiated location based tariff per generator.

Economic impacts

Efficiency
The introduction of a harmonised charging method for grid losses via a uniform energy based tariff would not change the merit order and would hence have no impact on the short and long term electricity system efficiency. Only if grid losses are calculated and charged individually to generators on the basis of their short term marginal cost, there would be a positive impact on the short and long term system efficiency, as generators that cause higher grid losses would then be penalised in the merit order.

Competitiveness of generators
Harmonized tariff principles for grid losses will improve the level playing field for generators.

The impact of tariff harmonisation on the competitiveness of individual generators can be positive or negative depending on the current situation and the new scheme.

Administrative burden
The administrative burden is likely to increase for several reasons. First of all, coordinated action is needed for enabling a common, harmonized methodology for charging grid losses by EC or ACER. This would require a transmission tariff guideline or network code. For enforcing compliance with a new guideline or network code NRAs or ACER need to carry out additional monitoring efforts. In case ACER is given this task, it requires that ACER should be given more powers. In addition, TSOs should change their charging methods for grid losses accordingly.

Transparency
A common, harmonized methodology for charging grid losses would be more cost reflective and more transparent than the current situation. Grid users will be better informed about the actual costs they impose to the network, and the calculations and (methodological) assumptions made by TSOs in deriving charges for grid losses.

Social impacts

As the costs related to grid losses are currently in most MS mainly charged to load, the introduction of a harmonised methodology to charge part of the costs to generation, would lead to a shift of transmission charges from load to generation. The application of a uniform energy based tariff for all generators will however in principle not change the employment in the electricity sector as the incremental cost will be transparently passed through to end-users. Only if grid losses are calculated and charged per generator on the basis of the short term marginal costs, there would be an impact on the merit order and hence a minor shift in employment might occur from power generation plants that are faced with high costs for grid losses to power plants that have a more “favourable” grid related location.

Environmental impacts

The introduction of a uniform energy based tariff for generators will in principle have no environmental impacts compared to the current situation. If however grid losses are calculated and charged per generator on the basis of the short term marginal costs, the environmental impact will be positive as generators that cause high grid losses will be penalised in the merit order.

Stakeholders view

A stakeholder considers that an EU common cost allocation methodology to share the cost related to grid losses between generation and load might have more important drawbacks than advantages. Another stakeholder supports the idea that grid operators should in all MS procure energy for grid losses via market based mechanisms, but argue that the related cost should be recovered via L-charges only. Finally a stakeholder argues that the tariff to recover grid losses should take into account two aspects: recovering the average cost of losses and signalling forward looking marginal cost of losses.

Evaluation (including effectiveness/proportionality of the option)

The overview on charges related to TSO grid losses illustrates the diversity in charging methodologies and cost levels for grid losses within Europe; it clearly shows that MS are differently interpreting the tariff principles of cost reflectivity, non-discrimination and transparency. The current charging approach leads to a competitive disadvantage for generators in some MS[51]. Although generators are causing part of the costs for grid losses, they are in several MS exempted from any specific contribution. The current approach is hence not cost-reflective and not consistent across Europe. The option to harmonise the procurement and charging principles would be effective and proportional to improve the cost-reflectiveness and contribute to restoring a level playing field for generators. A full harmonisation of the tariffs for grid losses would however neither be feasible nor appropriate, as the cost components are different depending on the specificities of the national electricity systems.

4.1.7 Option 4C (Harmonised charges related to grid connection)

The harmonisation option would consist of adopting at EU level a common methodology for charging connection costs to generators. In order to avoid market distortions and to offer adequate and cost-reflective signals for siting decisions for new conventional and RES based power plants, a deep charging methodology could be an appropriate basis for harmonisation. However, given the potential risk for discrimination and distortion and the need to facilitate the transition to a more decentralised low carbon electricity supply, a shallow charging methodology based on connection capacity and distance related averaged and regulated standard tariffs should not be excluded as an appropriate basis for harmonisation at EU level. Both methodologies will hence be further considered in the impact assessment.

[51] The actual distortive impact is difficult to quantify, also due to limited availability of data. The current levels charged to generators range from 0 to 1.36 €/MWh; divergent levels in interconnected markets result in lower load factors and reduced profitability for power plants located in MS with higher cost levels charged to generators. Based on the current wholesale prices (e.g. average day-ahead prices in CWE ranged in 2016 from 29 to 36.6 €/MWh depending on the country), which reflect the variable cost of the marginal plant in the merit order, a grid tariff differential of 1.36 €/MWh represents a competitive disadvantage for the concerned generators.

Economic impacts

Efficiency

Connection charges affect investment decisions (siting of new installations and possibly also technology choices), but do not have an impact on operational decisions. The short term system efficiency will hence not be influenced, but only the long term economic efficiency. A deep charging methodology is more cost-reflective and has a higher positive impact on the overall system efficiency than a shallow charging methodology; it allocates the full grid investment cost to the concerned generator and hence offers a stronger locational signal. Deep grid connection charging would lead to higher investment costs for most new power generation projects, in particular for wind parks which are in most cases located in areas with limited available grid connection capacity. The overall economic system efficiency would however increase as the siting decisions for new power plants, including wind parks and other RES based installations, will be optimised on the basis of an integrated system cost approach.

Connection charges are, independently of the charging methodology, fixed costs. They do not change the merit order, and will hence in the short term not affect the produced volumes and related gross margins of the different generating units. The net margin will however be impacted; this impact in €/MWh output will be relatively higher for installations with a low factor (e.g. peak/back-up units, RES based installations) and will hence mainly affect the profitability of these technologies. Harmonisation of tariff principles will have no major impact on cost recovery of TSOs as the basis for network tarification i.e. total allowed revenues remains unchanged.

Competitiveness of generators

An EU wide harmonised charging methodology would, compared to the current situation, contribute to creating a level playing field for generators located in interconnected member states across Europe (less competition distortion). However, as the connection fee represents for most new power generation projects only a minor share of their overall investment cost, the current tariff divergences have a limited distortive impact (see overview in 3.5.3). A shallow methodology offers an equal treatment for all generators while a deep charging methodology can lead to discrimination amongst generators located in the same area, as a generator can be obliged to pay the full cost for a grid reinforcement which partly benefits to other generators in the same area.

The impact of tariff harmonisation on the competitiveness of individual generators can be positive or negative depending on the current situation, and the new harmonised methodology. On the basis of the currently available data it is however not possible to quantitatively estimate these different impacts.

Administrative burden

The administrative burden is likely to increase as a coordinated action is needed for enabling a common, harmonized methodology by EC or ACER. This would require a grid tariff guideline or network code. For enforcing compliance with a new guideline or network code NRAs or ACER need to carry out additional monitoring efforts. In case ACER is given this task, it requires that ACER should be given more powers. In addition, some TSOs should change their calculation of connection costs accordingly.

Transparency

A (public) discussion about an appropriate methodology for connection cost charging would contribute to more clarity for stakeholders about the actual costs new connections impose to the network, and the calculations and (methodological) assumptions made by TSOs in deriving connection charges.

Social impacts

The introduction of harmonised connection charging principles across Europe can, depending on the chosen methodology, lead to a shift of transmission costs between individual generators on the one hand and between generation and load on the other hand. The impact on employment would however be very limited.

Environmental impacts

The introduction of harmonised connection charging principles across Europe will in the short term not change the energy mix, and will hence have no short term environmental impact. As investment and siting decisions will be influenced by the connection charges, there will be a minor impact in the medium and long term. This impact will anyhow be limited as siting decisions are mainly influenced by other criteria than grid connection costs.

Stakeholders view

Some stakeholders do not see a necessity to implement harmonised rules and point to the drawbacks of a deep charging method: it is difficult to identify the actual costs and there is a risk for discrimination amongst grid users. Other stakeholders consider the deep charging methodology as unfair and are in favour of the implementation of a shallow charging methodology. They also refer to the need for transparency and consistency between the rules for transmission and distribution. Finally, a stakeholder argues that the approach to connection charging needs to be consistent with the approach on locational signals; deep connection charging does not seem consistent with sending locational signals elsewhere in the framework. If a harmonisation initiative is taken in one area, the other area should also be subject to harmonisation.

Evaluation (including effectiveness/proportionality of the option)

The current diversity in connection charging approaches across Europe leads to (limited) competition distortion amongst technologies/generators that are active in the same integrated market. From an economic perspective a deep charging methodology would represent an adequate basis for harmonisation, as it influences siting decisions of power plants and hence contributes to minimising the overall system costs. However, in order to reduce the potential risk for discrimination and distortion and to facilitate the transition to a more decentralised low carbon electricity supply, a shallow charging methodology based on capacity and distance related averaged and regulated standard tariffs would also be an appropriate common methodology. Although it is less cost-reflective than deep charging, it is transparent, non-discriminatory and offers a (limited) locational signal to generators. Independently of the chosen option, it is recommended that a harmonized methodology should equally apply to all installations, independently of the voltage level of the grid they are connected to and independently of the generation technology. As the actual distortion is limited, a binding harmonisation initiative on EU level seems at present not a priority.

4.1.8 Option 5 – Harmonized G:L split percentage

Economic impacts

Efficiency
Provided that option 1 is realised, energy-based network charges are no longer in place and short-term market efficiency will be unaffected. Provided that option 2 is realized, a harmonized definition of cost reflectivity is in place, thus preventing that different interpretations of cost reflectivity will distort the absolute transmission tariff levels of countries that are taken as a basis for applying the harmonized G:L split percentage.

The long-term market efficiency will increase since the option would induce more similar levels of non-energy-based G-charges across the EU, preventing negative spillover effects from countries without or with lower G-charges on countries with (higher) G or L charges, and thus preventing regulatory competition with transmission tariffs across Member States. At the same time, when harmonising G:L split percentages, absolute network cost differences across Member States mean that some G-charge differences between countries remain. These differences are likely to reflect differences between countries concerning distances between generation and load, generation mix, connection density, terrain conditions etcetera, and are thus efficient. Furthermore, the option would improve cost reflectivity as generators have to bear a larger share of the costs they induce on the network.

Competitiveness

Overall gain in competitiveness for generators due to decline of fragmentation between Member States, enhancing the level playing field. At the same time, a redistribution effect occurs since generators in some Member States benefit from lower G-charges, while in other countries -depending on the exact G:L split percentage chosen- they suffer from higher G-charges or introduction of these charges.

Administrative burden

The administrative burden is likely to increase for several reasons. First of all, coordinated action is needed for enabling a common, harmonized G:L percentage split by EC or ACER. This would require a transmission tariff guideline or network code. For enforcing compliance with a new guideline or network code NRAs or ACER need to carry out additional monitoring efforts. In case ACER is given this task, it requires that ACER should be given more powers. In addition, TSOs should change their calculation of network tariffs accordingly.

Transparency

A (public) discussion about an appropriate G:L split percentage may deliver more information and thus contribute to more clarity for stakeholders about the actual costs they impose to the network, and the calculations and (methodological) assumptions made by TSOs in deriving transmission tariffs.

<u>Social impacts</u>

As with Option 2, the social impacts are limited. Harmonisation of the G:L split percentage may result in less competition distortion, and therefore change dispatch as well as investment and decommissioning decisions of generators. Consequently, total employment at power generators will change or slightly reduce in line with changes in the generation mix. Redistribution of employment over individual power plants may occur, but is likely to be limited.

<u>Environmental impacts</u>

Harmonisation of the G:L split may contribute to more cross-border competition and thus result in a smaller number of power plants deployed, with slightly lower CO_2 emissions since power plants on average are able to run at higher load levels. Furthermore, it is also likely to imply a different fuel mix and change of CO_2 emissions since technologies at the right side of the merit order are less frequently deployed. If for instance gas-fired power plants are less frequently deployed and coal-fired plants more frequently, it will mean higher CO_2 emissions, while if e.g. oil-fired power plants are ruled out CO_2 emissions of the total installed generation capacity will diminish. The direction of this effect and its significance differ from case-to-case.

Harmonisation of the G:L split percentages may also result in either a positive or negative impact on the local environment. Changes in the dispatch of power plants result in a change of the overall fuel mix of a country, and therefore in a change of the local emissions. Changes in siting of generators across countries also have an impact on the local environment. The negative impact on one EU location might be compensated by a positive impact on other locations within the EU.

Stakeholders view

Stakeholders do not see the economic basis for this fifth option and therefore are puzzled on its merits.

Stakeholders stress that the energy market will develop into competition between generation and active load. This should be more and more reflected in the transmission tarification principles. Nevertheless, stakeholders have noted that this option is not too attractive since it will not contribute to the level playing field for generation and active load. Since there are no harmonized rules for tariff calculation this option will be complicated to implement. Moreover, it will not result in harmonization of the absolute tariff levels.

Stakeholders also stress that when adapting the present principles, the benefits should outweigh the costs. Previous studies performed by ACER do not unequivocally conclude that this is the case.

Evaluation (including effectiveness/proportionality of the option)

This option would allow not only equal network tariff principles but also some harmonisation across Europe concerning the absolute network tariff levels, while respecting structural differences in network topology, geographical differences etc. between countries. Apart from a higher system efficiency resulting from more optimal G-charge levels, the option also helps to establish a level playing field for competition between generators and to achieve higher transparency for network users. On the negative side, harmonisation of the G:L split percentage for all Member States requires (very) substantial efforts to split cost and therefore tariff differences among countries in respectively structural and artificial policy-related components. It consequently increases administrative burden for NRAs, TSOs and ACER. Option 5 is also a drastic option since it harmonizes tariff principles and structures in one large step, rather than a set of more gradual and smaller steps that first addresses the tariff principles and afterwards the tariff levels such as option 2. It has therefore lower flexibility and higher implementation costs than option 2. All in all, taking into account the currently limited competition distortion effects of variation of G-charges, option 5 is considered to be disproportional.

4.2 Overall evaluation and comparison of the options

We will discuss impact-by-impact, allowing for a comparison between options, followed by a summarizing table and conclusions and recommendations.

4.2.1 Economic effects

Efficiency
Replacing existing energy-based G-charges by capacity based or lump sum G-charges in six countries increases economic efficiency of generation dispatch only marginally. At the same time, option 1 does not stimulate policy makers to set G-charges to an level that stimulates generators and consumers to take optimal investment and siting decisions that minimize overall European system costs, and therefore do not help to achieve affordable power prices and competitive industries across Europe. The patchwork of

different national transmission tariff structures which reflects the emphasis placed on different national policy objectives will continue under option 1. In addition, with more interconnectivity between Member States and continuation of current limited EU policies it is likely that the G-charges of the largest Member States in Continental Europe are becoming the benchmark and that a truly European internal market is not achieved.

A long-term trajectory with procedural obligations to develop a common set of principles for cost reflectivity, as foreseen in option 2, will increase the efficiency of dispatch and investment decisions by generators to a higher extent. Given that the need for harmonisation of tariff principles will evolve further over time, some first set of harmonisation measures e.g. transparency measures such as unequivocal obligations to TSOs and NRAs for data gathering and reporting should be pursued in the short-term while more advanced measures such as for instance regulatory accounting guidelines for the treatment of network depreciation policies and ITC costs should be prepared for the long-term.

Option 3 - locational capacity based G-charges – will positively affect the efficiency of the electricity system, as it will induce more efficient siting decisions of generators, in particular for conventional power plants and to a lesser extent also RES based installations, and hence lead to system efficiency gains, as investors need to take into account the effect of their location on grid system costs.

Harmonisation of charging principles for ancillary services and grid losses (Options 4A and 4B) would have a positive impact on the system efficiency, as grid users, including generators, will in a harmonised way be held responsible for the actual grid costs they cause. The impacts will be small though due to the limited shares of system services and losses in overall TSO costs. Harmonisation of connection charges (Option 4C) on the basis of a shallow charging methodology will in general not affect the system efficiency, while a deep charging approach would have a positive impact.

A harmonized G:L split as proposed by option 5 is advantageous for the European society as it helps to achieve system efficiency in the investment timeframe by preventing that levels of G-charges are being applied that lead to competition distortion or do not allow to minimise the overall system costs.

Competitiveness
Replacing existing energy-based G-charges by capacity based or lump sum G-charges in six countries improves cross-border competition between generators to a very limited extent.. Option 1 is thus not sufficient for a genuine level playing field as in the majority of countries generators do not face G-charges. In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), this option can therefore be considered as only one aspect of potential future coordination or harmonisation.

Option 2, a long-term trajectory with procedural obligations to develop a common set of principles for cost reflectivity, is likely to improve the level playing field for generators across Europe more structurally. Despite the fact that national tariff differences are only one of the drivers of current distortions of generators’ dispatch and investment decisions across Europe, the focus on cost reflectivity of transmission signals is key in order to prevent that negative spillover effects from national network charging policies occur in an increasingly European system which is highly interconnected.

The implementation of option 3 - locational capacity based G-charges – might, depending on the design and level of the tariff structures, have a high impact on the competitiveness of generators. The impact will be different depending on the location and the technology (load factor).

The harmonisation of charging principles for ancillary services, grid losses and connection costs (Options 4A; 4B and 4C) would have a positive impact on competitiveness, as the current competition distortions due to diverging national rules would be reduced.

Option 5, the implementation of harmonized G:L splits in percentages, contributes further to achieving a level playing field between European generators. By limiting G:L splits variation to structural differences between countries only, the option prevents artificial differences in generation tariffs resulting from Member States policies. Therefore negative spillover effects from countries with a lower G charge level on countries with a higher G charge level are counteracted when efficient.

Administrative burden
In the baseline option, in the short term no additional administrative burden is foreseen but in the longer term the administrative burden of heterogeneous national tariff policies will increase with deeper market integration.

A one-off increase of compliance costs is expected for the six countries that should replace energy-based G charges by capacity-based or lump-sum G charges following option 1. TSOs (or NRAs) need to adapt G charges, while NRAs need to approve adaptations and might have to propose mitigating temporary measures for those stakeholders (e.g. with low load factors such as RES-E) which are potentially negatively affected. Recurrent costs are on the same level as in the baseline option. The overall increase of administrative burden is expected to be the lowest of all options due to the limited nature of the policy change, its one-off character, and the low number of countries (only six) being affected.

In contrast with option 1, option 2 will lead to an increase of both initial and recurring costs related to implementation of changes by TSOs and NRAs. Although TSOs and NRAs already manage this at national level, they would have to make additional efforts for the elaboration and implementation of new tariff principles and, possibly, structures related to infrastructure costs, the associated data gathering, monitoring and reporting on compliance of new principles, and for resolving unexpected issues. Administrative efforts for basic harmonisation measures aimed at tariff principles are likely to be limited, while more advanced harmonisation measures involving deeper changes of tariff principles and possibly tariff structures would be more substantial. At the same time, market participants (e.g. generators and suppliers) that are active in multiple Member States may benefit from less heterogeneity in tariff principles and possibly tariff structures and therefore a lower administrative burden.

Option 3 would lead to the highest administrative burden compared to other options since its implementation necessitates a legal or regulatory initiative at EU level and profound changes in tariff structures in most MS. Moreover the charging principles will have to be regularly monitored and evaluated, and adapted where necessary (e.g. delineation of tariff zones).

The administrative burden to implement options 4A and 4B would also be relatively high, as the related processes should be adapted in several MS and the underlying system costs should be clearly identified and allocated in order to determine a new harmonised cost-reflective and transparent charging scheme. Sharing costs of reserved capacity for balancing services as well as grid losses on a 50/50 basis between generation and load across the EU probably has limited impacts on the administrative burden. In contrast, specific harmonized tariffs for each ancillary service across the EU as well as specific ToU or locational based marginal loss tariffs for grid losses require (very) substantial efforts. The EU wide implementation of a shallow or deep connection cost charging methodology (Option 4C) would only represent an administrative burden for the MS that are not yet using such a method.

Also option 5 will increase the administrative burden in the form of initial and recurring costs. Coordinated action is needed for enabling a common, harmonized G:L percentage split by EC or ACER, requiring implementation of a new transmission tariff guideline or network code. For enforcing compliance with this new piece of legislation, TSOs should change their calculation of network tariffs accordingly and NRAs or ACER need to carry out additional monitoring efforts. The administrative burden for option 5 is deemed to be substantial since cost differences need to be split in structural and artificial differences.

Transparency
The baseline option exhibits limited transparency of transmission tariff methodologies. Methodologies are often very complex and published in national language only. Often parts of the steps are not published, and thus known by TSOs (and NRAs) only. A systematic and coherent overview of the MS practices concerning transmission charges for different types of generators from EU perspective is currently lacking.

Option 1 increases transparency somewhat since the diversity of different national transmission charging methodologies is limited by the removal of energy-based tariffs compared to the baseline. The gain is relatively small as it concerns just one aspect of transmission tarification.

Option 2 increases transparency for network users about network infrastructure costs more fundamentally as a common set of cost reflectivity principles should substantially limit the wide diversity of different national charging methodologies. In contrast with option 1 a range of aspects is addressed. It should also lead to a higher predictability and certainty for network users with respect to the expected tariff development.

Option 3 would increase transmission tariffs' transparency for society as part of the transmission costs will be levied upon generators on the basis of their location, rather than averaged over all locations of a country or zone. At the same time, for generators the determination and calculation of G-charges would be more complex to grasp, decreasing transparency to some extent.

Option 4 would lead to increased transparency through development and implementation of common methodologies, and specific charges for ancillary services and grid losses rather than including these costs in an overall tariff structure. The transparency and predictability of connection costs charging for network users would increase if some countries would replace deep by shallow and regulated network charging. Deep charges are more transparent about the system and societal costs related to connection, and thus can be preferred from an overall system perspective.

Option 5 would increase transparency since implementation of a uniform G:L split percentage limits the current diversity of national charging methodologies. The discussion of the appropriate percentage can deliver more insights for network users in the calculations and (methodological) assumptions made by TSOs in deriving transmission tariffs, although the transparency gain is likely to be smaller than in option 2.

4.2.2 Social effects

The policy options affect employment levels at power plants mainly through their effects on the strength of cross-border competition.

The prohibition of energy-based G-charges and replacement by capacity-based or lump sum G-charges (option 1) leads to less competition distortion, a more efficient dispatch of power plants, and therefore a smaller number of conventional power plants which are being deployed at a generally higher average load factor. The overall employment level may therefore be somewhat reduced. Furthermore, employment levels at individual power plants can be affected, with the employment somewhat reduced at some power plants, while being increased at others.

Harmonization of tariff principles (option 2) and harmonisation of G:L split percentages (option 5) across Europe do have similar effects, although their cross-border effects and concomitant employment effects are estimated to be more significant than option 1.

Option 3 will in most countries lead to a shift of part of the transmission charges from load to generation and to a shift of costs amongst generators, which would in the long term lead to reduced employment in the power sector.

Equally, the implementation of option 4 might have small negative impacts on employment, depending on the sub-option and the tariff structure and modalities.

4.2.3 Environmental effects

The policy options affect also the environment i.e. system-wide CO_2 emissions as well as local emissions such as NO_x and PM_{10} through their effects on cross-border competition and the resulting effects on the fuel mix and full load hours of power plants.

Effects on CO_2 emissions
When network charging practices are made more homogeneous by a policy option, generators in countries which currently face lower or no G-charges at all are no longer partially shielded from cross-border competition. More competition amongst generators may have effects on CO_2 emissions for two reasons. First, it may result in a smaller number of power plants being deployed at higher load levels and therefore slightly lower CO_2 emissions, ceteris paribus. Second, it may lead to a different generation mix and change CO_2 emissions since technologies at the right side of the merit order will be less frequently deployed compared to a case with more heterogeneous network tariffs. It depends on the combined merit order whether this causes an increase or decrease of CO_2 emissions. In case gas-fired power plants are less frequently deployed and coal-fired plants more frequently it will mean higher CO_2 emissions, while if e.g. oil-fired power plants are ruled out in favour of less carbon intensive generation technologies CO_2 emissions of the total installed generation capacity will diminish. The net effect as well as its significance and direction are likely to differ from case-to-case. Options 2 and 5 are again expected to have a larger impact on the number and types of generators to be deployed and therefore CO_2 emissions, since they represent more drastic policy changes than option 1. As tariff structures in options 3, 4A (partly) and 4C would be mainly capacity-based the short term impact on the merit order, and hence on the CO_2 emissions, will be very limited. Only energy-based tariff structures, e.g. for some ancillary services as well as power losses (options 4A and 4B), would have a minor positive impact on CO_2 emissions. Option 3 will probably lead to a smaller number of generators to be deployed in the longer term, and consequently higher load levels and slightly lower CO_2 emissions.

Effects on local emissions
If a policy option through its effect on (cross-border) competition has an impact on the dispatch and/or investment and decommissioning decisions of generators, this will change the local emissions levels. In case of change of dispatch, the negative effect on local emissions such as SO2, NO_x and PM_{10} on one EU location due to more power plant running hours could be compensated by a positive impact on other locations where the number of power plant running hours decreases. In case fewer power plants produce due to decommissioning of plants, local emissions will be reduced at the locations where plants are decommissioned and slightly increase at locations where power plants run more hours. Options 2 and 5 are expected to cause a larger impact on the number of

generators and their load factor, and therefore local emissions, since they represent more drastic policy changes than option 1. Tariff structures in options 3 and 4 would be mainly capacity based and would hence have no short term impact on the merit order, and on local emissions. Only energy based tariff structures, e.g. for ancillary services and grid power losses, would have a minor positive impact on the overall local emissions' level.

4.2.4 Proportionality

Proportionality can be shortly summarized as follows; policy options should be commensurate with the problem i.e. (1) not going beyond what is necessary to achieve the objectives; (2) limited to those aspects that Member States cannot achieve satisfactorily on their own; and (3) minimize costs for all actors involved in relation to the objective to be achieved.[52]

For all options holds that they induce more stringent EU-wide requirements to national G-charges. Those requirements are not against the second aspect of the proportionality principle, since coordination is required to prevent that negative spillover effects from national network charging policies distort the level playing field for generators in an increasingly European system which is highly interconnected. Member States cannot achieve this coordination satisfactorily on their own. The differences between policy options are thus mainly related to the first and third aspects, which are actually closely interrelated i.e. when policy options are going beyond what is necessary to achieve a level playing field for electricity generators, costs for all actors involved in doing so are unlikely to be minimized. Let us now discuss option by option.

The size of the public intervention required for option 1 is unlikely to be disproportional since the size of the intervention remains unchanged, and only its specificity changes. The option is feasible as it can be implemented by adapting either Regulation No 838/2010 or alternatively by issuing an electricity transmission tariff guideline or network code (like for gas transmission tariffs). Such a guideline is enabled by article 8 (6)k of Regulation No 714/2009.

The proportionality of option 2 is not easy to assess, since cost reflectivity principles need further definition and elaboration, and choices need to be made including their scope and detail. Hence, quantitative testing of the impacts of these principles on society as a whole and generators, TSOs and NRAs in particular was not yet possible. On the other hand, the options focuses on infrastructure costs which make up for the largest part of TSO costs. In addition, despite the fact that national tariff differences are only one of the drivers of current distortions of dispatch and/or investment decisions between Member States, a stronger focus on cost reflectivity of transmission signals is key to prevent cumulative effects of a range of small factors including national tariff differences. Given that the need for harmonisation of tariff principles will evolve further over time, some first set of harmonisation measures e.g. transparency measures such as unequivocal obligations to TSOs and NRAs for common cost allocation methods, data gathering and reporting should be pursued in the short-term while more advanced measures such as for instance regulatory accounting guidelines for the treatment of network depreciation policies and ITC costs could be prepared for the long-term. Likewise for option 1, the option could be implemented by an electricity transmission tariff guideline or network code.

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[52] See EC (2015a), Commission Staff Working Document – Better Regulation Guidelines, SWD(2015) 111 final, 19 May.

The proportionality of option 3 (differentiated capacity based G-charges per area or per generator) is not clear-cut. On the one hand, this option undoubtedly offers substantial economic efficiency benefits by providing the right investment signals in cases of lasting mismatch of demand and supply in a country. It also helps to improve cost reflectivity of network tariffs for generators, and thus to improve overall system efficiency. On the other hand, challenges exist around the optimal delineation of the different transmission zones, which should be done at supra-national level, and it is probably administratively complex and challenging for national legislators, regulators and TSOs. Therefore, we tend to conclude that alternatives such as a review of the bidding zones and nodal pricing might be more proportional and effective options.

Although the absolute size of the distortions due to diverging charging methodologies for options 4A and 4B (ancillary services and grid losses) might at present be relatively limited, the impact of this distortion is important for some MS and generators and will increase with raising market integration. In addition, measures sharing costs of reserved capacity for balancing services as well as grid losses on a 50/50 basis between generation and load could be rather easily implemented by adapting either Regulation No 838/2010 or alternatively by issuing an electricity transmission tariff guideline or network code. On the other hand, ancillary services and losses constitute a quite limited share in overall TSO costs, which are dominated by capital expenditures for network infrastructure. Furthermore, impacts on cross-border competition are likely to remain limited due the structural differences between Member States concerning ancillary services and losses which cause different network costs and therefore tariff levels, and that are not resolved by these specific policy measures. Moreover, for some types of ancillary services like grid losses the costs are currently recovered through market solutions rather than network tariffs, hence further discussion is needed which cost items should preferably be recovered by market solutions and which by grid tariffs. For all these reasons, it is quite uncertain whether these suboptions are proportional. Some other considered measures, e.g. specific harmonized G-charges per ancillary service and charging of differentiated grid losses per generator, could help to bring more clarity about structural and artificial differences in network costs and tariff levels between Member States. However, they would have a major impact on the national regulation and processes in most MS and taking into account the limited shares of ancillary services and losses in overall TSO costs, therefore could be considered as disproportional.

Likewise for ancillary services and grid losses, distortions due to diverging connection charging methodologies (Option 4C) might at present be relatively limited, but the impact of this distortion is important for some MS and generators and will increase with raising market integration. In addition, different connection charging regimes could give rise to unfair cross-border competition between generators when countries could shift substantial costs from G-charges (‘Use-of-System’ charges) which are subject to EC Regulation No 838/2010 to connection charges which are currently explicitly excluded from European harmonisation efforts. Therefore, this option could be considered as proportional and beneficial. However, a common approach to setting principles for more long-term harmonisation (Option 2) may also mitigate the risks outlined above. The option 4C could be implemented by an electricity transmission tariff guideline or network code.

Option 5 helps to establish a level playing field for competition between generators, higher transparency for network users, and higher system efficiency by more optimal G-charge levels. On the other hand, harmonisation of the G:L split percentage for all Member States requires (very) substantial efforts to split cost and therefore tariff differences among countries in respectively structural and artificial policy-related components. It consequently increases administrative burden for NRAs, TSOs and ACER. Option 5 is also a drastic option since it harmonizes tariff principles and structures in one large step, rather than a set of more gradual and smaller steps that first addresses the tariff principles and afterwards the tariff levels such as option 2. It has therefore lower flexibility and higher implementation costs than option 2. All in all, taking into account the currently limited competition distortion effects of variation of G-charges, option 5 is considered to be disproportional.

Conclusions and recommendations

The table below summarizes our assessment, which is more extensively discussed above, and allows for a comparison amongst the different policy options.

Table 10 Scoring of transmission tariff policy options on impact assessment criteria

	Economic				Social	Environ-mental	Propor-tionality
	Efficiency	Compe-titiveness	Admini-strative burden	Trans-parency			
Option 1	**0/+**	**0/+**	**0/-**	**0/+**	**0**	**0**	**+**
Option 2	**+**	**+**	**-**	**++**	**0/-**	**0/+**	**0/+**
Option 3	**+**	**0/+**	**-**	**+**	**0**	**0/+**	**0/+**
Option 4A	**0/+**	**0/+**	**-**	**+**	**0/-**	**0/+**	**0/-**
Option 4B	**0/+**	**0/+**	**-**	**+**	**0/-**	**0/+**	**0/-**
Option 4C	**0/+**	**0/+**	**0/-**	**+**	**0/-**	**0/+**	**0**
Option 5	**0/+**	**+**	**-**	**+**	**0/-**	**0/+**	**-**

On the basis of this study, the following main conclusions and recommendations are provided:

First of all, diverging tariff systems can have a negative impact on competition between generators from different Member States, thereby creating obstacles to the internal electricity market. However, it is quite difficult to prove this in a quantitative way due to modelling difficulties and –most important- the lack of data. Modelling difficulties relate mainly to the complexity of the issue at hand with many variables impacting generators dispatch and investment decisions. The lack of data to quantify the policy options implied that we were only able to model policy option 1. Network tariff data is very heterogeneous at Member State level, and only summarized for a few types of generators and loads at European level to a limited extent. Available reports do provide little insights in underlying assumptions, parameters, and calculations.

Although distortions on cross-border competition due to G-charges *currently* are limited, we deem it likely that distortive effects of variation of G-charges on competition and overall system efficiency will increase in the (near) future for two reasons. First, the increase of transmission capacity between and within countries means that higher transmission costs are expected in the coming years and decades. Second, the progress that is expected in creating common internal electricity markets given the EC CACM guideline and proposed Energy Union legislation implies that cross-border competition will further increase, making variation of G-charges a more prominent factor in dispatch and siting decisions of generators. On the other hand, in a future where differences in national generation policies remain and national capacity mechanisms are more widely introduced distortions of generator decisions due to G-charges could still be overpowered by other factors such as market price differentials and differences of taxes and levies. All in all, differences in G-charges may contribute to the cumulative competition distortion effect and tackling them can make a difference, even if the effect would be small if they were to be tackled alone.

Several policy options analysed contribute to overcome this competition distortion by stimulating better cost reflectiveness and transparency of network charges, and realisation of a cross-border level playing field for generators.

Overall, policy option 2, a long-term trajectory with procedural obligations to develop a common set of principles for cost reflectivity, is deemed to be proportional as well as most beneficial for European generators and citizens. This option has the potential to increase system efficiency, competitiveness, and transparency, and focuses on infrastructure costs which make up for the largest part of TSO costs. In this respect, we also confirm the message of other studies (amongst others CEPA, 2015) that the EC should first focus on harmonisation of G-charge principles (cost reflectivity versus transparency, capacity versus energy based G charges) rather than on variation in G-charge levels which may result either from artificial, policy-related differences between countries or structural differences between countries such as network topology and geographical differences. At the same time, the administrative burden of option 2 is surmountable, and the option can be implemented in a flexible, stepwise manner by either an electricity transmission tariff guideline or network code. Given that the need for harmonisation of tariff principles will evolve further over time, some first set of harmonisation measures e.g. transparency measures such as unequivocal obligations to TSOs and NRAs for common cost allocation methods, data gathering and reporting should be pursued in the short-term while more advanced measures such as for instance regulatory accounting guidelines for the treatment of network depreciation policies and ITC costs could be prepared for the long-term.

Option 3 undoubtedly offers substantial economic benefits and may be an appropriate means to provide the right investment siting signals in cases of lasting mismatch of demand and supply in a country. However, due to its challenges around optimal delineation of the different transmission tariff zones and large impacts on regulatory and administrative processes, an alternative such as a review of the bidding zones might be more proportional and effective options.

Option 4C could be considered proportional and beneficial as it prevents unfair cross-border competition between generators with potentially countries shifting substantial costs from G-charges (‘use-of-system’ charges) which are subject to EC Regulation No 838/2010 to connection charges which are currently explicitly excluded from harmonisation efforts. The option could be implemented by an electricity transmission tariff guideline or network code. However, a common approach to setting principles for more long-term harmonisation (Option 2) may also mitigate the risks outlined above.

The positive effects of option 1 suggested by economic theory were not very much supported by our quantitative analysis, which indicated that option 1 has tiny effects on decreasing cross-border competition distortion. Nonetheless, given the expectation that variation in G-charges will increase in the future, this option does not require additional policy intervention but rather limited adjustment of EC Regulation 838/2010, and hence could be deemed proportional.

Likewise option 2, options 4A and 4B have the potential to increase system efficiency, generator competitiveness and transparency, although the shares of ancillary services and grid losses in overall TSO costs are much more limited than network infrastructure costs. Furthermore, impacts on cross-border competition are likely to remain limited due to structural differences between Member States concerning ancillary services and losses which cause variation in network costs and therefore tariff levels, and that are not resolved by these specific policy measures.

Option 5 is considered to be disproportional in the current situation to reach the objectives. On the one hand, option 5 helps to establish a level playing field for competition between generators, to achieve higher transparency for network users, and to realize higher system efficiency by more optimal G-charge levels. However, on the other hand, this option requires substantial administrative efforts by NRAs, TSOs and ACER, is not flexible and, taking into account the currently limited competition distortion effects of variation of G-charges, a bit too drastic at the moment.

Finally, it should be noted that time-of-use components of transmission tariffs have not been considered in this study. Given the need for flexibilisation of the electricity system, such tariffs could become an increasingly effective option and could form an important component of any future analysis or study on this topic. In addition, as suggestion for further work it is advised to take a broader approach and to develop a consistent network tarification approach which besides flexible generation also stimulates flexible demand in order to minimize overall system costs. For enabling such future quantitative studies on transmission tarification with an European scope it is key that MS practices are reported for a range of different types of generators and loads in a more systematic and coherent way. Such reports should not only include final network tariffs but also provide insights in underlying assumptions, parameters, and calculations.

PART II: CONGESTION INCOME

5 ASSESSMENT OF CURRENT SITUATION ON CONGESTION INCOME SPENDING

5.1 Current spending of congestion revenues

The current situation with regard to the spending of congestion revenues in the EU is stipulated by Regulation (EC) No 714/2009 on conditions for access to the network for cross border exchanges in electricity. More specifically, Article 16 (6) of this Regulation states that:

> *"Any revenues resulting from the allocation of interconnection shall be used for the following purposes:*
>
> *(a) guaranteeing the actual availability of the allocated capacity; and/or*
>
> *(b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.*
>
> *If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) of the first subparagraph, they may be used, subject to approval by the regulatory authorities of the Member States concerned, up to a maximum amount to be decided by those regulatory authorities, as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs.*
>
> *The rest of revenues shall be placed on a separate internal account line until such time as it can be spent on the purposes set out in points (a) and/or (b) of the first subparagraph. The regulatory authority shall inform the Agency of the approval referred to in the second subparagraph."*

Purpose (a) includes in particular expenditures to cover the costs of redispatching, counter trading and other operational measures to guarantee the actual availability of allocated interconnection capacity. Purpose (b) includes all expenditures needed to maintain or increase the interconnection capacity, which includes, among others, investments in new links, upgrading of existing links and possibly investments to resolve bottlenecks in the national grid which increase the interconnection capacity available to market participants.

It should be noted that congestion rents may in principle be used for inclusion in the tariff base (thus lowering the network tariffs) but the formulation of article 16 (6) emphasizes that this may only be the case when the "revenues cannot be efficiently used for the purposes set out in points (a) and/or (b)". The word 'efficiently' has not been further defined, which leads to different interpretations in practice, for instance an economic interpretation versus a convenient interpretation. In the former case, inclusion of congestion rents in the network tariffs is only allowed when the amount of interconnection capacity has reached the social optimum. The common practice of inclusion of congestion rents in the tariff base, however, suggests that many Member States have interpreted this condition in a more convenient way (see below).

Objectives for the TSOs

With regard to the first two purposes (a) and (b) mentioned in article 16 (6) some relevant objectives of congestion management and revenue spending on cross-border network capacity can be easily distinguished:

1. Above all, congestion management needs to guarantee that the actual available capacity is offered to the market.

Whereas the interconnection capacity itself is defined by the TSOs involved, the design of the congestion management approach itself may contribute to an increase of the available cross-border capacity for market participants. In general, congestion management methods including short-term assessment of network flows and dynamic (market-based) allocation to market participants contribute to this aim.

Nevertheless, if TSOs decide to offer the maximum transport capacity to the market, it might occur (for operational or other reasons) that the capacity offered to the market needs to be reduced. In this case TSOs are entitled to compensate the market parties whose transport capacity is impacted, which invokes costs. These (ex post) costs are in practice considered as costs to guarantee the available capacity, but limit the revenue available for increasing the interconnection capacity with new (physical) capacity.

A problem exists, however, when one would require TSOs to offer the '*maximum* available capacity' to the market (whereas article 16 (6) instead mentions the '*actual* available capacity', which is a value presumably jointly decided by TSOs and NRAs). The calculation of a value for the maximum available capacity is extremely complicated and may be time-dependently related to not only actual dispatch of generation and load flows in the system, but also to necessary reserve margins to accommodate generator tripping and fluctuating renewable energy generation. On the other hand, due to the lack of transparency of any calculation of a value for the 'actual available capacity', it may be tempting for TSOs to offer less interconnection capacity to market participants which will provide more leniency for TSOs to mitigate any unforeseen incidents.

2. In case TSOs offer transport capacity to the market without rationing, the congestion revenues may be used to guarantee the availability of this cross-border or cross zonal capacity by counter trading or redispatch. Effectively, this guarantee does not imply a physical guarantee – if the transmission capacity needs to be reduced for technical reasons, a financial payment will not alleviate the constraint – but a financial guarantee. The latter means that market participants who have been awarded a title to transport over the interconnection will be compensated for the financial loss in case of network constraints.

   In this case the congestion revenues serve to pay for the firmness of this capacity. It differs from the previous measure in the fact that system operators allow market parties to trade as if there were no congestion (whereas in the previous option, capacity scarcity results in different market prices). When spending congestion revenues in this manner, the payment does not contribute to a long-term resolution for the congestion. Neither is this approach able to resolve issues with physical (capacity) shortage in the congested region. However, for non-structural congestion or congestion which cannot effectively be addressed by new investments, such measures may be considered efficient. However, also in this case, if congestion revenue is used for this purpose, it lowers the amount available for new (physical) capacity.

3. Congestion revenues may be spent on investments in network reinforcements, upgrading existing interconnections or investing in new ones, each option leading to an increase (or maintenance) of the available cross-border capacity.[53] By applying this solution the congestion will be addressed in a long-term manner. However, given the delay until the new capacity will become available for the market, it does not provide a short-term solution.

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[53] Network reinforcements in national networks which limit the net transmission capacity of international transmission links are included as well.

5.2 Spending of congestion revenues in 2011-2015

According to data from ENTSO-E, the total amount of TSO net revenues from congestion management on interconnections over the period 2011-2015 was, on average € 2.0 billion per annum, varying from € 1.2 billion in 2011 to € 2.6 billion in 2015. Figure **2** presents an overview of the spending of congestion revenues in million Euros (M€) per ENTSO-E Member State over the years 2011-2015, according to the four spending categories mentioned in Article 16 (6) of EC Regulation No 714/2009. Note that the annual average amount of congestion revenues presented in Figure **2** (i.e., on average, € 1.8 billion per annum) is slightly lower than the average figure mentioned above as in a few cases no distinction in spending categories is recorded.[54]

Figure **2** shows that a major share of total congestion revenues accrues to only a limited number of ENTSO-E Member States. For instance, over the years 2011-2015 almost half of total congestion income has been allocated to only four countries, including France (on average, € 352 million per annum), Italy (€ 261 million), Germany (€ 188 million) and the Netherlands (€ 125 million).[55] The main reason for the relatively high amount of congestion rents accruing to these countries is that they trade (import/export) a relatively major share of their electricity production/consumption with their neighbouring countries and/or that the electricity price differences between these neighbouring, trading countries are relatively substantial during at least a significant amount of hours during the year.

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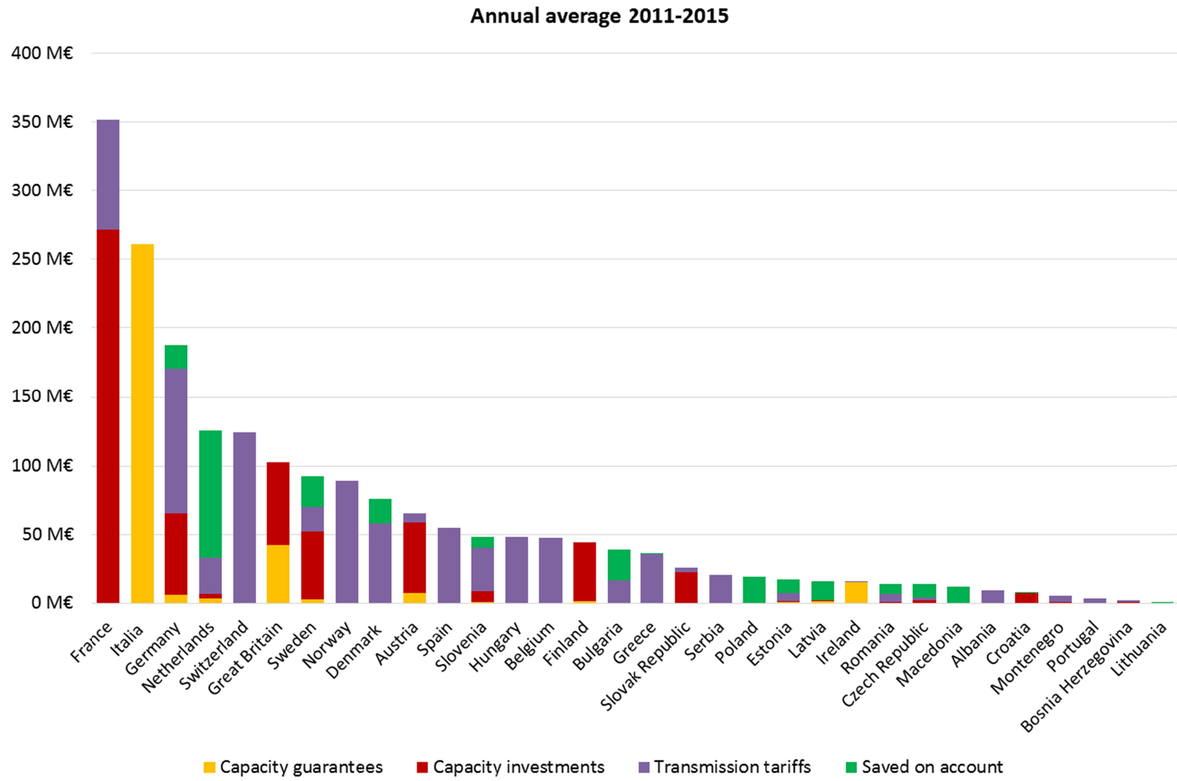
[54] These cases include congestion revenues allocated to Germany in 2011 and to Switzerland in 2011-2014, as well as congestion revenues accruing to the (merchant) BritNed interconnection – between Great Britain and the Netherlands – over the years 2011-2015. In addition, Luxembourg and Northern Ireland are not included in Figure **2** as their congestion revenues amounted to zero over the years 2011-2015.

[55] Note that the data for the Netherlands (and Great Britain) do not include the congestion revenues from the (merchant) BritNed interconnection. Moreover, for Germany the annual average figures refer to the period 2012-2015 – and for Switzerland to the year 2015 only – as data on the spending of congestion revenues per use category are missing for Germany in 2011 and for Switzerland in 2011-2014.

Figure 2 Spending of congestion revenues by ENTSO-E Member States, 2011-15 (annual average, in million € country)



Note: Capacity investments include investments to maintain or increase interconnection capacity.

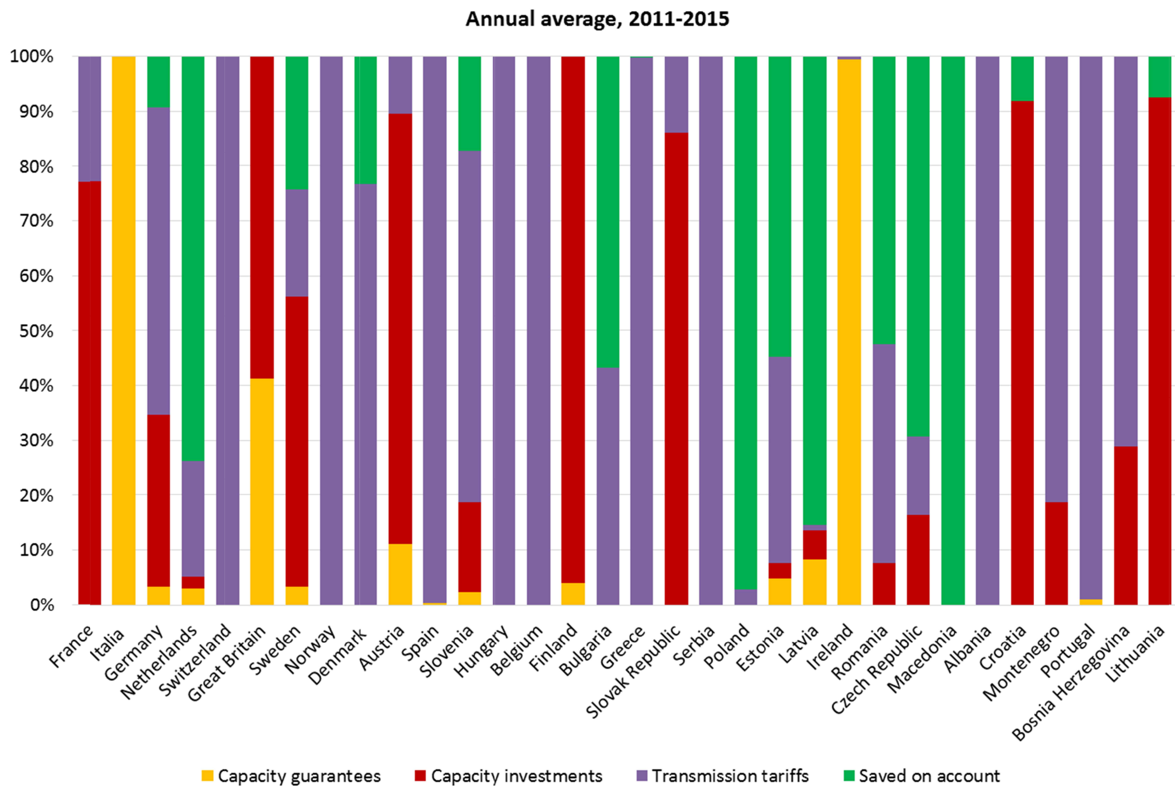
Source: ENTSO-E (2011-15).

In addition, Figure 2 shows that the spending of congestion revenues varies widely among ENTSO-E Member States (see also Figure 3 presenting the spending of congestion revenues over the years 2011-2015 in % of total revenues per Member State, as well as Table 11, providing data on the annual average spending of TSO congestion revenues per country over the years 2011-2015, both in million Euros and as a percentage of total spending). In particular, it can be observed that over the years 2011-2015:

- Two countries have spent 100% of their congestion revenues on guaranteeing interconnection capacity (Italy, Ireland);
- Three countries have spent more than 90% of their congestion rents on investments to maintain or increase interconnection capacity, i.e. Finland (96%), Croatia (92%) and Lithuania (93%);
- Several countries have spent up to 100% of their congestion income to account for in their transmission tariffs, i.e. Switzerland, Norway, Spain, Hungary, Belgium, Greece, Serbia, Albania and Portugal (995);
- A few countries have saved a major part of their congestion reverues on a separate internal account, i.e. Macedonia (100%), Poland ((97%), Latvia (86%), the Netherlands (74%), and the Czech Republic (69%).

Although the available information provides total amounts for the spending of congestion rents to the purposes mentioned in article 16 (6), it is not clear where this money has been spent. Specifically, if figures are given for spending on new investments, it is not clear which costs of which link(s) have been covered by this spending (and how this would relate to the regulatory treatment of investments in these links). Therefore, in general, more transparency on congestion income spending (and applied accounting rules) would certainly be welcome.

Figure 3 Spending of congestion revenues by ENTSO-E Member States, 2014-15 (annual average, in % of total revenues per Member State)



Source: ENTSO-E (2011-2015).

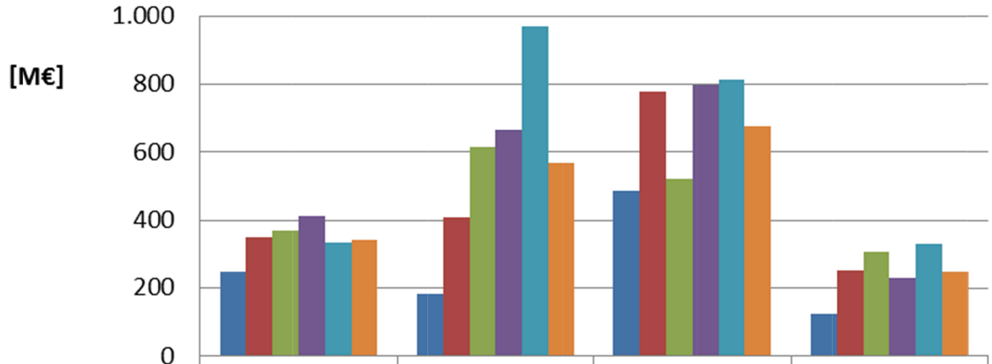
Table 11 Spending of congestion rents by ENTSO-E Member States, 2011-2015 (total annual average, in million Euro and in %)

Country	Total rents, annual average 2011-2015 (M€)	Average annual spending, 2011-2015 (M€)				Average annual spending, 2011-2015 (%)			
		Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
France	352	0	272	80	0	0%	77%	23%	0%
Italy	261	261	0	0	0	100%	0%	0%	0%
Germany[a]	188	6	59	105	17	3%	31%	56%	9%
Netherlands	125	4	3	26	93	3%	2%	21%	74%
Switzerland[b]	124	0	0	124	0	0%	0%	100%	0%
Great Britain	102	42	60	0	0	41%	59%	0%	0%
Sweden	92	3	49	18	22	3%	53%	19%	24%
Norway	89	0	0	89	0	0%	0%	100%	0%
Denmark	75	0	0	58	18	0%	0%	77%	23%
Austria	65	7	51	7	0	11%	78%	10%	0%
Spain	55	0	0	54	0	0%	0%	100%	0%
Slovenia	48	1	8	31	8	2%	16%	64%	17%
Hungary	48	0	0	48	0	0%	0%	100%	0%
Belgium	47	0	0	47	0	0%	0%	100%	0%
Finland	44	2	42	0	0	4%	96%	0%	0%
Bulgaria	39	0	0	17	22	0%	0%	43%	57%
Greece	36	0	0	36	0	0%	0%	100%	0%
Slovak Republic	26	0	22	4	0	0%	86%	14%	0%
Serbia	21	0	0	21	0	0%	0%	100%	0%
Poland	20	0	0	1	19	0%	0%	3%	97%
Estonia	17	1	0	6	9	5%	3%	38%	55%
Latvia	16	1	1	0	14	8%	5%	1%	86%
Ireland	15	15	0	0	0	100%	0%	0%	0%
Romania	14	0	1	6	7	0%	8%	40%	53%
Czech Republic	14	0	2	2	10	0%	16%	14%	69%
Macedonia	12	0	0	0	12	0%	0%	0%	100%
Albania	10	0	0	10	0	0%	0%	100%	0%
Croatia	8	0	8	0	1	0%	92%	0%	8%
Montenegro	5	0	1	4	0	0%	19%	81%	0%
Portugal	3	0	0	3	0	1%	0%	99%	0%
Bosnia and Herzegovina	3	0	1	2	0	0%	29%	71%	0%
Lithuania	0	0	0	0	0	0%	93%	0%	7%
Total	1840	343	569	679	249	19%	31%	37%	14%

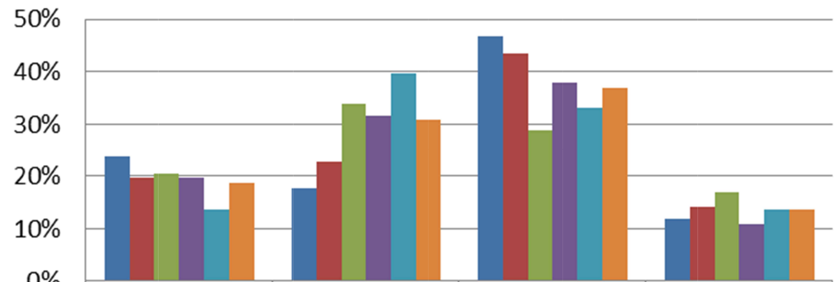
a) For Germany, the annual average figures refer to the period 2012-2015.
b) For Switzerland, the annual average figures refer to the year 2015 only.

Source: ENTSO-E (2011-2015).

Figure 4 Spending of congestion rents by all ENTSO-E Member States, 2011-15 (in million € and as % of total annual rents for all countries)



	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
2011	247	185	485	123
2012	352	409	779	255
2013	371	616	521	308
2014	412	666	797	230
2015	336	968	812	330
Av. 2011-15	343	569	679	249



	Capacity guarantees	Capacity investments	Transmisison tariffs	Saved on account
2011	24%	18%	47%	12%
2012	20%	23%	43%	14%
2013	20%	34%	29%	17%
2014	20%	32%	38%	11%
2015	14%	40%	33%	13%
Av. 2014-15	19%	31%	37%	14%

Source: ENTSO-E (2011-15).

Figure 4 presents the spending of congestion revenues aggregated for all ENTSO-E Member States over the years 2011-2015, both in million € (picture above) and as a % of total annual revenues (picture below). These revenues amounted to, on average, € 1840 million per annum in 2011-2015. Figure 4 shows that out of this amount, on average, € 343 million was spent on capacity guarantees (19%), € 569 on capacity investments (31%), € 679 million on reducing transmission tariffs (37%) and € 249 million saved on an account (14%).[56] This implies that, on average, about half of the congestion revenues in 2011-2015 was used to guarantee, maintain or increase interconnection capacity and, hence, that – in principle – there is room for increasing this share by alternative policy options, in particular through harmonised rules with regards to the effective spending of the congestion revenues on capacity guarantees, reducing the opportunity to spend congestion revenues on lowering transmission tariffs or saving these revenues on a separate account.

Note, however, that (i) as observed above, both the amounts and the shares of the respective congestion revenue spending categories vary widely by country (as also by year), (ii) both the amount and the share of congestion revenue spent on maintaining/increasing interconnection capacity has increased significantly over the years 2011-2015 (from almost € 190 million in 2011 to nearly € 970 million in 2015, i.e. from 18% to 40% of total congestion revenues spent in these years, respectively), and (iii) the share of total congestion revenue spent on reducing transmission tariffs has declined from 47% in 2011 to 33% in 2015, although in absolute terms this spending category has increased from approximately € 490 million in 2011 to € 812 million in 2015 (see Table 11 and Figure 4).

Again it should be stressed that the figures provided on spending congestion revenue are not too detailed and clear. Therefore, in general, more transparency on congestion revenue spending, applied accounting rules and rationale would certainly be welcome, which will also be necessary for the development of any further policy related to interconnection investment and regulation.

5.2.1 Additional interconnection investments are needed…

To be clear up front, there is a strong demand for further investments in interconnection capacity. Irrespective of the proposed policy options, the urgent need for more interconnection capacity is evident. ENTSO-e has provided an estimate of the total investment costs needed for additional interconnection capacity for pan-European projects (with a positive contribution to social welfare). The total investment costs amount to a stunning value in the range from 110 to 150 billion euro in the period up to 2030 (see**Table 12**).

5.2.2 … but investments are lagging

Kapff and Pelkmans analysed in 2010 numerous other reasons why the European regulatory framework leads to an 'interconnector investment failure':[57]

1. New interconnection capacity – even though socially beneficial – creates winners and losers. If losers (i.e. countries facing higher costs than benefits) are not compensated, they will oppose the investment.
2. Infrastructure investment may be necessary in a Member State that would not benefit from the new interconnector.

---

[56] Unfortunately, the data on capacity investments – i.e. the amounts used to maintain or increase interconnection capacity – do not make clear how much was actually spent on new interconnection.

[57] L. Kapff and J. Pelkmans, Interconnector investment for a well-functioning internal market, what EU regime of regulatory incentives?, Bruges European Economic Research Papers, BEER №18, 2010, p.11v.

Table 12 Breakdown of estimated investment costs for the portfolio of electricity transmission projects of pan-European significance (in billion euro)

AT	1.9	**IE**	2.0
BA	0.1	**IS**	0.0[30]
BE	2.0-4.0	**IT**	5.9
BG	0.3	**LT**	0.7
CH	1.6	**LU**	0.2
CY	0.0	**LV**	0.4
CZ	1.5	**ME**	0.1
DE	34.8-54.2	**MK**	0.1
DK	3.7	**NI**	0.5
EE	0.2	**NL**	3.3
ES	4.3	**NO**	7.9
FI	0.8	**PL**	1.9
FR	8.4	**PT**	0.7
GB	15.9-16.2	**RO**	0.5
GR	2.6	**RS**	0.4
HR	0.2	**SE**	3.6
HU	0.1	**SI**	0.6
		SK	0.3
Total	**110-150**		

Source: ENTSO-E, TYNDP 2014.

3. Investment incentives within an integrated [that is, not unbundled] vertical electricity company are likely to be distorted.
4. Planning and authorization procedures for new interconnectors are complicated, time consuming and costly. When two or more Member States are concerned by a project, lack of harmonized procedures often lead to excessive delays.
5. Interconnector investments are highly risky and complex ventures. In liberalized markets, grid and generation investments are decoupled due to unbundling. Grid investments thus face uncertainty on the actual use of the infrastructure. In the worst case, an interconnector can become a stranded asset. Furthermore, cross-border projects are subject to high regulatory uncertainty over time. Changing regulatory frameworks, the introduction of new congestion management mechanisms or the review of regulated tariffs might significantly alter the return on investment. Finally, investors also face uncertainty concerning possibly changing market architectures and energy mixes of the interconnected markets.
6. Potential interconnector investors are further discouraged by the existence of a regulatory gap due to the fact that each regulator only has authority within its national market and no authority decides on cross-border and regional issues.

The impact of a lack of interconnection capacity, or at least a deficit with respect to the social optimum[58], is that the European electricity system operates less efficiently and network users pay too much for their electricity.

58 See page 10.

5.2.3 Financial instruments to facilitate interconnection investments

According to a recent EU Communication (EC, 2015a), the Commission estimates that some € 200 billion are required up to 2020 to build the necessary infrastructure to adequately interconnect all EU Member States, that will ensure security of supply and enhance sustainability. For electricity projects some € 105 billion are needed, out of which some € 35 billion for the interconnections which have acquired a PCI status and which are necessary to reach the 10% target across the EU. Most likely investment needs in interconnections beyond 2020 will be even higher due to the expected growth of power generation from variable renewable energy sources across Europe as well as to meet other socioeconomic objectives such as promoting the internal energy market, improving energy security or enhancing competition and efficiency across European countries.

In order to facilitate investments in energy infrastructure, the EU has introduced a number of supporting financial instruments. These instruments include in particular:[59]

- The *Connecting Europe Facility (CEF)*. CEF is an EU initiative, established under Regulation (EU) No 1316/2013, in order to provide financial assistance to investments in trans-European networks in the transport, energy and telecommunication sectors. CEF offers both grants to contribute to the construction costs of new links as well as financial instruments – such as enhanced loans and project bonds – to mitigate certain risks, thereby helping project promoters to access the necessary financing for their projects.

  Under the CEF initiative, a budget of € 5.85 billion has been allocated to support energy infrastructure investments for the period 2014-2020. Although this funding represents only about 3% of the investments needed up to 2020, it may leverage other types of funding from public/private sources. While the bulk of the investment needed in energy infrastructure should be delivered by the market and its costs recovered through tariffs, it is however recognised that EU financing may be needed for specific projects with wider regional and European benefits which are unable to attract market-based financing. CEF can, therefore, play an important role to bridge the funding gap in regions where there is most need for European intervention. In order to be supported by CEF, a project must be listed as a Project of Common Interest (PCI). In addition, it has to meet several other conditions. Notably, it has to prove it is commercially not viable while meeting the specific criteria on the social benefits regarding market integration, sustainability or security of supply (EC, 2013a and 2013c; ITRE, 2016).[60]

- The *European Fund for Strategic Investments (EFSI)*. Early 2015, the Commission proposed the creation of EFSI in order to significantly improve EU investment projects' access to long-term financing. The Fund is at the very heart of the Commission's Growth, Jobs and Investment package ('Plan Juncker'). It aims to mobilize at least € 315 billion in private and public investments across the EU, against

[59] For a full overview of current EU initiatives and programmes supporting energy infrastructure, see Norton Rose Fulbright (2015; see also Figure 12 in ITRE, 2016). In addition, in the past the EU has also used other (temporary) instruments to stimulate investments in energy infrastructure, including interconnection projects, such as the European Energy Programme for Recovery (EEPR; see EC, 2015a, in particular Annex I).

[60] Recently, the EC has launched a mid-term evaluation of the CEF, including public consultations. For details, see https://ec.europa.eu/transport/themes/infrastructure/consultations/mid-term-evaluation-connecting-europe-facility-cef_en and http://ec.europa.eu/smart-regulation/roadmaps/docs/2017_move_003_mid_term_evaluation_connecting_europe_facility_en.pdf

an EU budget contribution of € 16 billion and a contribution by the European Investment Bank (EIB) of € 5 billion. EFSI could support PCIs or other electricity interconnection projects put forward, thereby accelerating and complementing other sources to finance these projects (EC, 2015a; ITRE, 2016). However, most of EFSI is invested in financing of small and medium sized enterprises, whereas in the energy field energy efficiency and renewable investments are predominant.

- The *European Structural and Investment Funds (ESIF)*. From 2014 to 2020, € 50 billion (€ 630 billion including national co-financing) will become available as ESIF support in order to strengthen EU economic structures and reduce development disparities across regions.[61] Under certain conditions, Member States may use ESIF, in particular the European Regional Development Fund (ERDF) and the Cohesion Fund (CF), to finance energy projects, including electricity interconnection investments (EC, 2015a; ITRE, 2016). Until now, only 2 Member States have used this opportunity: Poland uses ESIF for TEN-E investment, 105 million euros in electricity infrastructure and 430 million for gas, and Bulgaria uses 39 million for gas infrastructure.

Apart from funding investments through subsidies and providing cheaper financing, a 'natural way' to stem investments is to use the regulated income (tariff) and, specifically, within this income the dedicated congestion revenues. In case the latter are not sufficient to reach a socio-economic optimum, the wider regulated income could be used. As discussed in Section 5.1, over the years 2011-2015 only a share of the congestion revenues has been used for such investments, i.e. on average about € 680 million per annum, without any available evidence, that the socio-economic optimum (either national or European) has been achieved. Hence, there seems to be room to increase this amount substantially, notably by reducing the opportunity of TSOs/NRAs to use congestion rents for reducing transmission tariffs (see particularly Figure 4, as presented and explained in Section 5.1), or at least arrive at a common understanding of the investments necessary to reach the socio-economic optimum.

Congestion rents as a source of funding

One approach would be to severely restrict spending of congestion revenues on other purposes than guaranteeing, maintaining or increasing interconnection capacity, and earmark these resources for funding new investments in interconnection capacity. Notably, all remaining revenues which are used for decreasing the transmission tariffs could be used for additional investments in interconnection capacity. In fact, this was already the conclusion in the study performed by Kapff e.a.:[62]

> "All congestion rents should be channelled into interconnector building. A European fund for unused congestion rents should be established and supervised by a European agency. …
>
> Supra-national network planning should be undertaken by a European TSO organization taking a pan-European view and deciding by quality majority voting. The European network development plan proposal should be reviewed by an independent EU regulatory agency. The agency ought to decide on the prioritization and implementation of interconnector investment projects. If overall welfare increasing projects yield net losers, the agency should determine a cost reallocation

61 ESIF includes the European Regional Development Fund, the European Social Fund, the Cohesion Fund, the European Agricultural Fund for Rural Development, and the European Maritime & Fisheries Fund.

62 L. Kapff and J. Pelkmans, Interconnector investment for a well-functioning internal market, what EU regime of regulatory incentives?, Bruges European Economic Research Papers, BEER №18, 2010, p.23.

> to be implemented via a European interconnector fund. NRAs should be entrusted with the enforcement of the final European network development plan. In case of non-compliance, the agency should have the right to organize a tender in order to build the 'missing links'."

A strong motivation for adopting such an approach is that congestion revenues are scarcity rents. These rents are not a result of 'normal' business operation, i.e. the result of the exploitation of the transmission grid, but these are accrued due to the *lack* of transmission capacity. Hence, this income has a special status and ring fencing or a special treatment is desirable (as already expressed by the European legislator). However, to execute this special status and use the money efficiently, the socio-economic optimum has to be formulated and harmonised rules (across potentially interconnected borders) have to be applied.

In our opinion, this cannot be solved by only creating more transparency in the spending of congestion rents. Specifically, the apparent reluctance of some Member States to contribute to the construction of additional interconnections which are socially beneficial for Europe, could be seen as a major shortcoming in the present decision making approach on interconnection investment (and the related spending of congestion income on such investments).

A major issue is, as mentioned above, the asymmetric benefits of new interconnection investments. Here, the issue is more complicated than merely reaching a positive business case for the investment itself and solutions have to be found on a supra-national level:

- The basic dilemma is that interconnection investments based on a positive business case confine the costs and benefits to the capital and operational costs of the investment and the revenues of the additional congestion rents. However, given that additional interconnection capacity also results in a reduction of the price difference between countries, the interconnection value – not only for the new capacity but for all capacity between the two systems – will be reduced since the price difference between the systems involved will be lower (as a result of the additional investment).
- Furthermore, the new link will lead to an increase in social welfare (due to the higher efficiency of electricity generation serving consumers' demand), but the high price country will mainly benefit from an increase of consumer surplus whereas the low price country will benefit from an increase of producer surplus. For NRAs involved, especially in countries where NRAs are charged with promoting low energy tariffs for electricity consumers, approving a link which will (on average) lead to higher electricity prices for their consumers, it may be difficult to positively defend the investment decision in additional interconnection capacity.
- Moreover, other countries, not directly involved in the construction of the physical link, may benefit from the new interconnection capacity. Typically, these are not involved in the investment decision (and do not financially contribute to the investment)

A practical solution for these problems is provided in the TEN-E regulation, more specifically through cross-border cost allocation mechanisms. It is a cost sharing mechanism for the investment costs among all countries benefiting or impacted by the new link. In practice, both the identification of these countries and the calculation of such a cost sharing are complicated.

These decisions imply difficulties which could possibly be partly mitigated by strong ring fencing of congestion revenues and consequently transferring congestion revenues to a separate fund, which will no longer be under control of the national TSOs or the NRAs.

This fund could then be used for targeting specific links which are extremely important for the European electricity consumers but are nevertheless not constructed.

Strong ring fencing of congestion revenues may help as TSOs/NRAs will become indifferent with respect to the amount of the congestion revenues. When these revenues can no longer contribute to the tariff base (and thus be considered as a source of revenue for the TSO), any decrease of these revenues will no longer financially impact the TSOs. On the contrary, it may even become more profitable for TSOs to invest in more interconnection capacity, since these new investments will contribute to their asset base (which will increase in value).

5.2.4 Monitoring and assessing regulation on congestion income spending

As outlined in Section 5.1, Article 16 (6) of Regulation 714/2009 states that any revenues from the allocation of interconnection shall be used for (a) guaranteeing the actual availability of the allocated capacity, and/or (b) maintaining or increasing interconnection capacities through network investments. If the revenues cannot be efficiently used for these purposes, they may be used, subject to approval by the NRAs of the Member States concerned, up to a maximum amount to be decided by those NRAs, as income to be taken into account by the NRAs when approving or fixing network tariffs. The remaining revenues shall be placed on a separate internal account until such time as it can be spent on purposes (a) and/or (b). Finally, Article 16 (6) stipulates that the NRA shall inform ACER of the approval mentioned above.

In the current situation, TSOs report on the use of their congestion revenues to the NRAs. These NRAs check and approve, with regards to their interpretation of the legal provisions, whether this use is in line with Article 16 (6) of Regulation 714/2009, they decide on the maximum amount of congestion income to be accounted for when setting network tariffs, and they merely inform ACER on their approval of the congestion income use by the TSOs. Due to a lack of information and transparency, however, it is not entirely clear to which extent the rules are being applyied in accordance with provisions and aim at maximizing interconnections for an optimal social welfare. In particular, it is not clear:

- How the TSOs decide on the use of congestion revenues for either guaranteeing, maintaining or increasing interconnection capacity (as the TSO reports to the NRAs are usually not public, not readily available or only published in the national language concerned);
- Whether and how the NRAs check (i) that TSOs have used congestion revenues efficiently for either guaranteeing, maintaining or increasing interconnection capacity, and (ii) that the rest of the revenues cannot be efficiently used for these purposes (as the NRA documents do not include this information and/or are published in their national language only);[63]
- On which criteria the NRA decides on the maximum amount used as income to be taken into account when approving or fixing network tariffs (idem);
- How the congestion revenues are used during the period they are put on a separate account (as this information is usually not readably available);[64]

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63 See, for instance, the recent documents of the Dutch NRA (ACM) on the use of congestion revenues by the Dutch TSO (TenneT) over the years 2013-2015 (ACM, 2014 and 2015a).

64 For instance, recently the Dutch TSO (TenneT) and the Dutch NRA (ACM) agreed that up to 2020 some € 300 million of congestion revenues are used to finance the purchase of part of the German transmission system by TenneT (ACM, 2015b). This agreement was heavily contested by the Dutch Association of Energy Users (VEMW, 2015), arguing that these revenues should be used for reducing network tariffs already in the short term.

- How the NRAs inform ACER on their approval of the congestion income use by the TSOs (idem);
- Whether and how the compliance regime regarding the rules of Article 16 (6) are enforced (idem).

Therefore, besides policy options for changing the rules on spending congestion revenues, there seems to be need for enhancing the transparency regarding the compliance and enforcement of these rules.

5.2.5 Using congestion rents to fund interconnection investments

Congestion revenues shall preferably be used to fund the costs of interconnection investments. In general, the final decision to approve the costs of interconnection investments and to use congestion rents lies at the NRAs. NRAs, however, have to serve several social (national) objectives, including protecting power consumers against high tariffs due to monopoly rents, market abuses, inefficiencies, etc. So, they look critical to the costs of new interconnection investments and may be inclined to use congestion income primarily for serving (short-term) national interests, including controlling transmission tariffs for electricity end-users, in particular when the reserve (internal account) of remaining congestion rents is already significant and there are no short-term opportunities to invest in interconnection projects that have a clear positive national (social) outcome.[65]

Hence, leaving the decision to use congestion revenues to fund the costs of interconnection investments to NRAs, may prevent investments in interconnection capacity, notably for those projects that serve (long-term) regional or EU-wide interests – in particular the projects of common interests (PCIs) – but for which (short-term) national benefits are less clear. Therefore, changing the rules on spending congestion revenues may, in theory, result in more congestion revenues spent on enhancing interconnection capacity, including investments in projects of regional or EU-wide interests.

The total congestion revenues aggregated for all ENTSO-E Member States over the years 2011-2015 amounted to, on average, € 1840 million per annum in 2011-2015 (see Section 5.1). On average this amount was used as follows:

- € 340 million was spent on capacity guarantees (19%),
- € 570 on capacity investments (31%),
- € 680 million on reducing transmission tariffs (37%), and
- € 250 million saved on a separate account (14%).

This implies that, by changing the rules on using congestion rents, the amount spent on enhancing interconnection capacity can increase by, on average, some € 680 million per annum as a maximum, in particular if the option to use these rents on reducing network tariffs is no longer allowed under any condition.

[65] Moreover, although NRAs are independent and there is an unbundling of responsibilities between NRAs, TSOs and national policy makers, in practice NRAs may feel pressure from national policy makers and/or TSOs to use congestion rents for serving particular national (short-term) interests.

ANNEX

ANNEX A: DESCRIPTION OF THE EU ELECTRICITY MARKET MODEL COMPETES

Model overview

COMPETES[66] is a power optimization and economic dispatch model that seeks to minimize the total power system costs of the European power market whilst accounting for the technical constraints of the generation units, the transmission constraints between the countries as well as the transmission capacity expansion and the generation capacity expansion for conventional technologies. The COMPETES model can be used to perform hourly simulations for two types of purposes:

- Least-cost unit commitment (UC) and economic dispatch with perfect competition, formulated as a relaxed mixed integer program taking into account flexibility and minimum load constraints and start-up costs of generation technologies.
- Least cost capacity expansion and economic dispatch with perfect competition, formulated as a linear program to optimize generation capacity additions in the system using a two-period approach.

The formulation of generation capacity expansion and economic dispatch are based on complementarity and optimization modelling (Ozdemir et al., 2013). The unit commitment formulation is based on the relaxed UC formulation of Kasina et al (2013). The model is coded in AIMMS and uses the Gurobi solver.

Model formulation

Unit commitment and economic dispatch model

The COMPETES UC model is used to find an optimal generation schedule for the problem of deciding which power generating units must be committed/uncommitted over a planning horizon at minimum cost, satisfying the forecasted system load as well as a set of technological constraints. These constraints include the flexibility capabilities of different generation technologies as well as the lumpiness in generator start-up decisions, a feature not considered in most continent-wide electricity market models. The model also includes hourly profiles of wind and solar generation that are intermittent in nature.

Unit commitment problems are considered to be difficult to solve for systems of practical size due to their complexity of finding integer solutions. To overcome this, while the exact formulation of a Mixed Integer Linear Programming (MILP) is used for the units in the Netherlands, an approximation of MILP is formulated for the other countries/regions. The corresponding approximating problem proposed by Kasina et al. (2013) aims to solve large scale systems within a reasonable time while capturing the most of the characteristics of a unit commitment problem.

To summarize, the unit commitment formulation of COMPETES minimizes total variable, minimum-load and start-up costs of generation and the costs of load-shedding in all countries subject to the following electricity market constraints:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.

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[66] The COMPETES model has been developed by the Energy research Centre in the Netherlands (ECN), in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University (Baltimore, USA) as a scientific advisor of ECN.

- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.
- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.
- *Ramping up and down constraints:* These limit the maximum increase/decrease in generation of a unit between two consecutive hours.
- *Minimum load constraints:* These constraints set the minimum generation level of a unit when it is committed. For the Netherlands, every unit is modelled with minimum generation levels and the corresponding costs. For other countries, this constraint is approximated by a relaxed formulation since the generation capacities and the minimum generation levels represent the aggregated levels of the units having the same characteristics (e.g., technology, age, efficiency etc.).
- *Minimum up and down times (only for the units in the Netherlands):* These constraints set the minimum number of hours that a unit should be up or down after being started-up or shut-down.

The incorporation of start-up costs, ramping rates and minimum load levels allows a better representation of the system flexibility to accommodate the variability and forecast errors of electricity from variable energy sources such as sun or wind. In addition, the model also includes the flexibility decisions related to the operation of storage. The long-term planning decisions in the form of adequate generation capacity and cross-border import capacity is part of the scenario and thus exogenous to the model.

Generation and transmission capacity expansion model

The generation expansion formulation of COMPETES endogenously calculates the least cost transmission capacity and the conventional generation capacity additions taking into account generation intermittency (e.g., wind, solar) and RES-E penetration in EU member states. The renewable and nuclear installed capacities are assumed to be exogenous since capacity developments of these technologies are mainly policy driven. The model also decommissions the existing conventional power plants that cannot cover their fixed costs.

The model uses a two-period optimization approach as described in Ozdemir et al. (2013). It uses a two-stage optimization approach, as described in Özdemir *et al.* (2013). Investment decisions regarding a mix of new technologies are determined in the first stage (i.e. 2020), while the generation of electricity per technology and per country in future electricity markets is set in the second stage (i.e. 2030). It can also be used with a multiple recursive period approach which is essentially performing a series of a two-period optimization model with the aim to reflect the transition of the system.

Ozdemir et al. (2016) shows that, under the assumption of perfect competition, the two-stage competitive equilibrium of generation and transmission investments in energy-only electricity markets or electricity markets with a forward capacity market can be found by solving an equivalent optimization problem (i.e., a linear program. Thus, the dynamic COMPETES model is still formulated as a linear program in which the objective function minimizes the overall investment and system operating costs. The investment costs include annual investment costs of new transmission capacity (i.e., HVDC lines) between countries as well as the annualised investment costs of conventional generation, whereas the system operation costs consist of the annual generation operating cost and the cost of energy not served (i.e., 10.000 euro/MWh; Stoft,2002).

The model minimizes total system cost under electricity market constraints such as:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.

- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.
- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.

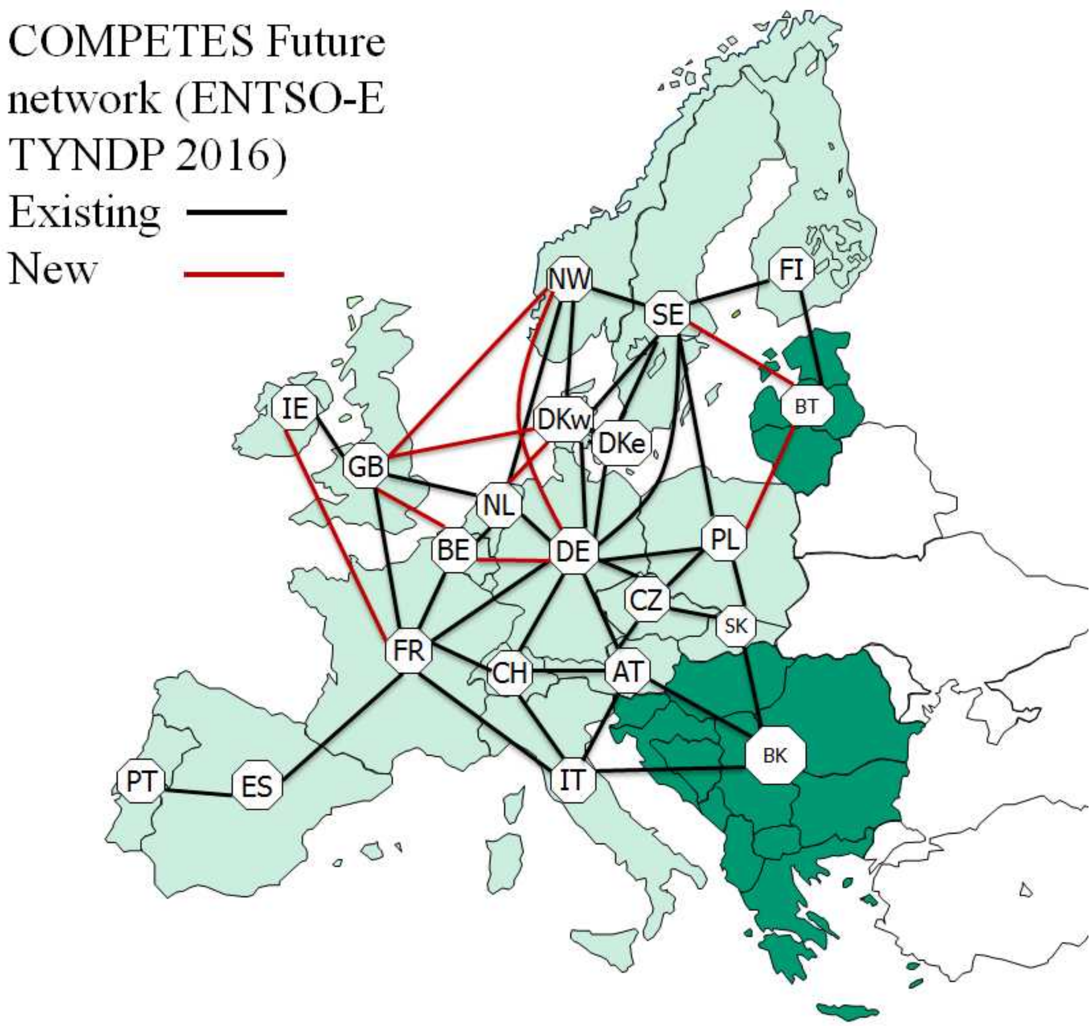
Given the specific levels of demand, the solution of the COMPETES expansion model specifies the least-cost/social welfare maximizing investments of generation and transmission capacity as well as their allocation in all the countries, whereas the competitive prices calculated at each node represent the locational marginal prices. The least-cost allocation of production implies that the conventional generation technologies and the flexible renewable technologies (e.g., biomass and waste) are dispatched according to their marginal costs and positions in the merit order for each country.

Model inputs and assumptions

Geographical and temporal scope

The COMPETES model covers 28 EU member states and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries) including a representation of the cross-border transmission limitations interconnecting these European countries. Every country is represented by one node, except Luxembourg which is aggregated to Germany, while the Balkan and Baltic countries are aggregated in one node, and Denmark is split in two nodes due to its participation in two non-synchronous networks (See Figure 5). The model assumes an integrated EU market where the trade flows between countries are constrained by "Net Transfer Capacities (NTC)" reflecting the ten year network development plan (10YNDP) of ENTSO-E up to 2030 (ENTSO-E, 2015). The model has time steps of one hour and in this study the target year is optimized for all 8760 hours.

Figure 5 Geographical coverage in COMPETES and the (future) representation of the cross-border transmission links according to the Ten-Year Network Development Plan of ENTSO-E (ENTSO-E, 2015)



Electricity supply characteristics

The input data of COMPETES involves a wide-range of generation technologies summarized in Table 13. There are 14 types of fossil-fuel fired power plants (which can operate with CCS or as combined heat and power plant) as wells nuclear, geothermal, biomass, waste, hydro, wind and solar technologies (in particular detailed out with unit by unit generation in the Netherlands). For the other countries, the units using the same technology and having similar characteristics (i.e., age, efficiency, technical constraints) are aggregated. The generation type, capacity, and the location of existing generation technologies are regularly updated based on the WEPPS database UDI (2012).

Table 13 The categorization of electricity generation technologies in COMPETES

Fuel	Types	Abbreviation
Gas	Gas Turbine	GT
	Combined cycle	NGCC
	Combined heat and power	Gas CHP
	Carbon capture and storage	Gas CCS
Derived Gas	Internal Combustion	DGas IC
	Combined heat and power	DGas CHP
Coke oven gas	Internal Combustion	CGas IC
Coal	Pulverized Coal	Coal PC
	Integrated gasification combined cycle	Coal IGCC
	Carbon capture and storage	Coal CCS
	Combined Heat and Power	Coal CHP
Lignite	Pulverized Coal	Lignite PC
	Combined Heat and Power	Lignite CHP
Oil	Oil	
Nuclear	Nuclear	
Biomass	Co-firing	
	Standalone	
Waste	Standalone	
Geo	Geothermal power	
Solar	Photovoltaic Solar Power	
	Concentrated Solar power	
Wind	Onshore	
	Offshore	
Hydro	Conventional	
	Pump Storage	

The main inputs for electricity supply can be summarized as:

- Operational and flexibility characteristics per technology per country:
  - Efficiencies
  - Installed power capacities
  - Availabilities (seasonal/hourly)
  - Minimum load of generation and minimum load costs
  - Start-up/shutdown costs
  - Maximum ramp-up and down rates
  - Minimum up and down times (only for the units in the Netherlands)
- Emission factors per fuel/technology
- Fuel prices per country, CO_2 ETS, (national CO_2tax)
- Hourly time series of intermittent RES (wind, solar etc.)
- RoR (run of river) shares of hydro in each country
- External imports from Africa (Optional)
- Overnight costs for conventional generation (Euro/MW)
- Transmission CAPEX (Euro/MW)

The flexibility assumptions for conventional units are assumed to differ with the type and the age of the technology as summarized in Table 14.

Table 14 Flexibility Assumptions for conventional technologies in COMPETES

Technology	Time of being commissioned	Minimum load (% of maximum capacity)	Ramp rate (% of maximum capacity per hour)	Start-up cost[a] (€/MW installed per start)	Minimum up time	Minimum down time
Nuclear	<2010	50	20	46 ±14	8	4
	2010	50	20	46 ±14	8	4
	>2010	50	20	46 ±14	8	4
Lignite and Coal PC/CCS	<2010	40	40	46 ±14	8	4
	2010	35	50	46 ±14	8	4
	>2010	30	50	46 ±14	8	4
Coal IGCC	<2010	45	30	46 ±14	8	4
	2010	40	40	46 ±14	8	4
	>2010	35	40	46 ±14	8	4
NGCC/Gas CCS	<2010	40	50	39 ±20	1	3
	2010	30	60	39 ±20	1	3
	>2010	30	80	39 ±20	1	3
GT	<2010	10	100	16 ±8	1	1
	2010	10	100	16 ±8	1	1
	>2010	10	100	16 ±8	1	1
Gas CHP	<2010	10	90	16 ±8	1	1
	2010	10	90	16 ±8	1	1
	>2010	10	90	16 ±8	1	1

a) Warm start-up costs are assumed for all technologies but OCGT. For OCGT, a cold start is assumed.
b) Source: Brouwer et al. (2015).

Overnight costs for conventional generation for capacity expansion model represent engineering, procurement and construction plus owners costs to develop the project and is taken from different sources (see Table 15).

Table 15 Overnight investment cost of generation technologies

FUELNEW	FUELTYPENEW	2030 (Euro/MW)
GEO	-	2450
HYDRO	CONV	2300
HYDRO	PS	2300
LIGNITE	PC	1550
NUCLEAR	-	3000
OIL	-	725
RESE	Others	2800
SUN	PV	1600
WASTE	Standalone	1900
WIND	ONSHORE	1100
WIND	OFFSHORE	2625
GAS	CCS CHP	1250
SUN	CSP	3500
GAS	CCS CCGT	1250
COAL	CHP	1350
LIGNITE	CHP	1550
BIOMASS	Cofiring	1600
BIOMASS	Standalone	1900
COAL	PC	1350
COAL	IGCC	1925
COAL	CCS	3200
Derived GAS	IC	825
GAS	CCGT	700
GAS	CHP	700
GAS	GT	400

Sources: ECF Roadmap 2050; ReportTechnical Analysis page 34.
ETP 2010, IEA Energy Technology Perspectives 2010, Scenarios and Strategies to 2050.
IEA ETSAP Technology Brief E05, Biomass for Heat and Power, May 2010.
IEA ETSAP Technology Brief E04, Combined Heat and Power, May 2010.
ZEP, The cost of CO_2 capture, European Zero Emission Platform.
TCE, Texas Clean Energy.

Investments in transmission are simplified in order to have a Linear Program (assuming continuous costs per MW) instead of an integer problem. In COMPETES HVDC investments are considered to be an overlay network. The unit investment cost of overlay network is assumed to be 0.0008MEuro/MWkm (IRENE-40, 2012). Furthermore it is assumed that HVDC cables can be utilized in two directions, i.e. from AC --> DC and DC --> AC. Hence, both at the beginning and at the end of the line two converters are needed. Hence we assume the upper value of 1-4 converter transformer costs based on ACER (2015) data for the additional converter cost (103566 euro/MVA).

Intermittent RES generation

The maximum hourly power generation from solar and wind depends on the hourly load factors and the installed capacities of these technologies that are inputs to the model. The hourly load factors - representing the variability of wind and solar - are calculated based on the historical hourly generation data of the climate years under consideration provided by ENTSO-E (2016) and the TSOs of different countries.[67] Especially for Northwest Europe this dataset is more or less complete for 2012 -2015. For countries for which the hourly data is not available, correlations from the TradeWind (2009) data set of the year 2004 are used to indicate which country-specific time series were applicable to represent the wind time series of neighbouring countries.[68] For solar, only a full dataset of 2005 and 2015 are available to represent hourly solar production (ENTSO-E, 2016 and SODA, 2011).[69] Since there is a seasonal correlation between wind and solar – e.g. summer is relatively more sunny and less windy - but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year.

Hydro conventional generation

Hydro production can be divided between conventional hydro, run-of-river (ROR) and reservoir storage. Hourly hydro conventional generation is calculated prior to the actual runs with the COMPETES model and assumed as an input to the model. Hourly Run-of-River (RoR) generation is determined by using data on annual hydro generation, the share of RoR per country, and monthly data on the RoR production. In order to calculate hourly hydro storage production, RoR is assumed to be must-run or inflexible generation, and the dispatch of flexible generation from hydro storage is assumed to depend on the residual demand hours (demand minus variable RES-E generation). Since the highest prices are expected in the high residual demand hours, hydro storage is assumed to produce in the highest residual demand hours in a certain year. The underlying idea for this approach is that there is a positive correlation between residual demand and prices. The generation from hydro storage is distributed over the year in such a way that the sum of the hourly generation is equal to the assumed annual hydro production for that year.

Storage

For the purpose of providing flexibility on timescales of an hour and more in sufficient volumes, we mainly focus on the bulk electricity storage technologies such as hydro pumped storage and compressed air energy storage (CAES). These electricity storage technologies are modelled to operate such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-

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[67] Wind times series from 2006-2014 for a few EU countries are given by Bach (2015) and of 2012 for the Netherlands by ECN (2014). Also Energinet (2015); Nordpoolspot (2015); Terna (2015); 50Hertz (2015); Amprion (2015); TenneT (2015b); and TransnetBW (2015); and Eirgrid (2015) provide hourly wind data.

[68] In case there is a strong positive correlation between two countries, it indicates that the countries generally show the same wind patterns. For example, data for Spain was available but not for Portugal. Since TradeWind data shows a strong correlation between Portugal and Spain (±80%), the wind profile of Portugal in 2012 and 2013 is represented by the profile of Spain. In case there was a weak correlation, the wind patterns of the two countries are generally not alike. Then, TradeWind data of the year 2004 was used.

[69] Solar hourly load factors were calculated on the basis of the sunsets time, sunrise time, their evolution throughout the year and solar irradiation values in 118 nodes distributed in Europe (SODA, 2011).

demand balancing. The amount of the power consumed and produced in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power/energy ratings which are input to the model.

Electricity demand

The demand represents the final electricity demand in each country. The hourly load profiles of demand are based on the latest historical hourly data given by ENTSO-E.

Model outputs

The COMPETES model calculates the following main outputs:

- The allocation of generation and cross-border transmission capacity
- Yearly generation mix in each country and emissions
- Hourly competitive electricity prices per country
- The supply of flexibility from generation, transmission, and storage
- Investments in conventional generation capacities (capacity expansion model output)
- Investments in transmission capacities (capacity expansion model output)

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