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COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying the document

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast)

Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast)

Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast)

Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

{COM(2016) 861 final}
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{SWD(2016) 413 final}

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4. Detailed measures assessed under Problem Area II, option 2(1); (improved Energy Markets, no CMs)

4.1. Removing price caps

4.1.1. *Summary table*

Objective: to ensure that prices in wholesale markets and not prevented from reflecting scarcity and the value that society places on energy.			
	Option 0: Business as usual	**Option 1: Eliminate all price caps**	**Option 2: Create obligation to set price caps, where they exist, at VoLL**
Description	Existing regulations already require harmonisation of maximum (and minimum) clearing prices in all price zones to a level which takes "into account an estimation of the value of lost load". Non-regulatory approach Enforceability of *"into account an estimation of the value of lost load"* in the CACM Guideline is not strong. Enforcement action is unlikely to be successful or expedient. Relying on stronger enforcement would leave considerable more legal uncertainty to market participants than clarifying the legal framework directly.Voluntary cooperation not provide the market with sufficient confidence that governments would not step in restrict prices in the event of scarcity.	Eliminate price caps altogether for balancing, intraday and day-ahead markets Removes barriers for scarcity pricing Avoids setting of VoLL (for the purpose of removing negative effects of price caps)	Reinforced requirement to set price limits taking "into account an estimation of the value of lost load" Allow for technical price limits as part of market coupling, provided they do not prevent prices rising to VoLL. Establish requirements to minimise implicit price caps.
Pros	Simple to implement – leaves adminstration to technical implementation of the CACM Guideline.	Measure simple to implement; unequivocally and creates legal certainty.	Compatible with already existing requirement to set price limit, as provided for undert the CACM regulation, provides concrete legal clarity
Cons	Difficult to enforce; no clarity on how such clearing prices will be harmonised. Does not prevent price caps being implemented by other means.	Can be considered as non-proportional; could add risk to market participants and power exchanges if there are no limits .	VoLL, whilst a useful concept, is difficult to set in practice. A multitude of approaches exist.
Most suitable Option(s): Option 2 - this provides a proportionate response to the issue –, it would allow for technical limits as part of market coupling and this should not restrict the markets ability to generate prices that reflect scarcity.			

4.1.2. *Description of the baseline*

Scarcity pricing is critical to investment in flexible generation and demand. Traditionally, power plants have been built based on receiving a stable revenue and operating with high levels of output for a significant proportion of time (i.e. high load factors). However, with more variable renewable technologies entering on to the system, with generally very low or zero marginal costs, the patterns that more conventional forms of generation operate (e.g. gas) is changing. Investment will no longer be able to take place based on the assumption that plants will operate at high load factors for a significant portion of their working life; with more and more generation from renewables, with lower running costs, these plants will operate less and less. However, they will remain critical in providing a stable electricity system. They will need to operate to keep supply steady in times of low renewable generation and flexibility will be key. There will be more and more occasions when prices could reach very high levels (in times of scarcity) but for very short periods of time. It is these peaking prices that can provide the signals and stimulate the investment needed in flexible capacity so long as investors have the confidence that they will be able to recoup their money based on such prices. Further, such prices are critical in stimulating other forms of flexibility, notably in the form of demand response – in the case where a consumer (industrial or residential) has a contract which reflects wholesale price movements, the greater the price differences, the greater the incentive to respond by reducing consumption and instead using energy at lower price periods.

It is not the case, however, that all consumers will necessarily see such short-term changes in prices. In general, consumers will be more affected by the longer-term changes in average prices; these will more likely feed through to energy bills for reasons explained below.

Whilst different formulas exist, unit costs in a standard fixed or variable (monthly) retail tariff will be an average of the wholesale price over a period of time, with additional costs added, such as network costs, taxes, etc., along with any supplier margins. Consumers on these tariffs will be shielded from period-by-period changes in the wholesale price, be they up or down.

Whilst the development of demand response will be enhanced by dynamic tariffs which better reflect the wholesale price, there is no proposal for this to be obligatory. If a consumer were to choose a tariff that mirrored the wholesale price on a 1:1 ratio, overtime they would likely pay less as their suppliers would face lower hedging costs, which they could then pass on to those consumers as tariff savings (lower margins). This is illustrated in the Nordic markets, where hourly tariffs are often the cheapest on the market for most consumers. Nevertheless, consumers whose peak consumption consistently coincided with price peaks on the market, and who chose a dynamic tariff, may end up paying more at the end of the billing period, reflecting their cost to the system.

The formation of scarcity prices can be contained directly or indirectly and, in particular, by caps on prices. These can be implemented for a number of reasons, including technical (e.g. required as part of the operation of the programs which determine market results), to improve the robustness of market operation (e.g. to prevent significant errors in bidding affecting market outcomes), for competition reasons (i.e. to limit any abuse of a dominant position), for consumer-related reasons (e.g. to limit consumer exposure to high prices) and for financial reasons (e.g. to limit the collateral needing to be posted).

In a perfect market, supply and demand will reach an equilibrium where the wholesale price reflects the marginal cost of supply for generators and the marginal willingness to pay for consumers. If generation capacity is scarce, the market price should reflect the marginal willingness to pay for increased consumption. As most consumers do not participate directly into the wholesale market, the estimated marginal value of consumption is based on the value of lost load (VoLL). VoLL is a projected value which is supposed to reflect the maximum price consumers are willing to pay to be supplied with electricity. If the wholesale price exceeds the VoLL, consumers would prefer to reduce their consumption, i.e. be curtailed. If, however the wholesale price is lower than the VoLL, consumers would rather pay the wholesale price and receive electricity. If prices are prevented from reaching the VoLL through the introduction of price caps, then short-term prices will be too low in scarcity situations. This in turn can affect investment signals - notably, it can reduce the incentive to investment in flexible capacity (i.e. of the type that can respond to short-term peaks in prices) and demand response.

However, currently all Member States have specific restrictions on the price to which wholesale prices can rise. In the day-ahead market, the most common cap is EUR 3000/MWh, which is by-and-large a technical constraint rather than implemented with the intention of keeping prices below VoLL. Some Member States have values somewhat lower, which could introduce distortions in the price signals.

Figure 1 – Day-ahead price caps

- Majority: +3000 EUR/MWh
- GB: +3000 or +6000 GBP/MWh
- Greece: 150 EUR/MWh
- Ireland: +1000 EUR/MWh
- Poland: 347 EUR/MWh, +3000 EUR/MWh (x-border)
- Portugal/Spain: 180 EUR/MWh

Source: "Market design: Barriers to optimal investment decisions" Impact Assessment support study, (2016) COWI

These values have limited relationship to the value of lost load and, therefore, if maintained would prevent prices rising to the level to which society values energy. For example, a recent study commissioned for the UK's Department of Energy and Climate Change estimated that VoLL for Electricity in Great Britain to be GBP 10,289/MWh for domestic users and GBP 35,488 for SMEs on a winter peak workday (approximately EUR 13,500/MWh and EUR 46,500/MWh at the time of writing)[1]. Whilst VoLL will change depending on the circumstances, the user and the location (it will not be the same in all Member States), it is clearly much higher than the limits that currently exist in many day-ahead markets. Price caps in the intraday markets show a lot less harmonisation - see map below. Whilst the level is generally much higher - i.e. no caps in some countries, and up to EUR 9999,99/MWh in others, and therefore are less likely to create distortions, some Member States have price caps which will fall far below VoLL.

Figure 2 – Intraday price caps

- Green: No ID market
- Light blue: -9999,99 to +9999,99 EUR/MWh
  - Stripes: DE: Discrete -3000/+3000 EUR/MWh
- Dark blue: No price caps
- Czech: +3700 EUR/MWh
- Dark red:
  - GB: 0/+2000 GBP/MWh
  - IT: 0/+3000 EUR/MWh
  - PT, ES: 0/+180 EUR/MWh

Source: "Market design: Barriers to optimal investment decisions" Impact Assessment support study, (2016) COWI

With regards to the balancing timeframe, price caps apply to the activation (energy) part of balancing services in several Member States. In some countries there are fixed price caps, like +/-9999,99 EUR/MWh in Slovenia, +/-3700 EUR/MWh in Czech Republic, or 203 EUR/MWh for FRR in Lithuania. In Austria and the Nordic countries, the floor price is equal to the day-ahead price, meaning that there is a guarantee that the payment for energy injected for balancing is at least equal to the day ahead price. In Belgium, FRR prices are capped to zero (downward regulation) and to the fuel cost of CCGT plus 40

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

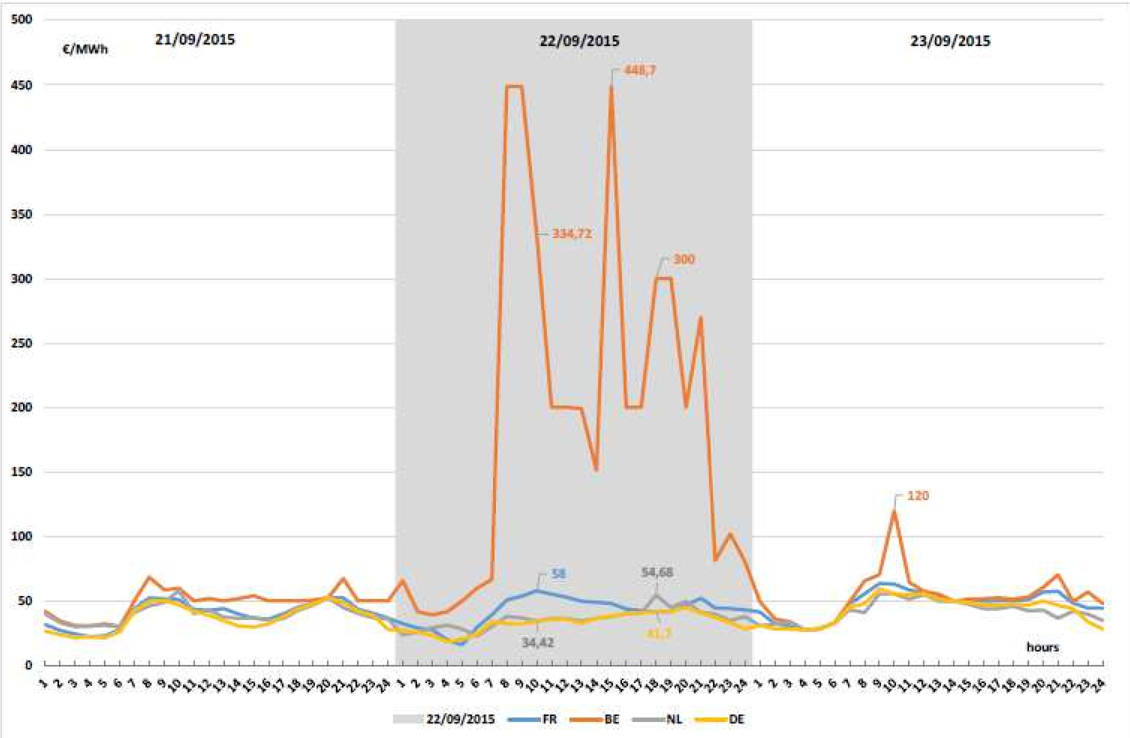
euros (upward regulation). Most Member States do not have price caps for capacity (reserve) bids.

There is an important relationship between the price paid for balancing services and the imbalance price – that is, the price determined by TSOs which producers and consumers must pay as they use or produce too much or too little energy compared to their contracted amount. As detailed further below, it is this real-time price which will have the biggest impact on prices in the intraday, day-ahead and forward prices. However, it will be heavily influenced by the price that TSOs pay for balancing services. In particular, under the upcoming Balancing Guideline, there are restrictions on how it can be formed based on the price paid for activation of balancing energy. The Guideline will also require that there are no caps or floors to balancing energy prices.

Free formation of prices in the balancing market is perhaps the most important issue; day-ahead and intraday markets effectively act as an opportunity to hedge against the expected imbalance price - they will not buy or sell energy above this price as it will be cheaper to be out of balance and pay the imbalance price. Therefore, the balancing price should not mute scarcity pricing by capping prices below VoLL, else prices in the intraday and day-ahead timeframes will not reflect scarcity, regardless of any caps put in place.

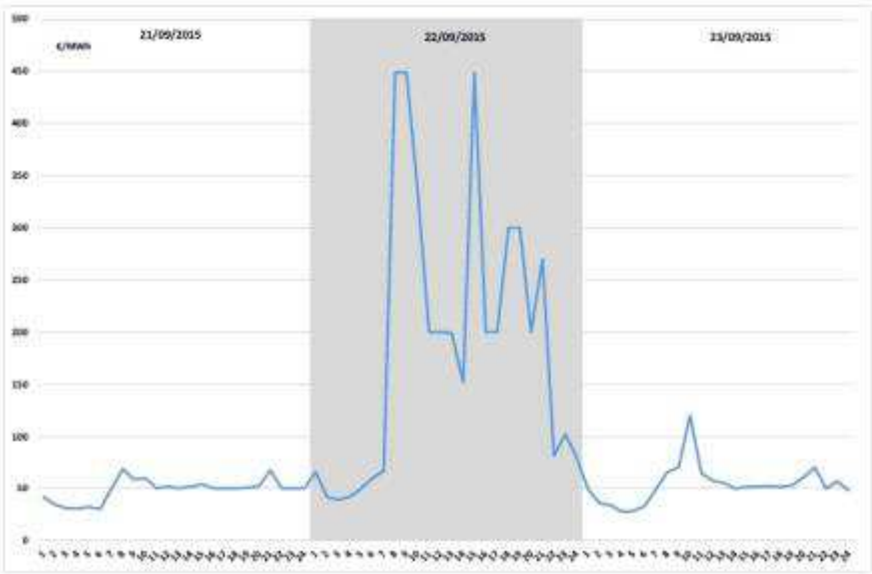
The following diagrams illustrate the relationship between prices in each of the three market timeframes, using the example of the imbalance price in Belgium on the 22nd September 2015. Figure 5 shows a high imbalance price caused by scarcity due to unplanned outages.

Figure 3 – Day-ahead spot prices as a result from the matching of orders in and the coupling of the bidding zones in the CWE-region on the 21st, 22nd and 23rd September 2015



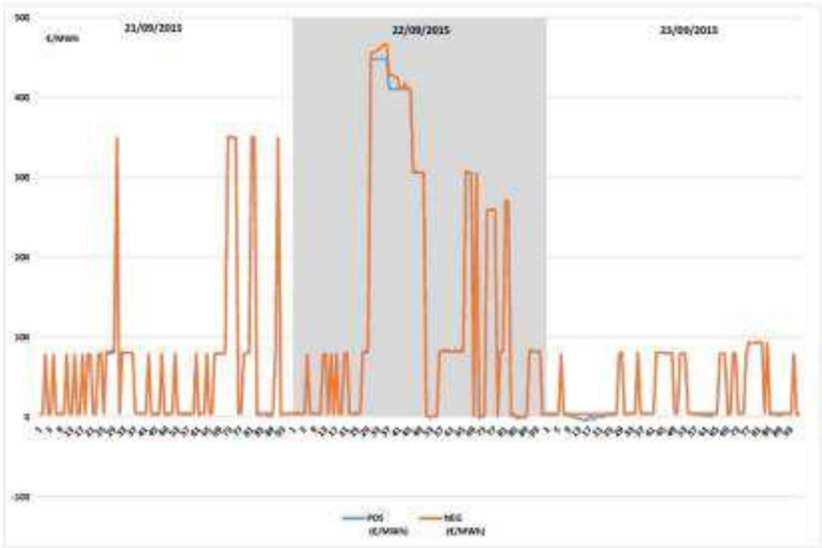
Source: Belpex, EEX, APX

Figure 4 – Intraday prices in Belgium on 21st, 22nd and 23rd September 2015



Source: Belpex

Figure 5 – Imbalance prices in Belgium on 21st, 22nd and 23rd September 2015,



Source: Elia

From these, it can be seen that the market is behaving rationally - i.e. that parties are trading in the day-ahead and intraday markets to hedge themselves. The prices are tracking the imbalance price. If it was prevented from going above a set amount, this would have an effect on bidding behaviour in the other two timeframes, which would also not go above this price. As the imbalance price will change in real time, market participants can only base their bidding in the day ahead and intraday markets based on what they expect the price will be. Therefore, such tracking of prices across timeframes will not happen where there are very short-term changes in the imbalance price, e.g. due to sudden tripping of equipment.

It should be noted that there is a difference between price restrictions on the price paid for activation of energy by TSOs in the balancing timeframe, and the imbalance price. The former will help inform the imbalance price, but it is generally the latter that has the most impact on behaviour in the day-ahead and intraday market.

Two issues exist relating to harmonisation of caps. Firstly, given the above, that of harmonisation between timeframes. If caps exist in the balancing timeframe, there is little point in having a cap higher than this in intraday or day ahead, as there will be no reason for market parties to bid or offer energy at a higher price - i.e. because it will be cheaper to pay the imbalance price. It is therefore important that there is consistency across market timeframes. The second issue relates to harmonisation between markets. If there are different price caps each side of a border, this can interfere with how energy flows in times of system stress. Take for example Member State A with a price cap of 1000, on a border with a Member States B whose price cap is 100. In the absence of a cap, energy would flow to the country who valued it the most, i.e. with the higher price. However, with these caps if there was a concurrent scarcity event which led to prices going above 100, then energy will always flow to Member State A, despite the fact that Member State B might value energy as much or more (i.e. because the price cannot attract flows of energy more than Member State A's prices).

Implicit price caps can also exist. For example, in some Member States (around a third), a shadow auction[2] is triggered if prices reach 500 euros /MWh (or goes below -150 euros /MWh). This can act as a disincentive to bid higher than EUR 500 . Other disincentives that have been identified include: general fears about competition law – for example, the market restricting itself out of fear of being seen to be abusing a dominant position; the price at which strategic reserves are activated; and TSO actions based on market price.

4.1.3. *Deficiencies of the current legislation*

Current European legislation contains very little reference to wholesale market prices caps. In fact, the only reference is contained in the CACM Guideline. Specifically, Articles 54 (covering intraday trading) and Article 41 (covering day-ahead) require power exchanges, acting in their cross-border roles as NEMOs to propose harmonised maximum and minimum bid prices. This needs to "take into account the value of lost load." This proposal is due to be made to regulatory authorities by mid May 2017.

As pointed out in the Evaluation Report, normally, well-functioning wholesale markets should provide price signals necessary to trigger the right investment. However, the ability of markets to do so is debated today because today's electricity markets are characterised by uncertainties as well as by a number of market and regulatory failures which affect price signals. These include low price caps, renewable support schemes, the lack of short term markets and lack of demand response operators.

4.1.4. *Presentation of the options*

Option 0: Business as usual

The option would allow for the continuation of limits on wholesale prices. This would in principle allow for different price caps in different timeframes. However, under the terms

[2] Auctions run to validate that the results of the first auction are correct and not abnormal prices due to either technical issues during the execution of the market clearing algorithms, or bidding behaviour of market participants.

of the CACM Guideline it would bring harmonisation in day-ahead and intraday as there is a requirement for a harmonised value in all bidding zones participating in market coupling. This value would have to "take into account" the value of lost load. It would not, however, have to represent this value and could be significantly lower. For example, as part of the NWE market coupling project, there is a maximum clearing price of 3000euros/MWh in those bidding zones taking part in the project. This limit has been applied to other markets, for example the German intraday auction (which takes place after the cross-border auction) and the GB day-ahead auction (a similar process, again after the cross-border auction, although the limit is expressed in GBP). This is most likely due to issues of convenience and to prevent creating perverse incentives to trade in one of the markets as opposed to another.

Option 1: Eliminate all price caps

This option would see a prohibition on all upper price restrictions in the wholesale market, in all timeframes. It would mean that prices would be able to reach VoLL. It would also involve a prohibition on any technical price limits imposed by power exchanges.

Option 2: Create obligation to set price caps, where they exist, at VoLL

This option would require that, where caps exist, they shall be no lower than VoLL in all market timeframes. This would be coupled with a requirement that Member States establish VoLL. This option would be compatible with a technical limit imposed by power exchanges, but would include a trigger to raise such limits in order to prevent them constraining acurate price formation coupled with a date by which the maximum must not be below VoLL. It would also make clear that, once at VoLL, the value need not be harmonised.

4.1.5. *Comparison of the options*

As detailed above, allowing prices to reflect scarcity, and investors having confidence that this will be allowed to happen, is key to stimulating investment in a more flexible system.

The options must, therefore, be assessed in this context i.e. those options which would prevent scarcity prices forming and, in particular, reflecting the true scarcity in terms of willingness to pay for energy, would not be compatible with the objective of creating an energy market that is able to face future challenges and stimulate the right investments.

The 'do nothing' option would not be consistent with the set objectives – even though harmonised maximum clearing prices would be implemented, these only have to 'take into account' the value of lost load and there would be no way to provide confidence that prices could indeed reach values which reflect scarcity. It would allow for price caps to continue existing within Member States. Whilst in practice, for most Member States, prices have not been constrained by existing caps (there have been no instances yet where they have hit the 3000 euros mark), this is not set to remain the case forever. Doing nothing, or relying on voluntary cooperation at the Member State level, would not provide investors with any confidence that restrictions would be removed (or raised) in the event they were hit and the default position is that they would remain in place. It therefore has to be assumed that such an option would shave off the peaks in pricing. Whilst the CACM Guideline contains a reference to VoLL, ‘take into account' is not enforceable.

Option 1 – to eliminate any price caps - would be the option most in line with this specific objective, in that it would allow prices to rise to any level, determined by supply and demand fundamentals. Making a strict, EU-level prohibition may provide investors with confidence that Member States would not intervene to keep wholesale prices low for political reasons – e.g. because of a negative perception of the impacts of peaking prices on consumers. This option, however, entails risks. In particular, it would prevent any limits being used in the market coupling system or by power exchanges. This could have technical impact on the operation of the systems used to run the markets and may influence the amount of collateral that market parties are required to post. Market parties are generally required to provide cash or credit to cover their potential exposure. Without limits in the clearing price, this could become more expensive or their credit more restrictive (e.g. on how much they can trade), as the potential exposure would be higher. Further, it could prevent the use of any explict price-based measure to detect errors in bidding.

Option 2 would allow for the use of limits to exist in the context of trading on the power exchanges and only in relation to maximum and minimum clearing prices developed in accordance with the CACM Guideline. In order to prevent such limits restricting accurate price formation, the option would also introduce a specific requirement that they be raised when a trigger point is reached coupled with a requirement that they be set at the value of lost load within a certain timeframe. The option would also prohibit Member States from introducing legal caps on the wholesale price unless this reflects a calculation of the value of lost load.

The advantage of this approach is that it would still allow for technical limits to be introduced by power exchanges, but would not constrain price formation and would give investors a clear signal that Member State authorities cannot step in artificially dampen prices. The disadvantage as compared to Option 1 is that, in order for such limits to continue to exist and to be effective, there may need to be a time lag between the trigger and the limit being raised. This would need to be as short as possible so not to prevent prices from rising.

A difficulty with this option is the complexity of establishing VoLL. It will change depending on the circumstances and the user and so one value will only ever be an estimation.

This option would also be bundled with a requirement placed on Member States to avoid and, where possible, eliminate any implicit price caps so not to disincentives the offering of high prices by market participants.

The benefits of better price signals and further articulated as part of the wider option to address uncertainty on future investments (Problem Area II, which includes policies on locational signals, scarcity pricing and price caps, resource adequacy planning and capacity mechanisms) in Section 6.2.2.

4.1.6. *Subsidiarity*

Given that the EU energy system is highly integrated, prices in one country can have a significant effect on prices in another. Further, if there are significant differences between countries on the level to which wholesale prices can rise, then energy may flow in the wrong direction during times of system stress. A coordinated and harmonised approach is, therefore, necessary.

This topic is, to an extent, already covered under the CACM Guideline – which notably requires the setting of harmonised maximum clearing prices which take into account the value of lost load.

Differences in national approaches could create significant distortions in the market and prevent the most cost-effective supply of electricity. It could also distort investment signals, for example those countries who have a higher cap would potentially attract more investment thnt those with a lower cap.

EU action is therefore necessary to ensure a common approach is taken which minimises distortions in the operation of markets between Member States.

4.1.7. *Stakeholders' opinions*

From the Market Design consultation, a large majority of stakeholders agreed that scarcity pricing is an important element in the future market design. It is perceived, along with current development of hedging products, as a way to enhance competitiveness. While single answers point at risks of more volatile pricing and price peaks (e.g. political acceptance, abuse of market power), others stress that those respective risks can be avoided (e.g. by hedging against volatility).

Many submissions to the consultation highlighted the link between scarcity pricing and incentives for investments/capacity remuneration mechanisms, as well as the crucial role of scarcity pricing for kick-starting demand response at industrial and household level.

Key stakeholder comments included:

- *"…energy prices that reflect market fundamentals, including scarcity in terms of time and location, are an important ingredient of the electricity market design. Undistorted prices (without regulatory intervention) should thus trigger optimal dispatch and signal the need for investments/divestments… Price caps and other interventions in the market hindering the appearance of scarcity prices should be removed."* Eurelectric
- *"…we need to better valorize flexibility. Prices reflecting scarcity are crucial in this context and should therefore be a key priority of the market reform… Prices better reflecting scarcity will be more volatile and might be higher than today during some periods of the day (assuming the end of price caps). Rather than a challenge, this represents an opportunity as it will unlock new strategies to hedge against risks on the wholesale market while triggering dynamic pricing offers on the retail side."* SolarPower Europe.
- *"In principle, electricity prices should reflect actual scarcity so that the most cost-efficient flexibility options on the supply and the demand side as well as the most efficient storage solutions are employed. Prices should also reflect the scarcity of transmission capacities within and across market borders"* EUROCHAMBERS
- *"In order to provide correct price signals for new investments (both generation and consumption), and to provide security of supply, prices which reflect actual scarcity are an important ingredient in the future market design."* BusinessEurope
- *"Citizens Advice supports efforts to move to market structures that more accurately reflect scarcity. This is an important way of conveying price signals reflecting the genuine value of consumption and production, at different times and in different locations."* Citizens Advice

- *"…energy prices should effectively reflect both temporal scarcity and surplus in order to adequately reward flexibility. Such an approach to energy pricing would better facilitate the investments required to address the European energy trilemma of sustainability, security of supplies, and competitiveness."* WWF

Further, in a position paper, Wind Europe state that "[i]*t is important that market prices are undistorted and allowed to move freely without caps. Transparent market prices must be in place in all time horizons, i.e. forward, day-ahead, intraday and real time, and also used for settlement of remaining imbalances. This will help to incentivise and reward the provision of flexibility services. Policy makers should be aware that price spikes are needed to trigger the right scarcity signals on both the supply and demand side; investment decisions based on a certain expectation of price spikes will only be made if there is enough trust by investors that politicians will not interfere and introduce price caps. "* [3]

The March 2016 Florence Forum made the following relevant conclusion:

"The Forum acknowledges the significant progress being made on the integration of cross-border markets in the intraday and day-ahead timeframes, and considers that market coupling should be the foundation for such markets. Nevertheless, the Forum recognises that barriers may continue to exist to the creation of prices that reflect scarcity and invites the Commission, as part of the energy market design initiative, to identify measures needed to overcome such barriers. In doing so, it requests the Commission take proper account of technical constraints that may exist."

[3] https://windeurope.org/fileadmin/files/library/publications/position-papers/EWEA-Position-Paper-Market-Design.pdf

4.2. Improving locational price signals

4.2.1. *Summary Table*

Objective: The objective is to have in place a robust process for deciding on the structure of locational price signals for investment and dispatch decisions in the EU electricity wholesale market.				
	Option 0	**Option 1**	**Option 2**	**Option 3**
Description	Business as Usual – decision on bidding zone configuration left to the arrangements defined under the CACM Guideline or voluntary cooperation, which has, to date, retained the *status quo*.	Move to a nodal pricing system	Introduce locational signals by new means, i.e. through transmission tariffs	Improve currently existing the CACM Guideline procedure for reviewing bidding zones and introducing supranational decision-making, e.g. through ACER. This would be coupled with a strengthened requirement to avoid the reduction of cross-zonal capcity in order to resolve internal congestions.
Pros	Approach already agreed.	Theoretically, nodal pricing is the most optimal pricing system for electricity markets and networks.	Would unlock alternative means to provide locational signals for investment and dispatch decisions.	This improvement will render revisions of bidding zones a more technical decision. It will also increase the available cross-zonal capacity.
Cons	Risks maintenance of the *status quo*, and therefore misses the opportunity to address issues in the internal market.	Nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.	Incentives would be not be the result of market signals (value of electricity) but cost components set by regulatory intervention of a potentially highly political nature. Does not address the underlying difficulty of introducing locational price zones, namely the difficulties to arrive at decisions that reflect congestion instead of political borders.	Does not address a situation where the results of the bidding zone review are sub-optimal. I.e. this option only covers procedural issues.
Most suitable option(s): Option 3 – this option will rely on a pre-established process but improve the decision-making so that decisions take into account cross-border impact of bidding zone configuration. Other options – e.g. tofundementally change how locational signals are provided, would be dispropritionate.				

4.2.2. <u>*Description of the baseline*</u>

The internal energy market is based on the concept of bidding zones, which are defined as *"the largest geographical area within which market participants are able to exchange energy without capacity allocation."*[4] They are effectively market areas within which energy is considered to be able to flow freely and within which, therefore, there will be a single wholesale price for any given market timeframe.

Currently, bidding zones are based on national borders, although there are some exceptions[5].

Figure 1, Curent bidding zone configuration

Source: Ofgem, 2014

The wholesale price will be the same in one part of France as it is in another, the same in one part of Spain as it is another part of Spain, the same in Germany as it is in Luxembourg and Austria, and so on. The wholesale price in Italy may be different in different parts, as it may be in Sweden and Norway.

This is critical, as the wholesale price is a crucial part of determining when and where people invest (and where there are no other revenue streams such as capacity mechanisms, the only basis). Higher prices in one area will in theory attract investment into that area

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4 Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets

5 There is currently one German-Austrian-Luxembourg bidding zone, and Italy, Sweden and Norway are split into several zones.

over and above somewhere with lower prices. This locational signal in the energy price will not exist within a bidding zone, and so will not encourage investment in one part as compared to another and, in the case where bidding zone boundaries are based on Member State borders, within one part of a Member State compared to another. This is despite the fact that there may be bottlenecks within that Member State that prevent the free flow of energy from one part to another and, hence, could create a greater need for investment in certain geographical areas.

Further, wholesale energy prices will determine when generating plants dispatch and, to a lesser degree (due to relative inelasticity in the demand-side) when load consumes energy. i.e. where the price is higher than a generator's short-run marginal cost, bar any external factors, they will run. If there are significant congestions within a bidding zone, and the price is influenced by demand behind such congestion, generators on the other side may still dispatch despite limited ability to transport the energy to the demand. This can result in the so-called 'loop flow' phenomenon whereby energy will flow around the congestions through another zone, against market price signals. These flows, as they have not been scheduled, can have significant implications. More specifically, they can reduce the amount of cross-border capacity made available to the market for trade and result in costly remedial actions, for example the need to redispatch (the reduction in the amount of power injected on one side of the congestion and, simultaneously, an equivalent increase in the amount injected on the other side). As an example, in 2015 the total cost for redispatching within the DE-AT-LU bidding zone was approximately 930 million euros[6]. Overall, the total welfare loss due to loop flows was estimated to be around 450 million euros in 2014[7].

An improved configuration of bidding zones, one which takes account of structural congestions within the European grid, would mitigate many of these issues, as it would improve the locational price signals. In particular, in the short-term it would affect how and where energy is dispatched and, for the longer-term, will improve the price signals on where to locate new generation investments. Clearly investment in transmission capacity is also critical, notably within a bidding zone so that energy can better flow from one area to another. However, the bidding zone structure itself may not provide strong signals for such investment; as Ofgem point out in its Bidding Zone Literature Review (2014)[8], impact on investment may be muted by practical consideration, for example, due to economies of scale, uncertainties about future generation investment, and difficulty in centralising charges or reliability and quality of service.

The precise definition of bidding zones, and realising maximum benefit from it, is complex and highly technical, and there are a number of variables which must be considered. Therefore, a review process, to be undertaken by TSOs, has been formalised in legislation under the CACM Guideline[9]. More specifically, once a review is launched[10], TSOs are to

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6 ENTSO-E Transparency Platform, at https://transparency.entsoe.eu/

7 "*Market Monitoring Report 2014*" (2015) ACER – social welfare losses for both unscheduled flows and unscheduled allocated flows.

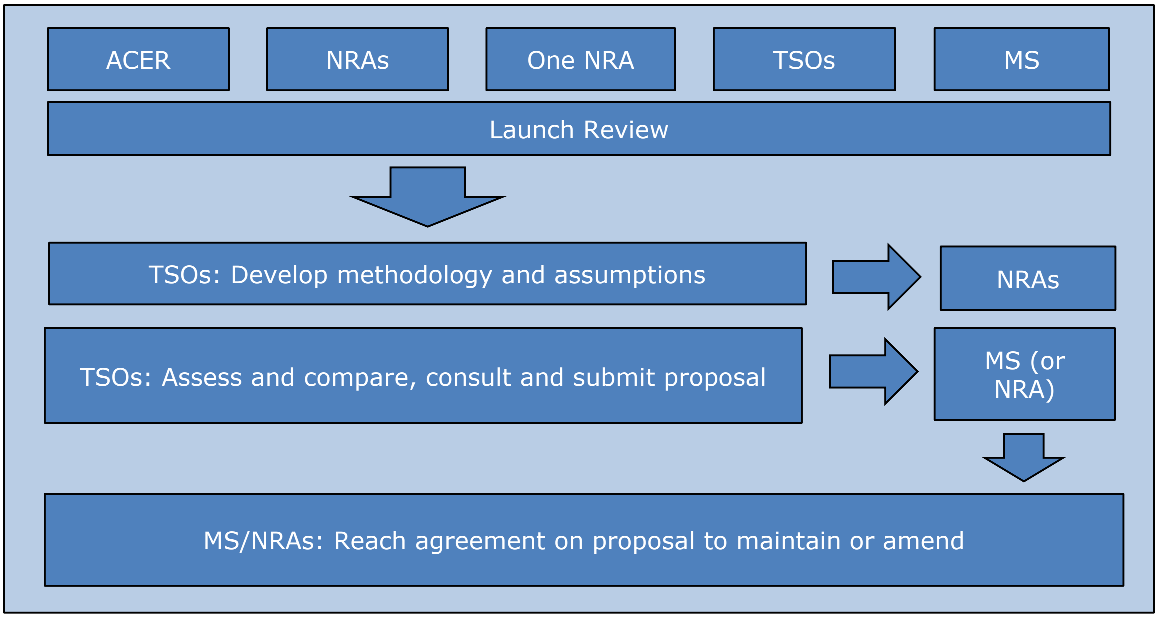
8 https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/fta_bidding_zone_configuration_literature_review_1.pdf

9 In practice, work has already started on this.

10 Which can be done by ACER, NRAs, Member States or TSOs, depending on specific criteria – Article 32

review the existing bidding zone configuration and alternative bidding zone configurations, and must submit this to Member States or, where so determined by a Member State, NRAs for a decision on whether to amend or maintain the zones. Figure 2 below provides a summary of this process.

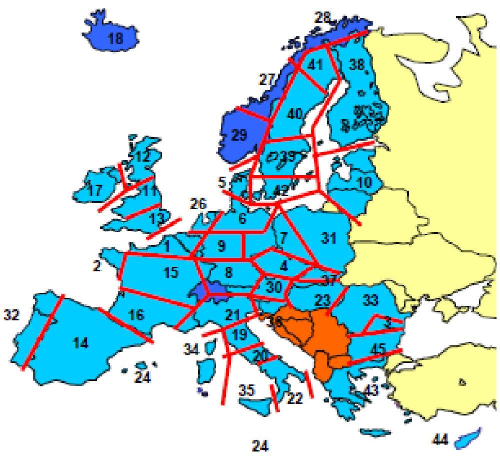
Figure 2, simplified flow chart of bidding zone review process under the CACM Guideline



When undertaking a review, TSOs must consider issues relating to network security, market efficiency, including any increase or decrease in economic efficiency of changes, and stability and robustness of bidding zones.

A number of authors have already suggested alternative configurations, for example as shown in figure 3.

Figure 3, possible alternative configuration,



Bidding zones for Europe			
1	Belgie & France du Nord	23	Magyar
2	Bretagne	24	Mallorca
3	Bucureşti	25	Malta
4	Czech	26	Nederland
5	Danmark Vest	27	Norge Mellan
6	Deutschland Nord	28	Norge Nord
7	Deutschland Ost & Śląsk	29	Norge Syd
8	Deutschland Süd, Alsace, Lorraine, Schweiz, Tyrol & Vorarlberg	30	Österreich
		31	Polska centralna
9	Deutschland West & Letzeburg	32	Portugal & Galicia
10	Eesti, Latvija & Lietuva	33	Romania
11	England Middle	34	Sardegna & Corse
12	England North & Scotland	35	Sicilia
13	England South	36	Slovenija
14	España	37	Slovensko
15	France Centre & Suisse	38	Suomi
16	France Sud	39	Sverige Mellan
17	Ireland	40	Sverige Norbotten
18	Island	41	Sverige Nord
19	Italia Centro Nord	42	Sverige Syd & Danmark Ost
20	Italia Centro Sud	43	Ελλαδα
21	Italia Nord, Svizzera & Cote d'Azur	44	Κύπρος
22	Italia Sud	45	България

Source: Supponen, Influence of National and Company Interests on European Electricity Transmission Investments, 2011

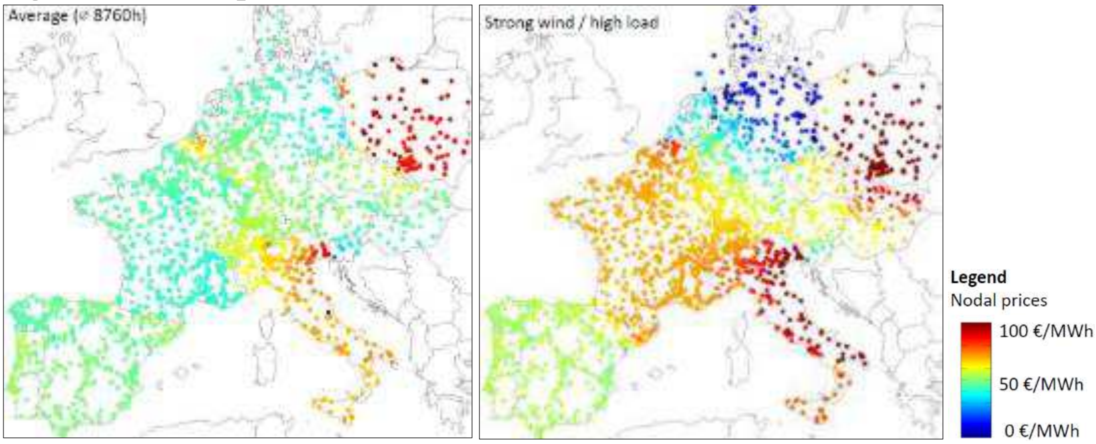
However, as pointed out by Supponen (2011), even price zones which reflect the most congested parts of the European grid, will not provide as efficient price signals as a system which is based on a more granular system, such as that of nodal pricing. Nodal pricing is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid called 'nodes'. These nodes would be determined based on the most congested points in the system. The price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it[11]. This model is used in much of North America. For example, the PJM's system includes over 10 000 price nodes across 20 transmission control zones, with trading available at nodes, at aggregates of several nodes, at 12 hubs consisting of hundreds of nodes each, and at 17 import and export external interfaces. The IEA conclude that *"This nodal pricing system facilitates adjustments to dispatch in the real-time market, efficient use of variable resources and demand-side response, and limits to market power by individual generators"*[12].

In 2014, Breuer simulated the potential price differences based on a nodal system in Europe, comparing average across the year with times of strong wind and high load in continental Europe.

[11] Phillips, Nodal Pricing Basics, Independent Electricity Market Operator, available at http://www.ieso.ca/imoweb/pubs/consult/mep/LMP_NodalBasics_2004jan14.pdf

[12] Repowering markets

Figure 4 – Nodal prices, base case (2016)



Source: Breuer, Optimised bidding area delineations and their evaluation in the European Electricity System, Brussels, April 2014 – Nodal prices (base case) 2016

As can be seen from the above, there could be significant changes in prices in a nodal system compared to average prices across Europe on windy days with high demand. Such a picture serves to illustrate what the prices should be if transmission capacity were fully taken into account. This does not cluster around the current bidding zone configuration as shown above and suggests inaccuracy of price formation in the current setup. It is also far from clear just from the above how this could be best grouped into a bidding zone structure, and several possibilities exist just from this one scenario. The complexity could be further increased when looking at alternative scenarios (e.g. high wind/low demand, etc.).

It is therefore concluded that it is correct to rely on a technical analysis where the costs, benefits and practical considerations (including those listed in the CACM Guideline) will be considered – this is much more likely to result in a more optimal configuration than the one currently seen. The issue at stake, therefore, is how to make any change based on the outcome of the review pre-establishing under the CACM Guideline, or whether to move to a wholly different arrangement for locational signals such as the mandatory introduction of locational elements in transmission changes or moving to a nodal system

Cross-zonal capacity calculation

With a, theoretical, 'perfect' bidding zone configuration, the only congestion would be on a bidding zone border. Therefore, there would be no internal constraints that would cause reductions in cross-border capacity. However, even if and when a configuration is implemented that better reflects structural congestion, there will still be internal congestion. The Electricity Regulation states that:

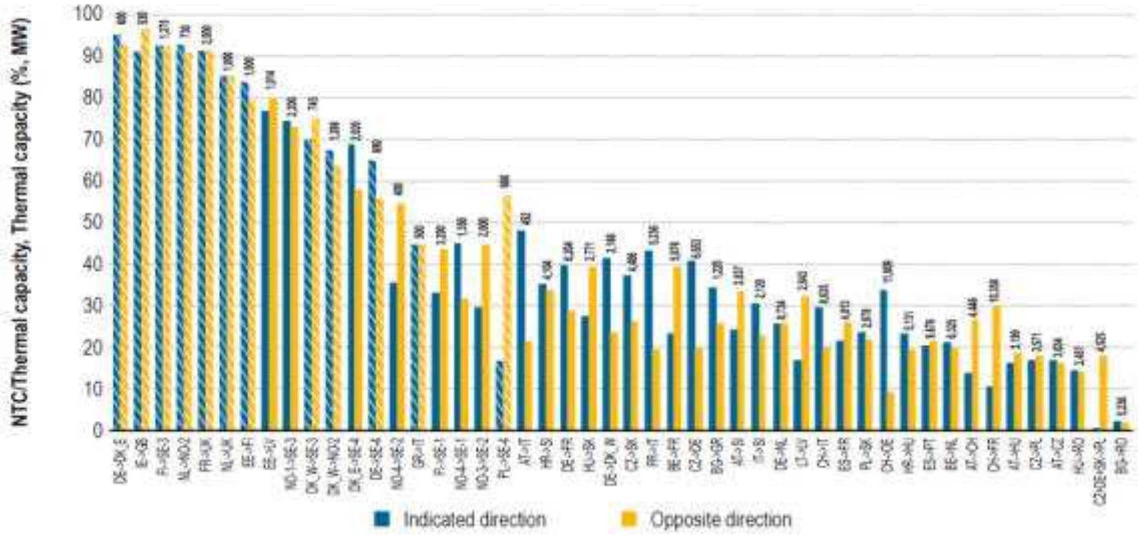
> *"TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons and reasons of operational security"*[13]

There is, however, evidence that cross-zonal (interconnection) capacity is indeed being limited in order to deal with internal issues. In its Market Monitoring Report, ACER

[13] Annex I section 1.7

analysed the ratio between thermal capacity (the theoretical maximum capacity) of interconnectors and the capacity offered for trade (with Net Available Capacity – NTC Capacity). The results showed that the ratios varied significantly and that on a number of borders the NTC was significantly below the thermal capacity.

Figure 5 – Ratio between available NRC and aggregated thermal capacity of interconnectors – 2014 (%, MW),



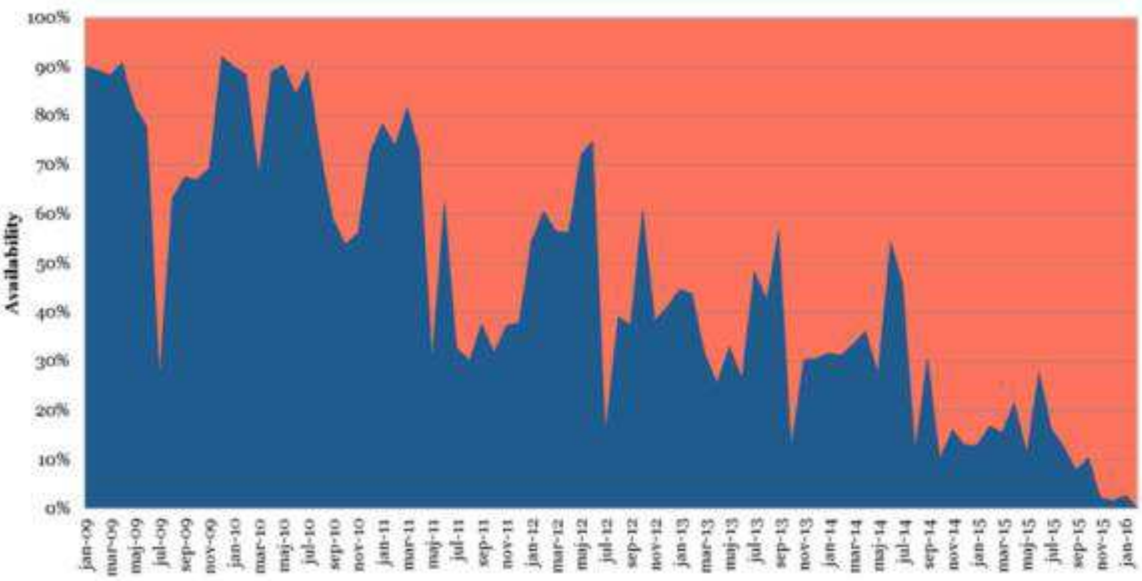
Source: ACER/CEER Market Monitoring Report 2015.

ACER concluded that "these results indicate that on the borders on the right side of the figure either the internal congestions are shifted to the border, or those borders are affected by a significant amount of unscheduled flows."

Regardless of the reason, the impact of this is the reduction of cross-border trade and has resulted in the need to curtail capacity the other side of the border. The German-Danish border provides an example of the sorts of impacts this can have. The below graph shows the average interconnection capacity was 250MW on DK1-DE in 2015, 15% of the maximum capacity. An investigation for the Danish TSO energinet.dk and the relevant German TSO TenneT found that a minimum capacity of 1.000 MW will bring a social economic benefit to the region of approximately 40 million euros per annum[14].

[14] Investigation of welfare effects of increasing cross-border capacities on the DK1-DE interconnector. Institute for Power Systems and Power Economics. RWTH Aachen University. June 2014. Study commissioned by TenneT and Energinet.dk.

Figure 6: Monthly average NTC as part of total transfer capacity (2009-2016).



Source: energinet.dk as reported by the Danish Energy Regulatory Authority[15]

4.2.3. *Deficiencies of the current legislation*

The most relevant legislation is the Electricity Regulation, which contains a detailed Annex on congestion management. However, it does not define bidding zones. In Section 1.7 it states that *"when defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity."*

More detail is provided under the CACM Guideline, which contains a detailed approach to reviewing and defining prices zones (Articles 32 through 34), as detailed above. Following TSOs' review and proposals Member States are required to "reach an agreement on the proposal to maintain or amend the bidding zone configuration."

This approach lends itself to the maintenance of the *status quo* as there are likely to be competing interests at stake. In particular, some Member States are unlikely to want to amend bidding zones where it would create price differentials within their borders; it is sometimes considered to be right for all consumers to pay the same price within a Member State, and for all producers to receive the same price. The current legislation does not, therefore, provide for the socially optimal solution to be agreed.

With regards to cross-zonal capacity, the current terms of the Electricity Regulation are unclear and allow for different interpretations and application.

The Evaluation Report concludes that *"the Third Package clearly lacks rules for the development and functioning of short markets as well as rules that would enable the development of peak prices reflecting actual scarcity in terms of time* and location*,"* and that *"given the economic importance (and distributive effects) of the decisions TSOs have to agree on, experience has shown that voluntary cooperation between TSOs was not able*

[15] "*STUDY ON CAPACITY REDUCTIONS ON THE GERMAN – WESTERN DANISH BORDER (DE-DK1) (Tender for Offers)*" - http://f.industry-supply.dk/2bjt3mw1t748a8fa.pdf

to overcome the problems that block progress in the internal electricity market (e.g. definition of fair bidding zones, effective cross-border curtailments)"

4.2.4. <u>*Presentation of the options*</u>

Option 0**:** BAU and stronger enforcement

This option would entail relying on existing legislation to improve the configuration of bidding zones. The likelihood of seeing any meaningful change as a result of this process is minimal. Existing provisions under the Electricity Regulation are arguably not sufficiently clear and robust to enforce a structure which reflects systematic constraints in the interconnected system. The provisions of the CACM Guideline do not provide for a clear decision-making process which provided any degree of certainty that the change will be made, but rather it is left to individual Member States to make the decisions even though these decisions have significant cross-border impacts.

Voluntary cooperation

As highlighted above, the evidence suggests that voluntary cooperation will not result in progress in this area, as there has been to date already significant opportunity to effect the necessary changes voluntarily.

Option 1: Move to a nodal-pricing system

A nodal pricing system would be the most granular way of determining location-based energy prices. In theory, this would eliminate the need for remedial actions by the TSO to alleviate congestion as the price of energy would determine exactly where it should be dispatched from. It would also create more accurate investment signals in new generation and infrastructure – in the case of the former in areas with higher prices, reflecting more scarcity.

Moving to a nodal pricing system would require a fundamental change in the way European energy markets are structured – current arrangements for cross-border trading (market coupling) would need to be redeveloped, implying significant IT and procedural changes. It would also be a significant change for market participants. The cost impact of this would, in the short-term, likely out weight the benefits.

Option 2**:** Introduce locational signals through other means

It is possible to introduce signals for investment and/or dispatch through other means than a market-based energy price. The main alternative method is through transmission tariffs – i.e. charging generators less in areas where more capacity and energy is required, and more where it is not. This can provide effective signals. It would mean a fundamental change to the tariffs structure as around half (15) of Member States do not apply transmission tariffs to generation. Further, this would not necessarily affect dispatch as, if charges are based on capacity, it becomes part of a generators fixed cost and will not affect when they generate. Moving to 'energy-based' charges could add distortions into the market as it would be very difficult to engineer this in a way which reflected the congestion and the dynamic-nature of production. Indeed, ACER has recommended the removal of energy based transmission charging on generators.

Option 3**:** Improve bidding zone review and decision-making process

As mentioned above, a review process is already detailed as part of the CACM Guideline. There is a requirement to review both existing and possible alternative configurations, the latter of which is triggered by specific circumstances. This option would see a strengthening of the decision-making process as a result of the review, in particular to ensure that the cross-border impacts of bidding zone configurations are appropriately taken into account. This would be achieved explicitly clarifying existing requirements for price zone borders to be based on congestion and not Member State borders. Procedurally, more powers would be given to EU institutions to decide on price zone configuration following the review. There could also be some amendments to the review process itself to ensure that it can show the optimal solution.

The option would be coupled with strengthened legal provision that make clearer the allowed derogations to the overriding rule that cross-zonal capacity must not be limited to solve internal congestion, and make any derrogation subject to regualtory oversight.

4.2.5. *Comparison of the options*

Maintaining the current system of review, and leaving the final decision-making in the hands of national authorities, would be the simplest option and the one which would yield the least disruption. However, as highlighted above, the process lends itself to maintenance of the *status quo* as decisions will be made on an individual, rather than collective basis. Difficulties have already arisen in the process (relating to some ambiguities in the current legislation). The benefits of price zone boundaries, reflecting structural congestions would not be seen, or would only partially be realised, if there is no coordinated decision. These have been estimated to be between 300-400 million euros per annum[16] to around 800 million euros[17].

The second option (Option 1), to move to a nodal pricing system, would be the most complex to implement. It would involve a complete redesign of the current system. It would involve fundamentally moving away from the current market setup and would significant changes to trading arrangements. By way of example, the current approach for coupling national markets would likely need to change significantly, which would involve large changes to IT and practices of traders, TSOs, power exchanges, suppliers and generators. The costs of change would be significant. Burstedde, in an analysis of a number of central European countries[18] found that there would be overall savings in the total cost of electricy supply from a nodal model, compared to a model based on bidding zones around Member State borders, of around 940 million euros, mostly due to redispatch costs. However, she also concluded that "the increase in overall system costs which results from aggregating nodes into zones remains negligible in relative terms" and that there would be savings from any move from nationally-based bidding zone borders[19].

The assessment of a nodal model will also form part of the review of bidding zones structures by TSOs – it is therefore considered premature to conclude that Europe should

[16] Bauer, ibid.

[17] Duthaler, C. (2012): "*A network and performance based zonal configuration algorithm for electricity systems"*, Dissertation, EPFL, Lausanne (Switzerland)

[18] Comprising of AT, CH, DE, NL, VE and FR

[19] Around 280 million euros in the case of moving to 9 zones.

move to such a model before this review has concluded; the process will allow a proper assessment of the different options and a decision can be taken on the basis of this.

Option 2 would require the introduction of administered locational signals. It is very unclear what the costs and benefits of this approach would be, given that it would depend on the prices set. If it were done on a capacity basis it would only impact the investment signals, and not dispatch signals. If it were done on an energy basis, then it could add significant distortions, e.g. by changing the merit order between different plants. This would be counter-productive and erode the benefits from the market design initiative.

Option 3 builds on the system already established in the EU, as well as processes already developed as part of the CACM Guideline. However, by moving to a more coordinated decision-making process, one which does not prejudice the assessment of the benefits and the costs of potential alternatives by TSOs, the likelihood that decisions are taken which reflect the cross-border impacts of the bidding zone structure is greatly increased. A more appropriately defined bidding zone structure could reduce the need for remedial actions, such as redispatch, reduce unscheduled flows in the form of loop flows, and improve signals for investment. Even so, an improved bidding zone structure would not eliminate internal congestion. Strengthened provisions in the Electricity Regulation to provide very clear rules on when cross-border capacity can be limited will help alleviate the economic impacts of this happening in order to address internal issues.

The benefits of better locational signals are further articulated as part of the wider option to address uncertainty on future investments (Problem Area II, which includes policies on scarcity pricing and price caps, resource adequacy planning and capacity mechanisms) in Section 6.2.2.

4.2.6. Subsidiarity

Networks in the EU energy market are highly meshed and therefore energy trading in one part has a significant part on another part. There are, however, naturally bottlenecks in the system that prevent unhindered flow of energy – termed congestion. These do not necessarily (and, in the case of the continental and Nordic synchronous areas) follow Member State borders.

The Third Package already contains provisions relating to congestion management, requiring procedures to be put in place, which is further elaborated by the CACM Guideline. It is important to have a harmonised approach to the management congestion in order to manage it cost-effectively across the market and allow for maximum cross-border trading.

Markets are split based on price zones, where the wholesale price is the same for each given timeframe. These provide locational signals for dispatch and investment.

Whilst the Third Package has achieved much, further action is needed at the EU-level – price zones based on Member State borders do not reflect the actual locational need for investment or demand for energy in a particular location. More coordinated action is therefore necessary to direct dispatch of energy and investment in infrastructure based on where it is needed and will provide most benefit to the EU interconnected system as a whole. This will become increasingly important with more and more variable sources of generation coming online over the coming years.

Action is already underway reviewing the structure of price zones in the EU. However, the decision-making is still left at the national level, which lends itself to maintenance of the *status quo*, which can have negative cross-border impacts (such as unscheduled flows of energy from one country to another as a result of inefficient price signals).

4.2.7. *Stakeholders' opinions*

A large number of respondents to the Energy Market Design consultation agreed that energy prices should not only relate to time, but also locational differences in scarcity (e.g. by meaningful price zones or locational transmission pricing). While some stakeholders criticised the current price zone practice for not reflecting actual scarcity and congestions within bidding zones, leading to missing investment signals for generation, new grid connections and to limitations of cross-border flows, others recalled the complexity of prices zone changes and argued that large price zones would increase liquidity.

WindEurope (formally EWEA) commented that "[w]*holesale electricity prices reflecting scarcity and physical constraints, including transmission capacity, are desirable in a fully functional electricity market. This is already expressed in the present zonal pricing model inside bidding zones and between bidding zones where price differentials signal the need for transmission investments."*

In their joint response to the consultation, ACER/CEER stated that "[p]*rices reflecting scarcity (both in terms of time and location) of generation resources in each bidding zone of organised markets in the different timeframes (day-ahead, intraday and balancing) should become a key ingredient of the future market design."*

EURELECTRIC *"generally favours larger bidding zones as they present more advantages for the functioning of the market and its liquidity, however bidding zone configuration should duly take into account the grid capacity. Zones should respect structural bottlenecks that do not necessarily correspond to national borders."*

The European Association for Storage of Energy (EASE) said that "[p]*rices need to reflect the physical limitations of the grid in order to deliver optimal locational signals for investment, consumption and production."*

Another is example is that of Norderegi, who view is that "[f]*undamentally, the borders between Bidding Zones should be based on the physical characteristics of the power system. Bidding Zones should be aligned with where structural constraints occur. Leading principle is that cross border trade must not be restricted. Moving internal national transmission bottlenecks to national borders must not be used as a congestion management method."*

On the other hand, some stakeholders highlight risks to changes in price zone configuration. For example, the European Energy Exchange (EEX) states that *"The development towards large, cross-border bidding zones supports the efficiency of the power system by integrating markets. Supply and demand can be brought together more efficiently. The prerequisite for this is grid expansion. Delayed or insufficient grid expansion even in a national context has a negative impact on the market as a whole, as is currently seen in the discussion of splitting the German/Austrian bidding zone. Such a decision would be a huge step back in the creation of the internal market, splitting Europe's most liquid bidding zone, decreasing the possibilities of risk mitigation and eventually causing higher energy prices for consumers."*With regards to congestion management, there have been significant concerns raised by industry about the practice of limiting cross-border capacity to deal with internal congestion. For example, Nordenergi have said, in a public letter to the European Commission, that the *"principle that congestion needs to be managed where it occurs must be maintained as the governing rule in an internal market, and this principle does not allow for congestion to be moved to national borders in the extent and in the non-transparent manner that seems to be the case on the mentioned Nordic borders"* and that *"besides the continuous welfare losses due to curtailments of cross-border capacities, there are in addition severe long-term negative effects through inefficient investment signals to both generators, consumers and TSOs."*

4.3. Minimise investment and dispatch distortions due to transmission tariff structures

4.3.1. *Summary table*

Objective: to minimise distortions on investment and dispatch patterns created by different transmission tariffs regimes.				
	Option 0: Business as usual	**Option 1: Restrict charges on producers (G-charges)**	**Option 2: Set clearer principles for transmission charges**	**Option 3: Harmonisation transmission tariffs**
Description	This option would see the *status quo* maintained, and transmission tariffs set according to the requirements under Directive 72 and the ITC regulation. Stronger enforcement and voluntary cooperation: There is no stronger enforcement action to be taken that would alone address the objective. Voluntary cooperation would, in part, be undertaken as part of implementation of Option 2.	This option could see the prohibition of transmission charges being levied on generators based on the amount of energy they generate (energy-based G-charges)	This option would see a requirement on ACER to develop more concrete principles on the setting of transmission tariffs, along with an elaboration of exiting provisions in the electricity regulation where appropriate.	Full harmonisation of transmission tariffs.
Pros	Pros: Minimal change; likely to receive some support for not taking any action in the short-term.	Eliminating energy-based G-charges would serve to limit distortionary effects on dispatch of generation caused by transmission tariffs. Social welfare benefits of approximately EUR 8 million per year. Would impact a minority of Member States (6-8 depending on design).	Provides an opportunity to move in the right direction whilst not risking taking the wrong decisions or introducing inefficiencies because of unknowns; consistent with a phased-approach; could eliminate any potential distortions without the need to mandate particular solutions; consistent with the introduction of legally binding provisions in the future, e.g. through implementing legislation.	Minimises distortion between Member States on both investment and dispatch; creates a level-playing field.
Cons	In the longer-term, likely to be a drive to do more and maintaining the *status quo* unlikely to be attractive; risks of continued divergence in national approaches.	Social welfare benefits relatively small – could be outweighed by transitional costs in the early years. Can be considered 'incomplete' as a number of other design elements of transmission tariffs contribute to distortionary effects.	Still leaves the door open for variation in national approaches; will not resolve all potential issues.	Unlikely to a proportionate response to the issues at this stage; given the technicalities involved, it could be more appropriate to introduce such measures as implementing legislation in the future.
Most suitable option(s): Option 2 – aside from some high-level requirements, given the complexity of transmission charges, the precise modalities should be set-out as part of implementing legislation in the future if and when appropriate. The value in Option 2 will be to set the path for the longer-term.				

4.3.2. *Description of the baseline*

Tariffs are charged on demand and/or production in order to recover the costs associated with building, maintaining and operating transmission and distribution infrastructure. They can be used merely as a cost recovery tool, but also as a means to incentivise investments and behaviours. They also have the potential to have distortionary effects. In this annex, the focus is on the design of transmission tariffs, with distribution tariffs discussed further in Annex 3.3. However, there are potentially important interactions, which are touched on further below.

There are a number of decisions that regulatory authorities can take on the design of tariffs. These are summarised below:

Figure 1 – building blocks of transmission tariffs

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: Cambridge Economic Policy Associates Ltd for ACER.

The Third Package, and more specifically the Electricity Directive and Electricity Regulation, contain specific provisions for the charging of transmission tariffs. Requirements under the Directive include that tariffs, or the methodologies for calculating them, must be fixed or approved by NRAs in accordance with transparent criteria[20] and sufficiently in advance of their entry into force[21].

Article 14 of the Electricity Regulation provides further requirements, which include:

- that "[c]*harges 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;"* and
- that, "[w]*here 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."*

More specific requirements are provided for under the inter-transmission system operator compensation mechanism ("**ITC"**) regulation[22]. This regulation sets down limits on the average annual transmission charges that can be applied in each Member States to electricity producers[23]. The regulation also required ACER to provide an opinion to the Commission regarding the appropriateness of the range of charges, which it did on 15th April 2014.

In the opinion, ACER stated that it deemed it important that charges on generators ("**G-charges"**) are "*cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe."* It recommended that: G-charges based on energy produced (energy-based) should not be used to recover infrastructure costs; energy-based G-charges should be set at 0 euros/MWh, except where they are used for recovering the costs of system losses or costs relating to ancillary services. They concluded, however, that it was unnecessary to propose restrictions on charges based on connected capacity of the generation (what they term power-based charges) or fixed (lump sum) charges.

However, prior to this opinion, a report by Frontier Economics for Energy Norway, published in May 2013[24], concluded that the potential for welfare loss is significant, with effects on investment more significant than operational decisions, and strong welfare losses result from a lack of harmonisation.

Subsequently, and with the possibility existing to develop a 'network code[25]' to harmonise transmission tariffs, ACER commissioned a scoping study from Cambridge Economic Policy Associates Ltd (CEPA), which was finalised in August 2015. CEPA concluded that, whilst there are theoretical distortions introduced by different charging regimes in different Member States, the benefits of a short-term regulatory response (e.g. harmonising through

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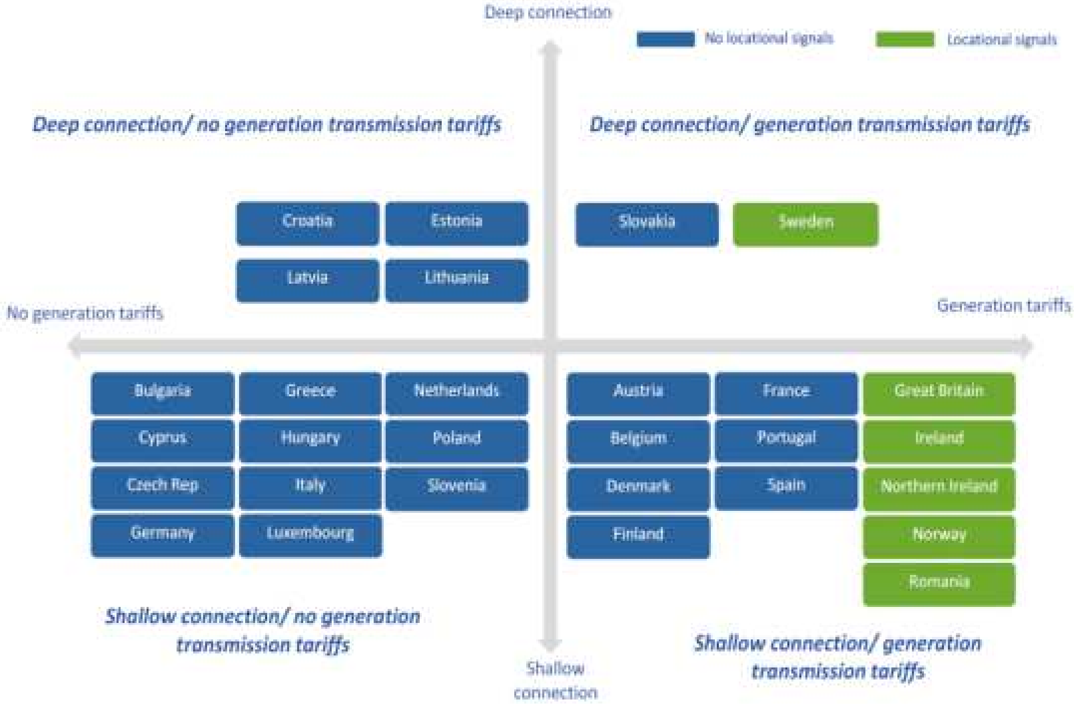
20 Art 37(1)(a)
21 Art 37(6)(a)
22 Commission Regulation (EU) No 838/210 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, *OJ L 250 24.09.2010, p5-11*
23 0-2 EUR /MWh in Romania; 0-2.5 EUREUR /MWh in UK and Ireland; 0-1.2 EUR/MWh in Denmark, Sweden and Finland; and 0-0.5 EUR/MWh in all other Member States.
24 "*Transmission tariff harmonisation supports competition"*, a report prepared for Energy Norway, May 2013
25 A Commission Regulation developed under procedures laid down in the Electricity Regulation.

a network code) were unlikely to outweigh the potential costs of change. However, they also concluded that in the longer-term, there is a stronger case for further harmonisation "*principally based on the need for greater consistency and application of "optimal" tariff structure that reflect the costs generating by market participants' decisions.*"

Figure 2 – Connection and generation tariffs in various countries



Source: Cambridge Economic Policy Associates Ltd for ACER, based on analysis of ENTSO-E data.

4.3.3. <u>Deficiencies of the current legislation</u>

As detailed above, a framework for transmission tariffs is provided for in the Electricity Directive, Electricity Regulation and in the ITC Regulation[26]. These all provide significant scope for national differences without a view on how any potential negative or distortionary impacts can be resolved. Further, the ACER recommendation has not been implemented into the ITC Regulation.

The Evaluation Report points out that *"whilst the Third Package contains provision on transmission tariffs, their level and design still differ significantly between Member States. This has the potential to distort price signals."*

4.3.4. <u>Presentation of the options</u>

Option 0 – BAU

This option would involve maintaining the *status quo*, and the provisions relating to tariffs in the Third Package and associated legislation would remain the same.

[26] Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, *OJ L 250, 24.9.2010, p. 5–11*

Option 0+: stronger enforcement and voluntary cooperation

There is no additional enforcement action to take that would address the points above.

Option 2 would entail a level of voluntary cooperation as part of its implementation – i.e. that regulatory authorities voluntarily work towards implementation of key principles developed by ACER in advance of further legally binding obligations.

Option 1 - Restrict charges on producers (G-charges)

This option would involve eliminating energy-based transmission charges that can be charged on producers (except where they are used for recovering the costs of system losses or costs relating to ancillary services), as set out in the ACER opinion. It would have an effect in the following Member States, who apply such charges[27].

- Denmark
- Finland
- France
- Portugal
- Romania
- Spain

In implementing this option, those Member States would have a choice as to how they then treat generators. They could either remove charges on generators all together, meaning that all tariffs would be charged to consumers, or they could replace them with alternative tariffs, namely ones based on the capacity or a lump-sum tariff. For the purposes of this analysis, it is assumed that these Member States continue to levy charges on generators.

Option 2 - Introduce more extensive and concrete principles on the setting of transmission charges

This option would involve giving responsibility to ACER to develop guidance addressed to national regulatory authorities, which would be developed over a time frame of 1-2 years. It would provide a basis on which NRAs could make their decisions with a view to more concrete legal measures in the future, notably though implementing legislation such as a network code or guideline. Such principles could relate to: the definition and implementation of cost-reflectivity; charges applied to consumers versus charges applied to producers; the types of costs which are to be included; locational and/or time-of-use element of charges; and principles relating to transparency and predictability. It would be accompanied by some higher-level principles in legislation, for example requiring regulatory authorities to minimise any distortions between transmission and distribution tariffs - e.g. on their impact on generators.

Option 3 - Full harmonisation

This option would not only see the process and criteria harmonised but also the components and levels of transmission charges so that the charges on load and production and comparable in each Member States. This would include the elaboration of a harmonised

[27] Excluding Austria and Belgium, who apply energy-based charges for ancillary services and/or losses

definition of cost-reflectivity, so that all Member States charge producers and/or consumers on the same basis. Further, it would ensure that costs related to ancillary services and losses are treated in the same way.

This option could be accompanied by a requirement that transmission charges include a locational element reflecting, in particular, transmission constraints within a price zone.

4.3.5. *Comparison of the options*

G-Charges

The option to remove energy-based transmission tariffs on generators has been assessed quantitatively based on ECN's COMPETES model[28]. COMPETES is a power optimisation and economic dispatch model that seeks to minimise the total power system costs of European power market whilst accounting for the technical constraints of the generation units, transmission constraints between the countries as well as transmission capacity expansion and generation capacity expansion for conventional technologies for given generation intermittency (e.g., wind, solar) and RES E penetration in EU Member States. The model also decommissions the existing conventional power plants that cannot cover their fixed costs.

In order to provide a frame of reference, three scenarios were assessed as regards the change on total system costs[29], TSO surplus[30], payments by consumers[31] and producer surplus[32] for a reference year of 2030:

- Reference case where no tariffs are charged. Implicitly, therefore, all the transmission costs are covered by congestion income and electricity prices charged to consumers - this was created for the purposes of assessing the options below, as opposed to being an option itself.
- Option 0: Reflecting the current situation with different G-tariffs per country (Euro/MWh or Euro/MW differing per country). The tariffs are taken from the ACER internal G-charges monitoring report.
- Option 1: Implementing capacity-based tariffs only in which case energy-based Euro/MWh tariffs of Option 0 are converted to Euro/MW capacity-based tariffs.

A figure for the total social welfare was calculated as {Change in TSO surplus + Change in Producer surplus - Change in Consumer payments}. The results for the total and comparison of the options are provided in table 1 and 2 respectively.

Table 1 – total values, all countries (million EUR)

	System Costs	TSO surplus	Consumer payments	Producer surplus
Reference (no tariffs)	85,082.2	2,102.3	226,821.0	138,455.7

[28] *" Transmission Tariffs and Congestion Income Po6licies",* ECN, DCision, Trinomics (Intermediate Report)

[29] Generation OPEX + Generation CAPEX + Fixed O&M + Transmission Investment

[30] G-charge payments + Congestion income - Transmission CAPEX

[31] Payments consumers make for their electricity use, i.e. electricity use (in MWh) x electricity price (in Euro/MWh)

[32] Short run profits - Gen CAPEX - G-charge payments

Option 0 (current situation)	85,094.7	3,044.6	227,617.6	138,282.9
Option 1 (cap.-based tariffs)	85,094.0	2,875.1	227,298.2	138,141.1

Table 2 – option comparison, all countries (million EUR)

	System Costs	TSO surplus	Consumer payments	Producer surplus	Social welfare
Option 0 vs Reference	12.5	942.3	796.6	-172.8	-27.1
Option 1 vs Reference	11.8	772.8	477.2	-314.6	-19.0
Option 1 vs Option 0	-0.8	-169.5	-319.4	-141.8	8.1

Moving from the current system (Option 0) would result in an increase in economic efficiency of generation dispatch and investment decisions as well as overall competition between generators. More specifically, there would be some limited effect on dispatch and investment decisions of generators in countries that have to replace energy-based by capacity-based or lump sum G-charges. On the other hand, decisions of generators in countries that currently either have no energy-based G-charges or only non-energy based G-charges in place would not be affected. Cross-border competition between generators is likely to induce regulatory competition between Member States and, as such, likely to serve as an implicit upper limit to all types of G-charges, preventing larger divergence of within the EU. However, this this does not imply that G-charges will be set to their optimal long-run cost-reflective level i.e. the level that stimulates generators and consumers to take investment and siting decisions that minimise overall system costs, which is the sum of generation, network, and societal costs. Rather it is likely that the G-charges of the largest Member States in Continental Europe become the benchmark. In the absence of incentives for multilateral coordination of country practices regarding transmission charges for generators (either regional or EU-wide), this option can therefore be considered as incomplete. As can be seen from the above, the social benefits of moving from the current system would be in the region of EUR 8 million a year – a small proportion of overall system costs. This risks being outweighed by implementation costs.

Principles for transmission charges

It is naturally more difficult to quantitatively assess the impacts of this option, as they will by-and-large depend on the precise design of such principles and the extent to which they are implemented prior to any legal mandate (e.g. from implementing legislation such as a network code). Therefore this option is assessed qualitatively.

A harmonisation of the tariff principles to better reflect the grid costs will have a positive impact on the efficiency of dispatch and investment decisions by generators. Concerning the latter, harmonised tariff principles will improve the investment climate for power generation by offering a higher predictability with regard to the expected tariff development. It will overall reduce competition distortions amongst generators, but the impact of tariff harmonisation on the competitiveness of individual generators can be positive or negative depending on the current situation.

As discussed above, there are a number of issues that need to be addressed in the design of tariff structures. These include the extent to which charges are applied to generators as compared to consumers (the Generation: Load or "G:L" split), the basis on which they are charged, the interpretation of the principle of 'cost reflectivity,' whether there are signals on location or time of use, etc. Whilst the discussion here has mostly been focused on generators and the wholesale market, a significant proportion of transmission tariffs on are charged on consumers/load – all Member States apply charges to load, with some applying all of them (15). Therefore the design of tariff structures can have a significant impact on consumers, both financially and economically, and on their behaviour. There are clearly a number of complexities which will need discussion among regulators, TSOs and stakeholders to determine the most beneficial approach.

Despite the fact that national tariff differences are only one of the drivers of current distortions of dispatch and investment decisions between Member States, the focus on cost reflectivity of transmission signals is key in an increasingly interconnected system in order to prevent negative spill-over effects.

Harmonisation

Full harmonisation would involve decisions on many of the same topics as mentioned above, but determining them in legislation immediately. It would require upfront decisions on the 'optimal' tariff structure, something that so far has not been determined with a clear articulation of the benefits. As mentioned above, there already exists a legal mechanism for harmonising tariffs – Article 8 of the Electricity Regulation already provides the ability to create implementing legislation, in the form of a network code, something that would be developed collaboratively by TSOs, regulators, ACER and stakeholders. Doing this as part of Market Design is very unlikely to elicit better results than could be achieved with the detailed and ongoing participation of experts that the development of a network code would involve. Further, flexibility would be compromised. Given the complexity and the amount of 'unknowns' there is a significant risk that any attempt to fully harmonise would result in issues that could only be identified once Member States start to implement the requirements; a network code allows for significantly more flexibility to respond to such issues if and when they arise. Requirements set out in an ordinary legislative act would prove much more difficult to adapt.

There are two sub-issues that have also been considered as part of this option: that of harmonised charges relating to ancillary services and grid losses; and locational-charging.

There is significant diversity in charging methodologies with regards to ancillary services. For instance, in most Member States, all costs for balancing services are recovered via charges on load. Only in a few Member States do generators pay grid charges that comprise a specific contribution for the cost related to balancing services[33]. With regards to grid

[33] Austria (2.81 EUR/MWh in 2015), Belgium (0.9111 EUR/MWh, which represents 50 % of the overall reservation cost for balancing services), Bulgaria (3.65 EUR/MWh to be paid only by wind and solar generators to cover the cost for balancing services), Finland (0.17 EUR/MWh), Ireland (0.3 EUR/MWh), Northern-Ireland (0.31 EUR/MWh), Norway (0.21 EUR/MWh – the costs for procuring balancing services are in Norway divided equally between generation and load) and Sweden (0.087 EUR/MWh).

losses, again most European countries recover them through charges on load, but in a few countries the related cost is partly or fully charged to generators[34].

If charges for ancillary services were to be harmonised, the impact on short-term and long-term electricity system efficiency would depend on the level of the charges and the charging modalities but may not be substantial. If charges for ancillary services were to be more correctly and transparently allocated to the market parties (generation and load) on basis of needs of the parties, market operators would contribute to minimising the overall need for such services, particularly frequency-related services, with more flexible demand and supply. It could, however, contribute to a higher cost-reflectiveness and fairer cross-border competition amongst generators as the currently diverging charging practices and cost allocation can lead to competition distortions between power generators active in the same integrated regional market.

The impact of a harmonised charging method of grid losses via a specific tariff on the short-term and long-term electricity system efficiency would be very limited. Only if grid losses are calculated and charged individually to grid users would there be a higher impact on the short and long-term system efficiency. There is, however, scope to correct competitive distortions on generators, although this will only have an impact in those few Member States where losses are (partly) charged to generators; in the large majority of Member States grid losses are entirely charged to load.

With regard to providing appropriate locational signals for investment and dispatch of generation through tariffs, clearly this can only be achieved where generators are charged tariffs (so in 12 Member States) and, with regards to the latter, only where there is energy-based charging (8 Member States). Administratively setting tariffs to affect dispatch could add significant distortions into the energy market and requiring this is not an option that is explored further. As to investment signals, i.e. making it more expensive to locate in areas of less need, and less expensive in areas of higher need, proponents would argue that it gives economic signals about where to site new generation capacity and use existing capacity, and that it reflects the costs to the transmission network that generators cause. However, opponents believe that locational charging is designed to reflect a generating mix predicated on generation close to centres of demand and not designed to encourage a fundamental shift to more mixed and geographically spread energy supply. Any concrete impact of location-based charging on economic efficiency will largely depend on the level of the fee and its form, and it is not clear that this would override other factors influencing siting (regulatory, planning, meteorological, etc.). Further, it is potentially complex to implement and could add uncertainty to generators. If price zones are formed based on structural congestion, part of an objective of Market Design (see Annex 4.2) this could anyway remove the need to introduce locational signals by other means – i.e. as the energy

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In Great Britain, the costs incurred by the TSO (NGET) in balancing the transmission system are recovered through Balancing Services Use of System (BSUoS) Charges, which are shared equally between generators and suppliers. *ACER, Internal Monitoring Report on Transmission charges paid by the electricity producers*, May 2016.

[34] Austria (0.45 EUR/MWh in 2015), Belgium (balancing responsible parties are obliged to inject, depending on the time, 1.25 or 1.35 % more than their offtake from the grid), Greece (average = 1.08 EUR/MWh based on zonal Generation Losses Factors), Ireland and Northern-Ireland (1.36 EUR/MWh), Norway (average = 0.57 EUR/MWh based on marginal loss rates which are different depending on the location and the time), Romania (0.23 EUR/MWh) and Sweden (0.40 EUR/MWh) - ACER, *Internal Monitoring Report on Transmission charges paid by the electricity producers*, (May 2016).

price would provide such signals. This is not to say that the approach is not succeeding in those countries that already employ it (e.g. GB, Sweden) or that it is definitely unsuitable for the future, but rather that the first step should be to implement appropriate defined price zones and that further, detailed consideration is needed at the regulatory level on whether and how to implement such an approach. It is, therefore, not considered an appropriate response to design or mandate its introduction as part of this legislative package.

Summary

Given the number of design features and complexities regarding transmission tariffs, and the potentially small benefits associated with harmonising the less-complex aspects individually, it is concluded that the most appropriate option is to leave any full harmonisation to future implementing legislation as part of a network code or, if appropriate, through an amendment to existing implementing legislation[35]. This will minimise disruption and implementation costs, allow the precise package to be worked up over time and with full involvement of experts, and also allow for the interactions between distribution tariffs and transmission tariffs, and their impacts on consumers and generators at both connection-levels, to be more fully reflected. Further, it will allow time to determine the most beneficial approach and tackle the most significant issues holistically. The development of principles to guide NRAs when designing tariffs regimes (Option 2) would provide the first step in this process, and facilitate early decisions and implementation prior to any legally binding instrument. As the topic falls within the regulators' field of competence, this would be appropriately led by ACER. Further, augmentation of the high-level principles in the Electricity Regulation is necessary to reflect evolution of the market since they were originally introduced, for example to avoid any discrimination between distribution-connected and transmission-connected generation when setting or approving tariffs.

4.3.6. *Subsidiarity*

Charges applied to generators in relation to their connection to, and use of, networks can be significant. Differences in these charges can therefore have an effect on decision-making, whether it is on investment locations or on dispatch of energy, and can therefore add distortions into the market. Given the highly integrated nature of EU electricity markets, this can add distortions between Member States.

EU-level action is therefore warranted, in order to ensure the minimum degree of harmonisation needed to avoid distortion in investment and generation is achieved. The Third Package already lays down a number of rules relating to these changes (notably Article 14 of the Electricity Regulation), and also requires NRAs to take an active role (under the Electricity Directive). Further provisions relating to transmission tariffs are contained in the inter-transmission system operator completion mechanism (ITC) Regulation, aimed at the issues mentioned above.

Whilst much has been achieved, there is still scope for improvement, particularly given the importance of minimising distortions to the benefit of consumers. EU-action is needed to addresses this as it needs to be coordinated across the EU.

[35] E.g. changes to G-charges could be effected by amending the ITC regulation.

4.3.7. *Stakeholders' opinions*

Stakeholder feedback suggests there is a case for change, particularly in the medium to long-term. In 2015, ACER ran an exercise looking at potential harmonisation of tariffs through the development of a network codes. This included stakeholder questionnaires (run by Cambridge Economic Policy Associated – CEPA). In their report, CEPA highlighted a number of points:

- The majority of stakeholders (79 responses) across European countries consider that the current electricity transmission tariff structures do impact on the efficient functioning of the European electricity market;
- Around 80% of respondents agreed that generators' operational and investment decisions are affected by transmission tariff structures;
- The majority of respondents also considered differences in current transmission tariff structures across Europe to be a source, or a potential source, of regulatory and market *failure* in the IEM. Differences in transmission tariff structures across European countries were identified by stakeholders as a problem today and potentially in the future, citing distortions to operational (as well as investment decisions) as a source of regulatory or market failure;
- Over 60% of respondents also agreed or strongly agreed that differences in transmission tariff structures across European countries could hamper cross-border electricity trade and/or electricity market integration. Energy-based tariffs were cited as a particular issue;
- Around 70% of respondents believed that there are benefits that can be achieved through harmonisation of transmission tariff structures. Only 7% of all respondents rejected the idea that harmonisation of transmission tariffs would be beneficial for the IEM;

Further, Eurelectric, in their market design publication[36], state that "[r]*egarding transmission tariffs applied to generators, their structure and methodologies to compute the costs need to be harmonised. Furthermore, their levels should be set as low as possible, in particular the power based charges (€/MW) which act as a fixed cost for generation and therefore distort investment decisions*."

[36] *"Electricity market design: Fit for the low carbon transition,"* Eurelectric (2016)

4.4. Congestion income spending to increase cross-border capacity

4.4.1. *Summary table*

Objective: The objective of any change should be to increase the amount of money spent on investments that maintain or increase available interconnection capacity				
	Option 0: Business as usual	**Option 1**	**Option 2**	**Option 3**
Description	This option would see the current situation maintained, i.e. that congestion income can be used for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities through network investments; and, where they cannot be efficiently used for these purposes, taken into account in the calculation of tariffs. Stronger enforcement: current rules do not allow for stronger enforcement. Voluntary cooperation: would offer no certainty that the allocation of income would change.	Further prescription on the use of congestion income, subjecting its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities (i.e. allowing it to be offset against tariffs) to harmonised rules.	Require that any income not used for (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities flows into the Energy part of CEF-E or its successor, to be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs.	Transfer the responsibility of using the revenues resulting from congestion and not spent on either (a) guaranteeing availability or (b) maintaining capacities to the European Commission. De facto all revenues are allocated to CEF-E or successor funds to manage investments which increase interconnection capacity.
Pros	Minimal disruption to the market; consumers can benefit from tariff reductions – unclear whether benefits of better channelling income towards interconnection would provide more benefits to consumers, given that it may offset (at least in part) money spent on interconnection from other sources.	More guarantee that income will be spent on projects that increase or maintain interconnection capacity and relieve the most significant bottlenecks; could provide around 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; can be linked to the PCI process.	Guarantees that income will be spent on projects that increase or maintain interconnection capacity and relieve the most important bottlenecks; could provide up to 35% extra spend; approach reflects the EU-wider benefits of electricity exchange through interconnectors; firm link with the PCI process.	Best guarantee that income will be spent on the biggest bottlenecks in the European electricity system, ensuring the best deal for European consumers in the longer run; approach reflects the EU-wider benefits of electricity exchange through interconnectors; to be linked to the PCI process.

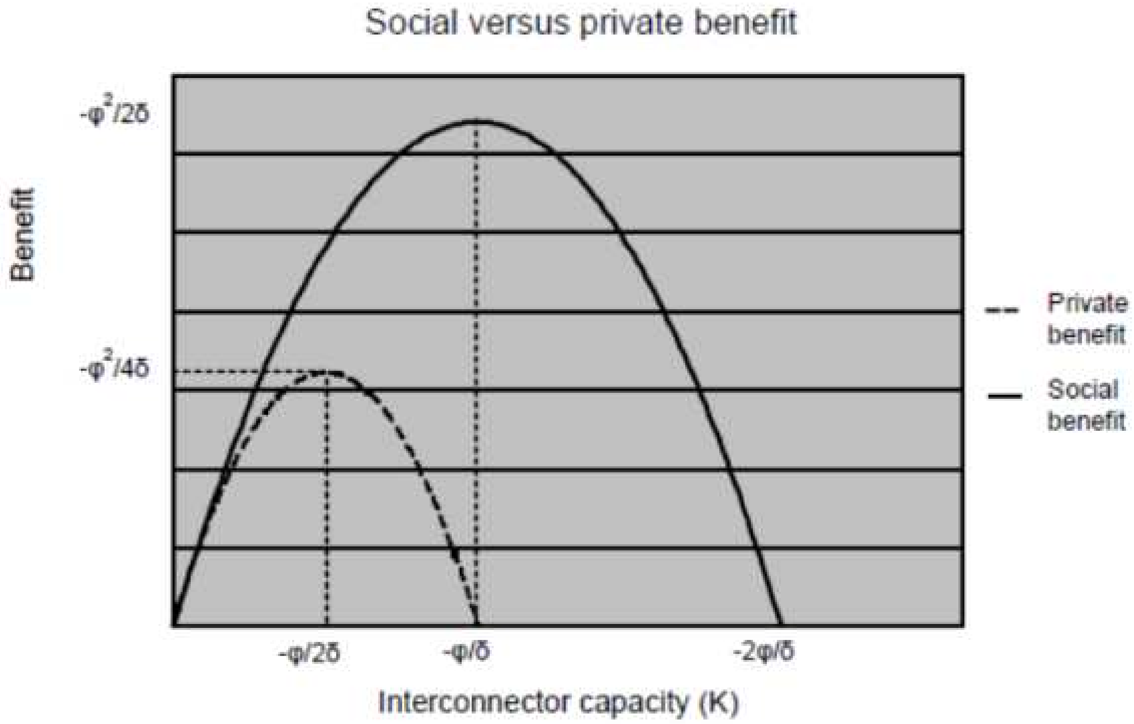
Cons	Missing a potentially significant source of income which could be spent on interconnection and removing the biggest bottlenecks in the EU.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Restricts regulators in their tariff approval process and of TSOs on congestion income spending. Could mean that congestion income accumulated from one border is spent on a different border or different Member States. Additional reporting arrangements will be necessary. Requires stronger role of ACER.	Could prove complicated to set up such an arrangement; could mean that congestion income accumulated from one border is spent on a different border or different Member States. Requires a decision to apportion generated income to where needs are highest in European system. Will face national resistance. Will require additional reporting arrangements to be put in place. Requires stronger role of ACER.
Most suitable option(s): Option 2 – provides additional funding towards project which benefit the EU internal market as a whole, while still allowing for national decision making in the first instance. Considered the most proportionate response.				

4.4.2. *Description of the baseline*

Congestion[37] income arises across an interconnection due to price differences on each side of it. Such effects happen between price areas (i.e. bidding zones), as opposed to between Member States. The higher the price difference, the greater the income generated. Conversely, the greater the levels of interconnection, the more arbitrage opportunities and, therefore, the lower the price differences each side. Congestion income per MW is therefore lower.

The issue of optimising interconnection capacity from a private versus social cost-benefit perspective has been analysed, among others, by De Jong and Hakvoort (2006; see also De Jong, 2009).[38] They show that, under certain assumptions (two-node network with perfect competition and linear supply and demand curves), the capacity that maximises social benefits is twice the capacity that maximises private benefits. This relationship changes a bit, however, when investment costs are also taken into account. In that case, De Jong and Hakvoort show that the interconnection capacity that maximises social value exceeds the capacity that maximises private profits by even more than a factor of two.

Figure 1 - Optimum interconnection capacity from a social versus private benefit perspective



[37] The term 'congestion' means a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the national transmission systems concerned.

[38] De Jong, H., and R. Hakvoort (2006), *Interconnection Investment in Europe – Optimizing capacity from a private or a public perspective ?,* in : Proceedings of Energex 2006, the 11th international energy conference and exhibition, 12-15 June 2006, Stavanger, Norway, pp. 1-8. De Jong, H. (2009), *Towards a single European electricity market – A structural approach to regulatory mode decision-making,* Ph.D.-thesis, Technical University Delft, the Netherlands.

Source: De Jong (2009), p. 261 (see also De Jong & Hakvoort, 2006))

Congestion income from interconnection capacity is a major source of revenues for TSOs' investment in network expansion. Therefore, in theory, TSOs will invest in new interconnection capacity as long as the congestion income outweighs the investment and operational costs (including a reasonable rate of return) and the potential decrease of congestion income on existing cross zonal interconnectors in the case that the new interconnector serves as a substitute to existing interconnectors. From a social point of view, this may result in underinvestment in interconnection capacity and, hence, in a sub-optimal level of cross-border transmission capacity.

Partly to address this, Article 16 of the Electricity Regulation seeks to restrict how congestion income can be used[39]. Specifically, it only allows it to be used to:

1. guarantee the availability of allocated interconnection capacity;
2. maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors;
3. to be offset against network tariffs; or
4. held on account until it can be spent on one of the above.

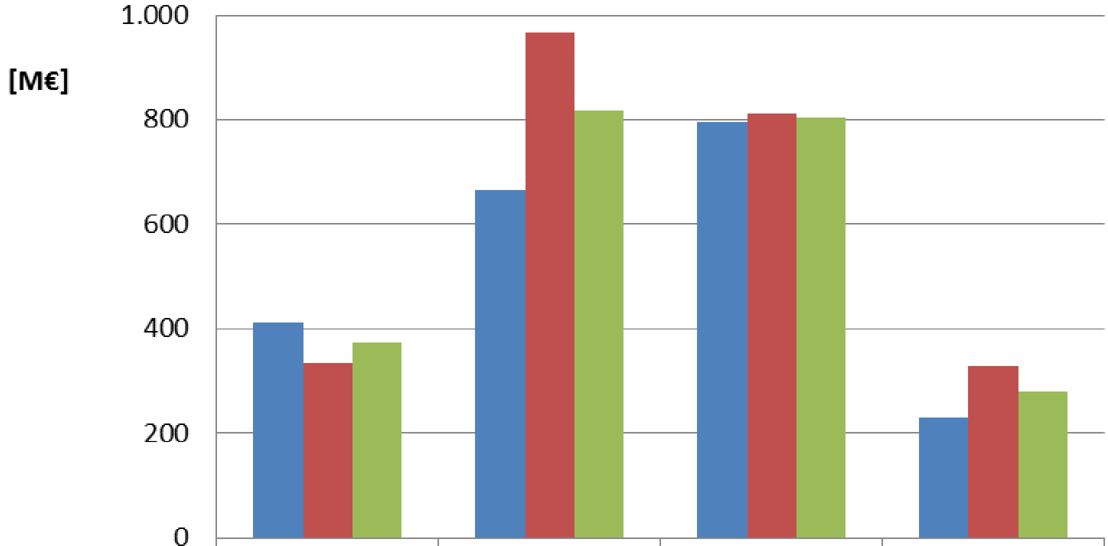
According to data from ENTSO-E, the total amount of TSO net revenues from congestion management on interconnections was EUR 2.3 billion in 2014 and EUR 2.6 billion in 2015. Figure 2 presents the spending of congestion revenues in 2014-15 aggregated for all members of ENTSO-E, both in million EUR and as a % of total annual revenues. These revenues amounted to, on average, EUR 2.275 million per annum in 2014-2015. Figure 2 shows that out of this amount, on average, EUR 374 million was spent on capacity guarantees (16%), EUR 817 million on capacity investments (36%), EUR 804 million on reducing transmission tariffs (35%) and EUR 280 million saved on an account (12%). This implies that, on average, about half of the congestion revenues in 2014-15 were used to guarantee, maintain or increase interconnection capacity and, hence, that – in principle – there is room for increasing this share by alternative Options.

It should be noted, however, that changing the rules on spending of congestion income may not by itself be sufficient to stimulate investment in relieving the biggest bottlenecks in the EU. There are a number of reasons why investment in interconnection capacity might not be forthcoming: they are complex projects with a number of socio-economic impacts, and often face barriers relating to, for example, planning; the decisions are complex, and often require the involvement of two or more parties; additional investments may be needed in national networks in order to accommodate new capacity. Further, TSOs are able to cover the investment and operational costs of interconnectors – which are approved by their NRAs – not only from congestion revenues but also, or even exclusively, from regulated transmission tariffs. Therefore, there is theoretically already a source of funding for such projects, although in practice the regulated tariff system may be considered too restrictive for socially optimal investments in interconnection capacity, for instance because certain costs may not be approved to be part of the regulated cost base, or because

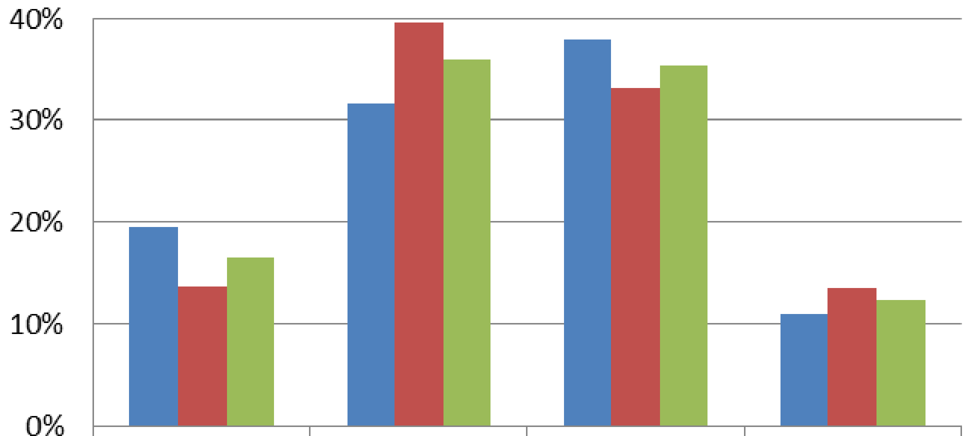
[39] In the case of new interconnectors, exemptions can be given to these requirements subject to a number of conditions being fulfilled.

the allowed rate of return may be considered too low to cover the risks, uncertainties or other challenges involved.

Figure 2- Spending of congestion revenues in 2014-15 (in million EUR and as % of total annual revenues for all countries)



	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
2014	412	666	797	230
2015	336	968	812	330
Av. 2014-15	374	817	804	280



	Capacity guarantees	Capacity investments	Transmission tariffs	Saved on account
2014	20%	32%	38%	11%
2015	14%	40%	33%	13%
Av. 2014-15	16%	36%	35%	12%

Source: ENTSO-E (2014-15)

4.4.3. *Deficiencies of the current legislation*

Current legislation is not providing for sufficient investments in bottlenecks within the European electricity system. Whilst, as highlighted above, this is unlikely to be due, at least solely, to how congestion income is spent, there is clearly scope for significantly more funding to be directed toward this ends from congestion income. As demonstrated from the above figures, the amount spent on increasing or maintaining interconnection capacity is less than half of the available funds. Further, despite existing bottlenecks and interconnection levels well below the optimum ones, the legislation offers incentives to NRAs to retain congestions, as the income they generate can be used to lower national tariffs. There are also significant deficiencies in transparency with regards to the spending of congestion income. Whilst current legislation contains obligations relating to transparency, this is ineffective in practice and it proves difficult to assess how the provisions of Article 16 are being applied. For example, it is unclear:

- how the TSOs decide on the use of congestion revenues for either guaranteeing, maintaining or increasing interconnection capacity;
- whether and how the NRAs check (i) that TSOs have used congestion revenues efficiently for either guaranteeing, maintaining or increasing interconnection capacity, and (ii) that the rest of the revenues cannot be efficiently used for these purposes;
- on which criteria the NRA decides on the maximum amount used as income to be taken into account when approving or fixing network tariffs;
- how the congestion revenues are used during the period they are put on a separate account;
- the projects towards which the funds are being allocated, including the split between investments towards capacity maintenance and capacity increases.

The Evaluation Report points out that "*another problem is the lack of adequate and efficient investment in electricity infrastructure to support the development of cross-border trade. ACER's recent monitoring report and other reports on the EU regulatory framework stress that the incentives to build new interconnections are still not optimal. In the current regulatory framework, TSOs earn money from so-called congestion rents. If TSOs reduce congestion between two countries, their revenues will therefore decrease. The Third Package has identified this dilemma and addressed through obliging TSOs to use congestion rents either for investments in new interconnection or to lower network tariffs. Experience with this rule has, however, shown that most TSOs prefer to use congestion rents to lower their tariff to investing into new interconnectors.*"

4.4.4. *Presentation of new measures/options*

Option 0 – Do nothing.

This would maintain the *status quo*, i.e. rules on spending covered by Article 16 of the Electricity Regulation. The methodology currently being developed under the Capacity Allocation and Congestion Management regulation (CACM) would provide the main rules on how the income is allocated between TSOs on each border.

Option 0+: Non-regulatory approach

Stronger enforcement of existing rules will not allow an improvement of the current situation.

Voluntary cooperation will provide no certainty that there will be a change in the current allocation of congestion income. Given there are already rules in place, a change to these rules is needed to address the issue.

Option 1 – Harmonised use of congestion income

The first option would maintain all the options for the use of congestion income as already provided for in the regulation, but be more prescriptive about when it can be taken into account in the calculation/reduction of network tariffs. More specifically, it would require that its use on anything other than (a) guaranteeing the actual availability of allocated capacity or (b) maintaining or increasing interconnection capacities be subject to harmonised rules developed by ACER.

These rules would clearly define the situation when, and when not, the alternative options could be pursued. Indicatively, the possibility to decrease the network tariff through congestion income would be allowed only when there is clear and justified evidence, according to the ACER rules, that there are no cost-effective projects that would be more beneficial for social welfare than tariff reduction. Rules would also detail how long/which revenues could be kept in internal accounts until they can be effectively spent for the above purposes.

This option would be combined with more transparency and additional rules for publication and monitoring of this spending.

Option 2 – Harmonised use of congestion income with basic CEF option

The second option would, similarly, restrict spending to (a) guaranteeing availability or (b) maintaining or increasing interconnection capacities. If the income cannot be effectively used on (a) or (b), it would flow into the Connecting Europe Facility for Energy (CEF-E) or its successor, and be spent on relieving the biggest bottlenecks in the European electricity system, as evidenced by mature PCIs. Unlike Option 1, there would be no option to use the income when calculating tariffs until such time that all the biggest bottlenecks have been removed (which practically will not happen in the foreseeable future).

This option would, similarly to Option 1, include harmonised compliance rules to be set out and monitored by ACER, and combined with more transparency.

Under this option, it is possible that congestion revenues that would normally be used to lower the national network tariff accrued in one Member State will be spent in another Member State allowing spending on those projects that would bring the greatest benefits to the EU as a whole.

Option 3 – Harmonised use of congestion income with full CEF option

The third option is an extension of the second. TSOs would, at the national level, be permitted to use income for (a) guaranteeing the actual availability of allocated capacity or (b) maintaining interconnection capacities. However, they would not be permitted to use it to *increase* interconnection capacity, and neither could it be used against tariffs.

Instead, all income not spent on (a) and (b) above would be directed to the European Commission, *de facto* to the CEF-E or successor funds, to manage interconnection capacity. This way, the revenues that, up to now can be used by TSOs/NRAs for increasing capacity or lowering network tariffs, would be spent on the biggest bottlenecks in the European electricity system as evidenced by mature PCIs. Again, as with Option 2, if and when all these are removed, income could then be taken into account when calculating tariffs.

This option would, similarly to Option 1, include harmonised compliance rules to be set out and monitored by ACER, and combined with more transparency.

Again, under this option it is possible that congestion revenues accrued in one Member State will be spent in another Member State allowing spending on those projects that would bring the greatest benefits to the EU as a whole.

4.4.5. Comparison of the options

The options have been compared against the following criteria:

- Effectivity. Effectivity implies that, as much as possible, congestion income is used to maximise the amount of cross-border capacity available to market participants. The criterion assesses whether and to what extent the Options achieve this objective;
- Efficiency. Efficient use of congestion income means that the procedure for the spending of congestion income provides a simple and straightforward approach to guaranteeing that congestion income is used for maintaining or increasing the interconnection capacity;
- Transparency. The spending of congestion income should be transparent and auditable;
- Robustness. The spending rules should be set in such a way to avoid influence over the rules beyond what it envisaged;
- Predictability. The spending rules should allow a forecast of the financial outcome and allow for reasonable financial planning by the TSOs involved;
- Proportionality. Congestion income policy options should be commensurate with the problem i.e. not going beyond what is necessary to achieve the objectives, limited to those aspects that Member States cannot achieve satisfactorily on their own, and minimise costs for all actors involved in relation to the objective to be achieved;
- Smoothness of transition. The current congestion income spending should not be changed in a radical way in the short-term in order to limit the financial impact on all system participants.

Effectivity

With respect to the effectivity of the policy options, all three positively contribute in more or less the same manner. Currently, congestion income may be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs. In all three options this type of usage will be strongly restricted or forbidden causing a larger share of the congestion income to be allocated to maintaining and/or increasing cross-border capacity. However, for the actual construction of these links, there may be additional barriers like the licensing procedures for the new corridors, so the availability of more financial resources may not in all cases guarantee interconnection expansion.

Efficiency

Currently, TSOs and NRAs have the possibility to allocate the congestion revenues in the most economically efficient manner. However, due to flexibility at the national-level it cannot be guaranteed that congestion income will always be spent on maintaining and/or increasing the available interconnection capacity. In each of the three options the level of freedom for TSOs and NRAs to decide otherwise will be significantly reduced.

Since in Option 2 congestion income for investments are managed at a European level, whereas the operational measures to guarantee or maintain the interconnection capacity are dealt with nationally, this Option might be less effective than the other two. Furthermore, there is some possibility that Member States prefer to withhold funds from being transferred to a European institution by previous spending on operational measures.

Transparency

There are currently reporting obligations for the TSO on the spending of congestion income. It is nonetheless not entirely clear, which criteria are applied for allocating congestion income to operational measures, investments in capacity expansion or inclusion in the transmission tariffs. It is expected that each of the three options will increase the transparency of the allocation and spending of congestion income.

Robustness

The present methodology for spending congestion income is monitored by the NRAs whereas the revenues themselves are ring fenced. There is not much room to spend the income for other purposes than that envisaged. Each of the three Options further narrows down the discretion of TSOs and NRAs. In each Option a larger share of congestion income will be used for investments, since decision making is either more heavily regulated or transferred to the European level.

Predictability

Currently, it is not clear how congestion income will be spent. It does not only depend on the operational costs needed to guarantee the cross-border capacity, but also to the discretion of the TSOs (and the approval of the NRAs) in deciding how to spend the income. Each of the three Options contributes to a better predictability. However, the first option leaves more freedom to Member States to decide on new investments than the other two options, under which the income is added to the CEF-E funds, which are only used for PCI investment projects. In the latter case the predictability of the manner of spending is very good.

With respect to spending congestion income on operational matters, clearer rules will contribute to higher transparency on the amount of funds needed for it. This will materialise in all three options.

Proportionality

If the objective of the policy options is to enhance the actual availability of the interconnection capacity by relieving the financial constraint, each option that effectively increases the financing of investments can be considered as proportional. With respect to the implementation differences between the three options, it is debatable which measure is more (or less) proportional than the other: adding detailing regulation (as in Option 1) or shifting decision making power from the national to the European level (as in Options 2 and 3).

Smoothness of transition

The smoothness of transition is assessed with respect to the amount of change involved when implementing each Option with reference to the current situation. The implementation of additional regulation does not significantly change the present powers of TSOs and NRAs, which is why Option 1 is positive with respect to smoothness of transition.

For Options 2 and 3 decision making on new investments and operational measures for maintaining the interconnection capacity shifts to the European level, which will have a larger impact. It is possible that there will be objections to such a change, especially the third option where more congestion income is managed on this level.

Summary

Overall, do nothing is not considered an appropriate response, as it does not address the deficiencies in the current legislation. Changing the current arrangements will not only increase the incentives on TSOs, but also on Member States and NRAs – i.e. there is a sum of money that must be spent on interconnection in some form. Whilst tariffs can always be used to fund such developments, there are counter-incentives, i.e. to keep tariffs lower by limiting development to that which is strictly necessary as opposed to being of longer-term benefit and of benefit to the EU internal market as a whole.

Option 1 is the least change, and the most flexible. However, due to this flexibility it is also the option which could see the least amount of money redirected from being used when calculating tariffs or from internal accounts towards projects that increase interconnection capacity. Option 3 would be a significant change and takes away all national-level decision-making on new investment using congestion income. This may be less proportionate than allowing some national autonomy, at least in the first instance if it achieves broadly the same ends. Option 2 would see the same financial potential for new network investments that increase interconnection capacity – i.e. up to EUR 1.14 billion per annum. It is therefore considered the most proportionate response to achieve the ends sought.

4.4.6. <u>Subsidiarity</u>

The use of congestion income by TSOs has already been addressed at EU-level as part of the Third Package. The issue is very much one of a cross-border nature, as the majority of congestion income is raised on infrastructure that crosses Member State borders. A common approach across the EU is necessary to ensure a level-playing field between Member States and leaving the issue at national, or bi-lateral, level risks inconsistent application.

35% of congestion income was used on average over 2014 and 2015 to reduce tariffs, despite the increase of cross-border trade in electricity between most EU Member States and the growing need to strengthen the physical connection of electricity markets. Also, maintaining grid stability becomes more challenging as increasing shares of variable renewables enter the energy mix; higher interconnection levels could decrease the necessity for redispatch and lead to lower network tariffs. These issues, given their cross-border impacts, can only be dealt with at an EU-level.

Given that the most common use of congestion income does not seem to address the current needs of grid development and maintenance, further EU action is necessary to ensure that there is an increase of the proportion of congestion income spent on maintaining or increasing interconnection.

4.4.7. *Stakeholders' opinions*

Whilst there was not a specific question in the energy market design consultation on congestion income, and many respondents did not comment on the issue, some did express views. For example, comments included:

> *"... It should be a common European interest to reduce or remove permanent bottlenecks between countries within the EU. Primarily it should be done by using the congestion incomes for investments instead of simply managing the congested transmission lines. There is no need for separate capacity pricing for the energy only markets."*

> *"At the moment, income from congestion management shall be used to mitigate the bottleneck or decrease the end user tariffs. However clear mechanism for setting up the financing of the new projects shall be in place (including needed change in accounting standards and income tax rules). With the new investment the respective bottleneck is dismissed and there is no further income from congestion management. This makes the return on investment impossible."*

> *"According to the Communication it is essential to achieve the previously established target value of 10% for the interconnection of electricity networks, and its increase to 15%. To this end, the current effective EU regulation provides adequate support. At the same time, according to the Commission's concept the utilisation of fees currently charged for congestion management should be regulated in a manner which would facilitate the development of the electricity system. We would be in a position to support this concept if there is guarantee that once the target value has been achieved by a Member State the revenues could still be used for other purposes as well (e.g. tariff cuts)."*

> *"...funds* [for cross-border redispatching] *could come from congestion rents which are not possible to be attached to a border anymore in a flow-based world. This common TSO income should be spent commonly on costly coordinated actions."*

5. Detailed measures assessed under Problem Area II, Option 2(2) (improved energy markets - CMs only when needed, based on common EU-wide adequacy assessment (and Option 2(3) (Improved energy market, CMs only when needed based on common EU-wide adequacy assessment, plus cross-border participation)

5.1. Improved resource adequacy methodology

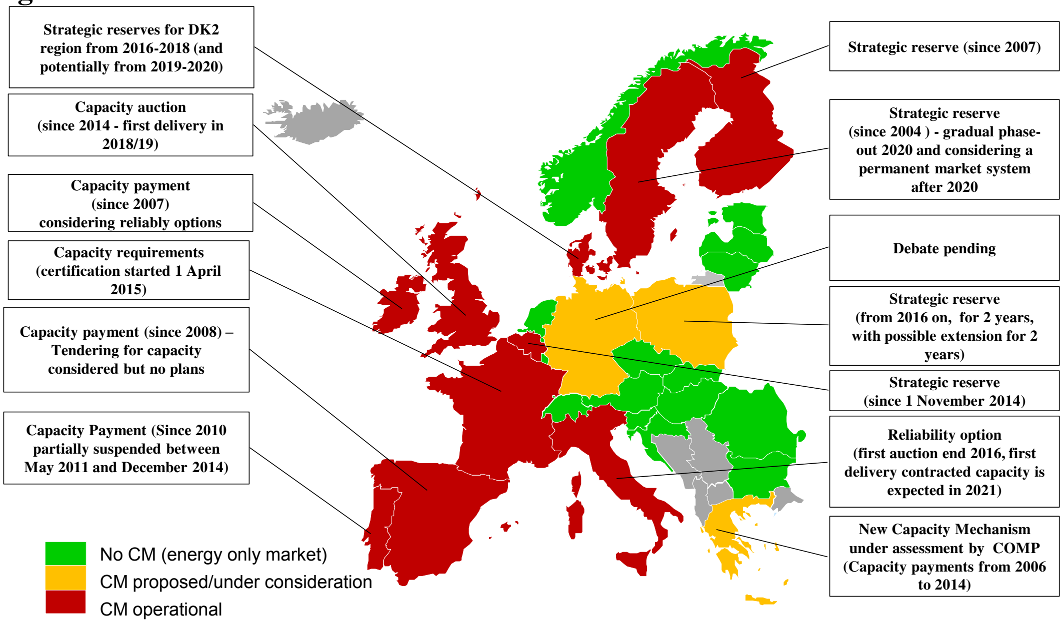
5.1.1. *Summary table*

	Option 0	Option 1	Option 2	Option 3
Objective: Pan-European resource adequacy assessments				
Description	Do nothing. National decision makers would continue to rely on purely national resource adequacy assessments which might inadequately take account of cross-border interdependencies. Due to different national methodologies, national assessments are difficult to compare.	Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs.	Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring Member States to exclusively rely on it when arguing for CMs.
Pros	Stronger enforcement: Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for Capacity Mechanisms (CMs).	National resource adequacy assessments would become more comparable.	In addition to benefits in Option 1, it would make it easier to embark on the single methodology.	In addition to benefits in Options 1 & 2, it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. Results are more consistent and comparable as one entity (ENTSO-E) is running the same model for each country.
Cons		Even in the presence of harmonised methodologies national assessment would not be able to provide a regional or EU picture.	Even in the presence of a single methodology, national assessments would not be able to provide a regional or EU picture. National TSOs might be overcautious and not take appropriately cross-border interdependencies into account. Difficult to coordinate the work as the EU has 30+ TSOs.	It would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work.
Most suitable option(s): Option 3 - this approach assesses best the capacity needs for resource adequacy and hence allows the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.				

5.1.2. *Description of the baseline*

Based on perceived or real resource adequacy concerns[40], several Member States have recently introduced resource adequacy measures. These measures often take the form of either dedicated generation assets kept in reserve or a system of market wide payments to generators for availability when needed (Capacity mechanisms or 'CM's).

Figure 1: CMs in the EU



Source: ACER 2015 Monitoring report

National resource adequacy assessments

To determine whether these concerns require the introduction of a CM, Member States[41] first need to carry out an assessment of the adequacy situation. Indeed, all Member States that are part of DG COMP's Sector Inquiry on Capacity Mechanisms measure the security of supply situation in their country by carrying out an adequacy assessment in which one or more methodologies are applied that give an indication of the potential of the generation fleet to meet demand in the system at all times and under varying scenarios.

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40 The sector inquiry has shown that a clear majority of public authorities expect reliability problems in the future even though today such problems have been extremely rare in the past five years. In nine out of ten Member States, no such problems have occurred at all. The only exception is Italy, where such issues have arisen on the islands of Sardinia and Sicily which are not well connected to the grid on the mainland. Although the Member States do not experience reliability issues at present, many Member States are of the opinion that reliability problems are expected to arise in the coming five years.

41 In most countries, TSOs are the responsible bodies for monitoring and reporting on long-term resource adequacy. Other responsible institutions are NRAs or governments In the UK, the medium and long term resource adequacy assessments are carried out by the NRA and government respectively. In Estonia, the long term monitoring is managed by the government.

The methodologies are however rarely comparable across Member States. Methods vary significantly, for instance when it comes to the question whether to take into account generation from other countries, but also regarding the scenarios and underlying assumptions[42].

The Council of European Energy Regulators (CEER)[43] performed a survey over European countries showing that security of supply is dealt with at national level through quite different approaches:

- Assessing resource adequacy requires the definition of one or more **scenarios** that can affect generation and demand projections. These scenarios are elaborated according to different assumptions about load (typically high vs. low demand scenario), and type and amount of future installed capacity (e.g. conservative or baseline vs. high RES penetration scenario). Regarding the scenarios[44] used in the different Member States, the methodologies differ greatly depending on the targeted timeframe[45] and the majority of them do not seem to be consistent throughout most of the national resource adequacy assessments.

- Regarding **load forecast**, Member States base their projections on historical load curves, with assumptions on the evolution of specific parameters. The most exploited parameters are economic growth, temperature, policy, demography and energy efficiency. The extent to which types of consumers are grouped to appraise carefully different consumption patterns can be very different[46]. Moreover demand response is largely not included as a separate factor in load forecast methodologies, even though it may appear that it is indirectly included in the projections through the effects it has had on the historical load curves[47].

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42 JRC (2016), "Generation adequacy methodologies review"

43 CEER (2014), *"Assessment of electricity generation adequacy in European countries"*

44 In at least 6 countries (including Sweden, Romania, Malta, Finland and Norway) resource adequacy is assessed against a single pre-defined baseline scenario. For the other cases (UK, France, the Netherlands, Estonia, Hungary, Lithuania, Belgium, Spain, Ireland and Italy), several possible scenarios are considered on the basis of different assumptions about load as well as type and amount of future installed capacity, such as a conservative scenario, a baseline scenario a RES penetration scenario, for example.

45 In at least 9 countries (France, Estonia, Malta, Hungary Lithuania, Belgium, Spain, Ireland and Italy) the scenarios are compounded taking as a reference the short, medium and long-term horizons. In the Netherlands and Finland, the long term is not considered, while in Sweden and Norway only the short-term is taken into account. In Denmark, only the long-term scenario is considered. In the Czech Republic and Switzerland, the only scenario considered is the very long term, while in Spain the latter scenario completes the short, medium and long-term analyses. Finally, in Romania, no short-term analysis is performed (only mid and long-term scenarios are considered).

46 In 10 national resource adequacy reports (the UK, France, Norway, Malta, Czech Republic, Hungary, Lithuania, Ireland, Austria and Italy) more than one category of consumers (e.g. residential, industrial, commercial, agriculture, etc.) serve as a basis for the forecasts; while in 4 reports (the Netherlands, Estonia, Belgium and Sweden), load only is forecasted at an aggregate level.

47 Only 3 countries include demand response as a separate factor in their load forecast methodology i.e. the UK, France and Spain. In Norway and Finland, the contribution from demand response is not included as separate factor, but peak load estimation is based on actual load curves which include the

- Regarding **generation forecast**, the most important inputs are the information received by those intending to build new generation and rules on how to consider existing infrastructure. All Member States take projected investments into account, sometimes with very heterogeneous sources and assumptions[48]. In addition, there are also various ways generation from variable output (i.e. intermittent RES) is modelled[49]; from no consideration at all, to precise hourly estimations based on sophisticated data. It is commonly agreed that there is a need to improve methodologies to better address how variable output impacts adequacy.

- With an increasing proportion of variable renewable resources, electricity systems have become more complex. To address this increased complexity, some Member States have replaced relatively simple, 'deterministic' assessment metrics[50] – which simply compare the sum of all nameplate generation capacities with the peak demand in a single one-off moment – by more complex **'probabilistic'**[51] **models**, which are able to take into account a wide range of variables and their behaviour under multiple scenarios. This includes not only state of the art weather forecasts, but also factors in less predictable capacity sources such as the contribution from

effect of demand response. Sweden does not consider demand response, and do not assume that consumers respond to peak load in their analysis.

48 For instance, decommissioning (and mothballing) of investments is not systematically taken into account. Most collected data come from generators, partly directly via the TSOs.

49 Some countries (Estonia, Romania, Malta and Denmark) still go with the approach of unavailable capacity while there are also others like the Netherlands, Norway, Spain and Sweden, which take a certain percentage as available generation. On the contrary, France and the UK go up to detailed modelling based on climate data, hub heights (for offshore wind farms) and detailed coordinates for the generation sites.

50 One of the simplest measures to determine the level of resource adequacy is the capacity margin. This deterministic methodology simply expresses the relation between peak demand in the electricity system and the total available supply, usually as a percentage. In only two of the eleven Member States analysed in the sector inquiry, this relatively simple capacity margin is calculated. For instance in 2016, France had 104,480 MW of production installed capacity whereas peak demand during winter 2015/2016 was 84,700 MW; from that, one could say that France has approximately a 23% capacity margin (RTE figures). Of course, no form of generation can always output its full nameplate capacity with 100% reliability. Therefore, each source of input needs to apply a de-rating factor in order to reflect its likeliness to be technically available to generate at times of peak demand (e.g. in Ofgem's electricity capacity assessment, a combined cycled gas plant is assumed to be available 85% of the time). In 2014, CEER found that 6 Member States were using de-rated capacity margins: Estonia, Malta, Hungary, Belgium, Spain and Sweden.

51 Around half of the Member States of the sector inquiry carry out a 'probabilistic' calculation that can be either expressed in LOLP, LOLE or EENS: (i) Loss of load probability (LOLP) quantifies the probability of a given level of unmet demand at any particular point in time; (ii) Loss of load expectation (LOLE) sets out the expected number of hours or days in a year during which some customer disconnection is expected. For instance, French TSO RTE expects some customer disconnection to happen during 1h45 over winter 2016-2017; (iii) Expected energy non served (EENS) measures the total shortfall in capacity that occurs at the time when there are disconnections. EENS makes it possible to monetise where VoLL has also been calculated.

demand response, interconnectors or renewable energy sources. Nonetheless, these adequacy methodologies[52] still differ (deterministic vs. stochastic).

- Despite on-going developments, some assessments are still considering isolated systems and/or developing ways to include interconnectors[53]. Others use non-harmonised methodologies to consider cross-border capacity, with no cross-border coordination foreseen. The availability of interconnection capacity is mostly based on historical data (export and import flows during various periods of time) and to lesser extent, on estimated data (e.g. market component such as future prices estimations). Generation and load data correlations at supranational levels are rarely considered[54], and for country-wide modelling, the "copperplate approach" prevails[55].

- It should be noted that monitoring and assessing resource adequacy is a very complex process which requires defining robust concepts, criteria and procedures in order to give a reference tool to decision-making bodies if problem are encountered. In almost all EU countries, the body responsible for ultimately ensuring resource adequacy is the national government. However, monitoring responsibilities are usually shared among the TSO, the NRA and the government. These responsibilities can evolve depending on the timeframe considered. For the medium and long-term timeframes, TSOs are the responsible bodies for monitoring and reporting in most Member States. Other responsible institutions are NRAs or governments[56]. In most cases, the assessment is carried out yearly.

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52 Half of the national studies are based on a 'probabilistic' approach (the UK, France, the Netherlands, Finland, Romania, the Czech Republic, Lithuania, Belgium, Ireland, Italy) while six of them are based on a deterministic approach (Estonia, Malta, Hungary, Belgium, Spain and Sweden). Denmark uses a deterministic approach, but takes into account the outage percentage of power plants which is based on both historical observations and Monte Carlo simulations.

53 The extent to which current resource adequacy reports take the benefits of interconnectors into account varies a lot: 4 reports still model an isolated system (Norway, Estonia, Romania, and Sweden); 2 reports use both interconnected and isolated modelling (France and Belgium); 3 report methodologies are being modified to include an interconnection modelling; 9 reports simulate an interconnected system (UK, the Netherlands, Czech republic, Lithuania, Finland, Belgium and Ireland, while France and Italy use both methods).

54 It is not obvious that national resource adequacy reports generally take interactions between generation and demand profiles into account. Moreover, it seems that most reports do not consider correlated data, which could be done (for example with the use of a common correlated climate database at regional level, or a common methodology for load sensitivity to temperatures). One direct consequence is that most reports do not intend to identify the impact on security of supply of potential simultaneous severe conditions in different electricity systems.

55 In the process of assessing resource adequacy, transmission and distribution networks can be modelled in a very different manner, from a highly realistic description of the technical parameters which constrain the power flows in the system, to a simplified modelling where these networks are considered as a copperplate grid. Some systems are said not to be subject to structural internal congestions (including France and Romania).

56 In the UK, the medium and long term resource adequacy assessments are carried out by the NRA and government respectively. In Estonia, the long term monitoring is managed by the government.

Table 1: Deterministic vs probabilistic approaches to adequacy assessments

Adequacy Assessments							
Country	Y/N	Who?	What?	Country	Y/N	Who?	What?
Belgium	Y	TSO	Probabilistic assessment based on LOLE	Italy	Y	TSO	EENS, LOLE, LOLP and Capacity Margin are calculated
Denmark	Y	TSO	EENS, LOLE and LOLP	Poland	Y	TSO	Capacity Margin
France	Y	TSO	LOLE	Portugal	Y	TSO + Gov	Load Supply Index (supply/demand per hour)
Germany	Y	TSOs + NRA	Calculation of EENS, LOLE, LOLP and Capacity Margin	Spain	Y	TSO	Capacity Margin
Ireland	Y	TSOs + NRA	Probabilistic assessment based primarily on LOLE	Sweden	Y	TSO	EENS, LOLE and LOLP are measured

Source: European Commission based on replies to sector inquiry, see below for a description of capacity margin, LOLP, LOLE, and EENS

ENTSO-E carries out an EU-wide resource adequacy assessments

In addition to resource adequacy assessments carried out by Member States, there are also EU level rules foreseen by the Third Package (the Electricity Regulation) requiring ENTSO-E to carry out a medium and long-term resource adequacy assessment (so-called, Scenario Outlook and Adequacy Forecast or SO&AF) in order to provide stakeholders and decision makers with a tool to base their investments and policy decisions.

ENTSO-E is currently moving from a deterministic approach to a probabilistic approach (sequential Monte-Carlo). This evolution will be done progressively and is expected to be completely implemented by 2018. The first steps of the new methodology were carried out in the latest published report so-called SO&AF 2015.

The ENTSO-E SO&AF 2015 presents the following characteristics/ limitations[57]:

- ENTSO-E uses a deterministic assessment which calculates for each country deterministic security of supply indicators (namely 'remaining capacity' and 'adequacy reference margin') only at particular points in time (the 3rd Wednesday of each month on the 19th hour in the pan-European assessment or at national peak load time in the national assessments). The report presents results for the mid-term and long-term timeframes (5-year and 10 years ahead, respectively)[58].

- Regarding load forecast, there is no explicit modelling of demand-side response in the SO&AF 2015 but is expected to be taken into account from 2017 onwards.

- Regarding generation forecast, the analysis is based on two different scenarios for generation (conservative and best estimate). The conservative scenario considers only new capacity if it is considered as certain and for the decommissioning, it considers the official notifications but also additional criteria as for example,

[57] JRC Science for Policy Report (2016), *"Generation adequacy methodologies review"*

[58] Since 2011, ENTSO-E performs a SO&AF annually, with a time horizon of 15 years until SO&AF 2014 and 10 years in SO&AF 2015.

technical lifetime of generators (additional criteria which are not considered in the best estimate scenario). RES (wind and solar PV) are taken into account for the first time in the SO&AF 2015 assessment by estimating their load factor (with a Pan-European Climate database of 14 climatic years).

- Regarding interconnection, the ENTSO-E SO&AF 2015 assessment only considers import and export capacities for each country. There is no explicit modelling of flow-based market coupling.

Voluntary initiatives to carry out regional resource adequacy assessments

Some Member States have voluntarily decided to cooperate and deliver a regional resource adequacy assessment. This is the case of the seven TSOs in the Pentalateral Energy Forum[59] ('PLEF') who have decided to move away from country specific point in time assessments to an integrated chronological probabilistic assessment. The new methodology is based on harmonised and detailed input data to capture the main contingencies[60] susceptible of threatening security of supply. This voluntary approach developed by the PLEF TSOs is currently used as a test-lab for upgrading the ENTSO-E methodology.

Table 2: PLEF vs ENTSO-E approaches to adequacy assessments

	PLEF	ENTSO-E	
		Current	Targeted
Approach	Probabilistic	Deterministic	Probabilistic
Scale	Regional (at least direct neighbours, up to second degree neighbours)	National – simplified regional	Pan European
Network representation	Current (NTC[61]) and targeted (PTDF[62])	None on small scale, maximum flows on regional scale	First, NTC Later, possibly flow-based
Security of supply indicators	Loss of load (energy duration, probability, frequency,…), capacity margin	Capacity margin	Loss of load
Uncertainty considerations	Monte Carlo simulations	Additional margins	Monte Carlo simulations

Source: Artelys (2016), "METIS Study S4: Stakes of a common approach for generation and system adequacy"

59 An inter-governmental initiative designed to promote collaboration on cross-border exchange of electricity in Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland.

60 These contingencies include outdoor temperatures (which result in load variations, principally due to the use of heating in winter), unscheduled outages of nuclear and fossil-fired generation units, amount of water resources, and wind and photovoltaic power production.

61 Interconnectors are usually modelled as commercial flows with no network physical constraints, but constrained by maximum net transfer capacities (NTC). In practice NTC values can vary quite often, due to outages, maintenance and temperature affecting lines' physical properties.

62 Power Transfer Distribution Factor

5.1.3. *Deficiencies of the current legislation*

As highlighted in Section 7.3.2 of the Evaluation, resource adequacy is not addressed in the Third Package. The Commission's current tool to assess whether government interventions in support of resource adequacy are legitimate is State aid scrutiny. The EEAG require among others a proof that the measure is necessary. However, the framework does not allow the Commission to effectively judge whether there is a resource adequacy problem in the first place.

To date, the need for CMs are based on national adequacy assessments and Member States rely on them when arguying for CMs. However, national assessments are undertaken in different ways across Europe. These assumptions may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility are taken into account in calculations. For example, the Council of European Energy Regulators (CEER) recommends to "*take into account the potential benefit provided by interconnectors in national resource adequacy analyses in a coordinated and consistent way across Member States*"[63]. In addition, CEER is of the opinion that "*these different procedures pose difficulties (especially for neighbouring countries) as it is a challenge to understand the different procedures and processes from one country to another*"[64].

Art. 8 of the Electricity Regulation gives to ENTSO-E the responsibility for carrying out a European resource adequacy outlook. It requires amongst others that the European resource adequacy outlook should build on national resource adequacy outlooks prepared by each individual TSO. Consequently the ENTSO-E assessment is rather a compilation of national assessments than a genuine calculation based on raw data input. Also the applied methodology needs a review in particular with regards to the input data and the calculation method used. For example, the European Electricity Coordination Group recommends that "*The improvements in the existing ENTSO-E methodology should focus on the consistent treatment of variable RES generation and interconnectors*"[65].. In their current form and granularity they are not suitable to assess whether certain Member States are likely to face resource adequacy problems in the mid to long-term.

Further to the difference in approach, CEER highlights that "*there are also differences between the System Outlook & Adequacy Forecast (SO&AF) undertaken by ENTSO-E and the national assessments that occur due to different quality of data and a more sophisticated approach in some countries*"[66].

All in all, neither national assessments nor ENTSO-E's European resource adequacy outlook, in their current form a) appropriately inform investors, governments and the wider public of the likely development of system margins and b) allow the Commission to

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63 CEER (2014), *Recommendations for the assessment of electricity generation adequacy*

64 CEER report on *"Assessment of generation adequacy in European countries"* (published in 2014) http://www.assoelettrica.it/wp-content/uploads/2014/10/Ceer_GenerationAdequacyAssessment.pdf

65 *Report of the European Electricity Coordination Group on The Need and Importance of Generation Adequacy Assessments in the European Union*, Final Report, October 2013

66 CEER report on *"Assessment of generation adequacy in European countries"* (published in 2014) http://www.assoelettrica.it/wp-content/uploads/2014/10/Ceer_GenerationAdequacyAssessment.pdf

effectively judge whether the proposed introduction of resource adequacy measures in single Member State is justified.

5.1.4. *Presentation of the options*

Option 0 - BAU

National decision makers would continue to rely on purely national resource adequacy assessments which inadequately take account of cross-border interdependencies. In addition, due to different national methodologies, national assessments are difficult to compare.

The Commission would continue to face difficulties to validate the assumptions underlying national methodologies including ensuing claims for CMs.

Option 0+ stronger enforcement

As the current legislation foresees that national resource adequacy plans are the basis for ENTSO-E to draw up its resource adequacy assessments, stronger enforcement is not a viable option.

Some Member States (e.g. PLEF) have voluntarily decided to cooperate and deliver a regional resource adequacy assessment. However, the PLEF geographically covers only part of the EU electricity market and hence its role cannot go beyond that of a test-lab for upgrading the ENTSO-E methodology. Indeed, without a common methodology for all EU Member States, the Commission would continue to face difficulties to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.

Option 1 – Binding EU rules requiring TSOs to harmonise their methodologies for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs

Option 1 would require TSOs to harmonise their methodologies for calculating resource adequacy and require Member States to exclusively rely on them when arguing for CMs. TSOs would have to cooperate to upgrade their methodologies based on probabilistic calculations, with appropriate coverage of interdependencies, availability of RES and demand side flexibility and availability of cross-border infrastructure in times of stress.

In this option, Member States would be responsible for carrying out the assessment.

Option 2 - Binding EU rules requiring ENTSO-E to provide for a single methodology for calculating resource adequacy + requiring Member States to exclusively rely on them when arguing for CMs

Option 2 would require ENTSO-E to provide for a single methodology for calculating resource adequacy and require Member States to exclusively rely on them when arguing for CMs. The ENTSO-E methodology should be upgraded based on propabilistic calculations[67] and should appropriately take into account foreign generation, RES and demand response.

In this option, Member States would be responsible for carrying out the assessment based on the ENTSO-E methodology & coordination.

Option 3 - Binding EU rules requiring ENTSO-E to carry out a single resource adequacy assessment for the EU + requiring Member States to exclusively rely on it when arguing for CMs

Option 3 would require ENTSO-E to carry out an EU-wide resource adequacy assessment and Member States to exclusively rely on it when arguing for CMs. In other words, this would mean that, ENTSO-E would be required to not only provide for the methodology (similar to Option 2) but also carry out the assessment. The ENTSO-E assessment should have the following characteristics:

i. It should cover all Member States
ii. It should have a granularity of Member State/ bidding zone level to enable the analysis of national/ local adequacy concerns;
iii. It should apply probabilistic calculations that consider dynamic characteristics of system elements (e.g. start-up and shut-down times, ramp up and ramp-down rates…)[68]
iv. It should calculate resource adequacy indicators for all countries (LOLE, EENS, etc.)
v. It should appropriately take into account foreign generation, interconnection capacity, RES[69], storage and demand response
vi. The assessment should be carried out every year
vii. Time span of 5-10 years

It should be noted that under this option each Member State would be allowed to carry out their national resource adequacy assessment if they wish to but they would not be able to rely on these results when arguing for CMs.

5.1.5. *Comparison of the options*

Contribution to policy objectives

Under **Option 0**, proposed CMs would be based on national resource adequacy assessments and projections. National assessments may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility and variable renewable generation[70] are taken into account in

[67] The PLEF approach could serve as a pioneer for applying the advanced methodology for a wider perimeter.
[68] This means considering flexibility issues, temporal constraints and a realistic evaluation of the expected role of interconnectors.
[69] National but also foreign RES should be considered as the IEM and the interconnection capacity are the basis for a more and better integration of RES allowing a higher capacity factor for RES. The same can apply to storage.
[70] Some countries still assume zero capacity value for wind and PV. Countries that do not assume a zero value differ on the methodology to estimate the capacity value of RES.

calculations. Some countries even use deterministic methodologies that are obsolete (they do not consider the stochastic nature of forced outages and variable renewable generation). In addition, these national assessments are often not in line with the current EU-wide assessment carried out by ENTSO-E. All in all, this approach reinforces the national focus of most mechanisms and prevents a common view on the adequacy situation. Remaining in the *status quo* may therefore lead to significant capacity overinvestments. In consequence, it creates more uncertainty in neighbouring countries as each Member State takes individual actions in putting in place CMs.

In **Option 1**, proposed CMs would still be based on national resource adequacy assessments but these would adopt harmonised methodologies including input data. The assessments would thus become more comparable across Member States. However, even though this approach is an improvement compared to Option 0, it seems likely that Option 1 would still lead to significant capacity overinvestments. Although this option provides a minimum harmonization, the implementation time will take longer as some Member States current methodologies are far from the target one. An entity or body needs to assure that the harmonized methodology is properly implemented and check the consistency of the results across countries. This option can produce significant delays.

Option 2 would make it easier to embark on a single methodology. Moreover, this approach is likely to result in less over-investment in power infrastructure. However, it would be difficult to coordinate the work of the 30+ TSOs in Europe. In addition, national TSOs might be overcautious and not take appropriately into account cross-border interdependencies. Even in the presence of a single methodology, national assessments would not be able to provide an effective regional or EU picture.[71] Indeed, national interests could still play a role in the manner in which the assessments are done. There is a risk that Member States would deviate from the single methodology when implementing it which means that an enforcement and monitoring mechanism should be provided for.

Option 3 would most likely be the best option to reach the set objectives as it would make sure that the national puzzles neatly add up to a European picture allowing for national/ regional/ European assessments. A major advantage is that ENTSO-E has already been carrying out an EU-level resource adequacy assessment based on the Union legislation. By requiring ENTSO-E to carry out the assessment, Option 3 appears to be appropriate to overcome the main obstacles that prevent Option 1 and 2 from being effective. Indeed, there would be less room for Member States to deviate in the implementation of the single methodology. This would favour neutrality as it would avoid national interests playing a role in the manner in which the assessments are done. Efficiencies would arise from a reduced need for coordination between Member States and a reduced need for oversight during the implementation of the methodology by the Member States. As a drawback,

[71] For example the extent to which Member States can rely on each other for contributions to their own security of supply depends, among other things, on the likelihood of scarcity situations occurring simultaneously in those Member States. Even if Member States calculate their resource adequacy assessment based on a single methodology it cannot be ensured that they arrive at exactly at the same outcomes except if all Member States share all data sets generated by the other and if they carry out exactly the same computational steps using those data sets.

Option 3 would potentially reduce the 'buy-in' from national TSOs who might still be needed for validating the results of ENTSO-E's work. All in all, this option would best assess the capacity needs for resource adequacy and hence allow the Commission to effectively judge whether the proposed introduction of resource adequacy measures in single Member States is justified.

Key economic impacts

An expert study carried out using METIS[72] assesses the benefits of cooperation for resource adequacy. The study highlights that significant capacity savings can be obtained from a European approach to security of supply with respect to a country-level resource adequacy assessment. The reasons for these savings is that Member States have different needs in terms of capacity with peak demands that are not necessarily simultaneous. Therefore, they can benefit from cooperation in the production dispatch and in investments.

The model jointly optimises peak capacities for two reference cases for EuCO27[73] – without cooperation (capacities are optimised for each country individually, as if countries could not benefit from the capacities of their neighbours) vs. with cooperation (capacities are optimised jointly for all countries, taking into account interconnection capacities (NTCs).

In both options, capacity dimensioning has the following characteristics: (i) removal of peak fleets (CCGT, OCGT and oil) to avoid excessive overcapacity); (ii) Other units are kept (including nuclear, coal and lignite), which creates overcapacity for CZ, SK and BG; (ii) Optimisation of gas and peak fleats (modeled as OCGT) with VOLL = 15k EUR/MWh and peak annual price = 60k EUR/MW/year.

The difference in installed capacity between the two cases reveals how much savings could be made from cooperation in investments.

Results show that almost 80 GW of capacity savings (see figures 2 and 3) across th EU, which represents 31% of the installed gas capacities, can be saved with cooperation in investments. This represents a gain of EUR **4.8 billion per year** of investments.

It should be noted that this figure does not assess at which stage Member States are currently (i.e. whether some Member States already benefit from the capacities of their neighbours), as the benefits have already been reaped by some. It should also be noted that **this figure does not include savings on production dispatch**, which could lead to much higher monetary benefits.

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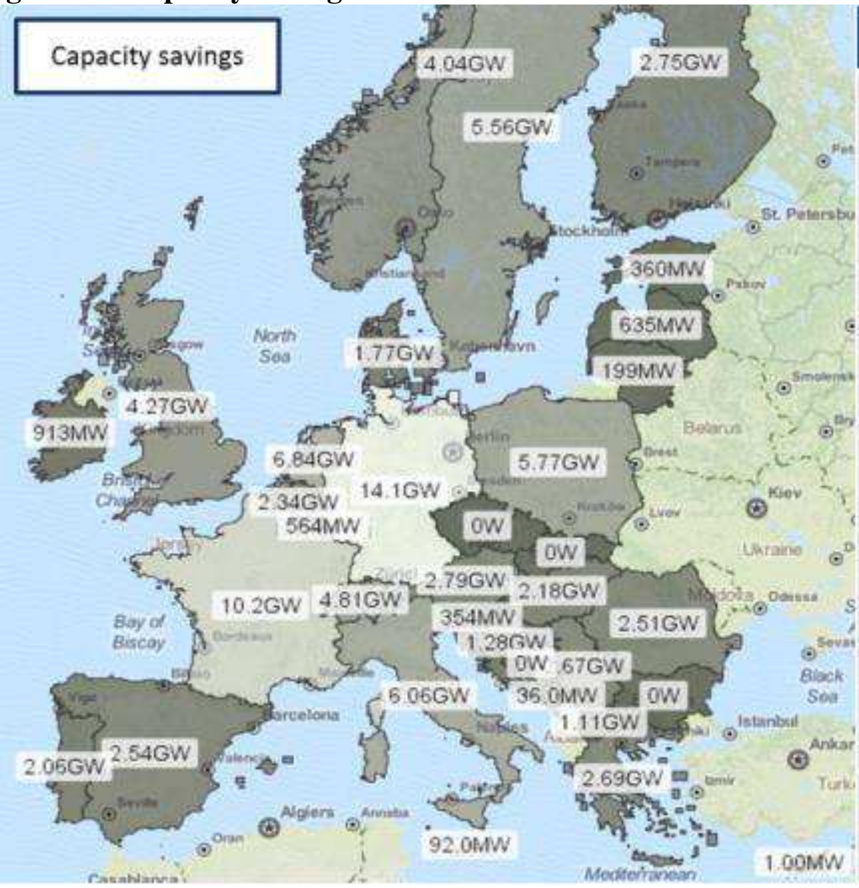
[72] "*METIS Study S16: Weather-driven revenue uncertainty for power producers and ways to mitigate it*", Artelys (2016).

[73] The scope of the model comprises EU28 + (CH, NO, BA, MK, ME, RS) and 50 years of weather data.

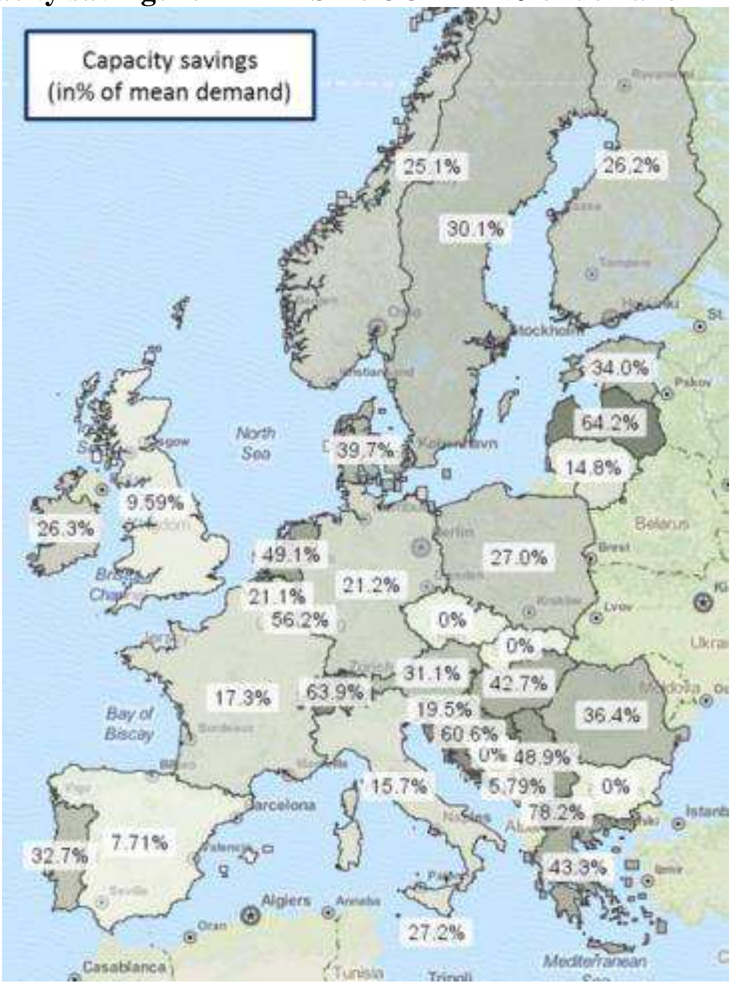
Figure 2 – Capacity savings for METIS EuCO27 in GW



Zone	Capacity savings (in GW)
EU28	79
AT	3
BE	2
BG	0
CY	0
CZ	0
DE	14
DK	2
EE	0
ES	3
FI	3
FR	10
GR	3
HR	1
HU	2
IE	1
IT	6
LT	0
LU	1
LV	1
MT	0
NL	7
PL	6
PT	2
RO	3
SE	6
SI	0
SK	0
UK	4

Source: METIS

Figure 3 – Capacity savings for METIS EuCO27 in % of demand



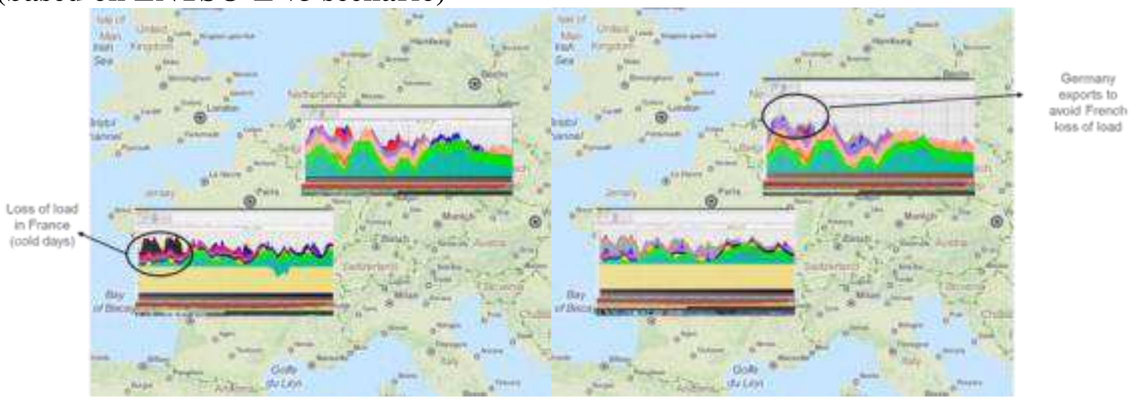
Source: METIS

The main reasons for these capacity savings are twofold: (i) variability of peak demand across Europe and (ii) variability of weather conditions (and consequently of RES generation profiles) across Europe.

- Variability of power demand profiles across Europe: Energy end use practices are different and the deployment of equipement using electricity (for instance electrical heating) varies across Member States. In particular, the sensitivity of Member States national demand with regards to temperature varies from one country to the other. Moreover, low temperature events do not occur at the same time in all Member States[74]. As a consequence, the aggregated European demand peak is lower than the sum of all national demand peaks (which do not occur at the same time). A European electric system with cooperation in capacity dimensioning would therefore face a lower capacity need – defined by the aggregated European demand peak – than a set of isolated national systems, which would require a global generation capacity as high as the sum of national peak demand.

[74] For instance, extreme temperature conditions are often not correlated between Western Europe and Northern Europe (Norway, Sweden, Finland and Estonia).

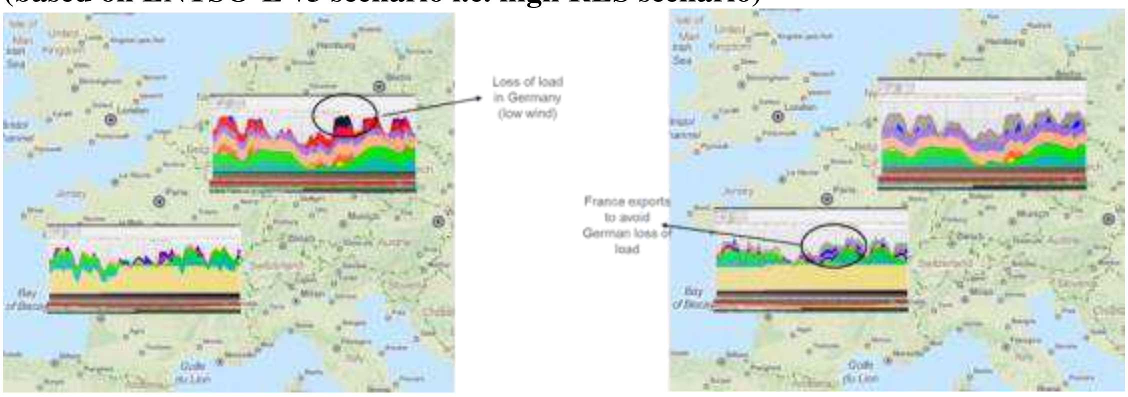
Figure 4 – illustration of cooperation in variability of peak demand across Europe (based on ENTSO-E v3 scenario)



Source: METIS

- Variability of RES generation profiles: Despite geographical correlations at the regional scale, different climatic regimes produce different weather conditions across Europe, which often compensate one another. This influences the RES generation profiles. Indeed, aggregating European RES generation profiles leads to higher load factors for RES than single country RES load factors.

Figure 5 – illustration of cooperation in variability of RES generation across Europe (based on ENTSO-E v3 scenario i.e. high RES scenario)



Source: METIS

Impact for businesses and public authorities

The **administrative costs**[75] are expected to be marginal compared to the economic benefits that would be reaped. ENTSO-E currently employs two FTEs to carry out its resource adequacy assessment and has a working group of 10 FTEs from national TSOs. In addition, we assume approximately 100 FTEs working on national resource adequacy assessments in TSOs across Europe (Option 0). Option 1 is assumed to require require 20-25 additional FTEs for coordinating the harmonisation of national assessments. It is likely that Option 2 would be slightly less human intensive – only 15-20 additional FTEs would be needed. Under Option 3, it is assumed that the same amount of FTEs would be needed as in Option 2 but these would be employed by ENTSO-E. In monetary terms, this can be translated

[75] The economic costs linked to resource adequacy assessments are based on own estimations, resulting from discussions with stakeholders and experts.

into 2-3 million euros annually in terms of personnel costs for Option 3. In addition, IT costs are equally likely to be small. For Option 3, IT costs are assumed to be in the range from 2-3 million euros per year as ENTSO-E would need more calculatory power that has IT implications. For options 1 and 2, they are likely to be lower than for Option 3 as TSOs across Europe have already developed their own IT systems. All in all, the estimated administrative costs of ENTSO-E providing for a single methodology and carrying out the assessment (Option 3) would range from **4 to 6 million euros per year.** This is marginal compared to the estimated benefits presented above.

Table 3: Comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

	Option 0: No further action	**Option 1**: Harmonisation of national assessments	**Option 2:** ENTSO-E provides for single methodology, Member States carry out the assessment	**Option 3:** ENTSO-E provides for single methodology and carries out the assessment
Quality of the methodology	-- No progress or uncertain progress as it depends on Member State independent initiatives	0 Progress remains limited as only harmonisation	++ Efficient as there is a single methodology	++ Coherence as ENTSO-E runs the same model for all Member States and the pan-European assessments. Input and output data are more coherent.
Use of established institutional processes	- Unclear which processes to be used	+ Can build upon established processes	0/+ Can partially build upon established processes	- Requires building up new processes (ENTSO-E to carry out the assessment)
Efficient organisational structure	- Each Member State carries out its own assessment	- Each Member State carries out its own assessment	0/- Each Member State carries out its own assessment based on ENTSO-E methodology	++ Efficient as ENTSO-E carries out the assessment for all Member States
Capacity savings	-- Low capacity savings	- Higher capacity savings due to different treatment of cross-border capacity	+ Higher capacity savings as single methodology	++ Highest capacity savings as single methodology and calculation

The assumptions are based on the Market Design Initiative consultations and other meetings with stakeholders

In summary:

- Option 0, "No further action": will likely lead to significant over-investments and hence will fall short in providing the adequate level of security of supply for Europe for any given provision cost level.
- Option 1, "Harmonisation of national assessments": is likely to be more efficient than Option 0, but cannot be expected to fully meet the specific objectives.
- Option 2, "ENTSO-E providing for a single methodology but Member States carrying out the assessments": is likely to lead to less overinvestment. Nonetheless,

national interests could still play a role in the way in which the assessments are done.
- Option 3, "ENTSO-E providing for a single methodology and carrying out the assessments": seems, according to the assessment of the options, to be the most appropriate measure for assessing generation adequacy assessment.

5.1.6. *Subsidiarity*

The **subsidiarity** principle is fulfilled given that the generation adequacy challenges the EU power system is facing cannot be optimally addressed based on national adequacy assessments as is currently the case, as foreign contribution to national demand might not be sufficiently taken into account. This can be the case because national assessments apply different assumptions, calculatory approaches and data input. This is why it would be best suited to require ENTSO-E to carry out a single updated generation adequacy assessment for the EU based on a revamped methodology and high quality and granular data input from TSOs including requiring Member States to exclusively rely on it when arguing for CMs.

Requiring ENTSO-E to carry out a single generation adequacy assessment for the EU would also be in line with the **proportionality** principle given that the total capacity requirements for ensuring the same level of security of supply will be lower than in the case of national adequacy assessments. This will strengthen the internal market by making sure that resources are deployed and utilised efficiently across the EU.

5.1.7. *Stakeholders' opinions*

Replies to the public consultation on the Market Design Initiative

A majority of stakeholders (34%) is in favour of sticking to an "**energy-only**" market, possibly with a strategic reserve. Many generators and some governments disagree and are in favour of market-wide CMs (in total 22% of stakeholders replies). Many stakeholders (31%) share the view that properly designed energy markets would make capacity mechanisms redundant (21% disagree).

There is almost a consensus amongst stakeholders on the need for a more aligned method for **generation adequacy assessment** (73% in favour, 2% against). A majority of answering stakeholders (47% of all stakeholders) supports the idea that any legitimate claim to introduce CMs should be based on a common assessment. When it comes to geographical scope of the harmonized assessment a vast majority of stakeholders (86%) call for regional or EU-wide adequacy assessment while only a minority (20%) favour a national approach.

Most of the stakeholders including Member States agree that a regional/European framework for CMs are preferable. Member States, however, might want to keep a large degree of freedom when proposing a CM. They might claim that beyond a revamped regional/ EU generation adequacy assessment there is legitimacy for a national assessment based on which they can claim the necessity of their CM.

Sensibilities

The CEER claims that "*security of supply is no longer exclusively a national consideration, but it is to be addressed as a regional and pan-European issue*" and that "*generation adequacy needs to be addressed and coordinated at regional and European level in order to maximise the benefit of the internal market for energy*". As a conclusion to their survey, the CEER published recommendations[76] that emphasize the need for the implementation of a single harmonised methodology. The PLEF has already used such a common approach in a recent security of supply study[77]. In addition, ENTSO-E's target methodology is announced to be "*fully in line with the methodology developed by the TSOs of the PLEF*"[78].

EFET[79] is of the opinion that "*the current 'national approach' potentially leads to an over procurement of capacity as Member States do not appropriately take into account what capacity is available outside of their borders. As a medium step, regional assessments based on clusters of countries that are highly interconnected can be efficient, as they will effectively pool resources over a wider area. The ENTSO-E SO&AF reports are a first step in the direction of a European approach to adequacy assessment. However, the reports so far only consolidate the analysis of individual TSOs for their respective control area/country. Market participants still expect a truly European adequacy assessment from ENTSO-E, and national regulators should support the requests of ACER and the European Commission in that regard.*"

On the ENTSO-E methodology, Wind Europe[80] is of the opinion that "*most national adequacy assessments focus on the contribution of firm generation units, with little or no consideration for the contribution of other energy sources such as demand-side response, storage, imports/exports or renewables.*" It recommends that "*developing a holistic approach that systematically and realistically include renewables, demand response, storage and interconnections' contribution to adequacy."*

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76 Recommendations for the assessment of electricity generation adequacy, CEER

77 Pentalateral Energy Forum [PLEF] – Support Group 2, Generation Adequacy Assessment

78 Energy Community Workshop: "*Towards Sustainable Development of Energy Community*", RES integration: the ENTSO-E perspective

79 EFET answer to the public consultation on the market design initiative

80 Wind Europe, "Assessing resource adequacy in an integrated EU power system" (May 2016)

5.2. Cross-border operation of capacity mechanisms

5.2.1. *Summary table*

Objective: Framework for cross-border participation in capacity mechanisms			
	Option 0	**Option 1**	**Option 2**
Description	Do nothing. No European framework laying out the details of an effective cross-border participation in capacity mechanisms. Member States are likely to continue taking separate approaches to cross-border participation, including setting up individual arrangements with neighbouring markets.	Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme.	Option 1 + EU framework harmonising the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …).
Pros	Stronger enforcement The Commission's Guidance on state interventions[81] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders. There is no reason to believe that the EEAG framework is not enforced. To date, however, there are not many practical examples of such cross-border schemes.	It would reduce complexity and the administrative impact for market participants operating in more than one Member States/bidding zone. It would remove the need for each Member State to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs and regulators. It would preserve the properties of market coupling and ensure that the distortions of uncoordinated national mechanisms are corrected and internal market able to deliver the benefits to consumers.	In addition to benefits in Option 1, it would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand.
Cons	As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers).	It would be a cost for TSOs and regulators which would have to agree on the rules and enforce them across the borders. These costs would be lower than in Option 0 though.	In addition to the drawback of Option 1, it would limit the choice of instruments.
Most suitable Option(s): Options 1 and 2			

[81] http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

5.2.2. *Description of the baseline*

DG COMP's sector enquiry on Capacity Mechanisms found that cross-border participation is not yet enabled in the majority of CMs, and with different Member States developing different solutions for their already different national capacity mechanisms there is an emerging risk of increasing fragmentation in the market.

The exclusion of foreign capacity from CMs reduces the efficiency of the internal market and increases costs for consumers. The most damage is done if Member States make no assessment of the possibility of imports when setting the amount of capacity to contract through a CM (in a volume-based model) or setting the price required to bring forward the required volume (in a price-based mechanism). In this approach (**no cross-border participation**), there would be greater distortion of the signals for where new capacity should be built, and an increase in overall system costs due to overcapacity. In addition, CMs would fail to adequately reward investment in interconnection that allows access to capacity located in neighbouring markets. The potential unnecessary costs of this overcapacity has been estimated at up to 7.5 billion euros per year in the period 2015-2030[82].

Some Member States have attempted to address the problem by taking account of expected imports (at times of scarcity) when setting the volume to contract in their capacity mechanism (defined as **implicit participation**) This reduces the risk of domestic overprocurement and recognises the value to security of supply of connections with the internal energy market. However, implicit participation does not remunerate foreign capacity for the contribution it makes to security of supply in the CM zone. If only domestic capacity recieves capacity payments, there will be a greater incentive for domestic investment than investment in foreign capacity or interconnectors resulting in less than optimal investment in foreign capacity and in interconnector capacity.

The best approach to this would be **explicit participation** which means that the contribution of imports to the CM zone must not only be identified, but the providers of this foreign capacity need to be remunerated for the security of supply benefits that they deliver to the CM zone.

This approach has been formalised in the Commission's Guidance on state interventions[83] and the EEAG which require among others explicit participation of foreign capacity in the CM (EEAG 232).

However, putting in place a functioning explicit cross-border CM requires multiple arrangements involving several parties (e.g. resource providers, TSOs, regulators). This is a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted. This could explain why, to date, there are not many practical examples of such cross-border schemes.

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82 See Booz & co, 2013, *'Study on the benefits of an integrated European Energy market'*

83 http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

Member States who have implemented an explicit cross-border scheme have taken different approaches. Portugal, Spain and Sweden appear to take no account of imports when setting the amount of capacity to support domestically through their CMs. In Belgium, Denmark, France and Italy, expected imports are reflected in reduced domestic demand in the CMs. The only Member States that have allowed the direct participation of cross-border capacity in CMs are Belgium, Germany and Ireland.

Foreign plants were allowed to participate in the Belgian tender for new capacity, provided that they would subsequently become part of the Belgian bidding zone even if geographically located in another Member State.

In the Irish tender, foreign capacity could participate if it could demonstrate its contribution to Irish security of supply – no foreign capacity was selected in the tender. In the existing Irish capacity payments model, foreign capacity can benefit from capacity payments. However, the method for enabling this participation involves levies and premiums on electricity prices and is not therefore compatible with market coupling rules which require electricity prices, not capacity premiums/taxes, to provide the signal for imports and exports[84].

None of the strategic reserves are open to generators located outside of the Member State operating the reserve mechanism; except for the German network reserve which contracts capacity outside of Germany provided that it can contribute to alleviating security of supply problems in Southern Germany through re-dispatch abroad.

Despite the current lack of foreign participation, many Member States are trying to develop cross-border participation in their mechanisms. France carried out last year a consultation which outlined different options for the participation of interconnectors or foreign capacity in the decentralised obligation scheme. Ireland published a consultation in December[85] on options for cross-border participation in its planned mechanism. Italy is apparently considering future foreign participation in its capacity mechanism. Since December 2015 the British capacity mechanism has included interconnectors with Britain, which can participate as price takers in capacity auctions.

5.2.3. *Deficiencies of the current legislation*

The Commission's current tool to assess whether government interventions in support of generation adequacy are legitimate is State aid scrutiny. The EEAG require among others a proof that the measure is necessary, technological neutral and allows for explicit cross-border participation. Beyond the requirements of the Commission's guidance on state intervention and the EEAG, there is no European framework laying out the details of an effective cross-border participation in capacity mechanisms.

This could explain why few Member States have developed cross-border schemes with explicit participation, which means that (at best) they only **implicitly** take into account foreign capacities. If Member States limit participation in a national mechanism only to capacity providers located within their borders, and make overly conservative assumptions

[84] Note however that the Irish capacity mechanism does operate across the UK and Irish border because of joint market arrangements and a single bidding zone covering Ireland and Northern Ireland.
[85] https://www.semcommittee.com/overview?article=f254d505-16bc-4a66-b940-bf2cc7b614ae

about their level of imports they should expect, this will lead to distorted locational investment signals and over-capacity in areas with capacity mechanisms. These distortions can benefit incumbent market participants which will further reduce competition in the long run.

Member States wanting to comply with the EEAG requirements have to individually arrange, for each of their borders separately, the necessary cross-border arrangements involving a multitude of parties including regulators, resource providers and TSOs. Arranging cross-border participation on individual basis is likely to involve high transaction costs for all stakeholders. This is also a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

When developing solutions for explicit participation of interconnectors and foreign capacity to their CM, Member States need to address a number of policy considerations. For example, an explicit participation model needs to identify:

- Whether there should be any restriction on the amount of capacity that can participate from each connected bidding zone;
- What type of capacity product (obligations and penalties) should apply to foreign capacity providers; and
- Which foreign capacity providers are eligible to participate (DSR, generation, storage).

It is therefore not surprising that 85% of market participant respondents and 75% of public body respondents to the sector inquiry questionnaire felt that rules should be developed at EU level to limit as much as possible any distortive impact of CMs on cross national integration of energy markets.

The fact that cross-border participation is not yet enabled in the majority of CMs as highlighted on p.30 of the Evaluation, and with different Member States developing different solutions for their already different national CMs, there is an emerging risk of increasing fragmentation in the market.

5.2.4. *Presentation of the options*

Option 0 - BAU

The Commission's Guidance on state interventions[86] and the EEAG require among others that such mechanisms are open and allow for the participation of resources from across the borders.

The EEAG include the following requirements related to cross-border participation in a generation adequacy measure:

i. Should take the contribution of interconnection into account (226);
ii. Should be open to interconnectors if they offer equivalent technical performance to other capacity providers (232)

[86] http://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd01_en.pdf

iii. Where physically possible, operators located in other members states should be eligible to participate (232);
iv. Should not reduce incentives to invest in interconnection, nor undermine market coupling (233).

As explained above, the EEAG requires among others explicit participation of foreign capacity in the capacity mechanism (EEAG 232). However, Option 0 does not provide for a European framework setting out harmonised rules of an effective cross-border participation scheme.

Option 0+

Despite the EEAG requirements for Member States to individually arrange, for each of their borders separately, the necessary cross-border arrangements, few Member States have voluntraily collaborated to develop an effective cross-border scheme. This is a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

Option 1 - Harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme

Under this option there would be a requirement for Member States to allow for explicit participation of foreign capacity in national CMs.

There would also be a harmonised EU framework setting out procedures including roles and responsibilities for the involved parties (e.g. resource providers, regulators, TSOs) with a view to creating an effective cross-border participation scheme. The framework would:

a) Define the appropriate share of foreign participation (de-rating of resources);
b) Allocation of 'entry tickets' to foreign resource providers[87];
c) Same remuneration principles for domestic and foreign resource providers;
d) No booking (or setting aside) of cross-border capacities for cross-border participation;

[87] The contribution foreign capacity makes to a neighbour's security of supply is provided partly by the foreign generators or demand response providers that deliver electricity, and partly by the transmission (interconnection) allowing power to flow across borders. Depending on the border, there can be a relative scarcity of either interconnection or foreign capacity. To ensure the right investment incentives, the revenues from the mechanisms paid to the interconnection and/or the foreign capacity should reflect the relative contribution each makes to security of supply in the zone operating the CM. Where interconnection is relatively scarce but there is ample foreign capacity in a neighbouring zone, the interconnectors should thus receive the majority of CM. This would reinforce incentives to invest in additional interconnection, which is the limiting factor in in this case. Conversely, where there is ample interconnection but scarcity of foreign capacity, the foreign capacity should receive most of the capacity remuneration. In this case, foreign capacity is the limiting factor that should receive additional incentives.

e) Contribution of foreign capacity in parallel scarcity situations[88] to be addressed by de-rating factors;
f) No delivery obligation (only availability);
g) No adjustment of cross-border schedules;
h) No limitation of the participation of a capacity resource to a single CM where the resource can contribute to security of supply in more than one CM zone.

More details regarding the harmonised EU framework

De-rating of resources: De-rating of interconnectors and/or foreign capacity refers to an evaluation of the expected actual contribution of a capacity provider on average, over the long-term, at times when it is required. This issue is critical as conservative assumptions will lead to overcapacity, and overly generous assumptions will potentially lead to unmet demand (and potentially reduced confidence in the value of interconnection).

Entry-tickets to foreign resource providers: Foreign capacity providers would have to acquire specific "interconnection tickets" to allow them to explicitly participate in the CM. Foreign capacity bids to get access to the capacity market via the interconnection, up to the level of available interconnection capacity. The interconnection receives revenues from "interconnection tickets" auctioning. Foreign capacities receive revenues at "local CM" clearing price. This would allow a priori a market-based split of value and the right incentive for investments.

Same remuneration principles for domestic and foreign resource providers: In principle, if the allocation process for capacity contracts allows interconnector or foreign capacity to compete directly with domestic capacity, the obligation and penalties faced by the interconnector or foreign capacity providers should be the same as the obligations and penalties faced by the domestic capacity providers.

No booking of cross-border capacity for cross-border participation: One of the basic features of capacity mechanisms is that the participating resources (mainly generators) receive a payment for their availably in times of expected system stress. Whether a participating resource actually generates electricity depends on short-term market price signals (effectively intra-day and balancing market prices). This mechanism makes sure that power flows to the area in Europe that needs it most. For example, if short-term prices in Belgium turn out to be 2.000 EUR/MWh while prices around Belgium are only 250 EUR/MWh the market coupling algorithm (and successive intra-day exchanges) will make sure that all available transmission capacities on the Belgian border will be used to flow power into the country. The limiting factor to supply Belgium in times of stress is (most likely) not the availability of generating assets in Europe but the relative scarcity of transmission capacities towards Belgium. Setting aside transmission capacities for the purposes of cross-border participation will therefore not improve the security of power supplies in Belgium but will only interfere with the efficient functioning of power markets. Participation of resources from across the border should therefore not be link to the effective delivery of electricity from that resource. Paying for capacity (availability) across the borders can still make sense as this provides incentives to keep resources available to produce if market prices signal so.

Contribution of foreign capacity in parallel scarcity situations to be addressed by de-rating factors: In practice, it is extremely unlikely that scarcity events will be perfectly correlated between two neighbouring countries. So, to avoid a situation where overall less contribution by imports to security of supply is assumed than is truly the case, a statistical judgement – de-rating of the interconnectors on each border to reflect expected long-run average import capacity at times of scarcity – is needed for each capacity mechanism. The

[88] The extent to which an interconnector can reliably provide imports to the countries it connects depends not just on the line's technical availability but also on the potential for concurrent scarcity in the connected markets. If zone A only has a winter peak demand problem and connected zone B only has a summer peak demand problem, each may expect 100% imports from the other at times of local scarcity. However, if countries A and B are neighbours with similar demand profiles and some similar generation types, there may be some periods of concurrent scarcity where neither can expect imports from the other.

amount of capacity demanded domestically should be reduced by this amount, and this capacity is then available for allocation to foreign capacity providers.

No delivery obligation (only availability): An availability cross-border product allows the internal market to function unimpeded and avoids creating distortions to merit order dispatch that might be created with delivery obligations. Moreover, an availability product provides an additional incentive for Member States to correct regulatory failures and ensure their electricity prices reflect scarcity – which has further benefits for market functioning as such prices provide a signal for investment in flexible capacity and enable demand response. Lastly, establishing a relatively simple availability product – along with other common rules – makes cross-border participation much more readily implementable.

No adjustment of cross-border schedules: Because of the potential for delivery obligations to create distortions in neighbouring markets and the fact that anyway such obligations can only incentivise actions which are likely to have a very limited effect on cross-border flows, delivery obligations are not appropriate for interconnectors or foreign capacity.

No limitation of the participation of a capacity resource to a single CM where the resource can contribute to security of supply in more than one CM zone: Without this requirement explicit participation is likely to lead to overcapacity which would be a worse outcome than implicit participation.

Option 2: – Option 1 + EU framework harmonises the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanisms, reserves, …)

In addition to Option 1, the EU framework would harmonise the main features of the capacity mechanisms per category of mechanism (e.g. for market-wide capacity mechanism, reserves, etc.), such as the properties of capacity product to be offered, the duration of the obligation, etc.

5.2.5. *Comparison of the options*

Contribution to policy objectives

Option 0 already requires explicit participation of foreign capacity in the CM under the EEAG rules. However, the EEAG framework does not set out harmonised rules of an effective cross-border participation scheme. This explains why few Member States have developed cross-border schemes with explicit participation, which means that (at best) they only implicitly take into account foreign capacities. If Member States limit participation in a national mechanism only to capacity providers located within their borders, and make overly conservative assumptions about their level of imports they should expect, this will lead to distorted locational investment signals and over-capacity in areas with capacity mechanisms, and an increase in overall system costs. As the conclusion of individual cross-border arrangements depend on the involved parties' willingness to cooperate it is likely that this option will cement the current fragmentation of capacity mechanisms. Arranging cross-border participation on individual basis for each of a Member States borders is likely to involve high transaction costs for all stakeholders (TSOs, regulators, ressource providers). This is also a difficult exercise requiring willingness and cooperation from all parties which cannot be taken for granted.

Option 1 would facilitate explicit cross-border participation as already required by EEAG by providing an EU framework with roles and responsibilities of the involved parties. This option would remove the need for each Member State to design a separate individual solution – and potentially reduce the need for bilateral negotiations between TSOs. It would also reduce complexity and the administrative impact for market participants operating in more than one zone. Hence, it is likely that an increased number of Member States would implement an effective cross-border scheme. Explicit participation would lower overall system costs as it corrects investment signals and enables a choice between local generation and alternatives. On one hand, the capacity in a CM zone will bid lower into the domestic CM as a result of access to revenues from electricity and capacity in neighbouring zones. On the other hand, this will lead to more investment in capacity in a non-CM zone, and in transmission to neighbouring CM zones, if capacity in a non-CM zone has access to neighbouring capacity and energy prices. All in all, with the design options of an EU framework chosen above, Option 1 is likely to better preserve operational market efficiencies (e.g. market coupling) and ensure that the investment distortions of uncoordinated national mechanisms are corrected and the internal market able to deliver the benefits to consumers.

Option 2 would facilitate the effective participation of foreign capacity as it would simplify the design challenge and would probably increase overall efficiency by simplifying the range of rules market participants, regulators and system operators have to understand. At the same time there is a risk that it would limit the choice of instruments and potentially the ability to answer a wider range of problems that capacity mechanisms could address.

Key economic impacts

The economic impacts of the different options are analysed in the core document "Section 6 - Problem Area II".

Impact for businesses and public authorities

Although the cost of designing cross-border participation in CM depends to some extent on the design of the CMs, an expert study[89] estimated that such cost corresponds roughly to 10%[90] of the overal cost of the design of a CM[91]. In addition, they estimate costs associated with the operation of a cross-border scheme i.e. additional costs if cross-border participation is facilitated to amount to 6-30 FTEs[92] for TSOs and regulators combined. TSOs and regulators have to check pre-qualification and registration (eligibility phase) and ensure compliance i.e. monitoring, control, penalties (control/ compliance phase).[93] Market participants participating in a cross-border scheme would potentially have additional costs of 0-3 FTEs.

The expert study found that providing for a common framework for cross-border participation (Option 1) would actually reduce the cost of cross-border participation when

89 Thema (2016), *Framework for cross-border participation in capacity mechanisms (First interim report)*
90 Costs in the design phase are one-time costs.
91 The same expert study also found that the overall cost of of the design are fairly small compared to the overall cost of the CM (remuneration of the participation ressources).
92 FTEs in other phases refer to (annually) recurring costs.
93 There is a difference between a generator model for cross-border participation and an interconnector model in relation to the costs. This difference can be explained by the number of participants and jurisdictions. The more participants and countries participate, the greater the potential for increased costs.

compared with Option 0. This is because in Option 0 cross-border arrangements have to be set up and operated based on indivdual arrangements which involve costs that can be saved if these arrangements follow a template. For TSOs and NRAs, the study estimates the cost saving for Option 1 to be 30% of eligibility costs and compliance costs compared to Option 0.

In analogy to Option 1 we would expect that providing for a common template for capacity mechanisms (Option 2) would actually reduce the design cost of CMs when compared with Option 0 and Option 1. This is because in Option 0 and Option 1 CMs are designed individually which involve costs that can be saved if the CM design follows a template. For TSOs and NRAs, the study estimates the cost savings to be 50% of eligibility costs and compliance costs compared to Option 0.

Table 1: Comparison of the Options in terms of their effectiveness, efficiency and coherence of responding to specific criteria

	Option 0: do nothing (EEAG)	**Option 1**: EU framework for cross-border participation	**Option 2:** EU framework for cross-border participation + blueprint
Investment distortions due to uncoordinated CMs	- More chance of distorted locational signals and over-capacity in zones with CM	+ Less chance of investment distortions due to effective cross-border scheme	+ Less chance of investment distortions due to effective cross-border scheme
Overall system costs	- Higher overall system costs	+ Lower overall system costs due to reduction in CM auction price	+ Lower overall system costs due to reduction in CM auction price
Speed of implementation	- Individual XB arrangements for each border	+ Harmonised XB arrangements across the EU	+ Harmonised XB arrangements across the EU
Complexity and administrative impact	-- High administrative impact for market participants operating in more than one zone	+ Reduced complexity and administrative impact due to harmonised rules	+ Reduced complexity and administrative impact due to harmonised rules

The assumptions are based on the Market Design Initiative consultations and other meetings with stakeholders

5.2.6. <u>Subsidiarity</u>

The **subsidiarity** principle is fulfilled given that the EU is best placed to provide for a harmonised EU framework with a view to creating an effective cross-border participation scheme. Member States currently take separate approaches to cross-border participation including often not allowing for foreign participation or only implicitly taking into account foreign contribution to own security of supply. As cross-border participation in CMs requires neighbouring TSOs' and NRA's full cooperation, individual Member States might not be able to deliver a workable system or only provide suboptimal solutions.

Providing for a framework on cross-border participation in capacity mechanisms would be also in line with the **proportionality** principle given that it aims at preserving the properties of market coupling and ensuring that the distortions of uncoordinated national mechanisms are corrected and the internal market is able to deliver the benefits to consumers. At the same time, it removes the need for each Member State to design a separate individual solution – and potentially reducing the need for bilateral negotiations between TSOs and NRAs.

5.2.7. <u>*Stakeholders' opinions*</u>

Public consultation on the Market Design Initiative

Stakeholders clearly support a common EU framework for **cross-border participation** in capacity mechanisms (52% in favour, 10% against). Most of the stakeholders including Member States agree that a regional/European framework for CMs are preferable. Similarly, Member States might instinctively want to rely more on national assets and favour them over cross-border assets. It is often claimed that in times of simultaneous stress, governments might choose to 'close borders' putting other Member States who might actually be in bigger need in trouble.

Sensibilities

EFET[94] is of the opinion that "*Member States with a CM need to explicitly take into account the contribution of foreign capacities. This will likely require advanced TSO-TSO cooperation, and will require more complex arrangement at EU or regional level. EFET therefore supports the establishment of EU rules in this domain. One note of caution though: in no case should the cross-border participation to national CMs result in any reservation of cross-border transmission capacity or alteration of cross-border flows from the market outcomes*".

Wind Europe[95] "*acknowledges the need for a common set of indicators and criteria for cross-border participation, as this is a necessary condition for the existence of capacity markets where needed.*" […] In addition, they "*call for a strong involvement of the Commission to ensure that such a common European framework for cross-border participation does not serve as a pretext for introducing potentially unneccesary CMs.*"

ACER and CEER[96] "*fully endorse that explicit participation of foreign capacity providers into national CMs through a market-based mechanism should be allowed. In this respect,* […] *a few important prerequisites need to be fulfilled to make explicit cross-border participation possible and beneficial: a) TSOs are incentivised to make a sufficient and appropriate amount of cross-border capacities available for cross-border trade throughout the year(s); b) TSOs are not allowed to adjust, limit or reserve these cross-border transmission capacities at any point in time, including in case of shortage situation; and c) TSOs agree ex ante on the treatment of local/ foreign adequacy providers in case of a widespread shortage situation (i.e. when a shortage situation affects at least two countries simultaneously).*"

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94 EFET response to the public consultation on the Market Design Initiative, 2015

95 WindEurope response to the public consultation on the Market Design Initiative, 2015

96 ACER-CEER response to European Commission Capacity Mechanism Sector Inquiry, July 2016