Bremen Energy Working Papers

JACOBS UNIVERSITY

Paperseries No. 27

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February 2018

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Suggested citing:
Brunekreeft, G. and Meyer, R. (2018). Cross-border Electricity Interconnectors in the EU: the Status Quo, *Bremen Energy Working Papers* No. 27, Jacobs University Bremen.

Cross-border Electricity Interconnectors in the EU: the Status Quo

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to be published in:
The European Dimension of Germany's Energy Transition – Opportunities and Conflicts
Edited by Erik Gawel, Sebastian Strunz, Paul Lehmann and Alexandra Purkus

February 14, 2018

Abstract: An important goal of the European Commission is the promotion of the internal energy market (here specifically electricity), which requires sufficient and adequate cross-border interconnector capacity. However, cross-border interconnector capacity is scarce and, more importantly, the progress of interconnector capacity expansion is too slow. As a result, the Commission has proposed several policy measures to accelerate interconnector investment. This paper provides an overview of the policy debate on interconnector expansion and studies two particular points. First, the effects of network regulation on the interconnector investment and the policy proposals to improve the investment incentives, and more specifically, how to deal with risks. Second, we study the policies and effects of capacity remuneration mechanisms (CRMs) on the use of and the need for cross-border interconnector capacity.

Keywords: electric utilities, regulation, market design
JEL-classification: L94, L51, D47

[1] This work includes results from the research grant „Modellbasierte Szenarienuntersuchung der Entwicklungen im deutschen Stromsystem unter Berücksichtigung des europäischen Kontexts bis 2050", funded by BMWi (Germany) under number 03ET4031B.

1. Introduction

Electric cross-border interconnector capacity is key to the internal energy market, promoting supply security, sustainability and affordability. Due to historic reasons from pre-EU times, cross-border interconnector capacity is scarce, and expansion is slow. This paper discusses selected current EU policy issues concerning the use of and the need for cross-border interconnector capacity.

The European Commission follows an active policy to promote and accelerate the expansion of interconnector capacity, as current progress is considered to be too slow. The so-called PCI-Regulation 2013, where PCI stands for “Projects of Common Interest”, addresses several hurdles. Two reasons for delays stand out: first, permitting issues, which is the main hurdle to expanding interconnector capacity and second, regulatory issues. In this paper, we concentrate on the latter issue. The worry is that the regulatory framework for interconnectors may impede adequate investment in interconnectors. We discuss two specific issues. First, the cross-border cost-allocation (CBCA) rule to internalize cross-border spill-over effects of interconnectors. Second, the regulatory treatment of investment risk. The risk of investment in interconnectors is perceived to be higher than the business-as-usual investments. The PCI-Regulation outlines additional regulatory incentives to deal with the higher risk.

There is widespread concern that the energy-only markets, which have so far dominated the European day-ahead markets, will not provide sufficient incentives for adequate generation capacity and hence may endanger supply security. Instead, market design may be changed to include capacity remuneration mechanisms (CRM). The debate as such has a long tradition, but the discussion has taken up speed recently, due to the surge of renewable energy sources: how do we produce electricity in times without sun or wind? Currently, there is no common European policy; the Member States decide unilaterally whether and how to implement CRMs. At the moment, anything goes. One of the more challenging issues regarding CRMs is how we should take account of interconnector capacity; this is a two-way relation. First, in the assessment of generation capacity in a country, we should consider the possibilities to rely on generation capacity of neighbouring countries; this, however, is restricted by interconnector capacity.

Second, the design of CRMs in neighbouring Member States affects the use of and incentives to expand interconnectors. We discuss the current state of the debate.

Section 2 provides the state of affairs of European policy of cross-border interconnector capacity. Section 3 discusses regulatory hurdles to efficient interconnector investment, focussing on the treatment of risk. Section 4 discusses the relation between CRMs and the role of cross-border interconnectors. Section 5 gives concluding remarks.

2. Cross-border interconnectors: background and overview

Achieving adequate cross-border interconnection between the energy systems of different Member States is one of the pillars of the energy policy of the European Commission.[2] Wikipedia defines an electrical interconnector as: "a high power AC or DC connection, typically across national borders or between different electrical grids. They can be formed of submarine power cables or underground power cables or overhead power lines." [3] Historically, the energy systems in the Member States developed quite independently from each other and with increased trade associated with market liberalization and the surge of renewable energies, it quickly turned out that the cross-border links between the energy systems were far too weak and needed to be strengthened.

In 2013, the European Commission adopted the energy infrastructure package, stressing the importance of the internal energy market. Following the background report of Booz & Company (2013), the Commission notes (EC, 2014b, p. 4): "the net economic benefits from completion of the internal market to be in the range of 16 - 40 billion Euros per year." If we compare this to investments in additional interconnector capacity in the range of €200 billion (see details further below), with life duration of over 40 years, it is immediately clear that these benefits are significant.[4]

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[2] This concerns electricity and gas. However, as this paper is on electricity, we will further ignore gas interconnectors.
[3] AC means alternating current and DC direct current.
[4] To be precise, in the *net* economic benefits in the numbers presented by the European Commission, the investment costs are already subtracted.

The European Commission stresses the well-known energy-goals-triangle as the three main advantages of the internal market and therefore of interconnector capacity (EC, 2014b, section 2): sustainability, supply security and affordability. More interconnector capacity allows renewable energies to be invested where they yield the highest efficiency (i.e. solar in the south and on- and offshore wind along the coast lines) and then traded and transported to the area where the load is. In fact, the European Commission is actively promoting cross-border support schemes of renewable energies (EC, 2016d). More interconnector capacity increases supply security. Concerning electricity, interconnectors allow sharing reserve capacities. Many countries are implementing some kind of capacity mechanism to deal with generation scarcity due to the so-called missing-money problem.[5] More interconnection relieves some of this pressure and can facilitate more efficient capacity mechanisms and reduce overall reserve capacity. Lastly, more interconnector capacity allows for more trade and will likely increase competition and will thus lower electricity prices.

The European Commission has set targets for interconnector capacity. EC (2015, p.2) states the goal of interconnection of at least 10% of their installed electricity production capacity for all Member States by 2020 and 15% by 2030 (EC, 2015, p.15). These goals are rather controversial and should largely be seen as political compromises or better, minimum requirements. Technically and economically, different Member States will have different interconnector requirements whereas the target is a one-size-fits-all. Yet, the good news is that there is a target at all, which gives TSO and investors a guideline on what to base the network development plans.

The need for new interconnector capacity is high and the development is slow. In 2011, the European Commission commissioned a study on the progress of interconnector capacity to Roland Berger Strategy Consultants. As illustrated nicely in Figure 1, the investment costs for electricity transmission (to 2020) is ca. €140 billion. This is a very substantial sum but given the size of the overall EU electricity market nothing out of proportion. More importantly though, Roland Berger (2011a) identifies a “financing gap” of half the investment requirement: half the required investment will be delivered

[5] See section 4 in this paper for more detail on this topic.

by the market, but it is unclear where the other half comes from. The reasons for the financing gap were studied by Roland Berger (2011 a and b) and have been addressed in various policy measures by the European Commission since then.

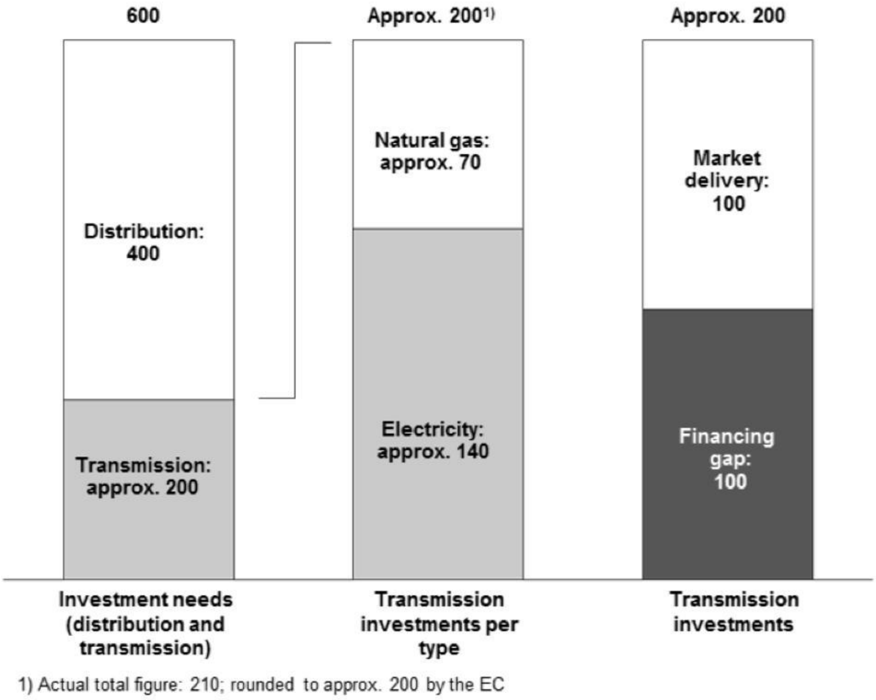

Figure 1: The investment financing gap.
Source: Roland Berger, 2011a, figure 2, p. 18.

The study by Roland Berger (2011a) identifies the following causes for the financing gap with varying severity.

- Permitting issues. This is *the* big hurdle to new interconnector capacity and, as will be discussed further below, still the major cause for delays. In fact, the issue is so big, that it was treated in a separate study by Roland Berger (2011b) for the European Commission. Permitting issues can be collected in two big groups: 1) bureaucracy (especially misaligned cross-border rules) and 2) the not-in-my-backyard (NIMBY) problem, i.e. public opposition against the building of new lines. So important the issue of permitting is in practice, it is not the focus of this paper; hence, we do not go into detail.
- Financing issues and financing conditions. Roland Berger treated these as two different aspects, but one could summarize these as one: given that the study was in 2010 and in the middle of the financial crisis, the worry was that the markets would not provide the necessary capital to the investors. This worry was unfounded.

- Operator capabilities. Some TSOs are considered to be too small or otherwise constrained in their capabilities to make the challenging interconnector investments. Overall though, this is not a major hurdle, and it does not concern the majority of TSOs.
- Specific types of projects. These mainly concern projects which aim to contribute to supply security. At least partly, supply security is a public good for which the market will not fully pay. Moreover, interconnectors typically affect different countries: what happens if an interconnector in country A derives benefits for country B, whereas country B does not contribute to the cost? This is an important point, which has been addressed by the European Commission with the cross-border cost-allocation rule (CBCA), which will be discussed in more detail below.
- Regulatory issues. Most interconnectors are regulated, and the worry is that the regulatory framework itself hinders efficient investment. One particularly important issue is how the *risk* of the investment in the interconnectors is addressed in the regulation. We will deal with this in more detail below.

The European Commission has responded with the so-called "PCI-Regulation", the Regulation No. 347/2013 (EC, 2013). PCI stands for "Projects of Common Interest". The main purpose of the PCI-Regulation is the promotion of cross-border interconnector investment. The two for our purpose most important ingredients of the PCI-Regulation are summarized in Figure 2.

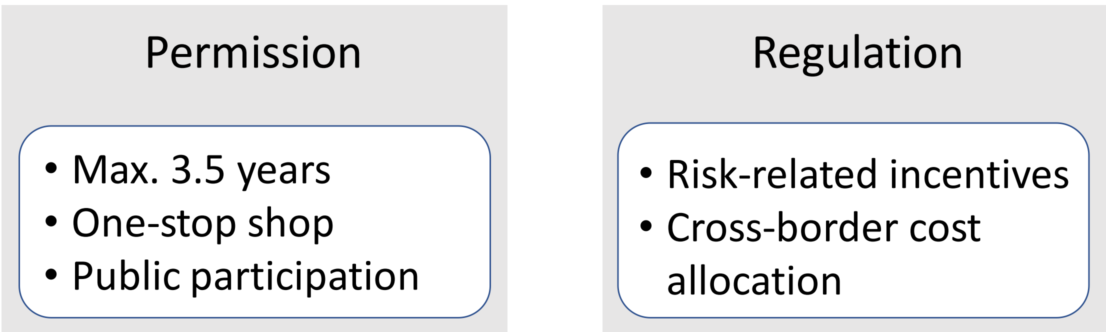

Figure 2: Two main instruments of the PCI-regulation
Source: based on ENTSOE (2016b).

Figure 2 shows two blocks of measures comprised by PCI-Regulation:

- Permitting. As mentioned above, permitting is a major issue. Two major improvements under the PCI-Regulation are first, that the member states committed to the goal that the permitting procedures for PCI projects should not be longer than 3.5 years (compared to the current 10-13-year average (EC, 2015, p.10)) and second, member states committed to create one-stop-shops for the necessary permits for the PCI-projects.

- Regulation. Two specific points have been addressed. First, the internalization of cross-border effects of interconnector investment with the so-called *cross-border cost allocation* rule (CBCA): if country A invests in an interconnector which benefits country B it can request a cost contribution from country B. Economically this sounds good, but politically this is a bit awkward if country B is not actively involved in the investment decision. Second, the appropriate remuneration of the *risk* of interconnector investment is addressed explicitly. We will step into this in more detail in section 3.[6]

What is the current state of interconnector investment? Figure 3 indicates that, after implementing the first round of PCIs till 2020, many of heartland European countries, notably Germany and France, will be in the range between 10% and 15% interconnection. Hence, the 10%-target will be reached, but the 15%-interconnection target till 2030 needs more investment.

The group of European Transmission System Operators for Electricity (ENTSOE) must prepare a detailed Ten-Year Network Development Plan (TYNDP) every second year. ENTSOE (2016b, p. 4) writes: "ENTSO-E's TYNDP 2016 identifies the need for up to €150 billion investment in electricity infrastructure only, of which 70-80 billion for mid-term and long-term projects (committed in national plans and to be commissioned by 2030)" and: "In its Progress Monitoring Report, ACER estimates the investment costs for electricity transmission Projects of Common Interest (PCIs) reported by project promoters to reach €49.3 billion." To summarize, up to 2030 ca. €150 billion investment needs to be made of which roughly €50 billion has CPI status.

[6] To be precise, there is a third line of measures. Investors can request *regulatory exemptions*, especially on third party access. This leads to the option of merchant investments. As this is not the focus of this paper we will further ignore this.

Figure 3: Map of interconnection levels in 2020 after implementation of current electricity-PCIs

Source: EC, 2015, p. 9.

Both ENTSOE (2016b, p.1) and the European Agency for the Cooperation of Energy Regulators (ACER, 2016, p. 35 ff.) study the progress of these projects and come to the similar conclusion that roughly one-third of the projects are delayed. Delays and rescheduling can be up to 4 years.

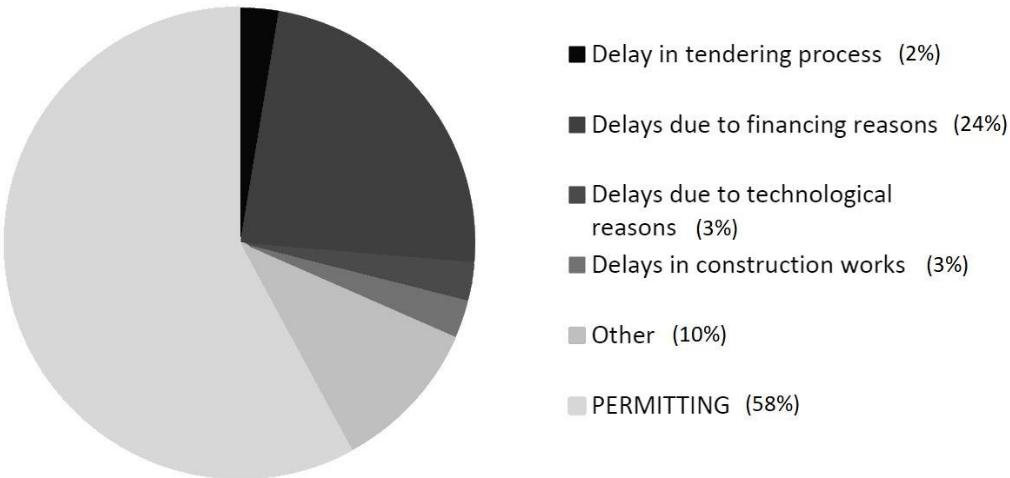

Figure 4: Reasons mentioned for the delays.

Source: ACER 2015a, p.40.

Figure 4 indicates that the main reason for the delays is, once again, permitting issues, here with 58%. It should be noted, however, that the majority of the projects are in a very early stage, mostly in a planning or study stage. Hence, some of the other hurdles are not yet important much by definition but may become more relevant later.

3. Regulatory policy to accelerate cross-border interconnector investment: how to address risk?

As mentioned in section 2, the CPI-Regulation 2013 specifies permitting and regulation as two major blocks of measures, and within these specifically the CBCA and risk-treatment. In this section, we deal with the third point: regulatory issues, focussing especially on risk-treatment.

CBCA

Art 12 of the PCI-Regulation 2013 titles "Enabling investments with cross-border impacts" and enables the Cross-Border Cost Allocation (CBCA). To be precise, "Regulation (EU) No 347/2013 facilitates in PCIs by envisaging decisions by National Regulatory Authorities (NRAs) or by ACER on the allocation of the costs of such projects across borders if project promoters submit an investment request, including a request for a cross-border cost allocation (CBCA)" (ACER; 2015b, p. 2). Three points are to be noted. First, the CBCA rules only concern PCIs. Second, the NRAs or ACER decide on the CBCA. Third, the project promoter has to request for the CBCA to be applied; the rule is not mechanically applied.

The key idea is that interconnectors typically have cross-border benefits for parties who do not incur costs. If investing parties do not consider these external benefits, the partial cost-benefit-analysis may turn out to be negative, whereas the overall net benefit may actually be positive. For example, say country A considers investing in a line with a cost of 100 and a benefit for country A of 90; assume the line has a cross-border benefit in country B of 20. Although the overall net benefit is positive (10), the line will not be built if country A pays all the costs, because the net benefit of country A alone is negative (-10). The CBCA-rule aims to internalize this externality, by making country B contribute to the costs (between 10 and 20).

To facilitate the investment request (including the CBCA-request), ACER (2015b) prepared a guideline document, setting out the required information. Two important elements stand out. First, requests can only be made for projects with sufficient maturity (ACER, 2015b, p. 3). This is a problem: if the initial investment decision is before the CBCA-request, the investment decision is in fact highly uncertain. In other words, theoretically, it may be the case that some potentially positive projects never actually make it to a CBCA-request. Clearly, the possibility to make a CBCA-request should be very early. Second, the project promoter has the burden of proof and must submit a detailed cost-benefit-analysis, showing and specifying the spill-over benefits (ACER, 2015b, p. 6). This is notoriously difficult and an endless source of debate. Alternatively, a specification of cross-border benefits of interconnectors as a standard procedure in ENTSOE's network development plan would address both problems mentioned above.

What is the experience with CBCA-requests so far? ACER (2016) states that by the end of 2015, out of the 100 projects, only 5 projects submitted an investment request. This is quite poor. Apparently, somewhat surprised itself, ACER (2016, p. 71) notes: "the low rate of submitted investment requests could be explained to some extent by the legal requirement that a project has to reach a sufficient level of maturity before the project promoter(s) can submit an investment request." A further explanation might be that the project promoters might be the wrong party to initiate the CBCA-request. Usually, the TSOs will be remunerated by the national regulation anyhow, and therefore their incentives to prepare a CBCA-request will be quite low: whereas the bureaucracy cost of making the request are substantial, the benefits for the TSOs may be quite low. Alternatively, the NRAs or the Ministry of the host Member States could be the party to initiate the request.

Risk-treatment

Section 2 mentioned the report by Roland Berger (2011a), which identifies hurdles to market financing of interconnector investment, among which, regulatory issues. *Inter alia*, Roland Berger (2011a, pp. 50 ff.) claims as a regulatory issue that projects with higher risk receive the same regulated rate-of-return as other projects. Consequently, Roland Berger (2011a, pp. 70 ff.) recommends making investments more attractive by introducing "priority premiums"; in other words, regulators should consider adjusting the risk-premium for investments with a shown higher risk.[7] Arguably, this will increase the investment incentives, however, it is easier said than done.

What are the risks? Figure 5 depicts the main risks as perceived by project promoters and makes two main points. First, cross-border interconnectors and especially offshore lines are risky vis-a-vis business as usual (i.e. non-TYNDP).[8] Second, regulation is one of the frequently mentioned sources of perceived risk.

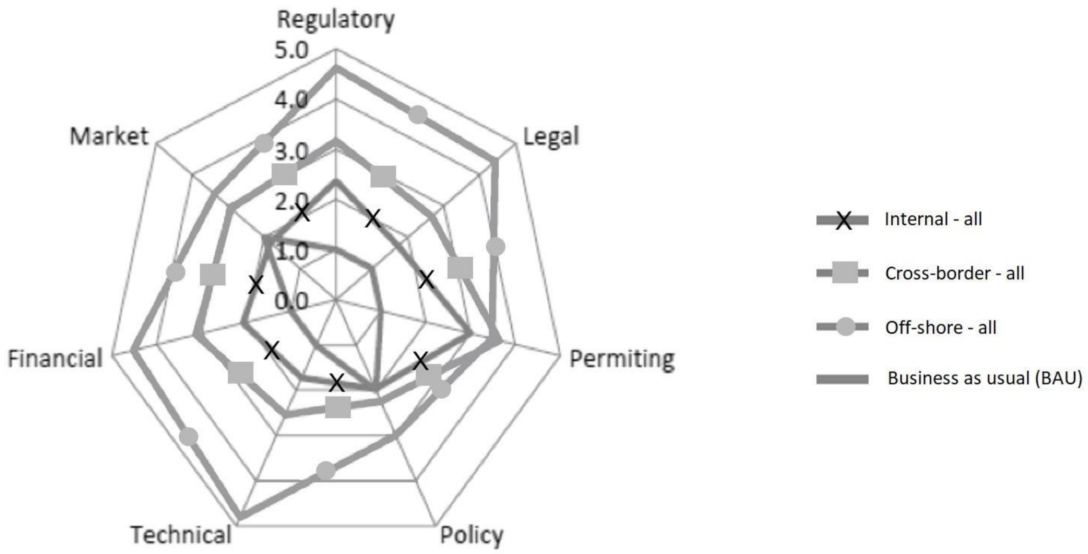

Figure 5: Which sources of risk matter?
Source: AF-Mercados EMI and REF-E, 2014, p. 22.

The key question then is whether the higher risk is reflected in a risk-adjusted regulated rate of return. Typically, this is not the case. Usually, regulation of network revenues knows only one-and-the-same rate of return on all assets and there is no distinction between different investments. This is precisely what a "priority premium" tries to achieve: it raises the regulated rate of return for a risky PCI above the usual level of the regulated rate of return. This should improve incentives to make the investment in the PCI.

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[7] The reader may note that "priority premiums" are also known as "rate-of-return adders" or "top-ups".
[8] To be precise, TYNDP projects are projects with pan-European significance; these can be national projects, with cross-border effects. Consequently, non-TYNDP-projects are national projects without significant cross-border effects (cf. ENTSOE, 2014).

Art 13 of the PCI-Regulation 2013 aims to improve incentives for PCIs with higher risk with *inter alia* precisely such priority premiums. The priority premium should be requested by the project promoter at the NRA. ACER (2014) developed a 7-steps procedure for these requests, where the burden of proof is for the project promoter:

- Step 1: Availability of information on project risks
- Step 2: Identification of the nature of the risk from a regulatory point of view
    - a) The risk of cost overruns
    - b) The risk of time overruns
    - c) The risk of stranded assets
    - d) Risks related to the identification of efficiently incurred costs
    - e) Liquidity risk
- Step 3: Risk-mitigation measures by the project promoters
- Step 4: Assessment of systematic risk and definition of cost of capital
- Step 5: Risk-mitigation measures already applied by NRAs
- Step 6: Risk quantification
- Step 7: Comparable project

Much can be said about this procedure, but for the scope of this paper, we will concentrate on three points only. First, the project promoter has to show and quantify the risk. This is challenging. Presumably, it might be better if ACER would develop a more general framework, specifying the type of investments, for which the priority premiums apply automatically. Second, as specified in step 4, the assessment of systematic risk and the definition of the cost of capital. This also is a challenge. Typically, the regulators rely on the CAPM-approach[9] to determine the risk-adjusted regulated rate of return on capital. As is well-known, the CAPM-approach relies on the risk-beta to estimate the risk-adjustment. Basically, step 4 requires showing that the normal risk-beta does not properly reflect the higher risk on the project for which the request is made. Moreover, the NRA are required to examine whether the project risk is systematic or non-systematic, such that it can be diversified. Third, the guidelines set

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[9] CAPM stands for Capital Asset Pricing Model and is a standard method to determine the rate of return of a company or an industry. For an explanation, see eg. Brealey, Myers & Allen (2016).

many restrictions for the application of the priority premiums. Many of these are sources of endless discussion and will likely discourage project promoters to try.

What are the experiences with requests for priority premiums so far? Only very few requests have actually been made: only 4 out of 100 projects (ACER, 2016, p. 73). As a possible explanation for this low number, ACER (2016, p. 73) writes: “With regard to the very low number of applications and plans to apply for specific incentives, while no investigation on the underlying reasons have been carried out, it seems that PCIs in general do not face higher risks compared to comparable infrastructure projects or that the existing regulatory frameworks already provide sufficient measures to tackle risks and therefore, already incentivise the necessary investments.“ That may be a bit too easy. In contrast, the European Commission seems to think that regulation itself may be a hurdle: “NRAs have faced challenges in applying the TEN-E Regulation.” (EC, 2015, p. 12).

There may be an alternative explanation: the question is whether project promoters really need the risk premium. In many cases, the risks (e.g. for outages of offshore lines) are insured (Umar, 2017). If an investor can insure the higher risk and if the insurance premium is part of the regulated cost base, then the higher risk is transferred into higher revenues and supposedly the problem is gone. Or put differently, step 5 in the 7-step ACER procedure would be fulfilled: through the backdoor, the regulation would already take account of the higher risk. As a side-remark, for the end-user it would be the same as with a higher rate of return; it is just a matter of who bears the risk, but at the end of the day the end-user pays for the risk.

4. Capacity remuneration mechanisms and the effect on interconnectors

The European Commission’s target model for the Internal Electricity Market is primarily based on a functioning energy-only market, where remuneration for generation and interconnection is solely based on electricity prices. In absence of market failures, electricity prices should provide efficient signals for both short-term trade and long-term investments. Increasing *prices* in one market incentivise generation investment, while increasing *price differences* between interconnected markets lead to an increase in congestion rents and thereby trigger interconnector investments.

In many European markets, however, concerns have been raised that electricity prices (especially in scarcity situations) may not be high enough to create adequate investment incentives. Large-scale integration of renewables may reduce scarcity revenues and thereby suppress efficient price signals for capacity investments needed to back up intermittent supply from renewables. The underlying discussion on generation adequacy is neither new nor is it limited to renewables. Subsumed under the term "missing money" (Cramton & Stoft, 2006) electricity markets in the US started to change their market designs already more than a decade ago. Different forms of *capacity remuneration mechanisms* (CRMs) have been developed to address the potential risk of underinvestment. CRMs aim to restore efficient investment incentives by providing revenues for available capacity in addition to the market revenues for produced electricity. Several European countries have recently implemented (or discuss the implementation of) CRMs. Although the European Commission acknowledges the potential need for CRMs in justified cases, it raises concerns about market distortions and cross-border effects CRMs may cause (EC, 2016c). Most importantly: what impacts do CRMs have on market integration and interconnector investment?

Capacity remuneration mechanisms in Europe

Various forms of CRMs are implemented or planned in EU Member States. Figure 6 gives an overview.

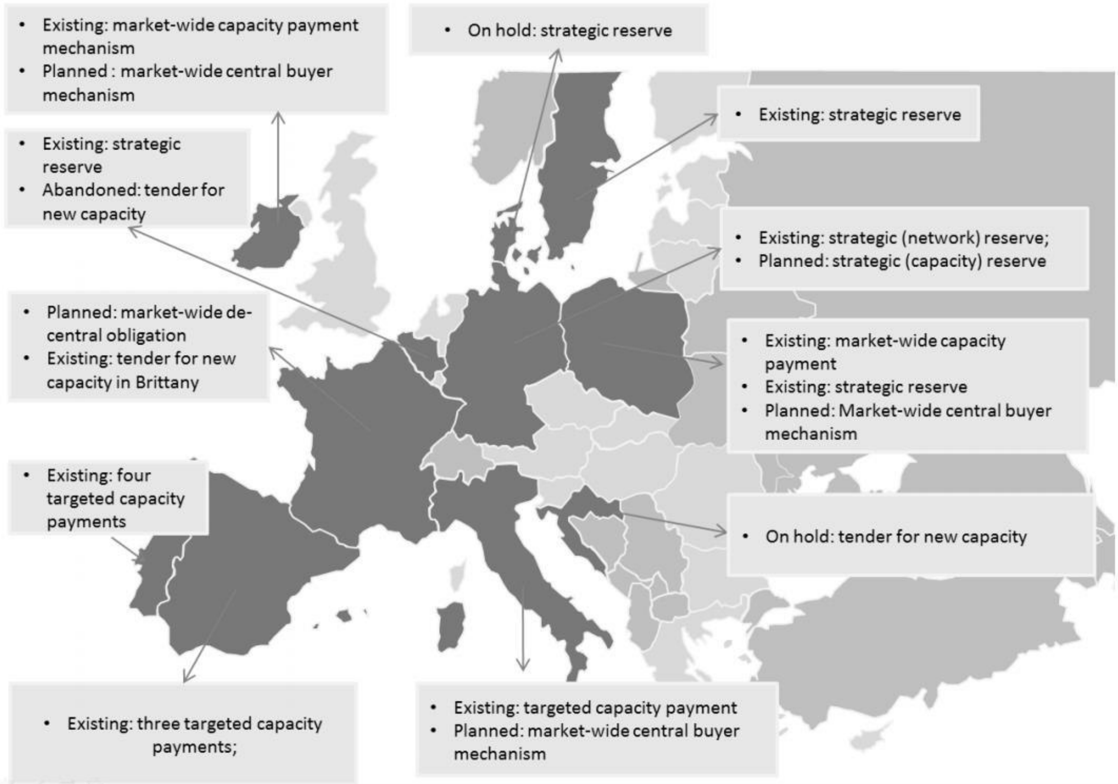

Figure 6: Existing and planned CRMs in EU Member States
Source: EC (2016a), p. 55.

From the European Commission's point of view, the most critical form of CRMs are *capacity payments*, where capacity providers are paid an administratively fixed price for available capacity in addition to the revenues they receive for selling electricity to the regular market. Such a mechanism, as for instance established in Spain, is called price-based, because the capacity price is fixed, while the quantity is determined by the market via individual investment decisions. The drawback of price-based CRMs is the risk of over- or underinvestment, as small errors in determining the capacity price may have large effects on the investment equilibrium (Brunekreeft et al., 2011)[10]. Moreover, capacity payments tend to distort technology choice and are potentially seen as discriminatory state aid by the European Commission (EC, 2014a). Hence, the European Commission concludes that "Administrative capacity payments are unlikely to be appropriate, regardless of the specific issues facing a Member State, because the

[10] For a general analysis concerning the control of prices vs. quantities, see the seminal paper of Weitzman (1974)

lack of a competitive process means a high risk of failing to achieve the capacity objective or of over-compensating" (EC, 2016b, p.18).

Volume-based CRMs are considered more effective in achieving a target level of generation adequacy, as they directly control for the quantity of capacity, while leaving price setting to the market. The procedure is that a predetermined volume of capacity is acquired through regular capacity auctions; the auction price then sets the remuneration for capacity providers. The two most common forms of CRMs are the *strategic reserve* and full *capacity markets.*

A strategic reserve is considered a targeted CRM, as it only provides capacity revenues for a certain amount of (reserve) capacity. Hence, the major part of the market remains energy-only. Strategic reserves are for instance established in Sweden and Finland. Both markets have a high share of hydro power which exposes them to the risk of capacity scarcity in dry winter periods. The common belief of a strategic reserve is that an energy-only market will bring about sufficient investments in all but exceptional scarcity situations. To take account of such extreme cases, a certain reserve is acquired by a central authority; often this is the TSO. The reserve is withdrawn from the market and will only be dispatched centrally in cases of extreme scarcity, i.e. when the market is not able to provide sufficient capacity.

Full capacity markets require a more fundamental change in market design. Capacity markets address the whole market and turn capacity into a separate, tradable product in addition to energy. Capacity markets can be organized as centralized *capacity auctions* or decentralized *capacity obligations*, depending on who is in charge of providing capacity: a central authority or the supply companies. In both models, the target volume of market capacity is fixed at expected peak demand plus a reserve margin. The supply side is formed by generators or demand response, who receive the capacity auction price in return for holding the tendered amount of capacity available.

The UK introduced a centralized capacity auction model in 2014, which is operated by the British TSO National Grid (DECC, 2012). The system consists of two auctions per year. One auction ("T-4") is four years ahead, with the first auction held in December 2014 for the delivery period of 2018/2019. Another one-year-ahead auction ("T-1") covers the remaining amount of capacity based on an update of demand forecasts. The amount of capacity acquired was 82 GW, thereby significantly exceeding the 2014 peak demand of 56 GW (Baker et al., 2015). France opted for a decentralized market, where supply companies are required to buy capacity certificates for their served customers. These certificates can be traded bilaterally and on the EPEX spot market. The French transmission operator RTE determines parameters for the required capacity obligations four years ahead of delivery and organizes the certification process in which all generators on the French territory must participate (RTE, 2014).

Cross-border effects of CRMs

As the European Commission's main focus is on an efficient energy-only market, the question is whether and how a CRM interacts with the energy market and cross-border trade. Two sources of cross-border effects can be identified that seem to be in the focus of discussion (Meyer & Gore, 2015):

1) "Capacity effects": CRMs may lead to overcapacities in a market which reduce cross-border trade and impose excessive costs on consumers.
2) "Price effects": CRMs may cause (or cover existing) price distortions in the energy-only market, which may hamper efficient market integration.

Capacity effects results from a CRM design that causes investment distortions. One concern of the European Commission relates to potential state aid. Most notably, CRMs may be intended by member states to subsidise old coal power plants, counteracting not only the European goals of free electricity markets but also environmental ambitions. In its so-called "Winter Package" on proposed measures for the European energy markets, the Commission therefore proposes to exclude highly CO2 emitting power plants from capacity markets, while especially Poland pushes towards a capacity market to keep their coal plants online (EC, 2017).

Another major concern of the European Commission is that CRMs may incentivize excess capacity investments, especially as the contribution of imports to available capacity is often underestimated. This may be due to political preference for national self-sufficiency over import dependency (Hawker et al., 2017). Consider a high-price country like the UK that used to import electricity from abroad. If the CRM does not account for imports, it will induce domestic excess capacity that replaces imports by reducing (peak) prices. This tends to lower the price difference to the neighbouring markets and thereby undermines the business case for interconnectors. Hence, "Ignoring interconnectors risks a self-fulfilling but expensive policy of autarky" (Newbery, 2016, p. 407). Accordingly, the lack of cross-border participation in CRMs is a major issue for the European Commission: "The current guidelines require that individual capacity mechanisms facilitate cross-border participation in order to maintain and promote market-wide efficiency. Thus far, however, cross-border participation is not observed in most capacity mechanisms" (EC, 2016c, p. 31).

In case of the UK, the first capacity auction carried out for the capacity market in the UK seems to confirm this concern: "Although the detailed assessment carried out by National Grid recognised that interconnection would likely contribute to security at times of peak demand, the amount of generation capacity to be procured for delivery in 2018/19 is based on the assumption of a zero net contribution from neighbouring systems" (Baker et al., 2015, p. 12). For the following auctions, however, cross-border contribution has been included. Similarly, the French capacity market was only opened stepwise to neighbouring market capacity. The European Commission finally approved the French CRM after some revisions which allowed capacity from abroad to participate in the capacity market (EC, 2016e).

The second source of cross-border effects as mentioned above relates to "price effects". CRMs may either cause price distortions themselves, or they cover distortions in the energy market which are already there. In both cases, market integration will be hampered as inefficiencies spill over to neighbouring markets. A typical form of price distortion is the capping of electricity prices. If a country implements a CRM, which reduces scarcity prices in return for additional capacity payments, this will have effects on the exchange with neighbouring energy-only markets. If revenues for exports and interconnection are reduced, the missing-money problem is partly "exported" from the CRM market to the neighbouring energy-only market (Meyer & Gore, 2015). Two examples:

- A strategic reserve may have a price-capping effect, if the reserve is activated whenever domestic energy prices reach a certain price level. If this price cap is set below the price of electricity imports, it will lead to a crowding out of imports, leaving generators in the neighbouring market with lower revenues. The strategic reserves currently in place in the Scandinavian markets, however, avoid such crowding-out effects by limiting the activation of reserves to situations when neither domestic nor imported market capacity can release the scarcity.

- A more important case of price effects applies to full capacity markets, if generators under the CRM change their bidding behaviour in the energy market. As generators are remunerated for capacity, they do not depend on high scarcity prices to recover their fixed costs. Hence, the two-part tariff (consisting of energy and capacity price) may lead to lower energy bids and thereby reduce scarcity prices. This in turn will affect remuneration of imported electricity from neighbouring energy-only markets, thus creating a missing-money problem on the other side of the border (Meyer & Gore, 2015).

Even if capacity markets themselves are not the cause of market distortions, a CRM may still cover market distortions already present in the energy market. If missing money is caused by market-design flaws in the energy-only market – like price caps – a capacity market will be the wrong instrument to solve the investment problem: market distortions will spill over to the neighbouring market and create a missing-money problem there. This explains why the European Commission is cautious about the implementation of CRMs without a well-founded reasoning: the priority should always be an undistorted energy-only market design (EC, 2016b).[11] Only if an efficient energy-only market design alone does not solve the missing-money problem, an additional CRM should be considered. The main challenge for an adequate CRM design is how to cope with the cross-border effects analysed above. The key term is cross-border participation.

Cross-border participation in capacity markets

Given that a CRM is considered the right solution to address the missing-money problem, some form of cross-border participation is essential to avoid market distortions. But how should this look like? EC (2016c) distinguished between *implicit participation* and *explicit participation*.

[11] In its State aid inquiry, the Commission already defined requirements, which should be fulfilled when implanting a CRM (EC, 2014a). This includes in the first place a profound demonstration that the establishment of a CRM is necessary at all to ensure capacity adequacy.

Implicit participation means that the CRM only applies to domestic capacity providers, but the import contribution from neighbouring markets is considered when calculating the amount of national capacity needs. This is regarded the minimum requirement for CRMs. It avoids building national overcapacities at the expense of cross-border trade – the above mentioned "capacity effect". However, this form participation does not prevent "price effects" leading to a spill-over of the missing-money problem to neighbouring markets. The problem is that domestic capacity will be compensated for the missing money through capacity remuneration, but the general shortfall of energy market revenues remains. Since neither foreign capacity nor interconnection providers receive capacity payments, the missing-money problem is "exported" to interconnected markets (EC 2016c).

Therefore, *explicit participation* of cross-border capacity is considered a more efficient solution. EC (2016c) distinguishes between two options. *Direct participation* allows cross-border resources to directly bid into the neighbouring capacity market. This is considered the preferred option, but it is also the most difficult one to implement. One of the challenges is to ensure availability of generation or demand resources and measure their respective contribution to generation adequacy – especially if they participate in more than one capacity market. To account for the probabilities of simultaneous stress events, a regional instead of national analysis and forecast of the interconnected electricity system is required (EC, 2016c). Furthermore, the question is how to ensure availability of interconnection capacity required to back up cross-border participation. As known from electricity markets, there are two forms of auctions for interconnection capacity. *Implicit auctions* would assign interconnection providers a congestion rent based on the capacity price difference between markets – similar to electricity prices differences in energy-only markets. Implicit auctions are known to be more efficient than explicit auctions, because the markets for energy and transmission capacity are cleared simultaneously. But it is unclear how implicit auctions can be implemented for decentralised capacity market models (EC, 2016c). On the other hand, separate, *explicit auctions* increase the risk for energy providers given the uncertain outcome of future interconnection auctions. This may reduce capacity bids and lead to lower expected rents for interconnection owners (EC, 2016c).

A second form of explicit participation *indirect participation*. This means that interconnection capacity (instead of cross-border energy capacity) would participate in a capacity market. In other words, capacity remuneration directly applies to interconnection providers, incentivizing them to invest in cross-border network capacity. Foreign production capacity would only benefit indirectly. This mechanism appears to be easier to implement, also for decentralized capacity markets, as it limits the number of counterparties involved in cross-border arrangements: typically, only the TSOs would participate.

5. Conclusions

Cross-border interconnector capacity is key to the internal energy market. Yet, capacity is scarce, and expansion is slow. The European Commission follows an active policy to use interconnector capacity efficiently and to develop interconnector capacity more effectively. In this paper, we discuss selected issues of the EU energy policy affecting cross-border interconnector capacity. In particular, we focus on two issues. First, reasons for delays in the expansion of interconnector capacity and policy measures to accelerate the expansion. Second, the developments towards capacity remuneration mechanisms (CRMs) and the effects on the cross-border interconnectors.

Expansion of interconnector capacity is too slow; delays are still substantial. Apart from permitting issues, regulatory issues are often mentioned as a hurdle for efficient interconnector capacity. Especially cross-border spill-over effects of interconnectors and the higher risk of interconnector investment seem to be important. The PCI-Regulation addresses these issues; the first with the cross-border cost-allocation (CBCA) rule and the second with additional investment incentives, most notably with the priority premium which reflects the higher risk. First experiences with these two policy measures indicate that they are not effective: the number of requests by project promoters is very low. It is not clear what the precise reason is. Upon theoretical reflection, however, we can draw two conclusions. First, in the CBCA-rule the TSO needs to make the request; this may be the wrong party because the TSO will be remunerated for the investment by national regulation anyhow, and thus the incentives to initiate a CBCA-request may be low. It might be better that the NRA or the Ministry, representing consumers, initiates the CBCA-request. Second, to the extent that risks of interconnector investment are insured and if the risk-premium is part of the regulatory cost base, the risk is in fact already internalized. We have to examine carefully, how the company or the regulation implicitly deals with the risk of the investment.

The debate on interconnector investments is also related to the implementation of CRMs in a growing number of European markets. CRMs should address the potential missing-money problem for generators in energy-only markets by raising investments through capacity-based revenues. However, this may negatively affect cross-border trade and interconnection revenues. If CRMs do not allow for explicit cross-border participation, only domestic capacity is compensated for the shortfall of energy market revenues, but imported capacity is not. This reduces incentives for trade and revenues for interconnection providers. The problem intensifies, if CRMs do not even consider the contribution of imports to domestic capacity and thereby induce overcapacities. As for now, only the weak form of implicit participation stands as the minimum requirement for approval of an CRM by the European Commission: import contribution should be subtracted from national capacity requirements to avoid a movement towards costly autarky. The preferred solution is explicit participation of either foreign capacity or interconnection in CRMs, which is more difficult to implement.

The debate has just started, and we will have to await further developments. The following issues for further research seem to be particularly important for next steps. First, the low rate of regulatory requests is puzzling, while it is of utmost importance why this is: it makes a difference whether there is no need for additional incentives or whether the policy measures are ineffective. This is not well understood. Second, how should interconnection capacity be included in CRMs, which currently strongly differ in design? Will a further harmonization of CRMs be necessary to foster European market integration?

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