Appendix 4.1: Market power in generation

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Introduction

1. This appendix sets out our initial thinking of whether any generator has the ability and incentive to exploit market power in the GB wholesale electricity market.

2. It starts by outlining the theory of harm we are investigating. It then explains the methodology for assessing market power, outlines limitations of the model, and presents results from the model before outlining other considerations affecting generators' ability to exploit UMP.

Theory of harm

3. Our main hypothesis relating to the exercise of UMP is that certain generators may have market power in the GB wholesale electricity market at particular times. Although market shares in generation as a whole are relatively low[1] the nature of demand and supply means it is possible that at certain times, one generator (or more) may unilaterally be able to influence the price of electricity in spot markets.[2]

[1] See the Descriptive statistics: generation and trading working paper.
[2] In addition, our theory of harm requires that affecting the spot market is likely to lead to increased price expectations in forward markets. This is not a naïve assumption, and the issues are discussed at greater length in paragraph 20.

4. The main way in which a generator can exercise market power is to withhold some capacity (either physically or economically[3]) to force a shift in the supply curve and hence the price.

5. A firm will only want to withhold some of its capacity if the gains from withholding exceed the costs from withholding. The loss from withholding is the profit that would have been made by the plant(s) being withheld if they had been operating,[4] and the gains from withholding is the additional margin earned on all remaining operational plants. This means that situations are possible where generators have the ability to shift the supply curve (and hence the price) but no incentive to do so, as the losses outweigh the gains.

6. Our hypothesis relating to the exercise of coordinated market power is that generators can together withhold capacity in the wholesale market to increase wholesale prices.

7. The three necessary conditions for the ability of firms to exercise coordinated power are that:[5]

   (a) firms are able to reach and monitor an understanding on withholding;

   (b) firms are able to internally sustain an understanding, for example through a punishment mechanism; and

   (c) firms are able to exclude competition from outside the coordinating group.

8. We consider that none of these conditions is likely to be met.

   (a) **Reaching coordination**. The reaching of an understanding among six companies requires that they are able to monitor any deviations from an agreement. This is likely to be difficult in the case of the electricity wholesale market because almost all trades are anonymous, with identities revealed only to the transactors and not to the market as a whole. Coordination would have to apply to forward market trades as well as spot market behaviour, and it would be very hard to tell whether any specific forward trade constituted an 'overselling' of capacity. Coordination among a larger group, including the larger independent generators, would be harder still.

[3] Economic withholding would involve a party contracting its power plant as if it were higher in the merit order.
[4] This can also include additional start-up costs.
[5] *Guidelines for market investigations: Their role, procedures, assessment and remedies (CC3)*, paragraph 250.

(b) **Internal sustainability**. The anonymous nature of trading means that it is very hard to associate a price outcome to the behaviour of a specific firm, and therefore hard to target any punishment strategy.

(c) **External sustainability**. If coordination were to be among the Six Large Energy Firms, then the large independents would benefit from their restraint and may be able to increase output in response. This limits the extent to which the Six Large Energy Firms could coordinate. Moreover, we have not found that the largest energy companies (including the large independents) can block entry into generation. Therefore, any coordinated benefits would be short-lived, as they would increase prices to a point that would attract entry.

We therefore do not consider coordinated strategies further.

Methodology

9. In this analysis we aim to quantify a firm's ability and incentive to exploit UMP in the GB wholesale electricity market.

10. In order to do this, we compare the 'competitive' market price to an 'optimal' price for each firm for each half-hourly period in 2012 and 2013. The competitive market price is the marginal cost of the marginal plant when all plants are stacked up in order of their marginal cost. The optimal price is the price that maximises profits for the firm in question. If the price increases from the competitive strategy, this optimal price is achieved by a firm by withholding capacity.[6] We take the firm's optimal withholding strategy as the profit-maximising response to other firms' competitive offerings, ie assuming that rival firms offer their output as if the market were competitive and do not withhold capacity. The best response of other firms to withholding by one firm is likely, in the specific circumstances of the GB electricity market, to be to maintain competitive levels of output. The reason for this is that market power, when it is exercised, involves making another technology the price-setting technology – for example, shifting this from coal to gas. Once this has been done, there is no further opportunity to raise prices by small additional capacity reductions. Therefore, we believe that the strategies we have identified as optimal for each firm would also be stable for the market as a whole.

[6] If the withholding strategy is inferior to the competitive strategy, the optimal strategy is the competitive strategy for that period.

11. We analyse the ability and incentive for each of the Six Large Energy Firms and Drax to exploit UMP.

12. The methodology involves the following steps:

    (a) Identifying the supply curve.

    (b) Identifying the competitive price.

    (c) Identifying the optimal withholding strategy and associated price.

13. A full explanation of the methodology is outlined in Annex A. The model developed is a simple model which ignores some significant constraints that generators would face when considering the dispatch of their plants. This simple model structure means that UMP opportunities are likely to be overestimated (see further details in the Model Limitations section below) and should be considered as an upper bound or worst case scenario. Thus, if we are unable to identify problematic incentives in this theoretical model, then they are unlikely to exist. In its response to our working paper, EDF Energy noted that this methodology therefore 'can be used to prove that a generator (or generators) cannot exercise market power, as is the case here, but that it is much more problematic to use [it] to demonstrate that market power can profitably be exercised.'

Model limitations

14. This modelling exercise provides something close to a necessary condition to a finding of UMP by any generator.[7] However, it does not provide a sufficient condition. Any modelling exercise of this type needs to make a number of simplifying assumptions. These simplifications limit the ability to strongly rely on positive results, and therefore will require further investigation and processing. However, if harm cannot be found in the simple model, we can almost certainly rule out there being harm in the more complex model which better represents the real world.

15. The significant simplifications in our model are as follows:

    (a) No dynamic constraints.

[7] Unilateral market power could conceivably be exercised by specific exploitation of the constraints that we have excluded from this model. For example, a particular generator might find that it has market power in the supply of the very flexible, rapid response capacity that is required at peak times or in times of system stress. We have not explored this possibility further in this paper. We consider the arrangements and incentives for the supply of flexibility in the Appendix 5.1: Wholesale electricity market rules.

(b) All output sold through spot/day ahead market at the same price (ie efficient spot trading assumption) – (no forward market considerations).

(c) No uncertainty about:

(i) demand;

(ii) wind;

(iii) actual capacity;

(iv) efficiencies of other plants; and

(v) competitor strategies.

16. Parties raised a number of points about the degree to which we can rely on positive results from the model. Below, we outline the arguments presented by parties and assess the impact of the arguments on the results.[8] Taken together, these arguments raise doubts about whether parties would have UMP opportunities, even if our model identifies such opportunities.

Current market design and forward trading

17. Our model takes a simplified version of the GB wholesale electricity market where all output is sold at a single price in the spot market and there is no forward trading. However, the market can be characterised better by both bilateral trading between parties and forward trading of output. This means that not all generators will necessarily receive the same price and generators may have sold much of their output before the spot market, so capacity withholding will not lead to the withholding generator fully benefiting from the increase in prices.

18. With respect to bilateral contracts, while there is no longer a single market price that all generators receive for their output, we would nevertheless expect the prices agreed to reflect underlying fundamentals of the market, and thus the single price assumption is reasonable in the circumstances. However, with respect to forward trading, a number of parties raised the concern that either a generator would have to be completely unhedged to benefit from capacity withholding, or the withholding has to be anticipated by other participants to affect forward prices.

19. We consider it highly unlikely that generators would only sell their output in the spot market and none in the forward markets, because generators sell

[8] Parties' views are outlined further in Annex B.

almost all of their output in the forward markets. The risk attached to this strategy would likely be larger than benefits from a theoretical withholding strategy. Therefore, for a generator to benefit from a withholding strategy, they would have to affect expectations of the forward prices.

20. To affect expectations of forward prices, other market participants would need to believe that this strategy was being consistently pursued. This might be difficult for a generator to achieve because the incentives for withholding in the spot market are affected by prior forward market behaviour. If a generator is expected to withhold, and therefore manages to sell forward energy at a high price, it could be tempted not to withhold when the time comes. A generator would therefore have to develop a reputation for consistently withholding even if immediate incentives did not warrant it.

21. Withholding capacity to affect future expectations involves a degree of risk which reduces the profitability of the strategy. This is because market circumstances may change between the period in which a generator withholds capacity and the period in which the expectations are affected (eg the relative position of coal and gas plants in the merit order may be reversed between one year and the next). In particular, Scottish Power said that:

> We think that a generator seeking to follow a withholding strategy would have great difficulty in doing so with sufficient consistency to change expectations of forward prices without the cost being disproportionate to the gain that could be made. We therefore consider that the model over-estimates – perhaps by an order of magnitude – the likely payback (though not the cost) from following a UMP strategy. Making allowance for this could well render the strategy unfeasible.

22. We consider further below the level of uncertainty in the market and the likelihood of the profitable strategy being identified.

Uncertainty

23. To be able to calculate the optimal withholding strategy in our model, parties will need to have good information on at least the following:

(a) demand;

(b) supply by other plants (notably wind); and

(c) shape of the stack, including:

(i) competitor efficiencies and costs; and

(ii) the relative price of coal and gas.

24. Uncertainty around these aspects of the market can affect the optimal withholding strategy in the short term. While we expect that generators, through repeated interactions, will be able to estimate the position of their plants in the stack relative to other plants, the potential problems presented by the ability to forecast actual demand and output by other plants can lead to a suboptimal withholding strategy being pursued.

25. This means the benefits of withholding will be overstated but the costs from withholding will not be. In addition, as mentioned in the section above, the relative prices of gas and coal will affect the strength of signal about current withholding to other participants. For instance, one generator may withhold some of its CCGT plants when they are peaking plants, but if the price of coal and gas were to switch, the ability and incentives to withhold may change. The cost of making a signal to the rest of the market will still be present, but the gain from withholding may not be.

Plant characteristics and operating parameters

26. All parties we contacted to test and evaluate the model highlighted that the model did not take account of plant characteristics, including dynamic constraints. The effect of this omission on the results of our model will be as follows:

(a) Certain UMP opportunities identified in the model being infeasible due to less flexibility of the plants than modelled.

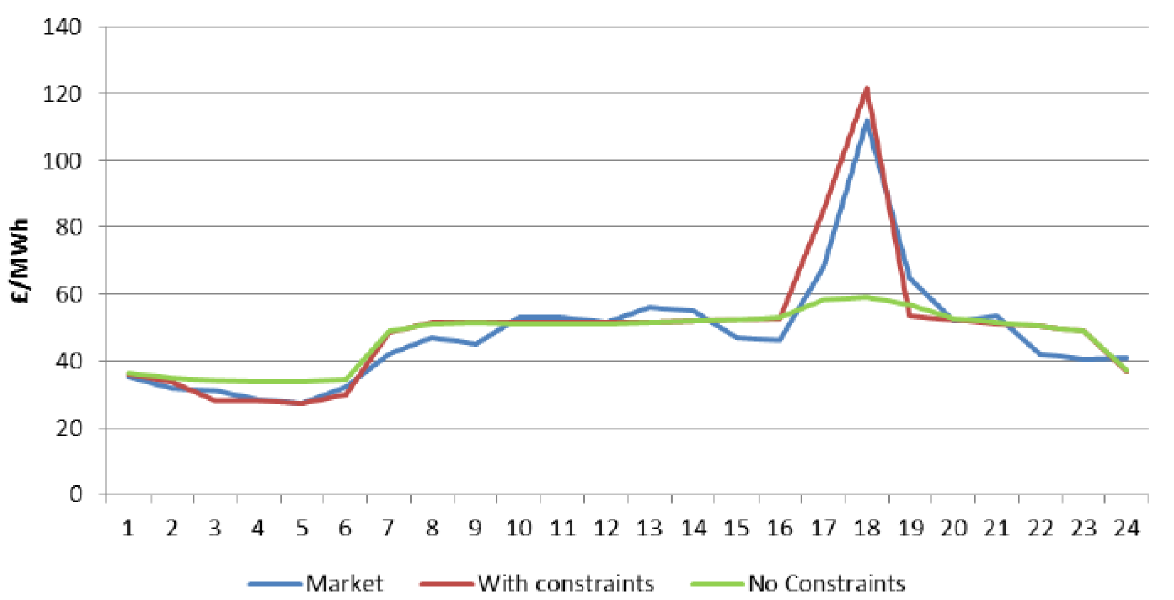
(b) Costs of UMP strategy being underestimated in the model given the additional start-up costs of an additional shut down and lost efficiency from part loading.

(c) Opportunity cost of withholding being underestimated in the model as shutting down a plant will mean less profit in following periods as plant is not able to run.

27. In particular, RWE provided an example of the outputs of its stack model which compared the power price on a certain day and the outputs of its model with and without dynamic constraints. This showed that the assumptions of no constraints led to a significant change in daily shape with:

- higher off-peak prices; and
- a much lower evening peak price.[9]

Figure 1: Power price profile with modelled prices on 22/11/12



Source: RWE.

28. The shape of evening peak is not calibrated well in our model and follows a similar pattern to RWE's model of prices without constraints (see Annex C). Underestimating the evening peak leads to an overestimate of the profitability of withholding in these periods. This is because rather than withholding to achieve a high peak price, the high peak price is one that would competitively emerge from a market where dynamic constraints are binding on participants. Therefore, there will be some periods in which our model predicts profitable withholding at the evening peak but in which withholding actually reduces profits.

29. Another simplification of our model was in relation to the ability to turn a power plant on and off in between half-hour periods. The minimum down time for a CCGT plant is at least 2.5 hours, and longer for coal plants. In addition, plants need to run for a minimum time. Turning on for a half hour is infeasible for

[9] Due to the difference between peak and off peak prices being lower in an unconstrained model, the amount of pumping by pumped storage units would likely be lower as the profit opportunity would be lower.

many CCGT and coal plants. Our model will have identified some UMP opportunities that violate these constraints.

30. Finally, we note that the unconstrained model over-predicts prices overnight. The overnight dips in real prices can be explained by generators bidding under their marginal cost to ensure they do not incur start-up costs. In effect, if the opportunity cost for a generator turning off overnight is higher than the costs of remaining on, the price is likely to be bid down to where these two costs equalise.

Results

31. This section sets out the final results from the models. These results consider the arguments made above and have been filtered to account for dynamic constraints and uncertainty. Further results are set out in Annex D.

32. In Tables 3 and 4, we present results from our model, once a filter for feasibility and profitability are considered.[10] These filters help to show the impact of considering dynamic constraints and uncertainty in our model, but are not a perfect substitute for a fully dynamic dispatch model. Therefore, they should be considered as illustrative of the likely profitability and number of UMP opportunities.

Table 3: Number of 30-minute periods in a year in which a party is able to increase prices by thresholds (feasibility and profitability filtered)*

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*Cells highlighted show where price rises are greater than the benchmark competitive price by 5%, 15% and 45% for more than 1,440, 480 or 160 half-hour periods respectively. These thresholds were used in the Market Abuse Licence Condition. See paragraph 2(a) in Annex D for further details.

[10] Feasibility and period filters are outlined in paragraphs 15 to 17 in Annex D. The profitability filter is outlined in paragraph 22.

Table 4: Average price increase (feasibility and profitability filtered)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

33. There appear to be some UMP opportunities identified in Table 3 which exceed the initial thresholds. In particular, [✂] appeared to be able to increase prices for a number of periods in 2013 and could raise prices by more than 1% over the whole year. We note that almost all of the UMP opportunities identified appear in the step between coal and gas (see Figures 2 and 3). This is when demand is relatively low.

Figure 2: Number of withholding periods in which the marginal plant was coal or CCGT, 2012 (feasibility and profitability filtered)

[✂]

Source: CMA analysis.

Figure 3: Number of withholding periods in which the marginal plant was coal or CCGT, 2013 (feasibility and profitability filtered)

[✂]

Source: CMA analysis.

34. All the parties who have UMP opportunities in the coal/gas step have some coal-powered power stations which they can withhold.[11] [✂] appears to be able to profitably increase prices more often than other generators. [✂].[12] The benefits from the withholding of coal power plants means that [✂] also receives a greater margin than under competitive assumptions. Therefore, the model predicts it can increase the price more than other generators (see Table 4).

35. However, as shown in the analysis of dynamic constraints (paragraphs 26 to 30), generators will sometimes accept prices below marginal cost to avoid being turned off and incurring the related operating costs. Therefore, our model is likely to over-predict the number of UMP opportunities that would arise in the step between coal and gas.

[11] [✂] and [✂] also have [✂] that can be withheld.
[12] While [✂] also has a share in the nuclear power fleet, it does not [✂] so does not have the ability to withhold in the coal/gas step.

36. In addition, many of these opportunities arise because of the increase in spread between coal and gas prices in 2013 (see Annex D, Figure 4). For a withholding strategy to be consistent with forward trading (given almost all output is sold ahead), the parties and the market in general would need to have anticipated the increase spread between gas and coal prices in 2013. We consider this to be relatively unlikely, and forward trading on these commodities may have reduced this spread.

37. Finally, these results do not fully account for uncertainty. Analysis in Annex D shows that most UMP opportunities are not consistent with demand (or supply) shocks, further reducing the number of UMP opportunities.

38. The application of the filters used in this section requires an element of judgement, although we have used a variety of filter thresholds to test the sensitivity of our findings. The ideas behind the specific filters are set out in the model limitations section. As the number of UMP opportunities decrease significantly when filters are applied, this strongly suggests that the initial results are not robust to the considerations of dynamic constraints and uncertainty.[13]

Further considerations

Regulations

39. A number of parties pointed to existing regulations and potential future changes to licencing conditions as reasons for firms not exercising UMP in the energy market.

40. In particular, capacity withholding could be considered a market abuse and therefore be punishable under REMIT.[14] If detected, penalties can be severe, meaning that gains from withholding would be more than offset. We therefore consider it unlikely that significant capacity withholding could profitably take place without being detected, although possibly lower levels of withholding might be.

[13] RWE has submitted detailed results which show that the CMA's model is highly sensitive to the assumed lack of dynamic constraints and the costs of additional starts. We have not had time to assess these modelling results in detail, but they appear to be consistent with our own filtering results.

[14] The REMIT regulation (Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency) explicitly prohibits market abuse, requires effective and timely public disclosure of inside information by market participants, and obliges firms professionally arranging transactions to report suspicious transactions. If GEMA is satisfied that a regulated person has failed to comply with a REMIT requirement, it may impose a penalty of such amount as it considers appropriate. While the primary responsibility rests with the regulated person, GEMA may also take action against individuals where there is evidence of personal culpability on the part of that individual (see The Electricity and Gas (Market Integrity and Transparency) (Enforcement etc.) Regulations 2013).

41. In addition, if withholding took place at times of system constraint, the punishments under TCLC[15] may also be a severe constraint on generators' behaviour.

42. These regulations can have a powerful effect on incentives to exploit market power. If withholding was obvious, it is likely to be observed by relevant authorities, and therefore the regulation is likely to constrain generator behaviour. If the withholding is less obvious, then the degree to which regulatory enforcement is a constraint might be questioned, albeit the profitability of smaller withholding may also be lower, leading to reduced incentives and concerns.

Future market conditions

43. While the current model shows some degree of possible UMP opportunities in 2012 and 2013 (under restrictive assumptions), the degree to which these results would hold in the future depend on these years being representative of future years. As mentioned above, demand and wind output may change both within days and between years.

44. The 2013 results were driven by the spread between coal and gas prices, and the relative position of coal and gas in the merit order. Both these factors could change, especially with the carbon price increasing over time. These factors would likely reduce the number of UMP opportunities identified in our model and the size of those opportunities.

45. In addition, the power station portfolio for each generator may change over time. For example, RWE mentioned that it had closed over 4,000 MW of coal, biomass and oil-fired power stations since 2013, with additional closures of 1,000 MW of oil capacity announced for March 2015.[16]

46. Also, new generating capacity may be built, for example wind farms and interconnectors, which change the merit order of power plants and thus ability and incentives for UMP. The incentives for building new generation capacity would also be increased if prices were consistently higher due to withholding, reducing the long term ability to maintain a UMP strategy.

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[15] Transmission Constraint Licence Condition. This is a licence condition to limit the behaviour of electricity generators during periods when there is insufficient capacity to transmit electricity from where it is generated to where the demand is. Ofgem has the power to sanction a licensee for the breach of this licence condition by imposing a penalty deemed to be reasonable under the circumstances, and which may not exceed 10% of the turnover of the licensee.

[16] As noted in the *Descriptive statistics: generation and trading* working paper, capacity margins decrease in 2015/16. However, as most of the UMP opportunities identified have been in the intermediate coal/gas step, rather than at peak times, we do not consider that our results would change significantly.

47. Finally, as part of the EMR programme, a number of fossil-fuelled power stations will be in receipt of capacity payments following the capacity market auction. Generators in receipt of capacity payments need to be available to generate at times of system stress. Failure to generate at these times can lead to penalties, leading to a reduction in the incentives for a generator to exploit UMP.[17]

[17] In addition, under EMR, new generating capacity in receipt of CfDs will be at least indifferent, if not against increases in benchmark prices as this reduces the payments a generator would receive from the CfD. Further consideration of this issue is in Appendix 5.3: Capacity.

Annex A: Methodology and inputs

1. This annex sets out the methodology for estimating UMP and the inputs used in our model.

Methodology

2. In this section, we describe in detail the three stages of the methodology as listed in the paper.

Identifying the supply curve

3. We have constructed a merit order stack model (ie ranked in order of increasing marginal cost) of all generators in GB – this forms the supply curve. To do this we have used a range of sources and publicly available data.

4. We have made a number of assumptions and simplifications in order to make the model transparent and tractable. The key assumptions are as follows:

   (a) We have assumed no start-up costs, ramp rates, or minimum up and down times. We have also assumed that the minimum stable generation is zero (ie any level of generation is feasible). This is likely to result in the competitive prices in the model being lower at peak periods and higher in overnight periods.[1]

   (b) We have modelled thermal plant availability as constant. In winter this is 90%, and in summer, 80%, to account for expected and unexpected outages.

   (c) We have given all wind farms the same availability within each half hour, equal to the national wind output for that half hour divided by total wind capacity. Similarly, for nuclear output, we have used average actual availability. Nuclear availability is generally constant and so we do not expect this to substantially influence our results. However, wind availability is very likely to differ across GB from day to day. Our assumption means we do not differentiate where the generation is taking place.

[1] This may also reduce incentives for withholding.

(d) We have made a number of assumptions regarding the costs of interconnectors, hydro plants, pumped storage, and DSR. These are discussed in more detail below.

(e) Our model uses daily spot prices for gas and average quarterly prices for coal, gasoil, heavy fuel oil and biomass. It therefore does not fully account for firms hedging fuel costs, and as a result, fuel prices in the model may be higher and more volatile than the prices actually faced by generators. Nevertheless, we would assume firms will consider the opportunity cost of running their plants on certain days, eg when the gas price is high.

(f) We have assumed that total generation is reduced by 1% to account for transmission losses.[2]

Identifying the competitive price

5. The competitive price is determined at the intersection of the supply and demand curves, and is equal to the marginal cost of the marginal generator, ie the last generator needed to meet demand in a given period.

6. Demand data from Elexon is given in half-hourly periods and covers 2012 and 2013. It includes demand met by all non-embedded generation in GB, as well as demand from interconnectors and pumped storage.[3] We have added 1% to the demand figures to account for transmission losses.

7. Demand is assumed to be perfectly inelastic (ie unresponsive to changes in price) for the purposes of this model. This appears to be a reasonable assumption given the nature of demand for electricity, although we are aware that there are some customers who can reduce their demand in times of high overall demand.[4]

8. The model does not take into account transmission constraints, so the dispatch predicted may not always be possible and competitive prices may be higher (this could also be true for UMP prices below).

[2] We have added transmission losses to both generation and demand given that the costs are shared equally between generators and retailers.
[3] For periods where demand has not been recorded in the data, we have made reasonable assumptions about demand, based on demand in neighbouring periods (smoothing between the periods where we have data). The number of these incidences is very few (around 50 HH periods out of 35,088 for 2012 and 2013 combined) so should not materially affect the robustness of the results.
[4] To take account of this, we have included a 1,000 MW plant to model demand-side response.

Identifying the optimal withholding strategy

9. To identify the optimal withholding strategy for any firm, we first find the profit-maximising output level. Our methodology involves the firm using the residual demand and firm specific marginal cost curves to calculate what the optimal output level would be.

10. Under normal circumstances, we would find the profit-maximising point where residual marginal revenue is equal to marginal cost of the firm. However, as the residual marginal revenue curve is undefined at the discontinuous points, we have instead found the point where the difference between total revenue and total cost (excluding fixed costs) is maximised. Therefore, we have calculated total cost and total revenue at each point and identified the maximum value of the difference to identify the optimal withholding strategy and hence the UMP price.

11. For each firm, we have taken the following steps to identify the optimal strategy:

    (a) Identify the firm's short run marginal cost curve. This is a mini merit order stack of the firms generating assets.

    (b) Identify the residual supply curve (ie the total industry supply less the generating assets of the relevant).

    (c) Identify the residual demand curve, ie the portion of the market demand curve which is not met by other firms. It is calculated by subtracting the residual supply curve from total demand. The price for the residual demand curve is defined by the marginal cost of the next plant in the merit order. The exception is the last step, where the residual demand is the system maximum price.

    (d) Calculate the total revenue at each level of own output of the firm by multiplying the available capacity by the relevant price in the average revenue curve (ie AR*Q=TR).

    (e) Calculate the total cost curve for the firm. This is done in two steps:

        (i) In the first step, we calculate the costs of the firm-specific infra-marginal plants. These are plants which we assume are fully loaded (subject to operating/availability constraints).

        (ii) In the second step we calculate the load factor of the marginal plant (ie this is a plant which will be partially loaded.) We first calculate the output of the plant and then multiply this by the short run marginal cost of the plant.

(f) Identify the profit-maximising point. This is the output where there is the largest difference between total revenue and total cost. This identifies the optimal withholding strategy in that period and the price if UMP was exercised.

Inputs

12. In this section, we describe the inputs used in the stack model. These include the plant, inputs into each plant (eg fuel prices) and plant characteristics.

Generators data

13. To identify power plants, we have used Elexon's list of Balancing Mechanism Units.[5] We have attributed ownership to each of the plants using data from DUKES, and from generators' own websites. Embedded generators have been removed. All of this data is publicly available.

14. The merit order stack contains all interconnectors and generators in GB that are transmission connected.

15. We have also included 1,000 MW of demand-side response (DSR) at the end of the stack.

16. Plant-specific efficiencies and installed capacities are taken from publicly available data on companies' websites, through DUKES and Elexon.

Inputs data

Fuel prices

17. All fuel prices have been converted into pounds per megawatt hour (£/MWh). Coal[6] and oil[7] prices are calculated as a quarterly average. Gas prices[8] are daily (gas-day, ie 6am to 6pm) averages to account for higher volatility and seasonality in gas prices. The data did not include prices for weekends and bank holidays so we have estimated these missing values as the price on the preceding Friday.

[5] ELEXON Balancing Mechanism Units.
[6] API Coal cif futures, NYMEX, Bloomberg.
[7] Gasoil 0.1% cif, Bloomberg.
[8] Day-ahead natural gas spot price, Bloomberg.

18. Data on biomass prices[9] gave an unrealistic price per MWh. We have therefore chosen a biomass price to reflect its appropriate position in the merit order, ie just before coal. This chosen price is consistent with the proportionate price of biomass relative to other fuels as modelled by National Grid in its Electricity Scenarios Illustrator.[10]

19. We have assumed no fuel costs for nuclear and renewable generators.

Carbon price

20. We have applied a price for carbon dioxide emissions to coal, gas and oil-fired generators.[11] We have used the quarterly average price of one EU emission allowance (EUA).[12] From April 2013, we have added a carbon tax levy of £4.94 per tonne CO_2.[13]

Non-fuel variable costs (Operation and Maintenance costs)

21. We have used publicly available data sources to estimate the non-fuel variable costs for different generator types. The assumptions and sources are as follows (all in £/MWh):

(a) Offshore wind: –£88.[14]

(b) Onshore wind: –£44.[15]

(c) Nuclear: £2.50.[16]

(d) Biomass: £1.40.[17]

(e) Coal: £3.38 (this includes transport and port costs of £1/MWh each).[18]

(f) CCGT: £0.08.[19]

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[9] Industrial wood pellets spot price, Argus Biomass Markets.
[10] National Grid Electricity Scenarios Illustrator.
[11] We are aware that oil-fired generators pay fuel duty rather than an explicit CO_2 price. However, given that they are entitled to duty rebates (essentially equal to difference between duty paid and carbon price), we assume that their net payment is similar to the CO_2 price.
[12] Carbon Emissions Futures.
[13] HMRC, 2012. Carbon Price Floors: Further Legislative Provisions and Future Rates.
[14] This is based on an average ROC value of £44. Onshore wind receives one ROC and offshore wind receives two. See *Renewables Obligation Annual Report 2012-13,* Ofgem.
[15] See footnote 14.
[16] See page 44, *Electricity Generation Cost Model – 2013 Update of Non-renewable Technologies*, DECC.
[17] See page 28, *Electricity Generation Costs Model – 2013 Update of Renewable Technologies*, DECC.
[18] See page 36, *Electricity Generation Cost Model – 2013 Update of Non-renewable Technologies*, DECC. The transport and port cost is a working assumption.
[19] Ibid, page 31.

(g) OCGT: £0.03.[20]

(h) GT: £0.11.[21]

(i) Oil: £1.[22]

22. To account for Balancing Service use of System (BSUoS) charges, we have added a cost of £1.53/MWh[23] to all generation types excluding pumped storage.

23. We have estimated average start-up costs of £28/MW[24] for OCGT and GT plants. Assuming the plant runs for two hours every weekday, this is approximately equivalent to £22.80/MWh

Marginal costs

24. The marginal costs for thermal, nuclear and wind plants is defined as the sum of the non-fuel variable cost (including applicable transport costs, port costs, BSUoS charge, and average start-up costs), the carbon price and the efficiency-adjusted fuel cost.

25. To ensure that interconnects, pumped storage and DSR take an appropriate position in the stack, we have assumed the following marginal costs:

(a) Imports from France and Netherlands – £25/MWh.

(b) Pumped storage – marginal cost of the least efficient CCGT + 5%.[25]

(c) Exports to Ireland – marginal cost of the least efficient CCGT + 7.5%.

(d) Imports from Ireland – marginal cost of the least efficient CCGT + 10%.

(e) DSR – £250/MWh.

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[20] Ibid, page 46.
[21] Ibid, page 45.
[22] This is a working assumption.
[23] Ofgem, *Impact Assessment on CMP2012 – proposal to remove balancing charges from generators*.
[24] Based on calculations from *Power Plant Cycling Costs*, NREL, US Department of Energy, April 2012.
[25] Modelling the economic running of pumped storage is complex, especially as the main marginal cost is the opportunity cost of running at other periods (or providing response services to National Grid).

Plant characteristics

26. Availability of thermal plants is, in summer (ie quarters 2 and 3), assumed to be 80%, and in winter (ie quarters 1 and 4), assumed to be 90%.[26]

27. Output of nuclear and wind plants is modelled using average historic availability of each type of plant in each demand period. In addition, nuclear and wind plants are assumed to be inflexible, so they cannot be used for withholding.

28. In the first instance the model assumes that flexible plants can be switched on and off for single half-hour periods with no constraints on running times.[27]

Plant-specific caveats

29. We have assumed that, where a plant is jointly owned, the minority owner has no control over generating decisions. For this reason we have applied slightly different methodology and/or assumptions to the following generators, which we do not expect will significantly alter our results:

    (a) Barking: Barking is owned by Thames Power Ltd (51%), SSE (30.4%) and EDF Energy (18.6%). For simplicity we have assigned all output to Thames Power.

    (b) Marchwood and Seabank: Marchwood and Seabank are jointly owned by SSE/MEAG and SSE/CKI respectively. We have assumed that SSE has total control and ownership of each of these plants.

    (c) Spalding: Spalding is owned by Intergen but the output is contracted to Centrica under a tolling agreement. We have modelled the plant as 100% owned and controlled by Centrica.

30. Given that we have modelled nuclear and wind capacity as inflexible, and therefore with no withholding potential, we have not made adjustments to these plants with shared ownership.

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[26] Parties had suggested that at peak winter periods, availability can increase. However, since other initial concerns with the model were rectified, we did not consider it necessary to vary the winter availability.
[27] We seek to adjust for this assumption when filtering the results.

31. Some plants opted out of LCPD[28] are subject to limited running hours varying from 14 to 36%. These plants run in, for example, the top 36% of demand periods in that quarter.[29]

32. Generators that have been decommissioned over the period examined have been removed from the supply curve at the end of the quarter in which they ceased operation.

[28] Large Combustion Plant Directive.
[29] We recognise that alternative assumptions could have been used, including running the plants on peak days rather than peak periods, or running the plants more in Q1 and Q4. We do not consider a change in assumption would lead to a change in our conclusions.

Annex B: Summary of party responses

Introduction

1. We shared an earlier version of our model and the methodology with the Six Large Energy Firms and Drax so they could comment on the inputs, the methodology and the model itself. This annex summarises the views of parties.

2. All parties considered that our modelling approach overestimated the ability and incentive to exercise UMP. None of the parties we consulted considered that UMP is an issue in the GB wholesale electricity market.

3. There were a number of common themes within the party responses. These included whether the model accurately represents the current market structure, the impact of forward trading on UMP incentives, our modelling approach, regulation and future considerations.

Market structure

The Pool vs BETTA

4. Some of the parties argued that the model does not accurately represent the structure of the GB electricity market (BETTA) but would be more relevant to the analysis of a power pool.

5. Centrica considered our approach misleading and more suitable to a more concentrated market operating in a power pool, as it excludes a number of key market features such as bilateral trading, gate closure and imbalance penalties.

6. Similarly, RWE said that our assumption of all plants being able to access a single day-ahead market price is reminiscent of the pre-2001 Pool and meant that we were modelling a different market to that which exists.

7. EDF Energy said that the results from a model of a gross day-ahead pool would be of limited relevance to the analysis of market power in BETTA, but can be useful to understand market fundamentals. It also argued that if no such instances of UMP are found in the simplified current model, this would rule out any possible UMP opportunities in a more realistic (ie dynamically constrained) model.

Forward trading and hedging

8. A second theme of party responses related to forward trading and was commented on by most of the parties involved. The overall consensus was that forward trading limits the potential gains from withholding capacity.

9. E.ON told us that it believes the majority of output is sold on the forward market, rather than the spot market, and therefore the model will significantly overstate the incentive to withdraw capacity.

10. RWE said the model will significantly overstate the incentive to withdraw capacity because, at the time of dispatch, most generators are almost fully hedged and the prices of the hedged volumes have been fixed in advance. It also noted that the presence of bilateral trading means that there is no single ‘spot’ price to manipulate.

11. Centrica also told us that forward hedging would materially constrain any potential gains from withholding, but acknowledged that withholding parties could hypothetically benefit with respect to future periods.

12. EDF Energy said that waiting until the day-ahead stage to sell output would result in unacceptable volatility in generator earnings. It also noted that our assumption of all supplying plants receiving the higher UMP price would only be the case if a generator was completely unhedged or if the threat of market power in the day-ahead market caused an uplift in the forward market from which all hedged volumes could benefit. From its own analysis, EDF Energy concluded that there is no evidence of the latter and the former would be an extremely risky strategy; it told us that hedging its nuclear output reduces downside risk by over 50% compared to the unhedged situation.

13. Scottish Power suggested that, while it may be plausible that continually high spot prices could feed into the forward market, the benefit is both indirect and uncertain; traders are unlikely to bid up the forward curve unless they believed that capacity withholding will continue for a sufficient period of time. It said a generator following a withholding strategy would not be able to influence the spot price in every period, and it would therefore be difficult to change expectations of forward prices. The costs of withholding to the generator would also be disproportionate to the potential gain.

14. In addition, Drax mentioned that it is not realistic to assume pre-sold capacity would be withdrawn if the generator would then incur penal imbalance prices.

15. However, Drax argued that the day-ahead approach is suitable for some marginal plants, eg old CCGT plants, which have no opportunity to trade in the forward market.

Modelling approach

16. The majority of respondents believed the model was oversimplified, particularly with respect to dynamic constrains, flexibility and availability, and would therefore overestimate the ability and incentive to withhold capacity.

Dynamic constraints

17. Scottish Power told us that ignoring dynamic constraints (eg start-up costs, ramp rates, etc) will underestimate the costs of withholding for short periods.

18. Similarly, Centrica noted that even a simple model should include start-up costs, running time constraints, and ramp rates, and omitting these from the model would lead to errors in the results. It suggested that including these additional costs would increase the level of marginal costs (and thus the competitive market price), and reduce the UMP opportunities by making them either infeasible or uneconomic.

19. SSE said that a decision to withdraw or introduce a large thermal unit would be based on prevailing conditions eight hours in advance, incurring costs of up to [✄] for a large thermal unit, plus any foregone revenue between start up and shut down. It added that it is highly unlikely that generators would know in advance that conditions will prevail in eight hours' time that would allow the exercise of market power. There would be significant uncertainty around both demand and, in particular, wind output.

20. RWE told us that most power stations have a maximum number of starts between major outages; therefore, the cost of a start may often need to include the lost opportunity of starting in a different period or bringing forward a major outage.

21. EDF Energy acknowledged that dynamic constraints would be complex and difficult to include in the model, but should be taken into consideration when assessing the results.

Plant flexibility

22. E.ON noted that it would not be possible to include more detailed plant flexibility without separating a plant into individual units.

23. Centrica also pointed out that some of the withdrawn capacity in the model is fairly inflexible (eg large coal plants) and so could not be switched on and off as quickly as the model suggests.

24. EDF Energy provided us with data from the Irish market (see Table 1) which indicated the various start-up times for coal and CCGT units. For example, once shut down, a small CCGT unit must remain down for at least one hour and would then take 1.5 to 2 hours to resynchronise to the grid. Larger CCGT units that are more common in the GB market take longer to restart and require more fuel to do so.

Table 1: Data on dynamic restriction on the operation of thermal plant from the Irish market

Type	*Size (MW)*	*Synchronisation time (hour)*		*Min run time (hour)*	*Min down time (hour)*
		Hot	*Warm*		
Coal	[✄]	[✄]	[✄]	[✄]	[✄]
CCGT	[✄]	[✄]	[✄]	[✄]	[✄]

Source*:* EDF Energy.

25. RWE told us that, although start-up costs vary between plant types, a typical RWE CCGT unit that has been off for less than eight hours would incur a start-up cost of [✄] and a MZT[1] of at least five hours.

Plant availability

26. Scottish Power noted that it would be rational for generators to increase availability during peak times, and our assumption of constant seasonal availability (for thermal generators) would overestimate the incentive for withholding.

27. E.ON also noted that availability should not be constant, and that more realistic availability assumptions would be needed in order to compare the model output to the market price.

28. EDF Energy told us that although the thermal plant availabilities were reasonable average values, the model should include the impacts of planned maintenance. It recognised, however, that the CMA may have concerns that the planned maintenance schedules could be part of a capacity withholding strategy.

29. SSE said that the availability rates in the model were lower than it has experienced; in 2012/13 its CCGT plant ran at an average availability of 94%, and coal at 90%. It believed that reducing this constraint on capacity, and hence increasing the availability of plant relative to demand, would have a material effect on the analysis in the model.

[1] Minimum Zero Time (MZT). The minimum time that a unit must be at zero before the station exports to the grid.

Plant costs/efficiencies

30. In addition to the above, Centrica believed our modelling of plant costs was also incorrect. In particular, it stated that the marginal costs should include opportunity costs and the future costs incurred from frequently ramping up and down.

31. EDF Energy told us that using a single efficiency rate for each plant is likely to underestimate the costs of reducing output. This is because the efficiency of a plant decreases as the load decreases, and there is a minimum amount of energy needed even when the plant is not generating. It suggested that the model could be improved by taking this into consideration.

32. Drax told us that there are a range of marginal costs at which a unit may be dispatched. A plant may turn off overnight, incurring a start-up cost, or discount the overnight price to avoid the start-up cost.

Other

Risk and uncertainty

33. E.ON said that, as margins decrease and there is a risk of scarcity, it would expect prices to rise above the short run marginal costs we have calculated to cover the risk associated with penal imbalance prices. It also said that the risk of plant failure is higher during start-up, again increasing the risk of paying the imbalance price. It suggested that this cost associated with this risk be added to the short run marginal cost.

34. In a previous version of the model, a generator could be in a position where it had withdrawn so much capacity it would be relying on wind generation to benefit from the UMP price. RWE argued that this would require significant certainty on the part of the generator that sufficient wind would be available, and ignores the high risk of wind being low, or zero.

35. EDF Energy also commented on the risk associated with a plant breaking down, which could result in it being unable to meet its contractual commitments, ie exposed to imbalance charges, or able to do so only at a higher cost than modelled.[2] Drax added that risk associated with a plant breaking down is increased for the marginal plant.

36. EDF Energy told us that our model assumption of perfect foresight ignores significant risks associated with withholding capacity. In reality, it is difficult for

[2] EDF Energy told us that, if a unit breaks down while the wholesale market is still trading, the owner can choose to trade in the forward or spot market rather than be exposed to imbalance prices.

a generator to forecast perfectly all of the input variables to its decision, including demand and wind output. If its forecast was incorrect, it could end up losing money from the withholding strategy. EDF Energy suggested that, from National Grid data, 40% of the time a generator might well mis-forecast the wind output and demand that will be included in the day-auction by an amount that is comparable to the output of an entire CCGT.[3]

Regulation/REMIT

37. Most parties noted that the model does not consider the regulatory framework, and that any potential withholding incentive or ability would be quickly noticed and punished under REMIT.

38. SSE noted that under REMIT, generators are required to report the cause and duration of all plant outages, and thus any large scale withholding in order to achieve a price rise of over 45% would be apparent and punishable. It also believed that the requirement for intermediaries to report suspicious transactions to Ofgem, and soon to ACER, would further increase transparency.

39. RWE said that Ofgem has powers to switch on/change Generation License Conditions and also to bring forward amendments to the Grid Code, Balancing and Settlement Code, and other industry codes. These powers can be used to adjust the market rules in the light of market developments and participant behaviour.

40. RWE also said that the wholesale energy is market is extremely transparent to Ofgem, market operators, and DECC, and so it believes that strategically shutting off plants for short time periods would inevitably be punished.

41. EDF Energy said that it is not realistic for a generator carrying out a repeated withholding strategy to get no response from the market or the regulator, and argued that the financial (ie fines) and reputational risks of withholding are enough to discourage such a strategy. It also pointed out that the withholding strategies modelled by the CMA would be obvious to anyone monitoring the market and would be a breach of REMIT.

42. Scottish Power believed that even if generators have the incentive to withhold capacity, they would be deterred from doing so under REMIT and potentially competition law.

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[3] Pages 6 to 8.

43. Centrica said that if capacity withholding was to result in ‘blackouts’, with prices rising to the system maximum, this would be highly transparent, and would result in action being taken by National Grid, and a high likelihood of political and regulatory investigations.

44. Even if market abuse was not illegal under REMIT, the regulation requires a high degree of transparency, and Centrica argued that capacity withholding would result in considerable scrutiny.

Future

45. Parties suggested that, with the introduction of the capacity mechanism and the changing generation portfolio, the current model would not be applicable to future market conditions.

46. Scottish Power believed that the introduction of the capacity mechanism would reduce any incentive to withhold capacity, and said that this is because the mechanism will penalise firms that fail to make generation available at times of system stress, making the costs of withholding much higher.

47. RWE said that the mechanism would increase the incentives to make capacity available and will add to the already significant penalties from withdrawing capacity.

48. SSE believed that the introduction of the capacity mechanism is consistent with a lack of market power and prices that are not materially above short run marginal cost.

49. RWE told us that its future generation fleet will be very different to what it was in the years modelled (ie 2012/13). In particular, it has closed nearly 4,000 MW of coal, biomass and oil-fired plants since 2013, with an additional 1,000 MW expected to close by March 2015.

50. EDF Energy said that the introduction of CfDs for new renewables and nuclear plants would further reduce the incentives of withholding, as there will be less capacity available to benefit from the higher day-ahead price.

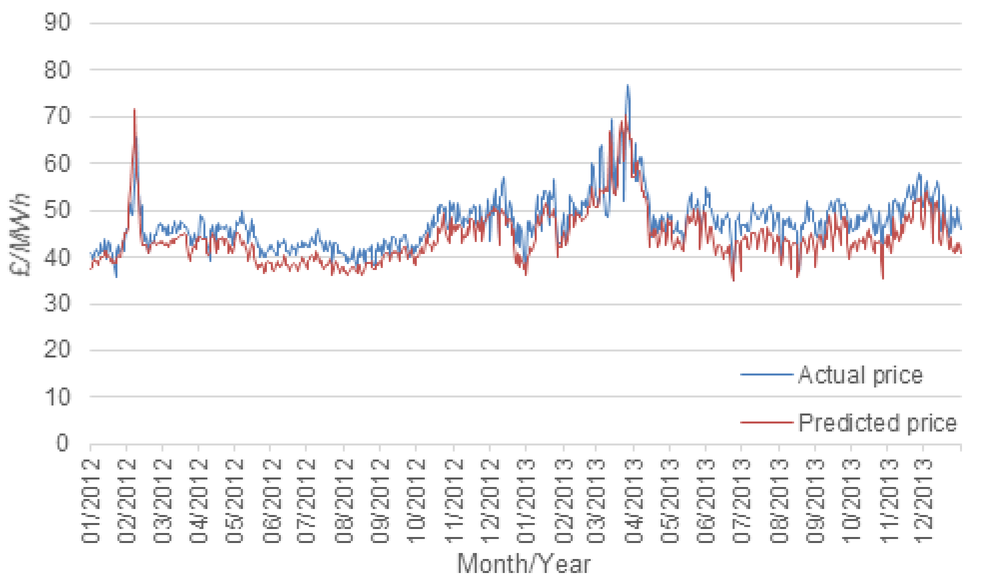
Annex C: Back-casting and model robustness checks

Back-casting the competitive price

1. We have back-casted the results of our model to evaluate its performance. We calculated hourly demand-weighted prices, predicted by the model, and compared these to historical hourly power prices.[1]

2. We found that the model performed reasonably well in predicting the variation in daily, weekly and monthly prices (see Figures 1 to 3). However, the competitive prices predicted by the model were consistently lower than actual prices, with an average under-prediction of £3.02/MWh. This could be due to underestimating costs (eg start-up costs) and ignoring risk.

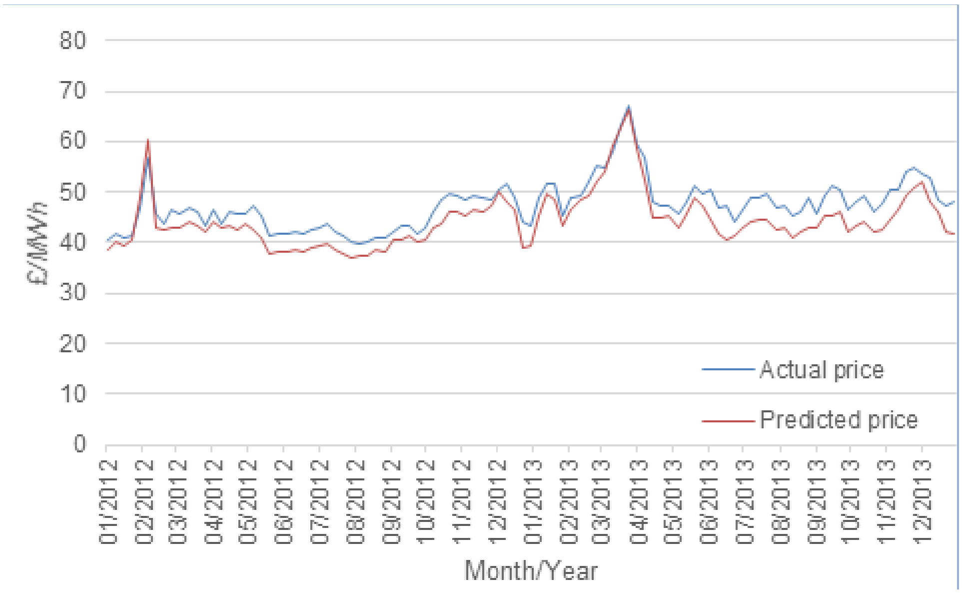
Figure 1: Daily predicted competitive prices compared to actual prices



Source: CMA analysis.

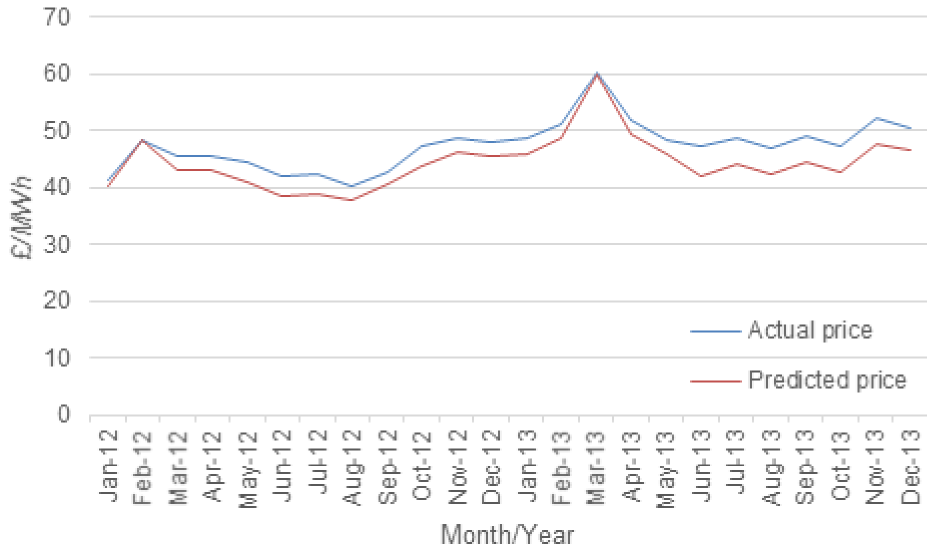
[1] N2EX Day-Ahead Power Prices, 2012-13.

Figure 2: Weekly predicted competitive prices compared to actual prices



Source: CMA analysis.

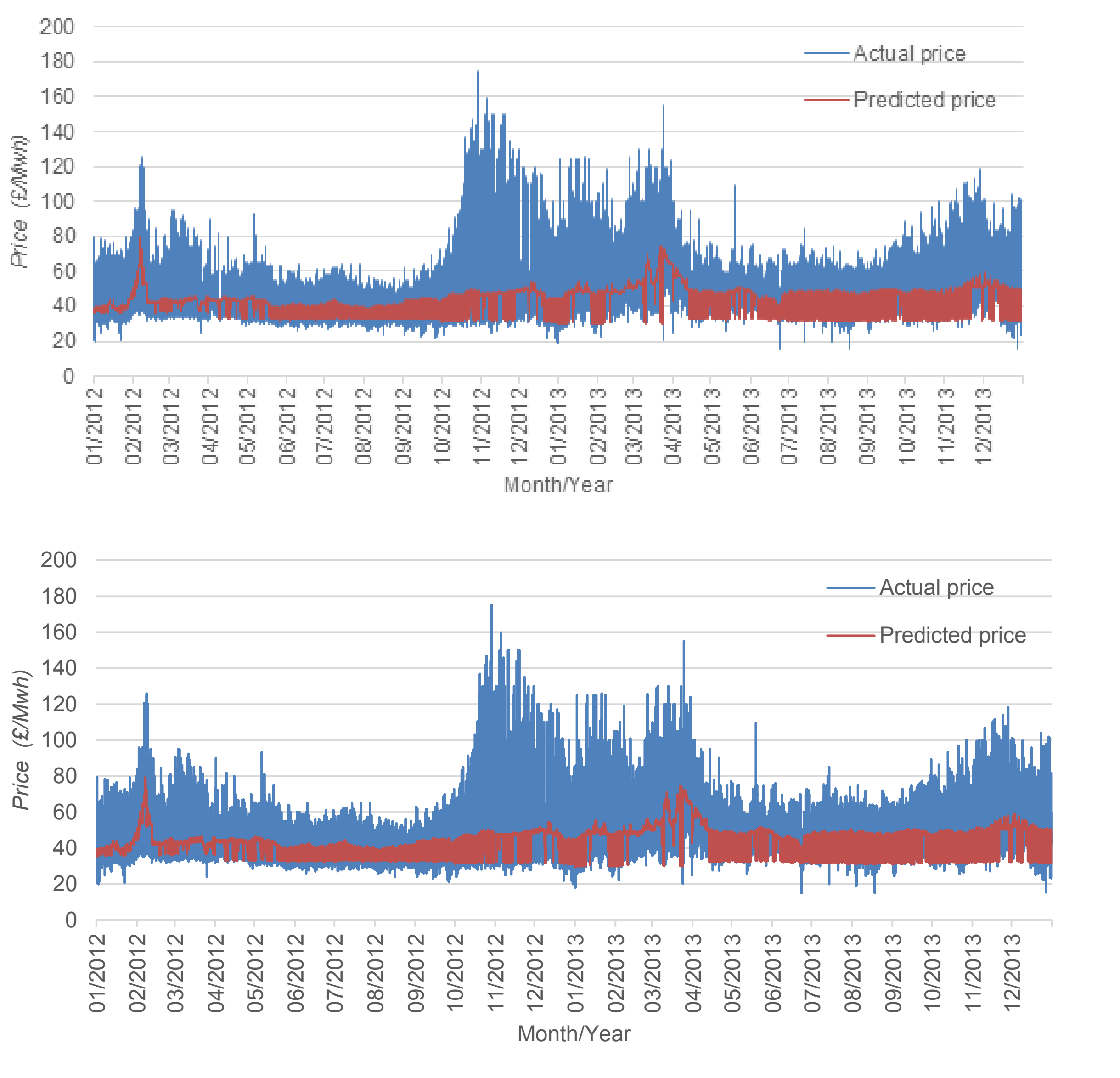
Figure 3: Monthly predicted competitive prices compared to actual prices



Source: CMA analysis.

3. However, our model did not perform as well on an hourly basis (see Figure 4). We were unable to capture the variation in hourly prices and especially the price peaks.

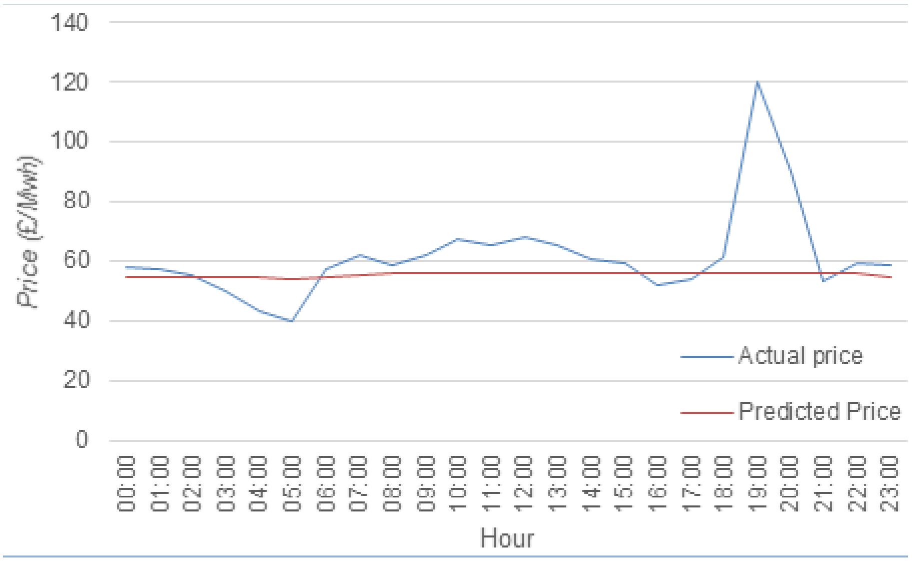
Figure 4: Hourly model predicted competitive prices compared to actual prices

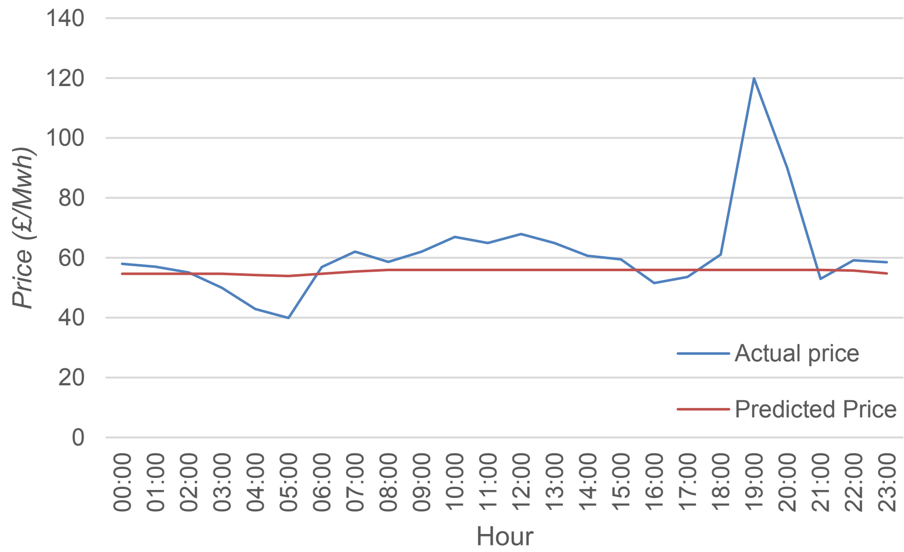


Source: CMA analysis.

4. In particular, we were unable to replicate the typical shape of prices within-day, as shown in Figure 5.

Figure 5: Model predicted competitive prices compared to actual prices on 18/03/2013





Source: CMA analysis.

5. We believe that the poor within-day performance is mainly due to a lack of dynamic constraints in the model. The evening peak can be explained by plants that are only on for a short period of time needing to recover their start-up costs for the period (ie their marginal cost for the period they are on is higher.) The overnight dips in prices (compared to our model) can be explained by generators bidding under their marginal cost to ensure they do not incur start-up costs. In addition, our model does not have the parties' detailed calculations of plant efficiencies. Therefore, there is less variation between plants than in reality.

Annex D: Model results

Introduction

1. In this annex, we set out the full results derived from our model. It also derives the final results displayed in the main paper.

2. Throughout this annex we present the results from the model in two ways.

   (a) The first presentation shows the number of half-hour periods where parties were able to raise the benchmark competitive price by 5%, 15% and 45%. Where they were able to do so by more than 1,440, 480 or 160 half-hour periods respectively, the cells are highlighted.[2]

   (b) In our second presentation of results, we set out what the demand weighted average price increase a firm is able to achieve over the year.

3. In addition, where appropriate, we set out the predicted demand weighted baseload and peak price increases[3] for each season due to UMP.

Initial results

4. In the first run of our model we used the methodology as outlined in Annex A. The initial results are shown in Tables 1 and 2, and Figure 3.

Table 1: Number of periods in which a party is able to raise price by a given percentage (unfiltered)

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

[2] These thresholds were used in Ofgem's Market Abuse Licence Condition (MALC), which it sought to put in place in the licences of generators it believed were likely to have substantial market power in determining wholesale electricity prices. Ofgem told us that MALC was designed so that it could take enforcement action if those licensed generators were found to be abusing a position of substantial market power. In assessing whether an abuse had occurred, Ofgem would have taken into account various technical system conditions and any other objective justifications. Although MALC was struck down by the Competition Commission in 2001, we found these thresholds to be a useful illustration of possible levels that we could use to measure ability to influence price.

[3] Peak prices are calculated using volume weighted average prices between 7am and 7pm.

5. In our initial results (Table 1) we can see that for most generators, there appear to be the opportunities to increase prices for a significant enough number of periods for there to be concern about UMP. The number of opportunities appear to be greater in 2013 than in 2012.

6. Table 2 translates these opportunities into yearly price rises due to UMP. Consistent with above, this appears to show potential price rises due to UMP to be greater in 2013 than in 2012. However, the largest price rises appear to be possible for [✂], [✂] and [✂].

Table 2: Average price increase

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source*:* CMA analysis.

7. In Figure 1, we break down further the source of price increases. The main price increases appear to be for baseload prices rather than peak prices.[4] This suggests that the UMP opportunities being identified are in the middle of the generation stack rather than at the end of the stack. The UMP opportunities also appear to grow in summer 2013 and winter 2013/14.

Figure 1: Average price increases by season and standard product

[✂]

Source*:* CMA analysis.
*As the model only looks at 2012 and 2013 data, Winter 11/12 and Winter 13/14 have a missing quarter of data.

8. Further to Table 1, we can break down where the UMP opportunities are arising.

Figure 2: Number of periods in which the marginal plant type was coal or CCGT, 2012

[✂]

Source: CMA analysis.

Figure 3: Number of periods in which the marginal plant type was coal or CCGT, 2013

[✂]

Source: CMA analysis.

[4] The main exception appears to be [✂] in the winter seasons.

9. It is clear that the majority of the UMP opportunities are coming in the step between coal plants and CCGT plants. Very few of the opportunities towards the end of the CCGT stack (ie when prices might be peaking).

2012 vs 2013

10. The number of UMP opportunities appears to increase between 2012 and 2013. This increase could be attributed to three potential factors:

    (a) The price of gas increasing in relation to coal in Q1 2013, leading to an increase in the attractiveness of withholding (see Figure 4).

    (b) A reduction in capacity due to some coal plants closing, leading to an increase in the number of times where demand was near the coal/gas step.[5]

    (c) A reduction in average demand leading to similar effects to *(b)*.

Figure 4: Coal and gas prices, 2012 to 2013

[✂]

Source: CMA analysis.

11. The combination of these factors increased both the number of opportunities and the incentives to take advantage of the opportunities for a number of suppliers.

Filtering results

12. Our model is, by nature, a simplification of the real world. Two particular simplifications were noted to have substantial effects on the optimal withholding strategies:

    (a) dynamic constraints; and

    (b) uncertainty.

13. The exclusion of dynamic constraints means we may be identifying UMP opportunities which are either unfeasible, un-economic (when start-up costs, risk of imbalance charges due to failed start-ups, reduced efficiency of part loaded plants and opportunity costs are considered), or both.

[5] Due to plant closures, the following plants were removed at the end of 2012 Q4: Kingsnorth, Shotton CHP, Derwent CHP and Grain. In addition, further plants were removed at the end of 2013 Q1: Uskmouth, Cockenzie, Didcot A and Fawley. Together they accounted for 8,064 MW of capacity.

14. The exclusion of uncertainty means that we identify UMP opportunities which are only possible if demand, wind output and other firms' cost structures are known. Under uncertainty the payoff would need to be relatively large, and the UMP opportunity would need to be consistent with varying demand.

Feasibility filter

15. As a first approximation of accounting for dynamic constraints, we developed filters for the results. The first set of filters sought to account for feasibility of UMP opportunities. While all the filters we use exercise judgement, there are objective reasons for using filters given the model simplifications.

16. We assessed UMP opportunities for feasibility by allowing firms to change output between periods by +/- 200 MW. For an increase or decrease greater than 200 MW, we checked the next period to ensure there was not an associated decrease or increase of greater than 200 MW. This filter was to allow for a reasonable amount of wind variability and plant flexibility[6] between periods.

17. We applied a period filter to ensure that there were at least six periods of consecutive feasible outputs.[7] We then counted the number of periods and the average price rise for the respective years, given the filters. The results are shown in Tables 3 and 4 below.

Table 3: Number of periods in which a party is able to raise price by a given percentage (feasibility and period filter)

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

[6] It could be argued that 200 MW is too harsh a filter. In Annex A, we also show the results when a 400 MW filter is used.
[7] Similar to above, it can be argued that six periods still allows some infeasible opportunities. We present in the annex results for 12 periods, combined with the 400 MW filter.

Table 4: Average price increase (feasibility and period filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

18. As can be seen, the number of UMP opportunities decreases significantly when this filter is applied. This suggests that a number of UMP opportunities identified initially were unfeasible.[8] In addition, we note in Figures 5 and 6 that many of these opportunities are still occurring in the step between coal plants and gas plants.

Figure 5: Number of periods in which the marginal plant type was coal or CCGT, 2012 (feasibility and period filter)

[✂]

Source: CMA analysis.

Figure 6: Number of periods in which the marginal plant type was coal or CCGT, 2013 (feasibility and period filter)

[✂]

Source: CMA analysis.

19. In addition, we note that baseload prices tend to be increasing more than peak prices (with the exception of [✂]), consistent with the UMP opportunities identified in our model being at times with relatively low demand.

Figure 7: Average seasonal baseload and peak price increases

[✂]

Source: CMA analysis.

Profit filter

20. This initial filter has had a significant impact on the number of UMP opportunities that arise. However, we have not yet considered the relative profitability of the UMP opportunities. There are two reasons to consider doing this:

[8] The 400 MW filter also significantly reduces the number of periods with UMP opportunities, although not as many as the 200 MW filter. The 12-period filter filters out more opportunities than the six-period filter.

(a) Our original model had largely ignored start-up costs and risks of turning power stations on and off.[9]

(b) Our model has ignored uncertainty, which reduces the potential benefits of the UMP opportunities.

21. In Figures 8 and 9 we show the distribution of profits from the UMP opportunities identified in tables for 2012 and 2013.

Figure 8: Profit distribution, 2012

[✂]

Source: CMA analysis.

Figure 9: Profit distribution, 2013

[✂]

Source: CMA analysis.

22. Many of the UMP opportunities produce relatively low levels of profit. Due to both uncertainty and the additional start-up costs, we consider it unlikely that a generator would risk withholding unless there was a significant profit opportunity. We applied a filter of £10,000 to ensure that relatively low profit opportunities were not considered.[10] The results are shown in Tables 7 and 8.

Table 5: Number of periods in which a party is able to increase profit by at least £10,000

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

[9] The original model also ignored the lost profit opportunities in following periods from turning off. However, as we applied a feasibility filter, we do not consider this issue further.
[10] In Annex A, we considered the results if a profit filter of £5,000 was applied. As with the £10,000 filter, many of the UMP opportunities are filtered out due to low profitability of the opportunities.

Table 6: Average price increase (£10,000 profit filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

23. This filter removes a number of low incremental profit opportunities, and the predicted average price increase reduces even further.

Uncertainty filter

24. Above, we used a profit filter as one way of considering the impact of uncertainty on our results. However, we also considered whether UMP opportunities would still exist if demand was to shift by +/- 500 MW from the actual demand. This type of change could be because demand shifted or wind output changed unexpectedly.[11] The results in Tables 9 and 10 are a manipulation of the unfiltered results presented in Tables 1 and 2 (and therefore do not consider the feasibility of UMP opportunities or the profitability of the opportunities).[12]

Table 7: Number of periods in which a party can increase price above a threshold (uncertainty filter)

Price rise greater than or equal to	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

[11] EDF Energy presented analysis to us, demonstrating that uncertainty was a real issue for generators. It also highlighted that nuclear output can vary, which may not (fully) be in its control.
[12] Due to potential double filtering for the same factors, we did not consider combining the uncertainty filter with other filters we have used.

Table 8: Average price increase (soft uncertainty filter)

							%
	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

25. A number of previously identified UMP opportunities were not consistent with unexpected shocks to demand. This suggests that many UMP opportunities may not be pursued when the risks of the strategy are fully considered.[13]

26. Combinations of some filters are more problematic, but it appears unlikely that a significant number of UMP opportunities would remain, once the uncertainty, feasibility and costs of pursuing a UMP strategy are considered.

[13] In the supplement to Annex D, we note that if a harsher uncertainty filter is applied (where results have to be consistent with both positive and negative demand shocks) then very few UMP opportunities are identified.

Supplement: Further results

1. This annex provides further results tables to show the sensitivity of our results above to changes in the filters applied. We outline further results from the feasibility filter, profit filter and uncertainty filter.

Feasibility filters

2. In this section, we present the results for the following scenarios:

   (a) Scenario 1: Feasibility allowance of 200 MW for at least 12 periods.

   (b) Scenario 2: Feasibility allowance of 400 MW for at least six periods.

   (c) Scenario 3: Feasibility allowance of 400 MW for at least 12 periods.

Scenario 1

Table 1: Allowing capacity changes under 200 MW, for a minimum length of 12 periods

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 2: Average price increase (profitability filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Scenario 2

Table 3: Allowing capacity changes under 400 MW, for a minimum length of six periods

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 4: Average price increase (profitability filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Scenario 3

Table 5: Allowing capacity changes under 400 MW, for a minimum length of 12 periods

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 6: Average price increase (feasibility and period filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Profit filters

3. Further to the profit filter of £10,000, we applied a profit filter of £5,000 to the feasibility filtered results found in the main results annex.

Table 7: Number of periods in which a party can increase price (£5000 profit filter)

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 8: Average price increase (profitability filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Uncertainty filter

4. Finally, we present the tables showing whether the unfiltered UMP results are consistent with a demand shock of +/- 500 MW. For a UMP opportunity to be identified, there has to be a positive profit from the 500 MW above and 500 MW below scenarios.[14]

[14] This filter could have been improved if we had fixed the firms outputs and then considered whether that strategy was consistent. Our approach has been to estimate whether there was a viable UMP strategy if demand fluctuated.

Table 9: Number of periods in which a party can increase price (given uncertainty)

Price rise greater than or equal to:	*EDF Energy*	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013							
5%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
15%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
45%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 10: Average price rise (uncertainty filter)

%

	EDF Energy	*Drax*	*SSE*	*Scottish Power*	*E.ON*	*Centrica*	*RWE*
2012	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2013	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.