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Electricity Market Reform: Assessment of Capacity Payment Mechanisms

A Report for Scottish Power

NERA
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1. Introduction

This paper has been commissioned by Scottish Power to:

- review the arguments for the creation of a "market-wide" capacity payment mechanism (CPM) in the electricity market of Great Britain (GB) given the challenges the market faces over the coming years (e.g., in particular, growth in intermittent wind generation);
- assess the relative performance of a market-wide CPM versus the kind of "targeted" scheme proposed by the government in its proposals for Electricity Market Reform (EMR); and
- identify solutions for potential problems related to the implementation of a market-wide CPM (e.g., double payment).

Our analysis suggests that many different forms of capacity can provide back-up for growth in intermittent generation. It also suggests that a market-wide (or at least "broad") capacity mechanism combined with a variable energy price will encourage the provision of such capacity more effectively than a targeted capacity mechanism. The market-wide capacity mechanism is a more efficient remedy than a targeted capacity mechanism for underinvestment caused by investors' distrust of peak energy market prices. Although the EMR raises the problem of "double payment" in relation to a market-wide capacity mechanism, such a problem does not necessarily exist and, even if it does, there are a number of practical solutions that avoid it.

The rest of this paper is organised as follows:

- Chapter 2 discusses the impact that growth in intermittent generation may have on the operation of the GB system, and how it will affect the capacity requirement;
- Chapter 3 discusses the economics behind the efficient design of energy prices and market interventions to promote security of supply;
- Chapter 4 describes our modelling of the relative performance of a market-wide CPM versus the targeted scheme proposed by the government;
- Chapter 5 then outlines key elements of the design of an efficient market-wide CPM.

Appendices provide more detail on the results of our modelling and the input data contained within it, as well as a more detailed review of CPM design and of the "CFD-variant" as a method of avoiding potential "double payment"

2. Defining the Requirement for Capacity

The EMR documents discuss at length the need for "flexible" capacity, to offset a growing reliance on baseload (nuclear) plant and "intermittent" output from wind generators. However, none of the documents define the precise nature of the capacity that is required.

The EMR documents state at various points that a new "targeted" scheme for procuring capacity might be structured like National Grid's current system for procuring Short Term Operating Reserve (STOR). STOR capacity is despatchable within very short timescales – ultimately within a half-hourly settlement period – and it may be that NG will require more capacity to be procured under the STOR mechanism in the future. However, the EMR documents do not discuss a simple increase in the volume of STOR capacity, but suggest that "flexible" capacity is different in kind from STOR. That would imply that "intermittency" does not occur *within* half-hourly settlement periods, but rather over an hour or even longer periods.

The EMR documents therefore seem to be hinting at a need for capacity that can vary its output with one hour's notice or longer. In practice, that definition would encompass a wide range of plants and may not be best served by a targeted scheme (unless it is "targeted" at all non-renewable, non-nuclear capacity). Given the damage that a poorly specified and partial scheme could inflict on the market as a whole, it is important to understand the requirement for capacity created by variation in wind output.

2.1. Variation in Wind Output

Figure 2.1 and Figure 2.2 show how much wind output might be expected to vary from one hour to the next, or over a period of 4 hours, in 2011, 2020 and 2030. These figures are based on the actual pattern of total windfarm output for approximately 2.4GW of GB wind farm capacity in 2010, as reported by the balancing system, scaled up to match forecast wind capacity in future years, and compared with a forecast of half-hourly demand in GB for the same years.[1]

Table 2.1 shows maximum changes in net demand (that is, total demand less wind output) over one hour. The first two rows imply a moderate increase in hourly variation from 2011 to 2030, with the maximum *positive* change in net demand rising from 8.4GW to 10.1GW (up 1.7GW), whilst the maximum *negative* change in net demand climbs from 5.2GW to 9.5GW (up 4.3GW). Those figures would imply a significant additional need for "downward regulation". However, they depend crucially on a small number of extreme hours. If the provision of this capacity has any substantial fixed costs (as implied by the need for a targeted capacity payment) it may not be economically worthwhile to construct reserve generation to meet infrequent needs (as with any form of peak load). Moreover, those figures may reflect the increased peakiness of our demand forecast due to assumptions about demand from heat pumps and electric vehicles, which may in fact be interruptible. An economically efficient approach to planning for intermittency might therefore exclude the most extreme hours.

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[1] We assume that the half-hourly pattern remains constant, even though total windfarm output increases, because the location of windfarms remains as diverse as at present.

Figure 2.1
By 2030, Forecast Net Demand Varies Over 1 Hour by +/- 5-8 GW, Except in a Few Extreme Cases

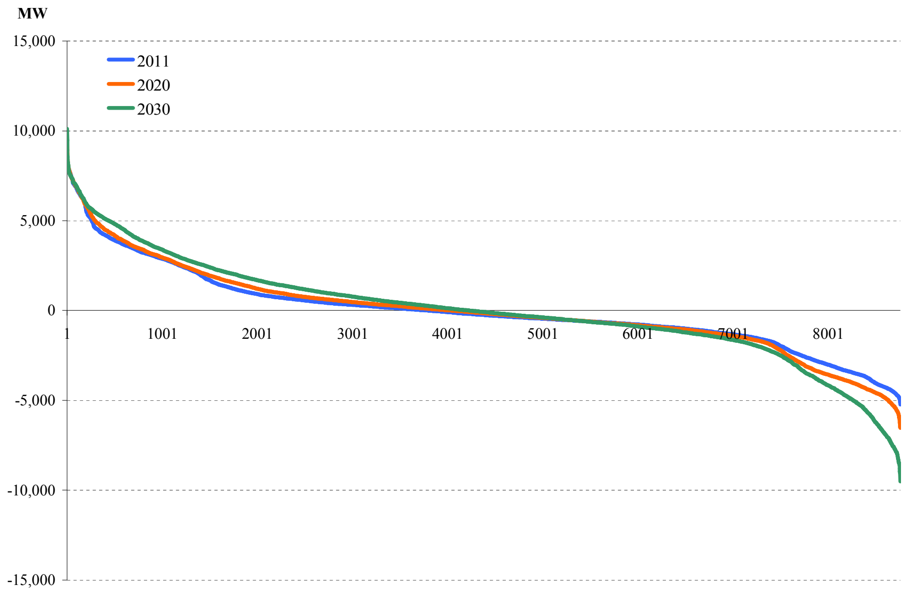

Figure 2.2
By 2030, Forecast Net Demand Varies Over 4 Hours by +/- 20 GW, Except In a Few Extreme Cases

Table 2.1
Maximum Change in Net Demand Within One Hour
(Total Demand less Wind Generation in GW)

Maximum Change in Net Demand	2011	2020	2030
Positive: All hours	8.4	9.4	10.1
Negative: All hours	-5.2	-6.5	-9.5
Positive: excluding the 20 Most Extreme Hours	7.8	7.9	7.8
Negative: excluding the 20 Most Extreme Hours	-4.8	-5.7	-8.3

The bottom two rows in Table 2.1 show that eliminating the 20 most extreme hours over a year substantially reduces the need for reserve. The maximum *positive* change in the remaining hours actually stays the same, at 7.8GW in 2011 and 2030 (+0.0GW), implying no need for any change in "upward regulation". Eliminating extreme hours also reduces the need for "downward regulation", albeit to a lesser extent. Over the period 2011 to 2030, the maximum negative change outside the 20 most extreme hours, i.e. the likely need for downward regulation, rises from 4.8GW to 8.3GW (+3.6GW after rounding).

Figure 2.2 shows the results of a similar exercise for four-hourly changes in net demand. Omitting the few most extreme hours suggests that the maximum need for four-hourly ramping is about 20 GW in both directions.

Table 2.2 below shows how much ramping is available from the current portfolio of installed capacity within GB (excluding the ramping capacity that is available from interconnectors, which is set to increase substantially in future, e.g., over the BritNed cable). It assumes relatively moderate rates of change, e.g. 8 MW/minute for CCGTs and 4.6 MW/minute for coal-fired plant. (For OCGTs and other fast response plant, we assume that the full capacity is available within one hour.) The column headed "h-1 ramp up" shows how much capacity is available within an hour, assuming that the plant is running at its minimum stable generation. The column headed "From Start-Up" shows how much is available if the plant ramps up for one hour from zero output (with a starting load of 5 MW for CCGTs, 20 MW for coal-fired plant, and zero for others). Finally, the column headed "h-1 Ramp down" shows how much each type of plant can reduce its output, starting from full load.

Table 2.2
Upward and Downward Regulation Available Within One Hour (GW)

Technology	Capacity	h-1 Ramp up	From Start-Up	h-1 Ramp down
CCGT	35.3	14.6	18.6	31.1
Coal	28.4	4.4	4.7	5.6
OCGT	0.7	0.7	0.7	0.7
Pumped Storage	2.7	2.7	2.7	2.7
Hydro	1.1	1.1	1.1	1.1
Thermal	0.1	0.1	0.1	0.1
Oil + AGT	2.3	0.1	0.2	0.1
CHP	1.8	0.9	1.6	1.8
Total	**72.4**	**24.6**	**29.7**	**43.2**

Operating constraints will undoubtedly limit the share of these ramping capabilities that are available at any time. However, CCGT capacity by itself (which is not expected to change greatly between now and 2030, as can be seen from the results of our modelling in the appendix) seems to offer plenty of ramping capability over one hour. Indeed, these figures even seem to be almost sufficient to deal with the four-hourly ("h-4") requirements identified above.

It is possible to envisage conditions in which CCGT capacity is not running (e.g. off peak conditions where load is being met largely by nuclear and renewable plant), in which wind output suddenly increases. In such conditions, it will be impossible to drop load on CCGTs. However, it would be just as impossible to drop load on OCGTs or other "flexible" plant, since it would not be running either.[2] Thus, the proposed contracts with "flexible" generating plant may increase costs without solving any problem that ordinary capacity cannot manage already.

2.2. The Duration of Variations in Wind Output

The discussion above examines the degree of short term variation in wind output, which has been described as "intermittency". However, recent evidence indicates that reliance on wind output creates problems that are not "intermittent", but rather "sustained" for a period of several days or even weeks.

Figure 2.3 below shows the actual output from 2.4 GW of windfarm capacity in Britain over a two month period in January and February 2010. Wind capacity in Britain is expected to increase substantially, but the half-hourly pattern of total output will be similar, if the capacity remains as geographically diversified as at present. The graph shows distinct and prolonged declines in wind output at various times in January 2010 and throughout the middle of February 2010, both of which were times of very high demand. Such episodes represent extended periods of low wind speed, which are known to result when a high pressure area settles over the country. Figure 2.4 shows the same data for the whole of 2010. Similar episodes, when windfarm output is a small fraction of the maximum possible for extended periods, occur throughout the year, but these episodes present the most serious problems at times of peak demand.

Prolonged declines in wind output do not create any need for "flexible" capacity, i.e. for capacity able to start and stop quickly. Instead, they create a need for capacity that can back up windfarms by sustaining output for long periods. OCGTs and other peaking capacity can provide both services, but they are not the most efficient (least-cost) way to provide a sustained increase in output in all circumstances. The most efficient way to provide a sustained increase in output (to replace intermittent windfarm output) depends on the level of demand at the time. At different times, each type of capacity (baseload, mid-merit and peaking) offers the most efficient way to provide a sustained increase in output. That suggests that a wider capacity mechanism, aimed at all types of capacity, would be more useful than a "targeted" one.

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[2] The only practical solutions in these conditions may be ramping up exports (if feasible), ramping down the output of nuclear plant (which may need extra investment to provide such flexibility), restarting interruptible demand (which is likely to be less reliable than interrupting demand) or curtailment of wind production.

Figure 2.3
Half-hourly Output of Windfarms in MW (Jan-Feb 2010)

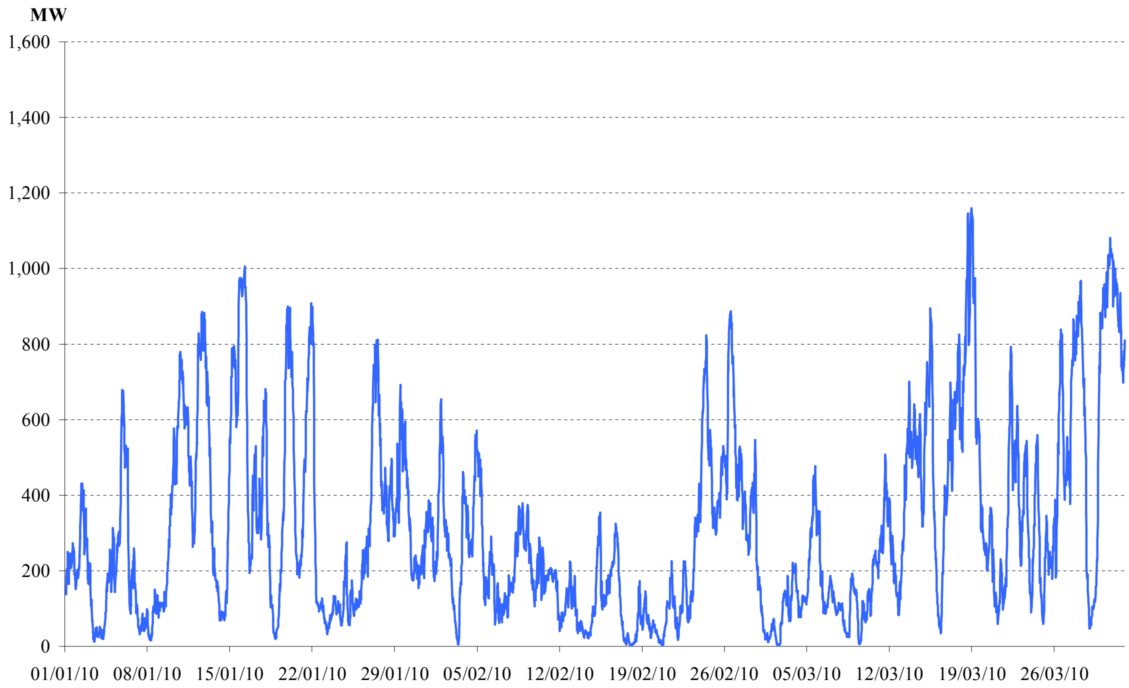
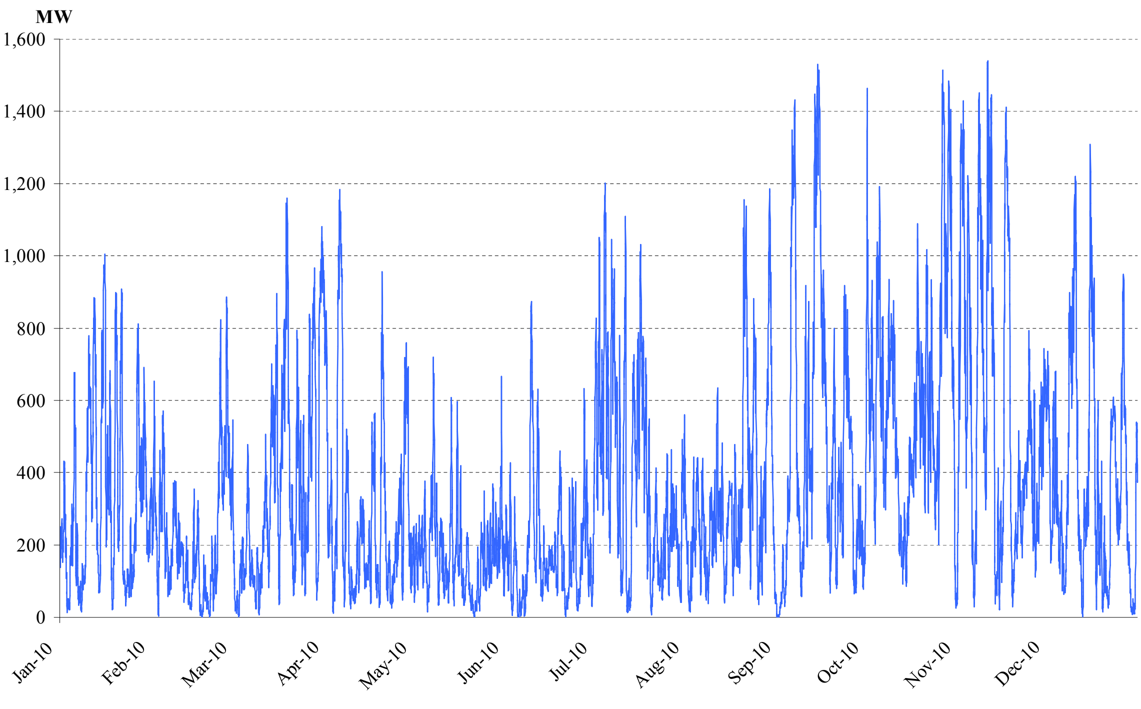


Figure 2.4
Half-hourly Output of Windfarms in MW (2010)



2.3. Conclusion

It is unclear precisely what kind of capacity is needed to deal with the "intermittency" of wind output. The EMR documents do not appear to be discussing a need for more Short Term Operating Reserve to manage variations within a half-hour. Indeed, total wind output seems to change relatively slowly in aggregate, so that the variation over an hour (or even over four hours) can be met by varying the output of ordinary capacity, both by changing the output of plant that is already running and by starting or stopping whole plants.

Greater reliance on such methods may require a reform of the energy pricing system (to ensure that variation in the value of electricity is properly reflected in market prices over a half-hour or an even shorter period) and/or of the despatch mechanism (so that the system operator has the necessary power to start, stop and direct the output of all generators). However, it does not seem necessary or desirable to provide a payment to a specific tranche of plant to provide this service, which may be available more cheaply from all conventional capacity than through a "targeted" scheme.

One problem that will emerge as reliance on windfarms increases is the prolonged drop in total output that occurs when a period of high pressure causes the wind to drop for several days at a time of high demand, such as mid-winter. In such conditions, thermal generators will need to start up relatively quickly, but also to sustain their output for several days at a time. This is not a requirement that Short Term Operating Reserve is intended to provide. Instead, it is the role of peaking capacity (at times of high demand) and of mid-merit capacity (at times of low demand).

Thus, the unreliability of wind farm output may well create new problems for the system operator, but it does not suggest any need for a new scheme to support specific, fast response ("flexible") plant. If windfarms create a need for more frequency response (i.e. variation in output within a settlement period), it may be necessary to amend and expand the current STOR mechanism, but not to implement an entirely new mechanism. The hourly and four-hourly variation in windfarm output does not seem to require a new service either, since it can be met adequately with the flexibility offered by conventional plant of all types. Windfarm output may die away for several days at a time, but that creates a need for additional capacity in total (and peaking capacity in particular), not for fast response plant.

These observations suggest the unreliability of windfarms will create a need for all generators to respond flexibly to market price signals, and for the market price to offer adequate incentives for investment in peaking plants (among others). The following sections therefore look at energy market pricing and alternative ways to encourage investment in generator capacity of all types.

3. Capacity Incentives and Energy Pricing

3.1. Electricity Pricing Rules

Incentives to build any type of capacity (baseload, mid-merit or peaking plant) depend heavily on the way in which generators' revenues capture the value of energy at peak times.

An energy-only market will experience occasional periods where demand exceeds capacity (or where there is a substantial probability that demand will exceed capacity). In these periods, energy prices uncouple from their usual level, i.e. the variable costs of generation, and include a premium, which the IA calls a "scarcity rent" (IA p33). This scarcity rent signals that capacity is scarce and is a necessary component of the incentive to invest in all types of capacity, not just peaking plants. The following sections explain the role of these scarcity events in investment decisions and show how all investment relies on the signal provided by peak energy prices – or some alternative payment mechanism.

3.1.1. Pricing in energy-only markets

Setting electricity prices equal to variable costs will not encourage investment in peaking plants. Like all types of capacity, peaking plant has a variable cost, V_p per MWh, and a fixed annual cost of construction and operation, F_p per annum. If peak electricity prices never rose any higher that V_p, and generators were only paid for their output of energy, there would be no way to recover the fixed costs of peaking plant and no one would invest in any peaking plant. This problem seems to be widely understood and recognised in the EMR documents.

What seems to be less well understood is how investment in other (baseload and mid-merit) plant also relies on peaking prices being able to rise above the variable costs of a peaking plant. In static conditions, assuming an economic (cost-minimising) despatch, it is simple to define an optimal electricity pricing rule. That rule is:

1. to set the energy price in every (half-)hour equal to the *variable costs* of the marginal generator (i.e. the generator with the highest variable costs running to meet demand at that time); and
2. to pay every unit of generator capacity the *fixed costs* of a peaking plant (F_p), either as an annual payment or as a premium in energy prices that is spread over the peak (half-)hour(s).

The derivation of this rule is set out in, among others, Hunt and Maloney (1975), IAEA (1984) and Masters (2004), where the model used to derive this optimal pricing rule is known as the "cost polygon" or "screening curve".

Actual investment decisions may be complicated by uncertainty and risk, with the effect that investors choose projects with higher costs in return for lower risks – see Beltran (2008), which uses conventional portfolio theory to examine a trade-off between costs and risks in the generation sector of Mexico. However, as the IA notes from time to time, CCGTs represent a technology that is *both* relatively low cost *and* relatively low risk for private investors in a competitive market, as long as electricity prices vary in line with the costs of thermal generation (and of CCGTs in particular). Investment in CCGTs therefore reconciles to some extent the twin desires for low costs and low risks. As a result, the existence of fuel price volatility and risks does not eliminate the need to consider whether electricity pricing allows a least-cost portfolio of generation to recover its costs. A well designed electricity market must allow investors to recover their costs, even if the market is competitive, fuel prices are static and investors chose an efficient (cost-minimising) portfolio of plant.

3.1.2. Electricity pricing and investment incentives

In an energy-only market for electricity, the fixed cost payment is replaced by scarcity rents within energy prices. The optimal electricity pricing rule requires peak prices to rise above V_p, to the Value of Lost Load, VOLL, or to some other concept of price that reflects consumers' short-run valuation of electricity consumption, rather than generators' short-run cost of electricity production.

The existence of price sensitive demand (i.e. allowing for a price elasticity of demand) modifies the picture slightly, by replacing the forced "loss of load" with voluntary reductions in consumption. Ultimately, however, each electricity market gravitates over time towards an equilibrium where revenues just cover costs: in this long-run state, the scarcity rent occurs just often enough (on average) to provide a return (over the variable costs of a peaking plant) sufficient to cover the fixed cost of a peaking plant. In this equilibrium, energy prices allow investors to recover all their costs if they choose an efficient portfolio of plant types and offer their plant to the market on a competitive basis.

Departing from the optimal electricity pricing rule therefore means that the electricity market will not reward efficient, competitive behaviour by investors in generation, unless it offers the same level of revenues in a different form.

3.1.3. Pricing, cost recovery and incentives to invest

To ensure the recovery of total costs in an energy-only market, electricity prices for all generators must cover the variable cost of the marginal plant at all times, and must also include the fixed cost of peaking plant at peak times (or some alternative source of revenue). If some energy sales are denied one of these required components of revenue – e.g. if conventional baseload and mid-merit generators are denied scarcity rents and are not offered any alternative source of revenue – it will not be possible for an efficiently designed fleet of generators to recover its costs, except perhaps through random effects.[3] For existing plant with sunk investment costs, imposition of a new system that resulted in the loss of scarcity rents would represent an expropriation of value. That would damage long-term investment incentives – at a time when the government is asking investors to trust it as a counter-party to low-carbon FITs.

The IA refers to the revenue foregone when electricity pricing rules omit the scarcity rents as the "missing money" problem. Such pricing rules discourage investment and threaten security of supply, unless there is some other way to give the "missing money" to all

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[3] Generators may derive some additional revenue from the effect of changing fuel prices and their impact on "inframarginal rents" (the small differences between a plant's own variable costs and the variable cost of the plant that is setting the price). However, such impacts are not a reliable source of revenue, since they depend on random and unforeseeable changes in *relative* fuel prices.

generators. The need to define and ensure payment of this "missing money" represents the main challenge for the design of an electricity market.

3.2. Market Design and Market Interventions

To provide the "missing money", electricity markets can adopt one of two broadly defined systems:

- either they can let short-term prices of electricity rise to shortage levels (VOLL) when demand exceeds capacity, so that generators earn scarcity rents;
- or they can set energy prices equal to the variable cost of the marginal plant (so peak prices never rise any higher than V_p) and offer a capacity payment *in lieu of* the scarcity rents.

As a matter of *market design*, therefore, a capacity payment is an *alternative* to the scarcity rents that would otherwise be contained within peak prices for electricity.

In practice, regulators may use a capacity payment system as a *market intervention* intended to encourage more investment in capacity than a market would produce.

3.3. Market Interventions to Increase Capacity Margins

3.3.1. Rationale for intervention

If the regulator intends to increase the capacity margin by strengthening investment incentives, the combination of payments to generators must award more revenue than an energy-only market would offer. There are several possible reasons why regulators might intervene in this way, as discussed below.

- **Higher valuation of VOLL than the market**

  Politicians may place a higher price on the loss of load (because of the adverse political consequences) than consumers are willing to pay for generation capacity. Politicians may then instruct regulators and other officials to shift the market equilibrium in the direction of more capacity and fewer losses of load. Such interventions are not uncommon, but are also inefficient, since they do not correct any particular distortion in the market. Instead, they impose a political valuation of capacity over that of the people who have to pay for it.

  An efficiency argument for such interventions would arise if consumers were unable to signal their true VOLL, e.g. because they did not face tariffs that varied by time-of-day due to a lack of half-hourly metering. The installation of smart meters provides one way to overcome this lack of market signals. However, consumers may not react to time-of-day prices, if they find it difficult or costly to do so. Installing smart meters may therefore be more expensive and less efficient than simply setting a higher capacity target centrally.

- **Capping of energy-only prices**

  A plausible reason for intervening to promote investment in capacity is the recognition that the market design is currently flawed and understates VOLL when a shortage arises, or threatens to do so. The EMR documents themselves recognise two sources of this problem within NETA.

- The IA (p28, para 8) recognises that the "cash-out price" is too low because it does not include all the costs of balancing actions. This criticism applies to the definition of SBP, the "cash-out price" charged for the sale of electricity to traders who are short. SBP lags behind the rising cost of electricity during a shortage, because it is calculated as an average over a range of accepted offers, not all of which recognise the existence of a real shortage.
- In principle, this flaw in the rules of NETA can be corrected simply by changing the rules, so that SBP more accurately reflects marginal costs during a shortage. However, the IA identifies another problem that would affect any energy-only electricity market, even one in which prices reflected marginal costs. Although efficiency requires high electricity prices during a shortage, politicians and regulators have strong incentives to intervene in electricity markets precisely at those times, by capping or reducing prices and profits within the sector. Even the threat of such interventions weakens the incentive to invest, due to the risk perceived by investors that energy prices will not be allowed to rise during a shortage.

In economic terms, the fear that political pressure will restrict peak prices for electricity has some basis in theory and fact. During a shortage, high peak prices (and hence high profits for companies that own generation) will coincide with a temporary period of interruptions to supply – i.e., apparently, low quality of service. Such events are not easy to distinguish (without close scrutiny) from generators withholding capacity to force up electricity prices. When a shortage occurs, therefore, governments and regulators have an incentive and a reason to restrict electricity prices, or to punish electricity firms for making "excessive" profits. They cannot diminish this threat by declaring beforehand that they will not intervene in such a manner. Pre-stated commitments not to intervene in peak prices are unfortunately "incentive incompatible", meaning that governments and regulators have no incentive to abide by such commitments in precisely those conditions where the commitments would be binding.

The solution is to create a set of "incentive compatible" market-based arrangements. Such outcomes are difficult to achieve, but one possibility is to use a capacity payment mechanism. Such mechanisms smooth out payments to generators and provide a substitute for the peaking prices, which would otherwise concentrate revenues and profits in times of shortage and interruptions.

3.3.2. Double payment

As a market design tool, capacity payments are often intended to act as a substitute for the "scarcity rents" that would otherwise be present in peaking prices. Such a market design might have to make sure that generators received a reward for investing in capacity from either one source or the other, but not both. The IA (p33, para 27) briefly discusses "double payments" as a possible disadvantage of capacity payments. It seems to have taken on more significance in subsequent discussions. However, double payment need not necessarily be viewed as a problem. In many regimes, the extra revenue provided by capacity payments is viewed as an incentive for additional investment in capacity which is intended to reduce or eliminate capacity shortages and the associated scarcity rents (as demonstrated by the modelling results in Appendix A). Some governments and regulators regard the additional security of supply as a benefit worth paying for. Others may regard such incentives and investment as inefficient, relative to a market outcome, but even in these cases the so-called double payment can easily be eliminated by astute market design.

3.3.3. Non-market interventions

Instead of providing extra revenue through the market to boost capacity margins, regulators might alternatively seek to mandate additional capacity through obligations placed on central agencies. This approach appears to be what the government has in mind with its proposal for a targeted capacity mechanism, though the details of how any such scheme would operate are unclear. The risk with a narrowly defined scheme is that it might lower peak energy prices and discourage investment outside the scheme. If the aim is to improve security of supply, this reaction would signal a need to broaden the scheme. However, continual changes to such schemes will create risk, discourage investment and threaten security of supply.

The government is conscious of this problem and discusses a "last resort dispatch" approach, modelled on the mechanism used in Sweden, as a means to avoid the "slippery slope" towards an ever-wide scheme. However, it is hard to see how such a scheme could work effectively in practice, and in any case "last resort dispatch" does not prevent the government-supported investment from displacing other investment. (It merely tries to minimise its effect on despatch.) Thus, even if the last resort dispatch can be made to work effectively, it is unclear that a targeted capacity payment mechanism will increase security of supply. Centrally procured capacity may just substitute for capacity that would otherwise have been provided by the market (i.e., simply "crowd out" other investment). Worse still, poorly justified government interventions may deter potential investors so much that security of supply actually falls.

3.4. Conclusion

In any electricity market, incentives to invest depend on the value of capacity during times of peak demand. This value may emerge as a "scarcity rent" in peak electricity prices, but such prices invite regulatory interventions and may not be a credible means of encouraging long term investment. Capacity payments potentially provide a more stable and spread out source of revenue to generators, which avoids reliance on high profits at the time when quality of service is lowest.

Adding capacity payments to an existing energy-only market strengthens the incentive to invest, unless it is offset by some other change. Government or regulatory policy may dictate a higher capacity margin than the market would otherwise bring about, but this decision about desirable levels of capacity is separate from any decision about the form of pricing. Governments may decide to use the capacity payment specifically to increase investment – i.e. to offset some other distortion such as an understatement of peak prices. Equally, governments and regulators may decide that generators do not need, and should not capture, both a capacity payment and a scarcity rent, but such double payments can be avoided in many ways. Some non-market interventions do therefore provide a potential means to boost capacity margins. However, it is unclear whether targeted schemes, such as that proposed by the government, will have the desired effect and they risk having the unintended consequence of deterring investment.

The next chapter summarises the results of our modelling of the relative performance of a market-wide CPM versus the targeted scheme proposed by the government. We then go on in Chapter 5 to explore the potential design of a capacity payment, its effect on investment, and the methods that might be used to avoid double payment.

4. Modelling of Alternative CPMs

4.1. Overview of Modelling Task

To define a baseline against which to compare alternative scenarios, we created a forecast of an efficient, energy-only GB power market, which allows prices to spike to the value of lost load (VOLL) in periods when demand exceeds available capacity. In this scenario, we assume a VOLL of £10,000/MWh.

We then examine the effect of assuming a cap on peak energy prices set at £1,000/MWh (i.e., below VOLL), which captures the constraint on expected prices implied by the risk of government intervention, e.g. interventions intended to prevent high prices in periods of shortage. This scenario approximates to the current institutional arrangements. By comparing the results of these two scenarios, we quantify the inefficiency created by the risk of political intervention to cap peak prices discussed in the EMR documents.

Against this background, we review the performance of the two main types of capacity payment mechanism discussed in the EMR documents, and assessed by Redpoint,[4] namely:

- A "market-wide" capacity mechanism, where every generation unit on the system receives a payment per MWh of available capacity, with the capacity price set equal to the fixed costs of a new entrant OCGT peaking plant; and
- A "targeted" capacity mechanism, where the TSO conducts a tender to procure a small quantity of OCGT peaking capacity, and recovers the fixed costs of this capacity through use of system charges or some other market-wide levy.

In both cases, we assume that these mechanisms start operating from 1 January 2015, on the basis that the government has stated it plans to enact the EMR proposals by the end of the current parliament.[5] We summarise the results that flow from our modelling below. Detailed results can be found in Appendix A and the source of data inputs is summarised in Appendix B.

4.2. Summary of Modelling Results

4.2.1. Projecting an efficient capacity mix

Our baseline forecast assumes a volume of investment in renewable and nuclear capacity that is consistent with government plans. The energy-only market structure in which prices are allowed to reflect the system marginal cost, up to the true level of VOLL, produces a forecast

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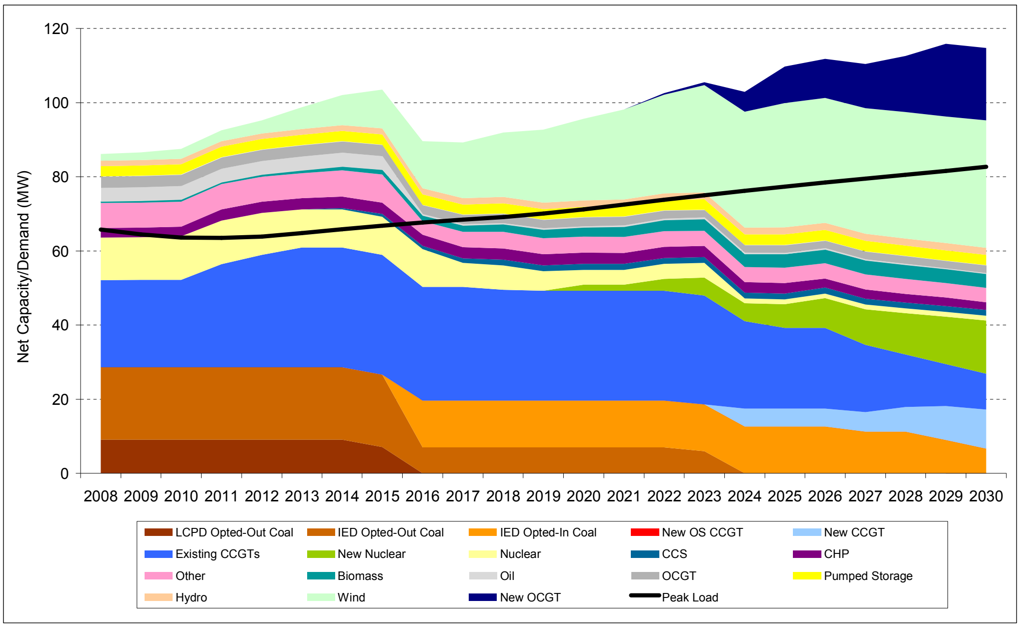
4 *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010.

5 The EMR Impact Assessment assumes that the capacity payment mechanisms begin in 2018, but that scenario lacks credibility for two reasons: (1) this date is beyond the life of the current parliament; and (2) it seems to be timed to coincide perfectly with the time when Redpoint predicts shortages will begin to emerge under the current market arrangements. Imposing a capacity payment only when energy prices would otherwise include scarcity rents will make investors nervous that the government will withdraw the scheme once investment has taken place and the risk of shortages recedes. That threat would undermine investment incentives and/or raise the cost of investing in generation.

of the efficient capacity mix for the GB market.[6] This capacity mix includes some new CCGT and OCGT capacity, as well as some investment in extending the lives of coal plants by fitting Selective Catalytic Reduction (SCR) equipment, as illustrated in Figure 4.1.

Figure 4.1
Projection of Installed Capacity vs. Peak Demand



Source: NERA analysis

4.2.2. Alternative scenarios

Figure 4.2 and Figure 4.3 summarise the results of our modelling in terms of total installed capacity and total unserved energy for each of the four scenarios we have modelled.

Assuming a cap on peak energy prices of £1,000/MWh (i.e., below VOLL) changes the trade-off between the construction of peaking plant and load shedding, such that the market provides less capacity and the quantity of load shedding increases.

As a corrective measure, a targeted capacity mechanism would have a negligible impact on installed capacity and unserved energy. In our model, as illustrated by Table 4.1, having the System Operator procure 3 GW of OCGT capacity merely "crowds out" other forms of capacity, such as existing CCGTs that could also be used to provide peaking capacity, or new OCGTs that would otherwise be delivered by the market.

6 At least, within the deterministic framework used by our model.

Table 4.1
Capacity with Targeted CP, less Capacity in Price Cap Scenario (GW)

	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Change in Installed Coal Capacity	-	-	-	-	-	-	-	-	-	-
Changes in Existing CCGT Capacity	-	-	-3.1	-3.0	-3.0	-3.0	-1.3	-	0.2	-
Change in New CCGT Capacity	-	-	-	-	-	-	0.0	0.0	-0.3	-0.2
Change in New OCGT Capacity	-	-	3.0	3.0	3.0	3.0	2.1	-0.0	0.2	0.2
Total Change in Capacity	**-**	**-**	**-0.1**	**-**	**0.0**	**0.0**	**0.9**	**-**	**0.1**	**-**

Source: NERA Analysis

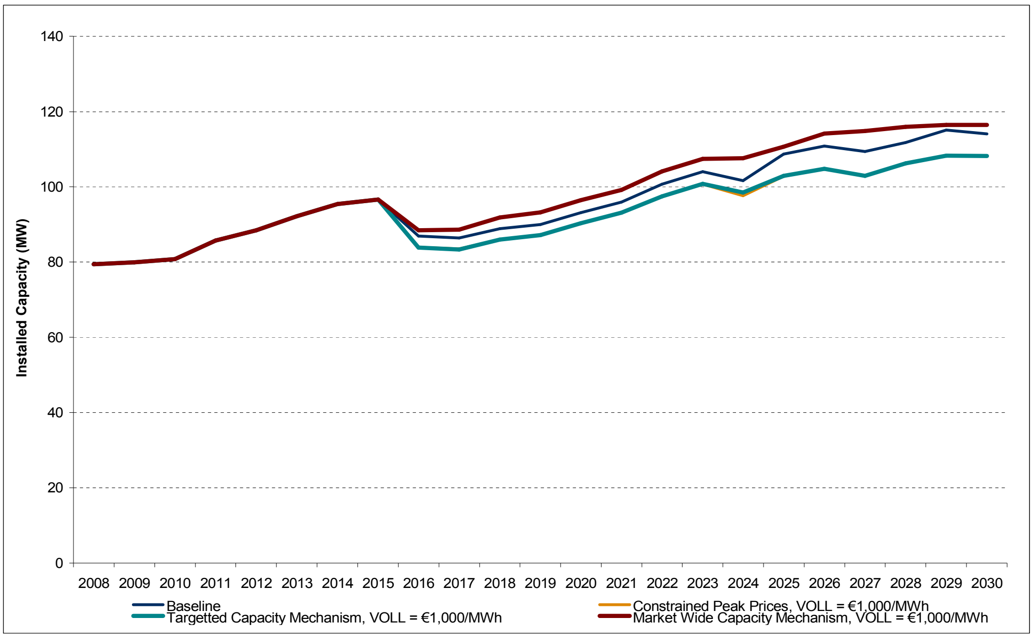
With a market-wide capacity payment, on the other hand, we estimate that the capacity provided by the market rises closer to (very slightly above) the total installed capacity in our efficient baseline scenario (Figure 4.2). The quantity of lost load also falls closer to the efficient level (Figure 4.3).

Within our deterministic framework, this result holds whether or not we assume a £1,000/MWh price cap operates alongside the market-wide capacity payment: with a market-wide capacity payment set equal to the fixed price of a peaking plant, the energy price never rises above the variable costs of a peaking plant in the long-run, and hence we see no material difference in capacity or prices between these two variants. In practice, supply and demand are not deterministic and the possibility of unanticipated shortages can never be ruled out. Such shortages provide upside for investors in a system without a price-cap and may cause some extra (inefficient) investment in capacity, or a small amount of "double payment" or some combination of the two.

As shown in Figure 4.4, none of these scenarios has any impact on CO_2 emissions from the power sector in Great Britain, because the generation mix (i.e., MWh produced by different technologies) does not vary between different scenarios:

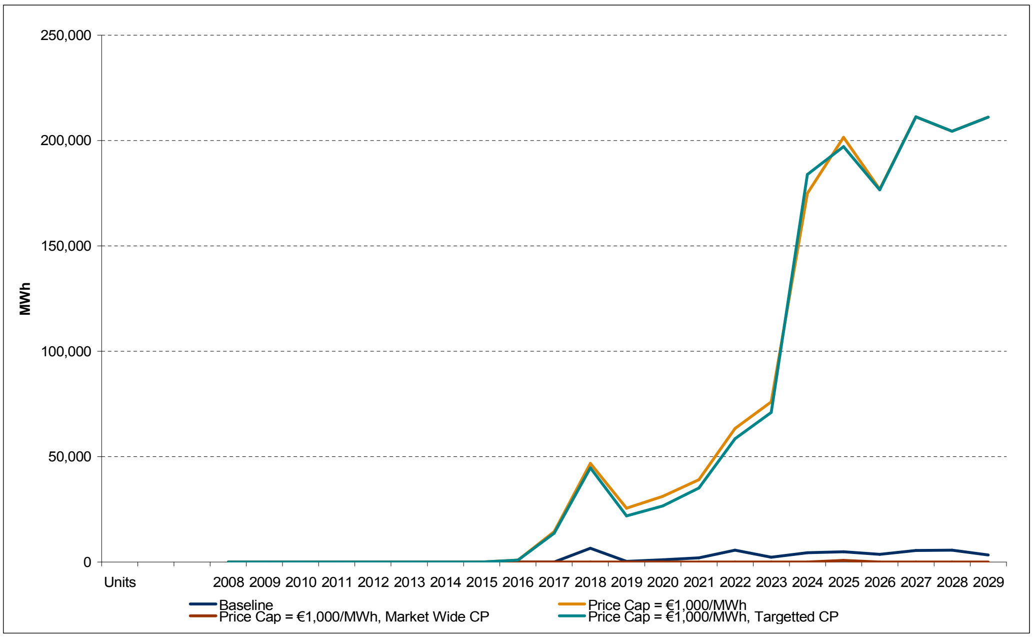
- we forecast the same output from renewables and new nuclear plant, because they are remunerated outside the market (e.g., via FITs);
- the retirement decisions of LCPD-opted-in coal generators depend on their decisions to opt in or out of the IED, which do not change between different scenarios;
- the only changes to capacity affect the amount and type of peaking capacity (and the volume of load shedding), which has no material impact on CO_2 emissions.

Figure 4.2:
Total Installed Capacity Across Scenarios (MW)



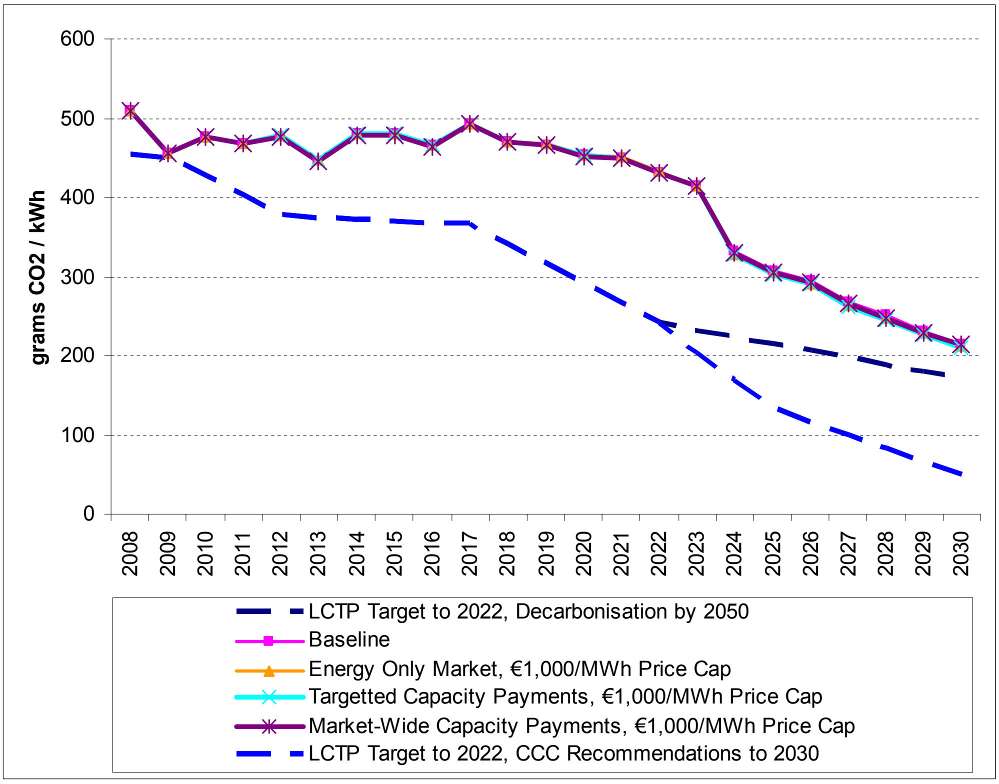
Source: NERA analysis

Figure 4.3
Expected Unserved Energy Across Scenarios (MWh)



Source: NERA analysis

Figure 4.4
Power Sector CO2 Emissions vs. Target Across All Scenarios (g/kWh)



Source: NERA analysis

4.3. Welfare Implications

Table 4.2 shows the welfare effects of the scenarios we considered in our modelling, relative to the efficient outcome, and broken down by producer and consumer surplus. The overall impact on welfare appears (highlighted) in the bottom line of the table. The table shows changes in welfare (i.e. increases/decreases in costs and benefits) relative to the efficient generation mix that results under the regime of an unrestricted, energy-only market.

The inefficiency caused by limiting VOLL to €1,000/MWh causes welfare to fall by £5.65 billion over the period 2012-2030, mainly due to a significant increase in involuntary load shedding. This scenario represents the likely outcome of current market arrangements – Business As Usual or "BAU" – if investors regard peak cash-out prices as an understatement of VOLL.

The effect of instituting the targeted capacity mechanism varies, depending on how we assume it affects investment outside the scheme. If we assume it has no distortionary effect on investment outside the scheme, overall welfare over the period 2012-2030 falls by £5.54 billion relative to the baseline efficient level, which is a negligible improvement on the price-capped energy-only market (i.e. a negligible improvement on BAU). On the other hand, the targeted scheme might actually increase regulatory risk in the market, because of uncertainty over how resources within the scheme will be offered into the market and/or over whether the scheme will be expanded in future, due to the "slippery slope" effect discussed in the EMR documents The targeted scheme would then reduce welfare relative to the price-capped energy-only market. For example, if we assume that the increased regulatory risk adds 200 basis points (bps) to the hurdle rate for investment in the market, the total welfare loss compared to the efficient baseline increases to £6.04 billion, mainly due to increased involuntary load shedding caused by capacity becoming more expensive.

Table 4.2
Welfare Effects 2012-2030
(2010 £ billion, NPV as at 1 January 2012, discounted @ 3.5%)

	Energy-only Market, €1,000 Price Cap	Targeted Capacity Scheme, €1,000 Price Cap: Baseline WACC	Targeted Capacity Scheme, €1,000 Price Cap: 200bps WACC premium	Market-Wide Capacity Scheme, €1,000 Price Cap
Changes to Producer Surplus				
Revenue from Energy Sales	-0.52	-0.64	2.71	-32.60
Generation Costs	1.74	1.72	2.09	-0.31
Capacity Payments	-	1.88	1.88	44.76
Sub-total	**1.22**	**2.96**	**6.67**	**11.86**
Changes to Consumer Surplus				
Cost of Wholesale Energy	0.52	0.64	-2.71	32.60
Capacity Payments	-	-1.88	-1.88	-44.76
Cost of Load Shedding	-7.39	-7.26	-8.13	0.24
Sub-total	**-6.87**	**-8.50**	**-12.72**	**-11.93**
Net Welfare Change	**-5.65**	**-5.54**	**-6.04**	**-0.07**

Source: NERA analysis

In contrast, a market-wide capacity payment mechanism has a significant positive effect on welfare in a price-capped market. It increases the amount of capacity being made available and reduces load shedding, back towards the efficient level.[7] Extra capacity might appear to be inefficient when added to a market that is perfectly efficient to start with. However, it represents a welfare improvement in an imperfect market suffering from the "missing money" problem due to a cap on prices. Correcting for the "missing money" problem moves the market outcome back *towards* the efficient generation mix. It reduces the overall loss of welfare compared to that baseline, from £5.65 billion without the capacity payment mechanism to a mere £0.07 billion (£70 million) with it. Therefore, compared with an imperfect energy-only market, in which prices are capped (or perceived as capped) at €1,000/MWh, a market-wide capacity payment mechanism increases welfare by £5.58 billion. This benefit dwarfs the administrative cost of running a capacity mechanism, which the IA[8] estimates at £3-10 million per year, giving an NPV over the period 2012-30 of £0.04-0.13 billion as at 1 January 2012.

4.4. Conclusion

Our modelling suggests that a market-wide CPM is an effective means of correcting the market failure resulting from the risk of political intervention to cap peak energy prices. In contrast, the targeted scheme proposed by the government will either "crowd out" investment that would have been provided by the market anyway, and hence have negligible effect, or reduce welfare by injecting regulatory risk and additional costs.

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7 Some commentators argue that a capacity payment mechanism has the benefit of reducing investment risk, and hence the cost of capital for generation investment. We are not aware of any reliable evidence of such an effect and hence we have not factored any such effect into our modelling. Furthermore, to the extent any such effect is due to risk transfer to consumers it ought not to affect overall welfare.

8 EMR Impact Assessment, page 50, paragraph 98.

5. Efficient Structuring of Capacity Payments

5.1. Capacity Payments as a Call Option

When consumers make capacity payments, they want to know what they are getting in return. The answer to that question is that capacity payments offer protection against high energy prices during a shortage of capacity:

- either through a cap on energy pricing (i.e. the capacity payment is an alternative to high energy prices during a shortage);
- or through the effect on the capacity margin (i.e. the capacity payment encourages construction of extra capacity, which makes shortages less frequent).

To put this arrangement into a market context, we can imagine that consumers are signing a one-way ("call") option contract with generators, under which they pay a fixed option fee (the capacity payment) in return for the right (but not the obligation) to take energy at a certain price and no more. If the "spot" market price is lower than this maximum, consumers do not "call" this option, but take energy from the market instead. This contract replicates the effect of a capacity mechanism, so efficient contract forms will provide a guide to efficient capacity mechanisms.

5.2. Defining the Strike Price of the Option

The maximum price defined in this call option (the "strike price") can be set by considering the costs of generation, but may in practice reflect the maximum level of prices that can be tolerated in an energy-only market (tolerated, that is, before either causing distress to consumers or threatening to provoke an intervention by government officials).

In the idealised pricing system set out in the "screening curve" analysis, the annual capacity payment is F_p, the fixed cost of a peaking plant, and the maximum energy price is V_p, the variable cost of the type of peaking plant used to define the capacity payment. In practice, regulators often set a cap which is some way above any estimate of V_p, in order to allow for possible variation in variable costs, or underestimation of fixed costs.

If the cap were set exactly equal to an estimate of V_p, some generators might find they were under-remunerated for maintaining and operating their plant. Even if one had confidence that the market operated efficiently, the consequences of setting the cap too low (plant closures and shortages) are likely to be much more serious than the consequences of setting the cap too high (slight over-payment or over-supply of capacity). When there are doubts over the strength of investment incentives under any arrangement, the consequences of setting the cap too low could be disastrous. Risk analysis therefore tends to suggest strongly erring on the "up" side when setting price caps.

5.3. Source of Double Payment

The efficient design of a capacity payment treats it as an option contract, with consumers paying the capacity payment, representing an option fee, in return for generators agreeing a strike price at a level consistent with the desire to stabilise costs to consumers.

The problem of "double payment" arises if generators receive a capacity payment, but consumers receive no obvious benefit from capping or lowering energy prices. In a perfectly functioning market, the source of that concern is easy to identify. At times of peak demand or capacity shortage, electricity prices may rise above any reasonable definition of V_p, the variable cost of a peaker, so that consumers find themselves contributing towards the cost of capacity both through the capacity payment and through energy prices. In practice, since we do not live in a world of perfect electricity markets, such concerns may be misplaced.

In an imperfect market such as BETTA, where the energy-only price understates the value of electricity at peak times and provides a relatively weak incentive for investment, consumers would benefit from the extra capacity brought forth by offering a capacity payment in addition to the current energy price. Cash-out prices would never reach VOLL, because they would continue to understate the value of energy during a shortage (and remain exposed to the threat of other, more formal caps). However, the resulting increase in security of supply would provide consumers with a benefit that justifies the apparent increase in payments to generators. This was the finding that emerged from our modelling, when we imposed a price cap and then added a market-wide capacity mechanism.

Therefore, double payment might not be an important issue of market design. The addition to revenues might be a useful counter-measure to perceptions that peak electricity prices provide an unreliable incentive for investment. The increase in total payments to generators would result in additional capacity and higher security of supply. However, the topic of double payment appears to have become a focus of debate within the EMR consultations. This debate implies that the capacity mechanism is intended to be "revenue neutral", i.e. to offer *more stable* returns for investment, without *increasing* total payments to generators.

In practice, even if a capacity payment increases security of supply back towards the efficient level, consumers may still complain about a "double payment" if the electricity market ever experiences a capacity shortage and prices rise to the level of VOLL (or similar). In such conditions, there is in fact still no double payment, as the total level of payment is necessary to increase the capacity margin. However, whilst increasing capacity margins reduces the risk of a capacity shortage, it can never guarantee to eliminate shortages entirely. Consumers pay extra for a reduction in risk, not for complete security. Unfortunately, consumers (and politicians) may not see it that way if a shortage occurs. At that time, the government will still face pressure to intervene in the market. To make the system acceptable to consumers and government in times of capacity shortage (and therefore a credible, "incentive compatible" form of market design), a well designed capacity mechanism would anticipate this problem and offer a solution to it.

5.4. Avoiding Double Payment

There are several ways to remove or restrict the potential for double payment, as explained below.

Within the framework of an option contract, there are several ways to design the "option" in a way which avoids any possible double payment. The following three are taken from real world examples:

- **Ireland: Adjustment to Capacity Payment:** set the capacity payment equal to the cost of a "best new entrant" (BNE) peaking plant, but deduct an estimate of any "inframarginal rents" ($V_p - V_{BNE}$) expected to arise when electricity market prices exceed the variable cost of the BNE plant (V_{BNE}). In practice, the regulatory authorities in Ireland seem to have dropped this element of the calculation only a couple of years after the start of the SEM (in 2007), partly because such inframarginal rents disappeared when total demand fell, and partly because this item was difficult to estimate accurately in an objective manner.
- **US, Spain and Ireland: Caps on Energy Prices:** Several electricity markets put a cap on the energy price, either at V_p or at a higher level intended to permit some scarcity rents but not an excessive amount. Indeed, many capacity payments have emerged as a method of encouraging investment in response to a decision by a regulator to cap energy prices (rather than vice versa). Estimates of the appropriate cap vary widely, from a few hundred £/MWh to thousands of £/MWh. For instance, in Ireland, the cap on energy prices is €1,000/MWh. In Spain, the cap is only €180/MWh, but the capacity payment no longer covers the fixed costs of a peaking plant, so that there is widespread concern about investment incentives. Given such fears (and the difficulty of amending a price cap once it has been introduced), it would be wise to err on the side of caution by adopting a relatively high value. In any case, it is inefficient to constrain energy prices when a shortage occurs, because high energy prices provide a useful tool for managing shortages (i.e. they encourage generators to provide additional capacity and consumers to reduce their demand).
- **GB: Extension of the CFD Model (as in FITs) to Capacity Payments:** As with the government's proposed design for Feed-In Tariffs, it would be possible to adopt the CFD format for the capacity mechanism. The scheme would specify a strike price, but would allow electricity market prices to vary without constraint, and then arrange a *financial* refund from generators to consumers if electricity market prices exceeded a certain strike price (see Appendix C for details). This approach preserves the incentives for efficient behaviour offered by a freely adjusting electricity market price (i.e. spot price or cash-out price). However, by affecting the risk structure of market prices, it may cause a fall in trading and the liquidity of contract markets.

Of these approaches, the cap on market prices appears to be the most easily implemented, since the rules on cash-out prices can simply be amended to incorporate a maximum value. Indeed, the IA suggests that cash-out prices already suffer from a *de facto* cap, because of the way they lag behind the costs of balancing during a shortage. No formal cap may therefore be required, and the capacity mechanism may serve as a corrective measure to offset this distortion, as we saw from our modelling results in the previous chapter.

Ofgem has been charged with investigating ways to create a more effective energy market. A capacity payment may be one way to achieve that aim, given investors' distrust of peak energy market prices as an incentive to invest in capacity. However, Ofgem may not wish to formalise this distrust in an explicit cap on energy prices, but may still want to ensure that no apparent double payment arises. Appendix C therefore discusses the design issues that arise from any attempt to create a "CFD-variant" capacity payment. The main problem is the identification of a suitable reference price. This obstacle can probably be overcome (as it would have to be for FITs to operate as CFDs, as the government is proposing). However, any capacity payment that varies inversely with peak-period energy prices affects the ability of generators to hedge and their incentive to participate in contract markets. A CFD-variant capacity mechanism may therefore solve the problem of double payment, but at the cost of reducing contract market liquidity.

5.5. Conclusion

As suggested above, the current electricity market may appear to investors to be subject to a de facto price cap, for which a market-wide capacity mechanism would be a useful corrective measure. In this “second best world”, a market-wide capacity mechanism improves welfare, by encouraging investment in capacity that is closer to the efficient level than otherwise.

Of course, any distortion of energy market prices is undesirable and the IA suggests that Ofgem may be asked to devise a more efficient or transparent electricity market pricing rule. The electricity market may be reformed, both to improve investment incentives and to provide a reference price for FITs in CFD format. Such reforms might remove the de facto cap on energy prices – but the IA seems to accept that doubts will always surround the ability of peak prices to remain unfettered in any electricity market.

The creation of CFD-FITs would also create an opportunity to apply the CFD format to the capacity mechanism. As far as we are aware, this option is not used anywhere. The CFD format offers the advantage of allowing market prices to match competitive market signals, including scarcity rents when capacity is scarce, without leading to any double payment. However, its main disadvantage is that it would substitute for other hedging contracts and may reduce the liquidity of contract markets.

In any case, the initial design of a capacity mechanism can be based on the idea that energy prices are already capped below the optimal level, and require a corrective measure to encourage efficient investment in generation capacity. In this context, our modelling shows that market-wide capacity payments would not represent a double payment, but would simply be replacing the “missing money” as defined within the EMR documents.

6. Conclusion

Our analysis suggests that many different forms of capacity can provide back-up for growth in intermittent generation, and that a "market-wide" (or at least "broad") capacity mechanism and a variable energy price will encourage the provision of such capacity much more effectively than a "targeted" capacity mechanism.

The market-wide capacity mechanism is also a more efficient remedy than a "targeted" capacity mechanism for the underinvestment caused by investors' distrust of peak energy market prices. Although the EMR raises the problem of "double payment" in relation to a market-wide capacity mechanism, it such a problem does not necessarily exist and, even if it does, there are several practical solutions that avoid it. We therefore conclude that a market-wide capacity payment mechanism is a practical solution to the regulatory failures affecting the current energy-only market.

Appendix A. Market Modelling Results

We have undertaken a modelling exercise to estimate the impact of capacity payment mechanisms on the evolution of the British wholesale electricity market. For this task, we have used an in-house fundamentals model of the British market ("EESyM") to estimate investors' response to capacity payments, and to assess whether the introduction of capacity payments improves or reduces economic efficiency in the electricity market.

In the following sections of this appendix, we describe our approach to modelling the impact of these capacity payment mechanisms using the assumptions set out in Appendix B, and the modelling results we obtain.

A.1. Modelling Approach

A.1.1.Overview of modelling task

To define a baseline against which to compare alternative scenarios, we created a forecast of GB power market evolution assuming an energy-only market structure that functions efficiently, allowing prices to spike to the value of lost load (VOLL) in periods when demand exceeds available capacity, as we describe in Section A.2. We then examine the effect of assuming a cap on peak energy prices set to £1,000/MWh (i.e., below VOLL), which captures the constraint on expected prices derived from the risk of government intervention intended to prevent high prices in periods of shortage, as we describe in Section A.3 – this latter scenario approximates to the current institutional arrangements. By comparing the results of these two scenarios, we quantify the inefficiency created by the risk of political intervention to cap peak prices discussed in the EMR documents.

Against this background, we then review the performance of the two main types of capacity payment mechanism discussed in the EMR documents, and assessed by Redpoint,[9] namely:

- A "market-wide" capacity mechanism, where every generation unit on the system not receiving a FIT receives a payment per MWh of available capacity,[10] with the capacity price set equal to the fixed costs of a new entrant OCGT peaking plant, as we describe in Section A.4; and
- A "targeted" capacity mechanism, where the TSO conducts a tender to procure a small quantity of OCGT peaking capacity, and recovers the fixed costs of this capacity through use of system charges or some other market-wide levy, as we describe in Section A.5.
- In both cases, we assume these mechanisms start operating from 1 January 2015 on the basis that the government has stated it plans to enact the EMR proposals by the end of the current parliament.[11]

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[9] *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010.

[10] Our modelling takes the volume of renewable and nuclear capacity as a given, on the assumption that it is driven by factors (FITs) outside the market that we are modelling.

[11] The EMR Impact Assessment's assumption that the capacity payment mechanisms begin in 2018 lacks credibility for two reasons: (1) this date is beyond the life of the current parliament; and (2) it seems to be timed to coincide perfectly

A.1.2. Modelling tools

To form projections of market evolution under alternative scenarios regarding future GB market arrangements, we have used our proprietary wholesale market model, EESyM. EESyM is a fundamentals model that uses an optimisation algorithm to minimise the cost of meeting demand, making a trade-off between dispatching existing generators, constructing new capacity and load shedding.

To forecast investment and to despatch generators, EESyM uses a load duration curve modelling framework, so it minimises total system costs across a number of demand levels that characterise the demand conditions that are observed across the year. As we describe in more detail below, we use EESyM to forecast investment in new OCGTs and CCGTs, existing coal plants' decisions to opt in or opt out of the EU Industrial Emissions Directive (IED), and the closure dates of coal plants and existing CCGTs.

The prices that emerge from EESyM are equal to the system marginal cost (SMC), i.e. the marginal cost of the most expensive generator required to meet demand in each hour. If there is insufficient capacity available to meet demand, the price will rise to the Value of Lost Load (VOLL), which we assume to be €10,000/MWh, based on the VOLL parameter applied in the Irish Single Electricity Market (SEM) rules.

Investors in new generation capacity recover their fixed costs in this framework through the "inframarginal profit" between the SMC and their own marginal costs of production. For example, in the long-run new OCGTs recover their fixed costs through the margins they earn during the small number of hours when prices spike to VOLL. New generators running at baseload or mid-merit load factors also earn inframarginal profit when generators with higher short-run marginal costs than their own set the SMC. Because fixed costs are remunerated through the energy market, our modelling framework does not require us to apply any "uplift" to ensure investors recover their fixed costs.

A.1.3. Assumptions on investors' behaviour

Our modelling framework assumes that investors make the best use of the information available at the time when making investment decisions. Our modelling approach therefore assumes that investors optimise their behaviour based on the outlook of the future defined by our modelling assumptions. Rather than assuming perfect foresight, this approach assumes that market participants make the best use of information available when making investment decisions (i.e., we assume rational expectations); to do otherwise would assume that investors engage in systematically irrational behaviour.

Within this framework, investors still need to expect that they will earn a reasonable return on investment taking account of the risk of the activity. We capture this constraint by including a cost of capital or WACC for generation investments, which reflects the market returns required by investors on other investments of equivalent risk. The sources we use for our

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with the time when Redpoint predicts shortages will begin to emerge under the current market arrangements, which will make investors nervous that the government will withdraw the scheme once investment takes place and the risk of shortages recedes.

WACC assumptions are internal estimates derived using market data, or estimates taken from external sources such as City analyst reports.

In normal conditions, the WACC derived from these sources provides the best estimates of the hurdle rates applied by investors for decision-making. However, as has been discussed in the literature on “real options”, there are conditions in which investors may require a higher hurdle rate incorporating a premium over the WACC before they will invest. For this to be the case, investors must expect some of the investment risks to fall over time, for example because uncertainties regarding future government policy or the cost/performance of new technologies are removed. This expectation of information revelation regarding the future value of investments creates an incentive for investors to delay investments and wait for information about future uncertainties to emerge, thus creating a “value to waiting” or “option premium” that increases the hurdle rate required by investors today.

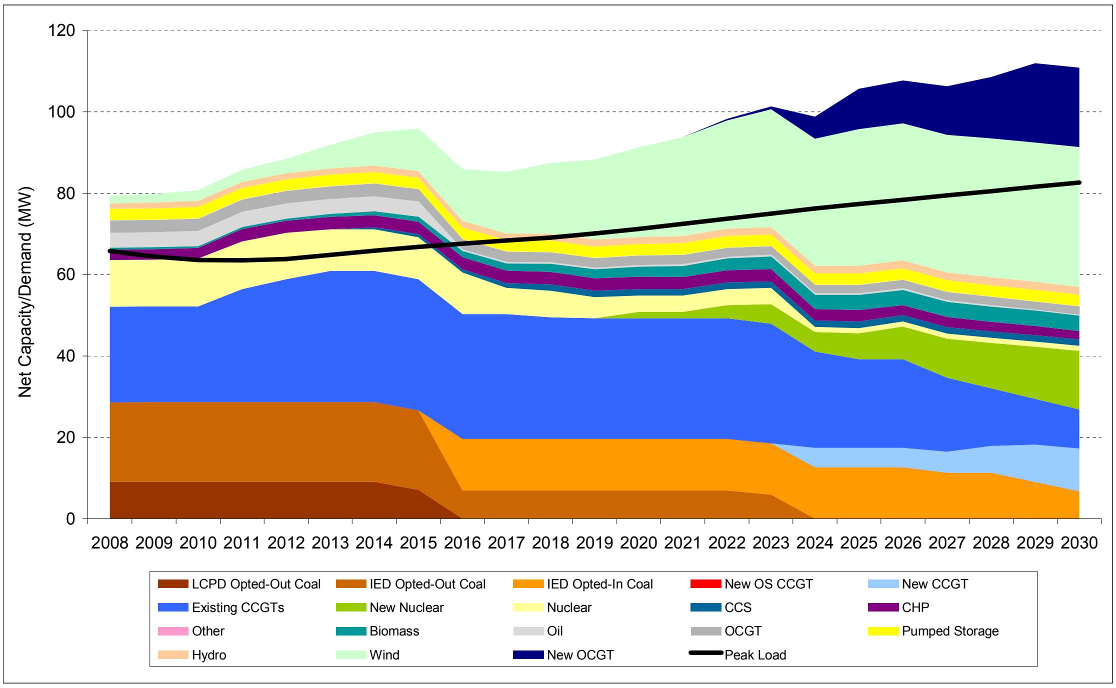
Calculating “option premiums” using an objective bottom-up procedure is notoriously difficult, and there is little consensus on the right approach. The alternative is therefore to rely on market data in the form of the hurdle rates actually used by investors (e.g., City analysts) to value and appraise specific types of investment, which must incorporate any “option premium”, which is the approach we use as a baseline.

A.2. Baseline: Projection of an Efficient Generation Mix

A.2.1.Wholesale market projections

As described above, we used our EESyM model to project the capacity mix that would occur in an efficient energy-only market, in which prices reflect the SMC in all hours, up to the value of lost load (€10,000/MWh). As Figure A.1 shows, installed generation capacity currently stands at around 85GW, compared to peak load of around 65GW.

Figure A.1
Baseline Projection of Installed Capacity vs. Peak Demand (MW)



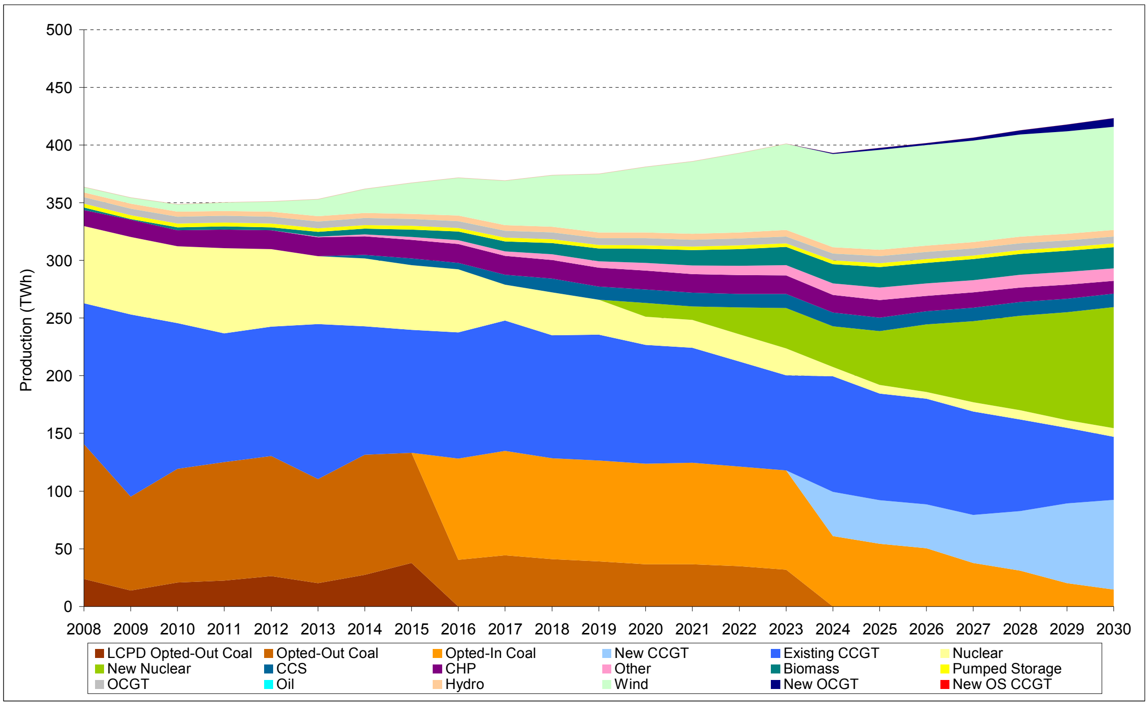
Source: NERA analysis

Over the period to 2015, our modelling predicts the margin of installed capacity above peak demand increases as new renewables come onto the system, and the new CCGT capacity currently under construction is commissioned. The market then tightens in 2016 as the LCPD opted out coal plants close at the end of 2015. At this point, the model show 13.5GW of capacity opting into the IED, with the remainder committing to close by 2023 and to run less than 17,500 hours between 2016 and 2023.

The model predicts investment in new OCGT capacity from around 2022, with new OCGT capacity reaching 19GW by 2030. New CCGT investment takes place from 2024 when the coal plants opted out of the IED are required to close.

As shown in Figure A.2, over the medium term the model indicates that coal plants and CCGTs make up the majority of production, each providing 100-150TWh per annum until 2015. Even after the LCPD opted out coal plants shut and some of the remaining plants accept limited running hours, the total output from coal generators declines only slightly over the period to 2023. After 2023, output from coal generators fall as the IED opted out coal plants close, and the others begin to retire gradually as they reach the end of their assumed maximum economic lives.

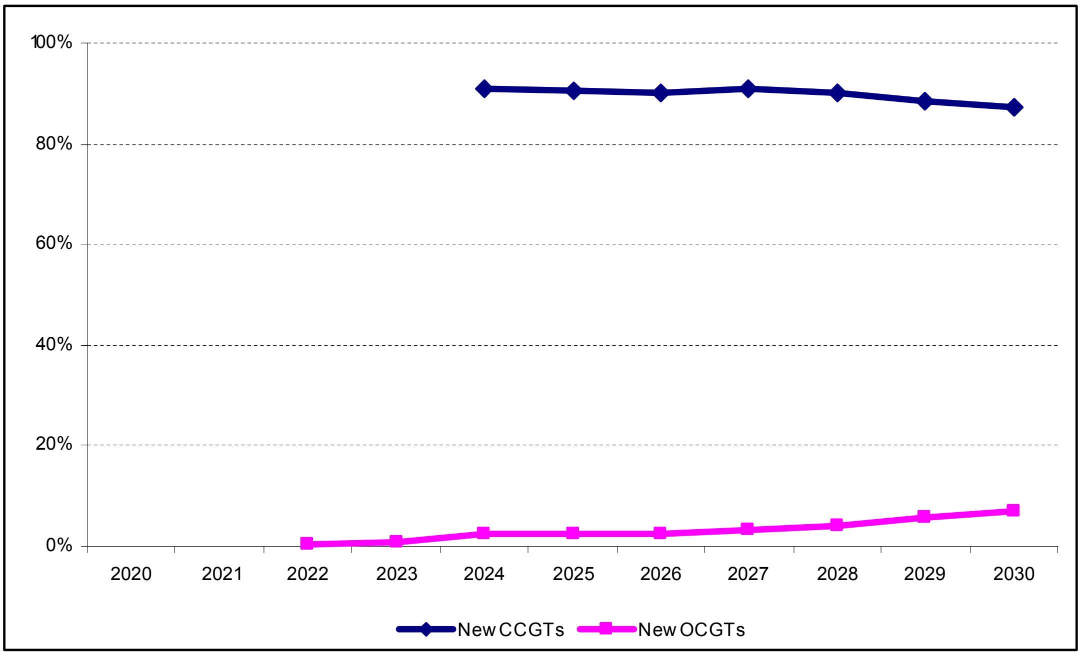
Figure A.2
Baseline Projection of the Generation Mix (TWh)



Source: NERA analysis

Production from existing gas-fired CCGTs declines gradually over the modelling horizon, resulting from increasing penetration of renewables, and in the period after 2020, investment in new nuclear plants and new CCGTs. Production from new OCGTs contributes only a small share of generation, running at load factors below 10% as Figure A.3 shows. New CCGTs run at close to baseload load factors, although their load factors fall as the penetration of new nuclear capacity rises towards 2030.

Figure A.3
Baseline Load Factors of New OCGTs and CCGTs (%)



Source: NERA analysis

Hence our modelling indicates that in the period after 2020 the market requires investment in peaking capacity to run at relatively low load factors so it is a least-cost solution for the model to build a mix of OCGT and CCGT capacity. In contrast, Redpoint's modelling work projects investment in new CCGT in its baseline, but not investment in new OCGT capacity.[12] Redpoint does not seem to consider new OCGTs as a new build option, possibly because the model does not take a general view of investment, but relies on certain rules-of-thumb that will not produce efficient decisions in future conditions.

Largely due to the assumption of rising gas and CO2 prices (see Section B.4), modelled power prices rise throughout the modelling horizon, as Figure A.4 shows. Clean dark spreads also rise gradually over the modelling horizon, driven by our assumption of rising gas prices, and our assumption that growth in clean dark spreads is not constrained by the potential for new entry by non-CCS coal generators, due to the constrainst on new build imposed by the EMR's emissions performance standard (EPS). Clean spark spreads fall gradually over the period to 2015, driven down by rising gas prices relative to coal, and already-committed new investment in CCGT capacity and renewables. Only in the early-2020s do clean spark spreads rise to the levels required to remunerate new CCGT investment.[13] Baseload prices

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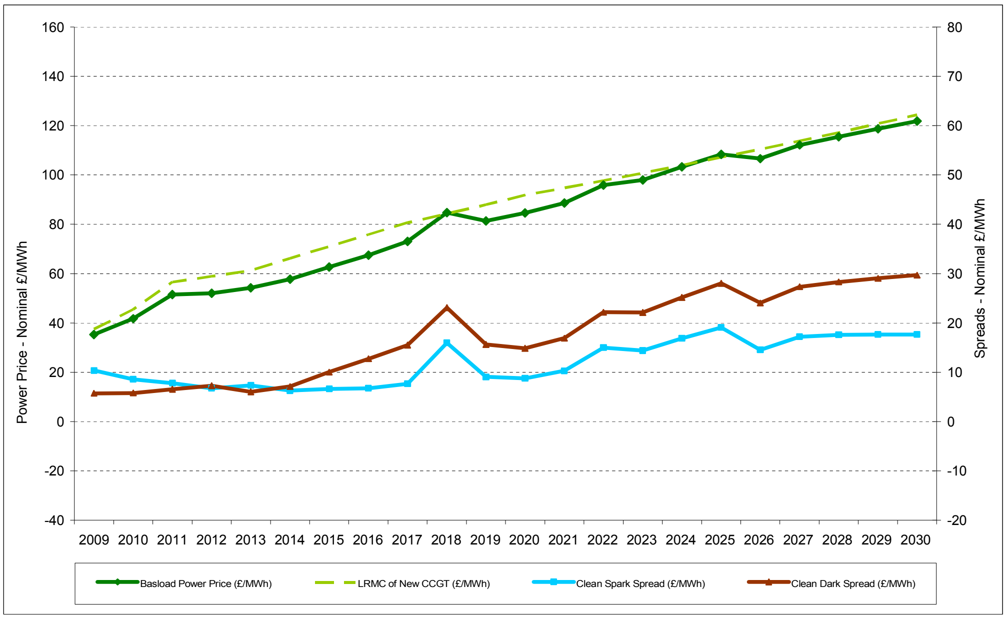
[12] *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, section 3.3 and figure 3.

[13] The clean spark spreads shown in this graph and all others in this appendix are for a new entrant CCGT running at an efficiency of 51.9%. They are also conditional on a wide range of assumptions, including the treatment of BSUOUS, losses, variable O&M, etc., which may not be comparable to those used by others and thus may result in spreads that are higher or lower than those produced by other similar modelling exercises. For example, the long-run spark spreads that emerge are closely tied to the costs of new entrant CCGTs, estimates for which vary significantly depending on the sources used, as we discuss further in Section B.1.6.

eventually rise to slightly below the long-run marginal cost (LRMC) of a new gas-fired CCGT running baseload.[14]

Figure A.4
Baseline Wholesale Price Projections (2010 £/MWh)



Source: NERA analysis

A.2.2. CO2 Emissions

The Climate Change Act 2008 requires that the UK reduce greenhouse gas emissions by 80% compared to 1990 levels by 2050, and requires that the government publish 5-year carbon budgets describing how it will meet this target. Carbon budgets for the period 2008-2022 were implemented through the Carbon Budgets Order 2009. The Carbon Budgets Order 2009 sets targets for total emissions, and the Low Carbon Transition Plan (LCTP) published by DECC in July 2009 breaks down these carbon budgets into sectors. We have used the budgets for the power sector in the LCTP to define a reference against which to compare the CO2 emissions forecast by our market model.

The UK government has not yet set carbon budgets for the period after 2022. We have therefore defined a range of potential CO2 targets for the power sector between 2022 and 2030. The first assumes that the CO2 target for the power sector will tighten gradually between the end of 2022 and 2030 on a trajectory that would allow CO2 emissions from the power sector to reach zero by 2050. This path is consistent with the projections in the 2010 DECC "Pathways" document in which all the scenarios presented imply that CO2 emissions from the power sector reach zero by 2050.[15] In the second, we assume that the CO2 emissions target tightens over the period to 2030, reaching the levels recommended by the

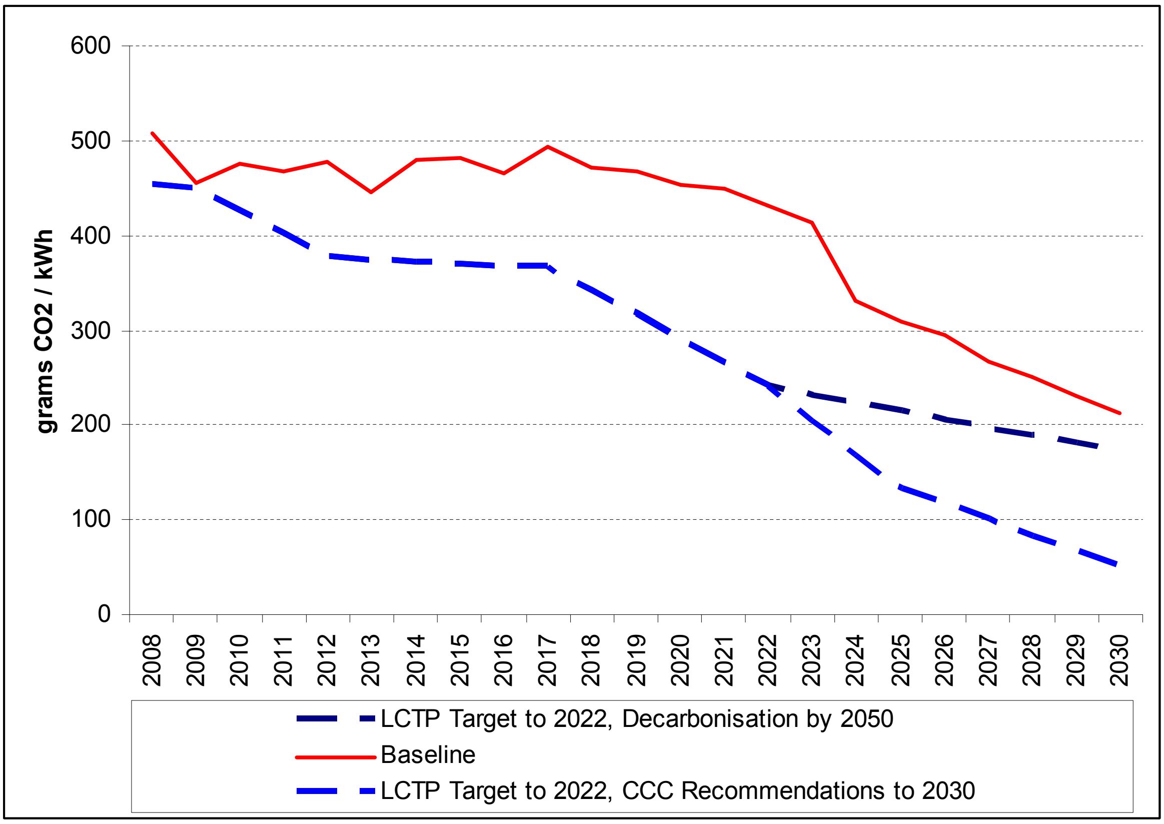
[14] Prices remain below the LRMC of a new CCGT because of low off-peak prices in periods when new CCGTs will be out of merit.

[15] The only exception is the "reference case", where there is "little or no attempt to decarbonise" and the UK falls well short of meeting CO2 targets. Source: 2050 Pathways Analysis, DECC, July 2010, page 30.

Committee on Climate Change for 2030 in its recent proposals on the 4th carbon budget.[16] The resulting CO2 targets we assumed for our modelling horizon are shown in Figure A.5.

This figure also shows that in this scenario projected CO2 emissions remain above target throughout the modelling horizon. However, the extent to which the projected emissions over-shoot the target decreases significantly post-2023 as the coal plants opted-out of the IED close. These coal plants are replaced by a mix of new nuclear and gas-fired capacity, leading projected emissions to converge towards the higher of the two CO2 targets of 200 grams of CO2 per kWh in 2030, but remaining well above the lower Climate Change Committee target for 2030.

Figure A.5
Baseline Power Sector CO2 Emissions vs. Target (grams CO2 per kWh)



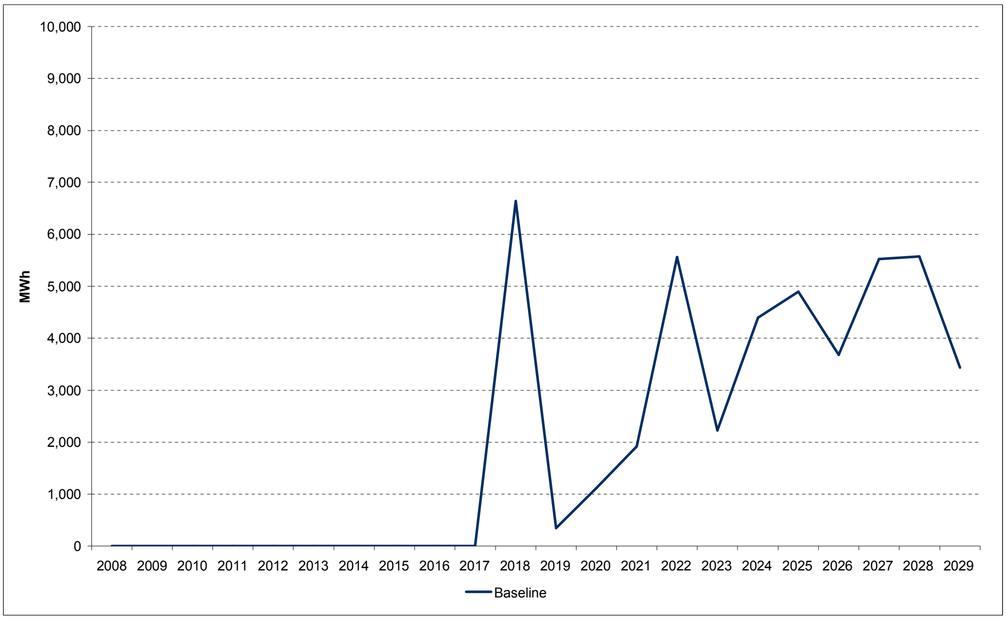
Source: NERA analysis

16 *Advice to Government on the 4th Carbon Budget, covering the period 2023-27*, 7 December 2010, Committee on Climate Change.

A.2.3. Security of supply

In this "efficient" capacity mix, the figures below show that our market model converges on an annual quantity of unserved energy of approximately 4GWh on average per annum.

Figure A.6
Baseline Expected Unserved Energy (GWh)



Source: NERA analysis

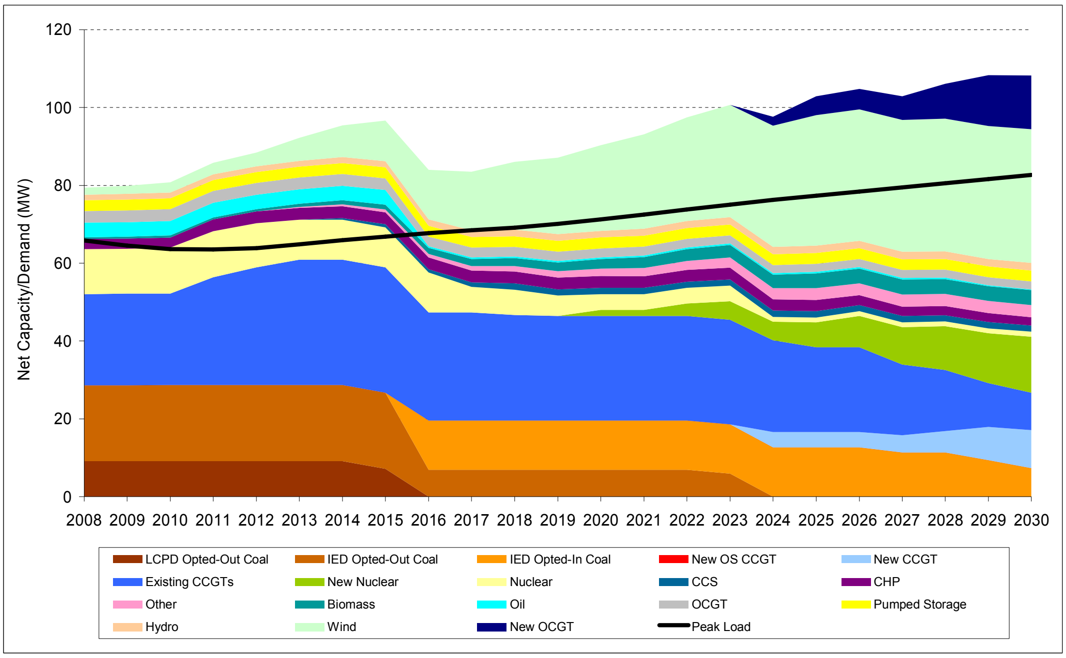
A.3. The Impact of Constrained Peak Prices (Business As Usual)

In the previous scenario, we assumed an efficient energy only market in which prices were allowed to reflect the SMC in all hours, which could take any value up to and including the value of lost load that we assumed to be €10,000/MWh. In this scenario, we examine the effect of assuming a cap on peak energy prices of €1,000/MWh, based on the price cap applied in the SEM. This restriction on peak prices may occur due to the risk of government intervention to prevent high prices in periods of shortage. It also acts as a proxy for other market distortions, such as the problem with cash-out prices at peak times, which prevent energy prices from signalling the true value of energy at peak times. This scenario therefore represents Business As Usual (BAU) under the current market,

A.3.1. Wholesale market projections

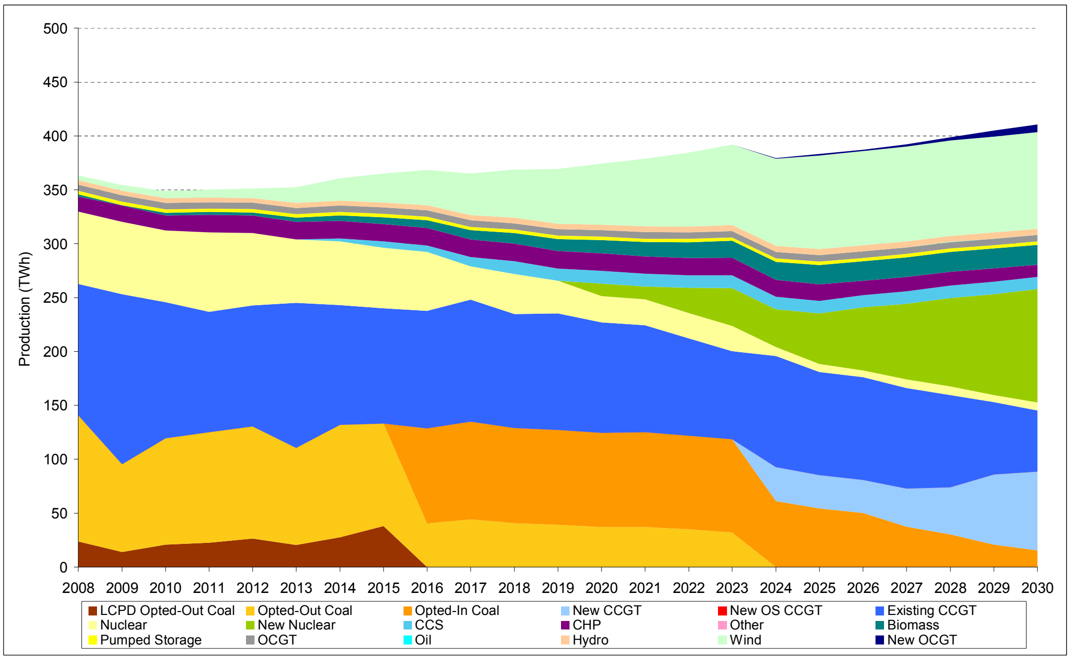
As Figure A.7 shows, our projection of the overall supply-demand mix in this scenario remains similar to the "efficient" capacity mix we project in the "baseline" scenario, so the production mix shown in Figure A.8 is also similar. However, as Figure A.9 shows, in this scenario there is slightly less installed capacity from 2016 onwards because slightly less coal-fired capacity opts into the IED (12.6GW rather than 13.5GW), existing CCGT capacity retires sooner with around 500MW less online in the 2020s than the baseline, and total investment in new OCGT capacity falls from around 19GW to 13GW. Hence, the main effect of the restriction on peak energy prices is to change the trade-off that the model makes between shedding load and building peaking capacity.

Figure A.7
BAU Projection of Installed Capacity vs. Peak Demand (MW)



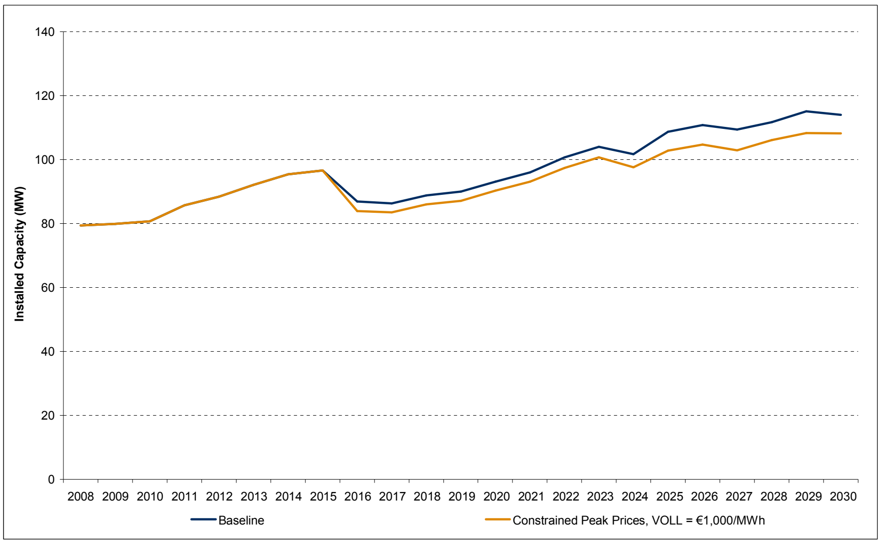
Source: NERA analysis

Figure A.8
BAU Projection of the Generation Mix (TWh)



Source: NERA analysis

Figure A.9
BAU Installed Capacity Compared to the Baseline Scenario (MW)

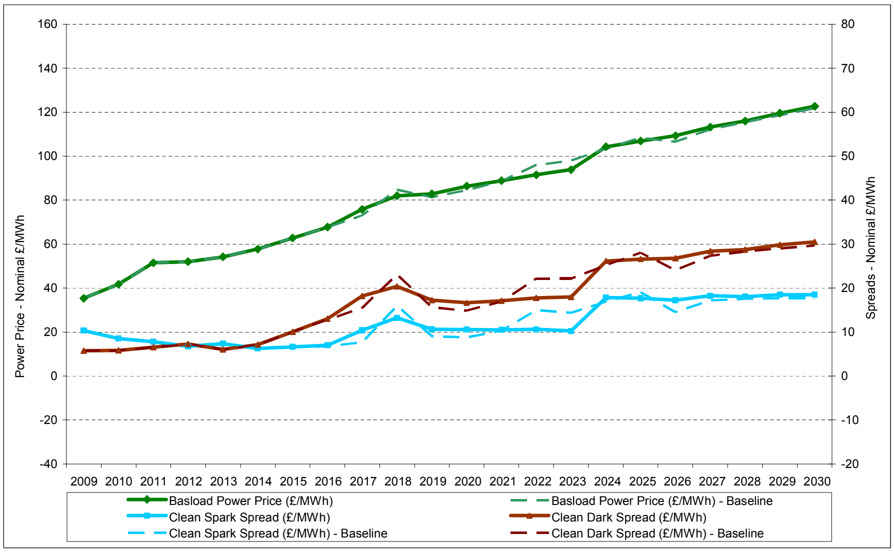


Source: NERA analysis

This scenario has a limited impact on baseload prices and spreads in the long-run. Although we assume peak prices are limited to €1,000/MWh, baseload prices must still rise to a level than remunerates investment in new gas-fired CCGTs by the mid-2020s. Hence, instead of prices spiking to VOLL (€10,000/MWh) in a small number of hours, prices now spike to €1,000/MWh for a larger number of hours, leaving baseload prices and spreads largely unaffected.

Although prices (Figure A.10) are similar in this scenario to the baseline, so it may appear superficially that costs to consumers do not change in this scenario, consumers must also incur the costs of load shedding in a higher number of hours, as we discuss below.

Figure A.10
BAU Changes in Wholesale Price Projections (2010 £/MWh)

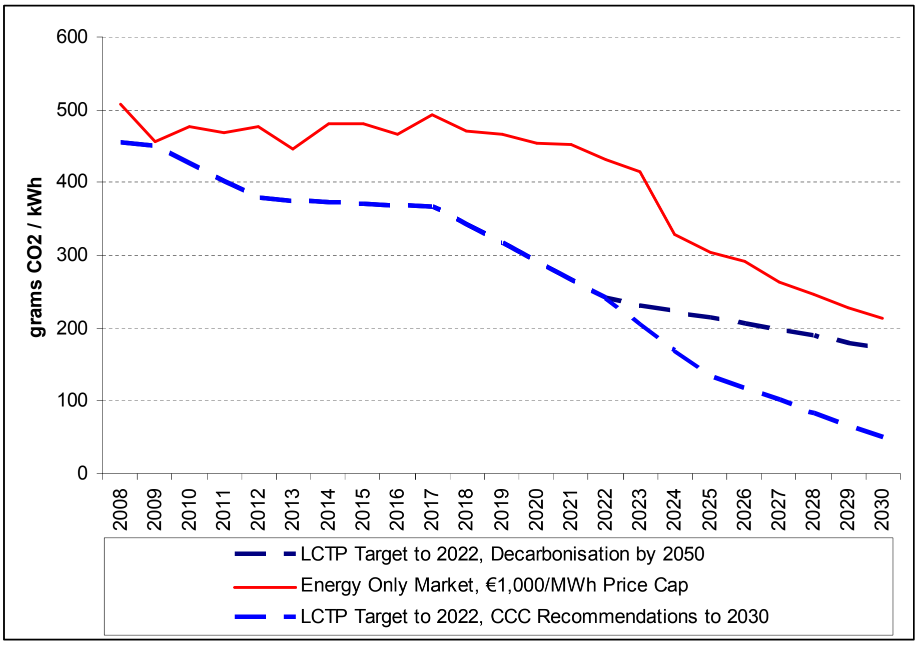


Source: NERA analysis

A.3.2.CO2 Emissions

As the production mix shown in Figure A.8 is similar to the "efficient" outcome, the projection of CO2 emissions shown in Figure A.11 is also similar.

Figure A.11
BAU Power Sector CO2 Emissions vs. Target (grams CO2 per kWh)



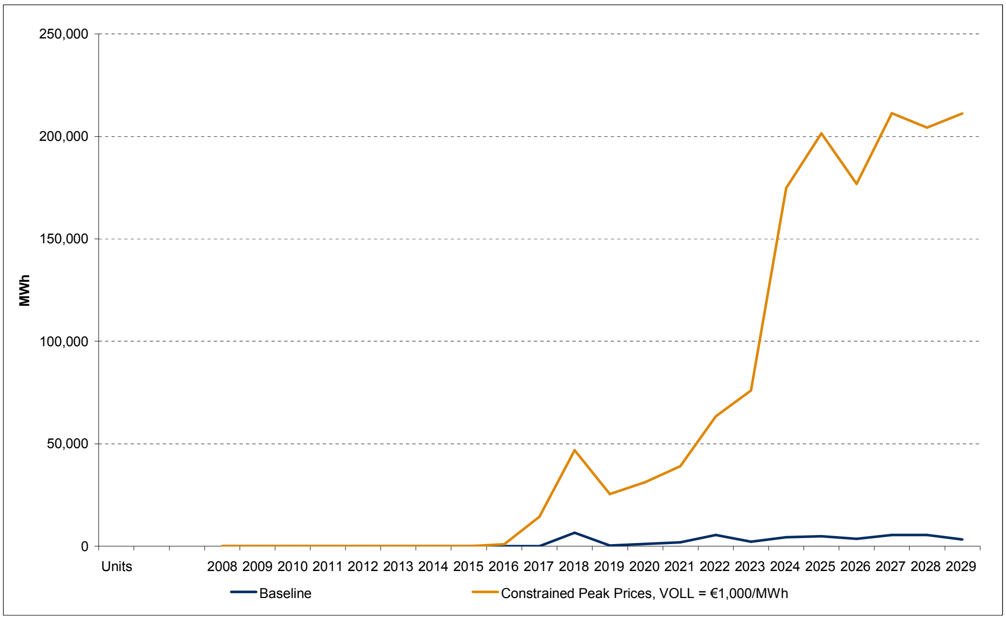
Source: NERA analysis

A.3.3.Security of supply

As described above, the main impact of imposing a cap on energy prices below the value of lost load is to reduce the quantity of peaking capacity to below the efficient quantity we estimate is required in the baseline scenario, as it changes the trade-off between load shedding and the construction of peaking capacity. The model therefore sheds more load in this scenario than in the baseline, as Figure A.12 shows.

This result illustrates the inefficiency introduced into market outcomes due to the limits on peak prices imposed by the risk of government intervention to prevent high prices in periods of shortage.

Figure A.12
BAU Expected Unserved Energy (MWh)



Source: NERA analysis

A.4. Impact of a Market-Wide Capacity Payment Mechanism (CPM)

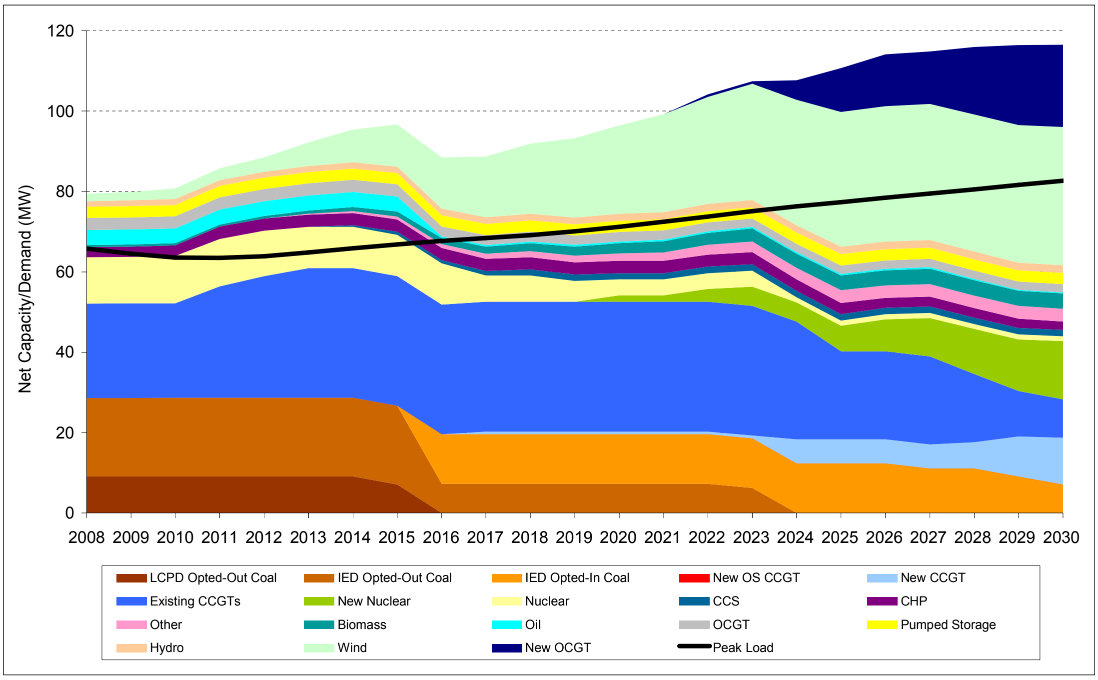
In this scenario we examine the impact of assuming a market wide capacity payment that pays all new and existing generation capacity a fixed payment per MWh of availability equal to the fixed costs of a new entrant OCGT plant. As we describe in section 4, a market wide capacity payment mechanism is one possible policy intervention that may correct the inefficiency created by the limits on peak energy prices due to the risk of government intervention to prevent high prices in periods of shortage. Hence, we still assume in this case that energy prices can rise no higher than €1,000/MWh.

A.4.1. Wholesale market projections

As Figure A.13 and Figure A.15 show, with a market-wide capacity mechanism the installed capacity that the model predicts is higher than where we assume an energy only market with prices capped at €1,000/MWh, and slightly higher than the baseline in some years because a small quantity of new CCGT investment is brought forward to 2017 and the increase in new OCGT investment in the long-run reaches 20GW in this scenario compared to 19GW in the baseline. Hence, the total quantity of capacity is closer to the "efficient" baseline scenario than to the energy only scenario in which prices are capped at €1,000/MWh.

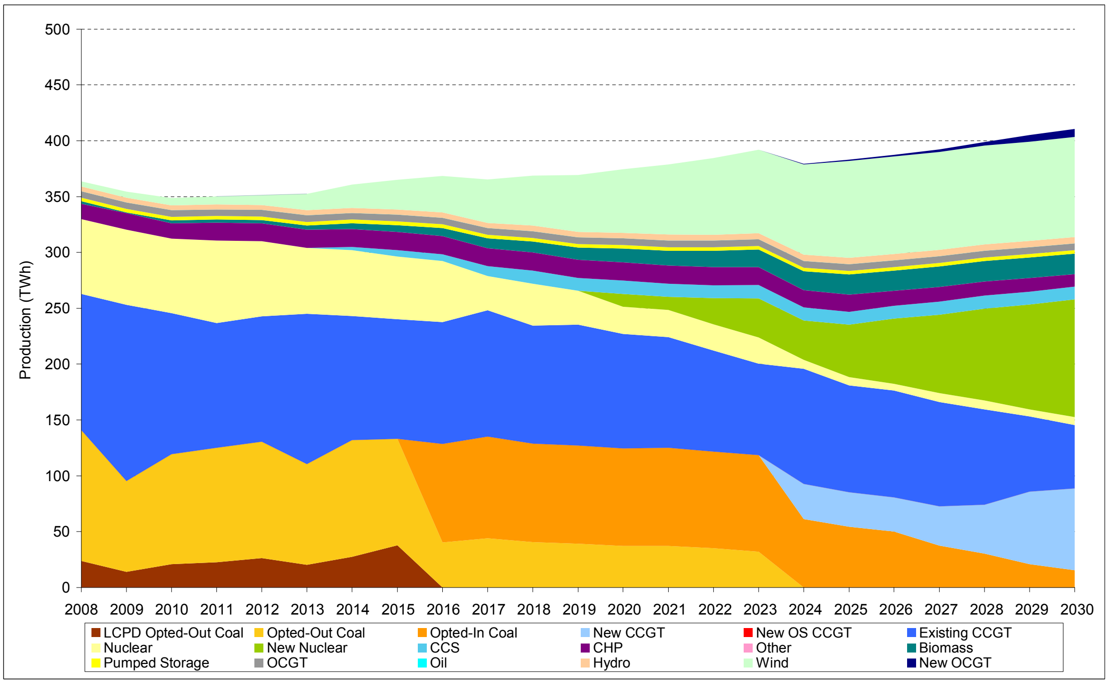
Figure A.13 also shows that a market wide capacity mechanism does not significantly affect existing coal plants' opt-in/out decisions under the IED. This occurs because we assume coal plants would receive the same capacity payments over the period between 2016 and 2023 irrespective of whether they opt in or out. Compared to the scenario without a capacity payment, the only extra benefit they obtain from opting in is the ability to earn capacity payments in the period between 2023 and their latest assumed closure date, which for several plants falls in the mid-2020s. Hence, the extra benefit of making an investment in SCR equipment is limited. The generation mix shown in Figure A.14 does not change substantially compared to the baseline.

Figure A.13
CPM Projection of Installed Capacity vs. Peak Demand (MW)



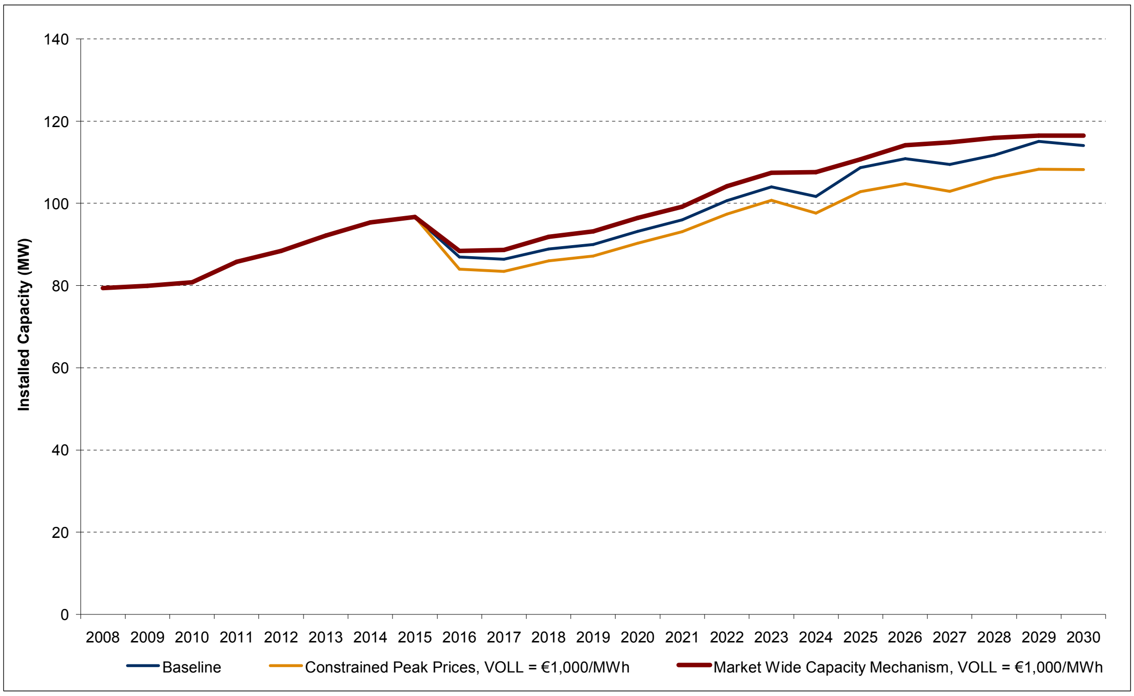
Source: NERA analysis

Figure A.14
CPM Projection of the Generation Mix (TWh)



Source: NERA analysis

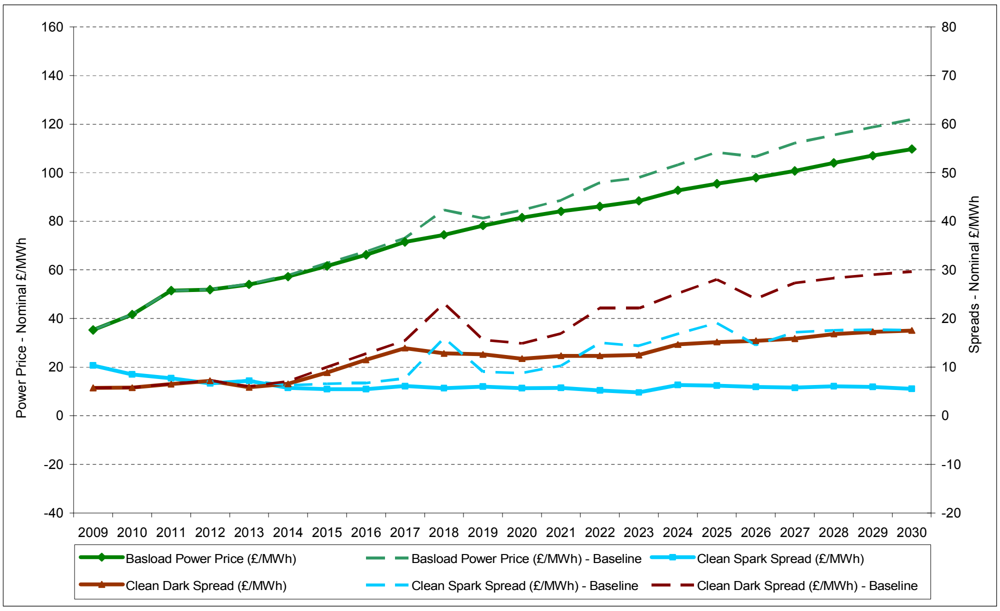
Figure A.15
CPM (and BAU) Installed Capacity Compared to the Baseline Scenario (MW)



Source: NERA analysis

The assumption that generators will receive capacity payments reduces the fixed costs that new entrants have to recover through energy prices in periods when they are inframarginal and/or in periods of scarcity. Hence, as Figure A.16 shows, prices and spreads are systematically lower in this scenario than in the baseline from around 2018 onwards.

Figure A.16
CPM Change in Wholesale Price Projections (2010 £/MWh)



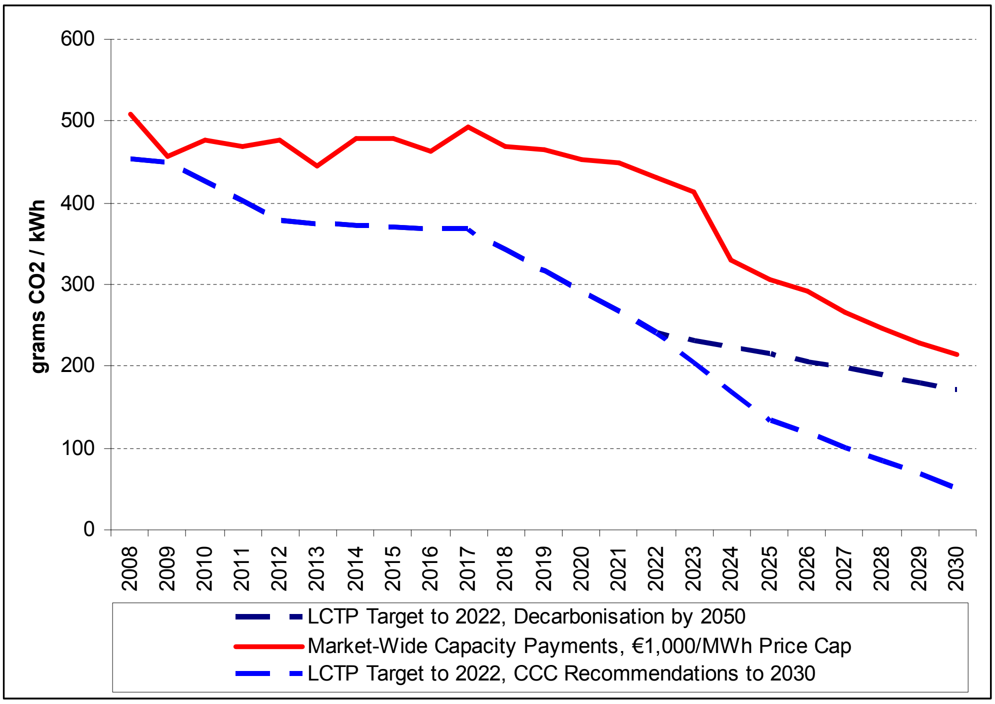
Source: NERA analysis

Although this reduction in prices reduces the costs of purchasing energy on the wholesale market, it does not necessarily reduce overall costs to consumers, as the costs of capacity payments to generators are socialised, as we discuss further in Section A.6.

A.4.2.CO2 Emissions

Because the production mix is similar in this scenario compared to the others described above, CO2 emissions are also similar as shown in Figure A.17.

Figure A.17
CPM Power Sector CO2 Emissions vs. Target (grams CO2 per kWh)



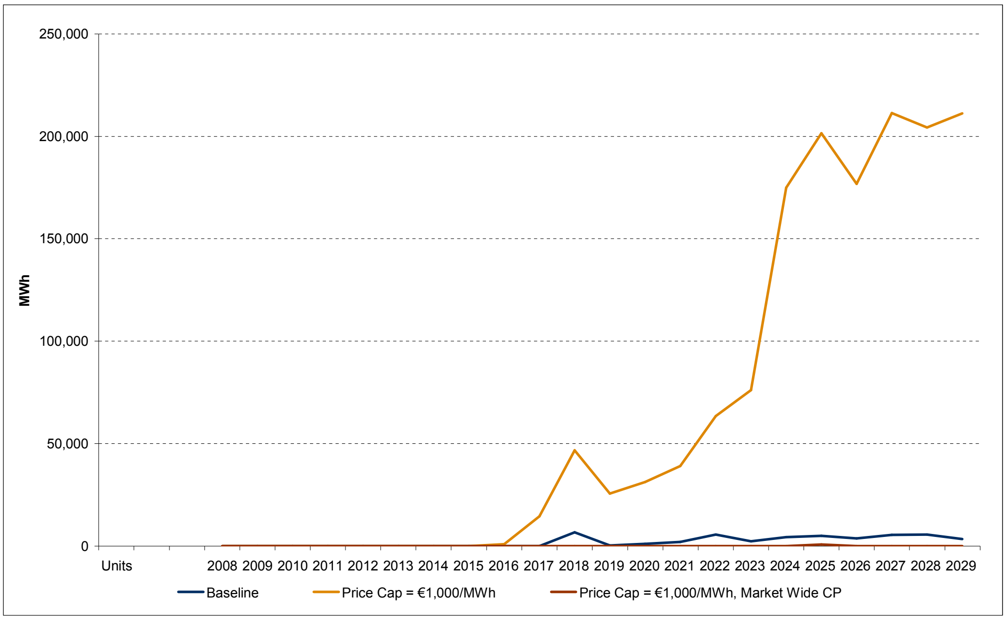
Source: NERA analysis

A.4.3.Security of supply

As Figure A.18 shows, the quantity of unserved energy in this scenario falls close to zero, which is much closer to the level of unserved energy resulting from the "efficient" generation mix in the baseline scenario. This result indicates that the market wide capacity mechanism has largely corrected the inefficiency that results from the restriction on peak energy prices and underinvestment in peaking plant with an implicit £1,000/MWh price cap.

However, as Figure A.15 above shows, a market wide capacity mechanism also incentivises slightly more generation capacity than the efficient outcome. Hence, to assess whether this market wide capacity mechanism improves efficiency overall, we examine in Section A.6 the overall welfare implications of the scheme.

Figure A.18
CPM Expected Unserved Energy (MWh)



Source: NERA analysis

A.5. Impact of a Targeted Capacity Payment Mechanism (TCPM)

Redpoint's report assumes that under a targeted capacity mechanism, the system operator would hold tenders for around 3GW of capacity.[17] To examine the impact of this "targeted" capacity mechanism, we consider a further scenario in which we assume that our model can develop 3GW of new OCGT capacity with the capital costs recovered outside of the market, e.g. through use of system charges.

Redpoint's report considers how this tendered capacity would influence prices in the energy market, and considers two alternative assumptions:[18]

- Using tendered capacity only as a "strategic reserve" to be deployed as a last resort before firm load curtailment occurs, which Redpoint states "*should mean that prices still spike to high levels when margins become very tight*"; or
- Using tendered capacity when the electricity price exceeds its short-run operating cost and "*price in the availability fees of the capacity into imbalance charges thus maintaining signals on parties to cover their peak positions*".

If the tender results in the TSO procuring new OCGT capacity, as we assume, then these alternatives amount to the same thing. The low position of OCGT capacity in the merit order means that it would only be called upon to generate when demand is close to or above the

17 *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, figure 59.

18 *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, section 5.3.1, page 97.

available capacity of all other generators on the system. Hence, we assume that the tendered capacity is offered into the energy market at its short-run marginal cost of production.

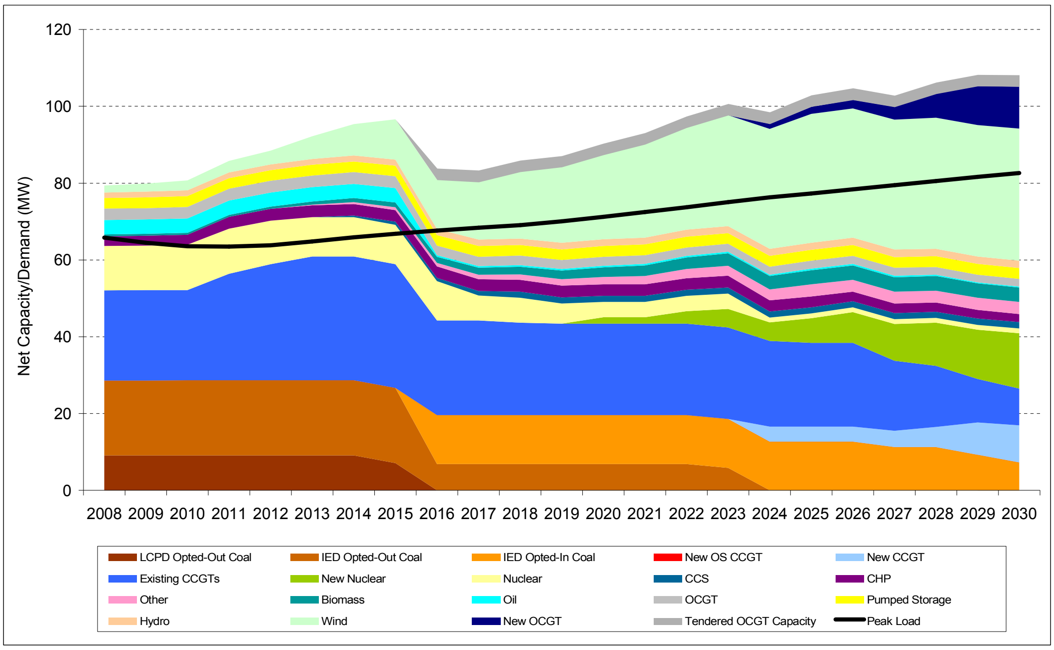
To assess whether the targeted capacity mechanism corrects the inefficiency created by restrictions on peak prices, we retain our assumption in this scenario that prices cannot rise above €1,000/MWh.

A.5.1. Wholesale market projections

As Figure A.19 shows, the model chooses to develop the tendered OCGT capacity in 2016 when the market tightens due to the retirement of the LCPD opted out coal plants.[19] However, the presence of the tendered OCGT capacity does not increase total installed capacity on the system, as it brings forward the retirement of existing CCGTs that in the energy-only scenario with constrained peak prices, and in the long-run, reduces the amounts of new OCGT capacity that is remunerated through the market. Hence, the targeted capacity mechanism has a negligible impact on the total installed capacity on the system, as Figure A.20 shows.

As there is a limited effect on the capacity mix in this scenario, the production mix and the wholesale price trends shown in Figure A.21 and Figure A.22 are also very similar to the baseline scenario and the scenario with constrained peak prices.

Figure A.19
TCPM Projection of Installed Capacity vs. Peak Demand (MW)



Source: NERA analysis

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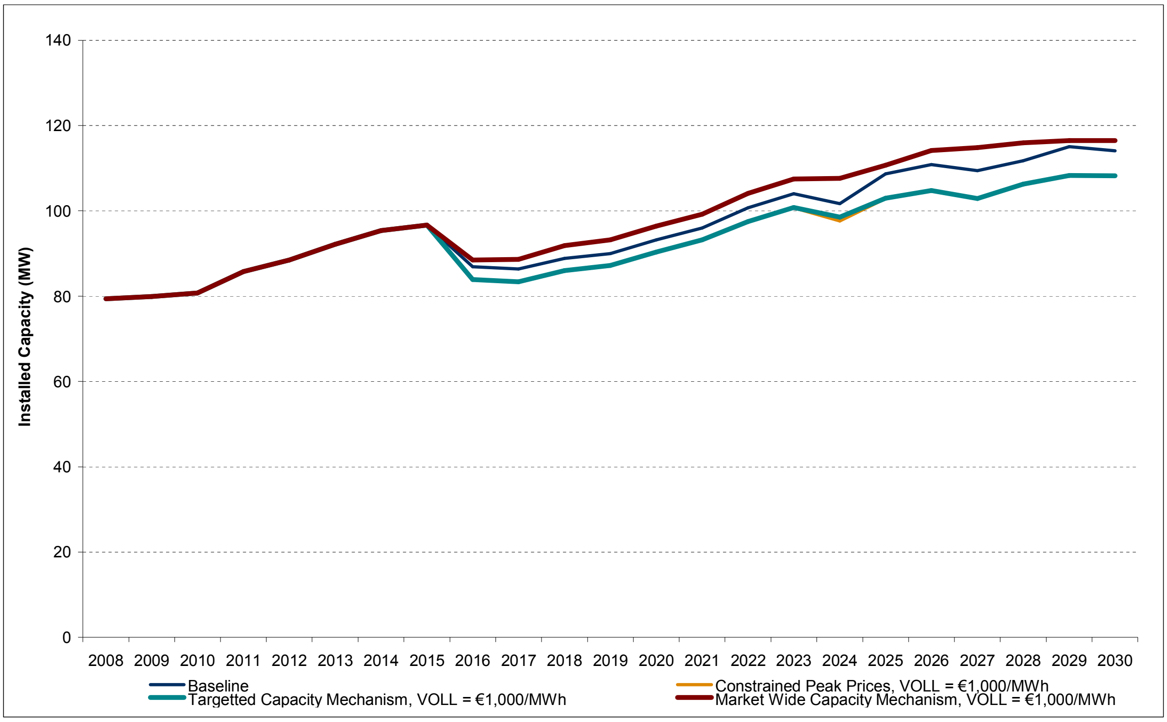
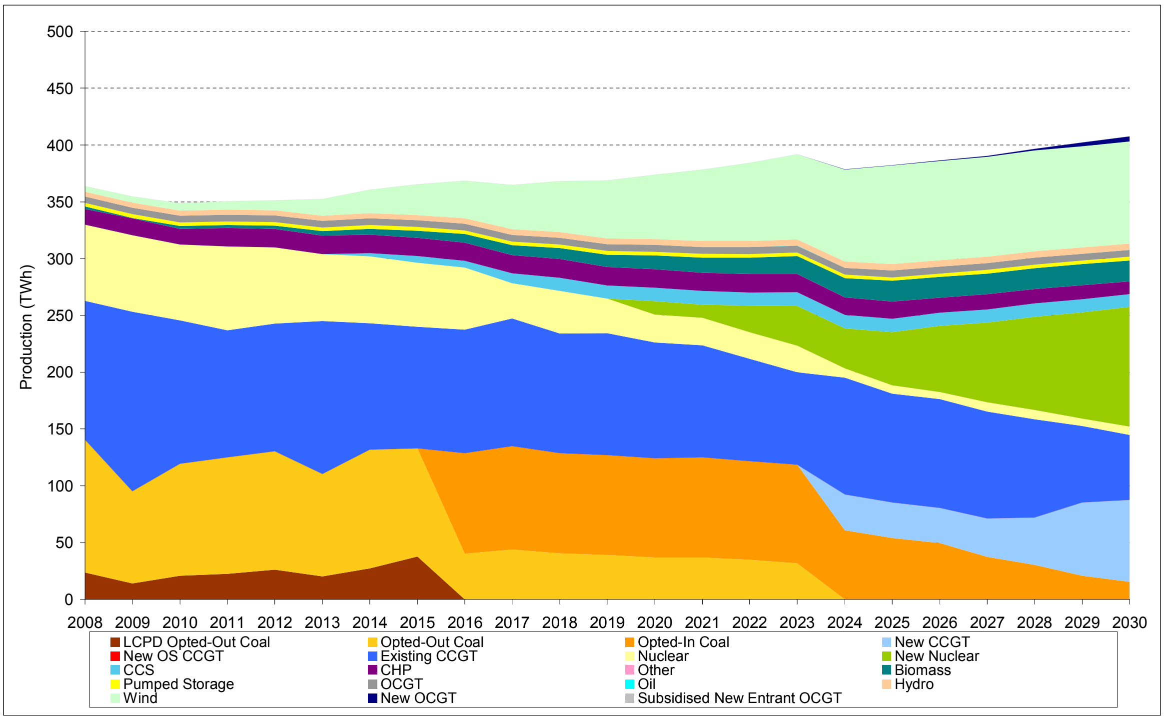
[19] We assume the tendered OCGTs impose a notional £1/kW fixed cost on the investors of this tendered capacity to ensure that the model only develops the capacity when it can fulfil some role in meeting energy or operating reserve requirements.

Figure A.20
Total Installed Capacity, All Scenarios (MW)



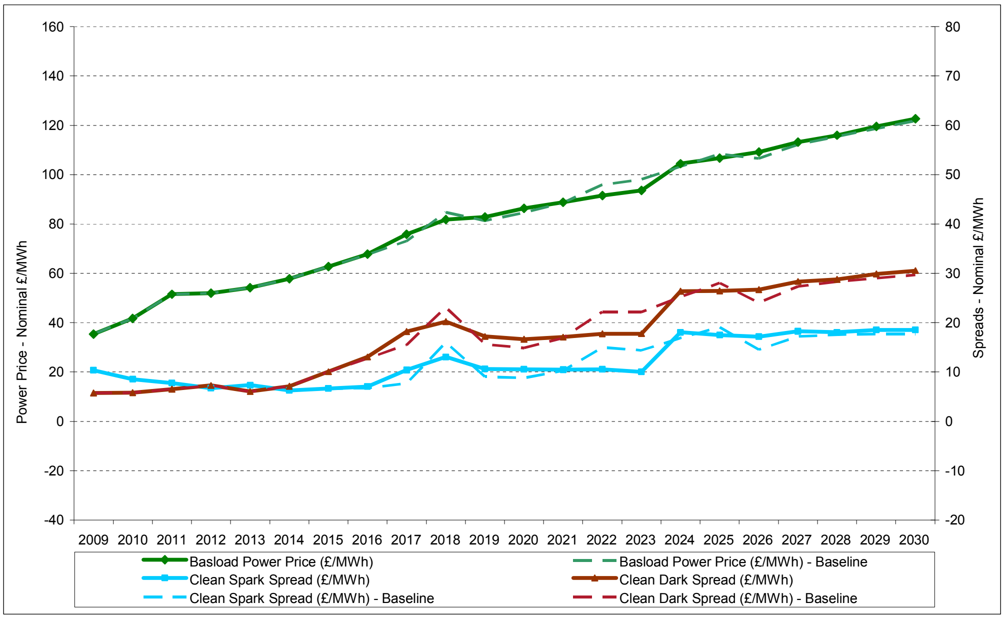
Source: NERA analysis

Figure A.21
TCPM Projection of the Generation Mix (TWh)



Source: NERA analysis

Figure A.22
TCPM Changes in Wholesale Price Projections (2010 £/MWh)

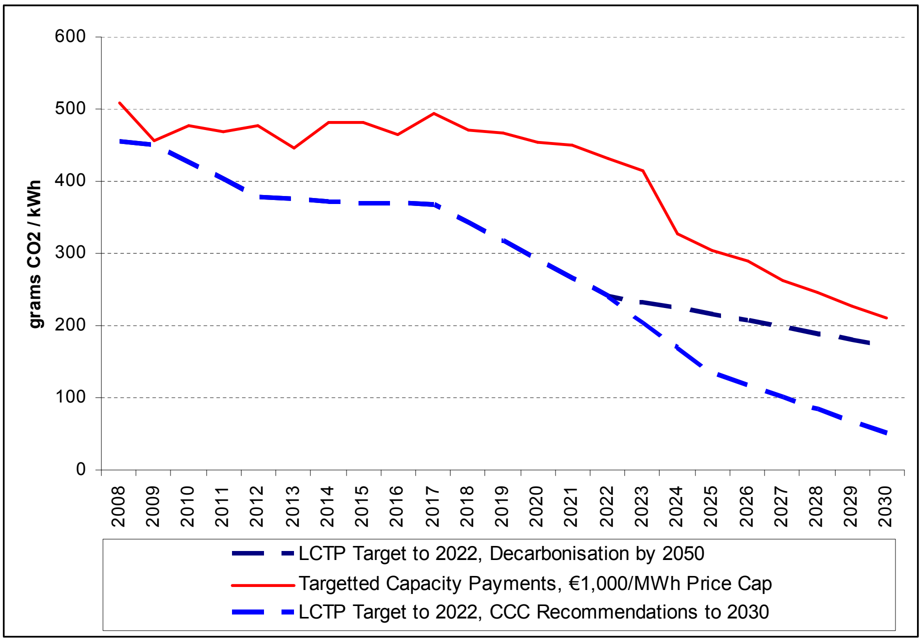


Source: NERA analysis

A.5.2. CO2 Emissions

As Figure A.23 shows, as in all three alternative scenarios we have modelled, the CO2 emissions are similar to the baseline.

Figure A.23
TCPM Power Sector CO2 Emissions vs. Target (grams CO2 per kWh)

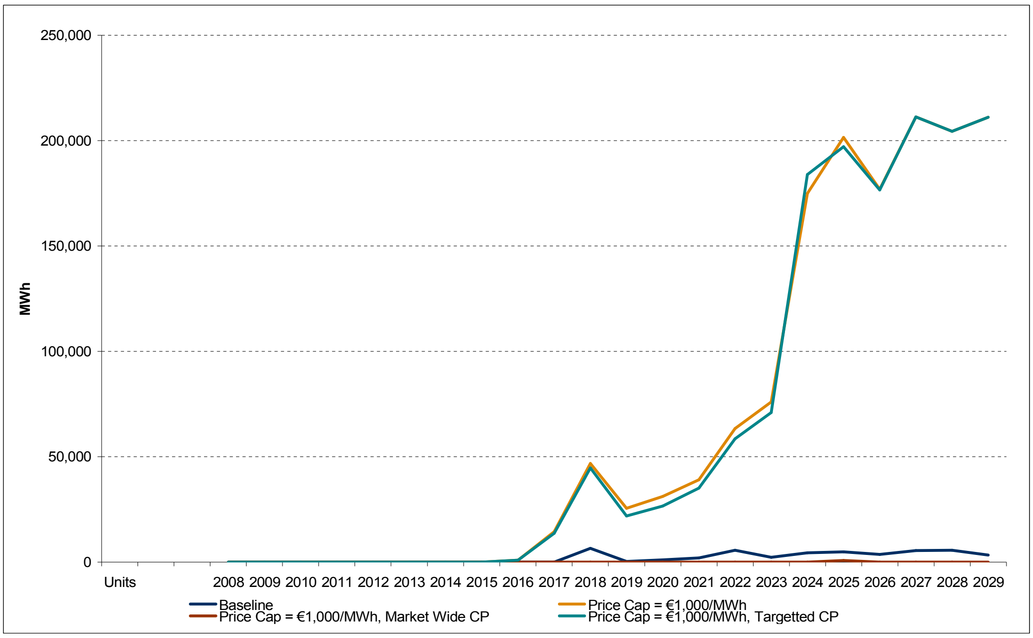


Source: NERA analysis

A.5.3. Security of supply

As the quantity of installed capacity in the market does not change materially in this scenario compared to the scenario with an energy only market and peak prices constrained below €1,000/MWh, there is a negligible impact on the quantity of unserved energy, as shown in Figure A.24. Hence, this policy intervention does not offset the inefficiency created by investors' expectation that prices will be constrained to a level below VOLL.

Figure A.24
TCPM Expected Unserved Energy Across Scenarios (MWh)



Source: NERA analysis

A.6. Conclusions

A.6.1. Summary of modelling results

By assuming an energy-only market structure in which prices are allowed to reflect the system marginal cost up to VOLL, we forecast that an efficient capacity mix for the GB market includes a mix of new CCGT and OCGT capacity, as well as some investment to life extend coal plants by fitting SCR equipment.

Assuming a restriction on peak energy prices below VOLL, to reflect constraints on prices due to the risk of government intervention to prevent high prices in periods of shortage, reduces the incentives to build peaking plant, and so reduces the capacity provided by the market and increases the quantity of load shedding.

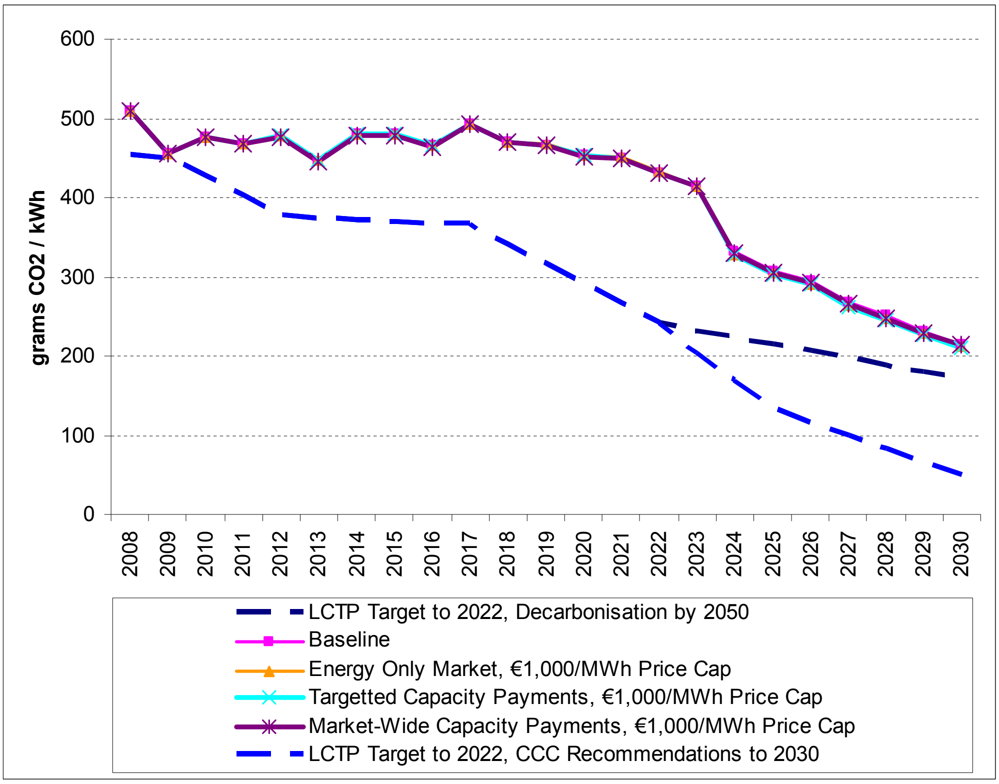
By providing all generators with capacity payments, but keeping an implicit or explicit cap on energy prices of £1,000/MWh, we estimate that the capacity provided by the market rises closer to (and slightly above) the total installed capacity in our projection of the efficient generation mix. The quantity of lost load also falls closer to the efficient level.

A targeted capacity mechanism would have a negligible impact on installed capacity and unserved energy, as the tendered peaking capacity procured by the TSO crowds out other forms of capacity, such as existing CCGTs that could also be used to provide peaking capacity, or new OCGTs that would otherwise be delivered by the market.

None of these scenarios has any impact on GB CO2 emissions from the power sector, because the generation mix (i.e., MWh produced by different technologies) does not vary across the scenarios:

- we have the same renewables and new nuclear because they are remunerated outside the market (e.g., via FITs);
- the retirement decisions of LCPD-opted in coal generators depend on their decisions to opt in or out of the IED, and these do not change between the scenarios;
- the only changes to capacity are in terms of the amount and type of peaking capacity (and volume of load shedding), which has no material impact on the amount of CO2 emissions.

Figure A.25
Power Sector CO2 Emissions vs. Target, All Scenarios (g/kWh)



Source: NERA analysis

A.6.2. Welfare implications

Table A.1 shows an analysis of the welfare effects of the scenarios we considered in our modelling, broken down by producer and consumer surplus, with the overall welfare impact shown in the highlighted bottom line of the table. The table shows the changes in welfare relative to the efficient generation mix that results from an unrestricted, energy-only market.

The inefficiency caused by limiting VOLL to €1,000/MWh reduces welfare by £5.65 billion over the period 2012-2030, mainly due to a significant increase in involuntary load shedding.

The effect of instituting the targeted capacity mechanism varies depending on the effect we assume it has on investment outside the scheme. If we assume it has no distortionary effect on investment outside the scheme, overall welfare over the period 2012-2030 falls by £5.54 billion relative to the baseline efficient level, which is a negligible improvement on the price-capped energy-only market. If, on the other hand, we assume that the targeted scheme adds regulatory risk to the market, because of uncertainty over how resources within the scheme will be offered into the market and/or over whether the scheme will be expanded unpredictably due to the "slippery slope" effect discussed in the EMR documents, then the targeted scheme could reduce welfare relative to the price capped energy-only market. For example, if we assume that the increased regulatory risk will add 200 basis points (bps) to the hurdle rate for investment in the market, the total welfare loss compared to the efficient baseline increases to £6.04 billion, mainly as a result of an increase in involuntary load shedding due to capacity becoming more expensive.

Table A.1
Welfare Effects 2012-2030
(2010 £ billion, NPV as at 1 January 2012, discounted @ 3.5%)

	Energy-only Market, €1,000 Price Cap	Targeted Capacity Scheme, €1,000 Price Cap		Market-Wide Capacity Scheme, €1,000 Price Cap
		Baseline WACC	200bps WACC premium	
Changes to Producer Surplus				
Revenue from Energy Sales	-0.52	-0.64	2.71	-32.60
Generation Costs	1.74	1.72	2.09	-0.31
Capacity Payments	-	1.88	1.88	44.76
Sub-total	**1.22**	**2.96**	**6.67**	**11.86**
Changes to Consumer Surplus				
Cost of Wholesale Energy	0.52	0.64	-2.71	32.60
Capacity Payments	-	-1.88	-1.88	-44.76
Cost of Load Shedding	-7.39	-7.26	-8.13	0.24
Sub-total	**-6.87**	**-8.50**	**-12.72**	**-11.93**
Net Welfare Change	**-5.65**	**-5.54**	**-6.04**	**-0.07**

Source: NERA analysis

In contrast, a market-wide capacity payment mechanism has a significant positive effect on welfare, by increasing the amount of capacity being made available and reducing load shedding. Although this might appear inefficient when added to a market that is perfectly efficient to start with, it represents an improvement for an imperfect market in which there is a "missing money" problem due to the effective cap on peak prices. Correcting for the "missing money" problem moves the market outcome back *towards* the efficient generation mix, and reduces the overall loss of welfare, compared to the baseline, to a mere £0.07 billion. Therefore, compared with the imperfect energy-only market, in which prices are capped (or perceived as capped) at €1,000/MWh, a market-wide capacity payment mechanism increases welfare by £5.58 billion. This benefit dwarfs the administrative cost of running a capacity mechanism, which the IA[20] estimates at £3-10 million per year, or an NPV over the period 2012-30 of £0.04-0.13 billion as at 1 January 2012.

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20 EMR Impact Assessment, page 50, paragraph 98.

A.6.3. Comparison with Redpoint's modelling

The analysis above shows that a market wide capacity mechanism can improve welfare by offsetting the inefficiency caused by the risk of government intervention to prevent high prices in periods of shortage, whereas the targeted capacity mechanism would have almost no impact due to its "crowding out" effect.

The main criticism of the market wide capacity mechanism raised in the Redpoint report is that:

> "*The modelled capacity mechanism treats all thermal capacity equally and therefore does not incentivise plant with any particular technical capabilities. There is therefore a risk with a universal capacity payment mechanism that the wrong type of capacity is incentivised.*"[21]

The analysis presented above contradicts this statement by showing there is little change relative to the baseline efficient mix of generation technologies installed on the system resulting from a market wide capacity mechanism. The main effect of the market-wide scheme is to increase the quantity of peaking capacity that the model predicts investors will provide, which also provides extra flexibility through extra investment in new OCGT capacity, and to bring forward investment in new CCGT capacity.

Redpoint's finding that new OCGT capacity is not provided by the market with a market wide capacity mechanism results from its assumption that the capacity price will remain "*below the level required to support new OCGT build due to the surplus of existing plant*".[22] This result may reflect an assumption that the design of the capacity mechanism will be inefficient, so will not remunerate the new OCGT investment that would be provided in an efficient market outcome. Such an assumption inevitably produces the result that the market wide capacity scheme will not encourage efficient investment. Alternatively, it may be that Redpoint's modelling indicates that there is no need for new OCGT investment because existing plants provide all the capacity that would be developed in an efficient market equilibrium. In this case, the market wide capacity scenario has delivered an efficient outcome.

Redpoint's suggestion that "*this older plant may not be sufficiently flexible*"[23] is also unsubstantiated by its own modelling as shortages of flexible capacity should show up through spikes in energy prices and thus incentivise new "flexible" generation, and in none of Redpoint's scenarios is new OCGT capacity developed by the market. Moreover, the alternative scheme suggested in the Redpoint report is a targeted capacity tender of around 3GW of capacity per annum, which its modelling suggests will comprise a mix of new

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[21] *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, page 93.

[22] *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, page 93.

[23] *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, page 104.

OCGTs, existing CCGTs and existing coal plants that does not provide any additional flexibility compared to the capacity that is already on the system.[24]

Finally, Figure 60 of the Redpoint report shows that with targeted tenders, the quantity of load shed reduces compared to Redpoint's baseline from 0-5GWh per annum to around 1GWh per annum. In contrast, our modelling suggests that targeted capacity payments have virtually no effect on the quantity of load shed in the model, as the tendered capacity crowds out investment that would otherwise be remunerated through the market. This indicates that Redpoint has assumed the tendered capacity will have no dampening effect on power prices, and/or has simply imposed extra capacity on top of the capacity forecast in its baseline. This approach does not credibly reflect how investors would respond to the targeted capacity tender, as the mandated provision of extra peaking capacity prevents prices from spiking to VOLL in periods when it otherwise would have done, as the reduction in lost load illustrates, which reduces incentives to provide generation capacity remunerated through the market in the first place.

We therefore conclude that the results of Redpoint's modelling cannot be relied upon, because they derive from assumptions which are not credible.

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24 *Electricity Market Reform: Analysis of policy options*, Redpoint Energy in association with Trilemma UK, December 2010, figure 59

Appendix B. Market Modelling Inputs

In this appendix, we describe the input data used in the market modelling work described in Appendix A.

B.1. Electricity Supply

B.1.1. Existing generation capacity

We rely on Platts' PowerVision database for information on new projects, cross-checked against company announcements and press clippings. We assume that all new projects that are listed as "under construction" in PowerVision represent firm commitments to deliver new capacity to the system. The latest version of the database shows 4.5GW of CCGT capacity currently under construction in the GB market at the Grain, Pembroke and West Burton sites. We have looked into the latest information on the progress of these projects (press clippings, company websites, annual reports, etc.) and found it corroborates the PowerVision data. As far as we are aware, there are no other significant fossil-fuel fired plants under construction in the UK.

In the limited number of cases where Platts Powervision contains closure dates for existing fossil-fuel fired generators, we adopted these retirement dates for our market modelling.

For existing CCGTs and coal plants, we allow our model to select retirement dates endogenously through its cost minimisation algorithm, taking into account assumptions on the fixed O&M avoidable through a plant's closure and any additional costs of complying with the IED (see below). However, we impose a maximum asset life of 55 years for existing coal plants, based on the top-end of the distribution of retirement ages observed across a range of coal power stations in Europe,[25] and 30 years for CCGTs based on Mott McDonald (2010).[26]

We fix the retirement dates of the existing nuclear fleet with reference to the dates announced by the Nuclear Industry Association,[27] which we then delay by two years reflecting the life extensions planned by Wylfa and Oldbury and an assumption that other nuclear plants will be granted similar life extensions.[28]

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25 Based on data from Platts Powervision, we examined the distribution of the ages of coal plants that have previously retired. Our analysis suggests that 95% of those coal plants that have retired did so before they were 55 years old. On this basis, we imposed maximum asset lives of 55 years for GB coal plants. This assumption reflects the fact that the UK government will not allow like-for-like replacement of UK coal units, so there is no possibility of "economic replacement". Instead, we assumed it will be possible for UK coal units to operate as long as is technically possible. Hence, we tie our assumption on the maximum life of a GB coal plants to the top-end of the observed distribution of retirement ages.

26 Mott McDonald, UK Electricity Generation Costs Update, June 2010, Appendix A.

27 Nuclear Industry Association Website, "UK nuclear power stations", 3 August 2006: http://www.niauk.org/uk-nuclear-statistics.html

28 The NIA retirement dates do not reflect the recent decisions by the Nuclear Decommissioning Authority to extend the retirement dates of Wylfa to 2012, and the expectation that Oldbury-on-Severn will operate until the end of 2010, and will run one of its two units until at least mid-2011. Sources: (1) Wylfa to continue generating until 2012, Nuclear

B.1.2. Generators' response to the LCPD and IED

We assumed that all existing coal and oil-fired plants that have opted out of the Large Combustion Plants Directive (LCPD) will need to close by 31 December 2015, although we allow the model to close them earlier if it is not economic to keep them online until then.

We also accounted for the impact of the Industrial Emissions Directive (IED). We assumed that coal plants opting in to the IED will need to incur the cost of fitting Selective Catalytic Reduction (SCR) equipment to their whole capacity,[29] as well as conducting associated life extension works, and will be able to run without any load factor constraints throughout the period to 2030. Plants that opt out will not incur these costs, but will be limited to running 17,500 hours between 2016 and 2023 and must close by end-2023. Our model optimises the allocation of opted-out coal plants' available running hours between 2016 and 2023.

Given this choice, our model endogenously selected whether each existing coal plant will opt in or out of the IED, with the exception of Ratcliffe-on Soar, where E.ON has already committed to invest in SCR equipment for all units and so we assume will opt in to the IED.[30]

The UK government's Impact Assessment for the IED assumed that retrofitting SCR in existing coal plants would cost £80/kW (real 2008).[31] However, we are not aware of any publically available estimates of the total cost of retrofitting SCR that includes the associated cost of life extension and refurbishment works, which we understand differ widely depending on the condition and configuration of each plant. Given this uncertainty, we have assumed that the total capex costs incurred by coal plants that opt into the IED is £180/kW based on our experience of assessing specific GB projects.

We assume that CCGTs do not face any additional technical requirements to comply with the emissions limits set by the IED, so face no additional capital or O&M costs to opt-in.

B.1.3. New nuclear generation

UK government bodies have made various statements about the planned capacity of new nuclear plant that they would like to see, or that they anticipate coming on line:

- At the low-end of the range, in its Project Discovery document Ofgem assumes one 1,600MW EPR is built between 2020 and 2025 ("Slow growth scenario");[32]
- At the top-end of the range, MARKAL modelling conducted for the Committee on Climate Change (CCC) in the summer of 2008 suggested 12,800MW of new nuclear

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Engineering International, 13 October 2010; (2) Magnox aims to run UK Oldbury reactor until mid-2012, Reuters News, 23 August 2010.

29 We understand that some plants face more choices, e.g. only fitting SCR to some units and not to others that share a common flue, but we ignore these options on the basis that we have insufficient knowledge from published sources of the compliance options available to individual coal plants.

30 Design and manufacture of first SCR economisers in UK won by Ekstroms / A&J partnership, A&J Fabtech limited website, 12 January 2010. URL: http://www.ajfabtech.com/cgi-bin/ajf.cgi?Command=ShowNews&db_nid=62&SN=0

31 Source: Phase 1 of the Impact Assessment of the Proposals for a Revised IPPC Directive – Part 1: Combustion Plants – Final Report, May 2008, Defra.

32 Ofgem (2009), "Project Discovery – Energy Market Scenarios", Ref. 122/09, 9 October 2009, pp. 84-85.

capacity would be built between 2020 and 2025, with a further 1,600MW added before 2030, giving a total of 14,400MW by 2030.[33]

However, most of the statements from government bodies suggest the authorities see something in between these two extremes as more realistic and potentially sufficient to meet the government's goals on CO2 reduction and security of supply, e.g., a middle scenario of 1,600MW in 2020 and 6,400MW (cumulative) in 2025, as per Ofgem's Project Discovery.

Similarly, electricity industry participants have made statements about their plans and ambitions to develop new nuclear capacity:

- EDF Energy has announced that it plans to develop 6,400MW (4 x 1,600MW) of new nuclear capacity for the UK market with the first plant operational by the end of 2017, and that it believes the UK market should have 15,000MW of new nuclear by 2030 (conditional on the government putting a floor under the UK CO2 price); [34]
- RWE/E.ON have announced they are jointly aiming to build 6,000MW of new nuclear plant for the UK market by 2025, with the first reactor online around 2020;[35] and
- SSE/Scottish Power/Suez have announced they are jointly aiming to build 3,600MW of new nuclear plant for the UK market, with construction on the first plant starting around 2015 (i.e., commissioning in the early 2020s).[36]

If these plans are implemented in full, 16,000MW of new nuclear capacity would be online by 2030, which is more than the 14,400MW by 2030 anticipated by the MARKAL modelling conducted for the CCC, and above the 15,000MW that EDF Energy has suggested is desirable for the UK by 2030. This comparison casts doubt on whether the industry's plans can all be implemented simultaneously even in a scenario where the government adopts much more pro-active measures to promote new nuclear.

Given the improved investment climate for new nuclear capacity that the EMR consultation proposes, such as the introduction of FITs for new nuclear, we have assumed in our modelling that by 2030 a quantity of new nuclear capacity towards the top end of this range comes online. Specifically, we have assumed 1,600MW of new nuclear will come online by 2020, with a further 4,800MW by 2025, and a further 8,600MW by 2030, taking the total

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33 AEA Energy & Environment (2008), "MARKAL-MED model runs of long term carbon reduction targets in the UK – Phase 1", November 2008, p21.

34 (1) EDF, "EDF Energy welcomes Energy National Policy Statements as ´defining moment´ on the road to secure, affordable and low carbon energy for UK consumers", press release, 11 November 2009;
(2) Platts Power in Europe, "ANALYSIS; UK nuclear new build – EDF Energy steps up CO2 demands", 13 July 2009. See also Platts Power in Europe, "ANALYSIS; UK nuclear – De Rivaz calls for carbon floor", 1 June 2009;
(3) EDF, "EDF Energy welcomes Conservative commitment to nuclear power and action on carbon price", press release, 19 March 2010;
(4) Platts Power in Europe, "Analysis; EDF buys British Energy – France leads UK nuclear charge", 6 October 2008.

35 (1) RWE npower, "RWE npower, E.ON UK nuclear joint venture fully established", press release, 5 November 2009;
(2) Platts Power in Europe, "PIE's New Plant Tracker – Europe on crest of CCGT wave", 24 August 2009.

36 (1) SSE, "SSE, GDF SUEZ and Iberdrola to acquire site from Nuclear Decommissioning Authority", press release, 28 October 2009;
(2) Platts power in Europe, "Anaylsis: Scottish and Southern Energy – SSE fires warning shot across BE bows", 1 June 2009.

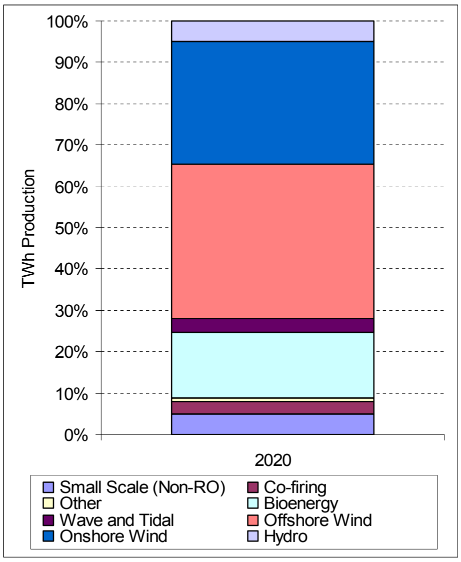
potential new nuclear to 15,000MW by 2030, which matches EDF Energy's suggested target for the UK. As we assume that this new nuclear capacity will be remunerated outside of the market through FITs, we do not endogenise the choice of whether to make these investments in new nuclear in our modelling. We assume that 15,000MW of new nuclear capacity will come online in all scenarios.

B.1.4. Expansion of renewable generation

EU Directive 2009/28/EC on the promotion of the use of energy from renewable sources requires that the UK increases its share of renewables in gross final energy consumption to 15% by 2020. To assess how this target would be achieved, the previous government published the Renewable Energy Strategy (RES) in July 2009, which showed its plans for achieving its 15% target by 2020. This document indicated that 49% of the UK's total renewable energy production would have to come from the power sector, which implies that 30% of electricity generation would need to come from renewable sources by 2020.[37]

The RES also contains projections of the mix of renewable generation technologies that will be developed to meet the 30% target, as illustrated in Figure B.1. In particular, the RES assumptions imply that around two thirds of renewable generation in 2020 will come from wind generation, with the remainder coming from a mix of other technologies, including biomass, hydro and other small scale renewables (i.e. microgeneration).

Figure B.1
Mix of Renewable Generation Technologies Implied by the RES (%)



Source: NERA Analysis of data from the RES

Given the proposals outlined in the EMR consultation document, we have assumed for this modelling work that investment in new renewable capacity will be remunerated outside of the market through a combination of feed-in tariffs and the renewables obligation. Hence, we

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37 The UK Renewable Energy Strategy, DECC, July 2009, Chart 2.

have not modelled renewables deployment, keeping our forecast of new renewables constant across scenarios.

We based our assumptions on the mix of new renewable technologies that will be deployed in GB on the RES assumptions projections shown in Figure B.1. We also assume that logistical constraints in developing new renewable generation, such as planning restrictions or delays in obtaining grid connections, delay achievement of the government target of sourcing 30% of electricity consumption from renewables from 2020 until 2025.

B.1.5. Carbon capture and storage

The government has committed to support carbon capture and storage (CCS) demonstration projects on four power stations, and is holding a series of competitions to identify projects that will receive funding. In the first round of the competition, only the CCS retrofit project at Scottish Power's Longannet plant remains in contention,[38] so we assumed in our modelling that this project will be developed as planned.

In line with current government policy, we assumed that the three further demonstration projects will come online. However, as no announcements have yet been made regarding which projects are likely to be selected for funding, in line with "level 1" of the CCS deployment assumed in the DECC Pathways document, we assumed that all four demonstration projects will be implemented before 2018, giving a total of 1.6GW of CCS demonstration capacity.[39]

B.1.6. New OCGT and CCGT investment

We give our EESyM model the choice of building new OCGT and CCGT capacity, with the characteristics listed in Table B.1. To estimate the costs of developing greenfield generators we used the upfront capital costs estimated in the Mott McDonald (2010) "medium" case.[40]

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38 Royal Society of Chemistry, "UK carbon capture a one horse race", 2 October 2010: http://www.rsc.org/chemistryworld/News/2010/October/22101001.asp

39 2050 Pathways Analysis, DECC, July 2010, page 180.

40 Mott McDonald, UK Electricity Generation Costs Update, June 2010, Appendix A.

Table B.1
New Entrant Cost Assumptions

		CCGT	OCGT
Construction Cost	2009 £/kW	718	411
Interest During Construction	2009 £/kW	66	38
Construction Cost + IDC	2009 £/kW	784	449
Real, pre-tax WACC	%	8.16%	8.16%
Fixed O&M	2009 £/kW	26	21.1
Variable O&M	2009 £/kW	2.2	1.4
Thermal Efficiency (HHV, Sent-out)	%	51.9%	40.2%

Sources: (1) Generation costs: UK Electricity Generation Costs Update, Mott McDonald, June 2010, (2) WACC: NERA analysis

To recover the fixed costs shown in the table above, we estimate that a new entrant CCGT running baseload would require a long-run clean spark spread of around £12/MWh in real 2009 prices, or £17/MWh in real 2025 prices.[41] However, the break-even point is sensitive to a number of parameters, in particular the construction costs and the required WACC as illustrated in Figure B.2 and Figure B.3 in real 2009 and 2025 prices respectively:

- *2009 real prices:* all else equal, a one percentage point increase to the WACC (9.2%) means the hurdle rate increases by approximately £1/MWh to £13/MWh. A five percent increase to construction costs leads to an increase in the hurdle rate of just under £0.5/MWh;
- *2025 real prices*: all else equal, a one percentage point increase to the WACC increases the required spread to £18/MWh. A five per cent increase in construction costs leads to an increase of the required spark spread of £0.6/MWh, or just under four per cent.[42]

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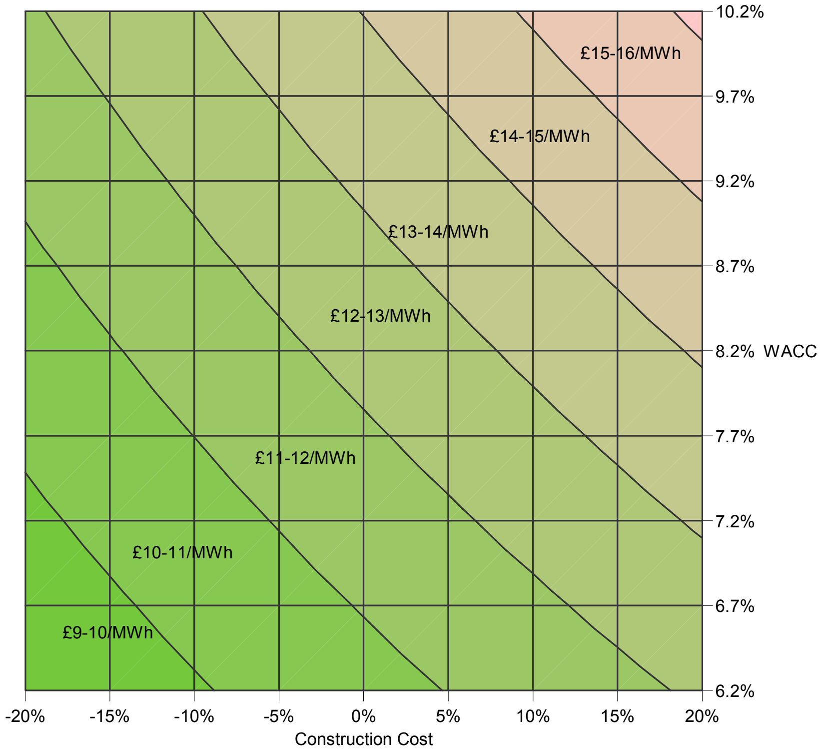
41 This clean spark spread is the equivalent of £8-9/MWh (real 2009) using the clean spark spread in the market as a whole, calculated using the standard 49% efficiency quoted in the market today.

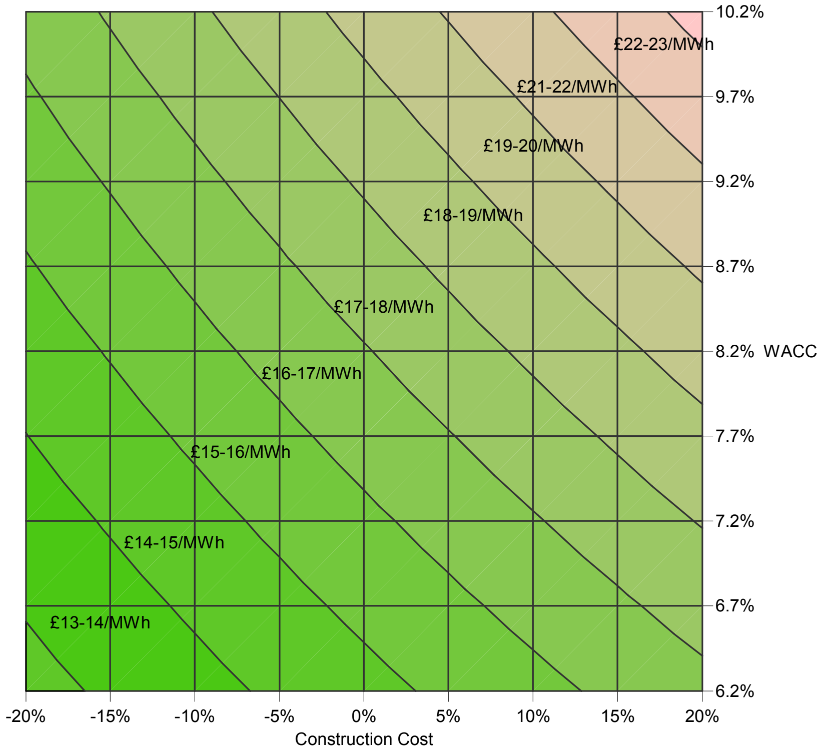
42 The increase is smaller than the five per cent increase because we retain fixed O&M unchanged in the sensitivity analysis.

Figure B.2: CCGT Required Clean Spark Spreads, £2009



Source: NERA analysis

Figure B.3: CCGT Required Clean Spark Spreads, £2025



Source: NERA analysis

B.2. Electricity Demand

The starting point for our demand forecast is the total energy supply figure reported in the Digest of UK Energy Statistics for 2009 (378TWh), from which we subtract exports (3.7TWh). This procedure ensures that our model includes the total energy demand that needs to be met by generators connected to the GB transmission system and embedded within distribution networks, including losses.

We rolled forward this energy consumption figure for the period until 2025 using the electricity demand growth rates forecast in DECC's "Updated Energy and Emissions Projections" (UEEP) document from June 2010.[43] We have taken these growth rates as the UEEP accounts for all government energy policies introduced prior to or as part of the July 2009 LCTP, as well as in the more recent Household Energy Management Strategy in March 2010. These projections also account for the expected impact of the Renewable Heat Incentive (RHI).

In the period after 2025, we assume that electricity demand will remain constant, reflecting the countervailing effects of energy efficiency improvements and economic growth, except for demand from heat pumps and electric vehicles. We assumed that the electricity demand for space and water heating continues to grow reflecting the increased penetration of heat pumps.[44]

We shaped this energy demand forecast using outturn hourly electricity demand published by National Grid for 2009. However, we adjusted this demand shape over time for the changing contributions of electric vehicles and heat pumps to total energy demand.

As the UEEP does not account for the impact of electric vehicles on electricity demand, we also added additional demand from electric vehicles based on the penetration rates forecast until 2030 in the "mid-range" scenario in a study prepared for the Department of Business, Enterprise and Regulatory Reform (BERR) and the Department for Transport (DFT) in October 2008.[45]

Our overall energy and peak demand forecasts are shown in Figure B.4 and Figure B.5 respectively. Our peak demand forecast grows more quickly over the modelling horizon than our energy demand forecast due to the relatively large demand imposed by heat pumps at peak time.

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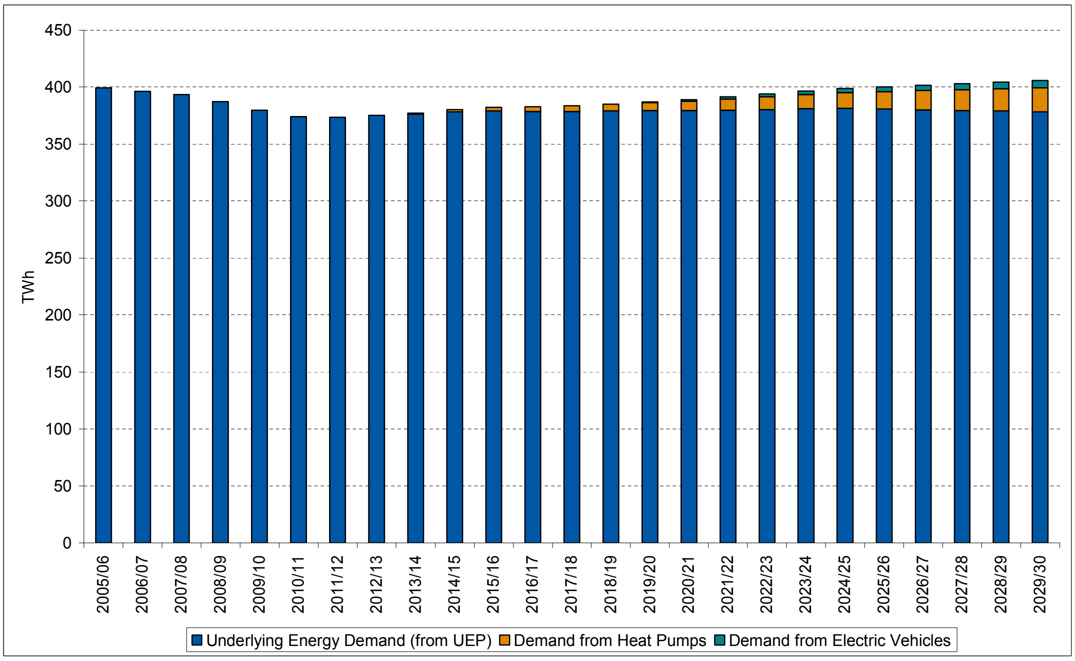
43 DECC, Updated Energy And Emissions Projections (URN 10D/510), June 2010.

44 Specifically, we assume that electricity demand from heat pumps reaches 8.4TWh, per annum based on assumptions in the Impact Assessment published on the RHI, and continues to grow to 22TWh by 2030.

DECC, Impact Assessment of the Renewable Heat Incentive scheme for consultation in January 2010 (URN 10D/547), 1 February 2010, page 27.

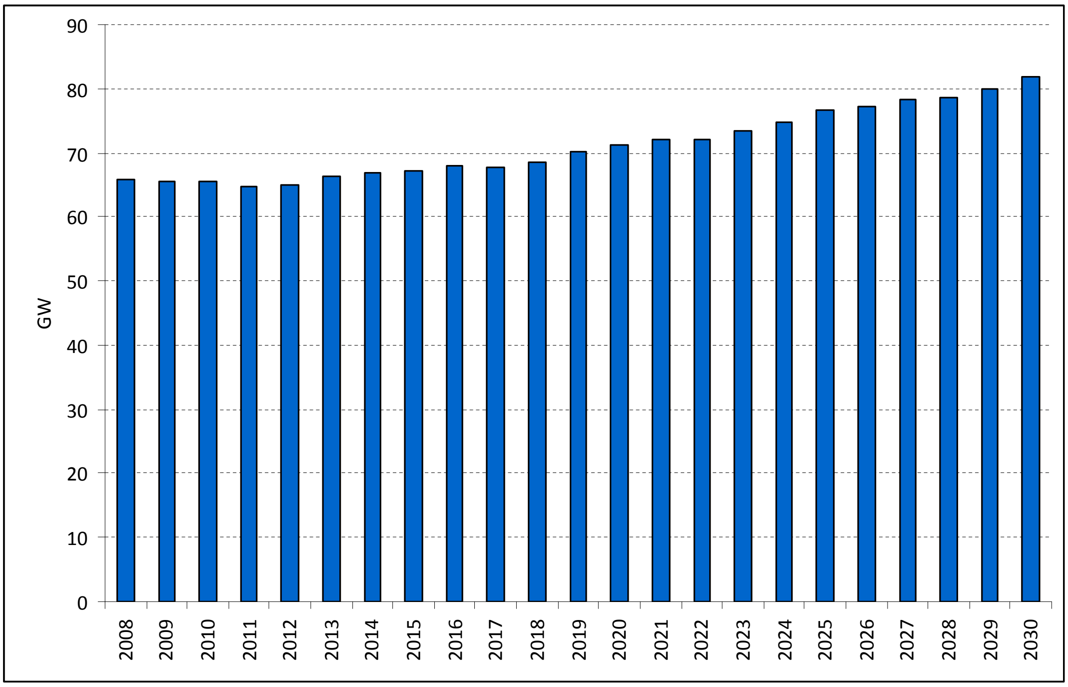
45 AEA Technology, Investigation into the Scope for the Transport Sector to Switch to Electric Vehicles and Plugin Hybrid Vehicles, October 2008, Section 2.5.

Figure B.4
Energy Demand Forecast to 2030 (TWh)



Source: NERA analysis of data from various sources

Figure B.5
Peak Demand Forecast to 2030 (GW)

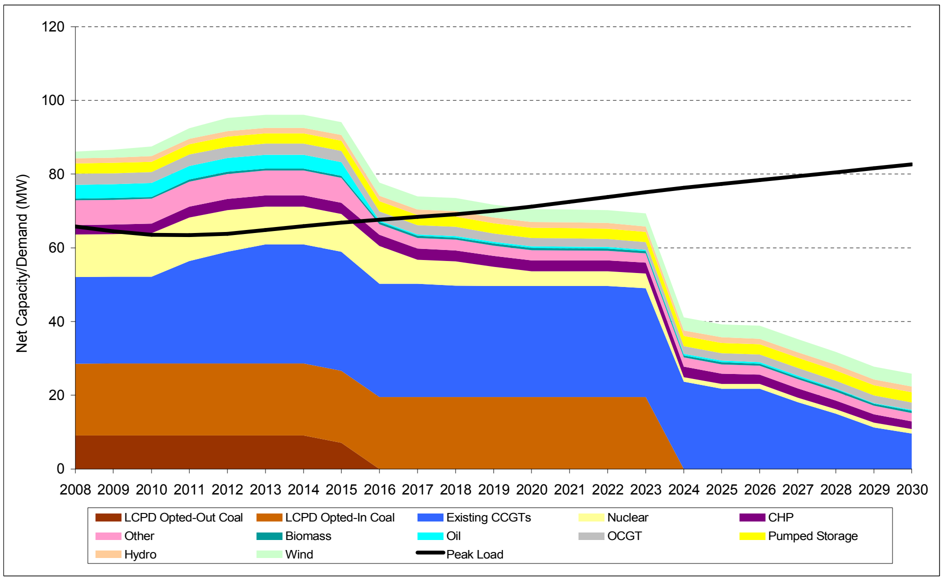


Source: NERA analysis of data from various sources

B.3. The Supply-Demand Balance

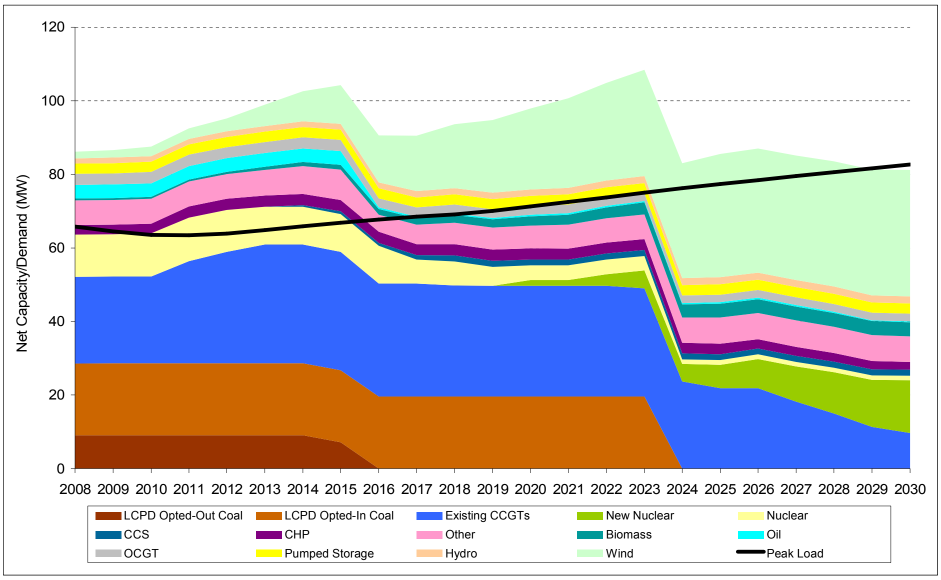
Without new generation investment, including investments required to opt coal plants into the IED, and assuming that existing plants do not retire until the end of their normal economic lives, our demand forecast suggests that a shortage of capacity compared to peak load arises soon after the LCPD opted out plants close at the end of 2015, as Figure B.6 shows.

Figure B.6
Projection of the Supply-Demand Balance: No New Investment (MW)



Source: NERA analysis of data from various sources

Figure B.7
Projection of the Supply-Demand Balance: Impact of Mandated Investment (MW)



Source: NERA analysis of data from various sources

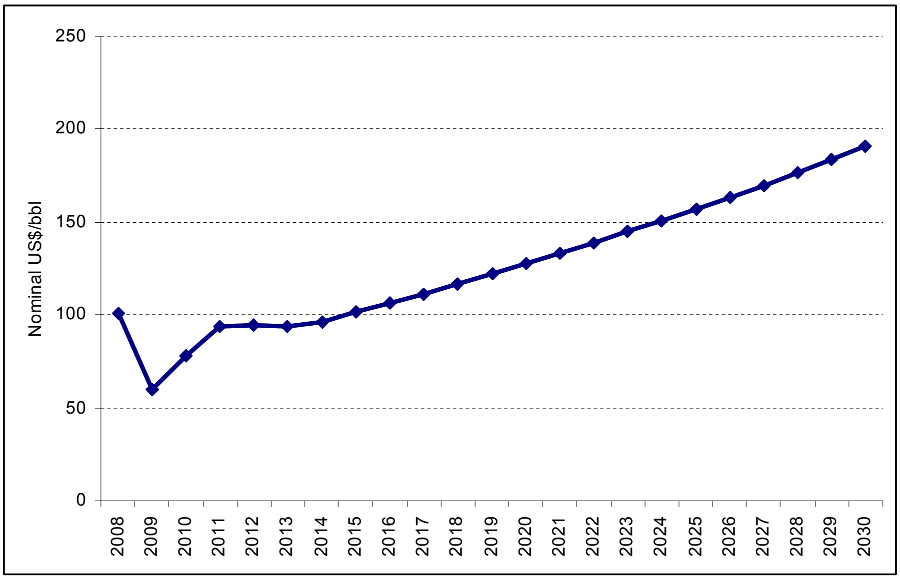
However, investments in new nuclear, CCS demonstration units and renewables mean that this shortage may be delayed somewhat, as Figure B.7 shows.

B.4. Commodity Prices

B.4.1.Fuel prices

Our method for forecasting commodity prices combines forward market prices, quoted on 31 December 2010, and long-term commodity price assumptions published by the International Energy Agency in its 2010 World Energy Outlook reference case. To forecast Brent crude oil and ARA coal prices until the end of 2013 (i.e. the liquid horizon of forward contracts), we use forward prices quoted by Bloomberg. We then interpolate prices linearly to the longer-term fuel price assumptions published by the IEA over four years. The resulting series are shown in Figure B.8 and Figure B.9.

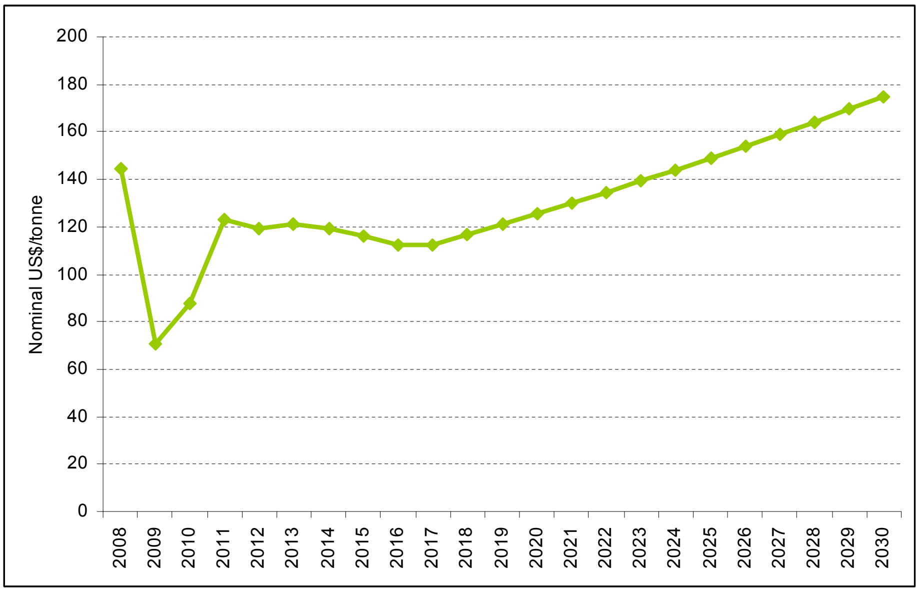
Figure B.8
Brent Crude Price Forecast (Nominal $/bbl)



Source: NERA analysis of data from Bloomberg and the IEA

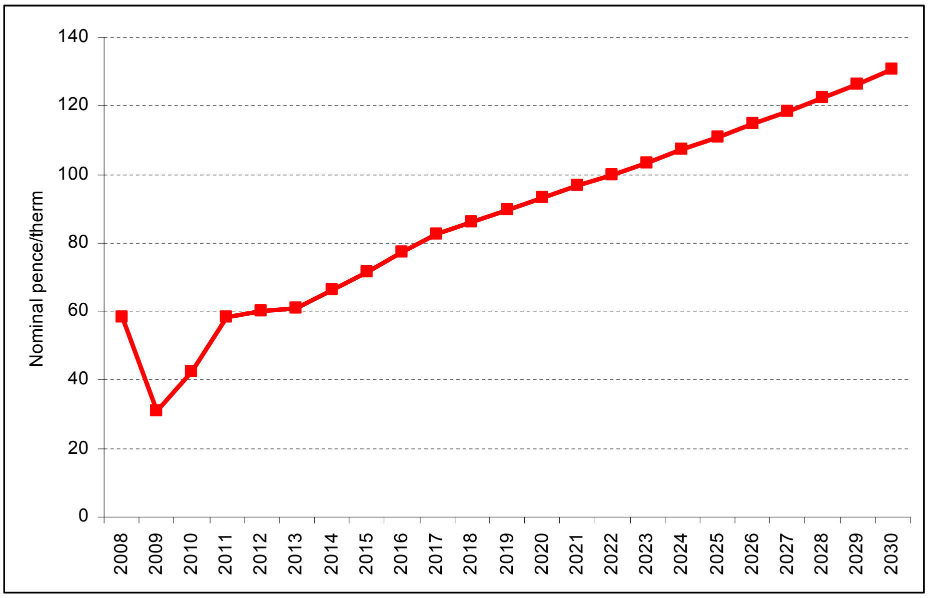
We adopted a similar approach to forecasting NBP gas prices, taking the forward curve until 2013 then interpolating to the IEA's forecast of the European gas price, as shown in Figure B.10. Our assumption that British gas prices will be set with reference to a common EU gas price in the long-run stems from the convergence observed recently between the NBP and gas prices on NW European hubs including the Dutch TTF and the emerging hubs in Germany and France (see Figure B.11), which is being driven by increasing liquidity and arbitrage competition across the hubs, along with a diversification of supplies including a big expansion of LNG.

Figure B.9
ARA API#2 Coal Price Forecast (Nominal $/tonne)



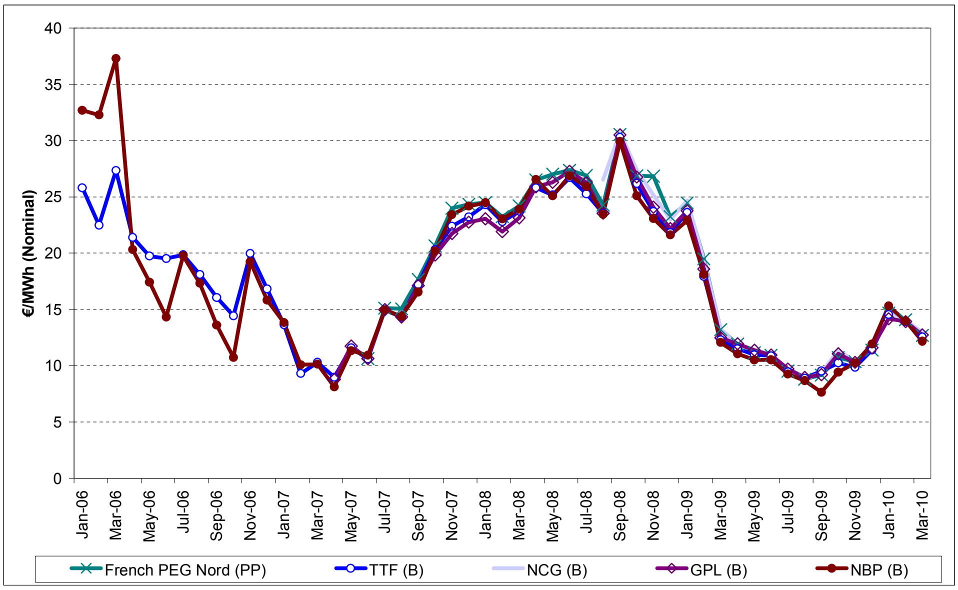
Source: NERA analysis of data from Bloomberg and the IEA

Figure B.10
NBP Gas Price Forecast (Nominal pence/therm)



Source: NERA analysis of data from Bloomberg and the IEA

Figure B.11:
Average Spot Gas Prices Across European Hubs (€/MWh)



Source: Platts PowerVision and Bloomberg.

B.4.2. CO2 prices

For the remainder of Phase II of the EU ETS (i.e. until end-2012), we base our CO2 price forecast on EU Allowance (EUA) prices published by Bloomberg. From 2013 onwards, we base our UK CO2 price forecast on the current proposals published by DECC and HM Treasury for a CO2 price floor.

Currently, the government is consulting on setting a CO2 price floor in GB through changes to the Climate Change Levy (CLL). The government is consulting on several possible levels of the CO2 price floor of between £20/tonne and £40/tonne in 2020, and has published an indicative figure of £70/tonne in 2030 (2009 prices).[46] Given this range of proposals, we have based our CO2 price assumption on an assumed UK CO2 price floor of £30/tonne in 2020 that remains constant in real terms thereafter. The resulting CO2 price series is shown in Figure B.12.

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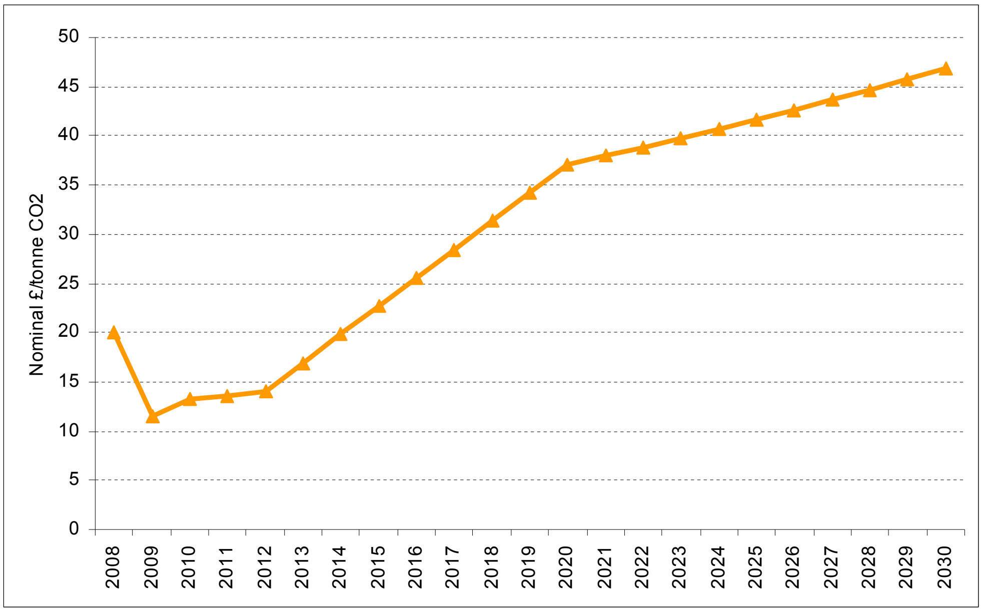
[46] Carbon price floor: support and certainty for low-carbon investment, HM Treasury, December 2010, para. 4.44.

Figure B.12:
CO2 Price Forecast (£/tCO_2)



Source: NERA analysis of data from Bloomberg and HM Treasury

Appendix C. CFD-Format Capacity Payments

The following discussion considers generic questions about the design of capacity mechanisms and then turns to the specifics of a capacity mechanism in CFD-format.

C.1. Generic Design Questions

C.1.1. Eligibility of capacity

Part of any capacity scheme is a definition of the capacity entitled to receive the payment. Such a scheme would be intended to encourage investment in the types of capacity needed to promote investment in "flexibility". Section 2 discussed what might be meant by this concept and how evidence on the rate and duration of variations in windfarm output suggested that all conventional capacity could make a contribution. Further discussion of the precise need might conceivably narrow down the amount of capacity that would be considered eligible, for instance, only the share of capacity available to start and stop within a short period (such as eight hours). However, the constant threat of a *sustained* drop in windfarm output suggests a need to encourage construction simply of "capacity", i.e. the ability to produce energy at times when demand is high. By this definition, all available capacity would be able to contribute and should be treated as eligible. The "screening curve" analysis described in chapter 3 confirms the desirability of rewarding all forms of capacity equally, in order to encourage efficient investment.

Methods for testing what capacity is available can be drawn from other markets.

C.1.2. Value of the capacity payment

As the capacity payment is an option fee, it could in principle take any one of an infinite number of values, each associated with a different strike price. Valuation of such options could apply the Black-Scholes theory of option valuation, using spot prices and volatility. Such methods are not well suited to transparent regulatory decision-making. However, the discussion of the "missing money", and of the requirement for cost recovery in efficient competitive conditions, implies that the capacity payment should be derived from the cost of a peaking plant.

The Irish system looks at the cost of a "best new entrant", which is not always the same as the peaking plant with the highest variable costs. The most expensive peaking plant may be old plant using a variety of technologies. However, in practice the difference between old and new plant is likely to have limited significance over the next few years in Great Britain, given the amount of re-planting that will be required. It therefore seems feasible to ask the market operators or a regulatory body to identify the peaking plant and its costs.

C.1.3. Corresponding limits on energy prices (if applicable)

As discussed above, the strike price of the option may be implemented as a cap on energy prices, or as the settlement price in a CFD (discussed further below). In either case, it can be set equal to the variable cost of a peaking plant, but experience from around the world suggests that some margin or flexibility is required to avoid problems in the energy market. In practice, the variable cost of running peaking plant includes not just the associated fuel costs and immediately identifiable variable cost of O&M. Running any peaking plant incurs: (1) the opportunity cost of predictable maintenance, because such plant can only run for a limited number of hours before requiring a major overhaul; and/or (2) the cost of risk, i.e. the risk of damage, a breakdown, and the cost of additional repairs. These factors both raise the actual variable cost of a peaking plant.

Furthermore, it is efficient to signal a relatively high price to consumers during a shortage, or else excess demand may create a need for load shedding that could otherwise have been avoided. These factors suggest that price caps, or the CFD strike price, should be set rather higher than the £100-200/MWh that corresponds to a simple estimate of fuel and other variable costs. In Spain, where the price cap is €180/MWh, there is widespread concern about the disincentives caused by eliminating occasional higher prices; in Ireland, the price cap is €1,000/MWh. This discussion suggests there is good reason for adopting the latter.

C.1.4. Price sensitivity of the capacity payment

The EMR Modelling Annex (MA) assumes that every unit of capacity will receive the same payment per unit, regardless of the current capacity margin. The result is over-capacity (though not much, it has to be said). It is difficult to tell precisely why this over-capacity occurs in the MA, or whether such a result is harmful or (as our modelling suggests) beneficial for consumers, given the obstacles to investment in generation such as understatement of cash-out prices. Whatever the source of the problem, however, this kind of modelling overlooks the fact that most actual systems include a price response. In practice, by one means or another, the payment per unit of capacity declines if there is excess capacity.

Some of these adjustment mechanisms involve *ex post* changes in pricing, when it becomes apparent that the current price is encouraging too much or too little investment of the desired kind. All around Europe (including in the UK), governments are looking at lowering FITs for solar power, in response to a rapid expansion of supply. However, such *ex post* adjustments are disruptive to investment and provoke major disputes.[47] To provide a stable and predictable regime, it is better to define the adjustment process in advance.

Several electricity markets in the United States have introduced "capacity demand curves", whereby the capacity payment falls if capacity exceeds the required margin, and vice versa. However, these schemes cannot be tied fully to market principles, or else the price of capacity would be as volatile as the price of electricity in an energy-only market, a situation which the system is intended to avoid. Instead, these schemes require detailed (and rather arbitrary) decisions by the regulator about the range of capacity over which capacity prices should vary between zero and a multiple (e.g. twice) of F_p, the fixed cost of the peaking plant. These schemes have proven to be both unstable (because of the temptation to change the rules at frequent intervals) and open to accusations of manipulation (because they are unduly volatile). It transpires that adding a small amount of capacity reduces the capacity payment

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[47] See the Daily Telegraph Business section of 18/02/11, which reports some potential litigation over the attempt by the UK government to withdraw solar power FITs from certain types of producer, who are deemed not to be the intended recipient of such subsidies. Similar stories have surfaced recently in Germany, Spain and the Netherlands.

for any consumer by a substantial amount. This effect is sufficient to encourage consumers to make uneconomic investments in new plant, in order to exploit their monopsony power.[48]

It would therefore be advisable to adopt a simple, transparent formula with a dampened response to the capacity margin, which nonetheless offers some adjustment to the price of capacity. The two extreme cases would be (1) zero elasticity and (2) actual market price elasticity. The former fixes capacity prices and may lead to excess capacity, as in the MA. The latter would require the payment for capacity to rise or fall by large amounts in response to small changes in capacity, thereby reintroducing the volatility that the scheme is intended to avoid.

The Irish system calculates a fixed annual amount of money and divides it among all the capacity made available over the year.[49] This rule implicitly applies a price elasticity of -1, which seems to offer a good compromise between the two extremes.

C.2. CFD Design Questions

C.2.1.Settlement of CFDs

There is no major difference between a CFD (as was used under the old Electricity Pool) and a so-called "physical" contract (of the type used under BETTA), except when it comes to settlement. Both types of contract include provisions on liability, credit control, confidentiality etc, they both define the commodity to be delivered, they both set out the process for arranging a delivery and they both define a price for the commodity when it is delivered. The difference lies in what constitutes the fulfilment of a delivery:

- A true "physical" contract would require the flow of electricity through a defined place (such as a named meter);
- Under BETTA, traders fulfil most contracts by "notifying" the settlement system of a transfer from one party to the other (which does not cause electricity to flow, but creates instead a liability or a credit that the contract parties must offset, by producing or consuming electricity, to avoid an imbalance and the associated cash-out price);
- Under a CFD, the seller hands over to the buyer the cash value of the delivery, where the delivered volume is valued at a *reference price.* (This cash liability from the seller to the buyer offsets in part or in whole the liability from the buyer to the seller for the delivery itself, so that settlement requires one party to hand over to the other the difference between these liabilities.)

The introduction of a capacity payment does not – contrary to what is stated in IA – require the creation of a compulsory pool (in addition to the compulsory settlement system to which all market participants must already belong). The CFD variant of the capacity mechanism

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48 This effect is the inverse of the market power possessed by generators, who can raise prices by withdrawing capacity. However, such behaviour is easier to identify and to punish than decisions to invest at a loss.

49 The allocation is split by month, to reflect the higher value of capacity in some months than others. The Irish system also allocates the money in part in proportion to half-hourly Loss of Load Probability (LOLP), but that seems to be an unnecessary complication, if electricity market prices provide similar signals about the value of energy at different times.

simply needs a reference price to work. Thus, the formula for the capacity payment would be:

(Duration of the settlement period in hours)
X
(Eligible Capacity in MW)
X
{(Capacity Payment per MW) – maximum(0, Reference Price/MWh – Strike Price/MWh)}

This payment removes any double remuneration of capacity, by subtracting from the capacity payment the value of energy sales in excess of the strike price. Virtually all of the time, the reference price would be less than the strike price, so that the final term in this expression would equal zero. However, on those rare occasions when capacity shortages drove the reference price to exceptional levels, the capacity payment for those half hours would fall.

C.2.2.Choice of the reference price

The main constraint on the choice of the reference price is the extent to which it allows generators to hedge the associated risks, and its implications for the liquidity of contract markets.

The government has proposed that Feed In Tariffs (FITs) should in future take the form of a CFD in order to prevent over- (or under-) remuneration of low carbon plant. A CFD-variant capacity payment could simply draw on the *same reference price as the FITs*. Given the intermittent and unpredictable nature of renewable energy output, many recipients of the FITs will want a CFD-FIT to use a short term market as the source for a reference price. Renewable energy producers would then be able to predict and to sell their output in the same short term market, so that they receive a revenue from energy sales which matches the deduction from the FIT. Such a procedure might concentrate liquidity in the relevant short term market, but draw it away from other markets.

The government has not explained how the reference price for FITs would be defined. The ultimate proposal might not be a short term contract price, but an average of longer term contract prices or even the imbalance price for a surplus (SSP, the System Sell Price). The longer term average would be easier to calculate, and might be less easy to manipulate than a specific contract market, but it would also be less easy for renewable producers to hedge against price variations in a long term contract market, when their long term forecast of output is so unpredictable. Renewable generators might be quite happy with letting their output accumulate as a surplus in the settlement system, if the CFD-FIT always made up the difference between the FIT and SSP. However, such a system would remove renewable generation from the contract market entirely.

This uncertainty provides a good reason for considering the use of different contract indices or prices in the settlement of a CFD-variant capacity mechanism. Moreover, a capacity mechanism is inherently different in kind from the FIT, since it is an option on energy in the market, not a fixed price contract per MWh of output. The total payment per MWh under a CFD-FIT would be inversely related to the reference price, so the FIT would provide a hedge against all variations in the reference price. In contrast, the capacity payment would normally offer a fixed premium on top of market prices for electricity, and would only be reduced if the reference price rose above a strike price. In other words, the CFD-variant capacity payment gives generators a *negative* exposure to the highest electricity prices, by the amount they exceed the implicit price cap, but it leaves the *positively* exposed to normal or low electricity prices. To stabilise their total revenues, generators would have to achieve two aims:

- to sell their output at the reference price when it is *above the strike price*, but
- to sell their output at fixed prices, but only in half-hours when the reference price is *below the strike price*.

These aims raise a question about the implications of a CFD-variant capacity payment for hedging and contract market liquidity. A capacity payment fixed independently of market prices will not affect generator's incentive to trade contracts. However, it may (very occasionally) allow electricity prices to rise very high. If the contract payment is adjusted for high electricity prices, generators are negatively exposed to peak electricity prices. However, consumers (and suppliers) would not be exposed to the same risk in reverse, unless charges for the capacity payment were allocated to suppliers with that aim in mind. That would require the total half-hourly capacity payment to be allocated to suppliers directly in proportion to their half-hourly demand. Suppliers would then pay less towards generators' capacity payments at times when generators were receiving less. All traders could then focus on hedging their remaining exposure to market prices, as at present.

Without this matching of seller and buyer exposure to risk, market liquidity might decline (possibly irreversibly), as generators and suppliers failed to find a form of contract that met both their needs.

C.3. Conclusion

Concern about double payment is unnecessary, if the effect of a capacity payment mechanism is intended to correct for the under-pricing of energy under BETTA, by offering an alternative source of revenue. Even if market reforms eliminate the under-pricing known to exist at present, a capacity payment mechanism need not cause any double payment. Creating a CFD-format capacity payment, with an adjustment to offset high energy prices, would be no more challenging than creating a CFD-format FIT. The form of capacity payment could prevent double payment, without requiring any cap on electricity market prices.

However, this arrangement would have implications for electricity trading and market liquidity. To the extent that a capacity payment changes the energy market risk faced by generators, it will affect their desire to hedge. If the capacity payment changes the energy market risks of consumers and suppliers differently (i.e. not inversely to those of generators), it will reduce the ability of generators and suppliers to find mutually beneficial hedging contracts.

These implications for market liquidity may affect the appraisal of the CFD-variant capacity mechanism, as well as alternatives such as putting a cap on electricity market prices.

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