

The impact of the Early Capacity Market Auction announcement on wholesale electricity prices and revenues

Summary¹

The objective of this analysis is to shed light on the interaction between the wholesale market and the Capacity Market. The analysis uses forward prices for winter 2017/18 before and after the announcement of the introduction of a Capacity Market Early Auction for delivery year 2017/18 to assess its impact on wholesale prices using the ‘difference-in-differences’ (DiD) method. The results suggest that the announcement of introduction of the Early Auction reduced the spread between peak and base prices by £0.66/MWh. This result is robust to our alternative specifications. Further tests suggest some variability of the magnitude of the price impact over time. The price effect may equate to an estimated reduction in forward prices of around £1/MWh for peak load and around £0.35/MWh for base load, and an associated reduction in wholesale revenues of about £150m. The net injection of money for generators resulting from introduction of the Early Auction, which pays generators £380m in 2017/18, may be up to around £230m. The analysis adds value in two respects. First, it provides (ex post) evidence of the transfer of value from wholesale market to Capacity Market, an interaction set out in DECC² Capacity Market (ex ante) impact assessments. Second, it may assist in shedding light on the extent of ‘missing moneys’ in 2017/18. An important caveat however is that introduction of the Early Auction is likely to have additional impacts on other revenue streams such as those associated with National Grid’s ancillary services and ‘embedded revenues’, analysis of which is out of scope of this paper.

Section 1: Introduction and background

In 2014, government runs the first of a number of Capacity Market auctions for delivery from 2018/19 onwards

Prior to the introduction of the Capacity Market, secure supplies were entrusted to wholesale markets³ (providing adequate capacity) in conjunction with National Grid’s deployment of balancing tools (managing the challenge of continuously balancing supply and demand).⁴

In 2013, government identified a risk to adequate supplies in the future⁵. In particular, government was concerned that at times of scarcity, wholesale prices may be too low to sufficiently reward

¹ Thanks to Dr Albert Banal-Estanol (Reader in economics, City University, London) for providing methodological advice and reviewing the analysis. Thanks for discussions also to National Grid trading team, BEIS Capacity Market teams. Thanks to Mobin Sediqi for his work at early stages of this report. All errors are our own.

² DECC, the Department for Energy & Climate Change was merged into BEIS, the Department for Energy & Industrial Strategy, in 2016

³ Electricity is a unique product that cannot currently be stored in large amounts. Supply and demand for electricity must be matched, or balanced, at all times. In Britain this is primarily done by suppliers, generators, traders and customers trading in the competitive wholesale electricity market. Trading can take place bilaterally or on exchanges, and contracts for electricity can be struck over timescales ranging from several years ahead to on-the-day trading markets.

⁴ Over 2014-17, these were complemented by additional balancing tools: the Supplementary Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR).

⁵ This built on analysis and evidence presented in Project Discovery, Ofgem's (2010) study of the adequacy of GB arrangements for delivering secure and sustainable electricity (and gas) supplies
<https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinalpdf>

generators that could provide power, and this ‘missing money’⁶ or even the perception of it may reduce planned investment in the capacity required to cover peak demand.

To address this risk, government announced in 2013 its commitment to introduce Capacity Market auctions delivering from 2018/19, with auctions held four years⁷ in advance, to pay⁸ generators that make capacity available during these years. These payments provide an additional revenue stream for generators who continue to be able to sell power in the wholesale market. Three major four-year-ahead auctions have been held so far for delivery years⁹ in 2018-19 and 2020-21 costing around £1 billion each (see Table 1 below).

On 1 March 2016, government consults on proposed Early Auction for 2017/18

The first indication from government of the possibility of a Capacity Market for 2017/18 was on 1 March 2016, when government consulted on its proposal¹⁰. The government confirmed its intention in the summer. The auction was held in February 2017, around 9 months ahead of delivery. 54.43GW cleared at a price of £6.95/KW, determining payments of around £380 million.

The rationale presented in 2016 for introduction of the Early Auction in 2017/18 was to address market failures and other drivers¹¹ in causing a lack of investment in traditional generation facilities. An Early Auction was identified as necessary to ensure sufficient existing capacity and provide incentives for new-build capacity and thereby enhance security of supply for winter 17/18. The proposal was consulted on against a back-drop (peaking in intensity in February 2016) of rumours or announcements of impending plant closures, which were reflected in scenarios (notably significantly enhanced closures) in DECC’s analysis¹².

Table 1: Major Capacity Market auctions

Delivery year	2017-18	2018-19	2019-20	2020-21
Main auction date – years before delivery	1 year	4 years	4 years	4 years
Price (£/KW per year)	7	19	18	23
Capacity (GW)	54	49	46	52
Total cost (£m, nominal)	378	956	834	1,180

Source: EMR Delivery Body

Importance of efficient interaction between Capacity Market and wholesale market

⁶ We define missing money as the difference between the total annual peak energy rents that capacity would earn if prices rose to the value consumer assign to uninterrupted supplies, minus the actual rents they earn (see Capacity Market Fundamentals by Cramton et al, 2013 for a discussion of ‘missing money’).

⁷ Auctions are also held one year before each delivery period. Transitional Capacity Auctions have also been held to help support ‘demand side response’ and small scale participation.

⁸ Existing generation, interconnectors and proven demand side capacity are eligible for one-year agreements only. Refurbishing and new build capacity are eligible to receive longer contracts provided they meet certain expenditure thresholds for their refurbishing works (up to 3 years) or building plant (up to 15 years).

⁹ ‘Delivery years’ run from October to September.

¹⁰ This draws on conversations with policy colleagues working in DECC at the time of the announcement, and who indicated that the department did not give any indication to the market prior to 1 March 2016.

¹¹ The effect of recent reductions of commodity prices reducing profitability of coal plant in particular.

¹² See

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf

A crucial component of ensuring a Capacity Market that functions in the interests of the consumer is its efficient interaction with the wholesale market. In practice, Capacity Market payments may be greater than the amount of ‘missing money’ in the wholesale market¹³. But the additional capacity procured in the Capacity Market should also enhance supply and thereby reduce wholesale prices. Expectations of the supply shift should similarly lower forward¹⁴ wholesale prices. In theory, the net injection of revenues should equal the missing money.

DECC’s Capacity Market Impact Assessments¹⁵ offered central estimates of the net benefit (the sum of societal benefits and costs weighted over time) of a Capacity Market ranging between -£0.6 billion and +£0.4 billion. An important determinant of the net effect is the assumed efficiency of the wholesale market response to Capacity Market introduction. The size of the sums involved combined with the uncertainty over how and whether practice will play out according to theory emphasises the importance to the consumer of the efficient response by the wholesale market to introduction of the Capacity Market¹⁶.

What we want to do

This paper assesses the impact of the announcement proposing introduction of the Early Auction on wholesale prices, and estimates the accompanying wholesale revenue impact¹⁷. It takes advantage of the unique opportunity to study ‘forward prices’ for winter 2017/18 both before and after the announcement of the introduction of a Capacity Market for that winter, an opportunity not available for other auctions which were announced long in advance of formation of forward prices. It draws on theory that suggests that introducing a Capacity Market should reduce wholesale prices by enhancing expectations of supply and thereby lower expectations of scarcity and market power (controlling for other factors), and that this price effect should be more pronounced in peak prices than in base prices¹⁸. Our analysis therefore examines how the spread between peak and base prices changes between the pre and post announcement periods, using base prices as a ‘control’ group

¹³ Because the market expects introduction of a Capacity Market to reduce wholesale prices and peak energy rents.

¹⁴ ‘Forward prices’ refer to the price at which the wholesale market traded forward – days, weeks, months and years in advance – commitments to provide a volume of energy, and include peak load products (energy to be delivered during 7am-7pm on weekdays) and base load products (every hour of the week).

¹⁵

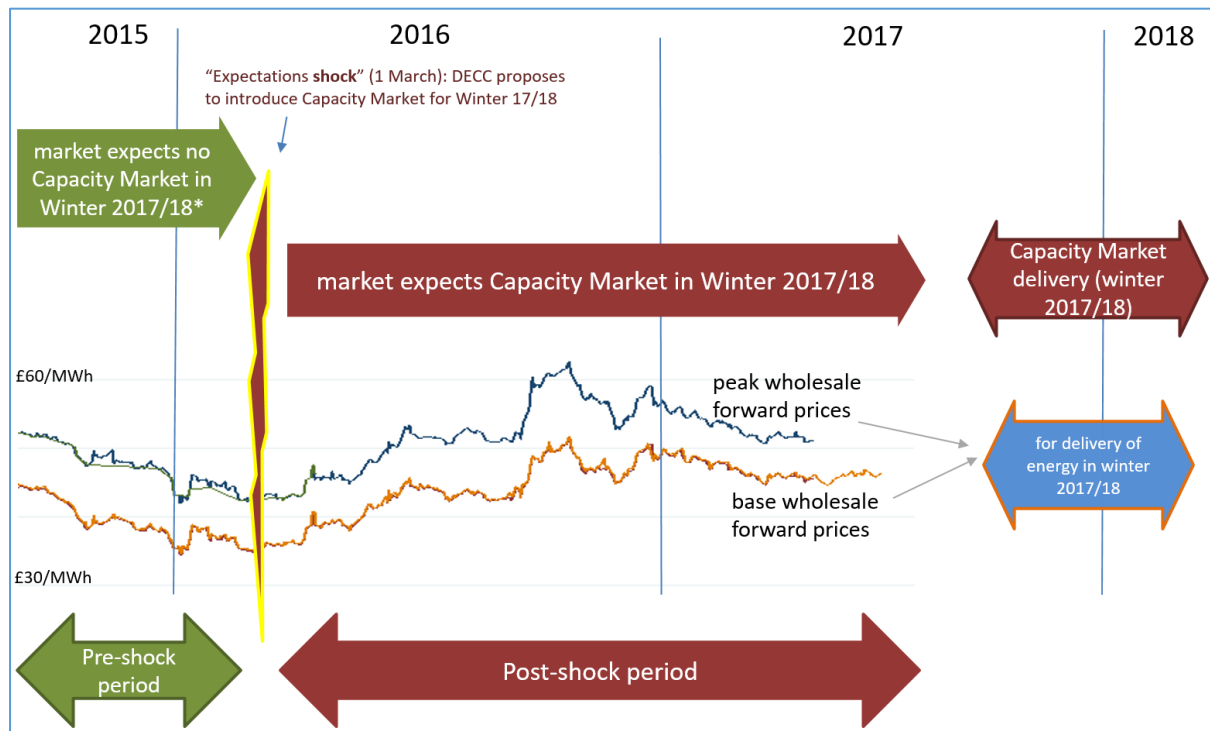
¹⁶ Academics in GB have started to explore the efficient interaction between the Capacity Market and wholesale markets, chiefly at the theoretical level. See for instance ‘Security of supply, capacity auctions and interconnectors’, by David Newbery, EPRG, 2013, and final reports on National Grid’s Electricity Capacity Reports by the Panel of Technical Experts advising BEIS on Capacity Market procurement.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/625885/PTE_Report_2017.pdf

¹⁷ In theory the results could also inform an assessment of the extent of ‘missing money’ – or at least expectations of – which may be proxied by looking at the difference between expectations of two revenue streams. First is the expected revenue of capacity generating at peak, in absence of expectations of a Capacity Market. Second is the revenue required to sustain capacity adequacy. Assuming a well-functioning Capacity Market, the latter may be proxied by the sum of Capacity Market payments plus revenues from other markets such as wholesale, in presence of expectations of a Capacity Market.

¹⁸ This builds on the observation that energy suppliers have more market power during peak periods when demand is higher. Since the supply schedule is highly convex and much steeper during the peak period, expectations of a shift to a higher capacity schedule should have much larger effects at peak times than off-peak times. Hence, we expect a convergence between peak and off-peak prices when expectations of capacity are enhanced, once other relevant factors are controlled for. As base load prices reflect a weighting of peak and off-peak prices, we expect a similar effect (in direction) between peak and base prices.

against which to test the effect of the announcement on peak prices (the ‘treatment’ group). The possibility of a price effect on 1st March builds on an assumption that the Early Auction was unexpected and therefore not already ‘priced in’. This assumption, which draws on our discussions with colleagues in DECC and is consistent with trade press reports¹⁹, we test later. The chart below shows key timings.

Figure 1: key timings



Structure of paper

The rest of the paper is structured as follows

- Section 2 presents a succinct summary of literature in the area
- Section 3 outlines theory
- Section 4 outlines method, data and final model
- Section 5 presents results and tests
- Section 6 discusses possible interpretations, and outlines assumptions and caveats
- Section 7 outlines opportunities for further research

Section 2: Literature

¹⁹ For instance, ICIS Heren daily electricity markets report (2 May 2017) states “...the government announced unexpectedly last year that the capacity market would be brought forward a year earlier than planned...”. Similarly industry responses to the DECC consultation conveyed an element of surprise, for instance icoss state: “the effect of this will be to increase supplier Capacity Mechanism charges unexpectedly with a significant increase now expected a year earlier in 2017”.

We are not aware of any paper that has empirically tested the impact of a Capacity Market on the wholesale market. However, we review some papers that are relevant to our study because they provide:

- analysis of wholesale price formation and forward prices – a first step to understanding how wholesale markets might interact with Capacity Markets,
- analysis of the effect of policy interventions (though not Capacity Markets) on wholesale prices.

Much of the literature on formation of wholesale prices examines the relationship between forwards and futures prices with spot prices, better to understand the nature of ex ante premia. Bunn et al.²⁰ analyse GB electricity forward premia to consider the importance of a number of elements in price formation including

- *fundamentals* (such as demand, fuel prices, and reserve margin),
- risk aversion to spot market volatility and skewness²¹ (the authors call these *statistical risk*),
- *behavioural* aspects (adaptive behaviour to lagged variables).

Their analysis of GB prices further along the curve (month-ahead prices, including both peak and base) finds *fundamentals* and *statistical risk* to be more important in driving components of forward prices than *behavioural* influences²².

A key paper that offers a promising method for identifying policy impacts such as the announced introduction of a Capacity Market is “Economic impact of enforcement of competition policies on the functioning of EU energy markets” recently published by the European Commission²³. This paper seeks to identify the impact of EU competition policy enforcement in driving stronger competition in European gas and electricity markets and therefore contributing to lower prices, higher investment and improved productivity. It evaluates empirically the price effects of two individual competition policy enforcement cases using the DiD approach.

Of particular note is the case study on the Commission’s case against E.ON (2008) for its alleged abuse of dominant position in the German wholesale electricity market. This study examines the impact of the Commission’s decision on wholesale electricity prices, using daily data of peak and off-peak prices from the European Energy Exchange (EEX). The results show that the Commission’s decision, by affecting supply and competition in the EEX, led to a reduction in wholesale electricity prices in Germany. This case study is particularly pertinent because it applies a method to identify the effect of withdrawing capacity from the market on wholesale prices, a method which can similarly be applied to identify the impact of adding capacity,²⁴ which we spell out later.

Section 3: Theory

²⁰ The forward premium in electricity futures, Bunn et al, Journal of Empirical Finance, 2013.

²¹ Skewness is a measure of a lack of symmetry in distribution. Skewness could occur if prices may jump in one direction, for instance jumping up if capacity is insufficient to cover a few hours of peak demand in the year.

²² The authors note a striking comparison with factors influencing *day-ahead* price formation, which they find to be linked with behavioural variables.

²³ See <http://ec.europa.eu/competition/publications/reports/kd0216007enn.pdf>

²⁴ In particular it draws from the detailed papers underpinning the EC analysis which are ‘Abuse of Dominance and Antitrust Enforcement in the German Electricity Market’, Discussion Paper, DIW Berlin, 2017, and ‘A retrospective evaluation of the GDF/Suez merger: Effects on gas hub prices’, Argentesi et al, 2017

Scarcity and expected scarcity mean higher prices

Among other important variables such as gas and coal prices, scarcity – and expectations of scarcity – should also influence prices (particularly in the face of constraints to storing energy). This is because greater scarcity, which reflects a reduction in the margin between capacity and demand, implies a higher risk of market power, with accompanying higher prices. This may allow prices to be very sensitive to information on scarcity and capacity margins, and for spot prices to move much higher than the long-term equilibrium price. Expectations of capacity margins can also influence more long-term (‘forward’) prices so, other things equal, heightened expectations of scarcity should translate into higher forward prices.²⁵

Peak prices reflect scarcity to a much greater extent than off-peak and base prices

Challenges in the storage of electricity contribute to the wholesale price difference between demand during peak hours and off-peak hours. Products that serve peak hours (peak load) are higher than base load not only because they employ their inputs less efficiently, but also because they are targeted at moments when demand is higher and pushes against the limits of available capacity, and it is for this reason that scarcity value – and the ability to express market power – is more likely to kick in.²⁶

The Capacity Market announcement should dampen expectations of scarcity and lower prices

Expectations of scarcity should be influenced by expectations of supply and demand, which in turn may be affected by regulatory interventions that drive a revision of expectations of supply or demand. In particular, the announcement of a Capacity Market, itself driven by concerns of insufficient supply, should serve to dampen expectations of scarcity by prompting traders to expect more capacity. Given the transmission mechanism outlined between scarcity and prices, it follows that the announcement of the introduction of the Capacity Market should serve to reduce prices.

Peak prices should fall more materially than base prices

Similarly, theory suggests that peak prices – which reflect scarcity to a greater extent than base prices – should fall more materially than base prices. This is because the supply schedule is much steeper in the peak period. Any impact on base load prices should reflect the effect on the portion of base load prices that correspond to peak hours²⁷. Empirical analysis provides evidence supporting this theory²⁸, showing more material impacts of changes in margin (and other related variables such as skewness) on peak prices than baseload.

Figure 2 below illustrates these points. In particular it shows peak load prices are higher than off-peak load (and by extension are also higher than base load), that the announcement of a Capacity Market serves to enhance (expectations of) capacity with the effect of dampening prices, and that

²⁵ Bunn notes “a reduction in the margin indicates relative scarcity and one would expect that this leads to a higher propensity for shocks to induce greater price volatility and spikes. Given an adaptive adjustment by market participants, a perceived decreasing margin in the spot market may cause expected spot prices and therefore forward prices ... to increase.”

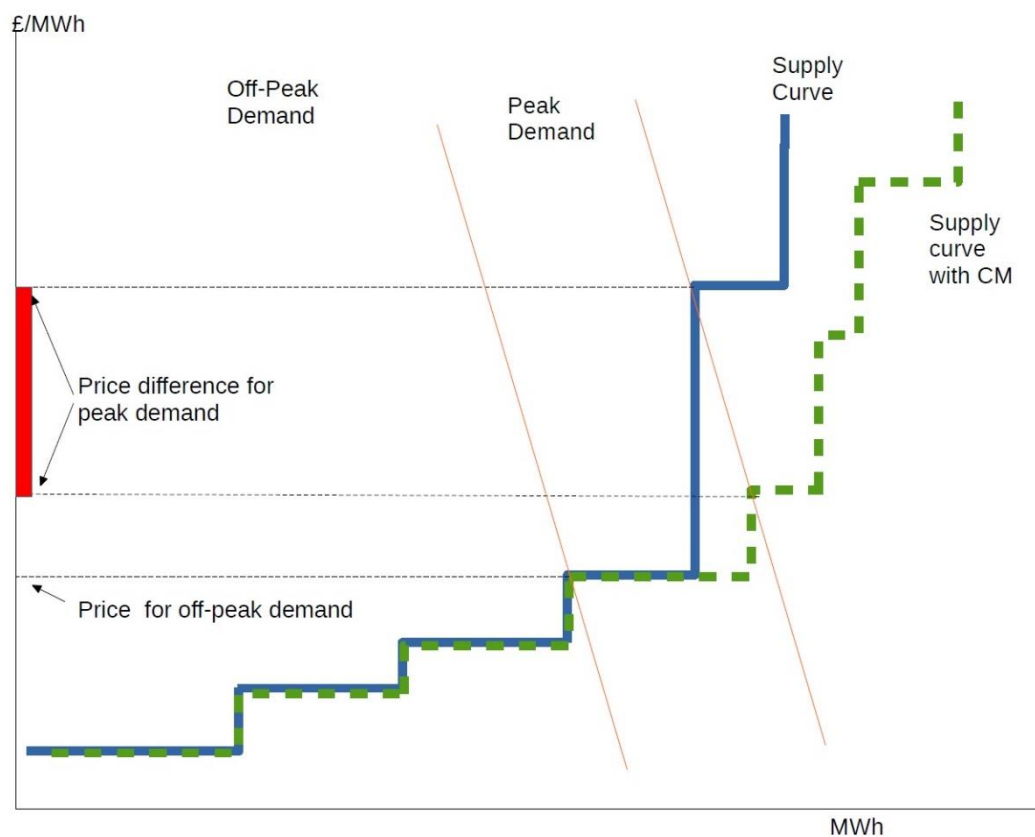
²⁶ Theory is supported here by GB analysis which suggests that variables associated with scarcity expectations (such as greater volatility and skewness) have distinct effects with respect to peak and off-peak (and by extension, base load) trading. See ‘The forward premium in electricity futures’, Bunn et al, Journal of Empirical Finance, 2013.

²⁷ This builds on our assumption that there are no effects on off-peak price. We discuss implications of relaxing this assumption later.

²⁸ Forward premia, Bunn et al, 2012

the announcement has a bigger impact on peak prices than off-peak (and therefore also base) prices.

Figure 2:



Section 4: Method, data and final model

Method

Overview

The primary focus of analysis is on whether peak prices fell following the Capacity Market announcement. We use DiD econometric analysis using the base-load price as a control group to test whether the announcement had a statistically significant impact on peak load prices, our treatment group. This technique builds on assumptions that

- base and peak load (and off-peak) are likely to share broadly the same exogenous influences over time. This fits with theory, and seems plausible looking at the data – see Figure 3 – which suggests the importance of the gas price for both peak and base load prices
- the effect on peak prices is likely to be much more substantial than base prices, as any effect on base load will be diluted by a negligible effect on off-peak. Again this fits well with economic theory.

DiD analysis allows for an assessment of the impact of the announcement by looking for a statistically significant change in the average price difference between the treatment group (peak) and the control group (base) after the announcement. This double differencing removes the time invariant individual effects (of treatment and control group) and the common time effects that

might otherwise confound identification of the effect of the announcement. We use the announcement of the Capacity Market proposal on 1 March 2016 as the cut-off point between the two time periods. In sum, therefore, we have introduced the following definitions:

- treatment group: peak forward prices
- control group: base forward prices
- pre announcement period: period before 1 March 2016
- post announcement period: period after (and including) 1 March 2016

Hypothesis

Our hypothesis is that the difference between our treatment and control groups – peak prices and base prices – will diminish following the announcement, controlling for other factors.

Controlling for other factors

Without controlling for exogenous factor that may have a different effect on the spread between the two groups between the two periods, we may suffer from omitted variable bias – where the DiD coefficient picks up the effect of these missing variables. For example, if an unexpected statement revealed decommissioning of a large peaking plant, its effect could be attributed to the announcement if not controlled for.

In order to identify possible important variables, we reviewed the literature and consulted with stakeholders including National Grid's trading team and BEIS. Table 2 presents a list of variables which hypothetically could bias results if unduly omitted from the specification.

Table 2: variables that may merit control

variables potentially influencing difference between peak and base prices of winter 17/18 forward product			expected effect	notes
expectations of fundamentals, and past values (behavioural)	demand	temperature	(-)	cold temperatures may stimulate demand
		GDP	(+)	greater activity may stimulate demand
		energy efficiency	(-)	may temper peak demand
		maturity	complex, potentially non-linear	literature suggests time until maturity of the forward contract may be important
	supply	fuel cost	(+)	peak plants are less efficient in application of inputs
		proportion of time CCGT ²⁹ is marginal plant (rather than coal)	(-)?	the price difference could be affected by the technology of the plant at the margin
		carbon cost	(+)	peak plants use inputs are less efficiently
		prices of inter-connected countries	(+)	higher peak prices abroad could contribute to higher domestic peak prices
		operating and maintenance costs	(+)?	peak plants are less efficient in application of inputs
		capacities of conventional plant	(-)	more coal and gas for instance ought to assist capacity adequacy. complex links with other variables
		renewables penetration	(+)?	solar installation for example might not be expected to contribute much to meeting

²⁹ CCGT (combined cycle gas turbine) is an energy generation technology that combines a gas-fired turbine with a steam turbine.

				peak winter demand, and might be expected to erode base prices
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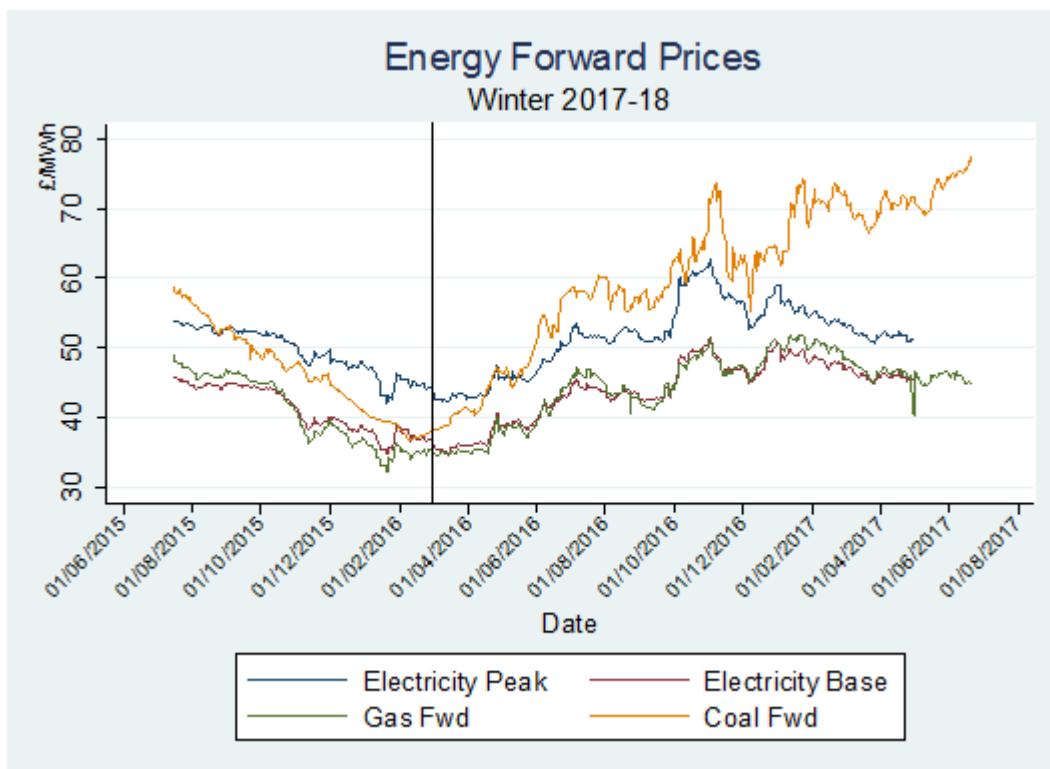
Data

We therefore collected data on the following variables:

- forward prices (peak and base) from the ICIS Power Index as well as from Bloomberg³⁰
- gas and coal forward prices (GBP) for winter 2017-18 from ICIS
- data on French forward peak prices for winter 2017/18 (in GBP), to control for expectations of interconnectors flows of energy, from Bloomberg
- data on GDP expectations from the Office of National Statistics (ONS)
- carbon prices from Aurora (eos.Auroraer.com)

Figure 3 below shows key variables: forward peak and base load prices as well as gas and coal prices. The upward movement of coal prices in the post-announcement period is striking. A quick eye-balling of the data shows it is not possible visually to identify a change in the difference between peak (blue) and base (red) prices from the Capacity Market announcement (marked by vertical line).

Figure 3: forward energy prices for winter 2017/18



We did not manage to obtain forward-looking data however for expectations of:

- CCGT margin
- capacities
- renewables penetration
- weather data

³⁰ We compared ICIS data to Bloomberg but found no large differences. We decided to use ICIS as it uses information from bids and offers which allows for a larger and more complete dataset.

- renewables penetration
- energy efficiency deployment
- operation and maintenance (O&M) costs

In order to overcome the absence of forward looking data we included backward looking data, on the grounds that traders could be influenced by such ‘behavioural factors’, particularly where there is an absence of forward looking variables for them to consider. Therefore, in absence of data on expectations of CCGT margin we use contemporaneous data from Aurora³¹. Similarly, we opted to control for weather changes using the average of the last two weeks³². We also collected monthly capacity data (by technology³³, including wind) from Aurora³⁴, and monthly solar photovoltaic installation data from BEIS³⁵, which we use in later tests.

We dropped some controls because we could not find any variable that would represent daily expectations for 2017-18 robustly, because their inclusion restricts the sample size, and because we did not consider they would have a meaningful influence on the price difference during the two periods in question (indeed their inclusion was not found to be important). In particular:

- both GDP forecast and carbon prices are produced relatively infrequently (monthly or quarterly frequency) and show little variation,
- we could not collect data on expectations of energy efficiency and O&M cost. We considered DECC’s updated estimates of levelised costs as a source, but ruled it out on grounds the data is only annual in frequency, and did not consistently cover the period in question. We consider it unlikely however that there was much variation in expectation of these drivers in the period in question, and posit their exclusion has limited impact on the key outcome.

Our data covered daily observations from the period 15 July 2015 to 1 May 2017. We imputed a data using a mean average approach³⁶, notably for CCGT margins data, available on a monthly basis, as well as some minimal imputation for missing dates of forward power prices³⁷. The final data set employed is presented in Table 3 below.

Table 3: fina data set

Date	Daily data from 1 May 2015 to 1 May 2017
Peak power price (£/MWh)	ICIS power daily data
Base power price (£/MWh)	ICIS power daily data
Gas Forward price (p/therm)	Bloomberg
Coal Forward price (£/metric ton)	Bloomberg
Average Temperature of last two weeks (C°)	National Grid, supplementary reports

³¹ This variable takes a number from 0 to 1, where for instance it takes the number 1 if CCGT (gas) is the marginal plant for the entire month, and 0.5 if CCGT (gas) is marginal for half the month. For all months in our dataset, CCGT and coal are the only plants at the margin.

³² Data was sourced from National Grid

³³ These are technologies connected to the transmission system and cover CCGT, Gas CHP-CCGT, Oil, Nuclear, Pumped Storage, OCGT, Coal, Wind (Onshore), Biomass, Wind (Offshore) and Hydro.

³⁴ Eos.Auroraer

³⁵ Solar Photovoltaics Deployment in the UK, BEIS, August 2017

³⁶ Basing estimates of missing data on the average of the data points either side of the missing data.

³⁷ This related to weekend data, and should affect both time periods – before and after the announcement – equally.

GDP Forecast (%)	MPC Forecasts of Annual GDP Growth based on Bank estimates of past Growth
CCGT Margin (%)	National Grid
France peak price index	Bloomberg
Capacities (MW)	Aurora
Renewable capacity (solar pv) (MW)	BEIS data

Final Model

Therefore, our final DiD specification is as follows:

$$p_{it} = \alpha + \beta_1 Treat_i + \beta_2 Post_t + \beta_3 (treat_i \times Post_t) + \beta_4 Maturity_t + \beta_5 Maturity_t^2 + \beta_6 CCGTMargin_t + \beta_7 GasForward_t + \beta_8 CoalForward_t + \beta_9 FrenchForward_t + \varepsilon_{it}$$

Where p_{it} is the daily forward price for winter 2017-18 for group i , for both peak and base load price.

There are two types of regression variables. One set controls for treatment groups and time periods and the other controls for factors that may shift the supply or demand curves of wholesale energy.

The first set of variables is the DiD part of our regression and includes *Treat* and *Post* dummy variables. The *Treat* variable takes the value 1 if it is Peak and 0 if it is Base; *Post* is a dummy variable taking value 0 before 1 March 2016 and 1 after; and $(treat_i \times Post_t)$ is an interaction variable representing the DiD estimator, which captures the effect of the announcement. Specifically, it looks for a change in the average difference between peak and base prices between the two time periods.

On the demand controls we included a linear trend (*Maturity*) to control for changes in the risk premium as the contract gets closer to the delivery date and a quadratic term ($Maturity^2$)³⁸. We also tried to control for weather (using average of last two weeks temperature)³⁹ but dropped this from the specification owing to doubts over its reliability as a control for future expectations and the fact that its omission had no significant impact in the DiD coefficient.

GasForward and *CoalForward* are our gas and coal forward prices for the same period of winter 2017-18, while *FrenchForward* is our index of French electricity forward peak prices. All these variables are expressed in GB pounds and should substantially capture exchange rate effects⁴⁰. *CCGTMargin* is the proportion of gas as a marginal fuel.

We recognise the possibility of issues arising from endogeneity between the gas forward variable and the forward prices we are trying to explain, in that GB gas prices may not only drive but may also be affected by GB forward power prices. We consider however that double differencing and the large number of demand and supply drivers we include should mitigate endogeneity problems. We also note the extremely high historic correlations with international gas prices (typically above 90%) should limit materiality of the issue.⁴¹

Section 5: Results and tests

³⁸ As the risk premium in forward prices may be non-linear.

³⁹ We used average daily temperatures for the day, 1 week and 3 weeks before, which all showed similar results. We also tried the average of the past year weather but this long-term average show little variation and could not be used in our estimation.

⁴⁰ Controlling for exchange rates may be important given dramatic swings over 2016.

⁴¹ See for instance Figure 27 in <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/10/NG-79.pdf>

The first specification of the DiD model follows ordinary least squares (OLS). Results are presented in Column (1) in Table 4. Coefficients significant above the 99% confidence level are marked with ***, 95% with **, and 90% with *. Errors are reported below in parentheses. All variables in this model are statistically significant.

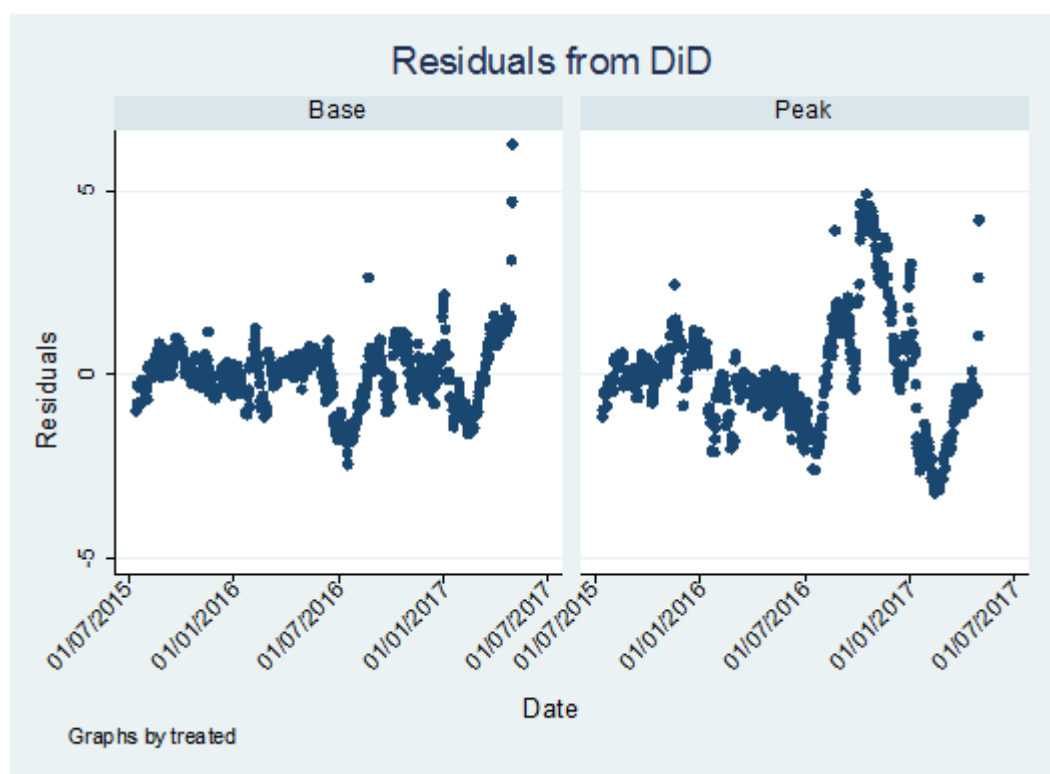
The *Post* variable is a time dummy for pre and post intervention periods, which takes the value 0 before 1 March 2016 and 1 after. It shows that, on average, prices were £2.50/MWh more expensive before the announcement. The *Peak* variable takes the value 1 for peak price (our treatment group) and 0 for base price (the control). It shows that base load prices for winter 2017-18 have been on average £8.31/MWh cheaper than peak prices.

The key coefficient *did* indicates the impact on the price difference of the intervention after controlling for other exogenous factors. The *did* coefficient is £0.66/MWh, and is statistically significant at the 99% level. *This suggests that the announcement of the Capacity Market lowers the peak–base differential by £0.66/MWh.*

This result is encouraging in that the sign of the coefficients are as expected and of a reasonable magnitude.

However the distribution of the error term violated the assumption of no auto-correlation⁴² and homoscedasticity (see Figure 4 below).

Figure 4: residual from DiD



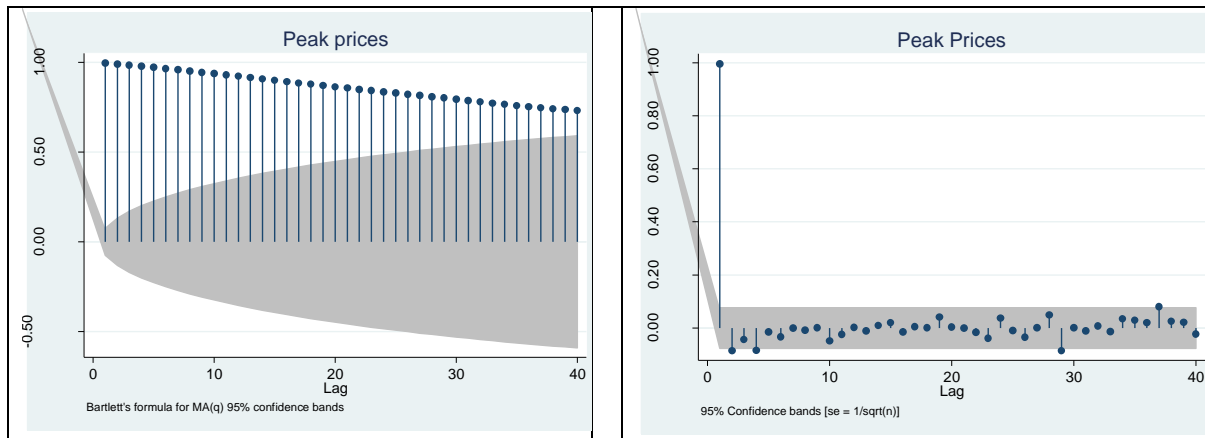
While highlighting pitfall of the DiD method, the literature does not provide many examples of possible bias associated with misspecification bias⁴³. To correct for residual autocorrelation, we

⁴² Auto-correlation is of particular concern in DiD analysis. See Bertrand et al

⁴³ Bertrand, M, Duflo, E, and Mullainathan, S (2004) 'How Much Should we Trust Differences-in-Differences Estimates' Quarterly Journal of Economics

estimate Newey-West standard errors, assuming a maximum lag order of autocorrelation of seven days.

Figure 5. Autocorrelogram and Partial Autocorrelogram graphs



In order to choose the precise lag order between 1 and 7 days, we tested for the order of the lag using the autocorrelogram and partial autocorrelograms of peak price and base prices. Figure 4 shows the result for peak prices, strongly suggesting a lag of order 1. Discussions with colleagues also supported the view that information in the market would be internalised very rapidly because of the speed in which information is shared and updated, and so we consider it reasonable to assume that the day before yesterday may not have a future influence in price.

Comparing columns (1) and (2) of Table 4, we see the errors are corrected with the Newey-West method⁴⁴. The results of the second regression show the same coefficients with corrected standard errors. All were statistically significant except the index of French forward prices. The key coefficient, *did*, is significant at the 99% confident level and it shows an impact on peak price of £0.66/MWh.

Table 4 Regression results

Variables	(1) DiD	(2) Newey West	(3) Test A: later cut-off	(4) Test B: earlier cut-off	(5) Test C: short- term
Post	-2.480*** (0.105)	-2.480*** (0.146)	1.704*** (0.303)	-0.708*** (0.265)	-1.066*** (0.185)
Peak	8.311*** (0.0604)	8.311*** (0.0831)	7.904*** (0.100)	8.293*** (0.108)	8.185*** (0.127)
<i>did</i>	-0.658*** (0.117)	-0.658*** (0.163)	-0.0415 (0.209)	-0.511*** (0.168)	-1.199*** (0.141)
Maturity	0.0406*** (0.00216)	0.0406*** (0.00298)	0.000160 (0.00310)	0.0179*** (0.00328)	-0.685*** (0.233)
Maturity^2	-3.31e-05*** (1.91e-06)	-3.31e-05*** (2.64e-06)	-3.60e-06 (2.69e-06)	-1.64e-05*** (2.62e-06)	0.000681*** (0.000232)
Gas Fwd	0.791*** (0.0286)	0.791*** (0.0371)	0.818*** (0.0382)	0.819*** (0.0384)	0.799*** (0.0402)
Coal Fwd	0.104*** (0.0179)	0.104*** (0.0237)	0.0245 (0.0260)	0.0553** (0.0250)	-0.0108 (0.0402)
CCGT Margin	-1.559***	-1.559***	-2.653***	-2.625***	-11.10***

⁴⁴ The error structure is assumed to be heteroskedastic and possibly autocorrelated up to some lag.

	(0.261)	(0.362)	(0.366)	(0.385)	(3.524)
Price France	0.00127* (0.000757)	0.00127 (0.00104)	-0.00103 (0.00130)	0.000590 (0.00117)	-0.00499*** (0.00164)
Constant	-7.739*** (1.207)	-7.739*** (1.645)	9.627*** (2.085)	1.156 (1.586)	188.6*** (60.89)
Observations	1,314	1,314	1,314	1,314	372
R-squared	0.956	0.956	0.948	0.947	0.986

One of the largest impacts in wholesale price was the CCGT Margin. This is the proportion of half hourly periods that gas is used as the marginal technology. Its negative sign suggests that the more marginal is gas, the cheaper are (expectations of) peak prices. Significant variables in this model were gas and coal prices and maturity effects, all of which show expected signs.

Since the assumptions on the error term are crucial, we performed several further robustness checks. In particular, tests focus on the concern that other factors – announcements or events – could drive our results. The chart below lists announcements or events that may be of relevance.

Table 5: announcements and events that might affect winter 2017/18 peak – base price differential

announcements/events	when	expected effect, if any	potential to affect winter 2017/18	main tests we conduct
National Grid's NISM (notice of insufficient margin)	(4 November 2015)	(+)		restricting time period to exclude announcement
Coal phase out announcement	(18 November 2015)	(+)	somewhat - though phase-out focuses on 2025	restricting time period to exclude announcement
plant closure rumours (uncertainty could drive irrational behaviours and unreliable observed prices upon which to base analysis)	(late-January / early-February 2016)	(+)		removing data four weeks either side; pushing simulated structural break forwards four weeks
National Grid's NISM	(9 May 2016)	(+)		pushing simulated structural break backwards four weeks
Transmission Entry Capacity (TEC) register publications (2016)	February: 22, 29 (published 1 March), and March: 7, 14, 31	(+ or -)		difficult to test for. TEC registers appear to be published around weekly or fortnightly frequency
Embedded benefits reform	on-going	(-)	limited - market unlikely to expect direct effects as early as winter 2017/18	unnecessary: theoretical effects are contrary in direction to those of CM introduction (hence likely to give conservative estimates); impact unlikely to be directly felt for winter 2017/18; no clear single date market became aware of likely change in arrangements

Columns (3), (4) and (5) of Table 4 show results of a series of robustness tests to explore whether our results are driven by other unexpected announcements or events. These tests simulate alternative dates of such events or announcements.

Test A in column (3) of Table 4, moves the data of the announcement artificially one month after 1 March 2016. The coefficient *didA* does not have a significant impact in wholesale prices, suggesting that events after March 2016 are not driving our results. At the same time, Test B moves the

announcement one month forward⁴⁵. The coefficient *didB* still captures the effect of the announcement but the impact is lower than the original *did* coefficient, -£0.51/MWh compared to -£0.66/MWh respectively. We repeat these two tests just two weeks either side of the announcement, with the same key results. These findings are consistent with our hypothesis as they suggest that an event at least within a fortnight either side of 1 March is driving a change in price differential.

Finally, Test C in column (5) shows results of a 'short-term' test that restricts the dataset to three months before and after the announcement. This short-term result is statistically significant. This suggests that we can rule out events or announcements more than three months either side of the Capacity Market announcement as driving our results. The impact is also bigger – almost double – than in the longer-term estimation: -£1.20/MWh and -£0.66/MWh.

There is a trade-off between a longer dataset, which presents a more fulsome picture, and a shorter dataset, which is less likely to reflect events we have not controlled for. On balance, we chose to employ the £0.66/MWh effect as our central estimate. This not only allows for greater confidence, but as it incorporates the period after the volume to procure was revealed in July 2016 and after the auction itself concluded in February 2017, it captures to some extent the effect of further revision of expectations as information from the auction is internalised.

We conduct further tests (not presented in the table above), none of which suggest doubt on the statistical significance at the 99% level of the finding of an effect equal to about £0.66/MWh. These tests are:

1. controlling for current capacities including gas, coal, wind and solar pv
2. removing February and March 2016⁴⁶
3. removing all control variables

We conducted further tests to explore for an effect on prices of first, DECC's announcement of the volume to procure (53.8GW) on 6th July 2016 and second, identification of the capacity payment price (£6.95/KW/yr) in early February 2017 following completion of the auction. While these announcements were not unexpected, the results (volume, price) could have been. Our tests suggest that the absolute price effect adjusts up and down quite significantly as further information on volume and price is revealed to the market, meaning our overall estimate of £0.66/MWh may mask a lot of variation of impact in the post-intervention period.⁴⁷

Section 6: Interpretation and caveats

Identifying the driver of the effect

In sum, the model captures an effect during the period within two weeks either side of 1 March 2016, the statistical significance of which is robust to a host of alternative specifications. This suggests the existence of an effect, driven by one of the following

⁴⁵ We would have liked to conduct a placebo test for around 1 February that omitted the post announcement period altogether, but owing to insufficient data did not do so.

⁴⁶ This test finds a stronger effect of around -£0.74/MWh. Removing January to April gives -£0.72/MWh. In theory, the value of such tests is to remove the effect of possible speculative influences and over- or under-reactions.

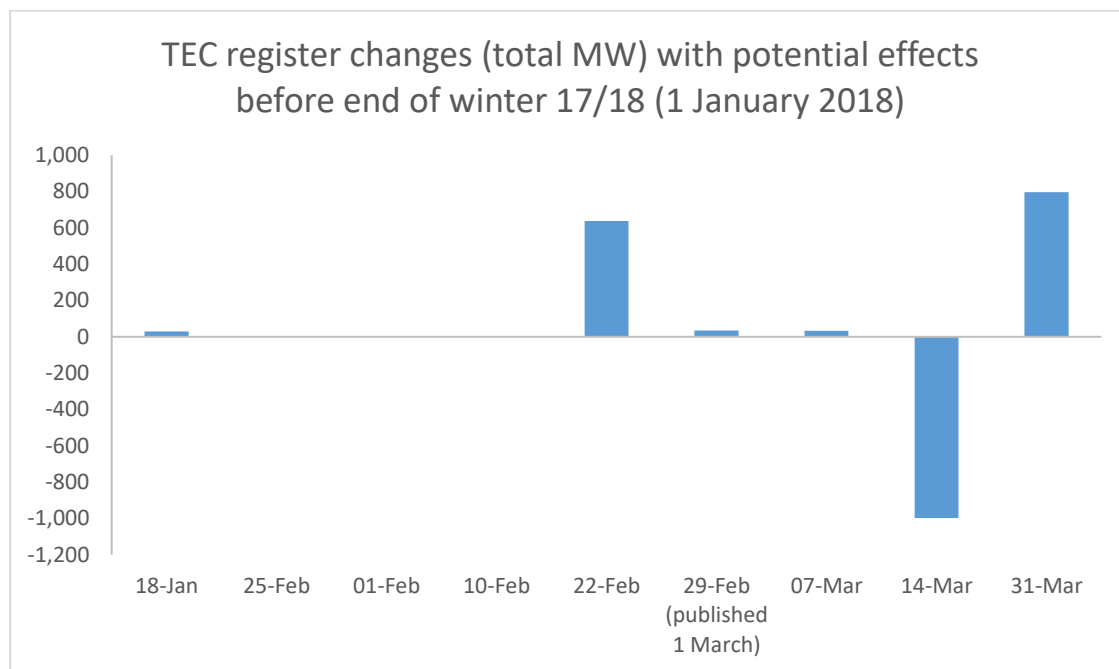
⁴⁷ Note the caveat that these tests may violate the key assumption of common trends between treatment and control underpinning the difference in difference method, and that we have not conducted further checks on these sub-sample tests.

- the Capacity Market announcement on 1 March
- publication of the TEC register on 1 March
- information on potential embedded benefit reform, noting Ofgem’s forward strategy published on 1 March makes some references to this

The latter can be discounted as its effect on the price difference should in theory be contrary to that of the Capacity Market announcement. Furthermore, we consider the market would not envisage an effect as early as winter 2017/18 – rather that any reform would affect later years – and finally that information on this issue was leaking slowly out over time through other publications and media, making 1 March as a ‘moment of realisation’ unlikely.

At first sight, the TEC register published on 1 March shows an increment of over 500MW of capacity compared with the previous register on 22 February. This change was attributable to an offshore windfarm. However, as the connected figure disappears in the subsequent registers it looks somewhat suspect. Figure 1 shows TEC changes that might affect winter 2017/18 prices below (removing suspect data from the TEC publication of 1 March 2016, since we are looking for an effect that was sustained)⁴⁸.

Figure 6: TEC changes



Quite eye-catching is the jump on 22 February – relatively close to the 1 March Capacity Market announcement date. If the 22 February TEC publication shifted expectations of the supply curve (and was therefore unexpected), then it could in theory contribute to the reduction we find in the difference between peak and base prices. Figure 6 shows, however, that even more significant changes were afoot in the publication of the 14 March and 31 March registers. Our Test A suggests however that the 31 March publication is not associated with a change in expectations that drove a change in prices. And the 14 March publication is associated with a *reduction* in capacity, which ought to enhance expectations of peak prices, other things equal.

⁴⁸ Data sourced from National Grid website (<http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/>) and with assistance of NG trading team.

This leaves us with the possibility that the 22 February publication drove a sustained effect on prices. We consider this unlikely, not least as the change is relatively small compared with others, which are themselves not found to have had an effect. However, the possibility remains that the contents of the other releases were in line with expectations and therefore already priced in by the market, while the 22 February release contents could have been a surprise. In discussion with National Grid's trading team however, they did not identify any clear 'surprises' to the market in the contents of the 22 February TEC release.

The changes are substantially driven by two plant: one acquiring 376MW TEC commencing April 2017, and another renewing 260MW TEC. The larger of the two should not have been surprising since their plans were public⁴⁹. We cannot find information that might have shaped market expectations of the other in advance of 22 February. This could suggest the absence of strong contrary a priori. We therefore cautiously consider that our results are more likely to be driven by the Capacity Market announcement, but note this as an avenue for further research.

Estimating the absolute effect on wholesale revenues

In order to provide a central estimate of the absolute reduction in both peak load and base load prices we make a simplifying assumption that scarcity value is reflected in prices in proportion to the relative number of hours of the two products. As the base load product covers all 7 days of the week and the peak load product covers a total of 2.5 days per week (7am to 7pm on weekdays), therefore we expect the impact on peak load prices of a given reduction in expected scarcity to be 2.8 times⁵⁰ that of the impact on base load prices. This translates to an absolute reduction of about £1/MWh⁵¹ in peak load prices, and £0.36/MWh in base load prices.

The product of base and peak load energy volumes and the appropriate price changes may give a sense of the potential absolute impact on wholesale revenues. In total, this suggests an estimate of around £130m.⁵² However, this method does not capture the relationship between price and demand volume, in that highest prices tend to occur when demand volumes are highest. For this reason, it most likely understates the impact, and the £130m estimate may be considered a lower bound. Discussions with National Grid's trading team yielded a model that estimates an impact of £165m.⁵³ We consider the evidence base plausibly suggests a wholesale revenue effect of *around* £150m.

⁴⁹ <http://www.telegraph.co.uk/news/earth/energy/coal/12027606/Coal-plant-gets-green-light-to-burn-American-wood-pellets.html>

⁵⁰ 7 divided by 2.5 equals 2.8.

⁵¹ The figure is £1.02 / MWh

⁵² About 271 TWh of energy was consumed (transmission system) in 2016/17. Roughly 19GW of this was baseload, which runs all the time, equivalent to about 164 TWh of energy over the year. For a £0.66 /MWh price differential, this gives an impact of £0.36/MWh on base, and an absolute reduction in base revenues over a year of around £60m. The impact on off-peak assumed to be negligible. Peak load energy on top of base load can be estimated at 70 TWh, which multiplied by a price effect of around £1/MWh amounts to over £70m. This gives a total of £130m. The equivalent effect for our sensitivity dropping February-March (£0.74/MWh price difference) is £150m.

⁵³ See Annex. In this model the baseload price effect is magnified across all periods in the year in a relationship that is inversely proportional to the frequency of demand exceeding a particular threshold (based on previous years). Effectively this models the Capacity Market payment as a (negative) fixed cost proportional to the size of the generator, such that the marginal price of a generator should be reduced in inverse proportion to the load factor of the generator. This more sophisticated model yields an estimated reduction in wholesale revenues of about £165m. Results are neither particularly sensitive to definition of demand employed

The analysis adds value in two respects. First, it provides (ex post) evidence of the transfer of value from wholesale market to Capacity Market, an interaction set out in DECC Capacity Market (ex ante) impact assessments. This estimated reduction in wholesale market revenues can be compared with out-turn Early Auction payments of around £380 million⁵⁴ (and total wholesale market revenues which in 2016/17 may be in the region of £10-£15 billion⁵⁵). Second, it may assist in shedding light on the extent of ‘missing moneys’. The net payment of around £230m (this is the £380 million minus the ‘about £150m’) to capacity providers could in theory represent for instance the ‘missing money’ required to provide an optimal level of security, or other reduction in risk. A caveat here however is that this analysis does not shed light on other important interactions notably potential effects on National Grid’s ancillary services (a reduction in ancillary services revenues intuitively seems quite likely) and on embedded revenues and so we caution against drawing firm conclusions here.

Assumptions and caveats

Apparent in this stylised interpretation are a host of assumptions with associated caveats.

- First, the assumption of perfect arbitrage (eg between summer and winter products, or between forward and spot markets) is unlikely to hold. Analysis by Bunn et al. for instance suggest the existence of a premium on forward prices with sophisticated drivers, cautioning against assuming perfect arbitrage over time. To some extent our maturity controls may address this.
- Second, the volumes of trades driving this result are small in comparison with total energy to be delivered, particularly at the start of the dataset, suggesting further caution in market-wide extrapolation of the results.
- Third, the assumption that the market was expecting an energy-only market in advance of the Early Auction announcement may differ materially from reality. Had the market already expected with some probability the introduction of a Capacity Market, then our analysis would tend to under-estimate the effect of its introduction on wholesale prices – and over-estimate the potential scale of missing moneys. On the other hand, the market might instead have expected SBR extension (noting SBR had been extended for the previous year). The higher the expectation of SBR extension (holding other factors equal), the higher should be expectations of scarcity, wholesale forward prices (and the spread between peak and base) and wholesale revenues. The wholesale price effects of expectations of SBR extension and Capacity Market introduction are therefore opposites. Given uncertainty, a central assumption that any SBR and CM expectations cancel each other out may however be a reasonable central case assumption to employ, with caveats.
- Fourth, the analysis assumes no important variables or events have been omitted that could impact the spread between peak and base load differently between the two periods.

(national demand vs transmission system demand) nor to year of demand data (2015/16 vs 2016/17). The model does not simulate previous year prices well, but may be sensible though, for estimating a *change* in the supply curve occurring as a result of a change in fixed costs.

⁵⁴ The Early Capacity Market Auction (February 2017) committed to pay around £6.95/kW year to 54.4 GW of capacity.

⁵⁵ This ball-park figure is derived by multiplying 271 TWh by stylised average prices of £40/MWh (base-load) and £50/MWh (peak load).

However, publication of National Grid's TEC register coincided with the CM announcement, and so it is not possible to disentangle the two.

- Fifth, the analysis assumes no effect on off-peak prices, which we consider reasonable, both in light of theory and on grounds it should give conservative results. To give a sense of sensitivity of results to this assumption, however, should off-peak prices fall by (a purely illustrative) £0.25/MWh, then this would suggest an additional reduction in wholesale revenues of around £50m⁵⁶.

More generally, it should be noted that analysis only applies to winter 2017/18. For instance the Early Auction differs from other auctions in that it was held very close to delivery, with many participants already holding agreements for later delivery years. For this and other reasons, the estimates cannot be extrapolated to other Capacity Market auctions and delivery years.

Section 7: Further research

This analysis offers many opportunities for further research.

- Further research may shed light on interactions with other opportunities for deriving value, such as from National Grid's ancillary services and embedded revenues, which this analysis did not consider. It could be explored whether a similar natural experiment could be constructed to assess this interaction – however this may be constrained by an absence of price data (National Grid does not hold its auctions for provision of ancillary services a year and a half or more in advance of delivery).
- Running the model for other announcements may suggest further improvements to the method.
- Analysis of the impact of previous publications of the TEC register may give a sense of its historical impact on wholesale prices, better to understand the materiality of the risk that the analysis is picking up the effect of TEC register publications rather than the Capacity Market announcement, noting coincidental dates of publication and announcement.
- While previous analyses⁵⁷ of forward prices find an absence of behavioural influences on GB prices further along the curve (month-ahead prices), further tests to control for such

⁵⁶ For a given peak-base differential, and illustrative volumes (TWh) of baseload, peak and off-peak at roughly 164, 70 and 37, a first-order estimate of an off-peak effect of £0.25/MWh is $(37 * £0.25) = £10m$ for off-peak; and peak plus base effect is $(4.5/7) * (70 + 164) * £0.25 = £37m$. Total effect £47m (or around £50m).

⁵⁷ Bunn et al analyse GB electricity day ahead premia to consider the importance of a number of elements in price formation including behavioural aspects (adaptive behaviour to lagged variables), fundamentals (such as demand, fuel prices, and reserve margin) and risk aversion to spot market volatility and skewness (the authors call these statistical risk). Their analysis of GB prices further along the curve (month-ahead prices, including both peak and base) finds an absence of substantial impacts on premia of behavioural influences, in terms of adaptation to lagged dependent variables. The authors note a striking comparison with factors influencing day-ahead price formation, which they find to be linked with behavioural variables (in particular day ahead prices). The role of non-fundamental drivers of price chimes with research from elsewhere. Analysis of Australian prices for example suggest futures prices cannot be considered as an unbiased estimator of the future spot price and expectations of fundamentals, but are influenced by historical spot price behaviour (The Relationship between Spot and Futures Prices: an Empirical Analysis of Australian Electricity Markets, Handiqa et al, Macquarie University, 2012)

behavioural variables may nevertheless be useful in testing the validity of our results. The fact that some of our behavioural variables (such as recent temperatures) are statistically significant suggests further scope for exploration.

- Further research could explore market expectations in advance of the Capacity Market of a number of scenarios including energy market, Capacity Market and SBR, better to interpret the results.
- Analysis could further explore the effect of changes in distributed capacities.

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Annex – National Grid’s (trading team) model of the impact of an (expected) change in Capacity Market revenue on the wholesale market price duration curve

The marginal price a generator is willing to offer to supply power can be modelled as:

$$P = \frac{FC}{Q_T} + VC$$

Where FC is the total fixed cost (£) incurred in a year (including fixed O&M, capital costs, transmission charges etc), VC is the variable cost (£/MWh) (including fuel, emissions, variable O&M etc) and Q_T is the total quantity of energy (MWh) sold in a year.

$$Q_T = RC * l * 8760hrs$$

Where RC is the size of the generator (MW) and l is the generator’s load factor.

Assuming the generator is either running at RC or off in any period in the year⁵⁸:

$$l = t/8760hrs$$

Where t is the number of hours in which the generator runs.

The Capacity Market provides a fixed revenue R_{CM} to the generator in the delivery year:

$$R_{CM} = P_{CM} * DRC * 8760hrs$$

Where DRC is the derated capacity of the generator and is proportional to RC and P_{CM} is the Capacity Market clearing price (in £/MW/hr).

We can model a change in CM Revenue as a change in fixed cost⁵⁹:

$$\Delta FC = R'_{CM} - R_{CM} = (P'_{CM} - P_{CM}) * DRC * 8760hrs$$

The consequent change in the marginal price of the generator is then:

$$\Delta P = \frac{\Delta FC}{Q_T} = \frac{\Delta P_{CM} * DRC * 8760hrs}{RC * l * 8760hrs} \propto \frac{\Delta P_{CM}}{l}$$

i.e. *The change in a generator’s marginal energy price is inversely proportional to its load factor.*

The energy market price in any given hour will be the marginal price of the marginal generator⁶⁰. The change in market price is then the consequent change in the marginal price of the marginal generator. Since the lowest priced generators will be ‘in merit’ most often, we can assume the load factor of the marginal generator will be proportional to the probability of demand exceeding that generator’s position on the supply curve.

Which means the change in market price for a given demand, Q, will be:

⁵⁸ Alternatively we could replace RC with the average power delivered in periods where the generator is running.

⁵⁹ Assuming Variable costs are not affected by changes in the CM clearing price.

⁶⁰ Assuming competitive and liquid markets.

$$\Delta P_M(Q) = \frac{k}{(t_q/t_b)}$$

Where t is number of hours where demand exceeds Q and $t_b = 8760$ hrs, and the subscript 'm' shows a change in the Market price instead of the price of an individual unit. 'k' is the constant of proportionality, and since for baseload $t_q/t_b = 1$, k should be equal to the measured change in baseload.

For baseload demand $t/t_b = 1$. Measuring the change in baseload price attributable to the announcement of the Early Capacity auction then provides an estimate of the proportionality constant, k .

