SCOPING TOWARDS POTENTIAL HARMONISATION OF ELECTRICITY TRANSMISSION TARIFF STRUCTURES

AGENCY FOR COOPERATION OF ENERGY REGULATORS (ACER)

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IMPORTANT NOTICE

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Executive Summary

Cambridge Economic Policy Associates (CEPA) has been appointed by the Agency for the Cooperation of Energy Regulators (ACER) to conduct a study on 'Scoping towards potential harmonisation of electricity transmission tariff structures'. The purpose of the study is to help inform ACER's future considerations in relation to electricity transmission tariff *structure* harmonisation policy in Europe.

Optimal transmission access pricing and cost allocation

In interconnected electricity transmission networks, electricity generators and consumers (load) may impose various costs on the transmission system. Most of these costs can be attributed to the generators' and consumers operational and investment decisions, and they often vary by location and with energy demand over time. Because of the physics of electricity, interactions arise in such networks and the costs imposed by one user of the network, often depend on the actions taken by other users.

A key requirement for economic efficiency (i.e., the least-cost development of the overall power system) is that all market participants, both generation and load, internalise all the costs they generate at the time they make their operational or investment decision. Transmission charging is one tool that can be used to convey some of the costs of using the power system. In order to ensure the most efficient (i.e., the least-cost) development of the overall power system, it is important to have a transmission charging regime in place that is *reflective* of all actual system costs imposed by each user of the transmission network.

However, due to the natural monopoly characteristics of the electricity transmission system, efficient (i.e. cost reflective) tariff structures, may not always guarantee that the Transmission System Operator (TSOs) is able to recover all of its costs. Therefore, further adjustments of its charges are often needed to reconcile the two objectives. Whilst economic theory points to how this issue can be addressed in an efficient way, there is still an inherent balance to be struck between, on the hand, applying efficient (i.e. cost reflective) charges, and on the other hand, ensuring that the tariffs applied *recover* the TSOs efficiently-incurred costs.

Transmission tariff structures in Europe today

Electricity transmission charging arrangements employed today across European Member States (MS) and neighbouring countries, such as Norway, are many and varied, and currently there is no common "model" adopted.

This reflects the different features of each national electricity market (e.g. the location and mix of generation and planned future investment in the network), but also the emphasis that individual MS have chosen to place on certain policy objectives for their electricity sectors and the design of the transmission tariff structure.

Some countries place an emphasis on developing a tariff structure considered, in the context of that country, to be *cost reflective*. In these cases, tariffs are based on forward looking (marginal) costs, and often vary by location.

Other countries apply a far simpler tariff structure, with the single objective of enabling the Transmission System Operator (TSO) to *recover* its costs. To recover costs, some countries levy transmission tariffs on *both* generation and load users of the network, whilst other countries apply tariffs only to load.

European MS also apply varying capacity and energy based components through their transmission tariff structures:

- in some countries, transmission *use of system* tariffs are predominantly capacity based (e.g. GB and Italy); whilst
- in other countries, the tariff structure is predominantly energy based (e.g. Denmark and Finland).

Problem identification

We have analysed whether the current absence of harmonisation in transmission tariff structures creates any problems for the European electricity market. We find that in theory, there is certainly the *potential* for the current absence of harmonisation to impact negatively on the efficiency of the European electricity market, by distorting the *investment* and *operational* decisions of market participants, in particular electricity generators. These distortions *potentially* prevent the efficient (i.e. least-cost) development of the European electricity system, and may, therefore, reduce economic welfare in Europe.

Our analysis also suggests that these problems are likely to be more of an issue in the future as national electricity markets become more interconnected and integrated.

However, for the identified theoretical harmful effects to actually apply in practice, a number of conditions must hold in Europe's electricity market. In particular, neighbouring countries, or bidding zones, that apply different tariff structures must be:

- physically interconnected;
- the countries or bidding zones must be highly integrated (resulting in cross-border competition); and
- market participants must have the flexibility to alter their behaviour (e.g. siting decisions) in response to incentives created by a lack of harmonised tariff structures.

Recognition of the *potential* negative effects from an absence of harmonisation is also already reflected in various regulations introduced through European legislation.

For example, Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity, was adopted as part of the Third Package to facilitate a competitive and integrated energy market across the EU. This sets out a series of common objectives for transmission network access charges in Europe including, among other things, promotion of transparency, the need to take into account network security, and tariff structures which reflect actual/efficient costs, are non-discriminatory, non-distance related and, where appropriate, provide locational signals.

Regulation (EU) No 838/2010 specifies guidelines on a common regulatory approach to transmission charging, including allowed ranges for annual average transmission charges levied on generators in each MS. ACER itself is required to monitor the appropriateness of the ranges of allowable generation transmission tariffs[1].

The key questions for this study therefore were whether:

i. The conditions which the theory may *suggest* could lead to distortions in investment and operational decisions apply in Europe today?

ii. These conditions may apply in future, particularly as Europe adopts the Electricity Target Model (ETM)? And

iii. Existing measures which regulate tariff structures at a European level, are considered sufficient to prevent potential negative effects from the absence of harmonisation?

Absence of harmonisation may potentially lead to distortions of investment decisions…

Transmission tariffs and tariff structures have the capacity to influence investment decisions of generation and large (transmission-connected) loads.

In the case of generation, *differences* in MS transmission tariff structures could in *theory* distort the siting of electricity generation plant between countries and bidding zones, resulting in European countries investing larger resources in generation to meet demand.

Based on our research, we have not found direct evidence of negative investment impacts arising from the current lack of tariff structure harmonisation in Europe; however, there are some indications that current electricity transmission tariffs, most likely in combination with other factors, could *potentially* lead to distortions and inefficient outcomes.

The regional Nordic electricity market, Central West Europe, and the 4M market coupling in the Central East Europe region, are current examples of well-integrated markets (e.g. high price convergence), with strong physical interconnections and, therefore, cross-border competition, and some evidence that the absence of harmonisation of transmission tariff structures today, *acts to* prevent a level playing field for all market participants.

But it is far more difficult to establish whether the lack of tariff structure harmonisation has led to inefficient decisions in these regions, or other European countries.

[1] Throughout the rest of this report we refer to "generation transmission tariffs" that include all charges levied on generators, such charges for the use of the transmission network, system services, transmission losses, etc.

In these case studies, and other examples which we have considered, there are many other factors which mean that market participants, even in the presence of further transmission tariff structure harmonisation, would not be competing on a level playing field. Fragmented national taxation or generation support mechanisms (e.g. renewable generation subsidies or capacity remuneration schemes) for example, differ significantly between countries, and these factors arguably have a far more material influence on the investment choices of electricity generators in European electricity markets today.

In this broader context:

- it is unclear *investment* decisions today, or in future, will be fundamentally altered, except perhaps marginal investment projects, by lack of harmonised tariff structures in Europe; and consequently
- it is highly uncertain that there have been, or will be, investment inefficiencies that can be *specifically* attributable to the current lack of transmission tariff structure *harmonisation* in Europe.

That is not to say that transmission tariffs are not taken into account in investment decisions, particularly in new generation investments.

Simply that there are other factors which potentially blunt the incentives, or disincentives, which may be created by *differences* in MS transmission tariff structure.

…and potentially distortions of operational decisions…

In theory there may also be negative operational impacts which arise from a distorted dispatch of generation, due to differences in non cost reflective generation tariffs between European countries or bidding zones. Our research demonstrates this may particularly be the case with energy based generation tariffs.

Our research has again identified a number of examples of where these operational effects *could* have occurred and again, may have acted against a level playing field for cross-border competition in the European electricity market.

However, the magnitude of the *potential* operational inefficiencies from an absence of harmonisation are also uncertain, and depend critically on market conditions (e.g. merit order of supplies in each country) under which cross-border competition takes place.

…but the more fundamental problem is the lack of agreement on charging principles.

To the extent there is a problem, or risk of a problem, from the lack of tariff harmonisation in Europe today, we believe it is more an issue of a lack of consistency in the principles which individual countries apply to their tariff structures.

Although there are a set of common regulatory objectives for transmission tariffs in Europe today, we do not observe any consistency or agreement across European countries on the necessary principles or factors for an "optimal" tariff structure. In most, but not all, European countries, current tariff structures generally do not align with what economic principles would suggest is likely to be an "optimal" (i.e. efficient) tariff structure.

General lack of efficient, i.e. *cost reflective*, tariffs means that in many circumstances, it is unlikely that all users of the European transmission system pay for and, therefore, internalise, the costs their decisions impose on the electricity system. As the European electricity market becomes increasingly integrated, this becomes a problem, and importantly a *European* rather than subsidiary problem, as the costs generated by market participants' decisions in one country may increasingly impose costs on market participants in other countries.

The challenge is that an "optimal" tariff structure will be dependent on harmonisation of other elements of wholesale electricity market design in Europe. The "optimal" structure may also differ by country and/or regions within the European electricity market and the state of development of the IEM. The need for:

- locational signals in transmission tariffs, for example, may be mitigated where deep connection charges are applied as a policy;
- tariffs based on forward looking (marginal) costs may be less important in some regions or countries, if there is limited flexibility for market participants to respond to the incentives; and
- harmonised tariff structures in general, are dependent on other conditions and harmonisation of other policy factors that influence investment and operational decisions (see discussion above).

Agreement on the necessary principles for an "optimal" tariff structure should, therefore, be addressed as part of the longer-term road-map to facilitate overall harmonisation, integration and efficiency of the European electricity market.

Ideally harmonisation of other elements of the market arrangements would be addressed *ahead of* agreement on principles for an "optimal" tariff structure to help ensure they support these market arrangements.

Policy options

There are a number of practical options for further harmonisation of transmission tariff structures in Europe.

We have grouped these options as potential short-term and longer-term regulatory responses to the issues and problems identified above.

Short-term regulatory response

In the short-term, options which have been proposed by some stakeholders, are either the removal of G-charges in Europe, or alternatively greater harmonisation of the proportion of costs which are recovered from generation and load (often referred to as the G:L split).

These options would need to be justified on the basis that they would address the *potential* investment and operational distortions of generation decisions, outlined above.

We believe that the former option (i.e. removal of G-charges) is not justified on cost-reflectivity grounds, as generator decisions clearly impose costs on the system.[2] *Provided* that the tariffs are *cost reflective*, applying a European policy of blanket removal of G-charges could result in less efficient development of the European electricity system.

We also see no justification for greater harmonisation of the G:L split, as although this would introduce greater harmonisation, in *proportional* terms, of the costs recovered from generation and load, differences in the historic cost base of the TSOs mean that in practice tariff *levels* could still diverge significantly, even if a common G:L split is adopted. As a consequence, this policy would not address the problems identified.

Given the uncertainty that the status quo arrangements in practice distort investment and operational decisions, i.e. there is a general lack of evidence that differences in tariff structure *between* European countries in practice lead to inefficient outcomes, we believe any benefits associated with such short-term harmonisation policies are highly uncertain.

Provided existing European regulations are enforced as intended, in particular the ranges for G-charges as set out in Regulation (EU) No 838/2010, existing policies should be sufficient to help prevent potential negative effects from the absence of harmonisation in the short-term.

It may however, be desirable that given the European issues that need to be considered in tariff structure design, that MS are required to justify that the application of their current tariff systems at least have some basis on cost reflectivity grounds. On this basis, as an example, energy based G-charges, to recover *infrastructure* costs, should be prevented on the grounds of a lack of objective justification.

Longer-term regulatory response

The longer-term case for harmonisation is more persuasive, given the expected size of investment in the transmission system and generation fleet across Europe in coming years.

We propose, as a starting point, MS look to establish a harmonised set of *principles* to transmission charging. This would create greater consistency in the principles that are applied

[2] The price responsiveness of generators means they are the market participants whose decisions are most liable to be distorted by the absence of harmonisation, but are also the users whose decisions could be made more efficient by adopting an optimal (i.e. efficient) tariff structure.

to tariff structures, but would also need more clarification and agreement on what the objectives set out in the Third Package really mean.

Specifically, we propose that European countries look to establish harmonised principles on two aspects of transmission charging regimes, having the overarching objective, that markets deliver the established policy goals at the least cost, in mind. These factors are:

- cost reflectivity and;
- cost recovery.

In the case of cost reflectivity, the basis on which different types of cost are charged for, the circumstances under which forward looking (marginal) costs are applied in the tariff structure and the role of transmission tariffs in supporting wholesale market design (e.g. definition of bidding zones), are all the types of principles we would expect to be addressed.

There are however, some practical issues that would make further harmonisation challenging and will require further consideration. For example:

- there are different voltage classifications that are currently applied across different European countries; and
- harmonisation could adversely affect the terms on which existing users gain access to the network.

Through appropriate transitional arrangements, these issues are not insurmountable. However, they highlight the importance of approaching tariff harmonisation as a longer-term project, focused on the design of "optimal" tariff structure that *supports* longer rather than short-term objectives for the development of the IEM.

Recommendations

In conclusion, the benefits of a *short-term* regulatory response on harmonisation are in our view unlikely to outweigh potential costs.

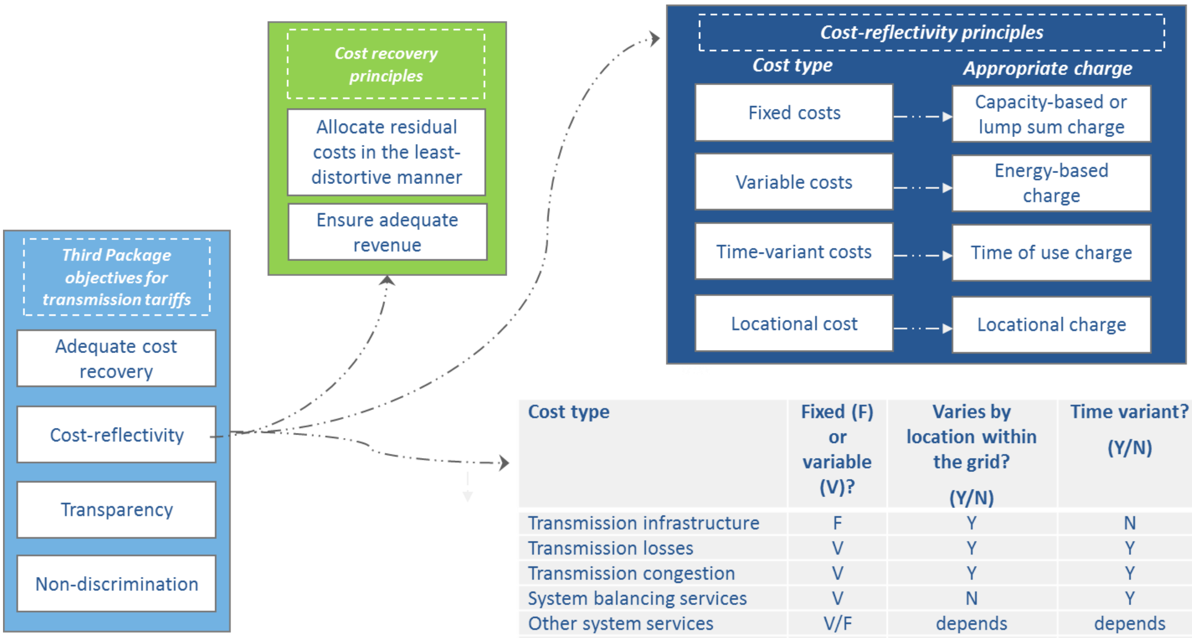
The likely incidence effects which may be required to implement harmonisation, and the reopening of regulatory frameworks under which the existing terms of access to the network were made in individual European countries, is more likely to undermine short-term confidence in investment than address *potential* distortions. There is also already an ambitious programme of European market reforms underway, and it would make sense to deliver these reforms first, before seeking tariff harmonisation.

However, in the longer-term, there is certainly a stronger case for harmonisation, principally based on the need for greater consistency and application of "optimal" tariff structures that reflect the costs generated by market participants' decisions.

We recommend, therefore, that ACER keep the issue of harmonisation under review and seek to develop a road-map for harmonisation. This should start with agreement on a harmonised set of principles for transmission tariffs, building on the existing objectives for tariffs introduced as part of the Third Package. Pursuing this option can do no harm and can facilitate development of a harmonised approach if needed.

For sake of clarity, we have summarised below (Figure 1) the principles we believe policy makers and market participants in Europe should start to consider and debate as part of developing a longer-term road map towards tariff structure harmonisation.

Figure 1 – Basic cost recovery and cost-reflectivity principles for transmission tariffs



Cost type	Fixed (F) or variable (V)?	Varies by location within the grid? (Y/N)	Time variant? (Y/N)
Transmission infrastructure	F	Y	N
Transmission losses	V	Y	Y
Transmission congestion	V	Y	Y
System balancing services	V	N	Y
Other system services	V/F	depends	depends
Other regulatory charges	F	N	N

1. INTRODUCTION

1.1. The European electricity market

Electricity transmission charging arrangements employed today across European Member States (MS) and neighbouring countries, such as Norway, are many and varied, and currently there is no common "model" adopted.

This reflects the different features of each national electricity market (e.g. the location and mix of generation and planned future investment in the network), but also the emphasis that individual MS have chosen to place on certain policy objectives for their electricity sectors and the design of the transmission tariff structure.

The historical differences observed in electricity transmission pricing systems across Europe are, to an extent, understandable given the national policy objectives which individual MS have applied to their choices of tariff structure to date.

Europe, however, has been progressively developing the internal market in electricity. The internal electricity market (IEM) aims to: *"deliver real choice for all consumers of the European Union, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices, and higher standards of service, and to contribute to security of supply and sustainability."*[3]

Various studies have been undertaken to estimate the benefits of market coupling and closer integration of European electricity markets, core objectives of the IEM and the Electricity Target Model (ETM) developed by the European Commission.

Newbery et al. (2015)[4] for example have estimated the potential benefit to the European Union (EU) of coupling interconnectors to increase the efficiency of trading day-ahead, intra-day and sharing balancing services across European borders. They find that, in the short-run, the gains could be as high as €3.3 billion/yr, more than 100 per cent of the current gains from trade. They also note that further gains are possible by eliminating unscheduled flows and avoiding the curtailment of renewables with better market design.

The potential benefits from greater cross-border competition and electricity market integration across European countries, introduces a new perspective to the optimal design and policy objectives for electricity transmission tariff structures in Europe.

With day-ahead market coupling having now been achieved from Finland to Portugal, including Great Britain (GB), and further growth in cross-border electricity trade and market integration expected in the future (with further planned investment in physical interconnection), the impacts of national transmission tariff structures on electricity market

[3] Directive 2009/72/EC
[4] Newbery. D, Strbac. G, Viehoff. I (2015): 'The benefits of integrating European electricity markets'

outcomes and market participant behaviour at a *transnational* European, rather than just national level, has become an increasingly important regulatory issue.

1.2. Tariff structure harmonisation

Recognition of this is already reflected in a number of regulations which have been introduced through European legislation.

Regulation (EC) No 714/2009, on conditions for access to the network for cross-border exchanges in electricity, was adopted as part of the Third Package to facilitate competitive and integrated energy market across the European Union (EU). This sets out a series of common objectives for transmission network access charges in Europe including, among other things, promotion of transparency, the need to take into account network security and tariff structures which reflect actual/efficient costs, are non-discriminatory and non-distance related, and, where appropriate, provide locational signals.

Regulation (EU) No 838/2010 specifies guidelines on a common regulatory approach to transmission charging including allowed ranges for annual average transmission charges levied on generators ("G-charges") in each MS. ACER also has a requirement to monitor the appropriateness of the ranges of G-charges and in 2014, issued its first opinion on this issue.[5]

A key question for ACER and other energy regulatory policy makers (including National Regulatory Authorities (NRAs)) in Europe today, is whether:

- further harmonisation of the principles and structure of setting electricity transmission tariffs in Europe would be beneficial, when considered from the perspective of the economic efficiency of the IEM; and if so
- what form that harmonisation might take.

1.3. Scope of study

Cambridge Economic Policy Associates (CEPA) has been appointed by ACER to conduct a study on 'Scoping towards potential harmonisation of electricity transmission tariff structures'. The purpose of the study is to help inform ACER's future considerations in relation to electricity transmission tariff structure harmonisation policy in Europe.

The objectives of our assignment are to:

- Analyse current electricity transmission tariff structures across MS to assess the extent to which these practices ensure or impede (both in theory and practice) integration, effective competition and the efficient functioning of the internal *European* electricity market.

[5] ACER (2014): 'Appropriate range of transmission charges paid by electricity producers

- Identify and develop proportionate policy options to address any actual or expected overarching problems or failures that *may* be identified with current transmission electricity tariff structures across Europe and to assess the associated impacts of these options.

The focus of the study is, therefore, the effects different transmission tariff structures, including the status quo arrangements, may have on relevant objectives for tariffs at an EU level, as opposed to the specific issues and national objectives that may affect transmission tariff structure choices at a MS level.

1.4. Study methodology

We have sought to evaluate current transmission tariff structure practices from a number of perspectives. This principally involves an evaluation of how current charging practices impact the functioning of the European IEM, in terms of:

- ***Investment decisions*** – do current transmission tariff structures impact detrimentally or positively on the efficiency of long term investment decisions in generation and the transmission network in the internal electricity market?
- ***Operational decisions*** – do current transmission tariff structures impact detrimentally or positively on the efficiency of operational decisions of existing and new network users (both consumers and producers)?

Linked to the question of the economic efficiency and functioning of the IEM, is also investigation of the impact transmission tariff structures have on European electricity market competition and integration:

- ***Competition*** – do current transmission tariff structures in Europe and some neighbouring states act to prevent a level playing field for competition in the European electricity market?
- ***Market integration*** – how do current transmission tariff structures affect (or potentially affect) expected integration of European electricity markets and incentives for cross-border trade in electricity?

In assessing the impacts of alternative policy options to the status quo arrangements, we have considered the extent to which:

- Policy options would ***address the problems*** identified with the status quo arrangements and, therefore, could be expected to lead to ***more efficient functioning*** of the European IEM.
- Policy options are likely to be ***feasible*** to implement, given the potential ***costs*** and ***risks*** which could be associated with seeking to introduce changes to the status quo arrangements.

We have drawn on a number of sources of evidence to inform an assessment of the status quo arrangements and, in particular, whether there is, or may *potentially* be, a problem, or set of problems, with the status quo arrangements. Specifically:

- We have undertaken a literature review of the economic theory and practice of transmission pricing with a particular emphasis on what the literature says can be the economic effects of transmission tariff structures on market integration and cross-border competition.
- Drawing on this literature review, we have then evaluated the *theory* of how differences in transmission tariff structures, when considered from a European IEM perspective, can promote or detract from economic efficiency.

  We also evaluate whether current arrangements appear to align with what economic theory would indicate is an optimal tariff structure regime, when considered from a pan European perspective.
- We have collected stakeholder views in the European electricity market on the importance and materiality of the effects of current transmission tariff structures in Europe. This is based on feedback provided through a stakeholder questionnaire and follow-up interviews with a number of IEM participants.

  Based on the stakeholder interviews and our own research, we have developed a set of case-studies of how the current absence of harmonisation of transmission tariff structures in Europe could, or may already have, a detrimental impact on the functioning and efficiency of the IEM.

1.5. Report structure

We have not been commissioned to undertake a formal impact assessment (IA) of harmonisation of transmission tariff structures; our remit has been to establish ("scope") the potential direction for electricity transmission tariff structure policy in Europe given an identified problem, or problems, with the status quo arrangements.

However, our report is loosely structured to follow the key analytical steps required by the European Commission IA guidelines:

- Section 2 provides a short discussion of recent relevant developments in the European IEM and the policy objectives which we understand European policy makers are seeking to support in relation to transmission tariff structures;
- in Section 3, we then summarise the current transmission tariff structures situation across European MS;
- Section 4 and 5 then provide our assessment of the status quo arrangements and views on the extent to which the current absence of harmonisation in transmission tariff structures in Europe creates a problem, or set of problems, for the IEM;

- Section 6 sets out *potential* policy options which would change the status quo arrangements in Europe to introduce greater harmonisation, including our assessment of those options; and
- Section 7 provides conclusions and summarises the recommendations resulting from the research and analysis undertaken.

2. CONTEXT OF STUDY

In this section we provide a brief discussion of recent relevant developments in the IEM and the policy objectives we understand policy makers are seeking to support in relation to transmission tariff structures and the development of the IEM more generally.

Electricity transmission pricing is closely interlinked with wholesale market design choices. That is to say, the two cannot, in our view, be considered independently. Therefore, in addition to the objectives for transmission tariffs, we review the electricity market context in Europe, and the objectives of the IEM.

We start with a discussion of the IEM and the policy objectives which are associated with its ongoing development.

2.1. The Internal Electricity Market

Historically, the design of electricity markets in Europe has had a national focus. The design of wholesale electricity markets, in particular, has typically evolved to achieve a balance of energy policy and regulatory objectives, including:

- security of supply;
- transition to a low carbon energy mix; and
- affordable energy prices for consumers.

Linked to these objectives, the design of national wholesale electricity markets, and the accompanying transmission pricing arrangements, have been heavily influenced by *national* differences in:

- the level, location and type of investment in electricity production (generation) and consumption; and
- the long term network development plans for the transmission system adopted by local electricity TSOs.

As electricity transmission tariffs are typically considered part of a regulatory "tool kit" for electricity market design, it is, therefore, not unexpected that NRAs and TSOs have also chosen to apply a national focus to the design of their transmission tariff structures.

However, as described in the introduction, the development of the IEM introduces a new perspective to the optimal design and principles for transmission tariff structures in European countries (as well as other aspects of electricity market design). The impacts on European electricity market functioning and integration also need to be considered, whilst recognising national policy objectives for electricity sectors still need to be facilitated.

The EU has set ambitious climate change related targets, including for the development of renewable generation. The EU's Renewable energy directive sets a binding target of 20% final energy consumption from renewable sources by 2020. To achieve this, EU countries have committed to reaching their own national renewables targets ranging from 10% in Malta to 49% in Sweden. EU countries also recently agreed on a new renewable energy target of at least 27% of final energy consumption in the EU as a whole by 2030. The net generating capacity in Europe is expected to grow between now and 2030 by around 20% to 70% depending on the future energy scenario envisaged.[6]

As the bulk of new renewable electricity generation investment in Europe is expected to come from technologies (such as onshore wind, offshore wind and solar power) that currently require support schemes (subsidies) to be competitive, the regional focus of generation investment in Europe is likely to change and be influenced by those locations that have the best access to resources (e.g. wind availability). One of the key objectives of the IEM is, therefore, to promote a more integrated European electricity market and more efficient use of future resources for electricity production across European countries. Studies such as Booz & Co et al. (2013) for the European Commission illustrate very clearly the *potential* benefits that could be achieved from full market integration, including a true common market for renewable energy "*achieved by making it commercially desirable to locate renewable generation capacity in locations that are most effective for it.*"[7]

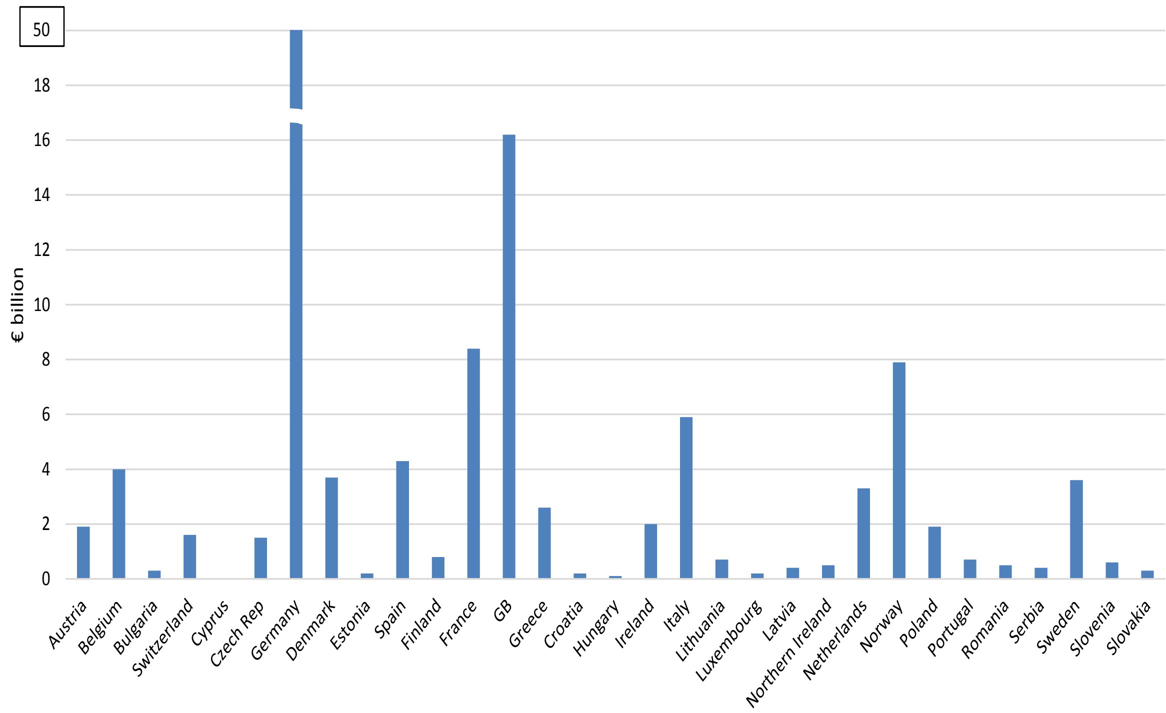
However, achieving closer European market integration (with associated changes to generation and load patterns) will require significant investment in the electricity transmission system. Booz & Co et al. for example note that "*full integration will require large investments in transmission capacity*" in part to support substantially different locations of electricity generation compared to what is observed across Europe today. These investment trends are illustrated in ENTSO-E's Ten-Year Network Development Plan (TYNDP), which has set out different visions / pathways for Europe's electricity sector (e.g. RES development) with corresponding impact on the need for the development and investment[8] in the electricity transmission network. The breakdown of the estimated investment costs by country in the TYNDP is provided in Figure 2.1 below.

[6] ENTSO-E, "Ten-Year Network Development Plan 2014"

[7] Booz & Co et al. (2013): 'Benefits of an integrated European Energy Market'

[8] The TYNDP notes that total investment costs for the portfolio of projects of pan-European significance amount to approximately €150 billion.

Figure 2.1 – Estimated investment costs for projects of pan-European significance



Source: CEPA based on ENTSO-E's TYNDP

The support mechanisms that apply to renewable generation in individual European countries will have a strong influence on generation investment. But as many of these support mechanisms also decouple generation revenues from electricity wholesale market prices, locational signals in wholesale prices between price areas (see discussion below) may in the future have less of an influence on locational investment choices of generation. One role which transmission tariff structures *could* potentially play, provided they were cost reflective, is to be used as a tool to help influence the efficiency of the planned investment in the network, under future pathways for the European electricity sector.

2.1.1. Electricity Target Model

The European Commission's Electricity Target Model (ETM) is a central part of the IEM. The ETM (which will be adopted through a series of market codes) aims to integrate EU electricity markets by coupling interconnectors, so that all electricity is efficiently allocated across the EU by a single auction platform, Euphemia.

Europe has sought to achieve the objectives of the Third Package through the development of the ETM[9], the principles of which have been applied through a series of draft network codes that will result in a top-down set of harmonised arrangements and requirements for cross-border electricity trading of wholesale electricity and balancing services across European

[9] Originally developed by the European Regulators' Group for Electricity and Gas.

countries. The objective of the ETM is to ensure an optimal use of power generation plants and transmission infrastructure across Europe.

The ETM foresees:

- a zonal, rather than nodal, market design based on bidding areas, i.e. a network area within which market participants submit their energy bids day-ahead, in intraday and in longer term timeframes (this implies zonal wholesale electricity prices);
- a coordinated process for calculating available day-ahead and intra-day transmission capacity across the EU;[10] and
- liquid wholesale electricity markets across forward, day-ahead and intraday timeframes.

The choice of a zonal, rather than nodal model[11] is a key component of the ETM. The ETM envisages bidding zones defined by network congestion rather than national borders, with an optimal delineation of bidding zones expected to promote: robust price signals for efficient short-term utilisation of the system; and signals for long-term development of the system.

In contrast, the majority of bidding zones in Europe are today defined by national borders (e.g., France or the Netherlands); however, some are larger than national borders (e.g., Austria, Germany and Luxembourg or the electricity market for the island of Ireland) and some are smaller zones within individual countries (e.g., Italy, Norway or Sweden).[12]

The delineation and objectives for the design of bidding zones under the ETM matters given there are interactions with transmission tariffs. As we expand upon in later sections of the report, bidding zones (through the energy price within the bidding area) and transmission tariffs can *both* provide locational signals which influence operational and investment decisions of participants in electricity markets. How the two location signals interact, and whether they support or hinder each other, must be evaluated carefully to reach views on the "optimal" system for transmission tariff structures in Europe.

Another key component of the ETM is the coupling of markets/zones through electricity interconnectors, whereby cross-border capacity (e.g. at the day ahead stage) is allocated implicitly within the market clearing algorithm, Euphemia. In Annex A we have provided a brief summary of recent progress on market coupling across European countries.

With further investment in interconnection expected across Europe in coming years, and significant milestones in market coupling having been reached, the degree of generation competition in Europe is changing. Generation can be expected to compete at a transnational

[10] This has, for example, involved the development of a Flow Based methodology for capacity calculation, which uses locational information in the grid model to assess system security at the allocation stage.
[11] Where wholesale electricity prices are determined by physical node on the network.
[12] Ofgem (2014): 'Bidding zones literature review'

level, and increasingly in "real time competition" terms, as markets are integrated via unconstrained links between "European competitors".

Given these changes, understanding how transmission tariff structures, as applied in their current form today, impact on competition, and the efficiency of operational and investment decisions in the European electricity market, becomes important. But it is important to note that the ETM will also restrict the degrees of freedom MS can in future apply to their wholesale electricity market design (aimed at supporting the market integration benefits described above). The role of transmission tariffs in this more restricted state of the world, must also be considered in designing an effective regulatory policy.

2.2. Objectives for transmission tariffs

European objectives for electricity transmission tariffs are set out in Regulation No 714/2009 and Directive 2009/72 which form part of the Third Energy Package.

Directive 2009/72 states "*measures should be taken in order to ensure transparent and non-discriminatory tariffs for access to networks. Those tariffs should be applicable to all system users on a non-discriminatory basis.*"

Article 14 of Regulation 714/2009 states that: "*Charges applied by network operators for access to networks shall be **transparent**, take into account the **need for network security** and **reflect actual costs incurred** insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a **non-discriminatory manner**. Those charges shall not be distance-related.*" The Regulation also states that: "*Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide **locational signals** at Community level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure.*" CEPA emphasis added.

Regulation (EU) No 838/2010 also specifies guidelines on a common regulatory approach to transmission charging. This includes allowed ranges for annual average transmission charges levied on generators in each MS and a requirement for ACER to monitor the appropriateness of the ranges of allowable generation transmission charges.

Collectively these Regulations would suggest that the objective in Europe is to achieve transmission tariffs that recover costs that avoid undue discrimination between network users and, where appropriate, provide locational signals. They should also be transparent, potentially in the way that tariffs are calculated, but also the signals which each MS intends to be provided through the tariff structure adopted.

However, particularly in the case of generation charges, there is also some recognition that the amount payable for access to the transmission system, and differences in the structure of the tariff systems which are applied in each MS, *could* impact or distort trade in the IEM. Regulation 714/2009 for example states that: "*A certain degree of harmonisation is therefore necessary in order to avoid distortions of trade*".

ACER's recent opinion of the range of transmission charges for electricity generators, supports the concern that with:

> "*the increasing interconnection and integration of the European market implies an increasing risk that different levels of G-charges distort competition and investment decisions in the internal market. In order to limit this risk, ACER deems it important that G-charges are cost-reflective, applied appropriately and efficiently and to, the extent possible, in a harmonised way across Europe.*"[13]

There are therefore, stated policy objectives for transmission tariff structures in Europe. However, as identified as part of the discussion of tariff harmonisation in the gas sector[14], there are various tensions and trade-offs between the objectives outlined above. For example, whilst there may be an objective to apply cost reflective tariffs at a European level, it may not be possible to design access tariffs that perfectly reflect the costs of all users accessing the network in particular locations and, therefore, completely non-discriminatory.

If there are conditions in one MS where it is deemed that locational signals are appropriate, whilst in another it is not, differences in the structures of the tariff system could also potentially lead to the distortions highlighted in Regulation 714/2009.

It is important to recognise these trade-offs exist, as they potentially constrain what can be achieved from further harmonisation of tariff structures in Europe.

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[13] Opinion of Agency for the Cooperation of Energy Regulators No 09/2014 of 15 April 2014 on the appropriate range of transmission charges paid by electricity producers.

[14] See Brattle (2012): 'Impact Assessment for the Framework Guidelines on Harmonised transmission tariff structures'

3. Transmission tariff structures in Europe today

In this section we summarise the electricity transmission tariff structures situation observed in Europe today.[15]

We begin by defining what is meant by a transmission tariff, as context to some of the concepts referred to throughout the rest of this section.

3.1. What are transmission tariffs?

Electricity transmission tariffs are used to recover the costs of providing electricity transmission services. Internationally, there are many different systems of electricity transmission pricing and associated tariff structures.

For example, it is possible to charge both electricity generators and load/end-consumers for the provision of transmission services. However, there are many different definitions and approaches that can be applied to the basis on which both electricity generation and load users are levied for those services. For example, deep or shallow connection charges can be used to recover the costs of new parties connecting to the network or a use of system (access) tariff used as the principle cost recovery tool. Transmission tariffs can also be levied on a capacity (MW) or production/consumption basis (MWh).

The types of cost recovered through transmission tariffs can also differ depending on the transmission pricing system adopted. Transmission tariffs are typically used to recover the fixed capital and operating (infrastructure) costs of providing the transmission network and also the costs of connecting new users (generation and load) to the network. However, in some tariff systems, ancillary service costs and losses may also be either totally or partially charged through transmission tariffs, rather than through market mechanisms.

Optimal network tariffs and allocation of transmission costs can also be designed to promote economic efficiency in the short run and long run:

- In the short run, transmission tariff systems can be used to promote the optimal utilisation of the grid[16] by setting prices at short run marginal cost (SRMC).[17]
- Long term price *signals* can also be provided through transmission tariff structures applied to influence the time of use of the transmission system, or the decision and location to connect to the network.

In the long run, the fixed costs associated with providing a transmission network also mean that a system of SRMC based tariffs may not be sustainable for a network operator that needs to recover (in full) the *efficient* costs of providing transmission services through its tariffs.

[15] A more detailed comparison of the current arrangements is provided in Annex C to the main report

[16] For a given level of network capacity

[17] See for example Econ Poyry (2008): 'Optimal network tariffs and allocation of costs'

"Optimal"[18] transmission tariff systems, therefore, typically need to be supplemented, to ensure efficient network costs are recovered in full.

Figure 3.1 - Transmission charging building blocks

Building block:	Notes:
Generation / load	Are transmission tariffs levied on generation or load, or both? Do transmission tariffs apply to embedded generation?
Capacity vs. commodity	Are tariffs levied on a MW (capacity) basis or MWh production/consumption basis?
Locational charging?	Are transmission tariffs locationally differentiated (with locational signals) or uniform?
Zonal vs. nodal?	If transmission tariffs are locational, do tariffs differ by node or do they differ by zone?
Time of day signals?	Do transmission tariffs provide economic incentives for time of use of the transmission network?
Types of cost	What types of costs does the transmission tariff recover?
Cost recovery	Are tariffs based on short or long term costs? Are tariffs based on marginal or average costs? How is full cost recovery achieved?
Connection regime	Are use of system charging arrangements accompanied by shallow or deep connection charging arrangements?

Source: CEPA (adapted from Poyry (2010)[19]

3.2. The situation in Europe today

3.2.1. Overview

Many of the tariff building blocks set out in Figure 3.1 are applied to Europe today but the characteristics of the tariff structure applied in each MS differ.

For example, different approaches to who contributes to the costs of the transmission network are employed across Europe. In some countries:

- costs are paid by load only (i.e. no tariffs are levied on generation);
- in other cases, costs are shared by generation and load.

[18] From an economic efficiency perspective
[19] Poyry (2010): 'Electricity transmission use of system charging: theory and international practice

Even where generation tariffs are applied in two countries, differences in the tariff structures may still arise between due to:

- the different allocation of costs between generation and load users (known as a different G:L split); or
- the basis on which the tariff is set (we discuss the basis on which MS generation tariffs are set below).

Different approaches and principles are also applied with respect the application of locational and time of use signals through transmission tariffs.

As a consequence, load and generation, can face very different incentives for the use of the transmission system across the different countries which participate in the European electricity market. In general however, time of use signals are more widely applied by MS in the transmission tariff than locational signals.

There is also variation in the scope of services and costs recovered through the TSOs tariffs. The treatment of losses and the means through which the cost of losses is recovered, for example, differs amongst European countries. The cost of losses is generally either:

- included as part of transmission tariff structure (in some cases losses may be charged as part of a separate tariff); or
- recovered in the energy market (for example, GB, Greece, Ireland, Northern Ireland, Portugal and Spain).

Similarly the approach to recovering the cost associated with other ancillary (system) services can differ from country to country:

- in most cases, these costs are included as part of TSOs' transmission tariffs (for example, France, Germany and Finland);
- in a number of other countries, ancillary costs are recovered through a tariff such as the Balancing Services Use of System (BSUoS) charge in GB; while
- in some countries, these costs are recovered through the energy market (for example, Spain and Portugal).

European MS also apply varying capacity and energy based components through their transmission tariff structures:

- in some countries, transmission *use of system* tariffs are predominantly capacity based (e.g. GB and Italy); whilst
- in other countries, the tariff structure is predominantly energy based (e.g. Denmark and Finland).

Figure 3.2 compares the shares of energy-related and capacity-related components of the unit transmission tariff reported in ENTSO-E's transmission tariff synthesis. Note that this includes tariffs associated with ancillary (system) services and losses, in addition to the tariffs that recover the infrastructure costs of the transmission system.[20] The former, even in countries that apply a greater capacity element in the tariff structure, tend to be energy based.

Figure 3.2 – Energy-related and capacity-related components of the unit transmission tariff

Source: ENTSO-E

As discussed in later sections of the report, whether transmission tariffs are energy or capacity based is important, as this is a crucial element to the consideration of whether a tariff structure can be considered "cost reflective" and may be expected to influence the operational or investment decisions of generation and load.

3.2.2. Generation tariffs

The application of transmission tariffs to generation in the IEM has become a particularly high profile issue. ACER provided an opinion on the issue in 2014 and there have been a number of MS reviews and judicial challenges of generation tariffs in recent years.[21]

A number of neighbouring European countries and regional markets (highly integrated by interconnectors) currently apply very different transmission tariff structures with regards to the applied G:L split and the treatment of generation:

[20] ENTSO-E (2014): 'Overview of transmission tariffs in Europe – synthesis 2014'
[21] The Brussels Court of Appeals annulled tariffs that were proposed for Belgium transmission grid.

- Nordic countries, for example, tend to recover a relatively large share of costs (related to the fixed network *and* energy market related) from generators.[22]
- In the central and eastern parts of the continent, MS typically apply no charges or recover a low proportion of charges from generators.

Of course, as discussed further below, although some countries may apply generation tariffs, they do still apply connection charges. This means that the incentives created for generators at the time of connection, can be a combination of generation site connection charge and the use of system and system services tariffs projected to be applied over the life of the plant.

Regulation 838/2010 sets the limits for the annual average generation *use of system* (i.e. grid access) tariffs, "G-charges" as follows:

- Within a range of 0 – 0.5 €/MWh for all countries except Denmark, Sweden, Finland, Romania, Ireland, GB and Northern Ireland;
- Within a range of 0 – 1.2 €/MWh for Denmark, Sweden and Finland;
- Within a range of 0 - 2.0 €/MWh for Romania.
- Within a range of 0 – 2.5 €/MWh for Ireland, GB and Northern Ireland;

Whilst a "G-charge" – related to recovery of the infrastructure costs of the network – may not be applied to producers in some countries, as discussed above, there are still tariffs which recover costs related to ancillary (system) services and/or losses.

Examples of both types are provided in the table below.

Table 3.1 – Generation tariffs

Country	Description
Austria	Energy based (separate tariff for ancillary services and tariff for losses)
Belgium	Energy based (covers ancillary services only)
Denmark	Energy based
Finland	Energy based
France	Energy based
GB	Capacity based
Ireland	Capacity based
Northern Ireland	Capacity based
Norway	Lump-sum[1] and energy based component
Portugal	Energy based

[22] Although even within this region of Europe we still observe significant variation in the tariff structure

Country	Description
Romania	Energy based
Spain	Energy based
Slovakia	Capacity based
Sweden	Capacity based

Source: ACER

Note 1 – based on long-term average energy production

In France, the energy based generation charge covers the costs for the Inter-TSO Compensation mechanism and is applied only to high voltage levels. In Portugal, the energy based generation tariff has two components, one for peak and half peak, and another for off-peak, and is intended to give a signal when the network is more stressed. In UK, Ireland, Norway, Romania and Sweden, charges vary by location, whereas countries such as Finland, apply a flat energy based charge.

Some of these tariffs are primarily associated with promoting the cost reflectivity of the overall tariff structure, whilst in other cases, their objective is primarily to recover TSO costs from generators as well as load (see Section 4 for further discussion).

3.2.3. Connection charges

Use of system tariffs are, however, not the only way through which generators contribute to the costs of providing a transmission network. The structure and level of connection charges also determines how much of the costs are covered by generators and how much is socialised.

Table 3.2 below shows the different approaches to connection charges applied today in different European countries. Our summary is based on the information in the ENTSO-E 2014 tariff synthesis and we note differs slightly from the classification that has been provided in previous ACER monitoring reports.

Table 3.2 - Type of connection charges applied across European countries

Country	Type	Country	Type
Austria	Shallow	**Italy**	Shallow
Belgium	Shallow	**Latvia**	Deep
Bulgaria	Shallow	**Lithuania**	Deep
Croatia	Deep	**Luxembourg**	Shallow
Cyprus	Shallow	**Netherlands**	Shallow
Czech Republic	Shallow	**Northern Ireland**	Shallow
Denmark	Shallow	**Norway**	Shallow
Estonia	Deep	**Poland**	Shallow

Country	Type	Country	Type
Finland	Shallow	**Portugal**	Shallow
France	Shallow	**Romania**	Shallow/Deep
Germany	Shallow	**Slovakia**	Deep
Great Britain	Shallow	**Slovenia**	Shallow
Greece	Shallow	**Spain**	Shallow
Hungary	Shallow	**Sweden**	Deep
Ireland	Shallow/Deep		

Source: ENTSO-E[23]

As Table 3.2 shows, the costs of connection that are directly paid by the new network user (i.e. separate from a use of system/access tariff) are reflected in different connection charging regimes, all of which are observed across Europe today:

- A **"shallow" connection regime** applies connection charges that are based on the costs of connecting a party to the grid, but excluding any wider network reinforcement costs associated with the new connection.
- A **"deep" connection regime** requires all, or a majority of, the costs associated with connecting assets *and* deeper network reinforcement works, to be borne by the connecting party.

The connection charging regime which applies in MS is particularly important when considering the relative strength of transmission price signals and the incentives for connection to and use of the network by generators across the IEM.

For example, both generation tariffs – whether applied to recover the infrastructure costs of the network or to reflect locational losses – and connection charges can provide locational signals for generators (and transmission connected load).

Shallow connection charges can provide strong locational signals for generators for locating in an area where the connecting costs are lower, whilst deep connection charges additionally provide strong locational signals related to grid reinforcement costs, as they reflect the incremental costs of connecting a new party to the transmission network. However, the perimeter and incidence of the locational signals are very different between connection and use of system charges, particularly when considering a market dominated by established electricity generators. Connection charges only apply to new entrants, whereas "G-charges" apply to all generation, including established generators.

Therefore, when evaluating the *relative* strength of locational signals for generation transmission use of system tariffs, it is important to consider this in conjunction with the connection charging regime applied in the relevant jurisdiction.

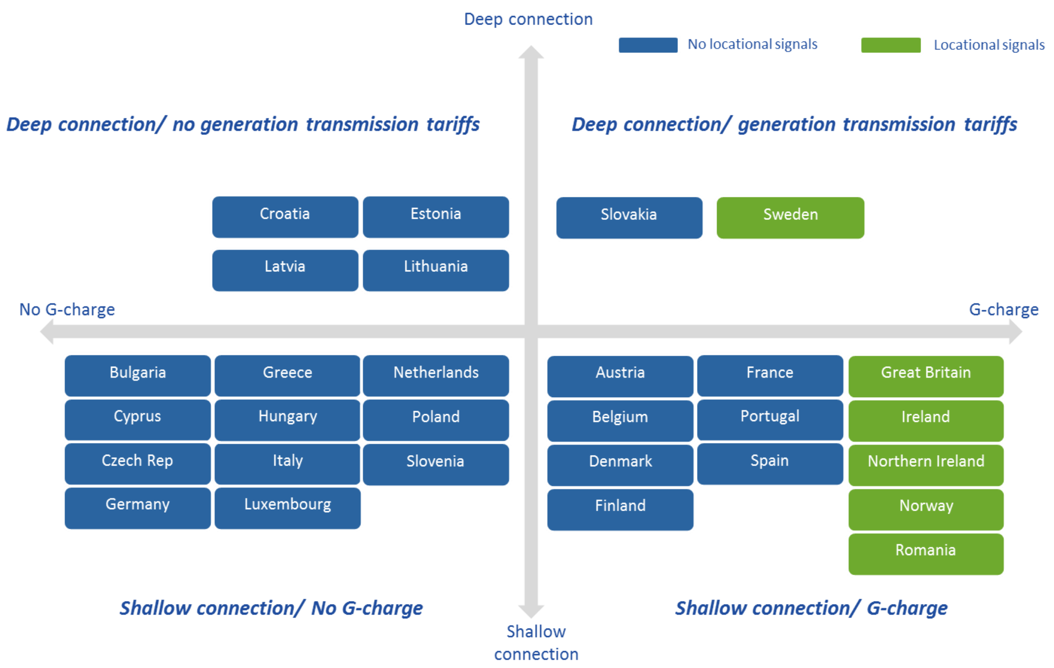
[23] ENTSO-E (2014): 'Overview of transmission tariffs in Europe – synthesis 2014'

Even in the absence of deep connection charges, new entrants may support physical limitations if they want to connect to a congested zone. These limitations act as implicit deep connection charges (or as zero nodal prices) from an economic point of view and need to be taken into account in the analysis of locational signals.

Figure 3.3 below shows how countries position themselves in terms of the application of generation connection and use of system charges. We have grouped countries depending on whether they apply deep or shallow connection charging principles and if they apply use of system charges to electricity generation.

This shows that very different degrees of cost-recovery are applied on generators in different countries. Some countries apply both generation use of system and deep connection charges thus placing a higher 'burden' of cost-recovery on generation, while other countries place a lower burden of transmission cost allocation on generation, by applying shallow connection charges and no generation use of system tariffs. The implication is that the signals which generators face for connection to and use of the transmission system across Europe can differ significantly, although under the objectives of the IEM, they compete in a single market.

Figure 3.3 - Connection and generation tariffs in various countries



Source: CEPA analysis of ENTSO-E[24]

[24] We note that there are a number of differences between the description of the connection regime in ENTSO-E's transmission tariff synthesis and ACER's monitoring reports for generation charging that have been shared with us for the purpose of this study. France, Italy, Portugal and Romania are, for example, classified as Deep in ACER documents, rather than Shallow in ENTSO-E's classification. Our understanding is that, since 2014, Bulgaria has also applied deep connection charges for some RES generators. For the purposes of Figure 3.3, we have classified Ireland as shallow (given that it shares an integrated approach with Northern Ireland), although the ENTSO-E tariff synthesis describes this regime as "semi-deep".

3.3. Summary

Our comparative review shows that different European countries apply many different transmission tariff structures. European countries differ both in the share of costs that are recovered from generation and load, and the basis on which tariffs are determined.

The signals and incentives which generators face for connection to and use of the transmission system across Europe can, therefore, differ significantly. One of the reasons for this is that different countries have placed a different emphasis on the objective of *cost reflectivity* rather than the primary cost recovery objective in cost allocation.

4. Optimal transmission access pricing and cost allocation

4.1. Introduction

In the next two sections we present our assessment of the potential impacts associated with the absence of harmonisation in transmission tariff structures in Europe. Our assessment is based on economic and case-study analysis, review of empirical evidence, telephone interviews with IEM stakeholders and the findings from our literature review.

Identifying and defining the nature and extent of the problem which needs to be addressed (if any) is a key part of the European Commission's guidelines on impact assessments. Any proposal to harmonise electricity transmission tariffs in Europe should result in more efficient market outcomes than the current arrangements observed today, and the expected benefits of such harmonisation should outweigh the costs.

This section provides a general discussion of the principles and application of economically efficient transmission access pricing, including key concepts of cost reflectivity *and* cost recovery in tariff setting. First, we examine the various cost components which are recovered through transmission tariffs in Europe today and then discuss the main principles to establish efficient charging mechanisms for those costs. Following this we consider how tariffs can be set to ensure European TSOs collect sufficient revenues to cover their costs, and how European countries address the cost recovery question today.

This discussion is very important to the current debate on tariff structure harmonisation. Where tariff structures are not cost reflective, or are considered to be broadly cost reflective in some, but not all, MS, then all users of the network simply do not all pay for the costs that they impose on the system. This potentially prevents the efficient development of the system and competition from taking place on a level playing field.

Building on this discussion, in the next section, we then focus on some more specific examples of how a lack of harmonised tariff structures *potentially* impacts on the efficient functioning of the European electricity market. This includes examples of how the absence of harmonisation can create inefficiencies, by distorting operational and investment decisions of certain generators and some transmission connected load.

4.2. Cost reflectivity

4.2.1. Principles of efficient transmission access pricing

In interconnected electricity transmission networks, generators and consumers (load) may impose various costs on the transmission system. Most of these costs can be attributed to the generators' and consumers' operational and investment decisions, and they often vary by location and with energy demand over time. Because of the physics of electricity, interactions arise in such networks and the costs imposed by one user of the network often depend on the actions taken by other users.[25]

A key requirement for economic efficiency (i.e., the least-cost development of the overall power system) is that all market participants internalise all the costs they generate at the time they make their operational or investment decision. Transmission charging is one tool that can be used to convey some of the costs of using the power system. In order to ensure the most efficient (i.e., the least-cost) development of the overall power system, it is important to have a transmission charging regime in place that is reflective of all actual system costs imposed by each user of the transmission network.

Because there is a variety of costs that are included in transmission tariffs, first we lay down some basic principles of an efficient (i.e. cost reflective) access pricing regime:

- **Fixed costs should be recovered through fixed charges, and variable costs should be recovered through variable, energy based charges**. The efficient way to recover each type of cost is if it is charged on the same (or at least similar) basis as it is incurred. For example, if some costs vary with the amount of energy produced or consumed, it should be charged on a per-MWh basis. Otherwise, the actual cost is unlikely to be internalised, since the charge is unlikely to reflect the actual costs incurred at that location at the given time, and will therefore likely lead to under (over)-consumption/production below (above) efficient levels.
- **Locational costs should be recovered through locational charges**. If the true cost a generator or load imposes on the system depends on the generator's or load's (electrical) location, it should be recovered through locational charges. If this is not the case, market participants' decisions may be distorted. For example, if locational costs are recovered through a charge that averages the costs across all locations or over time, some generators will face lower costs than the true cost and therefore they will generate more than economically efficient (i.e., the marginal benefit of the last unit of energy produced is lower than the marginal cost of that energy).
- **Costs that vary with energy consumption over time should be recovered through time-variant charges.** If some costs depend on the time of day or year (usually reflecting system conditions, e.g. demand), then it is appropriate to charge for those costs using time-variant tariffs. Otherwise, over-consumption or under-production may occur in periods when the tariff is lower than the actual cost, and vice versa. Development of the electricity transmission system to meet planning standards, typically driven by peak demand to access the system. This can potentially be signalled through the transmission tariff structure.
- **Costs should be allocated to those who cause them or are in the best position to manage them. Tariffs should also be set to reflect forward looking costs**. Cost-

[25] Brunekreeft, Neuhoff and Newbery (2005): 'Electricity Transmission – an overview of the current debate'

reflectivity of charges may not, by itself, be sufficient to ensure economic efficiency. In order to minimise overall systems costs, it is necessarily to make those responsible who can control them. An efficient access pricing regime also requires that charges should reflect (marginal) forward looking costs, given it is these costs that both generation and load users of the system have control over.

The last point is a crucial one. If the transmission tariff structure has been designed to reflect forward looking (marginal) costs, the investment and operational decisions of both generation and (price responsive - elastic) load users, will reflect the costs they impose on the system for decisions which they have control over.

In this case, users of the system will internalise those costs in their decision making – whether in determining output or consumption decisions, or when making investment choices – helping to ensure that those decisions are efficient ones.

If European MS transmission tariff structures are not harmonised, but reflect variations in marginal costs and other principles for cost reflectivity outlined above (e.g. charges related to the various cost drivers), they can be justified, as they reflect the costs which different users impose on the transmission system.

4.2.2. Cost types and characteristics

In this section we map out the type of costs currently recovered through electricity transmission tariffs in Europe today. For each type of cost we describe their main characteristics in terms of whether those costs: (1) are fixed or variable; (2) vary by location of generation or load; and (3) vary over time.

As discussed in the previous section, transmission tariffs currently applied in the EU are used to recover a range of costs including the costs associated with:

- transmission infrastructure (operation and capital);
- transmission losses;
- transmission congestion;
- system supply services;
- system balancing services; and
- other regulatory charges.

Table 4.1 characterises these cost types across three dimensions:

1) whether they are fixed or variable in the short term;
2) whether they vary by location within the transmission grid; and
3) whether they vary over time.

Table 4.1: Main characteristics of the types of costs included in European transmission tariffs

Cost category	Fixed (F) or variable (V)?	Varies by location within the grid? (Y/N)	Time variant? (Y/N)
Transmission infrastructure	F	Y	N
Transmission losses	V	Y	Y
Transmission congestion	V	Y	Y
System balancing services	V	N	Y
Other system services	V/F	depends	depends
Other regulatory charges	F	N	N

Source: CEPA

The subsections below describe in more detail the different characteristics of cost types presented in Table 4.1.

Transmission infrastructure costs

Infrastructure costs include new transmission required for newly-connected generators and loads, transmission system reinforcements (e.g., needed due to changes in the system, such as load growth or a significant change in the generation patterns), and ongoing operation and maintenance of the transmission system (e.g., repairs of failed transmission elements).

These costs are generally not a function of the amount of energy generated or consumed, but rather the amount of new generating capacity connected to the grid or the peak demand of consumers, and can thus be considered fixed. Transmission infrastructure costs are also generally location specific. For example, the costs of transmission upgrades with new connections directly depend on the location chosen by the new generator or load. Although the costs for required infrastructure may vary over time, in the short-term they can be fixed.

Transmission losses

Transmission losses vary by both location and the total amount of energy transmitted, thus they are both location-specific and time-variant. This is driven by the physics of electricity, i.e. that transmission losses depend on network topography and they exponentially rise as the current on a circuit increases.

The true cost of transmission losses that an individual generator or consumer generates is the incremental change in total system losses caused by a unit change in demand or generation (e.g., 1 MW increase or decrease in load or generation). Therefore the efficient, cost reflective way to charge for transmission losses is through time-variant (i.e., hourly), energy based and locational charges. If these charges are designed to be truly cost reflective, generators and loads would fully internalise them into their dispatch and consumption decisions. On the other hand, not providing generators with such cost reflective charges for losses would lead to a distortion in competition between generators, since those generators whose location entails lower losses would not (fully) benefit from that efficiency.

Transmission congestion

Transmission congestion is similar to transmission losses in that it is variable, location-specific and time-variant.

Transmission congested costs include the cost of re-dispatch (i.e., dispatching higher cost generators out of merit-order) due to transmission constraints in order to maintain system reliability. As is the case with transmission losses, the true cost of transmission congestion that an individual generator or consumer generates is the incremental change in total congestion costs caused by a unit change in demand or generation (e.g., 1 MW increase or decrease in load or generation).

Given these characteristics, cost reflective charging is on the basis of time-variant (i.e., hourly), energy based and locational charges; otherwise the same inefficiencies can occur as described above.

System balancing services

System balancing services involves short-term (near real time) balancing of supply and demand to correct deviation from contractual schedules of market participants.

Since balancing is performed on a system wide basis, the costs incurred are not locational. The contribution of each market participant to the total balancing costs is a function of its deviation from its own schedule. Because deviations are corrected by dispatching generators up or down the merit order, the cost will vary over time with the value of energy, and thus is time-variant.

Other system services

Other system services include:

- primary, secondary and tertiary reserves;
- black-start reserves; and
- voltage control and reactive power.

Primary, secondary and tertiary reserves include costs associated with keeping electricity generators (and potentially demand side resources) in reserve to respond to changes in system frequency. Since the providers of these reserves incur an opportunity cost of not being able to generate energy, the cost of these services varies with the value of energy, and is thus time-variant.

Black start reserves are used to restore the power system following a blackout, while voltage control and reactive power services are in place to maintain system voltage within the allowed limits and to control flows of reactive power in the network. Providing these services may involve both fixed and variable costs.

System services costs may also be locational if, for example, they are procured on a zonal basis. Since there is a variety of different services under this category, there is no single method of cost-reflectivity that could be applied in the tariffs.

Other regulatory charges

Other regulatory charges may include stranded costs, costs of supporting renewable or cogeneration energy production, regulatory levies, costs of diversification and security of supply, etc. These costs are likely to be fixed, and unlikely to be location- or time-variant. Furthermore, they are costs that individual market participants cannot control. They will, however, perceive them as costs when making operational and investment decisions, and may therefore lead to distortions.

4.2.3. Implications

The discussion above demonstrates that the different types of cost currently recovered through transmission tariffs in Europe have different characteristics and relevant cost drivers.

An optimal, or efficient, transmission tariff structure, based on cost reflective charging, would charge for each type of cost on an appropriate basis, following marginal cost principles.

Instead we observe different principles and approaches applied by electricity TSOs in Europe today. Some of these tariff structures, based on the principles we have outlined above, could be argued to be more cost reflective than others, and means that the current arrangements, *all things being equal*, most likely act to prevent a level playing field for all market participants across the European electricity market today.

As some tariff systems may be more cost reflective than others, there is also the risk that users of the transmission system may not be making efficient decisions.

This is increasingly an issue for all European countries, since in an integrated electricity market, which is the ultimate goal following the adoption of the ETM, these inefficiencies – created by *national* choices of tariff structure – potentially impose costs on other countries, as they effect the use and development of the wider *European* transmission system. We provide examples of this in Section 5.

4.3. Cost recovery

Due to the natural monopoly characteristics of the electricity transmission system, one of the implications is that efficient (i.e. cost reflective) tariff structures, based on the principles above, may not always guarantee that the TSO is able to recover its costs. Therefore, further adjustments of charges are likely to be needed to reconcile the two.

Economic theory (based on Ramsey pricing rules) is clear on how best to adjust efficient (cost reflective) prices to ensure an overall revenue objective. Any mark-up that needs to be made to efficient prices should be allocated to the least price responsive (inelastic) group and collected through a fixed charge to help minimise any distortions from tariffs that are simply aimed at ensuring cost recovery for the TSOs.[26]

Our brief review of current tariff arrangements in Europe has demonstrated how individual MS currently apply different principles to address the cost recovery question. Some countries, as a consequence of not applying generation tariffs, simply apply tariffs to load based on an average cost, rather than marginal cost, principle. Other countries, such as GB and Sweden, "mark-up" a set of tariffs that apply to both generation and load to achieve an overall revenue target. In Norway, both generation and load make a lump-sum contribution to residual costs (following the application of a losses based transmission tariff based on SRMC) based on their long-term average energy production.

In a European context, this means that market participants face different incentives for use of the transmission system in individual European countries.

Particularly for the most price responsive users of the electricity transmission system, some forms of generation and transmission system connected loads, this may distort their investment and operational decisions, and again, *ceteris paribus*, may act to prevent a level playing in the European electricity market.

4.4. Implications for European tariff structure harmonisation

Principles for efficient transmission access pricing and the characteristics of different cost types currently recovered through transmission tariffs, are crucial to the policy debate of tariff structure harmonisation in Europe today.

The discussion above shows how the efficient charging basis for the various cost types is different and that a starting point for ensuring cost-reflectivity of transmission tariffs should be to adhere to these principles by charging for each type of cost on an appropriate basis.

However, our review of the current arrangements in Europe (see previous section) clearly demonstrates that although there exist common *objectives* for transmission tariff structures in Europe (as set out in Article 14 of Regulation 714/2009), European countries today adopt very different principles of addressing both the cost recovery issue, and how an "optimal", i.e. cost reflective, tariff structure should be designed.

This absence of harmonisation, in tariff structure design and application, *potentially* leads to a number of problems for the IEM.

At a very basic level, if some countries broadly adhere to the principles of an "optimal", cost reflective, tariff structure, whilst others do not, then these policies act to prevent competition

[26] See Newbery et al. (2005): 'Long term framework for electricity distribution access charges'

in the European market place from taking place on a level playing field. As detailed in Section 5, this *potentially* leads to a number of operational or investment distortions which, particularly in an integrated electricity market, may reduce economic welfare.

These harmful effects are potentially greater if countries adopt very different principles of addressing the cost recovery and cost reflectivity questions.

As the need to recover the sunk investment (average) costs of the transmission system is such a key component of European TSOs allowed revenues, they are also a primary driver for European countries choices of tariff structure. Whilst economic theory points to how the cost recovery issue can be addressed in an economically efficient way, by European countries applying different principles to this issue, they potentially extenuate the *potential* problems that may result from an absence of harmonisation in cost reflectivity.

In the section which follows, we discuss how these issues *potentially* translate into specific problems and distortions in the European electricity market.

5. IMPACTS OF CURRENT ARRANGEMENTS

In this section, we focus specifically on how a lack of tariff structure harmonisation may lead to negative impacts on the efficiency of the European electricity market. We also provide specific examples where evidence suggests that distortions could have or may potentially occur in the future.

In the broadest terms, an efficient electricity market could be defined as one that minimises the overall, social costs of serving customers, both in the short and the long term. A fundamental characteristic of such markets is that efficient price signals are conveyed to both generators and consumers, and those price signals accurately reflect the true cost of electricity at each part of the grid at every point in time.

In the shorter-term (operational) timeframe, such price signals incentivise both electricity generators (producers) and consumers to produce/consume the socially optimal amounts of electricity at every point in time. This generally means that generators are dispatched in merit-order, according to increasing marginal costs, thus ensuring that consumers are provided with the least-cost combination of available power.[27] Efficiently functioning electricity markets also ensure efficient network utilisation. In practice this means that no transmission capacity should remain unused if any remaining capacity could be used to lower the overall cost of serving load.

In the longer-term (investment) timeframe efficient markets send price signals that ensure efficient investment in generating and transmission capacity. This includes siting of new generation and load at locations where the overall costs, including capital, operational, and any other costs they impose on the system or other market participants, such as required investment in transmission reinforcements, are the lowest.

Given this view of efficiently functioning markets, we evaluate how the absence of harmonisation of transmission tariff structures may negatively impact market efficiency. Given that generation charges have been identified as the primary source of such inefficiencies, our analysis focuses on supply-side impacts of that charge. Specifically, we investigate two issues: (1) impacts on operational decisions; and (2) impacts on investment decisions. However, similar end use consumers may also be theoretically impacted. Therefore, based on discussions with stakeholders, we also outline how a lack of tariff structure harmonisation in Europe may potentially also impact on end users of the system.

[27] Note that unconstrained merit-order dispatch is only possible up to the point when one or more transmission constraints become binding. In the presence of transmission congestion, higher-cost generators may have to be dispatched out-of-merit-order within transmission-constrained areas in order to preserve system reliability. As long as such re-dispatch is done to manage physical constraints in a least-cost manner, it is still considered efficient.

In each case, we start with a theoretical discussion of the *potential* problems that may arise, then using this theoretical basis, identify the conditions and assumptions that need to hold for the negative impacts to apply in practice.[28]

5.1. Impacts on investment decisions

Stakeholders who responded to our questionnaire generally indicated that differences in transmission tariff structures could have an effect on generation investment decisions.

Those stakeholders who agreed that transmission tariff structures impact on the efficient functioning of the internal electricity market (66 per cent either agreed or strongly agreed with that statement) the majority (59 per cent) also stated that the current heterogeneity in electricity transmission structures across European countries can and may in future give rise to altered investment decisions. Some stakeholders also stated that differences in tariff structures *distorted* investment decisions, and was one of the main problems identified with the current tariffs arrangements that apply between European countries.

A number of large transmission connected customers also indicated that transmission tariff structures can alter their investment decisions, as transmission charges are a considerable operational cost for their businesses.

An aluminium producer for example, noted that differences in transmission tariffs can pose a risk of smelter closures, flagging-out and "*negative effects on competitiveness of the aluminium smelter industry in general*." They stated that transmission tariff structures across European MS should "*emphasise the need for predictability and competitive transmission tariffs for both power intensive industry and power production in a competitive framework.*"

This feedback from stakeholders at least demonstrates that market participants view the *potential* for investment distortions and the impact of tariff structures on the economics of generation plant and large loads more generally, to be an important issue.

In this section we evaluate how a lack of harmonised transmission tariff structures may inefficiently alter generation investment decisions at the European level and the extent to which they may distort competition in the European electricity market.

First, we examine impacts on generation investments by assessing the: (1) theoretical impacts; (2) conditions that need to be satisfied for the theoretical impacts to occur in practice; (3) current evidence of potential distortions to investment decisions; (4) future likelihood of negative investment impacts. Following this discussion, we briefly address investment impacts on load.

[28] This draws on the literature review of transmission tariff arrangements we have undertaken, the findings of which are summarised in Annex B.

5.1.1. Theoretical investment impacts on generation

As discussed in the previous section, transmission tariffs, and their structures, theoretically have the capacity to influence investment decisions in both generation and large (transmission-connected) loads.[29]

Transmission tariffs are perceived as a cost by both producers and consumers and are, therefore, a component of their overall cost expectations, and will influence their operational and investment decisions.

If the transmission tariffs are not cost reflective, along the lines discussed in the previous section, generators and loads may make decisions that result in a development of the power system in a non-least-cost manner. Thus, market distortions and inefficiencies are expected to occur only when market participants' decisions are impacted by non-cost reflective tariffs. Of course, distortions to cross-border trade may also occur if tariffs in one country are cost reflective, while in another neighbouring market they are not cost reflective.

In the case of generation, differences in transmission tariff structures could in theory distort the siting of generation plants between countries and bidding zones. How that distortion applies will, however, depend on the form of the transmission tariff structure.

Energy based tariffs

For example, if an energy based tariff (€/MWh) is levied on generation by a TSO in one European country or bidding zone, but not a neighbouring (interconnected) TSO, and the interconnecting transmission lines between the two (coupled) countries/bidding zones are expected to be uncongested, then all things being equal, the energy based charge should be directly reflected in the electricity prices in both countries (e.g. through the market coupling algorithm or competitive forces).[30]

However, differences in the €/MWh incidence of transmission tariffs across both countries mean that investors in generation, all other things being equal, will face a lower cost base in the country or bidding zone, without the energy based tariff is levied on generation than the country that applies such a generation tariff. A rational investor maximises its expected return, and would therefore choose to site its generation plant in the country with the lower transmission related cost, as, *all things being equal*, it will receive a higher expected return on its generation investment.

If, however, all other generation costs are *not* equal, but the total differences in those other (fixed) generation costs are smaller than the differences in total €/MWh transmission charges between the two countries, then the absence of harmonisation of tariff structures will still lead to investment in relatively higher cost plant, simply because of the choice of transmission

[29] Smaller, less price responsive, loads are likely to be less affected by the structure of transmission tariffs given electricity costs are likely to form a much small part of their total cost base / monetary outlays.

[30] As it is variable cost that is passed-through by the marginal generation plant in the merit order of supplies to meet electricity demand.

tariff structure. Consequently, resources required for a given quantity of generation in Europe would then be higher than if the transmission tariffs were harmonised, which would be clearly inefficient.

On the other hand, if in certain bidding zones, true transmission costs related to some baseload generators are higher than transmission costs related to peaking generators (for example if baseload generators are far from load centres, and therefore they impose higher costs associated with transmission losses and congestion on the system than peaking generators which are sited within proximity to load), an energy based tariff (€/MWh) may be cost reflective. In that case, an energy based tariff (€/MWh) would not be distortionary, but economically efficient, by giving the right incentive to generation developers to invest in the bidding zone where a new generator provides the greatest value. The problem arises if only some countries decide to apply cost reflective generation charges and others do not.

Capacity based tariffs

What if one European TSO levies a transmission tariff on generators on a capacity (power) basis (i.e., € per MW) while a neighbouring TSO chooses to apply no generation tariff (e.g. recovering the cost of the transmission network from load users)?

According to economic theory, in a fully competitive energy-only electricity market, generators can expect to recover their fixed costs of generation through price spikes during periods of scarcity. In a long run equilibrium, prices during such periods should rise to a sufficiently high level, and the scarcity periods should occur sufficiently frequently, to allow the generators to recover all their variable and fixed costs.

Under this fully competitive state of the world, generators' fixed costs, including electricity transmission tariffs levied on a per MW basis, should therefore be passed through to final customers via the wholesale prices set by the costs of the marginal generator. As with energy based generation tariffs, capacity based transmission tariffs will be factored into the entry costs and prices that investors consider when choosing the location of their generation plant in Europe, and, therefore, similar investment effects, all things being equal, might be expected as described above for an energy based generation tariff.

However, transmission tariffs, levied as a fixed (per MW basis) cost, can also be viewed as a tax on generator prices, which the generators may not be able to fully pass on to final customers. Their ability to do so will depend on the elasticity of electricity supply and demand curves within a bidding zone. If a full pass-through of per MW transmission tariffs is not possible, then the application of a capacity based generation tariff in one country, but not in the other, all things being equal, will encourage investment (especially in peak generators) in the latter country whilst discouraging investment in the former.

Is this a problem?

It all depends on whether the levied generation transmission tariff is considered cost reflective or not.

If the tariff structure is cost reflective, based on the principles which were set out in the previous section, then arguably it is the country that *does not* apply a generation tariff that is distorting competition, as electricity generation investors, when forming their investment decisions, are not considering the full cost that they impose on the European transmission system (based on the beneficiary pays principle).

If, however, the tariff is *not* cost reflective, then choices of tariff structure (e.g. application of a G-charge or not) could distort investment by creating incentives to invest in locations that adopt a lower transmission tariff, but in practice involve higher cost.

In this case, European countries would be investing larger resources in *generation to meet the same level of demand*, when compared either to a counterfactual of:

- no capacity (MW) based generation tariff levied in either country (as all things being equal, a rationale investor would invest in the lowest cost location); or
- cost reflective transmission tariffs, applying in both European countries (in this case although such tariffs may affect investment siting decisions, it may not be inefficient as long as the transmission charges reflected all costs that each generator imposes on the transmission system).

However, determining whether differences in transmission tariff structures have a material *distortionary* impact on investment decisions is challenging because the counterfactual (i.e., what investment decisions would have been made had a different set of transmission charges been in effect at the time the decision was made) is not easily identifiable.

We also know that in practice there is a range of other factors that will influence investment decisions in new generation capacity.

Section 3 of CESI (2003)[31] for example, highlights a range of those factors, including differences in the support mechanisms for renewable generation. In general, investment decisions are driven by expectations about future conditions, and those expectations are surrounded by a great deal of uncertainty. Specifically, in deregulated electricity markets, such as the IEM, investors in generating capacity are neither guaranteed that their output will be needed nor are they guaranteed a price for their power.

The risks that investors in conventional generation in the European electricity market face include:

- ***Market revenue volatility and variability*** - Peak price and off-peak electricity prices vary with weather conditions and renewable generation.

[31] CESI (2003): 'Implementation of short and long term locational signals in the internal electricity market'

- ***Load factor risk*** - The growing penetration of renewable generation is likely to permanently reduce the load factors of thermal generators; thus their energy revenues are likely to fall, while other revenues for other services (e.g., flexibility) are highly uncertain.
- ***Price restrictions*** - For example, price caps may prevent efficient price formation during scarcity periods, which may lead to underinvestment in generation capacity.
- ***Incomplete markets*** - Flexibility provided by thermal generators is of value and is needed, but currently not (sufficiently) remunerated.
- ***Energy policy and regulatory risk*** - For example, stop-and-go nature of renewable energy policies and uncertain environmental regulations.

Therefore, when making a generation investment decision, investors have to take into account a range of these factors.

If investors were able to generate an accurate forecast of all them, then they would take into account all costs, however small. Thus, even small differences in generation transmission tariffs could feed into their investment decisions, as described in the theoretical impacts above. In practice, however, due to the inherent uncertainties in forecasting, investors are likely to make a decision on whether to invest based on an expected profitability that exceeds a certain (possibly subjective) threshold to guarantee future profitability of the investment under a range of likely scenarios. Thus, investment decisions in new generating capacity are likely to be fairly robust to the various assumptions and projections.

In other words, an investment decision in new generating capacity is unlikely to represent a knife-edge equilibrium where relatively small perturbations in assumptions would completely change the investor’s decision.

Therefore, we believe, that in practice the investment effect (distortion) may potentially exhibit itself only in a subset of investment decisions, where the above conditions are met, and the investor is more or less indifferent between siting a generator in one of two neighbouring countries with differing transmission tariff structures.

5.1.2. What conditions need to hold for the theoretical investment impacts on generation to potentially occur in practice?

Based on the above discussion we have sought to identify the conditions or assumptions that would need to hold for a distortion to cross-border investment decisions to occur in practice:

- Neighbouring countries or bidding zones that apply different transmission tariff regimes *must be physically interconnected*.
- The *transmission lines that connect the countries or bidding zones*, considered potential sites for the new generator, *must be generally unconstrained*. Persistent congestion between two zones would make siting a generator in one country an

imperfect substitute of siting it in the other country, and thus the investment impact would be weaker or non-existent.

- The *increase* in expected returns in the country or bidding zone without the generation tariff, all things being equal, must be greater than any other differences in generation costs – i.e. the strength of the transmission tariff signal must be greater than any other factors that may affect generation location decisions.
- An *investor/developer* of a new electricity generation plant *must consider multiple potential sites in different countries/bidding zones* when making the investment decision *and be able to relatively flexibly allocate its capital and resources between the potential countries/bidding zones*.
- The *investor must be of the merchant-type that relies on market revenues to recover its investment costs*. For example, nuclear projects that rely on government-backed long-term power purchase agreements or their inclusion in the regulatory asset base are not good candidates, because similar support mechanisms may not be available to them in the neighbouring countries.
- *Generator type must offer sufficiently flexible siting options*. Many types of generators have a limited choice of sites, often driven by fuel availability. The types of generators that are less likely to be affected by the investment effect include: renewable generators (because they are generally sited at locations with the highest output potential) and combined heat and power projects (because demand for the by-product, e.g. heat or steam, is usually needed at specific locations).

Furthermore, inefficiencies would arise only if the capacity (or energy based) tariff influencing the siting decisions were not cost reflective.

One of the key conditions that needs to hold (which results from a number of the conditions outlined above) in order for the negative distortions to investment to occur in practice, is that the transmission tariff must also act like a tax on generation.

If in contrast, all or part of the generation tariff can be passed through by the generator, the risk of distortion is significantly reduced.

In the sub-section which follows, we explore whether there is any practical evidence of these conditions applying in practice.

5.1.3. Current evidence of potential investment distortions

Based on our research, we have not found direct evidence of investment impacts arising from the current lack of tariff structure harmonisation in Europe; however, there are some indications that transmission tariffs, most likely in combination with other factors, may *potentially* lead to market distortions.

Generation investment in the Nordic region

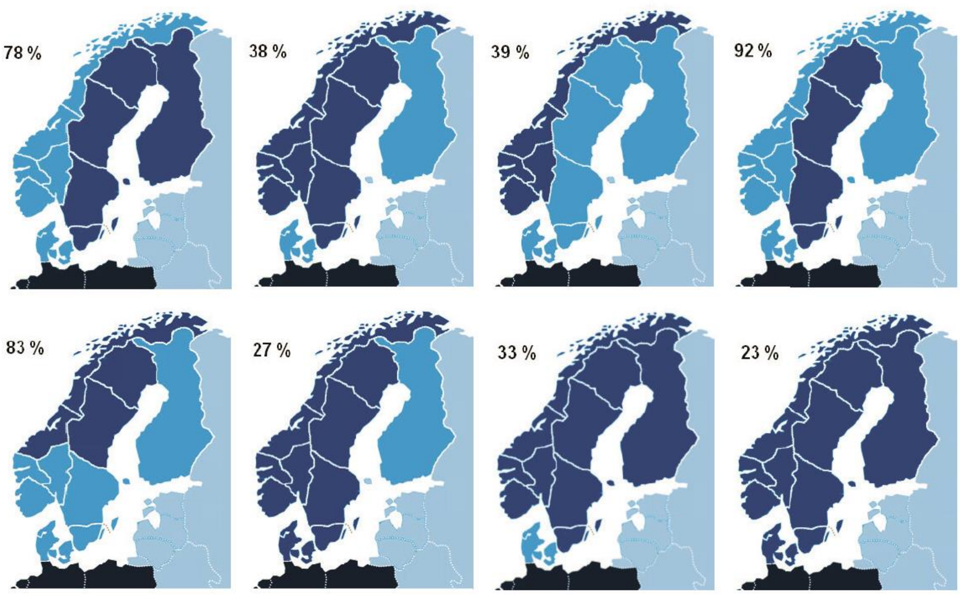
The Nordic region is example of a regional market area that fulfils many of the necessary conditions for the investment distortions outlined above.

Given the close integration of countries in the region through the Nordic energy market, transmission tariffs may potentially play a more significant role in investment decisions, especially given the fact that the transmission charging methodologies and tariff levels between the two countries are significantly different.

For example, since 1 January 2012, Sweden and Norway have had a common market for renewables electricity certificates. The objective of the scheme was to increase the combined renewable electricity production to 26.4 TWh by 2020 to meet the two country's renewable electricity targets in a cost-effective way. Under the scheme, renewable electricity generated in the two countries and the corresponding renewable certificates are fully fungible. A rational investor in this case might be expected to invest in renewable projects in the country where the overall investment and operational costs (including transmission charges) are lower.

The Nordic countries are also well interconnected and prices converge between a number of bidding zones during significant parts of the year. The Nordic market report for 2014 states that there was a common Nordic price for 23.4 percent of the hours in 2013. This share has fallen from 25.1 percent in 2012 and 26.2 percent in 2011. In more than 50 percent of the hours in 2013, there were only two different prices in the Nordic electricity market.

Figure 5.1 – Percentage shares of the number of hours with equal prices in 2013



Source: NordReg[32]
Note – the dark blue coloured areas denote which areas had equal prices in 2013

[32] NordReg (2014) – 'Nordic Market Report 2014'

A report by the Thema Consulting Group[33] – commissioned by Fortum, Skellefteå Kraft, Statkraft and Vattenfall, has specifically analysed the consequences of harmonising versus not harmonising the Swedish transmission tariff structure with other Nordic and European countries. They present a set of examples of how the current Swedish tariff system in their view impacts the economic decisions of power generators in the region, concluding that the capacity based tariffs applied in Sweden create "*distortions between generation technologies and runs the risk of reducing the investment incentives for renewable generation*."

From speaking to a range of market stakeholders in the Nordic region, there appears at least some concern that the different transmission tariff structures which apply in different countries, could act to prevent a level playing field in the region.

Generators in Sweden, for example, face several locational price signals. First, there is an annual fee for entry and exit capacity that varies by the generator's location. The fee increases linearly with the geographic latitude from south to north, ranging from SEK 19/KW (or about €2.04/kW) in the south up to a maximum of SEK 48/KW (€5.15/KW) at latitude 68° in northernmost Sweden.[34] There are also locational charges for transmission losses which than tend be significantly higher in the north compared to the south of the country. Sweden is also part of the Nord Pool wholesale electricity market. Within this market, Sweden is divided into four bidding areas, and generators located in the northern bidding areas tend to receive lower energy prices for their output. Lastly, Sweden also applies deep connection charges for new generators.

Compared to some regions in Europe, Sweden has comparably cost-efficient available resources of renewable generation, for example hydro potential. We have been informed that there remains unexploited hydro pump storage potential at the Juktan hydro plant potential in northern Sweden because such investment would not be profitable given the current level of transmission charges.[35] This may conflict with renewable goals and system flexibility needs, and thus may potentially be inefficient.

4M Market Coupling Region

We have developed a detailed case study of the 4M Market Coupling region, which is presented in Annex D. This case study provides an example of how the introduction of a G-charge in Slovakia has certainly had a negative impact on the profitability of existing generation plant in the country, as a consequence of the region being highly interconnected,

[33] Thema (2015): 'Harmonisation of generator tariffs in the Nordics and the EU'

[34] Blaiken wind farm is located at latitude 66°, so it is currently levied an annual capacity entry charge of about SEK 43/kW, or €4.65/kW.

[35] The Juktan hydro plant in Västerbotten in Northern Sweden was commissioned in 1979 as a pumped storage pant. In 1996, it was refurbished in and converted to a conventional plant because the transmission charges introduced by Svenska Kraftnät. See Section 3.2.2 of: http://www.thema.no/wp-content/uploads/2015/04/THEMA-Report-2014-43-FINAL-Harmonisation-of-transmission-tariffs.pdf

with Slovakia being particularly integrated with the Czech, and to a lesser extent with Hungarian markets.

However, in this example we found evidence of near-simultaneous construction of very similar CCGTs on both sides of the border between Slovakia and Hungary, even though market conditions in the two countries have been significantly different. This confirms our conjecture that cross-border investors are not extremely sensitive to relatively small differences in transmission tariffs when making cross-border investment decisions.

Current investment climate and likelihood of inefficiencies due to the "investment effect"

As noted above, we have not received any definitive evidence from stakeholders regarding the investment effect, nor have we found any such evidence through our own analysis. If there is currently no need for such investments or the current investment climate is unfavourable to them, then it is also unlikely that the investment effect has so far resulted in significant inefficiencies, if indeed it has taken place at all.

Currently, there is a widespread recognition that the investment climate for conventional thermal capacity is very challenging in Europe. In fact, the level of investment in such capacity is at an all-time low.[36] This is primarily the result of low wholesale electricity prices, caused by weak electricity demand (due to weak economic conditions) and rising renewable generation (which depresses wholesale energy prices).

Furthermore, most European MS currently have sufficient capacity to ensure supply adequacy in the intermediate term, and thus there are no immediate need for new investments.[37] These conditions imply that there is currently very little incentive to invest in new thermal capacity, and thus it is unlikely that any investments have been materially affected by the lack of generation tariff harmonisation.

5.1.4. Future likelihood of inefficiencies due to the "investment effect"

Potential inefficiencies arising from the investment effect depend on how much conventional thermal generation will be needed in the future and whether the future investment conditions will be favourable to the types of (market-driven) investments that are likely to be affected by the investment of differing transmission tariff structures. For this type of plant, siting decisions are more flexible and other factors which input to the investment decision may be less variable, compared to say renewables.

As Europe pursues its decarbonisation goal, there will be a need for new gas-fired generation in the intermediate term (i.e., next 10-15 years), caused by three main factors:

[36] For example, Platts' February 2015 edition of Power in Europe reports that there are currently only nine CCGTs under construction in all of West Europe. See page 12 of Platts (2015), Power in Europe, Issue 694, February 2, 2015.

[37] See ENTSO-E, Supply Outlook and Adequacy Forecasts, 2014-2030.

- ***First***, reserve margins are expected to decrease from the current (high) levels, and thus additional capacity will be needed to ensure security of supply.
- ***Second***, as the share of variable renewable generation increases, there will be a growing need for flexible gas-fired generators to balance the power grid.
- ***Third***, improvements in physical interconnections between countries and bidding zones are likely to lead to greater market integration, which makes the investment effect more plausible.

All these factors suggest that inefficiencies due to the investment effect are more likely to occur in the future than today.

On the other hand, national policies to decarbonise electricity systems that have been exacerbating investment risk and uncertainty may continue to discourage market-driven investment in conventional thermal capacity. For example, it is currently unclear if and how flexible generators will be remunerated for providing system flexibility services.

Several countries have or are considering to introduce capacity remuneration mechanisms (CRMs) to support such generators, but it is uncertain whether the level of support by such mechanism will be sufficient[38], and also differences in capacity payments between countries may become an additional consideration to investors, making the differences in generation transmission tariffs again relatively less important.

All these uncertainties constitute "regulatory risk". A Frontier Economics (2013)[39] study estimates a "financing effect" which results in higher financing costs due to increase investors' perceptions of increased regulatory risk. That study assumes that the lack of generation tariff harmonisation could be such a significant risk that it would increase the investors' cost of capital by 0.5%.

We would also argue that regulatory risk is a real phenomenon that is likely to be reflected in investors' cost of capital; however the factors discussed above are likely to be much more significant sources of regulatory risk, and any attempt to isolate the impact of a single factor on regulatory risk is highly speculative.

5.1.5. Impacts on load

Whilst we believe investment distortions *could in theory* also take place in specific circumstances for some large transmission connected loads (e.g. very marginal investment projects, businesses with very high energy use *and* where transmission tariffs are not cost reflective), we believe that distortions to investment are less likely to occur for most load compared to generation. Again, this is not to say that transmission tariff structures may not influence large transmission connected load decision making, but rather that it is unlikely that

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[38] "Potential support from capacity mechanisms is a marginal consideration in these oversupplied markets"; POWER IN EUROPE / ISSUE 694 / FEBRUARY 2, 2015, p.12.; except in the UK.

[39] Frontier Economics (2013): 'Transmission tariff harmonisation supports competition'

current *differences* in MS tariff structures result in investment or operational distortions, in the absence of other factors that may support such decisions.

5.2. Impacts on operational decisions

The responses to our questionnaire highlighted relatively clearly that the majority of stakeholders across European countries consider that the current electricity transmission tariff structures could have an impact on the efficient functioning of the European electricity market, today and in the future.

Energy based tariffs were cited as a particular issue, with one integrated European utility stating that: "*the heterogeneity of energy-based charges imposed on power injections across Europe can be detrimental to the efficient functioning of the internal electricity markets since it can generate discriminations between producers located in different countries. These negative effects will be intensified with the progressive integration of European electricity markets through market coupling.*"

For those stakeholders who agreed or strongly agreed that transmission tariff structures can affect the efficient functioning of the market, 55 per cent stated that they could lead to altered operational decisions by generators.

Operational distortions from *differences* in national tariff structures are extremely unlikely for load and, therefore, our discussion of *potential* operational distortions, focuses on the impacts of generator decision making.

As with investment impacts, we examine impacts on the operation of generation by assessing the: (1) theoretical impacts; (2) conditions that need to be satisfied for the theoretical impacts to occur in practice; (3) current evidence of potential distortions to operational decisions; and (4) likelihood of potential future distortions.

5.2.1. Theory

Operational impacts may arise from a distorted dispatch of generators due to differences in non-cost reflective generation tariffs between countries or bidding zones.

From the perspective of economic efficiency, it is most efficient to dispatch the least-cost set of generators to meet the demand for electricity. In practice, this means that generators with the lowest marginal costs should be dispatched first, followed by higher-cost generators dispatched in the order of increasing marginal costs ("merit-order") until total demand is met. If the transmission capacity between two bidding zones is not congested, then the generators in both bidding zones should be dispatched according to the joint merit order (i.e., the combined merit order of the two zones). Transmission charges that are not cost reflective may result in generators facing higher costs than their true marginal costs, leading to distorted dispatch decisions. This may include a generation tariff faced by some generators but not others, which may put the generators that are required to pay a generation tariff at a cost disadvantage.

We illustrate this point with an example.

Suppose that Generator 1 is located in Bidding Zone A, while Generator 2 is located in Bidding Zone B, and the transmission line connecting the two zones is uncongested. Assume further that the two generators are next to each other in the merit order, with Generator 1 having a slightly lower marginal cost. Lastly, assume that only Generator 1 needs to be dispatched in order to meet the demand for electricity (i.e., it is the marginal generator). Now suppose that a non cost reflective generation tariff is levied on Generator 1 only, and the level of the charge exceeds the cost difference between Generators 1 and 2. As a result, Generator 2 will be dispatched instead, and Generator 1 will remain idle. This is inefficient because: (1) Generator 1 has the lower marginal cost but for the generation tariff; and (2) the generation tariff does not reflect true marginal costs of generation. The result of such charges is that overall cost of meeting demand will not be minimised.

5.2.2. What conditions and assumptions need to hold for theoretical operational impacts on the European electricity market to potentially occur in practice?

Below we identify an initial list of conditions and assumptions that need to hold for distortions to operational decisions to occur in practice in the European electricity market:

- Neighbouring countries or bidding zones that apply different generation tariffs must be physically interconnected.
- Differences in generation tariffs must be sufficiently large to change the merit order, especially for marginal generators.
- Differences in generation tariffs must not reflect actual differences in marginal costs. If the generation tariffs reflect actual costs the generator face or impose on others, having a generation tariff would be less distortionary than not having one.
- If generators are not centrally dispatched, sufficient competition between generators is necessary to ensure that they vigorously compete until they offer their output at their respective marginal cost, and thus they are dispatched in an efficient manner.

5.2.3. Evidence of potential operational distortions

Our research has again identified a number of examples of whether these operational effects *could* have occurred, or may have in practice acted against a level playing field for cross-border competition in the European electricity market.

Blaiken wind farm and potential hydro expansion in Sweden

With 225 MW of installed capacity, Blaiken is one of the largest onshore wind farms in Europe. It is located in north-western Sweden, and is jointly owned by Skellefteå Kraft, a municipality-owned electricity company in Sweden, and Fortum, a Finnish energy company.[40] The location

[40] http://www.fortum.com/en/energy-production/wind-power/swedenprojects/pages/default.aspx

of the wind farm is considered to have very good wind conditions, with annual output estimated at 650 - 700 MWh, corresponding to a capacity factor of 33-35%. Blaiken is connected directly to the 400 kV transmission network.

As discussed earlier, generators in Sweden are subject to four different locational price signals: (1) annual fee for entry capacity; (2) transmission losses; (3) zonal energy prices; and (4) deep connection charges. Blaiken's operator estimates that its cost of grid access translates into €3.65/MWh, representing about 25% of its opex. Furthermore, it expects that, given proposed tariff changes by the Swedish TSO, G-charges will rapidly increase in the future. According to Blaiken's operator, the wind farm's output has been reduced by 7%, because of the current level of charges.

The case of the Blaiken wind farm and the unexploited hydro potential, discussed earlier, highlights potential inefficiencies that may emerge if locational price signals are excessive. We did not assess whether the charges currently in place in Sweden are cost reflective, but the mere fact that some charges are based on geography (latitude) suggests that not all of them may be fully cost reflective. Even if they were fully cost reflective, it may be inefficient to provide locational signals by four different means. If some of the charges were not cost reflective, or in combination excessive, they may distort the level playing field for generators both within Sweden and in the Nordic market.

Pumped storage plants

Pumped storage plants are the only currently available technology for large-scale electricity storage. They have traditionally relied on low-cost off-peak electricity to run their pumps to fill the reservoirs, and to generate power during high-priced peak periods.

While reliably integrating the projected large amounts of renewable capacity will likely require more than the existing storage capacity, market conditions in Europe have been challenging for existing pumped storage plants. The price spreads between peak- and off-peak periods have recently declined, to a large extent because a lot of renewable energy, especially solar, is now generated during the peak hours. This has greatly undermined the profitability of pumped storage plants, which in some cases may have further been deteriorated by transmission charging.

Unlike other generators, pumped storage facilities may be levied two types of transmission charges: (1) when they pump, they are treated like load, and thus are charged L-charges; (2) when they generate they are liable for G-charges (if they exist). Distortions may occur if one or both of these charges are not cost reflective. For example, if transmission charges levied on load are used to fund renewable subsidies, a cost not directly related to the use to the transmission system, and if pumped storage plants are also liable for these charges, their operation will be distorted, and they will not be at a level playing field vis-à-vis other generators. Another form of inefficiency could occur if transmission tariffs provided reduced incentives for pumped storage plants to provide flexibility services to back up renewable generation and to balance the grid. Providing such flexibility service would require more frequent pumping and generation, and thus would expose the pumped storage plant to higher transmission-related costs.

Currently, there are significant variations in the treatment of pumped storage plants in transmission charging across Europe. For example, pumped storage facilities receive a special tariff or are exempt from at least some grid charges in Austria, Italy, Germany, Lithuania, and Portugal, while in many other countries they are subject to the full L-charge.[41]

Central West Europe

Countries of the Central West Europe (CWE) region (Germany, France and the Benelux countries) have had their day-ahead markets coupled since 2010. Cross-border trading in the region is supported by relatively large amounts of transmission capacity between the CWE countries. As a result, national electricity markets are fairly integrated with their neighbours. This is especially true for the smaller countries, such as Belgium and the Netherlands, which have a single electricity price about 75% of the time, and also have relatively strong interconnections with other markets outside the region, such as Norway and GB.

In 2012, Belgium introduced two new transmission charges levied on generators: (1) an energy based charge for ancillary services; and (2) a capacity based G-charge. In addition, Belgian generators also face a federal levy on gas consumed, which in effect acts as another energy based charge. Although the capacity based G-charge was later annulled by a Belgian court, the energy based charges remain in effect, and currently amount to approximately €2.26/MWh for the most efficient CCGTs.

Concerns have been raised, that since similar generators in the Netherlands and other countries in the region do not face such charges, inefficient operational impacts may occur, whereby less efficient generators outside Belgium may displace a local, highly-efficient CCGT. This would be clearly be inefficient if the charges levied on the Belgian generators were not cost reflective. While we did not directly examine the cost reflectivity of the charges currently in effect, we analysed how such charges would impact the dispatch of an efficient CCGT. We found that our hypothetical generator would run about 5% more hours in a scenario without the current energy based charges, compared to the status quo. Furthermore, in 93% of the hours when the dispatch decisions of the hypothetical CCGT plant were affected, prices between Belgium and the Netherlands were equal. Thus any inefficiencies due to distorted dispatch could easily spill over into the regional market.

This is another illustration of how the application of generation tariffs (G-charges or tariffs related to recovery of system/ancillary services) could potentially impact on generators operational decisions. We expand on this case study in Annex E.

[41] https://www.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf

5.2.4. Discussion of current evidence base and indicators

Determining whether a welfare loss occurs due to the operational effect associated with generation tariffs requires an evaluation of the status quo, as well as alternative scenarios with harmonised transmission tariffs, against a counterfactual that represents the most efficient market outcome from the perspective of operational efficiency.[42]

This is necessary to ensure that if any tariff harmonisation were recommended, it would lead to a greater operational efficiency than the current status quo.

As discussed in Annex C (literature review), locational marginal pricing (LMP) is theoretically the most efficient form of electricity pricing. It ensures operational efficiency, because LMPs fully internalize physical constraints, as well as any costs associated with transmission congestion and losses. LMPs are calculated separately for each generator, and, if calculated correctly, they always equal the generators' marginal cost at its desirable level of output. Thus, LMPs efficiently signal whether a generator should be dispatched.

In contrast, the status quo pricing regime, implemented in Europe under the ETM, is a form of uniform pricing within bidding zones, whereas internal transmission constraints, and any costs associated with internal transmission congestion and losses, are not fully reflected in market prices. While each electricity generator receives the same (uniform) market price, their locational marginal costs are not identical.

For some generators, the uniform price may exceed what their respective (hypothetical) LMP would be, and thus those generators would have an incentive to generate more than what would be socially optimal. Similarly, generators that face a uniform price lower than their hypothetical LMP, would have an incentive to under-generate. Thus, uniform prices may not efficiently signal to generators whether they should dispatch, and if so, how much they should generate. Thus the current system of uniform, non-locational pricing within bidding zones may by itself be less efficient than the most efficient pricing benchmark.[43]

Introducing a system of generation tariffs that reflect the locational marginal costs associated with transmission congestion and losses into a system of uniform pricing may improve market efficiency by approximating some of the locational signals that are not present in the uniform price. On the other hand, locational generation tariffs implemented in one European bidding zone, but not in another neighbouring bidding zone, may distort cross-border trade, as discussed above. Thus, there are inherent trade-offs between the available options.

We also note two factors that may weaken the operational effect discussed above. First, small changes in generator costs due to the generation tariff may not change the merit order, especially for inframarginal generators (this point is discussed as part of both the 4M (see

[42] However, a cost-benefit assessment of potential harmonisation should be conducted against the status quo, not hypothetical counterfactual.

[43] We note here that in the absence of internal transmission congestion, uniform pricing and LMPs would result in an identical set of prices, except for the effect of transmission losses.

Annex D) and Central West Europe (see Annex E) market coupling regional case studies developed). Second, for welfare (deadweight) loss to occur, market demand has to be elastic; however demand for electricity tends to be inelastic, especially in the near term. Thus, generation tariffs may have a greater distributional impact in terms of *equity* (wealth transfer from consumers to generators) than efficiency (deadweight loss).

The problem is further complicated by the distortionary impact of other measures currently in place, such as renewable support and capacity remuneration mechanisms. Renewable policies ensure subsidies and priority dispatch for renewable generators; thus these policies clearly distort the dispatch merit order. Capacity remuneration mechanisms tend to be implemented on a national basis, and they are currently not harmonised across MS.

Generators that receive capacity payments are able to offer their energy production at a lower price both in their own market and neighbouring bidding zones, while generators receiving no capacity payments will have to rely fully on the energy market for their revenues, and therefore would not be able to lower their energy market offer prices. Thus, capacity payments implemented in one bidding zone, but not in a neighbouring one, may potentially distort dispatch decisions.[44] Since the differences in capacity payments and renewable subsidies tends to be higher than differences in generation tariffs[45], it is likely that these distortions are more significant than any distortions that would be caused by the lack of transmission tariff harmonisation.

5.3. Conclusions

In conclusion, there is certainly the *potential* for the current absence of harmonisation to impact negatively on the efficiency of the European electricity market, by distorting the *investment* and *operational* decisions of market participants, in particular electricity generators.

However, it is unclear that in practice *investment* decisions today will be fundamentally altered, except perhaps marginal investment projects, by a lack of harmonised tariff structures in Europe. Consequently, it is highly uncertain that there have been, or currently could be, investment inefficiencies that can be *specifically* attributable to the current lack of transmission tariff structure *harmonisation* in Europe.

Similarly the lack of operational inefficiencies that may be caused by an absence of harmonisation are also uncertain, and depend critically on market conditions (e.g. merit order of supplies in each country) under which cross-border competition takes place.

[44] Again, distortions would arise if the capacity payments were not reflective of the costs and value of reliability provided by generators.

[45] As highlighted above, Regulation (EC) 838/2010 limits the maximum allowed range of annual average transmission charges for generators at €2.50/MWh in Ireland, Great Britain and Northern Ireland, with lower caps applicable in other MS.

To the extent there is a problem, or risk of a problem, from the lack of tariff harmonisation in Europe today, we believe it is a more an issue of a lack of consistency in the principles which individual countries apply to their tariff structures (see discussion in Section 4).

Although there are a set of common regulatory objectives for transmission tariffs in Europe today, we do not observe any consistency or agreement across European countries on the necessary principles or factors for an "optimal" tariff structure. In most European countries, current tariff structures, given the design of their energy markets, generally do not fully align with what economic principles would suggest is likely to be an "optimal" (i.e. efficient) tariff structure, although some countries are further along than others.

A lack of efficient, i.e. *cost reflective*, tariffs means that in many circumstances, it is unlikely all users of the European transmission system pay for and, therefore, internalise, the costs their decisions impose on the electricity system. As the European electricity market becomes increasingly integrated, this becomes a problem, and importantly a *European* rather than subsidiary problem, as the costs generated by market participants decisions in one country may increasingly impose costs on market participants in other countries.

The challenge is that an "optimal" tariff structure will be dependent on the harmonisation of other elements of wholesale electricity market design in Europe. The "optimal" tariff structure may also differ by country and/or regions within the European electricity market and the state of development of the IEM. The need for:

- locational signals in transmission tariffs, for example, may be mitigated where deep connection charges are applied as a policy;
- tariffs based on forward looking (marginal) costs may be less important in some regions or countries, if there is limited flexibility for market participants to respond to the incentives; and
- harmonised tariff structures in general, are dependent on other conditions and harmonisation of other policy factors that influence investment and operational decisions (see discussion above).

Agreement on the necessary principles for an "optimal" transmission tariff structure thus requires a longer-term regulatory response to facilitate *overall* harmonisation to develop and integrated and efficient European electricity market. This is particularly the case with respect to regulatory principle of whether locational signals should be a necessary component of an "optimal" transmission tariff structure in Europe.

As discussed within our literature review (see Annex C), the current zonal rather than nodal energy market design envisaged under the ETM already provides locational signals to network users of the relative value of power *between* the individual bidding zones. The configuration of the bidding zones should reveal congestion costs in IEM, however the model does not provide further locational signals *within* the bidding zones.

Transmission tariffs are *potentially* one way of supplementing the current zonal market design to ensure overall objectives are met.

As discussed above, in some European countries, additional locational signals are already provided, either over the operational timescale – Sweden and Norway apply a locational losses tariff – or the investment timescale – GB and Sweden through the application of a locational capacity tariff. In the absence of a full LMP system (as detailed in Annex C, there may be reasons why this model may not be preferred in Europe), there is at least a case for European countries considering the need for some additional locational element to transmission tariffs to reflect short-term locational operational costs (e.g. losses) and/or location-driven investment needs. However, these other locational signalling mechanisms must be considered in conjunction with other parts of the policy framework, in particular, the connection charging regime and choices on energy market design.

The transmission/energy market design must be coherent to ensure proactive balancing of options and that overall objectives are met. Conceptually this means that the design of transmission tariff systems in Europe, should, going forward, be considered in the context of the objectives for an integrated energy market in Europe.

6. POLICY OPTIONS

A central objective of this study was to identify and develop proportionate policy options to address any actual or expected problems or failures with the current transmission electricity tariff structures across Europe, and to assess the associated impacts of these options.

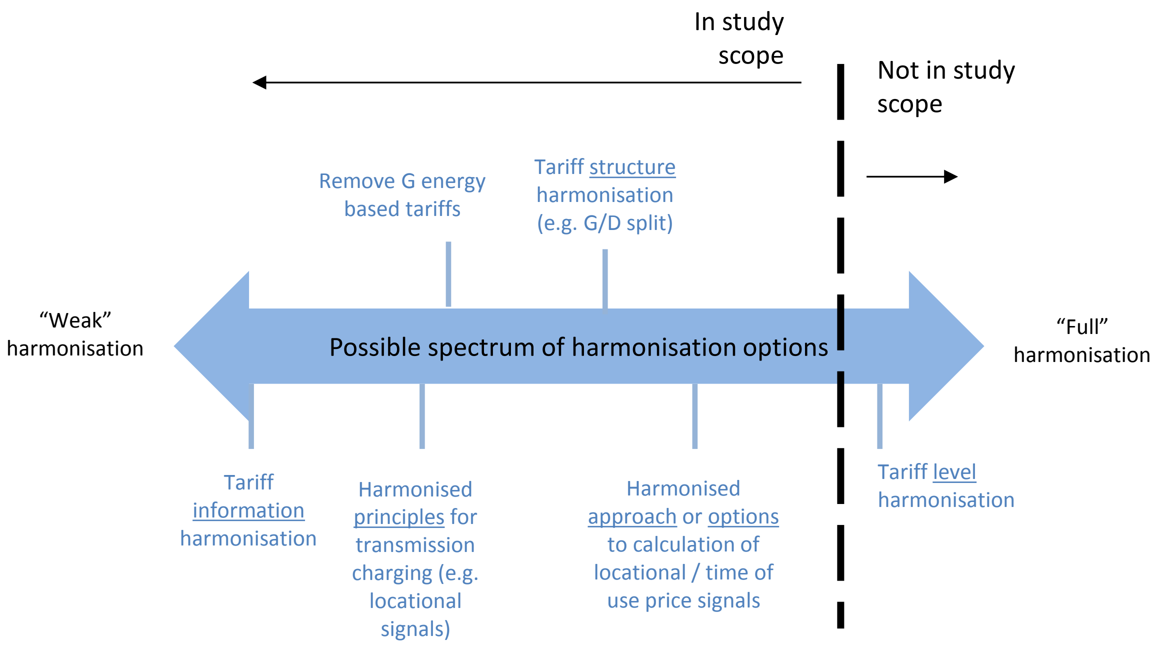
We have not found current evidence of welfare losses directly attributable to a lack of *harmonised* transmission tariffs. This is most likely due to the fact that the negative trends and distortions that can currently be observed are driven by a multitude of factors, not just transmission tariffs. Nevertheless, we believe that significant concerns have been raised with respect to the current arrangements that warrants some policy response.

Throughout this study, we considered a broad spectrum of policy options ranging from:

- harmonisation of the *incidence* of cost allocation (e.g., establishing a harmonised G:L split);
- harmonisation of specific tariff *components* (e.g., removal or capping of the G-charge component of a tariff structure);
- harmonisation of the *principles* applied to transmission tariffs in Member States (e.g., including a locational transmission loss component in the transmission tariff); and
- limited harmonisation, focusing primarily on transparency, including perhaps harmonised informational tools for transmission tariff publication.

The full spectrum of these options is illustrated in Figure 6.1 below. The figure also includes a "full" harmonisation option that would involve harmonising both transmission tariff *levels* and tariff *structures*. Although we considered this option to be outside the scope of our study, our findings confirm that harmonising tariff levels cannot possibly be cost reflective, and thus would be inefficient. Given the market participants' significant concerns with the status quo arrangements, we believe that there is scope for more harmonisation than that entailed in "weak" harmonisation, depicted at the opposite extreme of the spectrum. Although we will not discuss this in further detail, transparency is a key pre-condition of efficient markets, therefore measures contemplated under the "weak" harmonisation option, should be considered in conjunction with other options.

Figure 6.1: Spectrum of harmonisation options that could be considered



Source: CEPA

There are a number of practical options for further harmonisation of transmission tariff structures in Europe. We have grouped these options as potential short-term and longer-term regulatory responses to the issues and problems identified above.

6.1. Short-term regulatory response

In the short-term, options which have been proposed by some stakeholders are either the removal of G-charges in Europe, or alternatively, greater harmonisation of the proportion of costs which are recovered from generation and load (often referred to as the G:L split). These options are discussed further in the next two subsections.

Harmonising some components of tariff structures

Harmonising transmission tariff structures, including aspects such as the relative share of transmission costs allocated to generation versus load (i.e., G: L split), would be a relatively simple option that could also be easily monitored. The rationale for this option could be that if generators and large loads faced the same (relative) cost burden in every MS, then presumably a level playing field would be established for them within the larger IEM.

There are several problems with this approach. First, cross-border trade responds to differences in tariff levels, not tariff structures, and the harmonisation of the G:L split would not guarantee that tariff levels between MS would become similar, given that the TSOs' asset bases and costs vary. More importantly, there is no sound theoretical basis for choosing an "optimal" G:L split. Any G:L split would be arbitrary, and there is no reason to believe that harmonising tariff at any particular G:L split would be more cost reflective and efficient than the status quo.

Another option to harmonise tariff structures could involve harmonising whether tariffs should be levied as energy based or capacity based charges (or potentially lump sum). As discussed in Section 4.1.1, fixed costs should be recovered through fixed (i.e., capacity based or lump sum) charges. Therefore, the infrastructure component of the tariff should not be an energy based charge. On the other hand other variable costs, such as transmission losses or ancillary services, should be signalled to market participants through energy based charges, since the use of capacity based charges would lead to inefficient decisions.[46] Thus, unless the full set of harmonised tariff setting principles are applied in the transmission tariffs of each MS (e.g., what types of costs should be included in each tariff), any harmonisation based on limiting the use of energy based or capacity based charging would inevitably result in transmission tariffs that would not be fully cost reflective or efficient.

We have similar concerns with harmonisation options focused on other specific elements of transmission tariffs, such locational or time-of-use signals. Again, without establishing and implementing a clear set of principles to a harmonised transmission charging regime (as part of transmission/energy market design), it would be difficult, if not impossible, to establish cost reflective and EU-wide, locational or time-of-use transmission tariffs.

Harmonising G-charge levels

Harmonising G-charge levels by applying a cap on the maximum average G-charge an MS may levy, including a zero cap, is another possible option.

Although this option is to an extent already applied[47] and is favoured by some stakeholders, we do not believe that it sufficiently addresses the identified concerns. In particular, a mandated elimination of G-charges would likely result in significant inefficiencies in some countries, without any efficiency enhancements in cross-border trade. Our review has found that although G-charges currently in use may not be perfectly cost reflective, they often support valid policy objectives in a relatively efficient manner. For example, G-charges can convey locational signals to ensure more efficient generator siting, or they can signal other locational costs, such as transmission losses, in the generators’ dispatch decisions (the text box below reviews the GB experience with locational signals).

It is quite possible that if the locational tariff signals were dampened further or removed completely from the tariffs in some of these countries, market participants’ response to the tariff change would result in a less efficient outcome than the status quo in the long run. On the other hand, we have found cases, such as Belgium and Slovakia, where G-charges were introduced without a clear justification of a policy goal to be pursued, and they appear to be distortive. In these countries removing or changing how the G-charge is levied could improve

[46] This is consistent with ACER Opinion No. 09/2014 of 15 April 2014.

[47] The bands in Regulation (EU) No 838/2010 apply existing caps on average G-charge levels.

efficiency; however, this could be done at the national level, and it would not warrant an EU-wide harmonisation of tariffs.

<u>Text Box 6.1 – Experience with GB locational transmission charging</u>

Transmission Network Use of System (TNUoS) charges are applied in GB to recover the costs associated with the provision and maintenance of (potentially) shared electricity transmission infrastructure assets.[48] The TNUoS charging methodology provides for transmission access charges which vary by location, seeking to *reflect* the costs which users (generation and load) impose on the network.

There a number of components to the *current* tariff structure but one of the key components is the locational element. This is intended to cover "*all investments in "locational" assets such as lines and cables (historic or new) which provide grid access. To provide greater stability, and for administrative simplicity, tariffs are grouped into pre-determined geographic "zones" and a zonal average is calculated. In the case of generators, the locational element of transmission charges reflects the zonal average long-run forward-looking costs of connecting an incremental megawatt (MW) of generation at a given point on the transmission network. The same principles apply to demand customers.*"[49]

The locational element of the transmission network access charge does not recover the total amount of revenue allowed to GB electricity transmission companies (as it is based on long-run forward looking costs). As a consequence, once the locational tariff part of TNUoS charges is determined, a non-locational correction factor is applied to the tariffs to ensure the total allowed revenue is recovered from network users. This non-locational correction factor is applied so that a fixed proportion of allowed revenue is recovered in total from generators and a fixed proportion of revenue recovered from load users.

The merits of the GB TNUoS model have been debated extensively by the regulator and GB electricity market participants. Whilst the locational component does not perfectly reflect the costs different users impose on the network at specific locations (particularly as tariffs are then adjusted by the non-locational correction factor) there is at least some evidence that within the GB bidding zone, the locational signals provided are internalised by market participants in their decision making.

Some market participants for example, have stated that they took into account the locational element of both electricity and gas transmission charges when forming decisions on the siting of their gas fired power plants.[50] This is because under the GB scheme, the

[48] Ofgem (2010): 'Project Transmit: A Call for Evidence – Technical Annex

[49] Ibid. pg. 4

[50] For example, in its response to Ofgem's call for evidence for Project TransmiT – the review of TNUoS charges - Centrica noted that: "*The investment decision on Centrica‟s Langage CCGT Power plant just outside Plymouth was made after careful consideration of all the factors and the locational TNUoS and gas exit charges played a major role in this decision … Without this locational signal it is highly unlikely that Langage Power Station would have been built in its current location*".

locational element of the tariff structure provides an incentive for companies to site their plant in locations that may help ease pressure on the transmission system.

Source: CEPA

Assessment of short-term regulatory response

We believe that these options would need to be justified on the basis that they would address the *potential* investment and operational distortions of generation decisions, outlined above.

Given the uncertainty that the status quo arrangements in practice distort investment and operational decisions, i.e. there is a general lack of evidence that *differences* in tariff structures *between* European countries in practice lead to inefficient outcomes, we believe any benefits associated with such short-term harmonisation policies are highly uncertain.

Therefore, we do not believe that harmonisation on this basis would necessarily address a specific current problem, or set of problems, identified.

There are also a number of potential risks and unintended consequences of harmonisation based on the short-term policies outlined above:

- these options would result in incidence effects by changing the balance of cost allocation between load and generation in some countries (tightening caps on G-charges, for example, would likely increase consumer tariffs);
- they require reopening the existing regulatory frameworks and terms of access under which past investments were made in individual countries – in the short-term, this could undermine, rather than support, investor confidence; and
- as described above, the short-term policy options may undermine valid policy objectives that are being sought through the current design of the transmission tariff structure at a national level.

These issues may not necessarily be a reason for not pursuing further harmonisation, given that they are generally associated with any policy change option.

However, given that the *short-term* benefits of harmonisation are currently highly uncertain, they are particularly valid considerations, as they are likely to mean that the benefits of a short term regulatory response are unlikely to offset the significant negative impacts which may potentially affect *some* stakeholder groups from the changes. Thus, harmonisation imposed at a European level would not have a clear and objective rationale.

Given the extent of short-term issues identified, provided existing European regulations are enforced as intended, in particular ranges for G-charges as set out in Regulation (EU) No 838/2010, we believe that these existing policies should be sufficient to help prevent potential negative effects due an absence of harmonisation in the short-term. Although the existing bands for G-charges allow for variation between countries and, as a consequence, may currently act to prevent a fully level playing field for all market participants, these bands are also in some cases based on very valid national policy objectives.

6.2. Longer-term regulatory response

The longer-term case for harmonisation is more persuasive given the expected size of investment in the transmission system and generation fleet across Europe in coming years. Furthermore, pursuing a longer-term strategy would have no current harm, while it would facilitate future harmonisation.

The longer-term policy option involves establishing and implementing a harmonised set of *principles* for two key aspects of transmission charging having the overarching objective that markets deliver the established policy goals at the least cost, in mind:

- cost reflectivity; and
- cost recovery.

These two sets of principles could be developed and harmonised incrementally, thus minimising the distributionary and any inadvertent impacts. Work on these principles could start immediately, but developing a full set of harmonised principles would likely take some time, since it would require an agreement among all MS, and would also need more clarification and agreement on what the objectives set out in the Third Package really mean.

For both cost reflectivity and cost recovery, key aspects would need to be agreed upon and harmonised. In addition, there are some practical issues that are likely to make further harmonisation challenging and will require further consideration. For example:

- there are different voltage classifications that are currently applied across different European countries; and
- harmonisation could adversely affect the terms on which existing users gain access to the network.

We believe that via incremental harmonisation and through appropriate transitional arrangements, these issues are not insurmountable (see discussion below). However, they highlight the importance of approaching tariff harmonisation as a longer-term project, focused on the design of “optimal” tariff structure that supports longer rather than short-term objectives for the development of the IEM.

Harmonising cost reflectivity principles

In the case of cost reflectivity, the basis on which different types of cost are charged for, the circumstances under which forward looking (marginal) costs are applied in the tariff structure and the role of transmission tariffs in supporting wholesale market design (e.g. definition of bidding zones), are all the types of principles we would need to be addressed.

The following issues should be explored:

- **Clarifying the role of transmission charging within the overall European electricity market design and delivering European energy policy objectives in a lost-cost manner**—This would involve a review of a wide range of issues, not just whether transmission tariffs support or impede cross-border competition, but also, for example, whether explicit incentives should be incorporated into the tariffs to deliver the EU decarbonisation policy objectives at the least cost. This review would also consider whether transmission charging is the right tool to deliver those objectives, or perhaps other market instruments could more efficiently and feasibly convey the necessary signals to market participants.

  For example, as discussed in the previous section, transmission tariffs are one *potential* way of supplementing the ETM's zonal market design with further locational signals. Additional signals over the operational and/or investment timescale could *potentially* help promote more efficient use of the European transmission system by market participants. However, the objectives of providing these signals must be considered in a coherent way alongside: (1) zonal energy prices; and (2) the connection charging regimes. To ensure that overall objectives are met, harmonisation of transmission tariff structure must *first* address the question of the role transmission charging alongside other signalling devices.

  Our review of the current arrangements in Europe, and the findings from the literature review in Annex C, suggests there could be a gap in the existing arrangements. However, this requires a more fundamental review as part of the wider ETM development programme, particularly as objectives that might be address through harmonisation of transmission tariff structures, might be more efficiently and feasibly achieved through other means (e.g., market mechanisms).

- **Identify the types of costs to be included in transmission tariffs**—Once the role of transmission charging in Europe is firmly established, the cost categories to be included will need to be identified. This will naturally include infrastructure costs. Other costs should be included, only if it not feasible to signal them by other, potentially more efficient means.

  For example, costs associated with transmission congestion and transmission losses would ideally be signalled within the wholesale energy market, on a forward-looking basis, so that they are fully internalised by generators and loads, and appropriately reflected in their operational and investment decisions. Costs associated with system balancing would also ideally be signalled within the balancing market to those who contribute to the balancing need (i.e., electricity generators and loads that deviate from their schedules). It should be explored whether other charges, such as system services and regulatory charges should be included in transmission tariffs of generators, or only loads. System services are a form of insurance, which mostly generators supply. Since they are procured to ensure the reliable operation of the transmission system, which is primarily valued by loads, perhaps it should only be charged to load. Similarly, it should be examined whether any of the other regulatory charges should be levied on generators, or loads only, depending on what option yields the least-distortive outcome or which group benefits from the policy.

The key point is to ensure that transmission charging is viewed as a signalling rather than a cost-recovery mechanism, and that the same cost types are included in the harmonised tariff of each MS.

- **Harmonise charging principles to ensure cost-reflectivity**—Once the cost types are to be included in transmission tariffs are agreed upon, the right charging method needs to be established for each category.

  The guiding principle should be that transmission tariffs signal forward-looking costs, ideally on an ex ante basis. Cost reflectivity would require adherence to the efficient charging principles discussed in Section 4.1.1. Charging principles should be harmonised in all aspects. For example, if transmission tariffs are determined to be the most efficient tool to provide time-of-use or locational signals, then time-of-use or locational signals should be incorporated, using the same tariff setting methodology, into the tariff of each MS.

Harmonising cost recovery principles

We recognise that while cost reflective tariffs are efficient, they may not ensure full recovery of TSO costs. Partial cost recovery may occur, for example, if there are economies of scale, because efficient charges based on short-run marginal costs would fall short of average costs.

Therefore, it important to address the issue of cost recovery in a harmonised way, to ensure that cost recovery charges do not cause any distortions. The residual, unrecovered costs may not be attributed to the actions of particular market participants, therefore they may have to be recovered from all market participants.

Cost recovery charging should adhere to the following principles:

- **Recovery of residual costs should be collected in the least distortionary way**—Economic theory suggests that lump sum charges are the least distortionary. Other options including Ramsey pricing, capacity or demand-based charging.
- **Cost reflectivity of tariff components should not be sacrificed to ensure cost recovery**—If charges are truly-cost reflective, they accurately reflect the underlying costs in a given location, at a given time. These charges should not be scaled up or down to ensure cost recovery, because that would make them not cost reflective. Therefore, if some harmonised principles to cost reflectivity are already implemented, utmost care must be exercised to ensure that those tariffs are not distorted by any measures designed to ensure cost recovery.

Consider harmonisation of voltage level boundaries

Currently there is a great divergence in the delineation of Distribution System Operator (DSO) and TSO networks in terms of voltage levels, as shown in Figure 6.2 below. In the short-term, this is both a barrier:

- to harmonisation; and
- the expectation of achieving benefits from further harmonisation.

Therefore, the longer-term harmonisation option should also consider greater alignment of the definitions of transmission and distribution networks according to voltage levels in application of charging principles.

In principle, efficient transmission charging of generators at the TSO level should follow the same principles as charging at the DSO level. In practice, however DSO-level charges can vary from TSO-level charges.[51]

For example, in Slovakia 110 kV and lower voltage lines are considered to be part of the distribution system, and any generator connected at that level faces a higher G-charge than a comparable generator connected at the transmission level. However, not all generators connected to the distribution network are small distributed generation. Some are quite large and are active participants in the wholesale markets. The fact that they face higher G-charges than transmission-connected competitors can result in distortions both within the national market and in cross-border trade.

Furthermore, some generators were historically connected to the distribution network in proximity of loads in order to reduce transmission losses. Therefore, levying a higher G-charge on those generators is unlikely to be cost reflective.

[51] We note that the European Commission recently published a study on tariff design for distribution systems, which includes discussion of distribution tariff structures. The report is available here: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF

Table 6.2. Voltage levels operated by European DSOs[52]

Country/ Voltage level	LV	MV															HV												
		3kV	5kV	6kV	10kV	11kV	15kV	20kV	22kV	23kV	24kV	25kv	30kV	33kV	35kV	36kV	38kV	45kV	50kV	52kV	60kV	65kV	66kV	70kV	110kV	120kV	130kV	132kV	150kV
AT					✦			✦					✦												✦				
BE*				✦		✦	✦									✦								✦					
BG				✦	✦			✦							✦										✦				
CY						✦			✦																				
CZ		✦	✦	✦					✦						✦										✦				
DE					✦		✦	✦					✦												✦				
DK																					✦								
EE				✦	✦		✦	✦							✦														
ES						✦	✦	✦					✦					✦					✦		✦			✦	
FI								✦																	✦				
FR								✦																					
GR				✦			✦	✦	✦														✦						✦
HU					✦			✦							✦											✦			
IE					✦			✦									✦								✦				
IT**								✦																					✦
LT				✦	✦										✦														
LU			✦					✦														✦							
LV				✦	✦			✦																					
MT																													✦
NL***		✦		✦	✦			✦		✦		✦							✦				✦						
PL				✦			✦	✦					✦												✦				
PT				✦	✦		✦						✦								✦								
RO				✦				✦																	✦				
SE						✦					✦		✦											✦	✦		✦		
SI					✦			✦							✦										✦				
SK					✦				✦																✦				
UK						✦								✦														✦	
NO									✦																			✦	

✦ Voltage level used in a given country

Voltage levels according to European standardisation bodies CEN/CENELEC: LV (<1 kV), MV (1-36 kV), HV (>36 kV).
* Belgium: values according to federation legislation – regional legislation specifies that 30-70 kV lines are operated by the TSO.
** Italy: DSOs do not operate HV lines directly, but 132 and 150 kV substations including HV lines circuit breakers (on TSO request);
*** The Netherlands: Cross-border 150 kV lines owned by the DSOs are operated by the TSO.

Source: Eurelectric

Therefore, under the longer-term harmonisation option we would recommend to consider whether voltage level boundaries across Europe should be harmonised. We have not analysed whether such harmonisation would be warranted, nor what the appropriate boundary between transmission and distribution networks should be. Our proposal is to:

- **Explore whether harmonisation of voltage levels is necessary, and identify options to redefine and harmonise distribution network boundaries** — First, an assessment would need to be made on the number of generators active in wholesale markets that are connected at the distribution level in each country to determine whether harmonisation of voltage levels would be necessary. Next, common potential voltage boundaries should be explored such that all wholesale market participants would be part of the (redefined) transmission network, subject to technical feasibility.
- **Evaluate the cost reflectivity of each transmission charge at different voltage levels**—If different charges are applied at different levels, they should be justified on

[52] Source: p.15, http://www.eurelectric.org/media/113155/dso_report-web_final-2013-030-0764-01-e.pdf

the basis of cost reflectivity, according to established principles. Any such differences that are deemed not to be cost reflective should be eliminated.

Assessment of longer-term regulatory response

Unlike the short-term options, the proposed longer-term regulatory response would address the identified concerns with the current transmission charging arrangements in a systemic way. Establishing and implementing principles that ensure cost reflectivity, efficient cost recovery, and harmonised voltage levels for transmission and distribution network would not just facilitate future tariff harmonisation, but would also lead to more *efficient* electricity transmission charging across Europe.

This option has the great advantage that much of it could be implemented incrementally, in the course of several years, which would allow a prioritised approach to initially focus of the most important aspects. Work on establishing the relevant principles could start immediately, and gradual implementation would unlikely to cause any harm to the markets. Any distributionary or inadvertent negative impacts would be mitigated by the incremental implementation, and could be mitigated, if necessary. While such incremental implementation of this option is possible, full benefits would occur only after all aspects discussed above are harmonised. Therefore, a work plan should be developed, with clear milestones, to ensure that harmonised and efficient tariffs are in place before any potential future distortions due to the absence of harmonisation materialise.

Lastly, unlike the measures contemplated under the short-term regulatory response options, economic theory offers clear guidance to developing the principles considered as part of the longer-term regulatory response. Therefore, we believe that reaching a consensus on these principles should be feasible.

7. RECOMMENDATIONS

In conclusion, the benefits of a *short-term* regulatory response on harmonisation are in our view unlikely to outweigh potential costs.

The likely incidence effects which may be required to implement harmonisation, and the reopening of regulatory frameworks under which the existing terms of access to the network were made in individual European countries, is more likely to undermine short-term confidence in investment than address *potential* distortions. There is also already an ambitious programme of European market reforms underway, and it would make sense to deliver these reforms first, before seeking tariff harmonisation.

However, in the longer-term, there is certainly a stronger case for harmonisation, principally based on the need for greater consistency and application of “optimal” tariff structures that reflect the costs generated by market participants decisions.

We recommend, therefore, that ACER keep the issue of harmonisation under review and seek to develop a road-map for harmonisation. This should start with agreement on a harmonised set of principles for transmission tariffs, building on the existing objectives for tariffs introduced as part of the Third Package. Pursuing this option can do no harm and can facilitate development of a harmonised approach if needed.

ANNEX A EUROPEAN MARKET INTEGRATION

One of the key components of the ETM is the coupling of electricity interconnectors, whereby cross-border capacity (e.g. at the day ahead stage) is allocated implicitly within the market clearing algorithm, Euphemia.

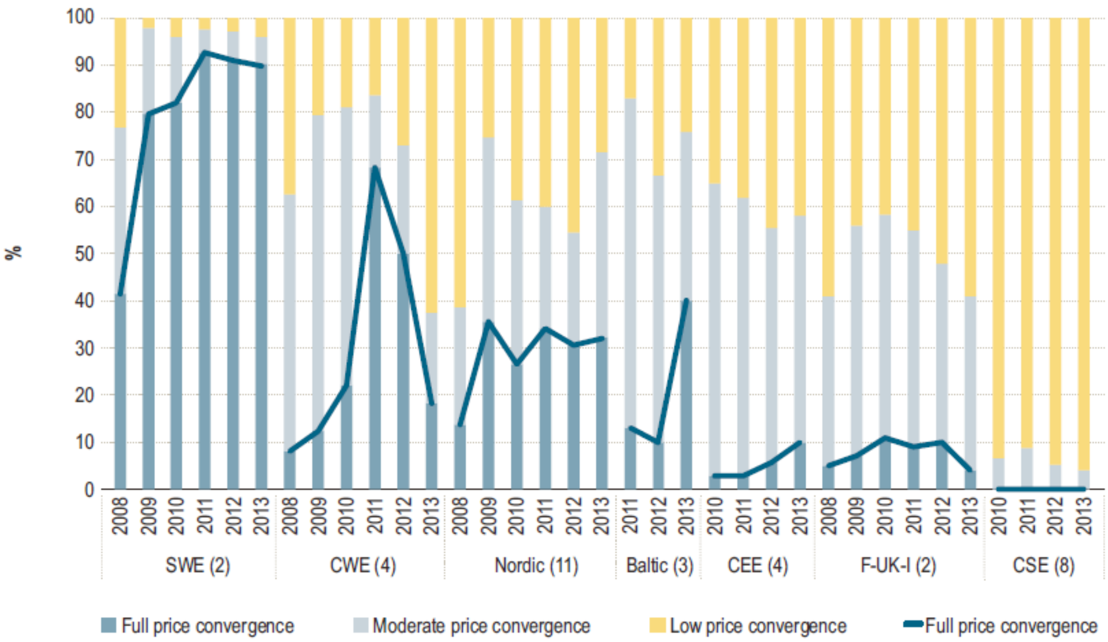
With regards to the day-ahead market, significant milestones have been reached on market price coupling:

- On 4 February 2014, the North-West European price-coupling implementation went live, while on 13 May 2014, the full price-coupling of the South-Western Europe (SWE) and North-Western Europe (NWE) day-ahead electricity markets was implemented.[53]
- On the 19 November 2014, the 4M market coupling project extended the day-ahead market coupling of the Czech Republic, Slovakia and Hungary to Romania, replacing the Trilateral Coupling that operated since 2012.

The convergence of wholesale electricity prices across Europe can be used as an indicator of market integration.

Figure A1 provides an overview of the development of hourly price convergence within EU regions over the last few years.

Figure A1 - Price convergence in Europe by region (ranked) – 2008 – 2013 (% of hours)



Source: ACER/CEER

Note – The numbers in brackets refers to the number of bidding zones per region included in the calculations

[53] Coupling of SWE and NWE day-ahead markets represent more than 75% of total European electricity demand, and as a result, electricity can now be traded from Portugal to Finland or from Germany to the UK.

ACER/CEER's 2014 monitoring report notes that: "*At wholesale level, while the electricity market integration progressed with observed improved use of cross-border capacity, this has not always resulted in an increased in price convergence, which actually decreased in the Central West Europe region during 2013*. *The rapid implementation of the Electricity Target Model (ETM) in all timeframes, the removal of barriers to the IEM*[54] *in Member States, further harmonisation of energy policies at Member State level, the integration of renewables in the market and the development of flexibility (including demand-side flexibility) are the main challenges ahead of us in the electricity sector*."[55]

Analysis by ACER shows that over the period 2008 to 2013 use of cross-border capacities has gradually increased, and "*overall, the efficient use of European electricity interconnections has increased from less than 60% in 2010 to 77% in 2013, following the implementation of market coupling at several borders between 2010 and 2013.*"

The above findings are relevant to this study as they show both an ambition and trend towards greater electricity market integration across Europe. As 2014 ACER/CEER monitoring report notes: "*Due to the implementation of market coupling on 25 out of 40 borders, the EU has made a significant efficiency gain (and hence improved social welfare) for the benefit of EU consumers*". One of the key benefits from market integration highlighted in the ACER/CEER's monitoring report is "*enhanced economic efficiency, allowing the lowest cost producer to serve demand in neighbouring areas*."

[54] Internal Electricity Market
[55] Ibid.

ANNEX B CURRENT TRANSMISSION TARIFF STRUCTURES IN EUROPE

This annex provides further details on the current transmission tariff structures that apply across European countries today.

Definitions

Our comparison of current tariff structures draws primarily from the ENTSO-E 2014 synthesis of transmission tariffs and monitoring reports of transmission tariffs performed by ACER.

This means that the definition of tariff which we use to produce this synthesis of the current arrangements includes tariffs for losses, ancillary services and other areas (e.g. reactive power) – sometimes referred to as system services tariffs - as well as tariffs used to recover infrastructure (capital and operational) costs of the transmission system – sometimes referred to as the transmission network use of system tariff (or grid access tariffs).

In the case of generation tariffs, the definition of a "G-charge" according to the Annex B of European Regulation (EU) No 838/2010 specifically excludes:

- charges for physical assets required for connection to the system or the upgrade of the connection (i.e. connection charges);
- charges paid by producers related to ancillary services; and
- specific system loss charges paid by producers.

The ENTSO-E synthesis includes all types of system and infrastructure cost related tariffs applied to generators. Therefore, our summary of the current arrangements also includes these generation tariffs, rather than focusing only on G-charges.

The analysis, therefore, refers to *all* tariffs that are charged by TSOs to grid users for utilisation of the transmission system.

Cost concepts

The cost concepts that are applied in the tariff structure differ across European countries. GB for example applies a concept of long run incremental cost in structuring the locational *relativities* of generation and load tariffs. A secondary adjustment mechanism is then used to scale and recover the total cost of the transmission system.

Norway has a 'point of connection' tariff system which means that users are charged nodally based upon the costs imposed by injections/withdrawals upon losses. Our understanding is that shared network costs are recovered by three different mechanisms:

- an energy based charge, based on the extent to which a party increases or reduces losses at a given node [56]; and

56

- a residual charge allowing recovery of remaining cost (this is a lump-sum charge calculated on the basis of long-term average energy production).[57]

This regime, therefore, accommodates the concept of short run marginal cost (SRMC) in the applied transmission tariff structure.

In contrast, most other European countries currently apply tariff structures that are based on average cost (e.g. Germany and Austria), with the objective of recovering the total costs the transmission system.

Capacity and energy based charges

As described in the main report, energy and capacity related component of TSOs current unit transmission tariffs can also differ significantly. This is illustrated in Figure B1 below which is derived from the unit tariff methodology which ENTSO-E apply in its tariff synthesis.

Figure B1 – Energy-related and capacity-related components of the unit transmission tariff

Source: CEPA analysis (based on ENTSO-E figures)

Important, the illustrated split of energy and capacity based charges, includes tariffs applied to recover *both* infrastructure and system related transmission costs.

Allocation of charges between generation and load (G:L split)

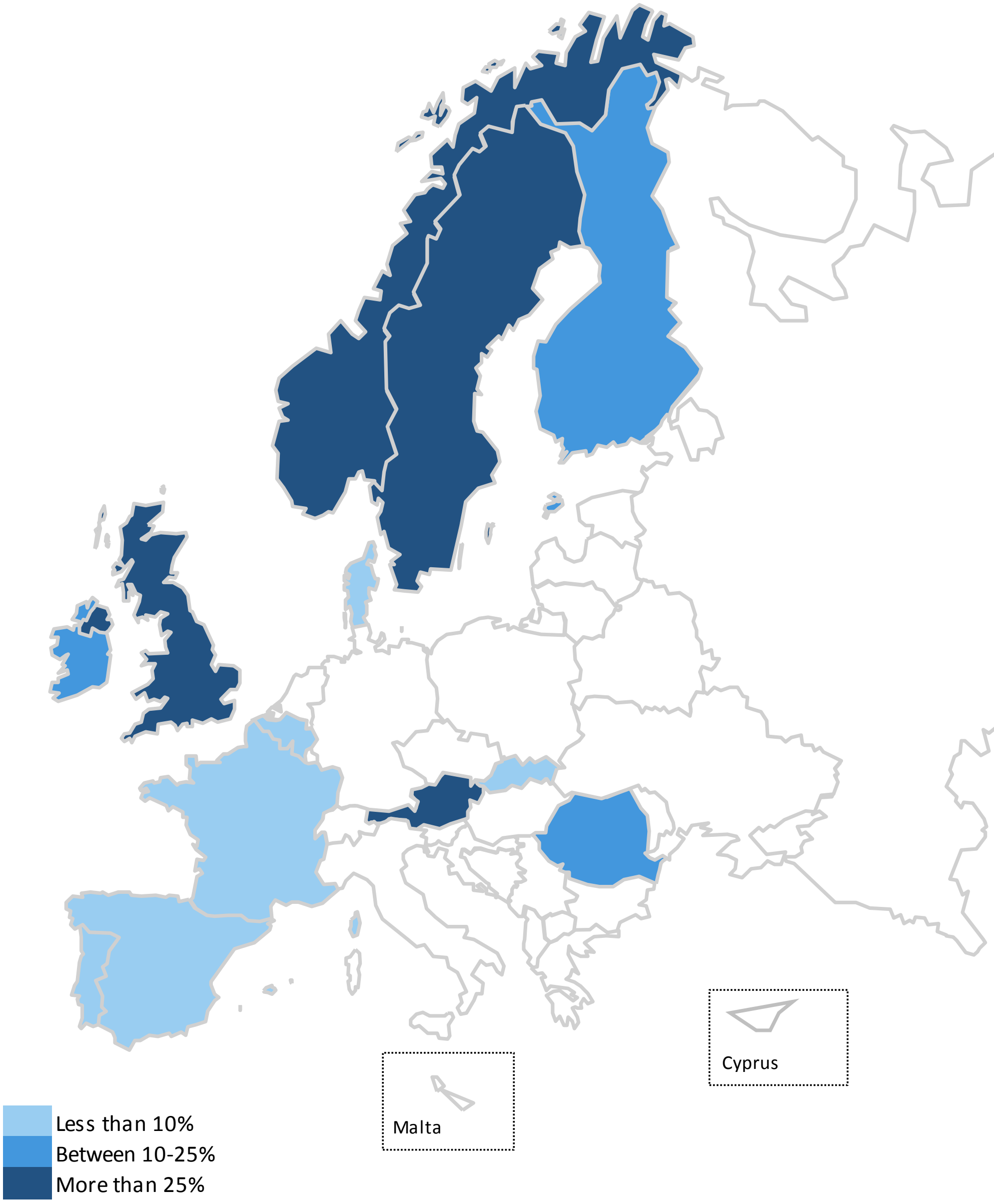
Figure B2 below illustrates the shares of transmission network tariffs between generation and load as reported by ENTSO-E in its 2014 tariff synthesis. These shares are calculated under

[57] Poyry (2010): 'Electricity transmission use of system charging: theory and international practice'

what ENTSO-E describe as a "base-case" characterised by (i) a pre-defined voltage level which generation and load are connected; (ii) a power demand; and (iii) a utilization time.

The unit transmission tariff and consequently the G:L split, is then calculated under the hypothesis that form the "base case" by adding the calculated charges applied to load (L) and generation (G) (in case G is charged), thus assuming that they produce and consume the energy they had in their programs. This may mean that in practice, the G:L split may differ from what the figures illustrated in Figure B2 below.

Figure B2 - Share of charges levied on generators as % of total network charges



Source: CEPA analysis (based on ENTSO-E figures)

Nordic countries tend to recover a relatively large share of costs (transmission system and infrastructure cost related) from generators, whereas countries particularly in the central and eastern parts of the continent, typically apply no charges to generation, or recover a low proportion of charges from generators.

According to the ENTSO-E tariff synthesis excluding countries where no transmission charges are levied on generators, the share of the network charges borne by generators ranges from 2% in France to 33% in Sweden and 38% in Norway[58] (2014 estimates).

Locational signals

Transmission tariffs structures in Europe currently include both:

- locational elements: GB, Ireland, Norway, etc.; and
- no locational elements: most EU countries.

Only five out of the twenty-nine countries considered (28 MS plus Norway) incorporate some form of locational signal into their transmission tariffs (see Figure B3).

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 an optimal generation area 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).

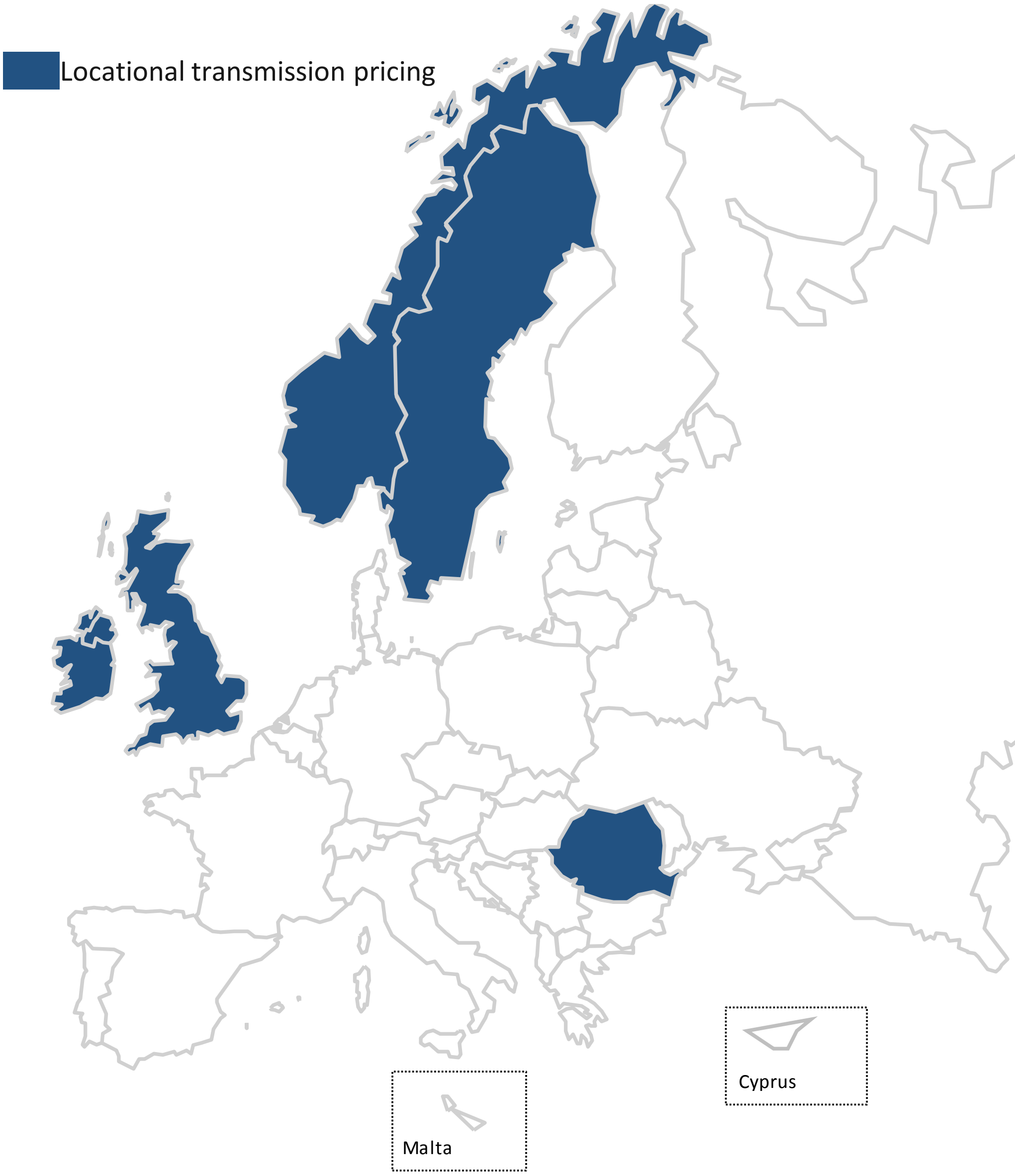
In Romania, the country is split into seven generation areas and eight load areas with charges reflecting surplus and deficit areas.[59] The locational element of transmission tariffs is given by the differences in the short term marginal costs at different nodes (zones) of the transmission system reflecting congestion and losses in the network. Revenue recovery is achieved by adding an average cost component to the calculated marginal costs. Generation surplus areas have the highest G-charge values while generation deficit areas have the lowest G-charge values. The same principle applies to load areas.

GB is considering changes to the incremental cost method it uses to set locational transmission tariffs for load and generation. Ofgem, after recently consulting on the methodology of setting transmission access tariffs, has recommended improvements in the methodology to take account of changing patterns of use of the network and changes in type of investment that could be required to evacuate power.

[58] Including revenue from transmission charges to the DSOs based on generation connected to the regional distribution networks.

[59] Generation and load areas do not match exactly.

Figure B3 - Countries applying locational transmission pricing in Europe



Source: CEPA analysis (based on ENTSO-E figures)

Time of use signals

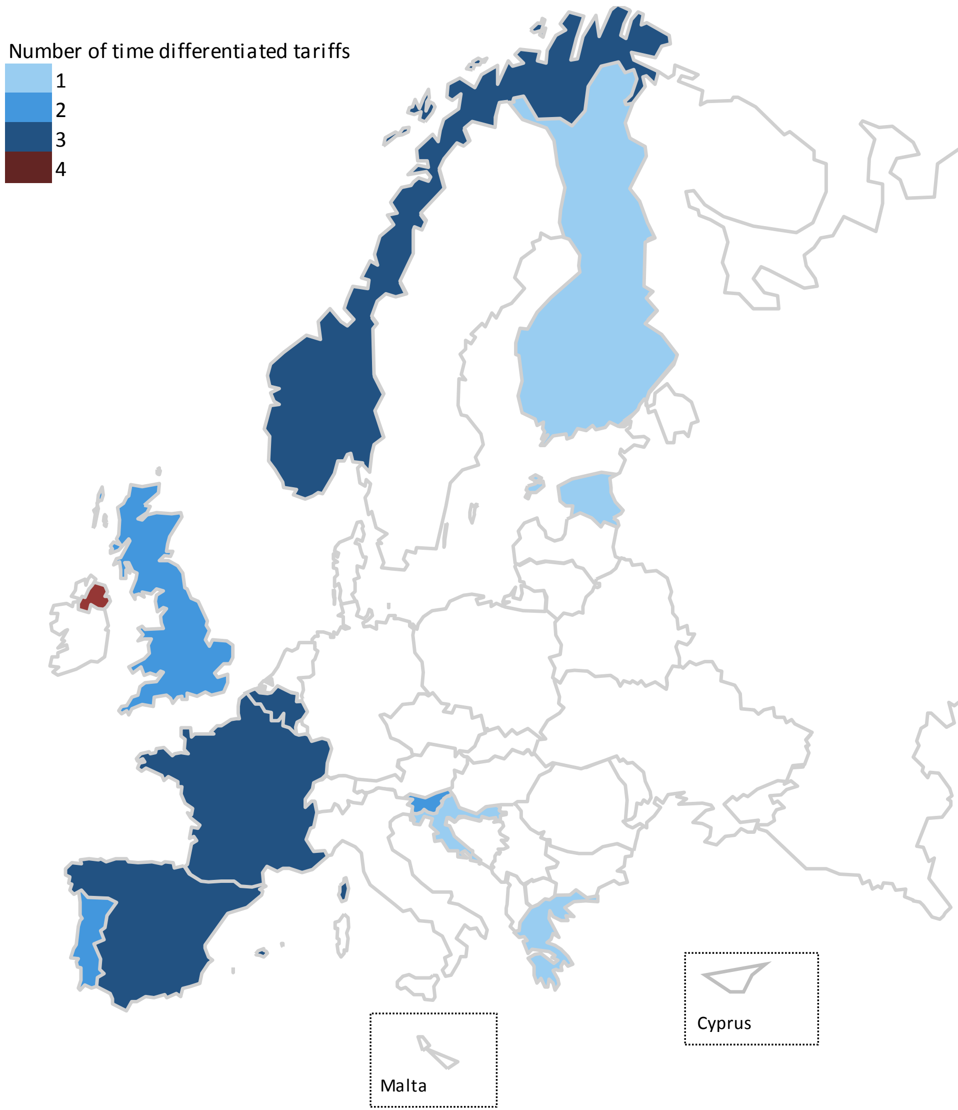
As transmission investment reflects the need to meet peak load demand, time-of-use signals can help to reduce the need for transmission investment in the long run by discouraging the use of the network grid at peak times. Compared to locational signals, time of use (ToU) signals are more widespread across Europe.

Tariff structures differ however depending on both:

- whether time of use signals are applied; and
- the number of time differentiated charges - day/night, seasonal, off-peak/mid-peak/ peak, etc.

Figure B4 below illustrates the number of countries applying ToU signals and the number of time differentiated tariffs applied.[60] Again, the reported number of time of use tariffs is based on what is reported in the ENTSO-E tariff synthesis.

Figure B4 - Countries applying ToU signals and number of time differentiated tariffs



Source: CEPA analysis (based on ENTSO-E figures)

Losses and ancillary services

The transport of electricity across transmission (and distribution) networks generates losses. Electricity losses can be defined as the difference between the amount of electricity entering the system and the outtake registered at exit points from the transmission system. The treatment of losses and the means through which the cost of losses is recovered differ amongst European countries.

[60] Each type of time differentiation (e.g., summer-winter, day-night, mid-peak/off-peak) is counted as one tariff. See ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2014.

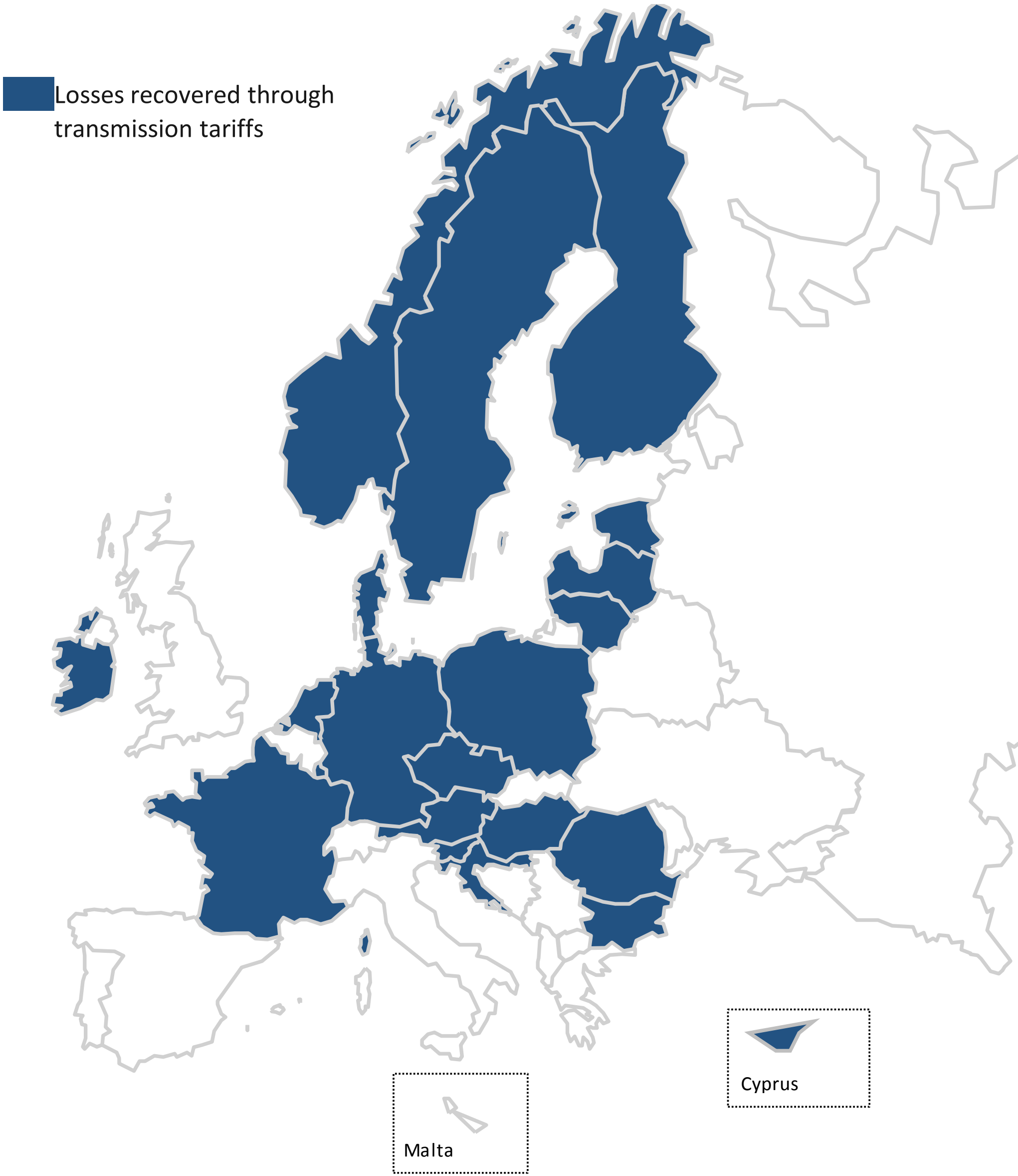
The cost of losses is generally either:

- included as part of transmission tariff structure (in some cases losses may be charged as part of a separate tariff); or
- Recovered in the energy market (for example, GB, Greece, Ireland, Northern Ireland, Portugal and Spain).

Figure B5 below illustrates the countries in Europe that recover losses through a transmission tariff (as defined in the introduction to this annex).

As discussed above, in some cases, for example Austria, losses may not be recovered with other network related costs through a single transmission use of system tariff, but instead may be recovered through a separate (e.g. system services) tariff.

Figure B5 - Losses recovered as part of transmission/system services based tariffs



Source: CEPA analysis (based on ENTSO-E figures)

Similarly the approach to recovering the cost associated with other ancillary services differs from country to country:

- in a number of other countries, ancillary costs are recovered through a separate tariff (e.g. Balancing Services Use of System (BSUoS) charges in GB); while
- in some countries, these costs are recovered in the energy market (for example, Spain and Portugal).

Summary

In the table below, we provide a summary of some of the key features of the tariff arrangements which apply across European countries today. This includes arrangements for both generation and load.

As described in the introduction to this annex, following the approach adopted in ENTSO-E's transmission tariff synthesis, we have reviewed *both* transmission network use of system tariff (or grid access tariffs) *and* system tariffs.

Therefore, when we describe losses and/or ancillary services charges as being part of the transmission tariff structure, it may be the case that these system services/costs are charged as part of a separate tariff to the transmission use of system tariff.

Table B1 – Summary of transmission tariff structure in Europe

Country	Is some form of generation transmission tariff levied on generation?	Locational signals	Connection charges*	Are losses and/or ancillary services part of the transmission tariff structure?**
Austria	Yes	No	Shallow	AS & losses
Belgium	Yes	No	Shallow	AS
Bulgaria	No	No	Shallow	AS & losses
Croatia	No	No	Deep	AS & losses
Cyprus	No	No	Shallow	AS & losses
Czech Republic	No	No	Shallow	AS & losses
Denmark	Yes	No	Shallow	AS & losses
Estonia	No	No	Deep	AS & losses
Finland	Yes	No	Shallow	AS & losses
France	Yes	No	Shallow	AS & losses
Germany	No	No	Shallow	AS & losses
Great Britain	Yes	Yes	Shallow	AS
Greece	No	No	Shallow	None
Hungary	No	No	Shallow	AS & losses

Country	Is some form of generation transmission tariff levied on generation?	Locational signals	Connection charges*	Are losses and/or ancillary services part of the transmission tariff structure?**
Ireland	Yes	Yes	Shallow/Deep	Both
Italy	No	No	Shallow	AS
Latvia	No	No	Deep	Both
Lithuania	No	No	Deep	Both
Luxembourg	No	No	Shallow	Both
Netherlands	No	No	Shallow	Both
Northern Ireland	Yes	Yes	Shallow	None
Norway	Yes	Yes	Shallow	Both
Poland	No	No	Shallow	Both
Portugal	Yes	No	Shallow	None
Romania	Yes	Yes	Shallow/Deep	Both
Slovakia	Yes	No	Deep	None
Slovenia	No	No	Shallow	Losses
Spain	Yes	No	Shallow	None
Sweden	Yes	Yes	Deep	Both

Source: CEPA analysis (based on ENTSO-E tariff synthesis)

**The exact definition of what constitutes shallow or deep connection charges may differ between countries. For a more detailed description of how connection charges are applied in different MSs, see ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2014.*

*** May be recovered either as part of a single transmission use of system tariff or as a separate system services or other charge.*

ANNEX C LITERATURE REVIEW

This annex reviews literature on the economic theory and practice of transmission pricing with a particular emphasis on what the literature says can be the economic effects of transmission tariff structures on market integration and cross-border competition.

We consider in turn, what the literature says on:

- optimal principles for electricity transmission pricing when considered from an economic efficiency perspective; and
- the potential effects of transmission tariff structures when considered from the perspective of cross-border electricity market functioning, integration, and competition.

In each case, we first summarise what the literature says about the issues, then as a second step, outline the implications for our study.

C.1. Optimal transmission pricing from an economic efficiency perspective

C.1.1. What does the literature say?

There is an extensive academic literature on electricity transmission charging arrangements which reviews both the theory of efficient pricing of electricity transmission services and the practical application of different systems internationally.

Brunekreeft et al. (2005)[61] for example surveys the key issues associated with electricity transmission and its associated charging / tariff structure arrangements. They note that in a liberalised power market and unbundled electricity industry in which generators and consumers react to market signals, the structure of transmission network charges will have a potentially significant impact on network use and its development.

For short-run optimal use of the network, Brunekreeft et al. state that the benchmark is locational marginal *energy* pricing (LMP), also known as nodal spot pricing or a fully coordinated implicit auction: "*For short-run congestion management there is agreement that a system relying on LMPs works and is efficient (provided that bids are competitive). The more challenging question concerns the long-run effects of nodal pricing.*"

Newbery (2011)[62] also concludes that: "*Nodal pricing* [LMP of *energy]* *is the natural counterpart in a meshed transmission network to competitive pricing in a market, where if each agent offers goods at marginal cost, the result will be the efficient market equilibrium. Just as these competitive prices can be found as the set of shadow prices associated with maximising some weighted sum of individual utilities, so the shadow prices computed from*

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[61] Brunekreeft, Neuhoff and Newbery (2005): 'Electricity Transmission – an overview of the current debate'

[62] Newbery (2011): 'High level principles for guiding GB transmission charging and some of the practical problems of transition to an enduring regime'

the dispatch algorithm gives a set of nodal prices that will lead to an efficient dispatch, provided they are based on the correct generator costs."

The academic literature notes that nodal (energy) pricing systems can also be used as a guide to long run use and investment decisions in the transmission system.

However, this requires a number of stricter conditions to hold, and in practice, complications such as lumpiness[63], uncertainty[64] and scale economies in transmission network delivery, can mean that short-run LMP systems are an imperfect guide to long-run investment decisions. The cost characteristics of electricity transmission networks also mean that a wedge will exist between TSO revenues that can be recovered from an LMP system and total transmission network cost, which means that short-run LMP may need to be supplemented by other cost recovery measures.[65]

Brunekreeft et al. (2005) therefore conclude that signalling the efficient location of generation investment (and other price responsive users of the network) will tend to require a competitive LMP system to be complemented with deep connection charges and charges to address the short-fall in transmission revenue recovery. Residual adjustments applied to system users to recover the revenue shortfall, they argue, should set to be: "*minimally distorting, and independent of any actions that those connected might take*"). This follows a principle of Ramsey pricing, an issue we return to below.

Econ Poyry (2008)[66] also find that the main criterion for economic efficiency is that transmission tariffs for use of the network should ensure that the existing grid is utilised to the maximum, subject to demand and the SRMC of transmission, with SRMC consisting of marginal losses at each point on the network, as well as capacity constraints and congestion.

They note that: "*If capacity is constrained, a congestion fee should be used to ration the available capacity (peak load pricing). Tariffs based on short-term marginal costs also give long-run investment signals. I.e., high congestion fees and marginal losses in a given point in the grid indicate the value of new network capacity – or local generation. Additional long-run price signals can be given through connection charges or project-specific investment contributions from the network customers (both positive and negative) that reflect the impact on system costs from a new connection at a given point in the grid.*"[67]

[63] Generation and transmission capacity is not added incrementally; thus it may be "overbuilt" dampening price differences between nodes.
[64] The transmission system is likely to be oversized because TSOs want to ensure reliability and as a consequence oversize the network than what may technically be required.
[65] In practice, congestion rents based on LMPs are not used to fund the fixed costs of the transmission network. Proceeds from the sale of FTRs in auctions are allocated to load, and FTR holders keep (or pay for) realized congestion rents. Separate transmission charges are, therefore, required to ensure full (fixed) cost recovery of the transmission network under an LMP system, as detailed below.
[66] Econ Poyry (2008): 'Optimal network tariffs and allocation of costs'
[67] Ibid.

They reference the example of Nordpool as an application of these economic principles, where congestion between the Nordic countries and between Norwegian regions is managed through a system of area prices (zonal pricing), using price differentials to reduce flows across congested links to the maximum available capacity.

However, there may be reasons why fully locational (LMP based) energy pricing is not considered appropriate. Significant benefits from implementing it would occur only if there is significant congestion within and between bidding zones, which may currently not be the case in many places. Furthermore, they are complex charging systems to implement[68] and may not be easy to understand for many market participants. Therefore, transmission use of system tariffs can be used as a substitute to the (theoretically) first best solution.[69]

Brunekreeft et al. (2005) for example suggest that the structure of transmission charges (if these objectives are not addressed through the system of energy pricing) should encourage:

- the efficient short-run use of the network (dispatch order and congestion management);
- efficient investment in expanding the network;
- efficient signals to guide investment decisions by generation and load (where and at what scale to locate and with what choice of technology – base-load, peaking, etc.);
- fairness and political feasibility; and
- cost recovery.

C.1.2. Could nodal pricing be an option for Europe?

While nodal pricing is theoretically the best option to incentivise efficient short-run operation of the system and to provide locational signals for investment, implementing it would be a major departure from the Electricity Target Model, and it would make sense to implement it only if the expected benefits outweigh the costs.

One of the most important benefits of nodal pricing is that it internalises many of the costs imposed on the system by each market participants into a set of market prices. These prices conform to the cost reflectivity principles discussed in Section 4. Specifically, nodal prices are the most efficient way to signal the locational and time-variant costs associated with transmission losses and transmission congestion. The alternative of signalling these costs via transmission charges would likely lead to some departure from the cost reflectivity principles. On the other hand, nodal pricing would not be sufficient to recover some costs, such as the costs associated with transmission infrastructure, and thus transmission pricing would still play a role, albeit with a smaller scope. Overall, the efficient price signals conveyed by a nodal

[68] Ideally, an LMP market would be implemented on an EU-wide basis using a single nodal model. This would require a cooperation between all TSOs and NRAs, which by itself could be challenging.

[69] Although LMPs are the most theoretically efficient form of pricing, they may not be necessary if there is no congestion or there are concerns regarding market power and liquidity as described below.

pricing system could to lead to a lower-cost development of the European power system than the current arrangements.

Implementing nodal pricing would involve significant costs, including the development of market software and other systems, as well as related costs incurred by market participants. The experience of other markets (e.g., ERCOT, the Texas wholesale electricity market, which recently implemented nodal pricing), however, demonstrates that while these costs may be high, estimated benefits can outweigh the costs by an order of a magnitude. Furthermore, implementation costs could be minimised by drawing on lessons from other markets which have moved from a system of zonal pricing to nodal pricing.

Introducing nodal pricing would likely result in some distributional effects, since some market participants may face significantly lower/higher nodal prices than uniform prices they currently pay or receive. These issues are related to equity, not economic efficiency, and could be mitigated by providing market participants with sufficient hedging instruments, such as Financial Transmission Rights.

If nodal pricing were introduced across Europe, ideally it would be implemented on an EU-wide basis, or at least uniformly within each synchronous grid (e.g., Continental Europe Synchronous Area). This could be challenging since nodal pricing on this scale has not been implemented anywhere in the world. Nevertheless, fragmented implementation could result in some pricing inefficiencies between markets (although pricing within market would remain efficient), as it has been observed between some regional US markets.[70] In order to minimise such inefficiencies and potential distortions to cross-border trade, nodal pricing should be implemented using a single market and transmission system model. Managing this would require an EU-level entity, perhaps an independent system operator, as opposed to individual TSOs calculating their own set of nodal prices, as is the case currently in the US markets.

Determining potential benefits of implementing nodal pricing in Europe could be estimated using detailed market modelling. Benefits should be calculated with respect to the status quo; thus any model used for estimating the benefits should be calibrated to current market outcomes (prices). Such modelling should determine both (1) short-term benefits associated with (potentially) lower cost of meeting demand; and (2) long-term benefits associated with lower-cost development of the power system (e.g., lower cost for new transmission infrastructure due to better generation siting).

Whether nodal pricing would be the right option for Europe depends on the balance between expected costs and benefits. Most efficient implementation of nodal pricing would also require an agreement between European regulators and TSO, which could be challenging.

[70] For example, significant “seams” issues have occurred on the border between the PJM and MISO wholesale markets. Both system operators calculate a nodal price at the border point. Theoretically, those prices should be equal. However, because of differences in market models and transmission system representation, significant divergence has occurred.

C.1.3. What are the implications for this study?

The European ETM is not a full LMP system, as for example is adopted in all organised wholesale electricity markets in the US. The ETM is currently based on a bidding zone model, with the *intention* that European bidding zones be defined by congestion.[71] This provides the scope for both sub-national and super-national bidding zones across Europe.

There is often a clear (historical) rationale for why we observe the electricity bidding zone configurations adopted today across Europe (e.g. national boundaries). However, a number of EU countries also face increasing challenges in facilitating changing flow patterns on the transmission system, driven by changes in the location and type of generation (e.g. intermittent renewable energy generation) and changes in power demand. These changes are expected to create congestion, bottlenecks and the need for investment in transmission systems across European MS.[72]

While the current bidding zone configurations provide a form of locational signal to network users that reflect the relative value of power *between* the individual bidding zones, they do not provide locational signals *within* the bidding zones. Electricity generators compete to inject energy based on their willingness to supply energy at their location, defined by the bidding zone configurations in Europe. While the expected challenges created by congestion and bottlenecks across European transmission systems *could* be managed by market splitting (e.g., redefining into smaller) bidding zones within which no or only little congestion arises), TSOs can also adopt measures such as re-dispatching power stations or undertaking investment in the network to relieve congestion and the bottlenecks on the existing network. These measures, however, impose costs.

These issues have led ACER to conclude that the configuration of bidding zones across Europe must be carefully monitored.[73] But whilst in theory market splitting (reconfiguration of existing bidding zones) would be a market based solution to regions where there are considered to be problems, other considerations, such as market power and liquidity, mean that market splitting may not always be the optimal solution to identified problems.[74] As noted above, explicitly defining (or redefining) bidding zones to always reflect congestion may also not be possible, because congestion patterns keep changing.

Why is the above relevant for transmission tariffs?

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[71]In the zonal market model, bidding zones are defined ex ante, based on the observed congestion pattern, while in the nodal model, zones are established implicitly during price formation, as congestion may cause nodal prices to diverge. Thus, price or bidding zones are dynamic in the nodal model, while in the zonal model they are relatively static. Therefore, explicitly defining bidding zones in the zonal model that always accurately reflect congestion may be very difficult since the congestion pattern keeps changing more frequently than the definition of bidding zones can conceivably updated.

[72] See for example the ENTSO-E TYDS or Booz & Co (2013): 'Benefits of an integrated European Energy Market'

[73] See ACER (2014): 'Report on the influence of existing bidding zones on electricity markets'

[74] See for example Frontier Economics and Consentec (2011): 'Relevance of establishing national bidding areas for European power market integration – an approach to welfare oriented evaluation'

One way that the impacts of changing generation and load patterns on transmission network investment *could* be managed *within* a bidding zone, is by providing locational signals to generation and load through the *transmission* pricing regime. This may not be the (first best) theoretical ideal of LMPs discussed above, but locational signals could potentially be provided through the applied structure of transmission network tariffs, leaving the uniform energy price within the bidding zone unaffected.

As the previous section shows, a number of European countries, including GB and Sweden have adopted charging systems that are based on this model. GB has had in force for a number of years a structure of transmission charges that is based on locational incremental cost, with recent improvements to the methodology (developed as part of Project TransmiT[75]) looking to reflect different patterns of usage of the network and the associated impact on transmission build costs.

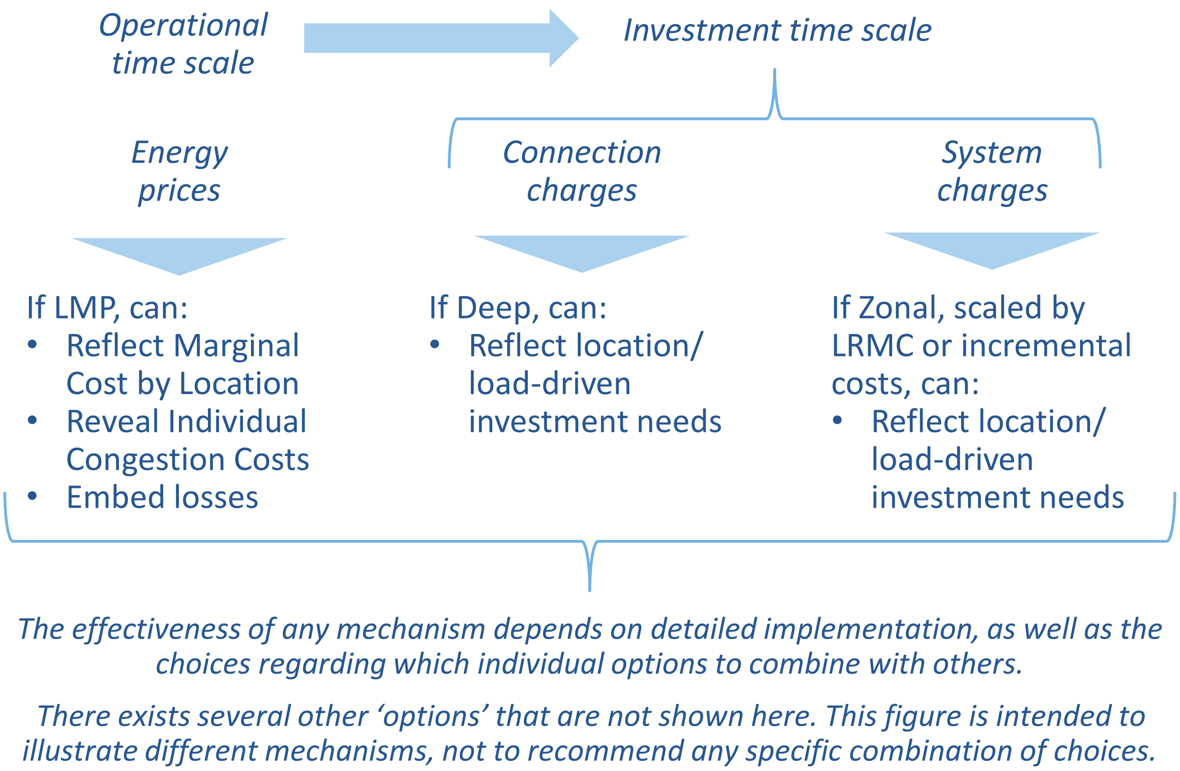
The point is that differentiation in energy versus transmission pricing (with the former, in a European market context, being defined by the configurations of bidding zones) are, to an extent, substitutable in respect of their role in sending investment signals to electricity market participants (both load and generation). CEPA (2011) notes that: "*although there are a variety of different "choices"* [for the different dimensions of electricity transmission charging]*, it is important to recognise that a coherent transmission/energy market design is achieved through proactive balancing of options to ensure that overall objectives are met. In doing this it is useful to recognise that at least potentially and conceptually, it is possible to approach a single design objective through different means*."[76]

The rationale for applying signalling mechanisms through transmission charges across both operational and investment timescales (see Figure C1) is therefore closely interlinked with the level of differentiation/signalling in energy prices and the extent to which different signalling mechanisms are truly substitutable. Whilst the academic literature is clear that an LMP system is the first best solution, Brunekreeft et al. (2005) note that: "*in the absence of LMP, there is a strong case for a locational element to grid charges, and these should be computed to guide location decisions to minimise the present discount cost of all G and T investments require to maintain reliability and security standards*."

[75] Project TransmiT is Ofgem's review of electricity transmission charging and associated connection arrangements in the GB market.

[76] CEPA (2011): 'Review of international models of transmission charging arrangements – a report for the Office of Gas and Electricity Markets'

Figure C1 - Illustrative summary of selected locational signalling mechanisms



Source: CEPA

Baldick et al. (2011)[77] raise a note of caution, however, stating that providing investment incentives for generation and load location using fixed transmission tariffs is "*laden with difficulties*" and they "*do not see an overwhelming efficiency argument for attempting to impose locational aspects to the TNUoS for anything but shallow connection charges as long as the transmission planning and investment process can be viewed as holistic*".[78]

The experience in GB is perhaps testament to this conclusion.

Project TransmiT was launched by Ofgem in [2010] and has only very recently reached its final conclusions (Ofgem's final decision is now being challenged in a Judicial Review (JR) process). The GB experience shows that designing, or indeed even updating, a locational, incremental cost based, transmission pricing structure, requires a range of dimensions to be considered and applied often in an imperfect way. Specific challenges within a national market also tend to have a major influence on what type of regime and associated charging principles are acceptable to market participants.

[77] Ross Baldick, James Bushnell, Benjamin F. Hobbs and Frank A. Wolak (2011): 'Optimal Charging Arrangement for Energy Transmission: Final Report'
[78] Ibid

C.2. Impacts of transmission tariffs on cross-border trade and investment

C.2.1. What does the literature say?

A limited number of studies and academic papers have considered the issue of electricity transmission pricing from the perspective of the IEM and how transmission tariffs, in particular, impact on the efficiency of investment and operational decisions in the IEM. The economic effects of transmission tariffs on cross-border trade is, however, increasingly perceived to be an issue and one that is referenced in academic literature.

The 2012 THINK report[79] for example focused specifically on the issues that may be associated with the heterogeneity in electricity transmission tariff structures across Europe. The report *stated* that the current heterogeneity probably hampered adequate investment in the transmission network and distorted competition, although the authors of the report did not provide supporting evidence to support this statement.

The authors suggest there are:

- strong arguments (see quotes below) in favour of introducing locational signals on an EU-wide basis in transmission tariffs; but
- that long term locational signals need to be efficient and accurate, implying that TSOs should implement a "sound" methodology respecting as far as possible the principle of cost causality (or 'beneficiary pays').

To avoid a distortion of competition in the internal electricity market, the authors suggest that some degree of harmonisation regarding the G-charge component of transmission tariffs should be adopted across European MS, noting that: "*If some countries apply a charge to their generators but others not, the former weaken the position of their utilities in the European electricity market. Differing principles of calculating the G-component will hamper competition, not the magnitude of a G-component itself. Current harmonization on EU-level regarding the G-component concerns only its average maximum level that countries can apply. We think that, in addition, the EU should also fix an average share of the G/L components, thus, introduce a minimum G-component, too.*"

The authors of the report conclude that there is a strong case for harmonisation of electricity transmission tariff structures arguing that this will:

- increase transparency, i.e. to clearly define which cost components transmission tariffs should contain;
- help to ensure that the behaviour of grid users in the competitive sector is not distorted due to tarification; and

[79] http://www.eui.eu/Projects/THINK/Documents/Thinktopic/ThinkTopic6.pdf

- help to ensure transmission tariffs should be allocated as far as possible based on the principle of cost causality.

They do not recommend:

"*a harmonization of the methodology applied to calculate locational signals. Instead, it is important that decentralized solutions applied consider the national system specificities and follow the above discussed principles (i.e. sound methodology based as far as possible on cost-causality, with ex-ante signals to especially new generators)*". Instead they suggested that the G-component should be harmonised and the "*EU should also fix an average share of the G/L components; thus, introduce a minimum G-component, too.*"

Brunekreeft et al. (2005) also highlight a similar concern regarding the applied G/L share in interconnected electricity systems:

"*Clearly, if two interconnected systems choose a different allocation* [of the G:L split] *there will be distortions. If, for example, one system places all the grid charges onto L and the other onto G, then the first system will have a comparative advantage selling to customers in the second, unless the interconnector levies a suitable charge. Harmonising the G:L balance therefore becomes important in interconnected systems* [as is increasingly the case in Europe]*, and there is some attraction in levying all the grid charges on consumers.* "[80]

Baldick et al. (2011) recommend that all costs of the *existing* transmission network should be allocated to load, stating that: "*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 of supply of wholesale energy*."

They argue that direct "*assignment of* [fixed network] *costs to load is unlikely to distort the behaviour of all but the largest electricity consumers. In contrast, direct assignment of these costs to generation unit owners can distort generation entry and operating decisions. For these reasons, we favour direct assignment of these costs to load … With load covering the cost of the transmission network, generators can focus their entry decisions on the most profitable location in terms of expected future energy prices, without having to worry about the risk of future changes in the TNUoS at that location relative to others. Therefore, this approach lowers the future price risk faced by potential new entrants relative to a scheme that also allows for spatial prices of the TNUoS.*"

Other academic papers, commenting both from a national and transnational perspective, also note that in recovering the historic/fixed costs of the transmission network, the economic literature suggests that Ramsey- Boiteux pricing principles should be applied in designing the tariff structure. Put simply, this means that tariffs applied to ensure full recovery of transmission network costs, should be structured in such a way as to limit any distortion to economic signals provided by marginal cost based tariffs, and, therefore, that the distribution of costs between different users of the transmission network should be differentiated by the

[80] Brunekreeft, Neuhoff and Newbery (2005): 'Electricity Transmission – an overview of the current debate'

price elasticity of demand of those different users or user groups. The text box below provides a more detailed description of the principles and application of Ramsey pricing in an electricity transmission context.

Text box C1 – Ramsey- Boiteux pricing in electricity transmission

As described by Newbery (2011)[81], applied to transmission tariffs, Ramsey-Boiteux pricing principles suggest that efficient prices (SRMC) be marked-up in a way that is inversely proportional to the demand elasticity – higher mark-ups where demand is less elastic, lower mark-ups when demand is more elastic.[82]

The idea is that the customers (resp. generators) with the least price-sensitive demand (resp. offer) should pay the largest relative mark-ups on the marginal short-term cost of transmission.

Econ Poyry (2008) notes that such *"a differentiation ensures that the grid company will cover its costs at the same time as the distortion in demand compared to the economically efficient solution (where all customers meet a price equal to marginal costs) is the smallest possible."* They also note that two-part tariffs can be designed according to Ramsey principles whereby *"grid customers pay a tariff per MWh consumed or injected, and a fixed part that can be designed in different ways. The criterion for the variable part is that it reflects short-term marginal costs (such as transmission losses and capacity restrictions). The fixed part should ideally fulfil the criteria of optimal utilisation of the grid and correct investments, that is, give as little as possible distortion on the decisions on the use and development of the grid."*

CESI (2003) note that a rational (economic) distribution of historic/fixed costs of transmission networks between generators and load should be proportional to *"the so-called "willingness to pay (WTP) of the agents. Ramsey pricing sees WTP as inversely proportional to the elasticity of act agent w.r.t the payment of higher transmission charge. As in a competitive environment generation shows typically a much greater elasticity to prices than loads, consumers should support a higher share of costs."*

However, while Ramsey pricing principles may be considered economically "efficient" and a tool to help minimise distortions to price signals, they may not be considered fair if certain customer groups are required to subsidise other customer groups.

Source: CEPA

[81] Newbery (2011): 'High level principles for guiding GB transmission charging and some of the practical problems of transition to an enduring regime'
[82] This is a simplification that holds if demands depend only on their own price and not on relative prices. The correct general rule is that mark-ups should be chosen to lead to an equi-proportional reduction in demands – hence lower mark-ups on elastic actions (Newbery (2011)).

Frontier Economics (2013)[83] in a report for Energy Norway focused specifically on estimating the *potential* economic impacts of an absence of harmonisation or changes to generator transmission charges between European countries.

They conjecture that there are three different types of impacts on economic welfare: a potential for distorted investment decisions in generating capacity ("investment effect"); a potential for higher financing costs due to increase investors' perceptions of increased regulatory risk due to a lack of harmonised transmission tariffs ("financing effect"); and a potential for distorted operation of generators ("operational effect").

They carried out high-level modelling of four EU countries (Germany, France, the Netherlands and Belgium) to empirically assess the potential scale of these effects and estimate that over the next ***two decades***. Based on the findings of the modelling in this region of Europe, they then scale up the findings from their quantitative analysis to give a broad indication of the potential scale of welfare losses from a lack of generator transmission tariff harmonisation across Europe. They find that:

- **the investment effect** could lead to a potential welfare loss of as much as €14bn;
- **the increase in the cost of financing** could increase the costs of generation by as much as €6bn; and
- **the operational effect** could lead to potential welfare losses of as much as €2bn.

The findings of this study were referenced by a number of stakeholders in response to our questionnaire (see Section 5).

C.2.2. What are the implications for this study?

The above referenced studies, and ACER's recent opinion on G-charges, demonstrate that the effects of transmission tariff structures are increasingly seen as an important issue for the European electricity market. There is a concern that with further European electricity market integration, transmission tariffs and tariff structures that are applied by MS *could* have a distortionary effect on the functioning of the electricity market.

We however, note the following.

Whether the economic effects that both the THINK report and Frontier Economics study identify from a lack of tariff harmonisation do or will occur in practice[84] and, importantly, whether the scale of the effects are *material*, is a more complicated question than how electricity markets are described in economic theory.

[83] Frontier Economics (2013): 'Transmission tariff harmonisation supports competition'

[84] The Frontier Economics (2013) study does not fully account for the context in which investment and operational decisions are made, and its main conclusions are largely driven by assumptions not facts. For further discussion, see Section 5.

As CESI (2003)[85] highlight, locational signals from transmission tariffs are not the only factors able to influence the siting of new generation and loads. Other elements such as factors related to:

- specific location (such as land, fuel transport costs, cooling water availability for thermal power plants or renewable resource availability); and
- legislation and regulation, can all make some locations more attractive than others for siting new generation or loads.

This is not to say we do not believe that locational signals provided by transmission tariffs are not important. Simply we consider that the materiality of distortions that may result from the current absence of harmonisation in tariff structures is a more complicated issue than the lessons that can be drawn from purely economic theory (see Section 5).

On the operational effects and distortions of transmission charges, when considered on a cross-border perspective, ACER (2014) highlights that *"Distortive effects imposed by G-charges to cross-border trade and investment signals will of course depend on the level of possible competition of power plants between the affected countries. Consequently, different levels of G-charges will be more distortive of cross-border trade and investment signals between countries which are well connected with high transmission capacities."*[86]

ACER's G-Charge opinion also notes that the impacts of differences in transmission tariffs on competition will be: "*affected by the **cost-relation of power plants**. If (in a certain period) the plants in one country show sufficiently lower production costs than in another country, the country with the lower production costs will export to the higher-cost country up to the maximum cross-border capacity. Different levels of G-charges would in this scenario have a low effect on competition. Hence the effects may also be **limited by heterogeneous power plant parks**.*"[87] CEPA emphasis added.

The implication is that modelling the operational and investment effects of transmission charges from a cross-border perspective under stylised assumptions, is not sufficient to conclude there are material investment and operational distortions from differences in transmission tariff structures in Europe. However, it does help demonstrate the potential *scale* of the impacts if there was greater evidence of the effects occurring in practice.

Whether the *conditions* that economic theory would indicate *could* lead to economic distortions, either apply currently or potentially in future, must be first investigated before any regulatory policy decisions are reached. This question is the focus of our analysis of current tariff arrangements in Section 5.

[85] CESI (2003): 'Implementation of short and long term locational signals in the internal electricity market'
[86] Opinion of ACER for the Cooperation of Energy Regulators No 09/2014 of 15 April 2014 on the appropriate range of transmission charges paid by electricity producers.
[87] Ibid.

The academic literature also highlights a key difference between heterogeneous, but cost reflective, transmission tariffs (e.g. that reflect incremental network costs) and tariffs that are instead set to recover historic cost (e.g. postage stamp pricing). Cost reflective, but heterogeneous transmission tariff structures, have a rationale from an economic efficiency perspective (the signalling effects discussed in the previous subsection). The literature clearly points to a principle of Ramsey- Boiteux pricing when considering the most economically efficient way to recover the fixed/sunk costs of the transmission network. Given the price responsiveness of generation to transmission tariffs, the literature emphasises that the burden of residual cost (i.e. total cost minus marginal cost) allocation between generation and load should perhaps be more weighted to load, subject to other objectives that may be sought from a transmission pricing regime.

Frontier Economics modelling suggests that of the three distortionary effects they identify from lack of transmission tariff harmonisation, the investment effect is by far the most material of the three. Whether the conditions for the investment effect hold in practice appears, therefore, to be critical to whether the benefits of progressive harmonisation in Europe are likely to outweigh potential costs and challenges linked to distributional effects. Again, we focus on this point in Section 5.

ANNEX D 4M MARKET COUPLING REGION

The 4M Market Coupling (4M MC) is an implicit, cross-border capacity allocation mechanism implemented in the day-ahead electricity markets of four countries in Central Europe: Czech Republic (CZ), Slovakia (SK), Hungary (HU) and Romania (RO). The current arrangements were preceded by a coupled Czech and Slovak day-ahead energy market, which Hungary joined in September 2012. Romania joined this trilateral market coupling in November 2014, establishing the current 4M MC arrangements.

Two 4M countries, Romania and Slovakia, currently apply a G-charge, while the Czech Republic and Hungary do not. Through this case study, we seek to explore evidence of distortions to cross-border trade between the 4M countries, due to the G-charge. Specifically, we focus on Slovakia where the G-charge was introduced recently (effective 1 January 2014), because it is much better integrated with its neighbours than Romania, and none of its neighbours (including countries outside 4M MC, e.g. Poland, Austria[88]) apply a similar G-charge.

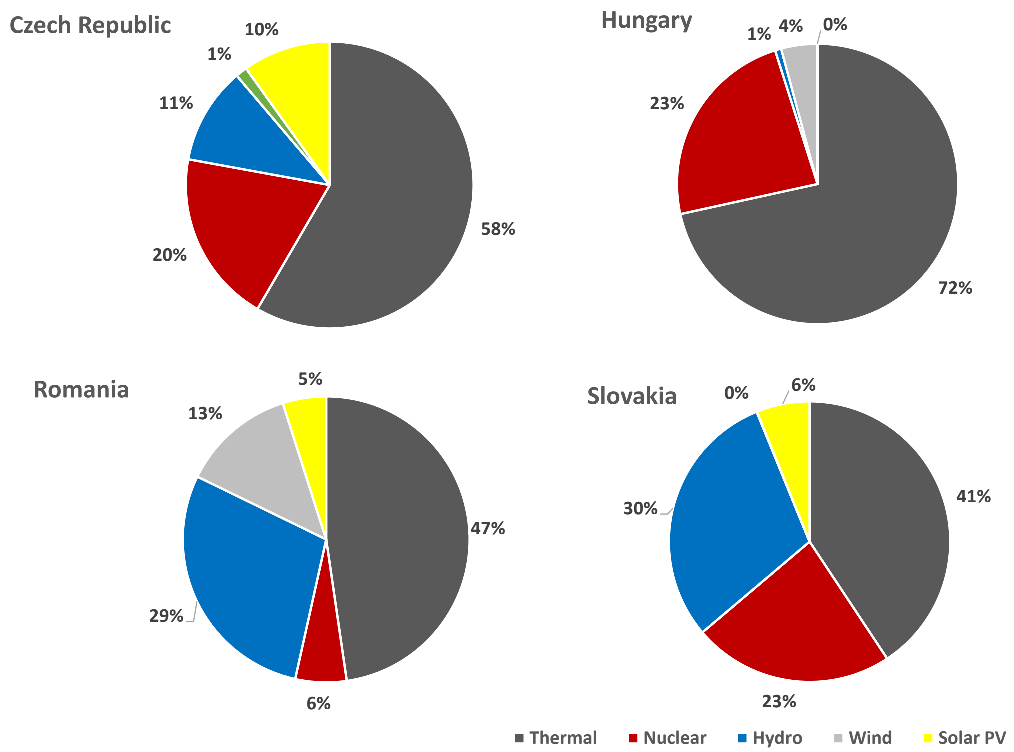
First, we explore differences in market fundamentals between the 4M countries, as well as the level or market integration and the main factors that may influence the magnitude of potential inefficiencies and distortions to cross-border trade.

Differences in market fundamentals

The 4M countries differ significantly in terms of the composition of their installed capacity, as illustrated in Figure D1. Thermal generation is the dominant type of generating capacity in all four countries, ranging from 41% in Slovakia to 72% in Hungary. Thermal generators in the CZ, SK and RO are primarily coal-fired; while in HU the majority of thermal generation is made up of gas-fired plants. RO and SK have the highest share of installed hydro capacity (30% in both countries), while hydro capacity's share is minimal (around 1%) in HU. Nuclear capacity has comparable shares (20-23%) in the CZ, HU and SK, while in RO its share is only 7%. Most of the renewable capacity in HU and RO consists of wind generators, while in the CZ and SK solar photovoltaics dominate.

[88] We understand that the G-charge currently levied in Austria applies to pump storage facilities only. Furthermore, Austria and Slovakia are not directly connected via transmission lines, therefore any impacts of differences in G-charges would be indirect.

Figure D1. Installed capacity by capacity type in 4M countries in 2015[89]



Source: ENTSO-E

Although current market conditions in the region are not favourable to investment in new generating capacity, significant changes are expected within the next decade, driven by the addition of new nuclear capacity. In SK, two nuclear units (Mochovce 3 & 4) with a combined capacity of 970 MW are currently under construction and are expected to become operational by 2018. HU plans to add two new units at its Paks nuclear power plant with a combined capacity of about 2,200 MW by the late 2020s.[90]

A key determinant of the degree of market integration between coupled electricity markets is the amount of transmission capacity that is available for cross-border trade between the coupled markets. Market coupling algorithms use Available Transfer Capacity (ATC) values, determined by the TSOs, as input in market clearing. ATCs represents the part of the Net Transfer Capacity (NTC) between markets that remains available for implicit allocation within the market coupling mechanisms. It is determined by subtracting from NTC[91] the transmission

[89] Total installed capacity in 4M MC countries: Czech Republic 20.8 GW, Hungary 8.2 GW, Romania 22.6 GW, and Slovakia 8.4 GW.

[90] Some of the new capacity additions will be offset by the closure of older units at the Paks plant in the early 2030s.

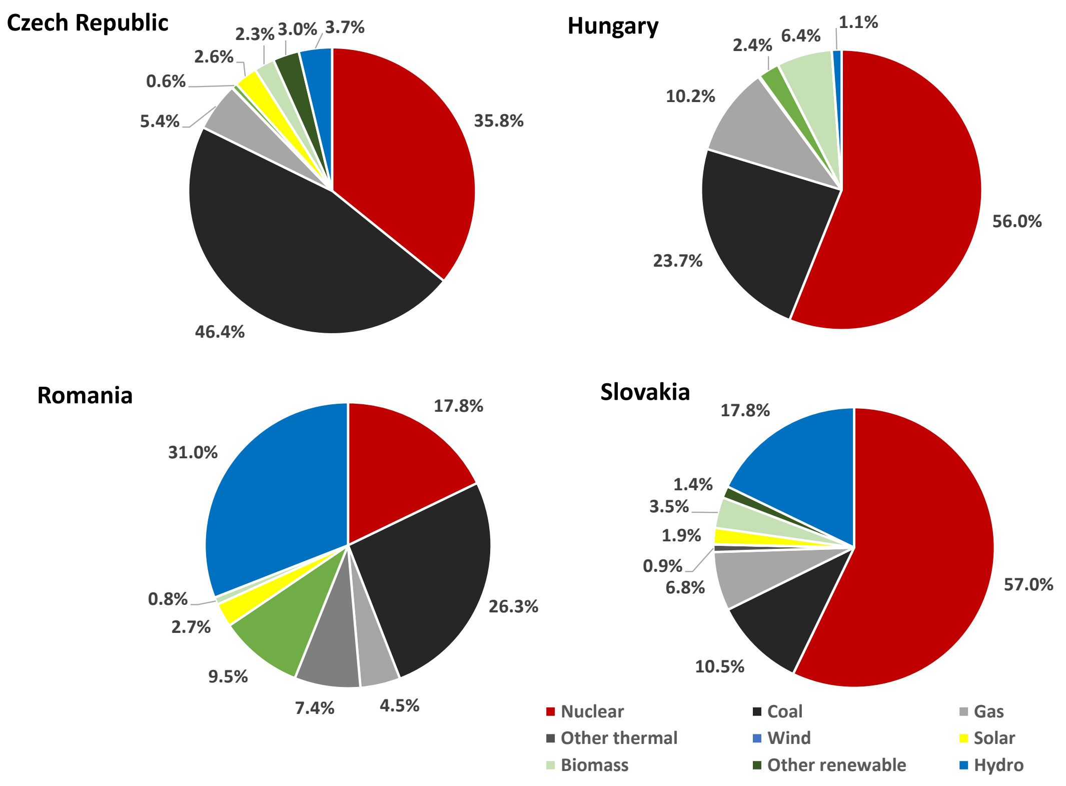
[91] NTC is the maximum total exchange program between two adjacent control areas that is compatible with security standards and applicable in all control areas of the synchronous area, whilst taking into account the technical uncertainties on future network conditions; https://www.entsoe.eu/publications/market-reports/Documents/entsoe_proceduresCapacityAssessments.pdf

capacity that has already been through other mechanisms. Since the start of the 4M MC mechanism, the following average hourly ATC values were in effect for the day-ahead market coupling:[92]

- From CZ to SK: 639 MW; from SK to CZ: 2,181 MW
- From SK to HU: 459 MW; from HU to SK: 1,327 MW
- From HU to RO: 1,184 MW; From RO to HU: 36 MW

In addition to available generation and transmission capacity, actual generation in each country, as well as cross-border flows between countries, are a function of the relative costs of each generator and the market demand in each country. These factors vary significantly among the 4M MC countries, as reflected in their supply-demand balances. In 2014, Hungary and Slovakia were net importers of electricity, with net interchange representing 30% and 4% of total consumption, respectively. The CZ and RO were net exporters, with net exports representing 27% and 13% of total domestic demand.[93]

Figure D2. Generation by capacity type in 2014



Source: ENTSO-E

[92] There are currently three Projects of Common Interest (PCI) underway (expected to be completed between 2018 and 2021) that will increase cross-border transmission capacity between Slovakia and Hungary.
[93] It should also be noted that the 4M countries engage in electricity interchange outside the 4M MC market. For example,

Other factors that may limit market integration in the 4M MC region include currency exchange risk and tax rates. Although electricity trading between the four countries is conducted in euros, it is the official currency only in SK, thus generators from the other three countries face some exchange rate risk when engaging in cross-border trade. Corporate income tax rates also vary: 16% in RO, 19% in CZ and HU, and 22% in SK.

Price convergence in the 4M market

The 4M MC algorithm optimally allocates ATC between the coupled markets by matching bids and offers from the combined coupled market, until the ATC is fully utilised. Thus, to the extent there is sufficient transmission capacity available between the coupled markets, they will clear at a single price. Under such circumstances, all generators in the coupled region are in direct competition with each other, and even small differences their costs may affect their bidding behaviour and dispatch, and potentially market prices.

We have reviewed the results of the 4M market coupling for the period spanning from November 2014 (after Romania joined) to April 2015. Below we summarise our key observations:

- **The Czech and Slovak markets are highly integrated**—Prices in the two markets were the same 93% of the time. Whenever prices in the two countries diverged (i.e., ATC was fully utilised), the market price in SK always exceeded that in CZ.
- **Prices in HU and SK were equal 41% of the time**—Usually when full price convergence between HU and SK occurred, the CZ price is also the same. Price differential between SK and HU was less than €2.50/MWh in 56% of the hours, and lower than or equal to €10/MWh 76% of the time. These facts suggest that in the majority of the hours the lowest-cost marginal resource in the 4M MC market tends to be a CZ generator. This finding supported by the fact that, whenever prices between CZ and SK diverge, the coupling algorithm allocates all ATC between the two markets in the CZ-to-SK direction. Similarly, whenever prices between SK and HU diverge, the ATC from SK-to-HU is fully utilised. Thus, the prevailing power flows (allocated by the market coupling algorithm) are from CZ to SK to HU.
- **RO is not (yet) very well integrated with the other three countries in 4M MC**—ATC from RO to HU has typically been very low, although at times even that capacity was not fully utilised, since price separation and cross-border flows have occurred in both directions. Prices between RO and HU was equal 21% of the time; 55% of the hours they were lower in HU, and 24% of the time they were lower in RO.
- **Average cross-border price differentials ranged from €0.90/MWh to €7.30/MWh**—As summarised in Table D1, prices between CZ and SK have been the lowest, and given high degree of convergence, the price differential between these two countries has been the smallest. HU has had the highest average prices, with average price

differential between HU and CZ, HU and SK, and HU and RO of €7.30/MWh, €6.40/MWh, and €3.70/MWh, respectively.

Table D1. Average day-ahead electricity price across all hours between November 2014 and April 2015

Country	Average price (€/MWh)
Czech Republic	32.30
Slovakia	33.20
Hungary	39.60
Romania	35.90

These observations suggest that if any distortions occur due to a lack of harmonised transmission tariffs, they are most likely to occur between the CZ and SK, followed by the Slovakia-Hungary interface. Given that very limited ATC is available from RO to HU, any distortions between those two countries are currently likely to be limited.

Current G-charges in Slovakia and Romania

As noted already, currently two of the 4M countries, SK and RO, apply a locational G-charge, while HU and the CZ do not currently levy such a charge on generators.

Slovakia

The G-charge in SK was introduced effective 1 January, 2014.[94] It is calculated as the product of: (1) reserved capacity to access the grid (i.e., installed capacity or capacity agreed upon during interconnection); (2) tariff rate (€/MW-year); and (3) an adjustment coefficient. The adjustment coefficient is a fixed parameter set by the regulator, and it is designed to ensure that on average the charge levied on generators does not exceed €0.5/MWh. The G-charge is not levied on a locational basis, and applies to all generators, except two exempt categories: (1) generators providing ancillary services (e.g., regulation); and (2) small hydro generators with installed capacity of 5 MW or less. The G-charge is payable upfront for the entire year.

Since the G-charge is capacity based and the adjustment coefficient is fixed, generators with a low capacity factor effectively face a higher €/MWh transmission cost than generators with high capacity factor. Thus, generators may face a G-charge significantly higher than €0.5/MWh, as illustrated below:

- For 2015 and 2016, the tariff rate is set at €37,468.5796/MW-year, and the adjustment coefficient is 0.0795.[95]

[94] Vyhláška Úradu pre reguláciu sieťových odvetví, č. 221/2013 Z. z. z 11. júla 2013 (in Slovak).
[95] For calendar year 2014, the tariff rate was €37,489.5067/MW-year, and the adjustment coefficient was 0.0810.

- Thus, a generator running at 25% capacity factor (e.g., running at full capacity for 2,190 hours annually) effectively pays €1.36/MWh, while a generator running at 75% capacity factor would face an average effective G-charge of €0.45/MWh.

Generators connected to the distribution network, which in Slovakia includes the 110 kV system, also pay a G-charge that may exceed the transmission-level G-charge levied on a comparable generator. For example, while a transmission-connected generator effectively pays €2,978/MW-year; a generator connected at the distribution level (above 52 kV), incurs a G-charge of €7,814/MW-year to €10,094/MW-year, depending on the distribution network.[96]

Romania

Unlike in Slovakia, the G-charge in Romania is energy based and it is applied on a locational basis. The current tariff methodology has been in effect since 2005. The regulator determines a zonal G-charge for each of the 7 generation zones.[97] Zonal tariffs are set based on the short-run marginal cost of injections/withdrawals at each node. For these calculations, short-term marginal cost is defined as the sum of the marginal cost of losses and the marginal cost of congestion. The locational short-term marginal cost is topped up by an average cost component to ensure recovery of the total allowed revenue.

The G-charge is applicable to all generators with installed capacity > 5MW. Table D2 summarises the current G-charges for each of the generation zones.

Table D2: Romanian G-charges in effect since July 2014

Zone	Code	Tariff (lei/MWh)	Tariff (€/MWh)	% average tariff
Muntenia	1G	8.60	1.93	84%
Transilvania Nord	2G	6.04	1.36	59%
Transilvania Central	3G	8.93	2.01	87%
Oltenia	4G	12.32	2.77	120%
Moldova	5G	7.80	1.75	76%
Dobrogea	6G	10.32	2.32	100%
Dobrogea renewables	7G	10.77	2.42	105%
Average		**10.30**	**2.31**	

Source: http://www.transelectrica.ro/documents/10179/28121/Ord+ANRE+51+2014.pdf/5eee6bbd-59bf-45e9-bcea-c10c59c1dfea

Note: €1 = lei 4.45. Romania has a G-charge cap of €2/MWh according to EU Regulation 838/2010.

[96] Based on monthly G-charges of €2,272.80/MW-month, €2,804/MW-month, and €2,170.70/MW-month levied in Západoslovenská distribučná, Stredoslovenská energetika-Distribúcia, and Východoslovenská distribučná distribution networks, respectively.

[97] Load is also charged locational, energy based transmission tariffs in 8 load zones.

The Romanian regulator (ANRE) recently issued a proposal to scrap the locational transmission tariffs and to replace it with a uniform tariff for all producers. The uniform tariff would equal the average of the current G-charges (but maintain locational differentiation for load). The regulator's proposal was motivated by the following facts:

- The current locational charging did not lead to a more balanced generation siting within the country. According to ANRE, the siting of new generators was driven by other factors such as availability of primary resources, land ownership and proximity to intended consumers.
- The tariff differentiation influenced the bidding price of producers on the wholesale market. This is in line with ACER's opinion on G-charges which states that different G-charge levels can have an impact on competition in the market.

Potential operational impacts of a lack of harmonised transmission tariffs on cross-border trade between the 4M countries

To examine whether the SK or RO G-charge could result in distorted dispatch decisions one would have to examine whether the G-charge changes the merit order within the 4M MC region, and whether the changes in the merit order are reflected in the market price. Focusing on a hypothetical generator in Slovakia that incurs the G-charge, we examine how its dispatch decisions are affected, and how those individual impacts could have an effect on the overall market.

First, using a simple dispatch model against 4M MC market prices observed since November 2014, we examined how the dispatch decision of a modern CCGT[98] would be affected by the current G-charge. We assumed that a generator will perceive a G-charge as a cost, irrespective of whether it is energy or capacity based. For a generator facing a capacity based G-charge, especially if it is paid in advance as in Slovakia, it is reasonable to assume that it will translate G-charge related costs into unit costs and reflect them in its market offers. Using this assumption, we simulated dispatch decisions in two scenarios:

- **Scenario 1**: the generator is dispatched whenever its marginal cost exceeds the SK market price, assuming no G-charge related costs. The model predicts a dispatch in 858 of the 3,719 hours, corresponding to a capacity factor of 23.1%. As one would expect, the generator is dispatched during the peak hours when the market prices are the highest.
- **Scenario 2:** the generator is dispatched only when the market price exceeds the marginal cost, including the G-charge spread over the expected annual output. At 23.1% capacity factor, the effective unit cost associated with the G-charge is €1.47/MWh. The resulting dispatch is 744 hours, 114 hours fewer than in Scenario 1.

[98] For this plant we assumed 58% efficiency, €2.5/MWh variable O&M cost, CO_2 emission rate of 345 g/MWh, and natural gas sourced from CEGH.

This example demonstrates that even relatively small G-charges can significantly alter the dispatch decision of individual plants; in our example above, the generator runs 13% less when it faces an additional cost of only €1.47/MWh.

Whether these altered individual dispatch decisions translate into market impacts (i.e., higher market prices and/or increase in overall dispatch costs) depends on: (1) whether (and how frequently) the affected generator is marginal (i.e., price-setting within the 4M MC mechanism); and (2) how easy it is for a cross-border generator to replace the SK generator in the merit order.

If the generator were always inframarginal, even with the transmission costs, the G-charge would unlikely to result in significant impacts on dispatch or market prices. The CCGT used in the above example clearly does not fall within the category. In fact, generators of this type have recently struggled to stay profitable in the 4M market. Our simulation suggests that these ultra-efficient CCGTs may be marginal in the 4M region about one quarter of the time. It is likely that the rest of the time coal-fired generators are marginal. Since those generators tend to run at a much higher capacity factor, the impacts on their dispatch decisions are likely to be much smaller.

In order to assess the ability of cross-border generators to replace an SK CCGT generator in the merit order, one needs to examine whether: (1) such cross-border generators with similar operational characteristics in the neighbouring markets exist; and (2) whether dispatch decisions are altered by the G-charge in hours with sufficient cross-border capacity between the markets to allow the cross-border generator to transfer its output.

- Similar generators assumed in our simulations currently exist in both Hungary (Gönyű CCGT) and Slovakia (Malženice CCGT). A similar plant is also currently under construction in the Czech Republic (Počerady CCGT). These plants are technologically very similar, and are therefore likely to have similar operating costs.
- In our simulations, 86% of the hours when the hypothetical CCGT's dispatch decisions were impacted by the G-charge, the CZ and SK markets cleared at a single price. This was the case between HU and SK about 33% of the time.

Thus, given the very high degree of price convergence between SK and CZ markets, potential operational impacts are most likely between these two markets, and less likely, though still possible, between the HU and SK markets.

Due to a lack of detailed operational data for all generators in the 4M region, we could not perform a full-scale simulation to study the dispatch decisions of every generator, or the impact of G-charges on overall dispatch costs and market prices. We understand that the operating characteristics of coal-fired generators within the regional market are more varied than those of the newest CCGTs modelled above. For example, while most coal-fired plants in the Czech Republic are located near a coal mine and/or burn higher-quality coal, the coal-fired generators in Slovakia are supplied by lower quality brown coal and/or imported coal, and are therefore likely to face higher operating costs. Thus, CZ coal-fired plants are likely to be lower in the dispatch merit order, and their dispatch is not likely to be affected by a G-charge incurred on SK generators.

Operational impacts of the SK G-charge on Hungary and Romania are likely to be limited, given that these two markets are disconnected from the SK market more than half the time.

Lastly, a full assessment of operational impacts would have to account for the bidding behaviour of market participants. In our simulations, we assumed that the hypothetical CCGT is a price taker and it bids in its marginal costs into power exchange. In reality, there is a significant concentration of ownership of generation assets in the 4M region. For example, in 2013, the market shares of the largest generators in CZ, HU, SK, and RO were 58%, 52%, 84%, and 27%, respectively.[99] Therefore, there is a potential that such structural market power may be reflected in the market offers of the generators.

Evidence of potential cross-border investment effects

Any evidence of investment effects associated with G-charges is difficult to identify because the potential impact of a G-charge cannot be isolated from the impact of other factors (e.g., low wholesale prices) usually considered in investment decisions.

As much of Europe, the 4M region has also experienced a recent decline in wholesale electricity prices. With the exception of the ongoing nuclear capacity developments (discussed above) and the addition renewable capacity, there is currently little market incentive to invest in new (thermal) generating capacity. Nevertheless, we have identified some examples to illustrate cross-border investment decisions in the region. An interesting example is the near simultaneous construction of two almost identical CCGTs in Hungary and Slovakia by E.ON:

- **Gönyű CCGT** is a 433 MW, high-efficiency generator, located in north-western Hungary. E.ON commissioned its construction in December 2007, and the plant became operational in May 2011.
- **Malženice CCGT** is a virtually identical 430 MW generator, also owned by E.ON, and located in south-western Slovakia, about 125 km from the Gönyű CCGT. Construction on the plant started at the end of 2008, and it entered service in January 2011.

Given that the two plants are so similar in technology, size, and timing of the investment decision, the relative importance of other factors considered in the investment decision can somewhat be isolated. These factors include: (1) differences in prices and expectations about future prices; (2) differences in transmission tariffs.

Prices in Hungary were higher but future price convergence could have been reasonably expected at the time. Although Hungary and Slovakia were not yet linked through a market

[99] Eurostat; http://ec.europa.eu/eurostat/data/database

coupling mechanism at the time, given the direction of European policy and already existing SK-CZ market coupling[100], there could have been the reasonable expectation that the two markets would be coupled in the future. Nevertheless, E.ON's decision to construct both plants implies that the price differentials (and other factors) were not significant to construct a (perhaps larger) generator at just one location, and export some of its output to the neighbouring market.

Transmission tariffs were unlikely to be an important consideration at the time, since neither Hungary nor Slovakia had a G-charge in place. We have no evidence that the future introduction of a G-charge was known (or could have been known) at the time.

This example highlights that cross-border investment decisions are complex considerations, and the differences in transmission tariffs must be significant in order to affect those decisions.[101]

Lastly, G-charges can potentially affect not just investment, but also closure and mothballing decisions. We have gathered evidence of such decisions, although we cannot fully attribute them to the introduction of a G-charge in Slovakia:

- **Mothballing of Malženice CCGT**—Around the time the Slovak regulator ÚRSO announced the introduction of the G-charge in July 2013, E.ON announced that it would mothball the Malženice CCGT effective October 2013.[102] E.ON explained that the plant can no longer operate profitably due to low electricity and carbon prices. During the first two and a half years of its operation, the plant only operated for about 5,600 hours, compared to 4,000 to 5,000 hours per year it was planned to operate.[103] We understand that in 2013 E.ON also considered the mothballing of the Gönyű CCGT, but eventually decided to keep that generator operational.[104]
- **Mothballing of PPC Bratislava CCGT**—220 MW of capacity was mothballed effective 1 January 2014.[105]
- **Mothballing of 2 units at the Vojany (EVO I) coal-fired plant**—two units (1 & 2) with a combined capacity of 220 MW were mothballed by Slovenské elektrárne (ENEL) in 2014.

An additional 1 GW of new capacity has been permitted years ago but net yet constructed.[106]

[100] The CZ-SK-HU Market Coupling project was announced in July 2011. http://www.europex.org/public/20110719-press-release-czskhu-mc-project-launched.pdf
[101] For key factors considered by E.ON, see: http://www.eon.com/content/dam/eon-com/de/downloads/ir/Equity_story_Generation_activities.pdf
[102] https://www.eon.com/en/media/news/press-releases/2013/7/15/gas--und-dampfkraftwerk-im-slowakischen-malenice-geht-in-kaltres.html
[103] http://www.eon.com/en/about-us/structure/asset-finder/malzenice-power-station.html
[104] http://www.energiafocus.hu/hirek/mar-heten-donthetnek-gonyu-leallitasarol/ (in Hungarian)
[105] http://www.mhsr.sk/10994-menu/143839s
[106] These projects include the KPPC Košice and Strážske CCGTs, and the Nitra-Chrenová CHP plant.

ANNEX E CENTRAL WESTERN EUROPE MARKET COUPLING REGION

The Central Western Europe market coupling (CWE) was launched in 2010 and implemented an ATC-based implicit auction mechanism for allocating capacity in the day-ahead markets of Belgium, France, Germany and the Netherlands. The CWE region joined the Price Coupling in North Western Europe (NWE) in February 2014 creating a coupled market covering the CWE region, Great Britain, the Nordic and Baltic countries.

In this case study we consider the impact of transmission charges on generators and market competition in the CWE region. We also consider the interaction of the CWE region with Norway and GB, particularly as G-charges in these two countries are among the highest in Europe. In the CWE region, Belgium has introduced an ancillary services tariff for generators in 2012 and France applies a G-charge of €0.19/MWh. No transmission system charges apply for generators in the Netherlands and Germany.

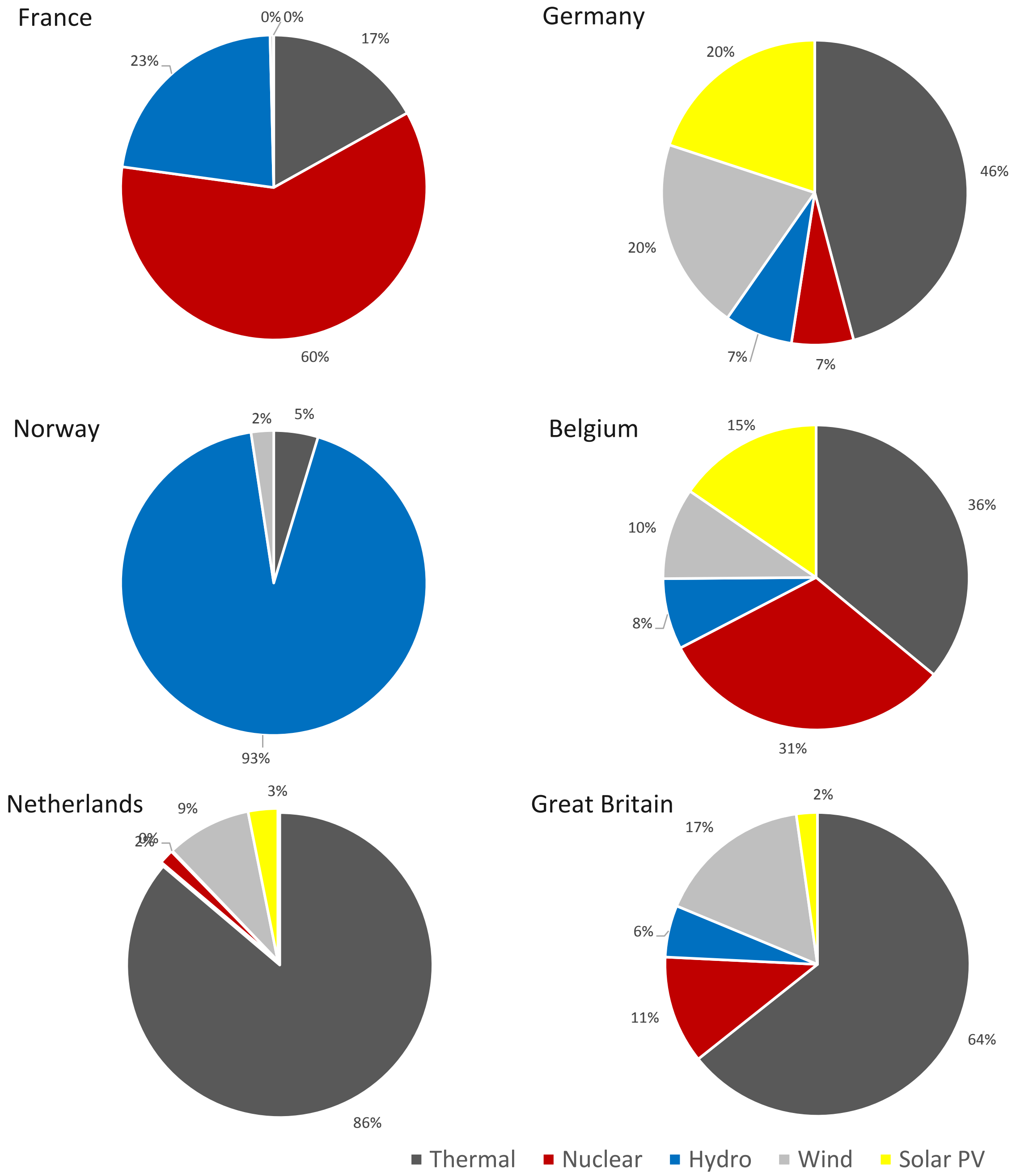
We start by exploring differences in market fundamentals between the countries, as well as the level or market integration and the main factors that may influence the magnitude of potential inefficiencies and distortions to cross-border trade.

Differences in market fundamentals

The countries we examined in the NWE and CWE regions have a varied installed capacity mix. About 60% of the generation capacity in France is nuclear, while 95% of generation capacity in Norway comes from hydro power plants. The Netherlands and the UK rely mostly on thermal generation, made up mainly of gas-fired plants; although coal plants represent a significant share of thermal generation capacity, particularly in the UK. Most of Belgium's installed capacity mix is made up of nuclear and gas power plants, with an increasing share of solar generation. The largest share of installed capacity in Germany is still represented by thermal (coal and gas) generation, although there is an increasing share of renewable generation (wind and solar) which already makes up 40% of total installed capacity. Germany's nuclear capacity will be phased out within a decade. Belgium also has legislation in place to phase out its nuclear reactors by 2025.

Germany has the largest amount of total installed capacity (197 GW), followed by France (105 GW) and GB (82 GW). Norway and the Netherlands each have around 33 GW of installed capacity while Belgium has around 20 GW installed capacity.

Figure E1. Installed capacity by capacity type in NEW/CWE countries in 2015



Source: ENTSO-E, EWEA[107]

The degree of market integration depends critically on the transmission capacity available for cross-border trade. Netherlands is connected with other markets in the NWE region through the NorNed subsea cable link with Norway, the BritNed cable link with GB and through onshore interconnection with Belgium and Germany.

[107] Wind generation capacity data for Norway was not available on the ENTSO-E Transparency Platform. We have used a figure based on end of 2014 data from EWEA.

Capacity on the AC onshore interconnection between the Netherlands and Belgium/ Germany is made available through explicit annual auctions; explicit monthly auctions; day-ahead implicit auction through the market coupling mechanism; and intraday explicit auction.

The capacity of the NorNed cable (nominally 700 MW in both directions) is offered daily and intraday and is made fully available to the spot market. Therefore, no annual or monthly market is organised for this. The BritNed capacity (nominally 1000 MW in both directions) is allocated via an explicit auction mechanism in different timeframes such as yearly, quarterly, monthly but also other timeframes can be applicable (i.e. weekend). Day-ahead and intraday allocation is done via the implicit market coupling mechanism.

The day-ahead market coupling uses Available Transfer Capacity (ATC) values, determined by the TSOs, as input in market clearing. The average hourly ATC values for the day-ahead market coupling in the region over the May 2014 – April 2015 period are presented in the table below.

Table E1: Average hourly ATC values between May 2014 and April 2015

Border	ATC (MW)	Reverse direction ATC (MW)
France to Belgium	1,411	2,206
Germany to Netherlands	1,660	2,721
Norway to Netherlands	663	683
Netherlands to Belgium	1,083	1,468

Source: CASC, ENTSOE TP

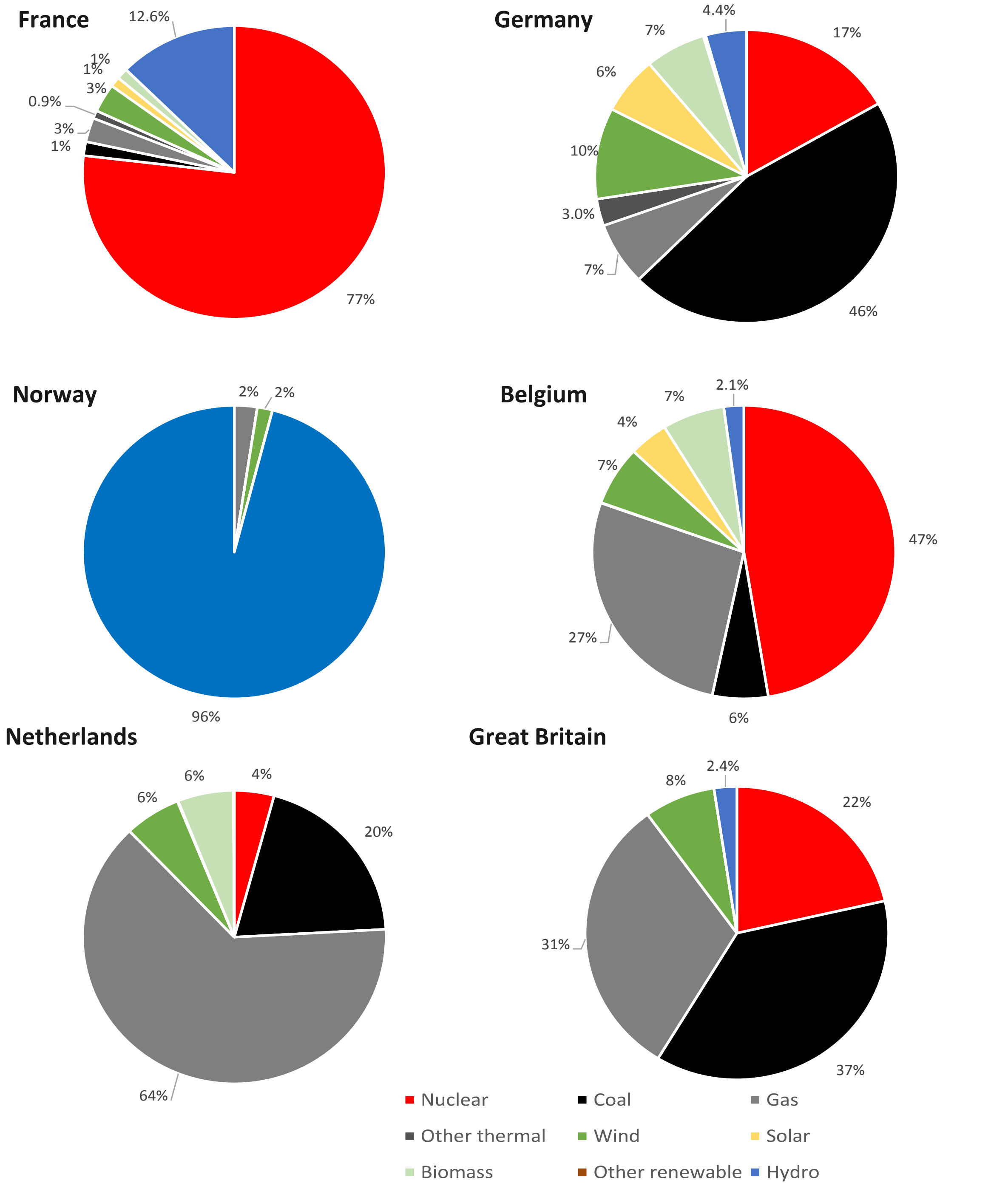
Actual electricity generation and cross-border trade volumes depend, apart from the availability of transmission capacity, on the supply-demand balance in each country and the relative cost of different types of generation. In 2014, Belgium, the Netherlands and GB were net importers of electricity with 21%, 13% and 5% respectively of domestic demand served by imports. Norway, Germany and France were net exporters, with 12%, 7% and 15% respectively.[108]

The import requirement of Belgium increased especially since 2000 MW of generation capacity has no longer been available at the Doel 3 and Tihange 2 nuclear reactors which had been temporarily shutdown while safety investigations have been taking place.[109] In addition, Doel 1 reactor has been permanently shut down in February 2015 as it reached the end of permitted operation cycle.

[108] These figures represent total net traded volumes for each country along all cross-border routes not only with the countries considered in this case study.

[109] Initial shutdown lasted almost one year from summer 2012 to May 2013. Reactors were again stopped in March 2014 and are expected to resume production in July 2015. (https://www.electrabel.com/en/corporate/company-news/topics/shutdown-nuclear-powerstation-doel)

Figure E2. Generation by capacity type in 2014[110]



Source: ENTSO-E

Plans to expand interconnection capacity in the future include a new interconnector between Netherlands and Germany scheduled for completion in 2016.

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[110] ENTSO-E actual generation production data for 2014 does not break down fossil fuel electricity generation in the Netherlands into separate categories (i.e. coal, gas). We have estimated the share of electricity produced by each plant type using installed generation capacity data.

Price convergence in the NWE region

The market price coupling in the region means that ATC in the day-ahead market is allocated implicitly through the market coupling algorithm. Prices should equalise unless insufficient transmission capacity results in price divergence.

We have looked at capacity allocation and price differentials in the NWE region over a one year period (from May 2014 to April 2015). Some key observations are summarised below:

- **The most integrated countries in the region are Belgium and Netherlands –** Prices in the two markets were equal 75% of the time and another 18% of the time the price differential was less than €10/MWh. When prices diverged, prices in Belgium were generally higher than in the Netherlands, and the transmission capacity from Netherlands to Belgium was fully utilised. The average price differential between the two markets over the period was €1.9/MWh.
- **Prices in the Norwegian market are usually the lowest in the larger region, while within the CWE region the lowest-priced market is usually Germany** – Prices in the German market were lower than in the Netherlands 73% of the time (prices were never higher in the Netherlands during the period).
- **Prices in all countries the entire CWE region were simultaneously equal only 15% of the time**.

Changes in electricity generation patterns across the region, such as the growth of renewable energy generation, particularly in Germany, have had large impacts on regional electricity market. In 2011, prices in the Dutch and German electricity markets were reported to be equal 90% of the time.[111] Since then, the increasing amount of intermittent solar and wind generation in Germany has caused frequent local electricity surpluses, even negative prices. The interconnector capacity between the two markets is thus no longer sufficient to allow prices to equalise. As a result full prices convergence between the two markets occurred just 30% of the time in 2013.[112]

Electricity flows in the region are largely determined by the generation mix in each country and the marginal cost of different generation types. Specifically, low-cost sources of electricity are the low marginal cost generators: (1) hydro generation in Norway; (2) renewable generation in Germany; and (3) nuclear generation in France.

Electricity flows from Norway and Germany to the Netherlands include both electricity for Dutch domestic consumption, as well as transit flows to Belgium and GB. Belgium imports electricity from low marginal costs producers, directly from France, and from Germany and Norway (through Netherlands). Given this differing mix of generation capacity in different

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[111] TenneT, http://www.tennet.eu/nl/news/article/tennet-to-further-expand-cross-border-electricity-connections-with-germany.html

[112] Idem

countries, it seems likely that any distortions from an absence of harmonisation of transmission tariffs are likely to occur between Netherlands and Belgium where market prices are equal most of the time and price differentials are lowest. In effect any cross-border competition distortions caused by the absence of harmonisation of transmission tariffs are likely to affect gas-fired power plants in Belgium and Netherlands.

Introduction of G-charges in Belgium in 2012

In Belgium transmission tariffs are reviewed and set in four-year cycles by the regulator, CREG, with the Belgian TSO (Elia) proposing tariff setting principles. During the last review for the 2012-2016 price control period, Elia proposed the introduction of two new tariffs for generators:

- An energy based (€/MWh) tariff for ancillary services, designed to cover 85% of the costs of operating and black start reserves; and
- A capacity based (€/MW) transmission charge for injection to the grid applicable to generators connected to the transmission network before 2002, set at €3.13/kW-year.[113]

These proposals were initially accepted by CREG, but they were later subject to legal challenges. The court hearing the challenges raised concerns that the new charges violated the principles of non-discrimination and cost-reflectivity, and therefore annulled the transmission tariff. Following the court decision, the share of ancillary services costs recovered from generators was reduced from 85% to 50%, and the G-charge was completely scrapped. Nevertheless, the originally-proposed charges were levied for approximately one year, and the energy based charges continue to remain in effect, albeit at a lower level.

In addition to the energy based ancillary services charge, currently €0.9111/MWh[114], gas-fired generators in Belgium are also subject to an energy based federal gas charge, levied on end users of natural gas and used to fund some public service obligations, currently set at €0.7959 for each MWh of gas consumed[115]. Thus, say a gas-fired generator with 59% efficiency, effectively faces a total energy based charge of €2.26/MWh. Although technically both of these are not transmission charges, the fact is that they are costs that the generators will factor into their dispatch decisions.[116] These costs could be significant enough to displace an efficient Belgian generator by another generator in one of the neighbouring countries. We illustrate these impacts using our simple dispatch model below.

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[113] In practice this meant the charge would apply to most generation plants as very few generation capacity was added after 2002.
[114] Elia, Tariffs 2014-2015 for Grid Use and Ancillary Services http://www.elia.be/~/media/files/Elia/Products-and-services/Toegang/Tariffs/Access_2014-2015_EN.pdf
[115] http://www.creg.info/Tarifs/G/2015/CotFed/CotFedG2015NL.pdf
[116] If the original capacity based G-charges were still in effect, that would impose an additional €0.50/MWh cost on the generators.

Potential operational impacts of an absence of harmonisation of transmission tariffs

We examine whether the application charges on electricity generators in Belgium distort the merit order by focusing on the dispatch decisions of a hypothetical Belgian generator. We use a simple dispatch model set against actual market prices observed in Belgium and the Netherlands from May 2014 to end of December 2014 to explore how the dispatch decision of a modern CCGT[117] plant would be affected by the introduction of the ancillary charge currently in place in Belgium.

As the charge applied in Belgium is an energy based charge we assume this results in an increase in the marginal cost of the generator equal to amount of the charge. In theory this could result in the generator being sometimes forced out of the merit order as its marginal cost climbs above market prices. To test the magnitude of this impact we have simulated dispatch decisions under two scenarios:

- **Scenario 1 (no ancillary services charge):** the generator faces no transmission charge (but pays the federal gas charge), therefore it is dispatched whenever the Belgian market price exceeds its marginal cost. The model predicts a dispatch in 3,370 out of 5,881 hours (57% of the time).
- **Scenario 2 (with ancillary services charge):** the generator faces the current ancillary services charge in Belgium and therefore is dispatched whenever the market price exceeds its marginal, including the ancillary services charge. The model predicts a dispatch in 3,189 out of 5,881 hours (or 54% of the time). The additional ancillary services charge thus results in a generator being dispatched 181 fewer hours (around 5% reduction in dispatch hours).

Our model illustrates that transmission charges applied to generators can have an impact on the dispatch decisions of individual plants. Our simple model does not show however whether these dispatch decisions translate into market impacts such as higher market prices. This depends on whether:

- the affected generator is the price setter within the market; and
- it can be easily displaced by a generator in a neighbouring country not facing the same transmission charges.

Our market analysis assumes that market prices remain the same despite the introduction of the transmission charge on generators. Economic theory tells us that within a given market an energy based charge applied uniformly on all generators should result be passed on to consumers through higher electricity prices without affecting the merit order. Effectively the only way for market prices to remain unchanged when such a charge is introduced is for markets to be sufficiently interconnected for domestic generous affected by the charge to be

[117] For this plant we assumed 58% efficiency, €2.5/MWh variable O&M cost, CO_2 emission rate of 345 g/MWh, and natural gas sourced from Zeebrugge.

displaced by generators in neighbouring countries. If the transmission capacity is fully utilised, however, and prices in the two markets are not equal, this implies that the marginal generator is a domestic one.

In the case of Belgium and Netherlands, as mentioned above, prices are equal 75% of time. Our modelling suggests that 93% of the hours when the dispatch decisions of the hypothetical CCGT plant were affected by the ancillary services charge the prices in the two markets were equal. This indicates there is a strong possibility for the Belgian generator to be displaced by a similar Dutch generator during those hours.