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### Citation for published version:

Bolton, R & Clausen, T 2019, 'Ambiguous interventions: Capacity remuneration mechanisms and the politics of energy transition in Britain and Germany', *Energy Research & Social Science*, vol. 56, 101218. <https://doi.org/10.1016/j.erss.2019.101218>

### Digital Object Identifier (DOI):

[10.1016/j.erss.2019.101218](https://doi.org/10.1016/j.erss.2019.101218)

### Link:

[Link to publication record in Edinburgh Research Explorer](#)

### Document Version:

Peer reviewed version

### Published In:

Energy Research & Social Science

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# ***Ambiguous interventions: Capacity remuneration mechanisms and the politics of energy transition in Britain and Germany***

Dr Ronan Bolton<sup>1</sup> and Dr Thies Clausen<sup>2</sup>

## **Abstract**

This paper analyses the introduction of capacity remuneration mechanisms (CRMs) in Europe, focusing on Britain and Germany. We show how CRMs in these countries are evolving from government interventions to deal with electricity system reliability to become important policy instruments designed address a wider range of economic and societal challenges related to decarbonisation. We pay particular attention to the ambiguous role that CRMs play as tools for governing the decarbonisation of electricity systems. On the one hand they are being legitimised by governments as a means of facilitating the integration of renewables, while at the same time they are seen by many actors as a contributor to carbon lock-in and a means of prolonging the fossil-fuel industry. We discuss key factors shaping the ambiguous role of CRMs in electricity system decarbonisation and their relation to the politics of sustainability transitions.

**Keywords:** *Electricity Markets; Capacity Remuneration Mechanisms; Socio-technical Systems; Sustainability Transitions; Energy Politics*

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<sup>1</sup> Corresponding author. Chisholm House, High School Yards, Edinburgh, EH1 1LZ. Ph: +44 (0)131 650 6366 Email: Ronan.bolton@ed.ac.uk

<sup>2</sup> Director Public Affairs bei Edelman GmbH. Schöneberger Straße 15 10963 Berlin, Germany

## 1 Introduction

This paper develops a socio-political analysis of electricity markets and low carbon transitions, focusing on a particularly contentious issue in the current policy debate in Europe; the introduction of capacity remuneration mechanisms (CRMs). A CRM, broadly defined, is ‘a measure taken by a state designed to support investment to fill an expected capacity gap and ensure security of supply’ (Hawker et al., 2017). While much of the literature on CRMs has focused on economic questions and their role in delivering electricity system reliability, in the context of decarbonisation they are becoming important policy instruments to address a wide range of economic and societal challenges related to energy transitions.

CRMs are ambiguities interventions, in the sense that they can be viewed simultaneously by different actors as enabling and constraining decarbonisation. On the one hand they are being legitimised by governments as a means of maintaining reliability of electricity systems whilst facilitating the integration of renewables, and at the same time they are seen by many actors, in particular NGOs and renewables industry lobby groups, as resulting in payments to ‘uneconomic’ coal and gas thermal power plants, in effect subsidising the fossil-fuel industry. With a focus on Britain and Germany in recent years, the paper analyses how the politics of electricity market reform has been shaped around the ambiguities of CRMs as actors argue pro and con their introduction and debate their design features.

The dilemma around the need for CRMs is particularly interesting from an energy and climate policy perspective because, unlike the forms of government intervention such as renewables support and carbon pricing policies, intentions around CRMs are often difficult to discern. In many ways they don’t fit neatly into the dominant strands of thinking about policy design for energy decarbonisation which often frame the transition as a battle between the old and the new, between the incumbents and new entrants etc. CRMs rather sit at the interface of old and new energy regimes and there are significant ambiguities and uncertainties around basic questions, such as whether they are needed in the first place, their design features, whether they constrain or enable decarbonisation and their long-term effects on investment and electricity system transformation<sup>3</sup>.

Britain and Germany, our case studies, are two leading countries in the low-carbon transition, each having undertaken to reduce greenhouse gas emissions to a level of at least 80% below 1990 levels by 2050. As they seek to decarbonise their electricity systems, both countries have recently introduced CRMs but with different outcomes in terms of how they should be designed and implemented, thus providing an insight into the different ways in which decision making about CRMs and electricity market design choices are being made in the context of transition. The British case outlines the lead up to the government’s decision to introduce a *capacity market* for the integrated market of Scotland and England/Wales, commencing in 2014. This is contrasted with the German federal government’s decision in 2016 to opt for a more targeted approach which only provides payments to selected capacity providers which do not participate in the main energy-only market – a *strategic reserve*.

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<sup>3</sup> Meadowcroft (2011) makes a similar point about ambiguous technologies, such as CCS, arguing that it can be difficult to categorise certain technologies ex-ante as facilitating system change or perpetuating fossil fuel lock-in.

In the next section of the paper we begin by providing a basic introduction to CRMs. This draws mainly from the energy economics literature as there has been very little research on the subject in the wider energy social science field (for an exception see (Leiren et al., 2019)). We introduce and explain key terms and review the main economic arguments behind CRMs which played a role in the the decisions made in Britain and Germany, particularly about the need for a capacity market versus a more targeted strategic reserve. Following this section, we develop the case studies of Britain and Germany. These are based on an analysis of electricity market reform policy documents and associated technical studies, along with 12 semi-structured interviews with energy industry experts and civil servants<sup>4</sup>. In line with emerging research on energy markets from a wider socio-political perspective (Webb and Hawkey, 2017, Bolton et al., 2016, Pallesen, 2016, Breslau, 2013, Jenle, 2015), we show how economic arguments about CRMs in each case needed to align with political interests, a process which played out in quite different ways in our two cases.

Following the main empirical section, in section 4 we identify and discuss two key ambiguities around CRMs which have framed the politics of market design for low carbon transition in each case: Firstly, how the economic and energy security justification for a CRM is made, and secondly, which forms of capacity are deemed eligible, or not, for payments. In this discussion we draw from EU Commission appraisals of the British and German CRMs to supplement the country-level evidence. In the final section we summarise the key arguments of the paper and offer some concluding remarks.

## **2 A brief introduction to the economics of electricity and CRMs**

As it is costly to store electricity a central electricity market design challenge is the need to have a *capacity margin*<sup>5</sup> in place. The question of the size of the capacity margin and how to value capacity which will only be utilised for short peak demand periods has been a central one in the electricity industry since its inception in the 19<sup>th</sup> century (Hughes, 1983, Yakubovich et al., 2005). It is not the commodity itself – the use value<sup>6</sup> of units of electrical power for practical purposes such as lighting and heating – which is valued in this case, rather the *capacity* to meet demand when called upon. How to value this additional capacity which has a collective benefit to all users of an electricity system involves difficult judgements, firstly about the the amount of additional capacity to have on an electricity system and who should take responsibility for it being in place – government or the electricity industry? Secondly, about how it should be paid for, i.e. how the costs are spread amongst different users of the electricity system – producers, large and small consumers etc.

The economic policy literature on how to deal with this problem is, unsurprisingly, vast (for recent overviews see: Keppler, 2017, Pollitt and Chyong, 2018, Höschle, 2018). One view held amongst some economists posits that no dedicated revenue stream for capacity providers is required to deliver long-term system adequacy; rather, the ‘energy-only market’ (EOM) is sufficient. While price formation in wholesale markets is typically on the basis of the day-ahead timeframe, there is, the argument goes, significant scope for generators to cover their capital costs from returns in these short-term markets. Conventional ‘spot’

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<sup>4</sup> 6 interviews in Britain and 5 in Germany

<sup>5</sup> Defined as ‘the *proportion* by which the total expected available electricity generation exceeds the maximum expected level of demand *at the time at which that demand occurs*’ (House of Lords, 2015: p.23)

<sup>6</sup> Defined by Aspers and Beckert (2011) as ‘what is gained from the *qualities* of a good through its use’ (p. 12)

markets have been designed around the notion of marginal cost pricing; the most expensive generators in the market sets the system price which all generators are paid. The most efficient generators whose costs are below those of the marginal plant can therefore earn 'infra-marginal rent', whilst highly flexible peaking plant can earn additional 'scarcity rents' during periods when the market fails to clear, resulting in market prices often well above marginal costs. EOM proponents argue that if prices are not artificially capped and can raise to the level that customers would be willing to pay not be disconnected – the value of loss load (VOLL) – both variable and fixed costs involved with generating electricity can be covered and hence the free market can deliver an efficiently sized capacity margin.

A number of key problems have been identified with this ideal EOM-based model however. In the event of a shortage of supply in the market – a period when scarcity rents might be available to generators – calculating the economic value of electricity supplies to customers, and hence the market price which reflects scarcity, is constrained. While certain customers may be willing to change their decisions about consumption, for example by switching off their machines and appliances, and others may be willing to pay extremely high prices to maintain their supplies, the ability to calculate marginal costs at the demand side is severely constrained because of technical limitations; i.e., the absence of real-time metering in many premises and the inability to direct power flows to individual customers. Due to these 'demand-side flaws' in the electricity markets (Stoft, 2002) severe constraints are placed on the flow of information about the preferences of market participants during these crucial periods when scarcity rents could be earned, and as a result the standard economic framework for valuation based on marginal prices breaks down.

In the absence of information about consumer preferences during scarcity periods, an approach taken by electricity system planners has been to set an administered VOLL which can then be used as a basis for calculating the socially optimal size of the capacity margin and the levels of payments to providers of the necessary capacity<sup>7</sup>. In theory therefore, a price cap set at or above the VOLL would enable peaking plant to earn scarcity rents and cover their costs. However, practice in many markets is not so clear cut.

A key argument against the EOM logic is that extreme price spikes which would be necessary to reflect the scarcity in the market are politically unsustainable as, in the face of pressure from voters and consumer groups, governments are likely to intervene and introduce a price cap below the VOLL for political expediency. Another source of uncertainty is the likelihood of intervention by the system operator (SO) – the body responsible for the technical stability of the system. SOs are understandably risk averse and are unlikely to allow the market participants to resolve system imbalances, particularly over short timeframes (Joskow, 2008). They will override the markets in the interests of technical stability and may have large amounts of capacity purchased via bilateral contracts and held as reserves which can be released into the market during scarcity periods, resulting in depressed prices for market participants. Another concern is that during a scarcity period it is extremely difficult to retrospectively evaluate whether the market has been manipulated, for example by a large generator holding back supply to raise the price, thus creating doubts for governments and regulators about the efficiency of free markets.

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<sup>7</sup> A useful summary of VOLL and its calculation is provided here: <http://fsr.eui.eu/the-value-of-lost-load/> (accessed on 5.2.19)

Based on these fundamental uncertainties about the likelihood of intervention during scarcity periods, some economists argue that there is ‘missing money’ in the electricity market. This has been used as a basis for arguing that there is a market failure with respect to investment in flexible peaking plant which is crucial for the security of the system. ‘Missing money’ serves as a justification for government action on the basis that there is a structural flaw in liberalised electricity markets with regards to long-term system adequacy which necessitates a market-wide solution. EOM proponents argue that market-based CRMs which make capacity payments widely available, whether through market-wide auctions for capacity contracts – *capacity markets* – or other forms of allocation mechanism<sup>8</sup>, are typically not required as system adequacy issues can often be addressed through more short-term and focused interventions, i.e. creating a *strategic reserve*<sup>9</sup>. Here, forms of generation which deliver flexibility in the specific locations where this deemed be necessary are taken out of the market and provided with targeted payments.

As the British and German cases will illustrate, alongside more immediate concerns about electricity system reliability, the debate about CRMs is now part of a wider set of questions around the role and design of electricity markets in a low carbon future (IEA, 2016). The need to integrate variable renewables (VREs) such as wind and solar power creates added challenges and uncertainties regarding the need for government intervention to deliver a safe capacity margin. VREs create uncertainty for operators and investors in power markets because their output is weather-dependent and hence less predictable. Also, they operate at close to zero marginal costs, meaning that they will tend to push conventional generators out of the market if weather conditions are favourable, creating what is known as the *merit-order effect*.

Some economists have argued, for example, that as societies move away from fossil-fuels and systems become decarbonised, market designs based on energy output will become redundant and prices will be increasingly determined by how capacity is valued, for example, through CRMs, auctions for long term capacity contracts (Keay, 2016, Helm, 2017) or trading mechanisms designed to specifically value flexibility (Liebreich, 2017, PöYRY, 2014). The question of how electricity capacity is valued in markets is likely to become increasingly politicised as different market actors seek to influence which technologies can access the new revenue streams and gain competitive advantage from providing capacity and flexibility services to the system.

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<sup>8</sup> There are a wide range of potential CRM designs (for an extensive overview and a discussion of the benefits and drawbacks of different models see European Commission (2016)). These can be usefully delineated into targeted and market-wide mechanisms. The former refer to ‘payments to selected categories of capacity providers only’ (e.g. a tender for new capacity, a strategic reserve or a targeted capacity payment), whereas the latter ‘are in principle open to participation from all categories of capacity providers’ (a capacity market with an auction and a central buyer, a de-central obligation on suppliers to procure a certain volume of capacity, or a market-wide capacity payment to all generators on top of the market price).

<sup>9</sup> Although the option was not discussed in the GB and German cases, it should be noted that an alternative to the capacity market and strategic reserve options has been proposed by Hogan and implemented in the ERCOT market (Texas) (Hogan, 2013). The idea is to construct a demand curve for reserves – termed a *regulated operating reserve demand curve (ORDC)* – which is based on bids and offers in the market and fed this as a price signal back into the wholesale market, thus linking and co-optimising day-ahead and balancing markets.

### 3 CRMs in the British and German energy transitions

#### 3.1 Introduction to the cases

The British case outlines the lead up to the government's decision to introduce a capacity market for the integrated market of Scotland and England/Wales. Prior to the introduction of the market in 2014, Britain relied on its energy-only market to deliver a safe capacity margin. In effect little new capacity was required following the 'dash for gas' of the 1990s (Winkel, 2002). This situation changed in the late 2000s when the UK passed a Climate Change Act (2008) which legislated for a 80% reduction in GHG emissions by 2050 from 1990 levels. Coinciding with this were concerns about an over-reliance on imported gas at a time of rising global prices and falling North Sea production relative to its peak in the early 2000s. A review of the UK's energy security situation, Project Discovery, was initiated in 2009 by the regulator Ofgem. The report concluded that: 'The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current arrangements will deliver secure and sustainable electricity supplies' (Ofgem 2010, quoted in Newbery, 2015). Project Discovery in particular expressed a strong concern about a lack of investment in new plant, and spurred by this the UK government initiated the electricity market reform (EMR) process. Largely based on this energy security concern, in 2013 the Department of Energy and Climate Change (DECC) in Britain opted for a market-wide CRM with payments offered on a competitive basis to all potential capacity providers who submit bids into a centrally organised capacity auction – a *capacity market*.

This second case sets out the process by which the Federal German Government decided against the introduction of a capacity market, as in the British case. The backdrop to the German case is the *Energiewende* (Energy Transition) which can be described as an overarching policy effort to transform the nation's energy sector, the ambition being to decarbonise the German economy whilst phasing out nuclear power. The last nuclear power plant will shut down by the end of 2022 and the share of renewables in total power consumption had reached 32.5% in 2015 (Agora Energiewende, 2016). Unlike in Britain, the coal industry and mining lobby have retained significant power in Germany (Renn and Marshall, 2016) and as a result the construction of new coal-fired power plants has continued well into this century. A key energy paradox therefore in Germany, and a challenge facing the achievement of its *Energiewende*, is the significant coal generation capacity which is retained on the system, currently at a level over one quarter of installed capacity and 44% of electricity produced (Agora Energiewende, 2015).

#### 3.2 Britain: Finding the 'missing money'

##### 3.2.1 2010 Consultation: Initial preference for a targeted mechanism

In December 2010 DECC published a consultation document which set out options for EMR (DECC, 2010b)<sup>10</sup>. Initially DECC considered four main options for a CRM; a capacity payment, a decentralized capacity obligation, a capacity market based on auctions and a targeted mechanism. DECC had an initial preference for a targeted as oppose to a market-wide mechanism. This was based on analysis conducted by an energy consultancy (Redpoint Energy, 2010) which found through market simulations that a capacity payment on the basis

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<sup>10</sup> There were four main pillars of the EMR: Carbon price support, feed-in tariffs, capacity payments and an emissions performance standard.

of a market-wide auction would benefit 'existing plant that no longer chose to close under new EU environmental legislation (the Industrial Emissions Directive) as this was the lowest-cost option for generators, allowing them to maximize returns from the mechanism'. Based on this, DECC predicted that a targeted mechanism would result in more new-build gas plant and offered 'greater flexibility in the type of resource supported which may be advantageous depending on future market developments (for example if needed to provide back-up for intermittent generation)' (DECC, 2010b: p.92). The ability to value the attributes of different forms of capacity, rather than a single payment, was cited as a key benefit of the targeted mechanism: 'A market-wide capacity mechanism pays the same capacity payment to all types of resource. However, they may not have equal value in terms of maintaining security of supply. A targeted capacity mechanism can run different tenders for different types of resource need, and so pay different prices. This is expected to result in lower rents/producer surplus than under a market-wide capacity mechanism' (*ibid*: p.95).

Relative to the market-wide option, the targeted approach resulted in a saving over the 2010-2030 period (DECC, 2010a), indicating a more preferential outcome in welfare terms for a targeted mechanism<sup>11</sup>. This was based on the ability to discriminate between capacity resources which would allow DECC to favour 'the 'right' type of flexible resource'. Also, at this time the level of intervention required was not viewed as substantial; it was estimated that 5GW of capacity 'to 2030 to maintain margins at 10%' would be required; the targeted approach thus had the benefit of 'lower implementation risks'. A targeted approach, it was argued, 'would be more flexible to respond to future changes than a market-wide capacity mechanism because it has more opportunity for the design to evolve, making it durable and more able to adapt to be compatible with European markets as interconnection increases' (DECC, 2010b: P. 96).

### 3.2.2 A reappraisal (2011-2013)

Following the views set out in the consultation document in late 2010, DECC undertook a reappraisal of its initial position. In its July 2011 White Paper titled *Planning Our Electric Future* (DECC, 2011b), DECC's tone was less committal, observing that in responses to the initial consultation there were 'mixed views' on the targeted proposal. They noted that 'Some respondents to the consultation took the view that capacity margins during this decade mean that a mechanism is likely to be needed. Others were sceptical of the need for a Capacity Mechanism and argued that the case for a significant market intervention had not been made' (*ibid*: p. 64).

There were three important arguments which contributed to the reappraisal, summarised as follows:

1. More concern about the capacity margin: In the 2010 consultation document, although concern about the capacity margin was expressed, it was expected to fluctuate within a range of 5-11% above peak demand in the 2020s. These early calculations presumed no intervention to reduce carbon emissions, whereas updated modelling for the 2011 paper which incorporated the effects of plant closures and increasing amounts of low carbon generation indicated that 'de-rated

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<sup>11</sup> Changes to NPVs resulting from reductions in expected energy unserved relative to do nothing baseline for market-wide and targeted interventions were £-774 and £-694 respectively. Figures here were based on a value of lost load (VOLL) of £10k/MWh.



capacity margins are expected to fall below five per cent in some years', particularly in the early to mid-2020s.

2. The 'missing money' problem: Although not mentioned in the 2010 consultation this emerged as a key argument in the consultation submissions and the subsequent reappraisal of options. As will be explained below, DECC began to incorporate this as a new variable into their cost-benefit calculations and this played an important role in the reappraisal.
3. The 'slippery slope effect': The risk that providing secure revenues to plants who operate within the reserve would reduce incentives to operate in the market was highlighted by many respondents. This is because wholesale price spikes are likely to be reduced if the reserve is deployed very regularly and if the trigger price for doing so is well below VOLL. This may necessitate government to continually expand the size of the reserve, resulting in the wholesale market being further undermined, thus exacerbating the original problem. This argument, DECC note, was highlighted in a large number of the consultation submissions and received more prominence in the 2011 document.

Based on these arguments one of the Annexes of the White Paper included a new consultation document on 'possible models for a Capacity Mechanism' (DECC, 2011b). The targeted mechanism, with plants in a strategic reserve only operating once a trigger price has been reached - referred to as 'economic dispatch' - remained the preferred option, however, significant weight was given to the slippery slope and missing money arguments. DECC subsequently addressed the consultation responses in the form of a Technical Update to the White Paper: Of a total of 74 respondents '35 per cent of respondents preferred some form of market-wide mechanism. Another 25 per cent of respondents preferred a Strategic Reserve, and 25 per cent of respondents did not express a preference on the type of mechanism. 20 per cent of respondents did not believe any form of capacity mechanism is required' (DECC, 2011c). Four of the six large utilities in Britain advocated a capacity market, largely on the basis that it would facilitate new investment by creating certainty in the market<sup>12</sup>.

Indicating that the missing money argument became increasingly important in DECC's appraisal, they highlight that a capacity market 'tackles at source the problem of volatile and uncertain prices, which may undermine the case for investing in capacity' (*ibid*: p. 28). This is a reframing of the basic problem, away from one of a capacity shortage on the British system over a specific timeframe, to a fundamental problem with the operation of liberalized electricity markets more generally. A similar phenomenon is highlighted by Breslau for the case of the PJM market in the United States where, rather than a capacity

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<sup>12</sup> Lockwood (2017) conducts a detailed analysis of incumbent market players' position in relation to the capacity market versus strategic reserve debate. Four of the 'big six' and four of the second tier generators initially supported some form of capacity intervention whereas RWE, E.ON, DONG and ESB had advocated an energy-only market based approach. The general trend was that companies with coal and nuclear dominated generated portfolios favoured the market-wide approach because they were more interested in steady payments rather than sharp and potentially very high prices at scarcity periods. E.ON, RWE, ESB and DONG had recently made investments or had interests in new gas plant. Lockwood argues that government ministers at this time was predisposed to introducing a significant market intervention and the incumbent generators were 'pushing at an open door'.

intervention designed to address a specific local issue, market-wide efficiency is the criteria against which options are assessed (Breslau, 2013).

Incorporating institutional and administrative costs and covering the 2010-2030 period, the net present value (NPV (£)) for the targeted and market-wide options were recalculated against the business-as-usual (BAU) trajectory as £-1116 and £-2613 respectively (DECC, 2011a). Similar to the 2010 impact assessment (IA), neither intervention could be justified on purely economic terms and the targeted mechanism had greater welfare benefits relative to the market-wide mechanism.

There were two notable changes from the previous IA however. Firstly, DECC conducted a sensitivity analysis with a 'stress test' scenario which included a £5,000/MWh price cap, representing missing money. In this scenario the cost of the capacity market was lower in NPV terms (£-2683 vs £-2734 for a strategic reserve (*ibid*: p.32)) because 'there are positive marginal benefits of increasing capacity above the level delivered in the BAU' and 'the closure of coal plant under the IED [Industrial Emissions Directive] which takes place under the central scenario, now no longer takes place' (*ibid*: p. 32). Second, DECC appraised the options both quantitatively and qualitatively. In a separate section to the IA costs are assessed alongside a wider range of risks and benefits, and particular consideration was given to the issue of market power. It was judged that a 'Capacity Market has the potential to be most effective at reducing gaming opportunities in the energy market' whereas a strategic reserve 'is unlikely to have benefits in reducing gaming as it is only dispatched at a generator of last resort...meaning that there is still scope for significant price spikes in the energy market' (*ibid*: p. 36).

Based on this reappraisal DECC's final view was that: 'A Capacity Market is the preferred option as it best addresses the market failures and is robust to a range of scenarios. It should also reduce regulatory and market risks for investors, potentially reducing investment costs' (*ibid*: p. 1). DECC had changed its initial view, largely based on concerns about a structural issue with the market which was resulting in missing money and which fed into concerns about long term reliability. A capacity market which was subsequently approved by Parliament in the 2013 Energy Act.

### **3.3 Germany: A flexibility framing**

#### *3.3.1 The Starting Point: A Debate on Capacity Remuneration Mechanisms (2011-13)*

In September 2011 a study commissioned by BNE (Bundesverband Neue Energiewirtschaft), a trade association advocating the interests of new entrants to the energy market, kicked off an extensive public discussion on CRMs in Germany (BNE, 2011). The key message of the report was that in order to guarantee security of supply, 30 GW of new firm capacity would be necessary until 2030, but that at the same time there was no business case for investments in power plants given prevailing low wholesale power prices. The underlying hypothesis was that the existing market design would not guarantee security of supply and that a CRM would be required. The report suggested the introduction of a CRM which was selective, in the sense that it only addressed *new* investment in capacities, and was centralized; i.e. that a government-controlled authority should have responsibility for estimating the capacity needed and procuring it through auctions. It was further argued that high windfall profits for incumbents would be the outcome if a market-wide mechanism was introduced.

While the idea of organizing an additional revenue stream by introducing a CRM was appealing to many stakeholders in the sector, the suggestion to exclude large parts of the existing capacities was highly controversial and the very idea of selectivity was criticised by many. A study commissioned by the German Federal Ministry of Economic Affairs and Energy (EWI, 2012) suggested a centralized and market-wide CRM. If a CRM is to serve the purpose of providing sufficient capacity, they argued, it cannot exclude existing capacity from auctions and be an efficient solution.

Interestingly, environmental NGOs, historically quite influential voices in German energy policy, adopted different positions on the issue. Greenpeace, for example, tended to be sceptical of the need for CRMs, while the World Wildlife Fund in Germany (Öko-Institut et al., 2012) favoured a targeted capacity market with payments limited to new and flexible capacities, partly because they were concerned that insufficient capacity margins might be used as an excuse to delay the planned nuclear phase-out.

Not surprisingly, since selective approaches are not in line with the interests of incumbent power-generators, the trade-associations advocating their interests – BDEW and VKU<sup>13</sup> – suggested a market-wide CRM, however, instead of administratively determining the amount and type of capacity needed, it was to be determined de-centrally by demand with an obligation to hold capacity placed on suppliers who sell power to customers, as set out in a report commissioned by VKU (Enervis Energy Advisors, 2013). In addition to the several CRM designs suggested, a strategic reserve was discussed in a BDEW report (Consentec, 2012), not so much as an instrument to meet the capacity challenge in the long term, but to provide an additional layer of security in times of economic and regulatory transformation.

Roughly, those were the options on the table of the Kraftwerksforum (*power plant forum*), a stakeholder-platform hosted by the Ministry of Economic Affairs (for an overview over all the options in discussed see: Energiewende, 2013). This forum had been mandated in late 2012 by the Chancellor and the Minister Presidents of the German states to work out a concept for a market design that would guarantee security of supply whilst retaining a competitive approach. Its findings were set out in a report published in May 2013 (BMW i, 2013). The main message was that, due to the fact that too many fundamental questions were still unanswered, a decision of such importance should not be taken at this point. After the report was published the discussion was put on hold for a year due to political attention focusing on federal elections in October 2013 and changing responsibilities at the Ministry of Economic Affairs.

### 3.3.2 *The Green Paper*

Until 2013 the responsibility for energy market design was primarily located in the Ministry of Economics and Technology, but the Ministry of Environmental Affairs' role was also key as it was responsible for administering renewable energy subsidies. Following the election, the new administration merged responsibilities of these two departments to form a new department, the Ministry of Economic Affairs and Energy (BMW i), and this institutional realignment played a key role in a reframing of the capacity question<sup>14</sup>. Although no clear

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<sup>13</sup> BDEW (Bundesverband der Energie- und Wasserwirtschaft) is the trade-association advocating the interests of a wide range of companies, including the large incumbents in energy-generation. VKU (Verband kommunaler Unternehmen) advocates the interests of municipally owned companies.

<sup>14</sup> Our insights on the formulation of the Green Paper in the German case, in particular how organizational changes in the government department influenced this, was informed by interviews with two civil servants

positions were stated prior to the merger and views were not uniformly held, the economics ministry traditionally had a preference for market-wide capacity solutions in the vein of the British capacity market, whereas there was more scepticism in the environment department on the grounds that technology neutral mechanisms would potentially favour incumbent coal and gas producers and act as a barrier to further renewables deployment. There was also some concern that introducing an elaborate and administratively burdensome capacity market would result in lock-in and would be difficult to dismantle further down the line.

Reform of the electricity market was the main item on the agenda of the new department, and in order to avoid conflict, efforts were made to find common ground between the different constituencies. The merger of the departments resulted in a blending of different views rather than an imposition of one view over the other. A group, primarily composed of former Environment Ministry analysts, began to propose an alternative framing of the problem; that the issue was not one of a capacity shortage in a conventional quantitative sense, rather a lack of flexibility on the system. This was backed up by a number of studies which were published around this time which concluded that there were in fact significant overcapacities if one analyzed the German system along with the capacity it could access in neighbouring countries through trading on the European day-ahead market. A later policy White Paper estimated this overcapacity to be in the region of 60GW (BMW, 2015c).

The broad outlines of a market reform proposal were set out in a Green Paper titled 'An Electricity Market for Germany's Energy Transition' (BMW, 2015b) which was published in October 2014. Two main options were proposed: The first was a capacity market similar to the British, the second was termed the 'Electricity Market 2.0' (EM 2.0) which is based on a capacity (strategic) reserve. The reserve was projected to be 5% of average annual peak load, with contracts to be awarded following a competitive auction. While the key technical study underpinning the Green Paper found that there was no long term structural issue with the German market in terms of missing money (Consentec and R2b, 2015), a simulation based on a 'worst case scenario' – involving delays in new transmission capacity, premature decommissioning of plant, poor functioning of the balancing market, extreme weather conditions etc. – resulted in a loss of load expectation (LOLE) of 5hrs/year, creating the need for a more limited form of capacity intervention. The German Government proposed three separate types of reserve:

1. A *capacity reserve* where providers seeking remuneration would be invited to bid into auctions jointly managed by the four TSOs. The reserve would be based on a two-yearly cycle with delivery of capacity one year after the auction, the first of which will be in 2018. The size of the reserve for the first of these periods would be 2 GW, with an indicative overall limit of 5% of peak demand for future auctions. The reserve would be utilised if the day-ahead and intraday markets did not clear, and penal imbalance charges (€20,000/MWh) would be charged to market participants found to be responsible for this.
2. A *network reserve* to deal with north-south bottlenecks in the transmission grid. This was first introduced in 2013 and the proposal here is simply to extend it. It enables the relevant TSOs to 'redispatch' by contracting with power plants, the majority of

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who were close to this process. Also, the second author had knowledge of this while he was working at the energy think tank Agora Energiewende. The Executive Director of that organization was appointed as secretary of state with responsibility for energy-related issues at the Ministry of Economic Affairs and Energy in 2014.

which are uneconomic plants located in southern Germany which would otherwise likely shut down. At times of grid congestion these plants are called upon while wind power plants in the north of the country are ramped down and paid compensation. In 2016 the size of the network reserve was 5.4 GW, at a cost of €126m. It is envisioned that as new transmission capacity is built the need for this would diminish.

3. A *lignite reserve* in which eight highly polluting coal plants would be taken out of the market, a total of 2.7 GW, or 13% of generating capacity from lignite plants in the country. This cost of this is estimated at €1.6 bn. As we discuss further in section 4, the government was motivated to introduce this as a measure to meet near-term climate change targets rather than to address system reliability concerns. In this sense the lignite reserve is more of a climate change policy rather than a CRM in the traditional sense.

The Green Paper was assembled and structured in a way which, as far as possible, sought to reduce and mitigate potential disagreements about the market design options. The need for greater flexibility in the electricity system, as oppose to expanding capacity, was set out upfront as it was seen by the authors of the paper as an area of mutual agreement between the two general constituencies. These were; 1) those primarily concerned with economic efficiency and pricing; and 2) those concerned with emissions and renewables. Although the Green Paper was initially thought of as the starting point in a broad public debate about the range of options, it leaned heavily towards the reserve option and extensive consultation with stakeholders – 696 participants, among them 484 citizens and 212 organizations – pointed to a strong degree of consensus. Not all stakeholders viewed it in this way however. The decision not to introduce a capacity market was contested by important stakeholders, among them the largest trade associations (BDEW, VKU), large utilities (RWE, EON) and two of the German states, Bavaria and Baden-Württemberg, who do not have significant coal mining industries and are most affected by the north-south bottleneck of Germany's transmission system (BMW, 2015a).

Building on the Green Paper and its consultation, a White Paper (BMW, 2015c) was published in July 2015 which contained a commitment to the so called *Electricity Market 2.0*. In September 2015 the ministry published a first draft law<sup>15</sup> and after consultation with stakeholders and the German states, the federal cabinet adopted a second draft in early November of that year. The parliamentary process commenced with a first reading in the Bundestag on January 29<sup>th</sup> 2016 and the law was adopted later that year (BMW, 2016).

#### **4 Key ambiguities shaping the politics of CRMs**

In this section we discuss the politics of CRMs in relation to specific debates around their justification and design, particularly with respect to the forms of capacity are deemed eligible or not for capacity payments. This section is based on a comparative analysis of the British and German country-level cases, along with evidence from EU Commission appraisals of the two CRMs.

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<sup>15</sup> 'Entwurf eines Gesetzes zur Weiterentwicklung des Strommarktes (Strommarktgesetz)' which translates to 'Draft Law for the Advancement of the Electricity Market (Electricity Market Law)'

#### 4.1 How are CRMs justified?

In both cases, particularly during the early phases when the case needed to be made for government intervention, the need for a CRM was questioned and debated. In Germany, when the Economic Ministry initially assessed the capacity issue at a national scale it was presumed that a capacity market would be necessary. However, renewables expansion has been significant over the past decade and its investment in coal generation capacity has not stalled to the same extent as it has in Britain where coal plants had been exposed to market signals from the mid-1990s. How to utilise its excess capacity rather than an issue of a lack of investment emerged as the key problem framing; a strategic reserve was legitimized on the basis that it would act as an insurance policy in a system increasingly reliant on renewable generation. Indicating the importance of different types of expertise in the process, it wasn't until the market dialogue brought about by the election and the subsequent institutional and personnel changes following the merger of the two ministries that the capacity situation was reassessed in the wider context of European international flows. The problem was subsequently reframed as one of a lack of flexibility.

The British case, where there was more concern about the need to attract new investment into the sector to replace retiring fossil-fuel plant, illustrates well how a calculation based on an economic theory – the ‘missing money’ – played an important role in reframing the system and legitimizing the capacity market option. This calculation, as DECC noted, was quite speculative as there was little knowledge as to the extent of the missing money in the market, and it was highly contingent on the value placed on lost load (VOLL). In this context, as Lockwood (2017) has noted, a government conscious of the political and economic damage of blackouts was always likely to risk over-procurement and the windfall payments to incumbent generators many attribute to a capacity market. Some commentators have criticised the government for underestimating the amount of capacity available on the system (Baker and Hogan, 2014), with one environmental think-tank posing the question: ‘Is the capacity mechanism trying to solve a non-problem?’ (Sandbag, 2014). The stated intention of the market had been to bring forward investment in new combined-cycle gas turbine (CCGT) plants, and detailed analysis by Lockwood (2017) indicated that the incumbent domestic generators lobbied hard against the SR option, as a market-wide intervention would tend to favour their plant. The outcome in this case, Lockwood argues, is symptomatic of a ‘dominant energy sector culture’ involving ‘incumbents, a handful of energy consultancy firms and a relatively small number of “experts”’<sup>16</sup>.

Aside from the physical characteristics of the two systems, a key difference in both cases was how the decision to opt for a particular CRM design, whether a market-wide mechanism or a strategic reserve, was justified on the basis of its alignment with free market principles. In one case (Britain) a strategic reserve came to be viewed as an unacceptable intervention in the market as it implied the imposition of a cap on wholesale market prices. In the other case (Germany) the strategic reserve option was framed as an enabler for an *energy-only market* where prices could form freely and direct dispatch and investments decisions. While the EOM was the main justification, these ‘market-friendly’ features of the German approach are by no means clear based on a reading of the economics literature. Some economists argue that the German approach of committing to undistorted and sharp price signals in energy and other short-term markets for balancing is

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<sup>16</sup> <http://projects.exeter.ac.uk/igov/new-thinking-the-capacity-market-how-did-we-get-here/>

enough to address the missing money issue (Hogan, 2016), while for others, ‘missing money’ is only one of a number of barriers and that the volatility of such a market would introduce risks and uncertainties which would not be conducive to new investment (Roques and Finon, 2017; Cramton and Ockenfels, 2011).

In a European context, electricity market reforms are shaped by complex, multi-level governance processes and the EU level appraisal of national CRMs is becoming more influential. The EU can exert influence in this area through its legal powers to enforce state-aid rules, however, EU powers in relation to energy policy are somewhat limited as Member States (MS) retain the right to determine their own generation mix to meet energy security and environmental goals. Within these constraints, DG Competition were assessing the CRMs mainly against the specific provisions of the State Aid for Environmental Protection and Energy Guidelines (EEAG)<sup>17</sup>, by which the Commission judges whether an intervention is compatible with various electricity market legislation and regulations. The EEAG provisions are mainly in place to provide MSs leeway to achieve collective environmental policies, in particular the 2030 Energy and Climate Framework. They include a section on ‘Aid for generation adequacy’ (section 3.9) which specifies the terms under which a CRM might qualify for approval, such as; whether it addresses a defined and quantified generation adequacy problem, that the underlying issue is as a result of a market failure, that alternatives were considered, and that the measure does not have negative impacts for competition and trade.

Concerned about the distorting impacts of national-level CRMs, DG Comp launched a sector investigation into the introduction of capacity mechanisms in a number of countries in April 2015<sup>18</sup>. Their main concerns were twofold, as expressed by the competition Commissioner Margrethe Vestager<sup>19</sup>; firstly, that CRMs would interfere with competition *within* markets and ‘unduly favour particular producers or technologies’, and secondly that they would interfere with trade *between* these markets i.e. ‘create obstacles to trade across national borders’. The analysis for the review is contained in an extensive a DG Comp staff working paper (European Commission, 2016) which found significant inconsistencies in the justification for CRMs and a lack of coherent cost-benefit appraisal. In many cases capacity assessments were not based on a defined reliability standard and there was no assessment of the value of the reserve capacity to the system as a whole.

While approving the UK application (discussed further below), DG Comp initially rejected the German government’s application for state-aid approval of its main capacity reserve, for three main reasons; 1) lack of a specified end date; 2) no definition of system parameters (LOLE or VOLL) upon which an economic appraisal could be based and 3) ambiguities around the scenario methodology used to quantify the size of the reserve. The German government had argued that the capacity reserve should be analysed separately from the market as it would not be possible to accurately cost the measure and evaluate whether the scheme would deliver the investment signals required to ensure that the reserve would not be needed in the long term. They went on to argue that, based on criteria which sets out the

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<sup>17</sup> Guidelines on State aid for environmental protection and energy 2014-2020.

[http://ec.europa.eu/competition/sectors/energy/legislation\\_en.html](http://ec.europa.eu/competition/sectors/energy/legislation_en.html)

<sup>18</sup> The German CRM was part of this wider inquiry. Decisions for all countries can be found here:

[http://ec.europa.eu/competition/sectors/energy/state\\_aid\\_to\\_secure\\_electricity\\_supply\\_en.html](http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html)

<sup>19</sup> [http://europa.eu/rapid/press-release\\_IP-15-4891\\_en.htm](http://europa.eu/rapid/press-release_IP-15-4891_en.htm)

definition of a ‘service of general economic interest’<sup>20</sup>, its reserves were not state-aid as they did not involve any direct payments to generators by government. However, this was rejected by the DG Comp. A CRM, or any intervention, such as a FiT, which involves an obligation on energy market participants and a cost which is recovered through tariffs, is regarded as state-aid<sup>21</sup>. Ultimately, although the German government did not agree to base the economic appraisal of the reserve on a VOLL, they committed to calculate the potential impacts of the ‘worst case scenario’ which could then be used as a basis for a CBA and an economic justification for the CRM (European Commission, 2018).

Despite the increasingly active role of the EU, the British and German state-aid cases show that there’s still significant room for ambiguity and flexibility at the national level, particularly in relation to the security of supply assessment upon which a capacity assessment is based, and eligibility criteria (discussed further below). In response to this ambiguity, the EU Commission, as part of its *Clean Energy for All Europeans Package*<sup>22</sup>, is now putting forward proposals for the harmonisation of capacity assessment methodologies and cost-benefit appraisals across Europe. It is too early at the time of writing to evaluate the significance of these proposals, but needless to say they raise questions about the autonomy of nation-states to introduce preferred capacity measures and the authority of different institutions in a complex multi-level market. It also illustrated how there are different logics underpinning the evaluation of proposed reforms and at times these can come into conflict.

#### **4.2 Which capacity is eligible?**

A second question and key factor shaping the CRMs and their interaction with the wider energy transition is how different forms of capacity are prioritised and deemed eligible (or not) to access capacity payments.

The measure to prioritise specific lignite power-plants in Germany is an obvious example of favouring domestic producers and the increasingly important interaction between CRMs and climate policy. The German government had been under pressure to meet its self-imposed target for economy-wide emissions reductions by 2020 of 40% from 1990 levels. Business-as-usual-scenarios have shown that Germany will miss this goal by five to eight percent (Energiewende, 2016) and in order to close this gap the federal government decided to implement a *Climate Action Program* in 2014 (BMUB, 2014), which included an obligation on the electricity sector to contribute an additional annual saving of 22m tonnes of carbon (Enervis Energy Advisors, 2015). Highly polluting lignite coal generation became a target for achieving this<sup>23</sup>. Initially, there had been a proposal to phase-out lignite by placing an obligation on generators to pay for additional certificates in the EU’s Emissions Trading Scheme (EUETS), however, this was seen as placing a cost on the industry and was not politically viable. Interestingly, the payments under the reserve proposal are not for the provision of capacity, rather based on compensation, calculated as the opportunity costs of not participating in the market on a normal commercial basis. It provides a more politically

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<sup>20</sup> Set out in the 2003 *Altmark* ruling Case C-280/00

<sup>21</sup> On the basis of the *Vent de Colère* case (ECLI:EU:C:2013:851).

<http://curia.europa.eu/juris/celex.jsf?celex=62012CJ0262&lang1=en&lang2=BG&type=TXT&ancre=>

<sup>22</sup> <https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans>

<sup>23</sup> The aim of the lignite reserve is to save 12.5m tonnes per year, with the first being decommissioned by end of 2020 and the last by end of 2023.



amenable ‘soft landing’ for these plants which are located in regions of the country which are heavily dependent on mining for employment and economic prosperity<sup>24</sup>.

The inclusion of coal plants in CRMs in recent years have become politicized as part of wider EU discussions about electricity market reform and climate governance. Greenpeace<sup>25</sup>, for example, estimated that across European markets capacity payments ‘have almost quadrupled in the last twenty years’ with €32.6 billion being spend between 1998-2018 and ‘a further €25.7 billion until 2040’. For both existing and planned capacity payments across European markets they found that 66% of revenues will likely goes to coal plants. Just before Christmas 2018 a compromise was reached at the EU level regarding emissions limits on new and existing capacity mechanisms through which capacity payments for new coal plants coming into operation after 2020 would not be allowed, and by 2025 this will cover all plants emitting 550gr CO<sub>2</sub>/kWh or more, apart from certain certain highly efficient peaking plant with low utilisation. The agreement drew criticism however as the Polish government successfully negotiated for a ‘grandfathering clause’ for capacity payments which had been agreed prior to the entry into force of the revised EU Directive in 2020, enabling plants emitting above the agreed limit to continue receiving payments<sup>26</sup>.

A key EU concern in relation to the German case was the ‘restrictive eligibility criteria’ which essentially meant that DSR would be severely limited – due to a minimum bid size of 10 MW and no access for aggregated loads – and that foreign capacity could not participate in the auctions. The German government’s logic for this was that the market price would be so high that in the event of a shortage only plant with very high marginal operating costs should participate in the reserve; all other sources should be made available to the market in order to prevent this from occurring in the first place. On the basis of the EU’s opening decision to reject the application, the German government later committed to address a number of these concerns, for example by reducing the size limit from 10 to 5 MW, by allowing aggregated loads to participate, to limit the term of the reserve to three 2 year periods and to update the methodology used to calculate the size of the reserve for each auction.

The British case was less problematic in the Commissions eyes and it was approved following a one month preliminary investigation, deemed not to require a more lengthy formal investigation<sup>27</sup>. One point of note was the UK government committed to allow non-domestic capacity to be able to benefit from capacity contracts. This was not to be the case in the first capacity auction as interconnector flows were to be valued *implicitly*, i.e. incorporated into the demand curve for the capacity auction based on historical trends and statistical analysis of flows under different scenarios. The Commission raised this as a point of concern which was discussed at length during the pre-notification stage of the state-aid assessment. DECC asked for more time to assess the technical feasibility of opening up the market, given uncertainty about interconnector flows under different conditions and other effects, for example, how the obligation to provide energy at certain times might distort neighbouring markets. They committed to ensuring that subsequent auctions would value

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<sup>24</sup> Lausitz in East Germany, the Rhine area and Helmsted in Lower Saxony

<sup>25</sup> [https://www.euractiv.com/wp-content/uploads/sites/2/2018/09/Capacity\\_Mechanisms-Media\\_Briefing-Greenpeace\\_20180913.pdf](https://www.euractiv.com/wp-content/uploads/sites/2/2018/09/Capacity_Mechanisms-Media_Briefing-Greenpeace_20180913.pdf) (visited on 19.2.19)

<sup>26</sup> <https://www.euractiv.com/section/electricity/news/eu-hammers-deal-on-coal-phase-out-with-special-polish-clause/> (visited on 19.2.19)

<sup>27</sup> State aid SA.35980: [http://ec.europa.eu/competition/state\\_aid/cases/253240/253240\\_1579271\\_165\\_2.pdf](http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf)

non-domestic capacity *explicitly* i.e. it could bid into the auction if judged to be capable of physical delivery and subject to the same penalties as domestic providers if obligations are not met.

Detailed analysis of the operation of the GB capacity market since its introduction in 2014 is beyond the scope of this paper (see: IPPR, 2016), but in this case we can see how the CRM has been shaped by the technology politics of transition. The first auctions for the main component of the capacity market - a T-4 auction - took place in December 2014, with the commencement of obligations on successful bidders in the winter of 2018. The price of £19.40/Kw was lower than expectations, while the most recent T-4 auction in 2017/18 has seen prices fall to £8.40/Kw. It appears that the optimistic demand projections upon which the original CM was based have proved the doubters correct; Lockwood notes that 'both industry and government modelling assumed a steady growth in demand through to the 2020s at around 2% a year, but in fact demand since 2010 has fallen by almost 8%'<sup>28</sup>.

Since its introduction in 2014 the capacity market in GB has become politicised with respect to the eligibility criteria for different forms of capacity in the auctions. Surprising many observers, following the second auction in 2015 it became clear that small scale diesel generators were emerging as winners, with 650 MW being awarded the lucrative 15 year contracts for new plant construction, with CCGTs winning none. A key reason cited for the success of these more polluting diesel plants was their connection to the lower voltage distribution networks which meant that they could access additional sources of revenue because of their ability to help suppliers reduce the burden they place on the transmission network at pre-defined peak demand periods (Triads), thus reducing their network charges<sup>29</sup>.

Overall the first two auctions saw most of the contracts being awarded to existing sources of capacity<sup>30</sup>. In response to this outcome government proposed changes to environmental legislation, closed a number of tax loopholes and altered the capacity market rules in a way which made it more difficult for diesel generators to win contracts. Also, for the 2016 auction they increased the target capacity to 54 GW – 46 GW was procured in the 2015 auction – firstly as a means of creating demand for new gas plant, and secondly in an effort to incentivise investment in alternative sources of capacity, particularly battery storage and demand side response<sup>31</sup>. Subsequent auctions have seen interconnector capacity prove increasingly successful<sup>32</sup>, leading to a push-back by some domestic generators. Recently, a

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<sup>28</sup> <http://projects.exeter.ac.uk/igov/new-thinking-the-capacity-market-how-did-we-get-here/>

<sup>29</sup> These additional sources of revenue are known as 'embedded benefits'. 'It is thought that distribution-connected generators now derive between 20% and 50% of their revenue from these embedded benefits' (Howard and Bengherbi, 2016: p. 62). Following criticisms the energy regulator consulted on the matter and has proposed a number of reforms on the basis that embedded benefits are distorting the market: <https://www.ofgem.gov.uk/publications-and-updates/decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators> (accessed 27.7.27). The issue is extremely complex and cannot be discussed further in this paper.

<sup>30</sup> IPPR analyzed the outcomes of the 2014 and 2015 auctions and estimated that the cost of contracts for capacity delivery in 2019/20 were £851m for existing capacity and £90m for new capacity (IPPR, 2016: p. 16).

<sup>31</sup> Slightly over 1.8 GW of new gas plant, 501 MW battery storage was awarded 15-year contracts in 2016. DSR did not qualify for 15-year contracts but 1.5 GW was awarded one-year contracts. For an overview of the 2016 auction results see (Sandbag, 2016).

<sup>32</sup> Making up over 5% of overall capacity in the market.

<https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Provisional%20T-4%20Results%20DY%202021-22.pdf>

number of them funded a consultancy report which criticised as unrealistic and overly optimistic assumptions about the reliability of interconnectors (Aurora, 2018)<sup>33</sup>.

The most recent, and surprising, development has resulted in the capacity market being suspended in late 2018 due to a controversy about the eligibility of DSR to access auctions for long term (15 year) capacity contracts. Under the original market rules DSR was part of 'Transitional Arrangements' under which they had a choice to either bid into a DSR-specific auction or the main auction and compete against conventional capacity. DSR at the outset was only permitted to be awarded one-year contracts under the capacity market, not for 3 or 15 years as available to conventional generators, interconnectors and storage operators. This was on the basis that DSR did not involve the same level of fixed costs and as such did not suffer from the missing money problem. A small scale DSR provider challenged this, taking a case to the ECJ, and following a protracted legal case the court ruled in November 2018 that the market be suspended, pending a review by the Commission<sup>34</sup>. In effect the Commission needs to review its earlier decision in 2014 to approve the capacity market and provide a better justification for excluding DSR. Until this time, payments to capacity providers will be to be suspended; with over £5.5bn has being awarded to date. At the time of writing the Department for Business, Energy and Industrial Strategy (BEIS) – responsible for energy policy following the dissolution of DECC in 2016 – have made a statement to the effect that this is a matter of providing clarification to the ECJ rather than a fundamental rethinking of the scheme<sup>35</sup>. Whether this is the case and payments can be swiftly resumed, or whether a longer investigation over many months and potentially amendments to the design of the CRM will be required remains unclear.

## 5 Conclusions

As low carbon transitions advance in leading countries and the need to integrate renewables into existing systems comes to the fore, the categorisation of energy transition policies as either supporting emerging sustainable technologies or the phase-out of fossil fuels will become less relevant. As we have shown, CRMs are examples of government interventions which are somewhat ambiguous in this respect; they can be framed as mechanisms to subsidise uneconomic and polluting thermal power plants, or as a crucial bridge between the fossil-fuel and low carbon energy regimes.

Through the analysis of the Britain and Germany, where CRMs have been introduced in recent years, we have shown that the politics of electricity market reform is being shaped around the ambiguities of CRMs. The paper analysed two specific areas of ambiguity and politicisation: Firstly, how actors justify or argue against the introduction of CRMs, and secondly, how actors seek to influence their design in such a way as to favour particular technologies. While these debates were informed and influenced by different theoretical

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<sup>33</sup> These assumptions are built into *de-rating factors* which are assigned to different sources of capacity based on their ability to be available during times of system need. For an extensive technical discussion see (Panel of Technical Experts, 2017). A particular issue discussed here the use of historical data for interconnectors and the need for probabilistic assessments based on more sophisticated model-based analysis.

<sup>34</sup> ECJ ruling in favor of Tempus energy: Judgment in Case T-793/14:  
<https://curia.europa.eu/jcms/upload/docs/application/pdf/2018-11/cp180178en.pdf> (press release).  
<http://curia.europa.eu/juris/document/document.jsf?text=&docid=207792&pageIndex=0&doclang=en&mode=req&dir=&occ=first&part=1&cid=1430154> (full judgment)

<sup>35</sup> <https://www.gov.uk/government/collections/electricity-market-reform-capacity-market> (accessed on 19.2.19)

arguments about market design and economic efficiency, we observe that the processes of market reform around the electricity capacity issue are being strongly influenced by political factors specific to each country context.

Although CRMs are interventions which have not been designed at the outset with the specific intention of supporting low carbon technologies or the phase-out incumbent forms of energy, the analysis is relevant to wider debates about the politics of low carbon energy transitions. CRMs can be designed in particular ways to prioritise and exclude certain forms of capacity and will thus have a significant influence on the energy mix in countries where they are implemented. However, we have also shown how, once implemented, they are not static and do not necessarily produce the effects intentioned by their designers. Rather, they are subject to political influence as they co-evolve with the technical dynamics of the complex energy system and other segments of the electricity market.

## **Acknowledgements**

Funding for this research was from two sources: 1) The EPSRC under the 'Reframing Energy Demand' (project number EP/M008215/1); and 2) the Research Council of Norway under its clean energy R&D program Energix, (project number 243994/E20). The second author would like to acknowledge the support of Agora Energiewende during his employment as a Senior Associate there. For comments on earlier versions we would like to thank Prof Jan Webb and Dr David Hawkey at the University of Edinburgh, and Dr Peter Holm Jacobsen, Dr Rasmus Ploug Jenle, and Dr Jens Stissing Jensen of Aalborg University Copenhagen. They are not responsible for the content or any errors.

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