Negative pricing in the GB wholesale electricity market

CLIENT: DECC

DATE: 01/07/2015

Version History

Version	Date	Description	Prepared by	Approved by
3.0	06/06/2015	Revised draft version for client	Mark Turner Debbie Buckley	Duncan Sinclair
4.0	11/06/2015	Final version for release	Mark Turner Debbie Buckley	Duncan Sinclair
5.0	26/06/2015	Typographical corrections	Mark Turner Debbie Buckley	Duncan Sinclair
6.0	01/07/2015	Typographical corrections	Mark Turner Debbie Buckley	Duncan Sinclair

Contact

Mark Turner (mark.turner@baringa.com +44 7584 290310)

Duncan Sinclair (duncan.sinclair@baringa.com +44 7887 500856)

Copyright

Confidentiality and Limitation Statement

Contents

Executive summary

Context

A new Contract for Difference (CfD) mechanism to support low carbon electricity generation has been introduced in the UK under the government's Electricity Market Reform (EMR) programme. The first CfDs have already been awarded, and CfDs will entirely replace the existing Renewable Obligation (RO) support mechanism for new large scale (>5 MW) renewable generators from 2017, with a transition from the RO to the CfD in place until then[1].

In granting State Aid approval for the new CfD mechanism, the European Commission (EC) mandated that the new support scheme should not encourage negative pricing in wholesale electricity markets, by providing incentives for supported plant to continue generating well below their true marginal costs. As a result, the Department of Energy and Climate Change (DECC) has been required to implement provisions in CfD for Renewables contracts to prevent payments to generators being made for hours in which the day-ahead (DA) electricity market price is negative – but only when a negative price has persisted for six consecutive hours or longer ('6+ hour negative price event').

Within this policy context, Baringa Partners LLP was commissioned by DECC to analyse the potential future incidence of negative prices in the GB electricity market, and to provide insights on the causes, implications and drivers of negative pricing.

The potential impact on renewable generators of the provision depends upon whether negative prices occur in the future in the GB[2] day-ahead market, and with what frequency and duration.

Drivers of negative pricing

The existing RO and new CfD for Renewables low carbon support schemes in GB are both output-based mechanisms where support payments are linked directly to metered output. If no output is produced, no support payments will be made. This means that there is an 'opportunity cost' of not generating. It can therefore remain profitable for RO and CfD-supported power stations to continue generating even when the wholesale electricity price is negative and parties are being paid to consume electricity.

For example, an onshore wind generator with variable operating costs of 1 £/MWh and a support payment of 40 £/MWh would in theory be willing to sell its output at a price of -39 £/MWh. In other words, the generator is willing to pay up to 39 £/MWh to produce output, in return for a support payment of 40 £/MWh thus receiving 1 £/MWh of revenue.

[1] The existing Renewable Obligation (RO) support mechanism closed to new solar accreditations on 31 March 2015, and will cease to be available for other renewable generators from 31 March 2017. For further details, refer to the ' Electricity Market Reform: Contracts for Difference' sections of the DECC website: https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference

[2] GB refers to England, Wales and Scotland but excludes Northern Ireland which is part of the Irish Single Electricity Market (SEM) encompassing both the Northern Ireland and Republic of Ireland jurisdictions.

Incentives for individual generators to sell output at negative prices do not necessarily translate into negative wholesale electricity prices overall. Market pricing for electricity is on a marginal basis – so only if the most expensive generator required to meet demand in a particular period (the 'price-setting' plant) is receiving a support payment – or is an inflexible plant looking to avoid incurring the costs associated with shutting down and starting up[3] – will the wholesale electricity price be negative overall. This could occur in periods when the volume of available generation (total potential electricity supply) willing to offer into the market at negative prices – those receiving support payments, plus other forms of inflexible generation – exceeds demand (and its ability to respond to negative prices).

In considering the commissioning brief set by DECC we sought to answer the question: how likely is it that plant receiving support payments (or other forms of inflexible generation) will be 'at the margin' in the GB market in future and under what scenarios will this occur more or less often?

Impact of negative prices on low carbon generators

The exact impact of negative prices on renewable generators will vary depending on the type of support the renewable generator receives (if any) and the nature of any offtake agreements which are in place.

Generators supported under the RO receive a defined number of Renewable Obligation Certificates (ROCs) for each unit of electricity they produce. The value of the ROCs received is a 'premium' on the wholesale value of generated electricity. Negative wholesale electricity prices could reduce the revenue from electricity sales for these generators, but so long as they continue to generate there will be no impact on the RO support revenue. If a generator sells its output via a Power Purchase Agreement (PPA) which provides a guaranteed floor price for the power, this could pass the risk of negative wholesale electricity prices to the offtaker. The '6+ hour negative price event' rule will have no direct impact on RO generators.

Intermittent generators supported by a CfD will be affected when prices go negative since CfD difference payments are capped at the contract strike price – this means that they will not be 'made whole' to their strike price level for the electricity they generate if the day-ahead Market Reference Price (MRP) falls negative. In addition, a CfD generator with the new '6+ hour negative price event' provision in its contract will risk that CfD support payments will fall to zero if the day-ahead price is negative for six or more consecutive hours. No CfD payments will be made from the first hour with a negative price until the price rises to a positive level.

For baseload generators supported by a CfD (such as nuclear or biomass plant), the MRP is a season-ahead forward index and not the hourly day-ahead price. The risk of forward indices becoming negative is very low, since this would require very prolonged periods of negative pricing. However, a baseload CfD generator with the '6+ hour negative price event' provision in its contract will still be affected if CfD support payments are set to zero during a negative price event under the proposed six hour rule.

The introduction of the '6+ hour negative price event' provision in CfDs could therefore increase the risk to CfD-supported renewable generators of negative pricing – by how much will depend on the frequency and duration of future negative price events last six hours or more.

[3] This can also be a driver of a generator pricing its output below its variable operating costs.

Our analysis

In seeking to address the commission set by DECC we have undertaken fundamentals-based modelling of European wholesale electricity markets. We have used a linear optimisation model to project hourly power station dispatch and wholesale electricity prices based on a range of defined market input parameters and assumptions.

We have analysed two core scenarios over the timeframe 2015-40:

- **Market scenario** – a central case independently developed by Baringa using the same methodology we provide to commercial clients. In this scenario the government pursues a balanced energy policy which attempts to meet the competing demands of security of supply, affordability and environmental sustainability.
- **Policy scenario** – uses assumptions provided by DECC and which are consistent with UK Government policy aspirations and DECC's central Updated Energy Projections (UEP). This scenario has a higher penetration of low carbon generation in the long term versus the Market scenario, alongside higher long term electrification assumptions leading to overall higher electricity demand.

We then conducted sensitivity analysis on these core scenarios to probe the impact of varying key assumptions such as the level of electricity storage, wind, nuclear and interconnector build-out.

We were asked to focus on developing an understanding of the incidence of negative price periods of six or more consecutive hours at the day-ahead stage, which would trigger CfD support payments to be set to zero under the EC's requirement. As requested by DECC we also then considered the potential changes in negative pricing which could occur closer to real time in the intra-day (ID) market.

Key messages

In the Market scenario, with moderate long-term decarbonisation and electricity demand, negative prices are not a significant feature of the GB day-ahead electricity market over the next 25 years.

In this scenario, we do not observe any 6+ hour negative price events in any year through to 2040 at the day-ahead stage and the policy setting CfD support payments to zero would not be triggered. Some negative prices occur, with an average of 2 negative price hours per year over the period 2020-35, and a maximum in any one year of 12 hours in 2020.

The number of negative price hours is closely linked to the amount of low carbon generating capacity in receipt of support payments – higher low carbon build supported under CfDs for Renewables or the RO could lead to occurrences of 6+ hour negative price events.

In the Policy scenario, which has higher deployment of subsidised low carbon capacity, negative price events lasting 6+ hours occur at the day-ahead stage in most years from 2023 onwards.

The policy setting CfD support payments to zero would be triggered around 80 times through to 2040 in this scenario. We project an average of 68 negative price hours per year in the period 2020-2035, and the peak year for negative prices in this scenario is 2028 with a total of 177 hours.

As more low carbon generating capacity reaches the end of the term of its support payments, the incidence of negative prices could decrease – even if the overall quantity of installed low carbon capacity does not. In the Policy scenario the incidence of day-ahead negative prices falls from 2033 onwards, even though the total installed low carbon capacity increases.

The number of negatively priced hours is very sensitive to the assumed bidding behaviour of low carbon generators.

In the two core scenarios, we have assumed that generators offer into the day-ahead market based on their variable operating costs minus the opportunity cost of support payments. There is some evidence from historical negative pricing observed in the Balancing Mechanism that low carbon generators could offer lower than this, particularly closer to real time. If low carbon generators did price a further discount in to their offers, for example to avoid incurring technical or commercial shut-down or start-up costs, then the number of negative prices could be substantially higher.

In our modelling of the intra-day timeframe, we assumed that wind generators did further discount their bids – this combined with lower system flexibility to respond to changes in forecast generation and demand resulted in an increase in the number of negative price hours in the Policy scenario from an average of 68 per year to 319 over the period 2020-35.

Sources of flexibility on the system play an important role in mitigating against negative prices in GB, both day-ahead and intra-day.

Flexibility can be provided by interconnection, electricity storage, demand side response – along with more flexible (or more flexibly operated) generation capacity. We found that the average number of day-ahead negative price hours over the period 2020-35 in the Policy scenario dropped to 51 per year when flexibility was increased by the addition of more electricity storage. Conversely, lower future new build of interconnection increased the average to 94 per year. In our intra-day analysis, allowing GB interconnection no flexibility to change its import / export position beyond the day-ahead stage increased the average number of negative prices from 319 to 874 per year over the period 2020-35 in the Policy scenario[4].

Table 1 presents a summary of the main negative price results for each scenario and sensitivity.

[4] Note that the intention of this sensitivity was to establish the 'range' of outcomes by considering the extreme case of zero intra-day flexibility for interconnection. This should not necessarily be taken as a realistic outcome as it would not comply with the requirements of the EU Target Model.

Table 1 Summary of scenario and sensitivity results

Name	Scenario / sensitivity	Day ahead / intra-day	Key features	Average annual number of negative price hours (2020-2035)[5]	Average annual number of 6+ hour events (2020-2035)[5]
Market	Scenario	Day-ahead	Commercial 'central' case	2	0
Policy	Scenario	Day-ahead	Higher low carbon build and higher long-term electrification than Market scenario	68	4
Market	Scenario	Intra-day	Market scenario in intra-day timeframe	18	2
Policy	Scenario	Intra-day	Policy scenario in intra-day timeframe	319	26
High Wind	Sensitivity (Market)	Day-ahead	Higher wind build (12 GW more by 2040) in the Market scenario	21	1
Low Nuclear	Sensitivity (Policy)	Day-ahead	Market scenario nuclear build applied to the Policy scenario	119	6
Increased Storage	Sensitivity (Policy)	Day-ahead	Higher storage build (5 GW more by 2040) in the Policy scenario	52	2
Low Interconnection	Sensitivity (Policy)	Day-ahead	Interconnector capacity capped at 7 GW in the Policy scenario	94	6
Low Interconnection	Sensitivity (Policy)	Intra-day	No interconnector flexibility post-day-ahead	874	70

[5] For the Market and Policy day-ahead scenarios this is the average of the annual results for years 2020-2035 inclusive. For the sensitivities and intra-day scenario results, this is the average of the four spot years 2020, 2025, 2030 and 2035.

1 Introduction

1.1 Context

There is the potential for wholesale electricity prices to become negative during periods of market oversupply when inflexible power generation combines with low and inflexible electricity demand. Negative prices have not yet occurred in the day-ahead (DA) market in Great Britain (GB), but they have been observed in other European markets such as Germany, the Netherlands and the Nordic region[6].

The Contracts for Difference (CfD) mechanism to support low carbon electricity generation has been introduced in the UK. The CfD for Renewables programme will replace the existing Renewable Obligation (RO) support mechanism from 2017, with a transition from the RO to the CfD in place until then[7].

In granting State Aid approval for the CfD for Renewables programme, the European Commission (EC) required that:

"By the beginning of 2016, the UK will modify the Contract for Difference to include provision ensuring that generators do not have an incentive to generate electricity under negative prices. If the day-ahead power auction hourly price is below zero support will be capped at the strike price Moreover, if prices remain negative throughout a six-hour period or longer then the difference amount under the CFD contract will be set to zero for the entirety of that period."[8]

In order to comply with this requirement, DECC has proposed that provisions are added to future CfD for Renewables contracts to prevent payments to generators being made for hours in which the day-ahead market price is negative, but only where a negative price has persisted for six consecutive hours or longer (the '6+ hours negative price event' rule). The potential impact of implementing this EC requirement depends upon whether negative prices occur in the future in the GB day-ahead market, and with what frequency and duration.

1.2 Objectives

In view of the potential importance of negative pricing in the GB market – especially in the context of the CfD for Renewables contract changes required by the EC – Baringa Partners LLP was

[6] Some negative cash-out prices have been observed in the GB market in recent years, and since our analysis for this report was completed in March 2015, negative prices on the APX intra-day market have been observed in a number of periods (during May and Jun 2015). It is likely that further negative price events will occur in the balancing market (and, potentially, intra-day) sooner than in the day-ahead market. Consideration of the balancing market was outside of the scope of this study.
[7] The Renewable Obligation (RO) support mechanism closed to new solar accreditations on 31 March 2015, and will cease to be available for other renewable generators from 31 March 2017. For further details, refer to the 'Electricity Market Reform: Contracts for Difference' sections of the DECC website: https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference
[8] European Commission – State aid SA.36196 (2014/N) – United Kingdom Electricity Market Reform: http://ec.europa.eu/competition/state_aid/cases/253263/253263_1583351_110_2.pdf

commissioned by DECC to provide market advice and analysis on the causes, implications and drivers of negative pricing.

DECC sought to understand when negative price events might first appear in the GB electricity market, and how their frequency, depth and duration might change over time. DECC also wanted to explore the potential influence of a range of market factors on negative price outcomes, including:

- Electricity Market Reform (EMR) and other subsidy mechanisms
- deployment of intermittent generation
- deployment of baseload generation
- flexibility of the baseload fleet
- interconnection
- electricity storage capacity, and
- commodity prices.

To meet these requirements, we have undertaken analysis including detailed modelling of the future development of wholesale electricity prices in the GB market. We have structured the analysis around two core scenarios. The first is an independent 'Market' scenario provided by us and developed using the same principles we would apply when working with our commercial clients to develop a 'central' scenario for the purposes of investment and divestment decisions. The second is the 'Policy' scenario which is consistent with DECC's policy goals and the assumptions contained within the 2014 Updated Energy Projections (UEP)[9].

We have analysed the negative pricing outcomes for these two core scenarios first in the day-ahead timeframe, and then closer to real time by modelling the intra-day market. We have also undertaken sensitivity analysis to probe the potential effect of altering key assumptions and drivers on negative prices.

1.3 Structure of this report

The remainder of this report is structured as follows:

- **Section 3** sets out the policy context and background for the study, including the background to the CfD for Renewables contracts, and possible drivers for negative bidding behaviour of generators.
- **Section 4** describes our approach and methodology, and sets out the basis for the two core scenarios.
- **Section 5** presents the results of our day-ahead market analysis, and the main messages which can be drawn.
- **Section 6** describes the outcomes of our intra-day analysis.
- **Section 7** presents the sensitivity analysis.
- **Section 8** summarises the main messages and conclusions of the study.

[9] DECC Updated energy and emissions projections: 2014 https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014

1.4 About Baringa

Baringa Partners LLP is an award-winning management consultancy specialising in energy, financial services, utilities, telecoms and media – in the UK and continental Europe. It partners with organisations when they are developing and delivering key elements of their business strategy, as well as working extensively with government and regulators providing policy and advisory services. Baringa works with its clients either to implement new or optimise existing business capabilities relating to their people, processes and technology.

Baringa is recognised both in the UK and internationally for its unique culture for which it has been awarded a number of accolades and continues to reaffirm its status as a leading people-centred organisation.

Formed by the merger of Baringa Partners with Redpoint Energy in 2012, our Energy Advisory practice offers a full spectrum of specialist advisory and analytical services, and transaction execution support. We bring together an unparalleled knowledge of the European energy sector and a quantitative approach built on evidence-based insight and powerful analytics. Our work is informed by knowledge of markets, regulation, assets, operations and capital, and in-depth insight into their interdependencies and the impact of their interactions. We provide our clients with a unique combination of flexibility, pragmatism and intellectual rigour.

2 Policy background and context

2.1 Background to EMR and the CfD mechanism

The Electricity Market Reform (EMR) programme in the UK is intended to support new investment in low carbon electricity generation and deliver security of supply, while ensuring affordability for consumers. The key aims of EMR will be delivered in large part through two new market mechanisms – Contracts for Difference (CfDs) and the Capacity Market (CM). The first CM auction took place in late December 2014, and the first CfDs were allocated in Q1 2015.

CfDs are designed to provide a high degree of revenue certainty to low carbon generators, and therefore to encourage new investment at a lower cost to consumers. The CfD will replace the existing Renewable Obligation (RO) support mechanism which closed to new solar accreditations on 31 March 2015, and will cease to be available for other renewable generators from 31 March 2017. As the RO scheme provides 20 years of support to new renewable generation, there will be a mixture of RO and CfD supported plant operating in the GB market well into the 2030s.

A CfD is a long-term (typically 15 year) bilateral private law contract between a low carbon electricity generator and the government-owned Low Carbon Contracts Company (LCCC). The contracts are structured as Feed-in Tariffs (FiTs) in the form of a CfD. These contracts will support a range of low carbon technologies, including nuclear and carbon capture and storage as well as renewables. Generators with a CfD will sell their electricity into the market in the normal way and the CfD will then pay, for each MWh of output, the difference between a Market Reference Price (MRP) for electricity and a contract 'strike price' established through the CfD allocation process. This difference payment may be positive or negative: the generator will receive a difference payment from the CfD if the MRP is lower than the strike price, but will have to pay back the difference if the MRP is higher than the strike price[10].

The CfD in Great Britain (GB) draws upon commercial sources in the calculation of the MRP. The MRP for intermittent CfDs (e.g. wind, solar) is based on the day-ahead market price, whereas the MRP for baseload CfDs (e.g. nuclear, biomass) is based on season-ahead market prices.

2.2 Existing measures in place to limit negative pricing

As low carbon generators under both the RO and CfD mechanisms will receive support payments based on metered output, there may be incentives to sell power into the market at a negative price (up to the level of financial support forsaken, less variable operating costs). In certain periods this could lead to negative prices in the market overall, for example in periods with high wind and/or solar output coinciding with low demand.

Price formation and the fundamental drivers for negative pricing are explained in greater detail in Sections 2.4 and 2.5.

[10] For further details on the Contracts for Difference scheme refer to the DECC website: https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference

In developing the CfD terms and conditions there arose a concern for the potential for 'spiralling' negative prices in the day-ahead market, whereby generators competing for dispatch in a particular period could submit increasingly extreme negative prices into the day-ahead auction in the knowledge that they would be topped up to their strike price. As a result, the CfD issued for the first allocation round contains a provision which caps difference payments at the strike price[11]. This was intended to dampen incentives on CfD plant to generate if the day-ahead price falls below zero, thus allocating some curtailment risk to those generators. This measure limits the potential for prices to fall below the 'minus strike price' level, but does not necessarily limit the potential for prices to fall below zero.

2.3 EU State Aid guidelines

In June 2014, the European Commission published its 'Guidelines on State Aid for environmental protection and energy 2014-20' (the 'Guidelines')[12]. The Guidelines set out the conditions under which new aid measures relating to energy and environment may be considered compatible with the EU Third Package. DECC was required to seek State Aid clearance for both the CfD for Renewables and CM measures, and as such the provisions in these EU Guidelines are applicable.

Section 124(c) of the Guidelines states that all new aid schemes for renewables must include measures "to ensure that generators have no incentive to generate electricity under negative prices". This condition will apply to all new CfDs allocated from 1 January 2016[13]. The condition does not apply to contracts signed prior to this date, such as CfD contracts awarded in the 2014/15 allocation round and the investment contracts awarded in 2014 as part of the Final Investment Decision (FID) Enabling project for Renewables.

In response to the Guidelines, in its August 2014 Statement, DECC updated its policy position as follows:

"To ensure compliance with the new State Aid guidelines on environmental protection and energy, we will make a modification for contracts allocated from the start of 2016. This will introduce a new cap on CfD payments at zero for any consecutive period of 6 hours or longer when day-ahead power auction hourly prices are and remain negative. For periods of less than six hours during which day-ahead power auction hourly prices are negative, CfD payments are capped at the strike price, as previously announced. This does not impact on contracts allocated in the 2014 allocation round, for which payments remain capped at the strike price."[14]

[11] For background and further details on this decision refer to the DECC Annex A Feed-in Tariff with Contracts for Difference: Operational Framework: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65635/7077-electricity-market-reform-annex-a.pdf

[12] http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=OJ:C:2014:200:FULL&from=EN

[13] Although our analysis in this report focusses on the GB electricity market, note that this condition will also be applicable to Northern Ireland CfD contracts.

[14] DECC EMR Stakeholder Bulletin: 1 August 2014 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/347899/1_august_sh_bulletin.pdf

It is in this context that DECC commissioned this study – to better understand the nature and potential extent of negative pricing in the GB market, so as to finalise its policy position for CfDs issued in 2016 in accordance with the EU Guidelines.

2.4 Price formation, bidding behaviour and generator incentives

Before considering future scenarios under which negative prices could occur in the GB wholesale market, it is important first to understand how negative prices could arise. This is a combination of:

- the way generators 'bid' into the wholesale market – in other words how they price their output generation when they sell it
- the incentives for some generators – such as those receiving support payments based on metered generation – which could mean that they are willing to pay to keep generating, and
- the way prices are formed in the wholesale electricity markets.

This section explains each of these important factors in the formation of negative wholesale electricity market prices.

2.4.1 GB wholesale market

The GB wholesale electricity market is a 'bilateral' market based on self-balancing in which power is predominantly traded 'over-the-counter' (OTC) and through exchanges between willing buyers and sellers. The onus is placed on suppliers to meet customer demand by contracting with generators directly or via an exchange for the required volumes. The System Operator, National Grid, is responsible for balancing the system in real-time, and charges market participants for the cost of resolving their imbalances.

Exchange trading – whereby generators, traders and electricity supply companies place bids (for buying) and offers (for selling) on the electricity exchanges, thus determining the demand and supply curves which are used as a basis for determining the prices and the supply volumes – is rapidly growing in importance for near-term trade. Currently, over 40% of the electricity generated is traded on the power exchanges operating in Britain: N2EX, APX-Endex, and ICE.

Prices are determined as follows. The power exchange matches individual bids submitted by suppliers, against individual offers submitted by generators. Whenever there is a 'match' (i.e. a bid equals an offer for a particular period) then a trade occurs. Thus the power exchange takes on the role of broker, and also takes on the role of counterparty, relieving the individual supplier or generator from having to find its own counterparty. Prices reported by the exchange are based on the averages of individual matched trades.

Power exchanges allow participants to buy and sell electricity for each half-hour period. Prices and volumes are different for different half-hours. This is one route for participants to 'fine tune' their positions – generators can match their sales to their likely generation output and suppliers can match their purchases to their overall customers' consumption, on a half-hour by half-hour basis up to 'gate-closure'. This is important because generators and suppliers are cashed out for imbalances (differences between their commercial supply and demand volumes) in the Balancing Mechanism (BM).

Generators / suppliers typically sell / buy a certain proportion of their expected volume in forward markets, and use near-term day-ahead and intra-day markets to optimise their positions and manage imbalance exposure. Near term markets are expected to become increasingly important in the future as the volume of intermittent renewable generation on the system increases near term output variability. The volumes traded on GB day-ahead markets (particularly the N2EX platform) have grown significantly in recent years. There are a number of factors which could increase liquidity further, such as the linking of the intermittent CfD with the day-ahead market via the Market Reference Price.

2.4.2 Market Reference Price

The Market Reference Price (MRP) is a measure of the wholesale price of electricity. It is a key parameter of the CfD contract, and together with the strike price it determines the level of difference payments due to or owed by generators. The MRP is different for intermittent and baseload CfDs:

- For intermittent generators, the MRP will be the GB day-ahead hourly price published under the European market coupling arrangements[15].
- For baseload generators, the MRP will be calculated from season-ahead indices of actual forward trades sourced from LEBA and Nasdaq.

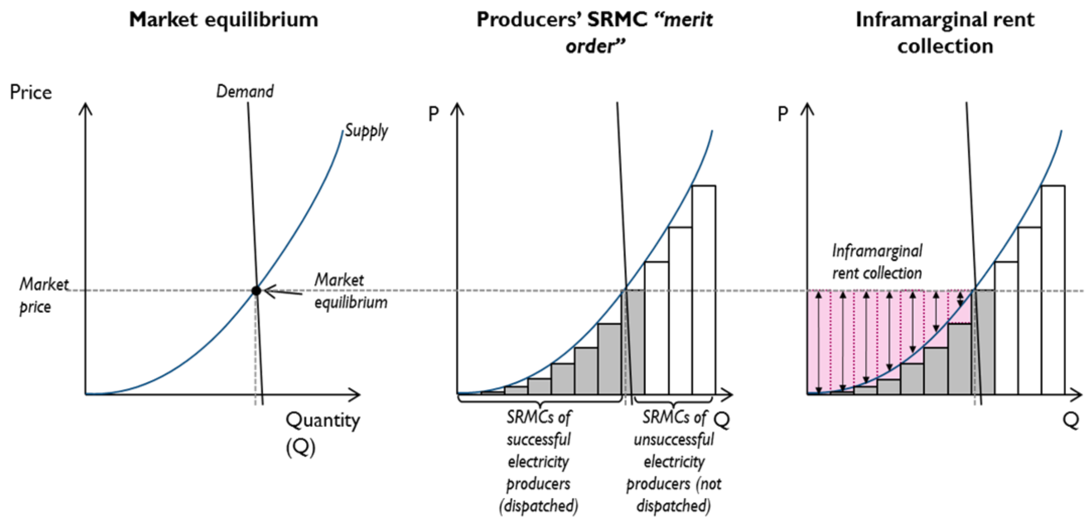
The MRP is subject to review procedures to ensure the price sources are appropriate and robust.

2.4.3 Fundamental bidding behaviour

As with other markets, electricity markets allow buyers and sellers of electricity to trade electricity for delivery at a specific point in time. These agents trade at the market equilibrium price which is governed by the short run marginal costs (SRMC) of producing electricity, competition between producers of electricity, and the quantity of electricity demanded by consumers in the market on the whole – as shown in Figure 1.

[15] Britain is part of the North West European price coupling region, and the N2EX and APX day-ahead exchanges have been coupled with other North West European markets since 'go live' in 2014. In the day-ahead market coupling process, a day-ahead auction for power is run simultaneously in each coupled market, using available cross-border interconnector capacity to clear demand as efficiently as possible using generation resources.

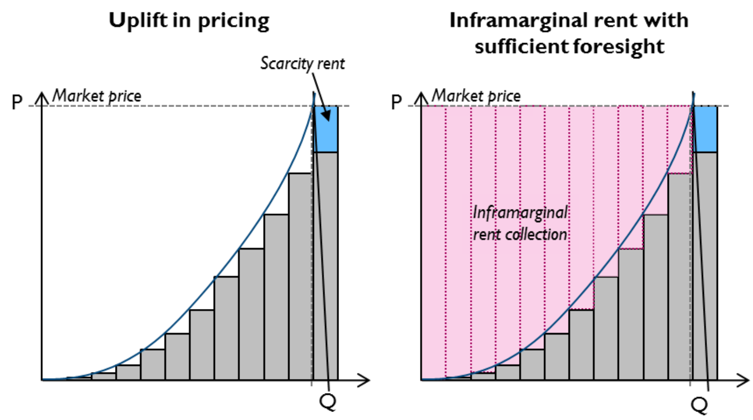
Figure 1 Market equilibrium price



While pricing at SRMC ensures recovery of the variable costs associated with producing electricity output such as fuel costs, electricity producers will still have fixed costs (such as rent, and wages) that are incurred irrespective of output. The ability to collect infra-marginal rent through pricing at the market equilibrium price allows them to meet some of these costs. Different generator technologies have different SRMCs (particularly given different fuel costs), and are therefore able to collect different levels of infra-marginal rent at any given point in time.

Producers with the highest SRMCs will not be able to run often, and will rarely be able to recover infra-marginal rents (if at all). When these producers dispatch, they look to sell their electricity at prices above SRMC, to collect 'scarcity rents' so that they too can pay their fixed costs (see Figure 2 below).

Figure 2 Scarcity pricing



With sufficient foresight of demand, all generators can also take advantage of scarcity pricing when the capacity margin is tight so as to increase levels of infra-marginal rent. For background on our scarcity modelling methodology refer to Section 3.2.4.

Prices could fall below SRMC levels under some circumstances. For example, if a generator is trying to avoid the cost of shutting down and starting up a plant, it may be willing to run at a loss on a SRMC basis – up to the point at which doing so would outweigh the cost saving of the avoided start.

2.4.4 Impact of support payments

Many low carbon technologies have high up-front capital costs but low variable running costs. This is particularly true of renewable technologies such as wind and solar, which can have high fixed and capital costs relative to fossil-fuelled thermal generators such as combined cycle gas turbines (CCGTs), and a low or close to zero SRMC. In the absence of any support payments (subsidies), these low carbon plants would thus typically offer low (at their SRMC) and be 'price takers' in the market. Provided that the long-run power price captured exceeds the long-run levelised costs[16] of the technology in question, the plants could operate in the wholesale market without support.

However, where long-run levelised costs exceed the expected future power prices, support payments are required to enable the investment to proceed. Both the RO and the CfD support mechanisms are intended to provide the 'top-up' required above the wholesale market price to enable the generator to recover its long-run levelised costs. The key difference between the two mechanisms is the level of certainty provided around recovery of these long-run levelised costs. The CfD is designed to maximise certainty while the RO leaves power price risk with the generator. Intra-day power price, volume and balancing risk remain with the generators under both schemes.

Output versus availability

Under the CfD, support payments are linked directly to the volume of output produced and metered. If no output is produced, no support payments will be made in that particular period. This may affect bidding incentives for plant receiving support payments, as it increases the 'opportunity cost' of not producing output. The opportunity cost of lost support payments will in theory be subtracted from the plant SRMC to calculate the marginal bidding incentive for a given period. For example, an onshore wind generator with an SRMC of 1 £/MWh and a support payment of 40 £/MWh would in theory be willing to sell its output at a price of -39 £/MWh. In other words, the generator is willing to pay up to 39 £/MWh to produce output, in return for a support payment of 40 £/MWh (which provides just sufficient revenue to cover its SRMC of £1/MWh). This generator would only elect to self-curtail if the market price fell below -39 £/MWh.

Both the RO and CfD mechanisms are output-based – support payments are made based on metered output – therefore incentives for negative pricing do exist.

2.4.5 Bidding incentives under the RO mechanism

Under the RO, the level of the support payment is set by technology ('banding') and indexed over time[17], but does not vary with the market price. Therefore an RO-supported generator bidding into the market (likely via an offtaker), will have a fairly stable incentive to offer negatively to the value of

[16] Levelised cost is a useful metric for comparing the unit costs (£/MWh) of different technologies over their economic lifetime. The levelised cost of a particular generation technology is the average unit price of electricity at which the plant achieves the specified hurdle rate across a specified timeframe and for a known output level.
[17] The ROC buy-out price is indexed, not the ROC price directly.

the ROC support it receives for each MWh of output. In the onshore wind example above, the generator would always generate when available, unless the wholesale price fell below -39 £/MWh. Bidding incentives will then vary depending on the vintage of the support for a given technology (for example, onshore wind in receipt of 1 ROC vs 0.9 ROCs will have marginally different incentives), or different levels of support for other technologies with a different cost base (offshore wind with 2 ROCs will have stronger incentives to offer negatively and remain on the system). The outturn market price will be determined by the marginal plant on the system in a given period.

2.4.6 Bidding incentives under the CfD for Renewables mechanism

Under the CfD mechanism, the support payment is calculated as the difference between the fixed Strike Price and the variable Market Reference Price. The strike prices are to be set via the CfD allocation process, either on a competitive basis through auctions[18] for specific technology groupings (established and less established) or bilaterally[19]. These strike prices will vary for plants depending their technology grouping, the allocation year (vintage), and the delivery year. The reference price will vary depending on the technology type – day-ahead for intermittent generation (such as wind and solar) and season-ahead for baseload generation (such as nuclear and biomass conversion). As the support payment will be based directly on the difference between strike price and Market Reference Price, generators will have an incentive to sell their power into the applicable reference market so as to earn the reference price and guarantee recovery of the strike price (leaving aside residual intra-day volume and balancing risk).

The opportunity to earn the strike price for a MWh of output means that CfD plants will be willing to submit a negative offer into the reference market to ensure dispatch. In fact, if there was no cap on difference payments, in theory there would be no floor to the price at which the generator would be willing to submit – there could be a 'spiralling' negative price in which generators offer increasingly extreme negative prices in the knowledge they will be topped up to their full strike price. DECC recognised this potential issue, imposed a cap on the difference payments at the level of the strike price. Therefore under the current arrangements, CfD-supported generators will have an incentive to offer down to minus strike price in the reference market, but no lower (as to offer lower would imply production below SRMC).

Actual support payments will then vary with the outturn price in the reference market, which will then affect bidding behaviour in subsequent markets leading up to real-time. Take the example of an onshore wind generator with a CfD strike price of 90 £/MWh and an SRMC of 1 £/MWh, selling all of its output in the day-ahead reference market. The generator / offtaker would submit an offer of minus strike price into the day-ahead market, signalling its willingness to produce output for any outturn price above this level. Then suppose that there is a situation of excess renewables in the day-ahead market, and the price outturns at say 0 £/MWh. This would give support payments to the generator equal to its strike price, of 90 £/MWh for that hour. For any volumes above the day-ahead forecast, the generator would now have an incentive to offer up to -89 £/MWh (SRMC less support

[18] If an auction is undersubscribed or clears above the administrative strike price for a particular technology grouping, then the strike price is the administrative strike price.

[19] Eight renewable electricity projects have been offered investment contracts through Final Investment Decision Enabling for Renewables (FIDeR) with strike prices agreed bilaterally through an administrative process. The Government's FIDeR programme is designed to enable developers of low carbon electricity projects to take final investment decisions ahead of the competitive CfD allocation regime being put in place.

payments) in the intra-day and balancing markets, which reflects its opportunity cost of not producing the extra output in that period.

2.4.7 Conclusions on bidding incentives for supported plant

In summary, there are incentives for generators to submit negative bids into the market under both the RO and CfD mechanisms. Table 2 summarises the bidding incentives for RO plant and intermittent / baseload CfD plant.

Table 2 Summary of fundamental support-related bidding incentives under RO and CfD[20]

Support type	Day-ahead market	Intra-day market
RO	Minus ROC × Banding Factor	Minus ROC × Banding Factor
Intermittent CfD FiT	Minus strike price	Minus day-ahead difference payment
Baseload CfD FiT	Minus season-ahead difference payment	Minus season-ahead difference payment

For plant supported under baseload CfDs – such as new nuclear and biomass conversion – the Market Reference Price is the season-ahead price. This means that the level of CfD payments will be established in advance at the season-ahead stage. In both the day-ahead and intra-day markets, baseload CfD plant would be incentivised to offer minus the season-ahead difference payment. The incentives therefore appear similar to those for intermittent CfDs at the intra-day stage.

The extent to which this translates into negative wholesale prices depends on the supply-demand balance in the period in question, which we discuss further in Section 2.5 below.

2.5 Drivers of negative pricing in the GB market

In the previous section we explained how the incentives for negative pricing come about – primarily as a consequence of support payments influencing generator behaviour. However, the incentives to offer negatively for individual generators does not necessarily translate into negative wholesale prices overall. In this section we explore the key drivers for negative prices in the GB context.

2.5.1 Drivers for negative prices in GB

The wholesale electricity price is driven by the economics of the marginal plant required to meet demand on the system and the competitive dynamics in each period. For example, if the marginal plant is a CCGT, the wholesale price will be determined by the SRMC of this unit (taking into account fuel and carbon costs, other variable costs and plant efficiency) plus any additional 'uplift' to cover start costs or to earn 'scarcity rent'[21]. Likewise, if the marginal plant required to meet demand is an onshore wind RO-supported plant, the wholesale price will be determined by its SRMC and opportunity cost of not producing which includes lost support payments. Only if the marginal price-

[20] 'Final' bids will also take account of variable generation costs, such as the cost of fuel for biomass conversion plant.
[21] 'Uplift' may be negative if the generator is trying to avoid shut-down / start costs.

setting plant is receiving a support payment, or is an inflexible plant looking to avoid the costs of shutting down and starting up in its bids, should the GB wholesale electricity price be negative overall. This could occur in periods when the volume of available generation (total potential electricity supply) willing to offer a negative price – those receiving support payments, plus other forms of inflexible generation – exceeds demand. This is referred to as a 'long energy market' or over-supply.

The potential future materiality of DECC implementing the '6+ hour negative price event' rule for CfDs for Renewables is therefore linked to the question: how likely is it that plant receiving support payments (or other forms of inflexible generation) will be 'at the margin' in the GB market in future, and under what scenarios will this occur more or less often?

In combination with generator bidding incentives, other potential drivers of negative prices in both day-ahead and intra-day markets include:

- **Generation mix**: the volume of supported low carbon generation on the system will influence the extent to which these plant become marginal, as will the flexibility of other generation[22], and the amount of flexibility that can be provided by storage, demand-side response (DSR) and interconnection.
- **Demand profile**: the level and shape of demand will also influence the extent to which we observe a long energy market. For example, we would expect to see an increased number of over-supplied periods in scenarios with lower demand (all else being equal). Also, the amount of flexibility on the demand side, for example customers reacting to time of use signals, will have an impact.
- **Interconnector flows**: the flexibility of interconnectors to respond to price signals across both day-ahead and intra-day timeframes will influence the extent to which supported plant becomes marginal. For example, exports from GB can reduce the risk of negative prices occurring to the extent there is export capacity available.
- **Forecast uncertainty**: the degree to which outturn generation differs from day-ahead forecast will influence the extent to which a long energy market (supply exceeds demand) is observed in intra-day markets (even if the day-ahead market was not oversupplied relative to demand).

Our scenario and sensitivity analysis has investigated the impact of each of these factors on negative price outcomes.

Another important consideration is the potential for System Operator (SO) actions that could mitigate the extent of a long energy market. For example, if there is low demand and an excess of wind forecast on the system, the SO could intervene in the market or Balancing Mechanism for system stability reasons – for example, to ensure there is enough reserve available. It could pay some wind generators to curtail their output whilst at the same time paying some flexible / controllable plant to turn on. This will not necessarily reduce the risk of negative pricing.

[22] The GB generation fleet is becoming less flexible as fossil fuelled plant close to be replaced by non-dispatchable generation.

2.5.2 PPA contracting

Generators typically sell their output to suppliers under long-term PPAs, with the supplier managing the sale of the output – and potentially any associated ROCs and Levy Exemption Certificates[23] (LECs) – for the duration of the PPA in exchange for a fee which is typically expressed as a 'discount' on the market price.

The discount charged by the offtaker will reflect a number of factors, including:

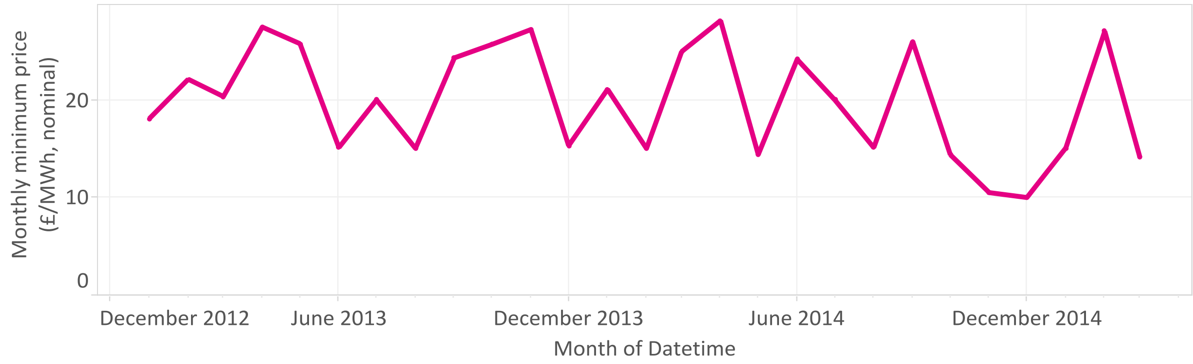
- **Expected imbalance costs**: the offtaker will charge a fee to reflect its expected cost of managing the imbalance associated with the generator's output as well as an assessment of likely imbalance prices in future. This will apply to PPAs for both RO and CfD-supported plant.
- **Whether a 'floor' price is included**: the offtaker will charge a fee for providing a guaranteed floor price for generation. This is typically included in PPAs for RO-supported plant, but is not required for CfD-supported plant given the long term revenue certainty provided by the CfD mechanism itself.
- **Expectations on negative prices**: the offtaker may charge a fee to reflect expected negative prices in the wholesale market, if these prices cannot be passed through directly in the PPA. Offtakers may choose to quote discounts in absolute £/MWh terms rather than as a percentage of the reference price, to protect themselves against low or negative prices. This may be a key contract term in PPAs for CfDs without a floor price in place.
- **The extent of competition** in the PPA market: more generally, the offtaker may be able to earn an additional margin for managing offtake, if there is a lack of competition in the provision of such services in the market.

2.6 Historical GB day-ahead and intra-day prices

To date there have been no incidences of negative prices in either the GB day-ahead or intra-day markets. Figure 3 charts the minimum hourly price on the N2EX day-ahead exchange for each month since December 2012. Monthly minimum prices have generally remained in the range 15-25 £/MWh over this period, dropping to around 10 £/MWh in the final two months of 2014 – but still firmly in positive territory.

[23] LECs are tradable certificates awarded to new renewables and Good Quality CHP which suppliers can purchase as an exemption from the Climate Change Levy (CCL).

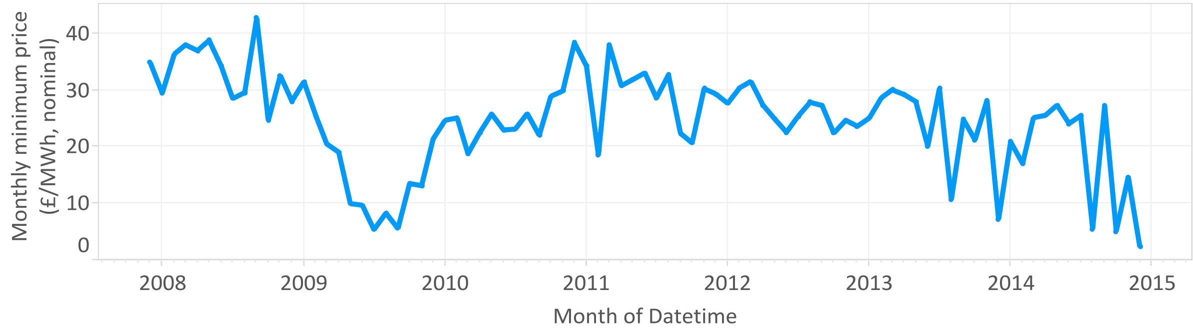
Figure 3 Monthly minimum N2EX day-ahead exchange prices



Intra-day prices have fallen to very low positive levels recently in the APX Power UK market as shown in Figure 4. Low positive price levels occurred in mid-2009, although these were at least partly caused by low commodity prices. More recently, there has been a notable downward trend in APX Power UK minimum prices since late 2010 – while installed low carbon generation capacity has increased significantly over the same period. Over the period since December 2012, minimum prices have generally been lower in the intra-day market versus the N2EX day-ahead.

In December 2014, intra-day prices dropped to a low of 2.2 £/MWh during a period of particularly high wind output. As the penetration of low carbon generation capacity such as onshore and offshore wind increases, there is the potential for the low positive prices historically observed intra-day to become negative in this timeframe as subsidised generators compete to remain on the system during periods of low demand and high wind output[24].

Figure 4 Monthly minimum APX Power UK intra-day prices



Closer to real time, negative bidding has been observed in the BM – and negative cash-out prices have already occurred in recent years. Detailed modelling and analysis of the balancing market was outside the scope of this study, but it is likely that further negative price events will occur in the balancing market, sooner than in the day-ahead or intra-day markets.

[24] Since the analysis was completed in March 2015, we have observed negative prices on the APX intra-day market in a number of periods (during May and June 2015). These occurred during the night in periods of high wind output and low demand.

3 Methodology and assumptions

3.1 Introduction

Based on the policy and market context outlined above, we have undertaken forward-looking analysis to project how often negative prices could occur in the future under different scenarios, and the potential duration and depth of negative price events. In this section we describe the methodology which was used in our analysis, and the assumptions which underpin the two core scenarios.

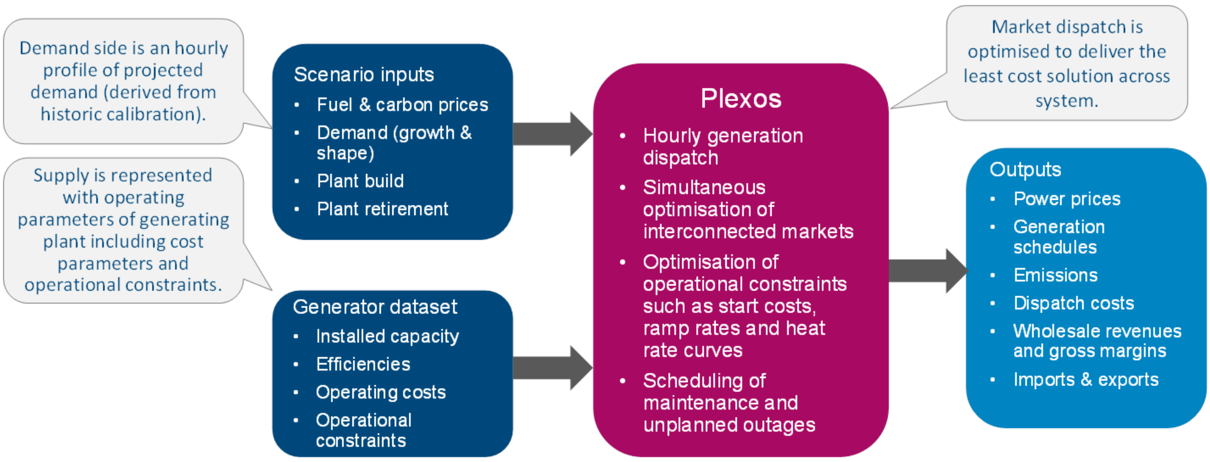
3.2 Modelling approach

3.2.1 PLEXOS market modelling

At the heart of our electricity market modelling lies a powerful dispatch 'engine' based on a detailed representation of electricity market supply and demand fundamentals at an hourly granularity. We run our models on commercially available software known as PLEXOS. It is used globally by power market participants, regulators, and analysts for modelling power systems with a diverse range of characteristics.

Figure 5 illustrates our PLEXOS market modelling approach at a high-level.

Figure 5 PLEXOS market modelling approach



The tool is used to model electricity system dispatch on a forward-looking basis, using key input assumptions on for example demand, capacity mix, fuel and carbon prices, and the level of interconnection. Variability in low carbon generation, demand and spot gas prices (relative to forward market prices) is captured through sampling of historic data sets. Details of the GB capacity mix and generator technical parameters are based on Baringa assumptions, sourced from publicly available information.

PLEXOS then dispatches the system on an hourly least cost basis, taking into account the operational constraints of the capacity on the system, as well as both planned and unplanned maintenance. Our

GB model includes a full representation of interconnection capacity and the capacity mix in interconnected markets, to enable simultaneous optimisation of GB with neighbouring markets on an hourly basis.

Key outputs from the model include hourly system marginal prices (including an uplift to reflect scarcity value), generation load factors, CO_2 emissions and interconnector flows.

We have adopted a multi-pass approach as described below to model the dynamic interaction between day-ahead and intra-day markets. Under this approach, for each hourly period we produce a day-ahead price and an intra-day price which may differ as expectations of supply and demand evolve through time. Since the intra-day market is a continuous one, it would be possible in theory to envisage numerous model passes to represent the evolution of intra-day prices. However, for simplicity we have adopted a single second pass to produce a 'typical' intra-day price – this is broadly equivalent to a single intra-day auction. This allows the key questions of likely timing, frequency and duration of negative prices in the day-ahead and intra-day markets to be addressed using an appropriate level of analytical detail.

3.2.2 Multi-pass modelling approach

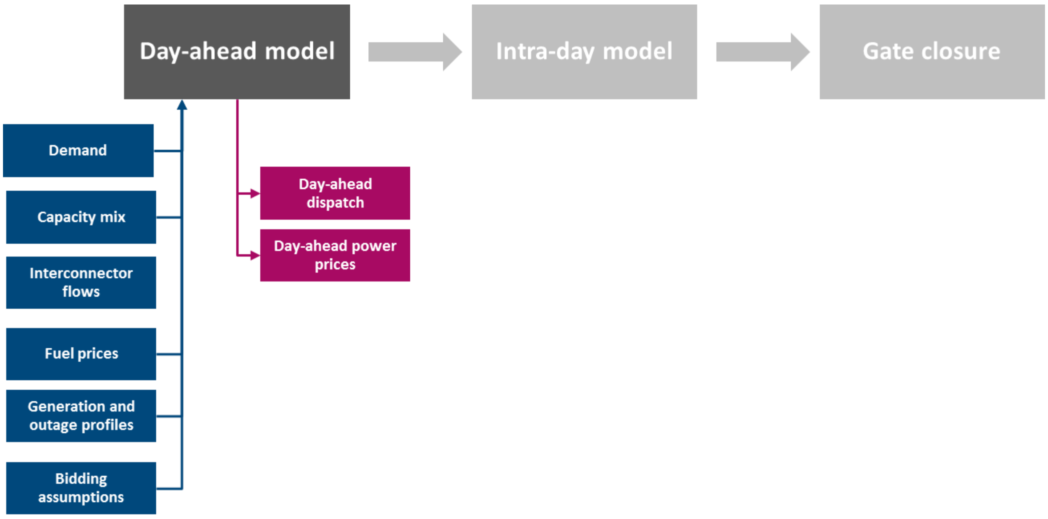
We have adopted a two-stage model to explore the timing, frequency and duration of negative pricing in both the day-ahead and intra-day markets. We discuss each modelling stage in turn below.

Day-ahead market modelling

First we simulated the GB day-ahead market, following the process described above. We ran this model for the core scenarios and sensitivities out to 2040.

Figure 6 illustrates the key inputs and outputs at the day-ahead modelling stage.

Figure 6 Day-ahead market modelling approach



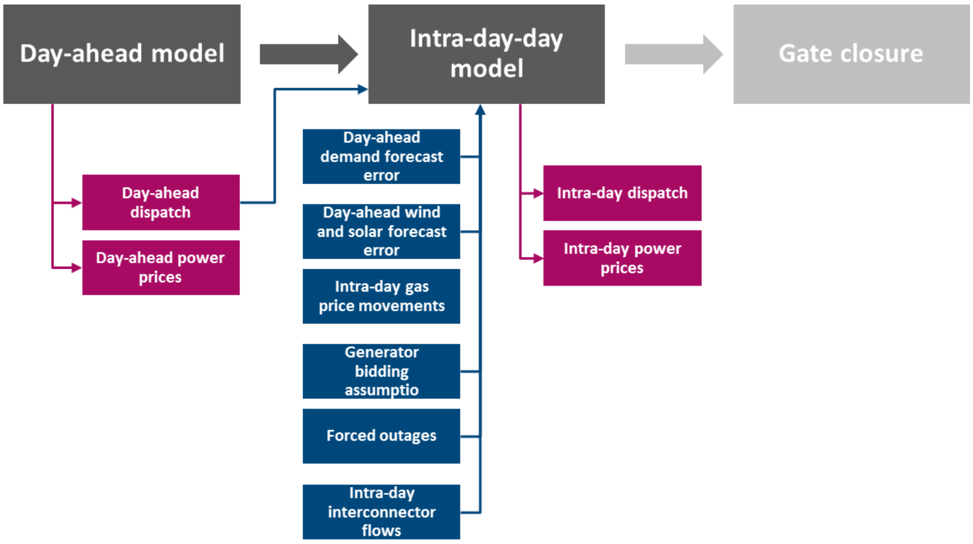
Key inputs to the model include generator bidding assumptions, in particular for plant receiving either RO or CfD support. The other key inputs used in the analysis are discussed in Section 3.3 and 3.4.

The main outputs from this stage include the hourly day-ahead price, the number of hours of with negative prices per year, and the duration of these negative pricing periods. The key output to 'pass' through to the next modelling stage is the day-ahead dispatch position for each unit.

Intra-day market modelling

The second stage of our modelling simulates the GB intra-day market, as illustrated in Figure 7 below.

Figure 7 Intra-day market modelling



Taking the day-ahead dispatch position as the starting point, in this modelling stage we have layered in the following:

- day-ahead forecast errors for demand and wind (calibrated from historical profiles)
- intra-day gas price movements (calibrated with historical data)
- intra-day interconnector flows, and
- intra-day generator bidding assumptions (which will change with the outturn day-ahead price each period)

These input parameters are intended to simulate the real-world fundamentals at play in the ID, in moving from a day-ahead position to a market closer to real-time (indicatively six hours ahead). PLEXOS re-dispatches the market taking into account this 'new information', while respecting the unit commitment decisions made at the day-ahead stage, and the operational constraints of the different plant types.

3.2.3 Plant dynamics

Our modelling takes account of individual plant dynamics, capturing a range of technical generator constraints, including:

- start-up costs

- no-load costs
- start times
- ramp-up and ramp-down rates, and
- minimum on and off times.

3.2.4 Scarcity pricing

Our methodology for modelling scarcity rent involves a calibration exercise whereby we:

- use historical fuel prices and dispatch results to compute the short run marginal cost of the system
- compare this with the market price to compute the difference which we term scarcity rent, and
- regress this premium against the capacity margin in order to determine the relationship used in our modelling.

Typically, scarcity rent is only material in around 20-30% of hours in the year. Scarcity value can fall negative during periods of oversupply as some generators may be willing to continue generating at a price below their SRMC to avoid incurring shut-down and start-up costs.

Scarcity rent is a function of volatile market forces, and its forecast depends on the extension of historical trends. It is possible that in future, when variable renewable sources account for a large proportion of generation and capacity markets begin to have an impact, these trends may break down and outturn levels of scarcity rent may diverge from our projections.

3.3 Core scenarios

We have explored the potential for negative prices in the GB wholesale electricity market in future under two alternative market scenarios:

- **Market scenario** – a 'market-credible' central case independently developed by Baringa using the same methodology we provide to commercial clients. In this scenario the Government pursues a balanced energy policy which attempts to meet the competing demands of security of supply, competitive market structure and environmental sustainability.
- **Policy scenario** – uses assumptions provided by DECC and which is consistent with UK Government current policy objectives and DECC's central 2014 Updated Energy Projections (UEP).

There are a number of key differences between the two scenarios. For example, the Policy scenario assumes a higher long-term electricity demand than the Market scenario, combined with greater efficiency savings in the short term. Another key differentiator of these scenarios is the future generation mix, with the assumptions on levels and proportions of flexible and inflexible low carbon generation capacity differing across the two scenarios. While the Policy and Market scenarios are relatively close in levels of wind installed capacity up to the early 2020s, in the long term the Policy scenario has higher wind build-out. Nuclear capacity is significantly higher in the long term in the Policy scenario, while the Market scenario has higher interconnector capacity in the short to medium term. As a result we should expect to see greater risk of negative pricing in the Policy scenario relative to the Market scenario.

Sections 3.3.1 and 3.3.2 describe the key input assumptions for each scenario in more detail, along with further background and the driving principles for each scenario. Refer to Appendix A for a full description of input assumptions.

3.3.1 Policy scenario

Scenario background and principles

The Policy scenario has been developed based on the assumptions set out in DECC's 2014 Updated Energy Projections (UEP) Reference scenario. The projections take account of government policies that affect energy use and greenhouse gas emissions where funding has been agreed and decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made. Under this scenario, it is assumed that Electricity Market Reform will result in a carbon intensity of generation of 100 gCO_2/kWh by 2030[25].

3.3.2 Market scenario

Scenario background and principles

The Market scenario is an independent case provided by Baringa which we have constructed using the same methodology we apply when working with our commercial clients. We do not explicitly assign probabilities to our scenarios, but the Market scenario is designed as a 'central' or 'expected' view of the world. The Market scenario is discrete and intended to be internally consistent in terms of both the various input assumptions and scenario results. The main characteristics of the Market scenario are shown in Figure 8.

Figure 8 Market scenario key characteristics

Baringa independent, in-house view	**Market credible**	**Renewables**: growth continues –2020 electricity targets met
Demand growth: moderate	**Fuel prices**: rise moderately in real terms	**Carbon**: becomes an important cost factor in the long term
Thermal capacity: continues to play an important role, with new additions primarily flexible	**New investment**: takes account of capacity and other revenues outside the energy market	

[25] For a detailed description of the rationale and principles behind the 2014 UEP Reference scenario refer to the DECC report 'Updated energy and emissions projections 2014':
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/368021/Updated_energy_and_emissions_projections2014.pdf

In this scenario, the government continues to pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability. The Market scenario assumptions take full account of the impacts of EMR. Two key input assumptions for the modelling include the de-rated capacity margin procured through the Capacity Market based on the target three hour loss of load expectation (which influences assumptions on new build and retirements for non-low carbon plant), and the UK Government decarbonisation targets to be met through CfD and other support mechanisms (which influences new build assumptions for low carbon plant).

3.3.3 Key scenario input assumptions

In this section we outline the key assumptions used in both the Policy and Market scenarios, focusing on those which are of particular relevance to negative price outcomes[26]. Input assumptions for the two core scenarios are presented on the same chart in this section to facilitate ease of comparison and highlight differences.

Figure 9 compares the nuclear capacity build profile and total GB interconnector capacity assumptions for the Policy and Market scenarios. Nuclear capacity is significantly higher in the long term in the Policy scenario (just under 9 GW of additional capacity), which has the potential to increase the number of negative price periods relative to the Market scenario, subject to the assumed nuclear plant dynamics and bidding behaviour. The Market scenario has higher interconnector capacity in the short to medium-term, with the capacity in both scenarios trending to a similar level of around10 GW by the late 2030s.

Figure 9 Nuclear capacity (LHS) and total GB interconnector capacity (RHS) assumptions

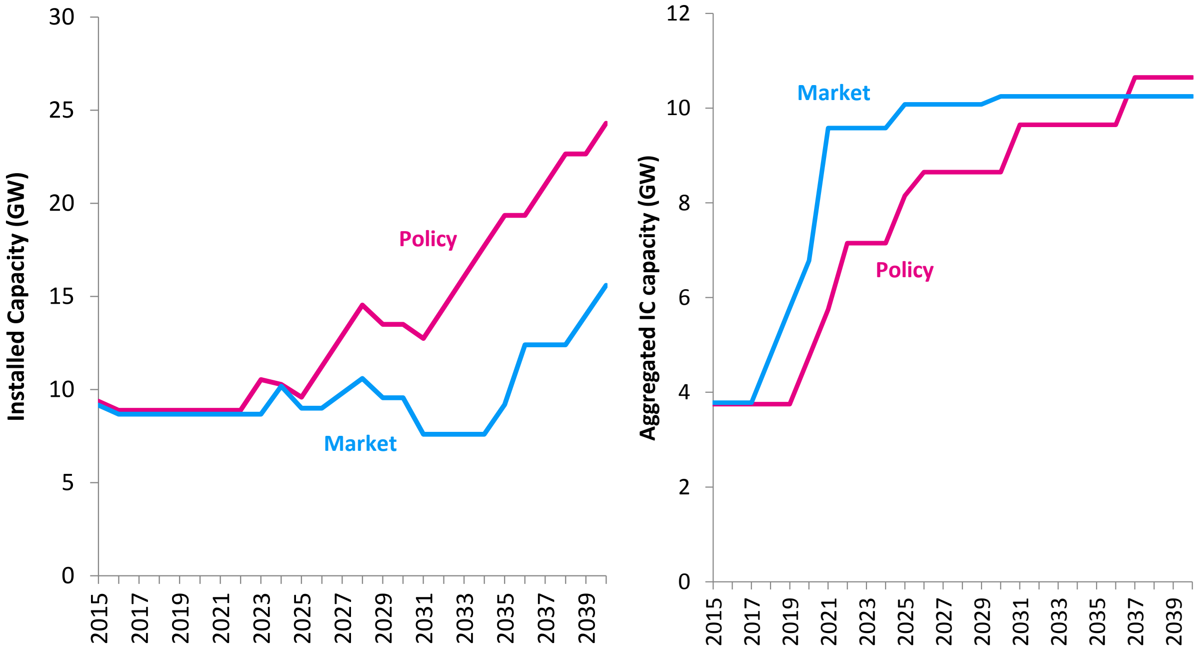
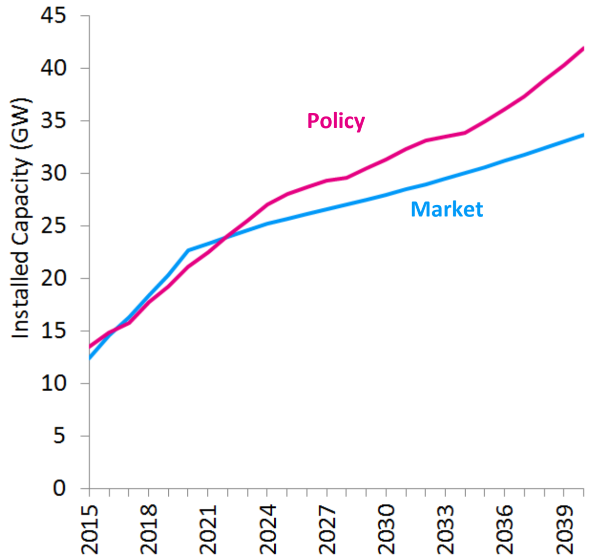


Figure 10 outlines the total wind installed capacity assumptions for the Policy and Market scenarios. Both scenarios follow a relatively similar trajectory to 2020 in accordance with budget availability

[26] Further details on input assumptions are provided in Appendix A.

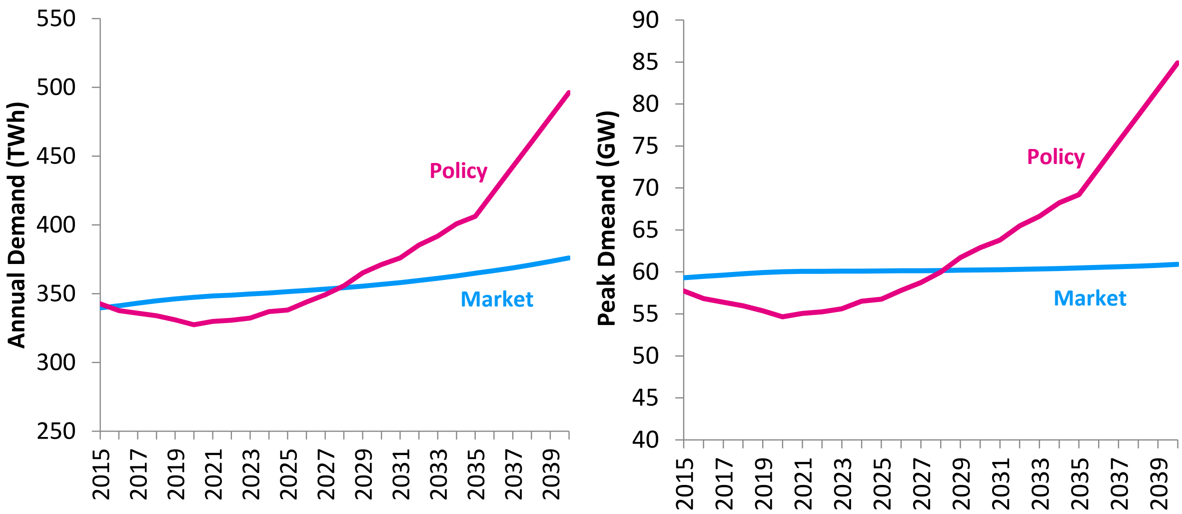
under the Levy Control Framework (LCF)[27]. In the long term, the Policy scenario has just over 8 GW more wind installed capacity than the Market scenario.

Figure 10 Installed wind capacity assumptions



Demand assumptions also differ across the two scenarios as shown in Figure 11. Greater efficiency savings are assumed in the short term in the Policy scenario, leading to lower annual and peak demand. The Policy scenario assumes greater electrification in the long term compared to the Market scenario, resulting in significantly greater annual and peak demand by the end of the modelled timeframe.

Figure 11 Annual GB electricity demand (LHS) and peak GB electricity demand (RHS)



[27] The LCF is effectively a total level of support available for renewable and low carbon generation from Government. Refer to the 2013 LCF Update for further details: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223654/emr_consultation_annex_d.pdf

3.4 Common assumptions

The following section sets out some of the main assumptions which were held constant across both of the two core scenarios in our analysis of the day-ahead market.

3.4.1 Day-ahead generator bidding

Bidding assumptions vary by generator type and modelled timeframe (day-ahead versus intra-day). We have kept generator bidding assumptions constant across the Policy and Market scenarios. The bidding assumptions assumed in the day-ahead timeframe are summarised in Table 3, and each is discussed in more detail below.

Table 3 Day-ahead generator bidding assumptions (Policy and Market scenarios)

Generator type	Core scenario bidding assumption	Comments
Nuclear	▸ Modelled offer level of -999 £/MWh ▸ Will be the last technology to turn off	▸ May be a significant driver of negative pricing – 'displacing' other low carbon capacity in the merit order
RO-supported plant	▸ Offers minus ROC value times RO banding factor, plus SRMC	▸ Offers may be discounted further due to commercial / technical shut-down / start-up costs
CfD-supported plant	▸ Always offers minus strike price ▸ Administrative strike prices assumed for CfD-supported plant ▸ New CfD contracts assumed available throughout the modelled timeframe ▸ Strike price for Carbon Capture and Storage (CCS) gas is set equal to offshore wind	▸ Offer behaviour could change if a 6+ hour negative price event is expected ▸ Lower strike prices may emerge through competitive price discovery ▸ CfD support could end sooner for some technologies ▸ Bids may be discounted further due to commercial / technical shut-down / start-up costs
Small scale FiT supported plant	▸ Offer at minus FiT level	
Non-supported low carbon plant	▸ Offer at SRMC of production without further discount	▸ Offers may be discounted further due to commercial / technical shut-down / start-up costs
Must-run plant	▸ Run in model to meet must-run constraint – no explicit offer assumption	
All plant	▸ Final modelled offer levels take account of variable operation and maintenance costs, fuel and	

	carbon costs, generator BSUoS[28] and losses	

Nuclear plant

In the two core scenarios we have assumed that nuclear capacity operates inflexibly and that they will be the last generators to self-curtail[29]. This is achieved in the model by assuming a very negative day-ahead offer price of -999 £/MWh which results in nuclear capacity having the lowest (or most negative) short run marginal cost of all generators, driving it to the very bottom of the merit order. The assumed inflexibility of nuclear plant, is likely to be a significant driver of negative prices as this capacity will 'displace' other low carbon capacity in the merit order. This assumption provides a 'lower bound' for the flexibility of nuclear. It is possible that more flexible technologies may be deployed for future nuclear new build. However, it is likely that such plants would themselves be supported via baseload CfDs and so would still be incentivised to offer negatively in order to avoid reducing their output.

RO-supported generators

We have assumed that any generators receiving a payment under the RO are willing to offer into the day-ahead market down to minus the ROC value times their technology-specific RO banding factor (the opportunity cost of their subsidy) net of any variable production costs. We have taken a ROC buy-out price of 42.35 £/MWh (real 2014) as an approximation for the ROC value.

CfD-supported plant

We have assumed that CfD-supported generators will offer at minus their strike price in the day-ahead market, net of any variable production costs. For simplicity, we have used DECC's administrative strike prices for all technologies[30]. The results of the first CfD allocation round[31], published on 26 February 2015, were not available in time to include the outturn strike prices in this analysis. Although outturn strike prices from this first competitive CfD allocation round are lower than the administrative strike prices (for all technologies except Energy from Waste CHP), this will have no impact on the results of our analysis in terms of the frequency and duration of negative price events in either modelled scenario[32].

[28] We have assumed that Balancing Services Use of System (BSUoS) charges continue to apply to generators throughout the modelled timeframe.

[29] It is very costly to turn off a nuclear power plant since the minimum off time can extend to several days, and there is limited evidence that existing GB nuclear plants are technically able or willing to reduce below full output.

[30] DECC Contract for Difference: Final Allocation Framework for the October 2014 Allocation Round, Appendix 1:https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/404405/Contract_for_Difference_Final_Allocation_Framework_for_the_October_2014_Allocation_Round.pdf

[31] For details of the Contracts for Difference Allocation Round One Outcome refer to: https://www.gov.uk/government/statistics/contracts-for-difference-cfd-allocation-round-one-outcome

[32] This is because CfD-supported plant are rarely the marginal 'price setting' generator in our analysis as they have amongst the lowest (most negative) offer levels and are some of the last generators to be curtailed. Lower CfD strike prices would result in a less negative offer level, but the change would not be sufficient to materially affect the bidding 'merit order'. This means that there would be no impact on the frequency of negative price events in our analysis, and a minimal impact on the magnitude of negative prices.

We have also assumed that new CfD contracts will be available throughout the modelled period, such that new low carbon generators commissioning beyond 2020 – the current horizon of the Levy Control Framework (LCF) – will be eligible for a support payment under the CfD mechanism in its current form. It is possible that if CfD support ended sooner for some technologies, negative price outcomes may change. For gas-fired Carbon Capture and Storage (CCS) units, we have assumed strike prices in line with those for the 'less established' technology group.

Small-scale FiT-supported plant

We have assumed that these generators will be willing to offer at minus their fixed FiT support level (varying by technology type), net of any variable operating costs. They are willing to sacrifice up to the net opportunity cost to remain generating and receive the FiT support which is paid based on output.

Unsupported low carbon plant

Once a generator's support mechanism expires (RO or CfD), we assume that these generators will offer into the day-ahead market at their variable cost of production until the end of their economic lifetime. For the majority of renewables this value will be a low but positive number.

At the end of their economic life we have assumed that wind and solar plant will re-power on a merchant basis – that is, they will refurbish and continue generating but without receiving any low carbon support payment from a government scheme.

With the future implementation of marginal cash-out pricing in the BM under the Electricity Balancing Significant Code Review (EBSCR)[33] there will be a higher risk of more negative cash-out prices. This may increase the likelihood of negative prices in intra-day and day-ahead markets, although the impact is uncertain at this stage. It is possible that for this and other reasons, actual bids for non-supported low carbon plant could fall below the SRMC level or become negative, and we have explored this in our analysis of the intra-day timeframe the assumptions for which are discussed in Section 3.4.3.

Must-run plant

There is no explicit bidding assumption for must-run generators in our modelling. Instead a 'must-run' constraint is specified for these generators in model which is then met in the most economical way.

3.4.2 Day-ahead bidding merit order

Figure 12 brings together our bidding assumptions and presents an approximate indication of the resulting day-ahead low carbon generator bidding merit order applied in the Policy and Market scenarios.

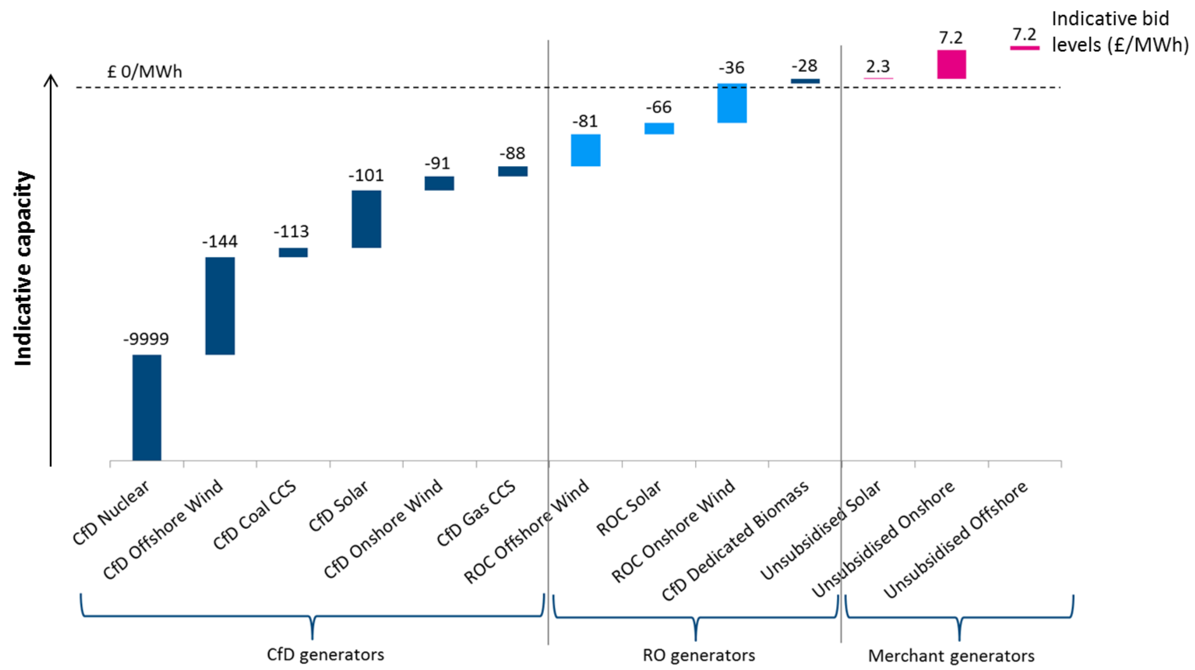
Under these bidding assumptions, CfD generators offer at the lowest (most negative) price, followed by RO-supported generators and finally non-supported generators. Exceptions to this trend are:

[33] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

- dedicated biomass plant with CHP, which have a net negative offer after accounting for biomass fuel costs which lies between RO-supported onshore wind and unsubsidised solar / wind, and
- biomass conversion plant which have a net positive offer after accounting for biomass fuel and other variable costs (not shown on the chart).

This illustrative merit order indicates why it is unlikely that CfD-supported plant will be marginal or 'price setting' during negative price periods, at least in the short to medium-term. For CfD generators to be price setting, demand in a particular period would need to be met by nuclear, must-run generators and CfD generators alone. With GB minimum demand of around 22 GW[34], there is insufficient available capacity bidding at or below the CfD-supported level to set the price in most years of our analysis.

Figure 12 Day-ahead low carbon generator bidding assumptions



3.4.3 Intra-day generator bidding

Potential for further offer discounts

As discussed in Section 2.6, negative prices have not been observed to date in the GB day-ahead market. However, negative prices and evidence of negative bidding have emerged close to real time in the balancing mechanism (BM)[35]. Figure 13 presents BM bid levels for onshore and offshore wind generators in Q4 2014.

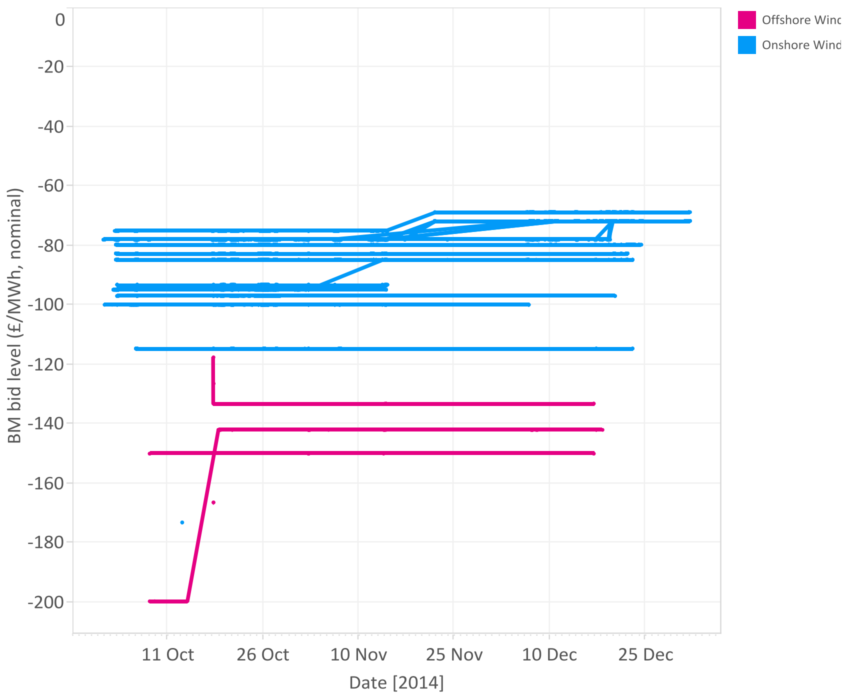
[34] Minimum modelled hourly demand for 2015 (includes demand met by embedded generation).

[35] Since the analysis was completed in March 2015, we have also observed negative prices on the APX intra-day market in a number of periods (during May and June 2015). These occurred during the night in periods of high wind output and low demand.

Assuming that these wind generators are supported under the RO, the BM offer levels appear to be below the 'minus subsidy payment, net of variable operating costs' level. This indicates that wind generators are further discounting their bids, particularly close to real time, in order to avoid curtailing their output or turning off. The technical and commercial conditions underpinning the bids in the BM are unknown. However, this additional discount may reflect factors such as:

- technical shut-down / start-up costs
- commercial shut-down / start-up costs
- other commercial or contractual incentives such as output maximisation clauses, or
- pricing in the risk of technical failure.

Figure 13 Historical BM bid levels for wind generators (Q4 2014)



Intra-day bidding assumptions

In the intra-day timeframe, we have adjusted the bidding assumptions for low carbon generators compared to the day-ahead bids in two main ways.

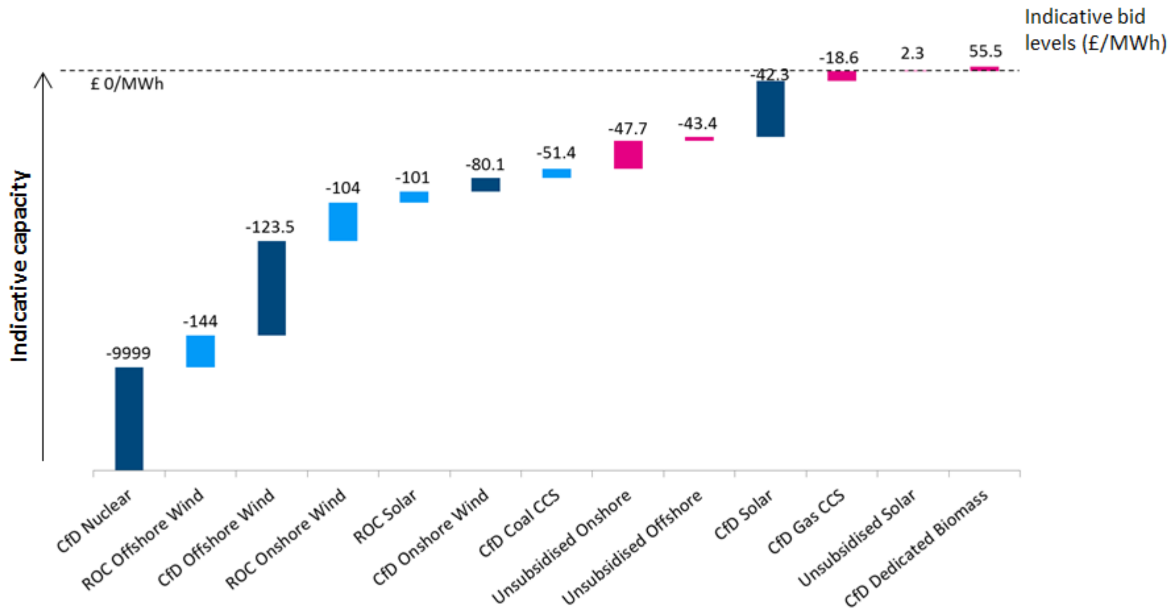
1. Support levels for intermittent CfD-supported generators such as wind and solar are fixed after the day-ahead timeframe as their CfD Market Reference Price (MRP) is the day-ahead market price (see Section 2.4). Therefore, intra-day we have assumed first that all intermittent CfD generators will offer at a level equivalent to minus their day-ahead difference payments, net of any variable production costs.
2. To analyse the potential impact of wind generators pricing these factors into their bids closer to real time as discussed above, we have additionally assumed that all wind generators (irrespective of whether they receive a support payment or not, or the type of support payment if relevant) discount their offers further intra-day to avoid incurring technical or commercial shut-down / start-up costs.

To estimate the discount levels of onshore and offshore wind plant intra-day we have analysed recent offer levels submitted by existing wind generators in the BM. Figure 13 provides a snapshot of offer levels for Q4 2014 and shows that a clear gap between offshore and onshore wind offer levels. We have assumed that wind generators are operating under the RO (rather than non-supported) and have estimated the additional discount being applied by netting off the opportunity cost of their assumed RO support payment from the offer submitted.

Intra-day bidding merit order

Figure 14 shows how the indicative low carbon generator bidding merit order for the two core scenarios changes at the intra-day timeframe based on these revised bidding assumptions. A more 'mixed' merit order picture emerges – with no clear 'blocks' of CfD, RO or non-supported capacity – intra-day compared to day-ahead due to the adjusted bidding assumptions, particularly for wind capacity.

Figure 14 Intra-day low carbon generator bidding assumptions



3.4.4 Interconnector flexibility

Interconnectors can potentially act to increase or decrease the frequency of negative price events, depending on the relative price dynamics in the interconnected markets. As part of this analysis we have investigated the influence of interconnector flows on the incidence of negative price periods in GB and the extent to which GB is potentially 'importing' negative prices. In the two core scenarios we have assumed that interconnectors are fully flexible to respond to price signals in both the day-ahead and intra-day timeframes, in alignment with full implementation of the EU Target Model.

4 Day-ahead results

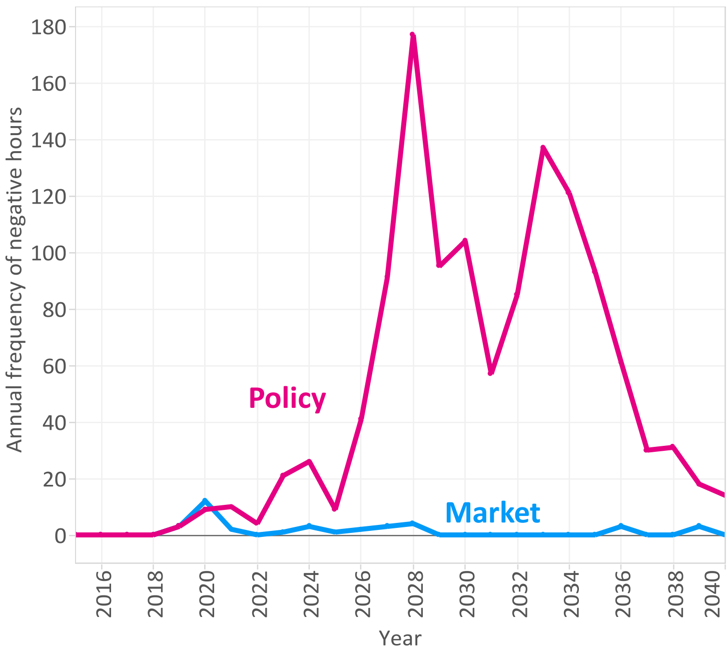
4.1 Introduction

In this section we present the results of the day-ahead modelling for both the Policy and Market scenarios. For ease of comparison results of both scenarios are presented on the same chart where possible. As a reminder of the policy context, the key modelling results of particular relevance to DECC's proposed implementation of the '6+ hour negative price event rule' (see Section 1.1) are the frequency and duration of negative price events at the day-ahead stage – and especially the projected incidence of events with six or more consecutive negative hours.

4.2 Frequency of negative price events

The projected number of negative price hours per year for each scenario is shown in Figure 15. This chart includes all negative price hours in each scenario, regardless of duration or depth of negative prices[36].

Figure 15 Annual frequency of negative price hours (day-ahead)



In the Market scenario, with 'moderate' demand and low carbon deployment assumptions, negative prices are not a significant feature at the day-ahead stage throughout the modelled timeframe. Some negative price hours do occur, mainly in the period 2020-2030 with an average of around 2.5 negative price hours per year. The maximum number of negative price hours in any year in the

[36] 'Duration' of negative prices refers to the length of time (hours) of consecutive negative price events. 'Depth' of negative prices refers to the extent to which the price is negative e.g. a price of -50 £/MWh has a greater depth than a price level at -30 £/MWh, etc.

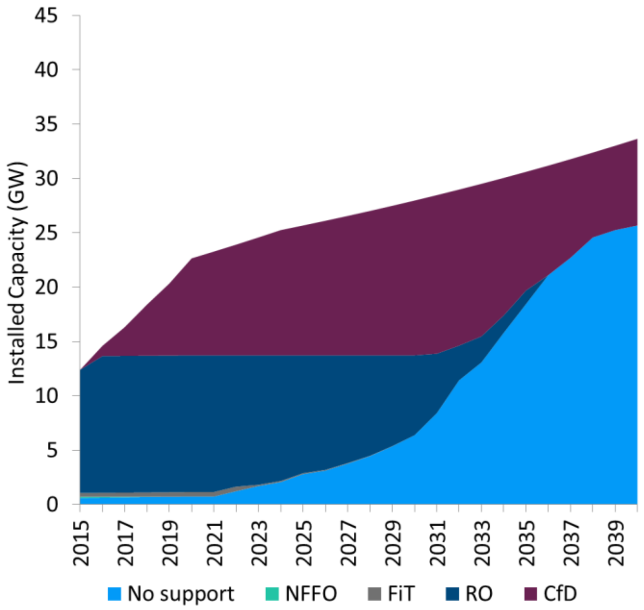
Market scenario is twelve in 2020. In most years of the Market scenario there are no negative day-ahead prices.

It can be seen from Figure 15 that the overall frequency of negative price periods is significantly greater in the Policy scenario than in the Market scenario. The majority of the negative price hours in this scenario occur over the period 2020-2040 within an average of 58 hours per year. The frequency of negative price frequency peaks in 2028 with 177 negative hours in that year (roughly 2% of all hours in the year).

This result is partly caused by different low carbon capacity assumptions in the two scenarios, particularly the relative volumes of wind and nuclear generation capacity from 2020 onwards. The different demand assumptions are also important. The lower demand in the Policy scenario in the short-term (before 2028) will tend to increase, and the higher demand in the long-term (post-2028) decrease, the number of negative price periods all else being equal. The lower interconnector capacity in the Policy scenario over most of the modelled timeframe (through to 2035) also contributes to the greater frequency of negative prices. Our analysis indicates that GB interconnection is usually net exporting during negative price periods, and on balance helps mitigate negative prices (see Section 4.5).

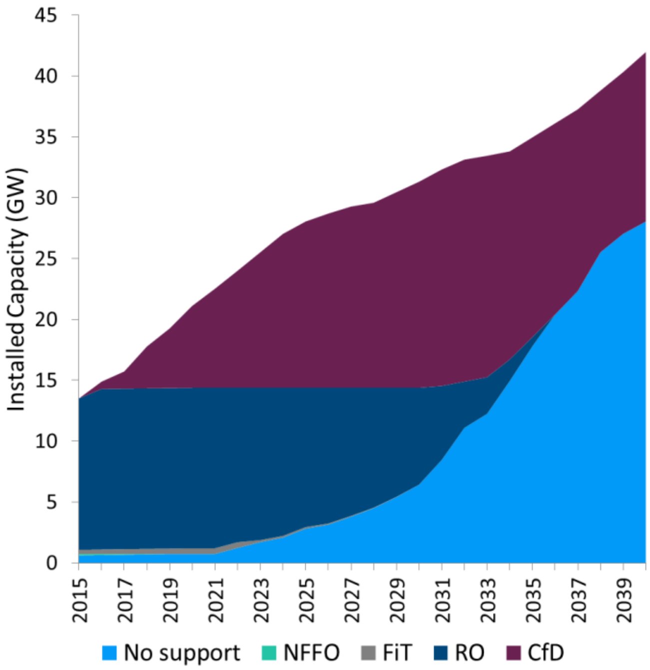
The frequency of negative price events declines in the long term in both scenarios, but this effect is most noticeable in the Policy scenario post-2033. The main cause of this is the increasing volume of renewable capacity on the system which has reached the end of its RO or CfD support period, and which is operating non-supported in the market. The evolution of supported and non-supported wind capacity is shown in Figure 16 and Figure 17 for the Market and Policy scenarios respectively[37].

Figure 16 Wind subsidised capacity profile – Market scenario



[37] Other low carbon capacity follows a similar trend in terms of the ratio of subsidised to unsubsidised capacity over the time horizon.

Figure 17 **Wind subsidised capacity profile – Policy scenario**



We assume in the day-ahead timeframe that merchant low carbon capacity bids at a small but positive level equal to its variable operating costs. Taking the example of wind in the Policy scenario, in 2020 there is around 20 GW of subsidised capacity (bidding negatively) and around 0.7 GW of non-supported capacity (with small but positive bids). By 2035, the capacity of non-supported wind has increased to almost 18 GW (i.e. capacity which is bidding positively), with 17 GW of supported capacity (bidding negatively). Over time the day-ahead marginal price is increasingly set by this growing pool of merchant renewable capacity bidding just above zero. This results in fewer negative prices, but a growing number of low positive prices (see Section 4.4).

This outcome in which the frequency of negative prices declines in the long term is dependent on the assumption that non-supported low carbon capacity bids into the day-ahead wholesale market at variable production costs without any further discount. We explore the impact of pricing in additional offer discounts for these generators in our intra-day analysis (see Section 3.4.3 and Section 5).

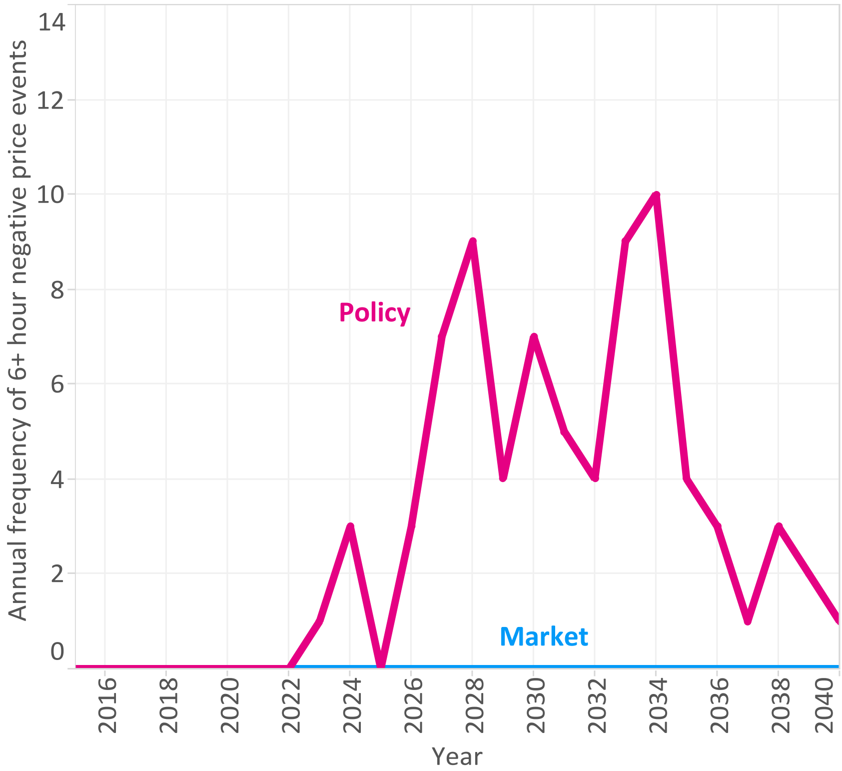
4.3 Duration of negative price events

4.3.1 The '6+ hour' rule

The proposed DECC policy position in response to EC State Aid Guidelines (see Section 2.3) is to set CfD payments to zero for any period with six or more consecutive hours of negative prices in the day-ahead reference market ('6+ hour negative price events').

Figure 18 shows the projected annual frequency of 6+ hour negative price events in the Policy and Market scenarios.

Figure 18 Annual frequency of 6+ hour negative price events (day-ahead)



- In the **Market** scenario:
  - We do not observe any 6+ hour negative price events in any year through to 2040.
  - The policy setting CfD support payments to zero would not be triggered.
- In the **Policy** scenario:
  - There are negative price events lasting 6+ hours in most years from 2023 onwards.
  - The policy setting CfD support payments to zero would be triggered around 80 times times from 2023-2040.
  - The majority of negative price events (77%) are less than 6 hours in duration.

In the Policy scenario these events occur most frequently between the mid-2020s and mid-2030s, when the greatest quantity of subsidised low carbon generation will be on the system and assumed to offer negatively. The peak year for 6+ hour negative price events in the Policy scenario is 2034 with 10 events, followed by 9 occurrences in 2028. In line with the decline in the total number of negative price hours, the occurrence of consecutive negative price hours in excess of five hours in duration declines in the long term in the Policy scenario.

We emphasise that the above scenario results are sensitive to changes in input assumptions. We explore the impact of key input assumptions on negative prices through sensitivity analysis in Section 6.

4.3.2 Negative price 'heat maps'

Figure 19 and Figure 20 present heat maps of the number of negative price events per year split by duration in hours for the Policy and Market scenarios respectively. 77% of the negative price events in the Policy scenario and all events in the Market scenario are less than 6 hours in duration.

We have not attempted to model 'reactionary' bidding behaviour in these scenarios. For example, if there are four or five consecutive hours of negative prices in the day-ahead market, participants may change their bidding behaviour in response. We have also not considered explicit demand-side response to negative prices. If this market participant behaviour were included, the negative price outcome, and particularly the frequency of events in excess of 5 hours may differ.

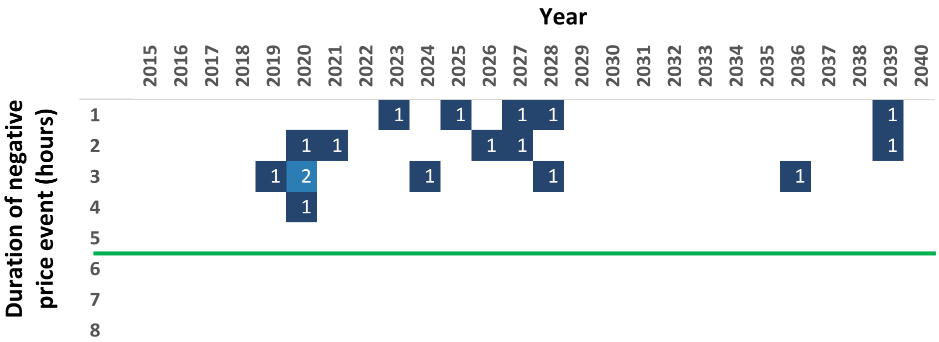
As well as having more negative hours in aggregate, the duration of negative price events is also greater in the Policy scenario versus the Market – including a 20 hour period of negative prices in 2032. There are negative price events of 12 hours or longer in most years from 2026-2036, although the number of long negative price events decreases in the long term in line with the decrease in overall negative price hours.

Figure 19 Annual frequency of negative price events by event duration in the Policy scenario (day-ahead)

Year

Duration of negative price event (hours)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1						1		2	2	4	2	2	6	18	10	11	5	7	8	10	11	4	3	2		1
2						2		1	2		1	2		8	7	4	2	3	2	6	2	2	1	1	1	
3					1				1	1			4	4	3	6	1	2	3	2	1		3			1
4						1						1		6	2	1	1	3	3	2	7	3		1		1
5							2		1		1	2	1	1	2	1	2	1	4	1	3	2	2	1		
6										2		1	3	3	1	4	4	1	3	2	1		1	3	1	1
7									1	1		1					1		1	3	1					
8												1	1	1		1				3		1				
9															1	1		1	1		1	1				
10													1							1	1				1	
11																			1							
12														1	1				2							
13													1							1						
14														1				1				1				
15														1					1							
16																										
17														1	1	1										
18													1	1												
19																										
20																		1								
21																										
22																										
23																										
24																										
>24																										

Figure 20 Annual frequency of negative price events by event duration in the Market scenario (day-ahead)



The heat maps in Figure 21 and Figure 22 illustrate how many negative price hours arise from events of different duration – they plot the annual total numbers of negative hours split by duration of negative price event, rather than the annual total number of events shown in Figure 19 and Figure 20.

Figure 21 Annual frequency of negative price hours by event duration in the Policy scenario (day-ahead)

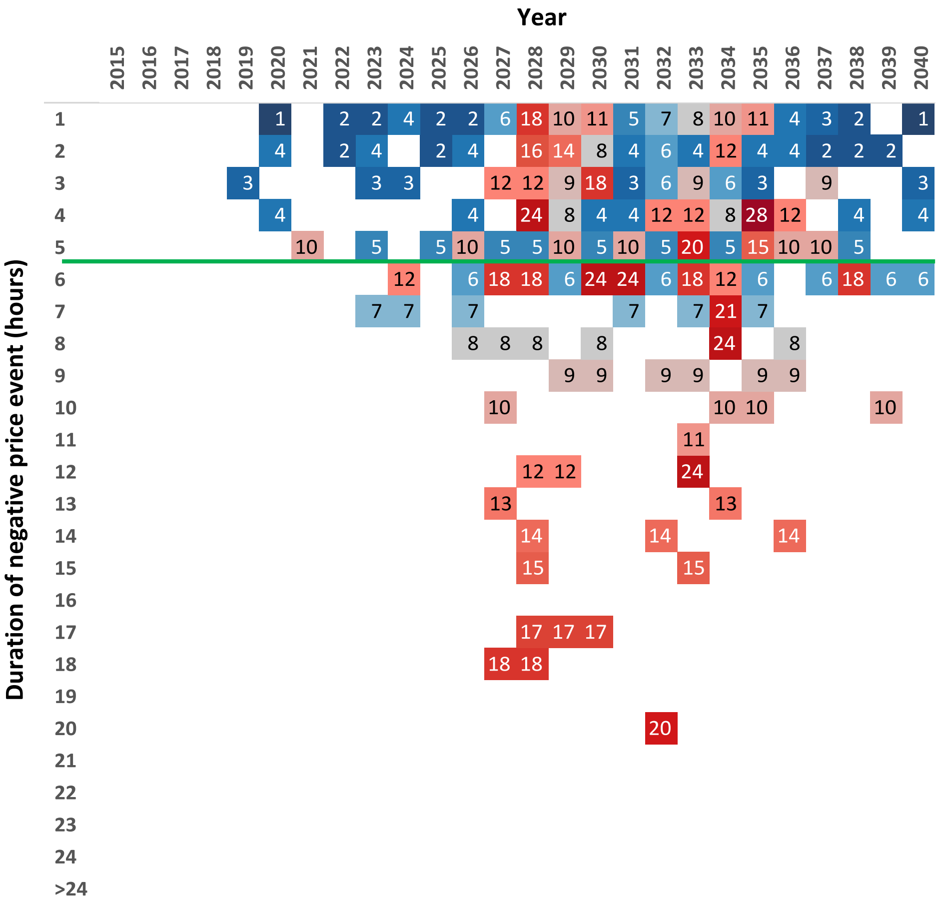


Figure 22 Annual frequency of negative price hours by event duration in the Market scenario (day-ahead)

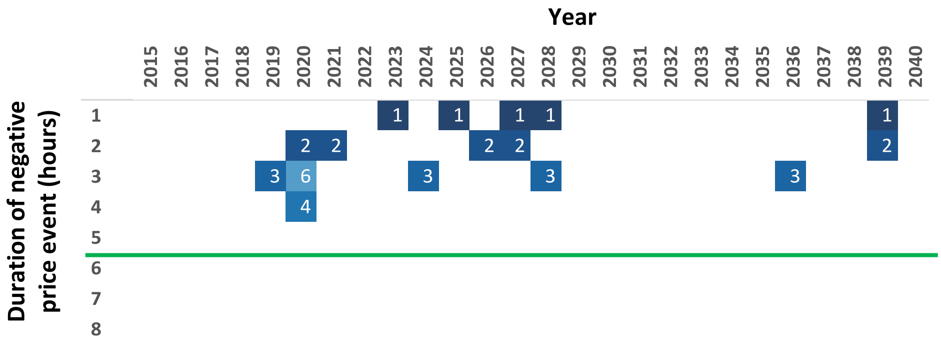
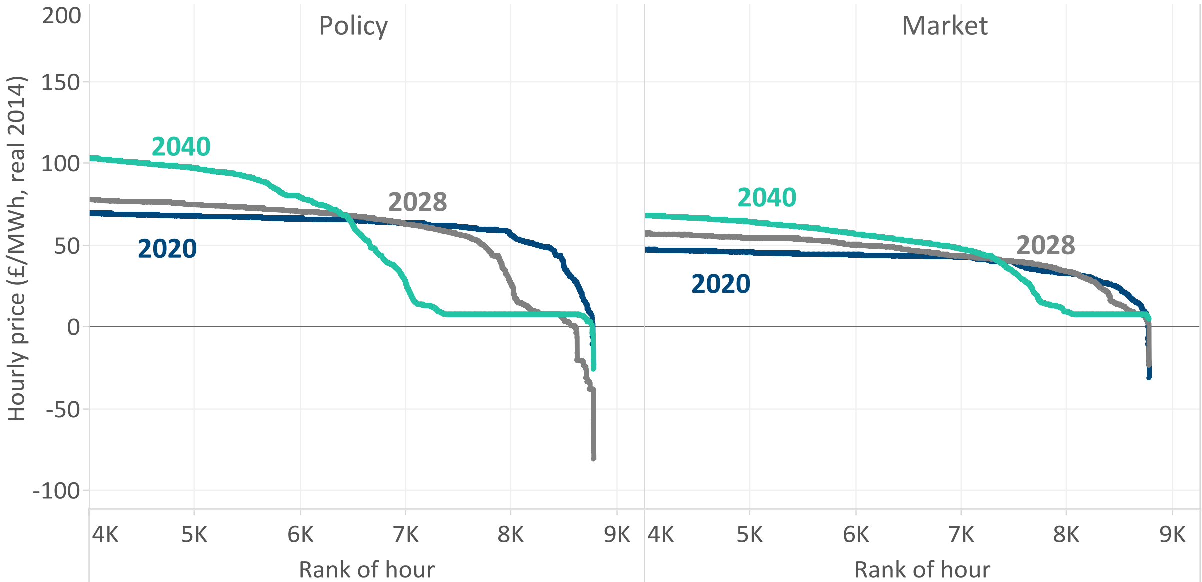


Figure 21 shows that, in the Policy scenario, a significant proportion of the total negative price hours is attributed to events which are infrequent but of long duration. While events of six hours or longer in duration are relatively uncommon, such events contribute a significant proportion of the total number of negative hours. For example, in 2030-31, the greatest number of negative hours is contributed by events with duration of six hours or longer

4.4 Price duration curves

Figure 23 presents the low-price end of the price duration curves (PDCs)[38] for three key years (2020, 2028 and 2040) for each of the two core scenarios.

Figure 23 Low-price end of the price duration curves for three key years



[38] Price duration curves (PDCs) plot the price for each hour of the year ranked in descending order. In these plots, we have zoomed into the bottom half of the curve and present the lowest-priced hours for the year.

The PDCs highlight that although the number of negative prices decreases in the long term in both the Policy and Market scenarios, the number of low positive prices (in the range 0-10 £/MWh) increases significantly. This result is driven by increasing volumes of low carbon capacity operating outside of support mechanisms which we assume bids at the variable cost of production at the day-ahead stage without further discount. In the long-term, the marginal price-setting plant during low-demand and high wind output periods is frequently a non-supported wind generator bidding just above zero. This gives rise to the 'plateau' in the PDC which is especially notable in the Policy scenario in 2040.

Although in the long term the number of negative price events falls in both scenarios, the presence of a significant quantity of capacity bidding just above zero presents a latent negative price risk. Relatively small changes in bidding behaviour for wind generators for example could move these low positive bids negative and potentially result in substantially more negative price hours. We have explored this risk further in our analysis of the intra-day timeframe which is presented in Section 5.

The PDCs also provide a useful indication of the 'depth' of negative price events in each scenario. In the Market scenario, the lowest projected prices over the timeframe to 2040 are in the range -35 to -40 £/MWh. This broadly corresponds to the offer level of RO-supported dedicated biomass or RO-supported onshore wind with a banding factor of 0.9.

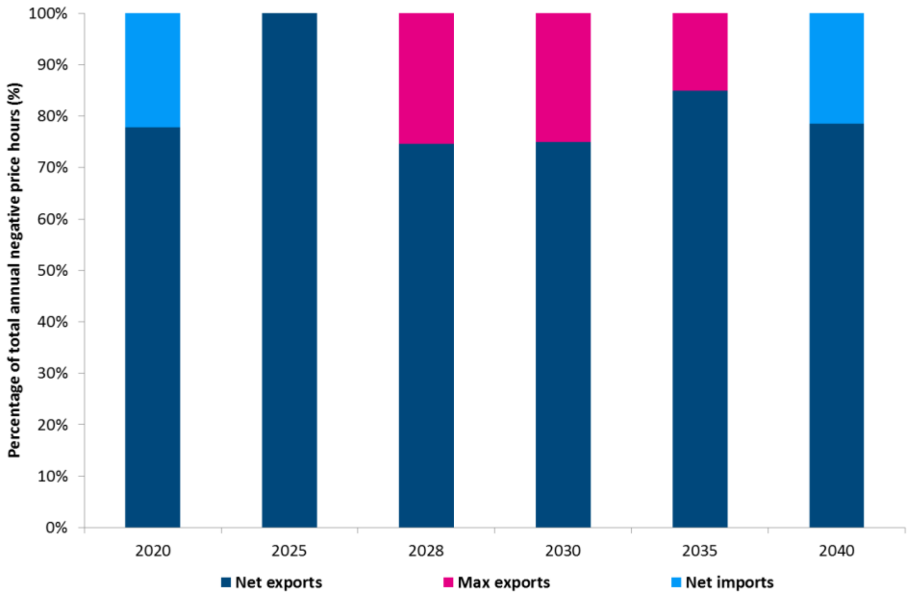
In the Policy scenario, the majority of negative prices are in the range 0 to -40 £/MWh, again with prices set by RO-supported plant. In 2028, which is the year with the most negative prices, there are a few hours in which the price drops to around -80 £/MWh which corresponds to the offer level of RO-supported offshore wind.

4.5 Interconnector flows

The direction and level of flow across GB interconnectors during periods of low or negative price provides an indication of whether interconnection is worsening or helping to alleviate the issue. In our analysis of the two core scenarios, GB is predominantly a net exporter of power during periods of negative GB prices. This is illustrated in Figure 24 which shows the proportion of negative price hours during which GB is either (i) a net exporter of power, (ii) exporting at maximum capacity, or (iii) a net importer of power in the Policy scenario.

We see GB exporting at full capacity in 25% of the negative price hours that occur in 2028 and in 2030, and in 15% of the negative price hours that occur in 2035 (pink bars on chart). This means that the price is more negative in the GB market in these hours than in any of its interconnected markets and GB is using its interconnectors to export this excess low-cost power. In the other negative price hours that occur in these three years, GB is still a net exporter but there are imports from some interconnected markets where the price is more negative than in GB. However, this is outweighed by exports to higher-priced regions, such that exports are still greater than imports and overall the interconnectors act as a net sink for negatively-priced generation in these hours.

Figure 24 Percentage of negative price hours when GB is a net importer, net exporter or exporting at maximum interconnector capacity (Policy scenario)



We do see net imports (total imports to GB exceeds total exports) in 20% of the negative price hours that occur in 2020 and in 2040. This occurs when prices are lower in the majority (but not necessarily all) of the interconnected regions. These imports to GB during negative price hours tend to come from the Netherlands and / or the Irish Single Electricity Market (SEM)[39] interconnectors.

In the case of imports from the SEM, highly correlated wind output tends to result in coinciding low or negative price periods with GB. The relatively high penetration of wind on the Irish system relative to peak demand (over 40%) can result in some exports from the SEM to GB during high wind output hours.

Germany has seen steep growth in wind and solar PV capacity, particularly in the period since 2010 – and total installed capacity of these two renewable technologies alone exceeds peak German demand. Although Germany is not directly interconnected with GB, due to the high penetration of low carbon generation capacity relative to German demand, Germany currently exports excess low carbon generation to interconnected markets during periods of high renewables output. If there is insufficient load to absorb all of this low or negatively-price generation in these directly interconnected markets (such as the Netherlands), it can be 'passed through' to GB across further interconnection. In the Policy scenario in 2028 (the year with the greatest number of negatively-priced hours in our analysis), 71 of the 177 hours of negative prices in GB coincide with negative price hours in Germany. In 28 of these 71 coinciding periods, the price is more negative in Germany than in GB. As a result, during each of these periods GB is not fully exporting across all interconnectors.

[39] The Single Electricity Market (SEM) encompasses both the Republic of Ireland and Northern Ireland jurisdictions.

5 Intra-day results

5.1 Introduction

For both the Policy and Market scenarios we have analysed some of the changes in negative price outcomes which could occur closer to real time in the intra-day market. We have modelled a representative 'snapshot' of the intra-day timeframe – indicatively six hours ahead of real time. Taking the day-ahead dispatch position as the starting point, in this modelling stage we layer in day-ahead forecast errors for demand and wind (calibrated from historic profiles), intra-day gas price movements (calibrated with historic data) and updated generator bidding assumptions which are described in Section 3.4.3.

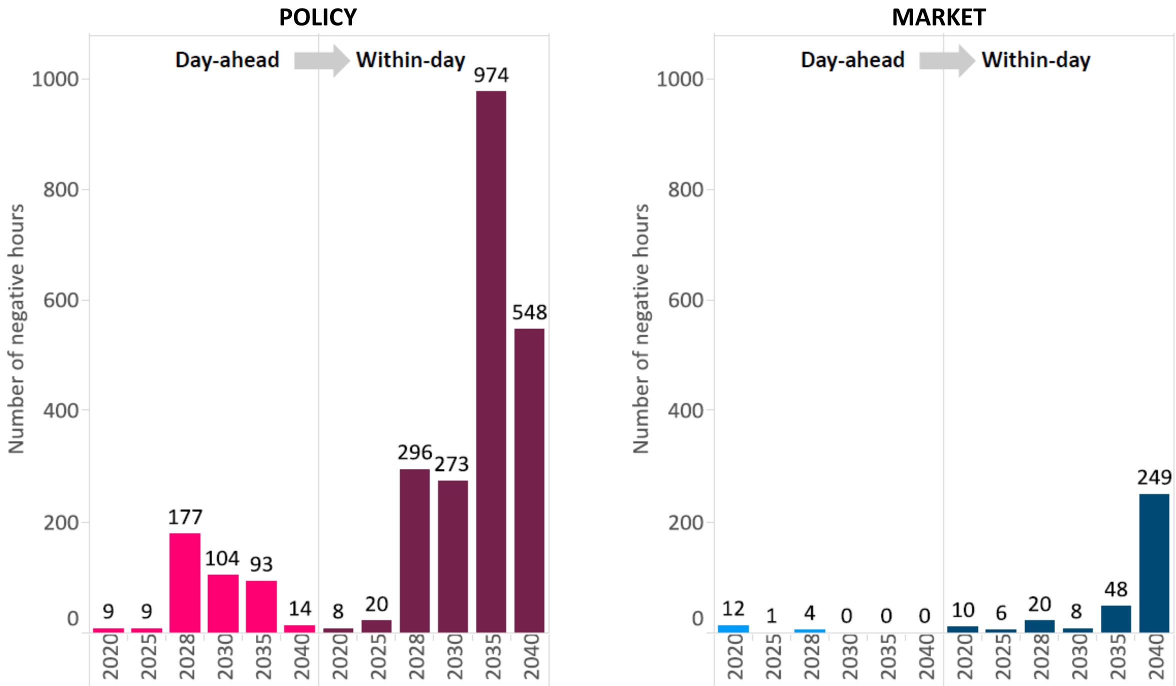
These input parameters are intended to simulate the real-world fundamentals at play in the intra-day market, in moving from a day-ahead position to a market closer to real-time (indicatively, six hours ahead of real-time). We re-dispatch the market taking into account this 'new information', while respecting the unit commitment decisions made at the day-ahead stage, and the operational constraints of the different plant types (see Section 3.2.2). Interconnectors are free to re-dispatch completely in the intra-day timeframe, which is consistent with full implementation of the EU Target Model, responding to changing market prices at the intra-day stage.

5.2 Frequency of negative prices

Figure 25 compares the total number of negative price hours in the day-ahead and intra-day timeframes for both the Policy and Market scenarios. The frequency of negative prices increases intra-day across both scenarios although the effect is more pronounced in the long term in the Policy scenario.

The increase in the number of negative prices moving to intra-day is mainly caused by the assumed discount which is priced into the bids of onshore and offshore wind generators (Section 3.4.3). This causes the bids of the tranche of non-supported onshore / offshore wind capacity, which in the day-ahead timeframe we assumed had small but positive value, to become negative. The material increase in the number of negative prices which results (from 93 day-ahead to 974 intra-day in 2035 in the Policy scenario for example) indicates the importance of the bidding behaviour of this group of generators in determining negative price outcomes.

Figure 25 Annual frequency of negative priced hours in the day-ahead and intra-day timeframes (Policy & Market scenario)



5.3 Duration of negative price events

In the intra-day timeframe negative price events are longer in duration in both the Policy and Market scenarios, as well as being more frequent, as shown in Figure 26. This is again driven by the change in bidding assumption for low carbon generators, wind in particular, compared to the day-ahead bidding assumptions.

Figure 26 Count of negative price hours by duration

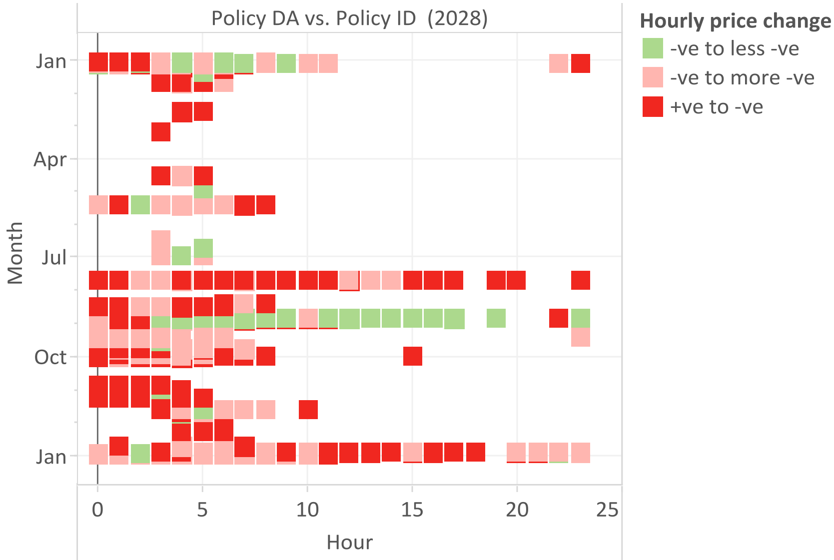
Duration of negative price event (hours)	Policy DA						Policy ID						Market DA						Market ID					
	2020	2025	2028	2030	2035	2040	2020	2025	2028	2030	2035	2040	2020	2025	2028	2030	2035	2040	2020	2025	2028	2030	2035	2040
1	1	2	18	11	11	1	2	2	11	13	36	36		1	1				1				6	9
2	2	1	8	4	2		1	1	6	8	16	11	1						1		1		2	6
3			4	6	1	1		1	9	3	8	9	2		1				1		3			3
4	1		6	1	7	1	1		2	6	4	8	1						1				1	2
5		1	1	1	3				2	1	5	4												4
6			3	4	1	1		1	7	9	11	10								1			2	9
7					1			1	2	5	13	4											2	3
8			1	1					2	5	6	5										1	1	4
9				1	1				1	2	12	6									1			3
10					1				2		7	2												
11										1	4	4												1
12			1						1	1	2	1												
13											4	1												
14			1						2		3	1												1
15			1						1	1														
16									1		1													2
17			1	1					1		2													
18			1						1		2	1												
19											1													
20											1	1												
21									1	1														
22																								
23																								
24											1													
>24											4	3												

5.4 Negative pricing dynamics

We have analysed the movements in each hourly price in the intra-day timeframe compared to the corresponding day-ahead core scenario. We have identified and plotted the hours which have changed in a material way in terms of negative pricing as a heat map. We have defined 'material' movements in terms of negative prices as hours where the price changes (i) from positive in the day-ahead timeframe to negative intra-day, (ii) from negative day-ahead to positive ID, (iii) from negative day-ahead to less negative ID, or (iv) from negative day-ahead to more negative ID.

Figure 27 illustrates these four types of price movements for the 2028 spot year in the Policy scenario – this was the year with the greatest number of negative price hours in the day-ahead timeframe. The predominance of red and pink versus green areas in the heat map indicates that while there are price 'sign changes' in both directions, these are predominantly from positive to negative moving from day-ahead to intra-day in our analysis. In reality, the emergence of more negative pricing intra-day could present a greater risk of negative pricing at the day-ahead stage.

Figure 27 Distribution of key hourly price movements moving from day-ahead (DA) to intra-day (ID) (Policy scenario, 2028)



6 Sensitivity analysis

6.1 Overview

We have undertaken sensitivity analysis on the two scenarios to determine the impact of varying key assumptions on negative price outcomes. We have explored four sensitivities in total, three of which have been applied to the day-ahead timeframe, and one to both day-ahead and intra-day. We have modelled the following spot years: 2020, 2025, 2028, 2030, 2035 and 2040 for each sensitivity and compared the results for these years to the same years in the relevant core scenario. The spot years were chosen at five-yearly intervals from 2020 onwards to probe the sensitivity impact across the modelled timeframe, with the addition of 2028 which was the year with the peak frequency of negative price hours in the Policy scenario.

Table 4 provides an overview of the sensitivities with a brief description and rationale – we then discuss the input assumptions and results for each of the sensitivities in turn.

Table 4 Overview of sensitivities

Sensitivity	Target scenario	Rationale
High Wind	Market (day-ahead)	▸ Renewables build in the Market scenario meets 2020 RES-E targets, but the build rate slows beyond 2020 ▸ Policy scenario has higher long term deployment of wind (+8 GW), but this is combined with higher electrification which mitigates the potential negative price impact to some extent ▸ This sensitivity investigates the impact of higher build out of wind capacity in a scenario with moderate long term demand and electrification assumptions
Low Nuclear	Policy (day-ahead)	▸ Nuclear capacity has a potentially large effect on the incidence of negative prices, since we assume it operates inflexibly, bidding very negatively to avoid shutdown ▸ If less nuclear capacity came forward than envisaged in the Policy scenario, this could have a material impact on the incidence of negative pricing, depending on what capacity was built in its place

Sensitivity	Target scenario	Rationale
Increased Storage	Policy (day-ahead)	▸ The Policy scenario sees significant long-term electrification and increase in peak and annual demand levels ▸ It is likely that electrification arising in part from uptake in electric vehicles (for example) would be accompanied by an increase in storage capacity available on the system ▸ This sensitivity investigates the potential mitigating impact of more storage under the Policy scenario
Low Interconnectors	Policy (day-ahead & intra-day)	▸ Interconnectors are a key source of flexibility, both at the day-ahead stage, and potentially, intra-day ▸ In the two day-ahead scenarios, GB interconnection is predominantly a net exporter of power during negatively-priced periods, helping to mitigate against negative prices ▸ The core scenarios assume full implementation of the EU Target Model in the intra-day timeframe, and therefore full flexibility of interconnectors to re-optimise based on with-in day developments ▸ This sensitivity investigates the impact of (i) lower interconnection build and (ii) low intra-day interconnector flexibility

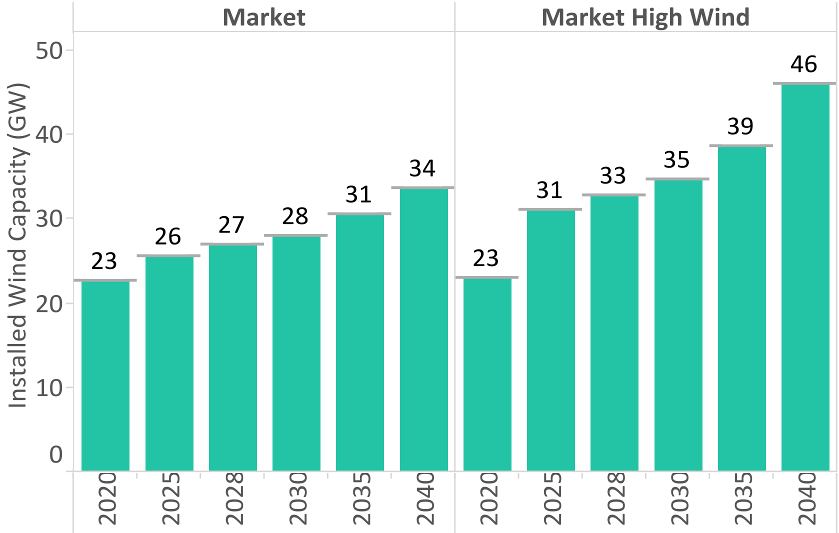
6.2 High Wind sensitivity

The High Wind sensitivity is applied to the day-ahead Market scenario. It aims to explore the impact of higher wind capacity build-out in a scenario with moderate long-term demand growth.

6.2.1 Input assumptions

For this sensitivity we increased the overall installed wind capacity to a level greater than that in either the core Market or Policy scenarios in order to understand the impact of substantially higher wind build out on negative pricing. All other assumptions remained unchanged from the Market scenario. Figure 28 compares the installed wind assumptions for the Market scenario and the High Wind sensitivity.

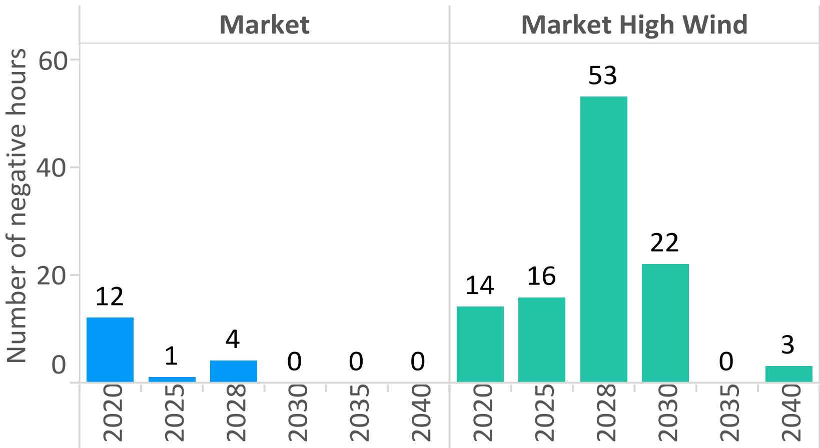
Figure 28 Installed wind capacity in the Market scenario and High Wind sensitivity



6.2.2 Results

As seen in Figure 29, the overall increase in negative price outcomes in this sensitivity is relatively moderate, despite the limited long-term demand growth in the Market scenario compared to the Policy scenario. In the Market High Wind sensitivity, negative price hours still account for less than one percent of total hours across all the modelled years. The additional wind generation has the greatest effect on the frequency of negative prices in 2028 and 2030.

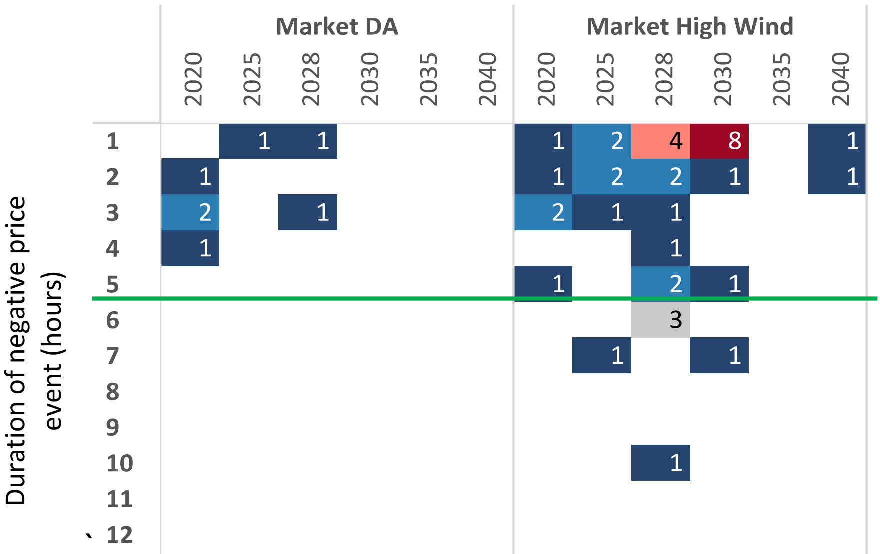
Figure 29 Annual negative price hours



The impact of this additional installed wind capacity on negative price periods declines towards the end of the modelled timeframe, suggesting that in the long run the impact of older low carbon capacity dropping off subsidy payments outweighs the impact of additional new wind capacity which is bidding negatively.

Figure 30 compares the frequency of negative price events by event duration in the Market High Wind sensitivity and shows that some 6+ hour events do now occur, in contrast with the Market scenario. Of the spot years modelled for the sensitivity, the peak number of 6+ hour negative price events is in 2028 with four in that year.

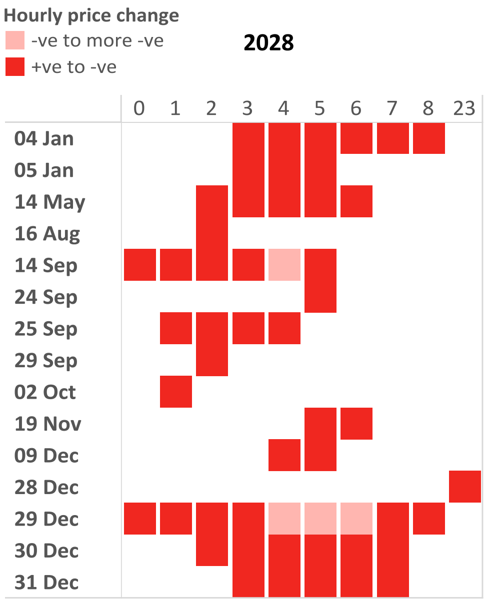
Figure 30 Frequency of negative price events by duration



For each sensitivity we have analysed the movements in each hourly price in the sensitivity compared to the corresponding core scenario. We have then plotted the hours which have changed in a material way in terms of negative pricing on a heat map. As mentioned in Section 5.4, we have defined 'material' movements in terms of negative prices as hours where the price changes (i) from positive in the day-ahead timeframe to negative intra-day, (ii) from negative day-ahead to positive ID, (iii) from negative day-ahead to less negative ID, or (iv) from negative day-ahead to more negative ID.

Figure 31 shows the hourly price change heat map for a 2028 spot year for the High Wind sensitivity versus the day-ahead Market scenario. In this sensitivity, this analysis of hour-to-hour price movements shows that the price does not increase in any hour in this sensitivity. In the sample spot year in Figure 31 there are 49 hours which have changed from a positive price in the Market scenario to a negative price in the High Wind sensitivity, there are 4 hours that have become more negatively-priced compared to the Market scenario, and there are no hours in which the price moves in a positive direction.

Figure 31 Distribution of price change hours



6.3 Low Nuclear sensitivity

The Low Nuclear sensitivity seeks to probe the impact of lower nuclear capacity build-out where this capacity is replaced with alternative capacity such that there is no overall increase in system carbon intensity.

6.3.1 Input assumptions

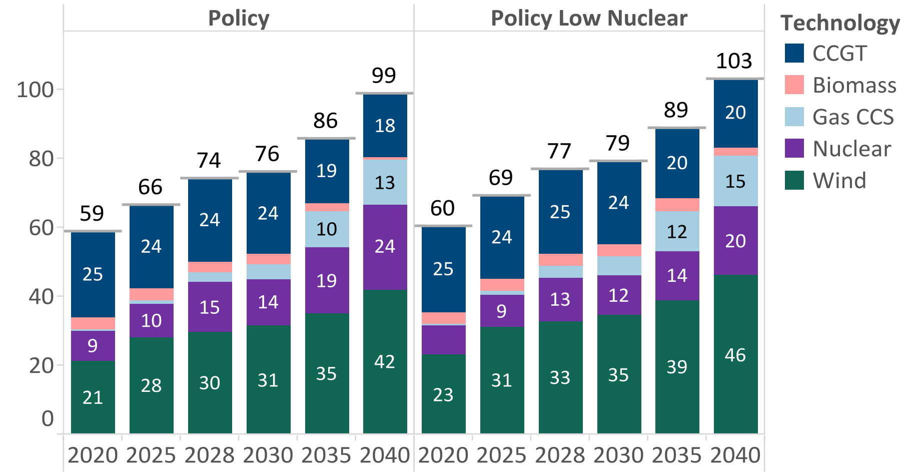
In this sensitivity we replaced the original Policy scenario nuclear installed capacity build-out with a nuclear capacity build-profile which is mid-way between the Market and Policy scenario profiles. This is equivalent to reducing the nuclear capacity in the core Policy scenario by just less than 5 GW by the end of the modelled timeframe. We have replaced the nuclear capacity with the following additional capacity in order to leave capacity margins and long-term system carbon intensity broadly unchanged:

- 1.5 GW of additional dedicated biomass
- 1.5 GW of additional gas-fired carbon capture and storage (CCS)
- 1 GW of additional unabated CCGT capacity, and
- 4 GW of additional wind capacity by 2040.

All other assumptions from the Policy scenario were held constant.

Figure 32 illustrates these capacity changes compared to the core Policy scenario.

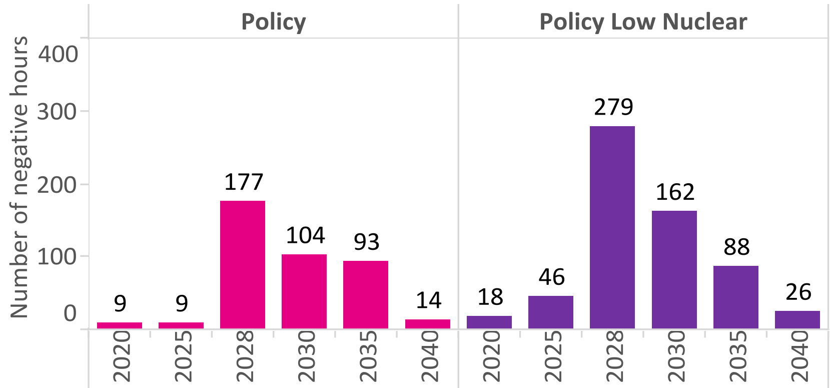
Figure 32 Installed capacity (selected technologies)



6.3.2 Results

Our analysis indicates that the absolute number of negative prices increases in most of the modelled spot years, as shown in Figure 33, in this sensitivity. The greatest increase is seen in 2028, with 102 additional negative price hours.

Figure 33 Annual negative price hours



The overall increase in the frequency of negative price hours suggests that the additional wind and other low carbon capacity in this sensitivity outweighs the reduction in nuclear capacity. We have replaced the removed nuclear capacity with wind and other low carbon capacity in order to maintain the same system carbon intensity. However, the lower annual load factor of wind versus nuclear, and the lower expected capacity contribution at the time of peak demand means that a greater quantity of wind capacity is needed to replace nuclear. This can increase the number of negative prices during periods of very high wind output and low demand. As shown in Figure 34, the frequency of longer duration negative price events also increases somewhat.

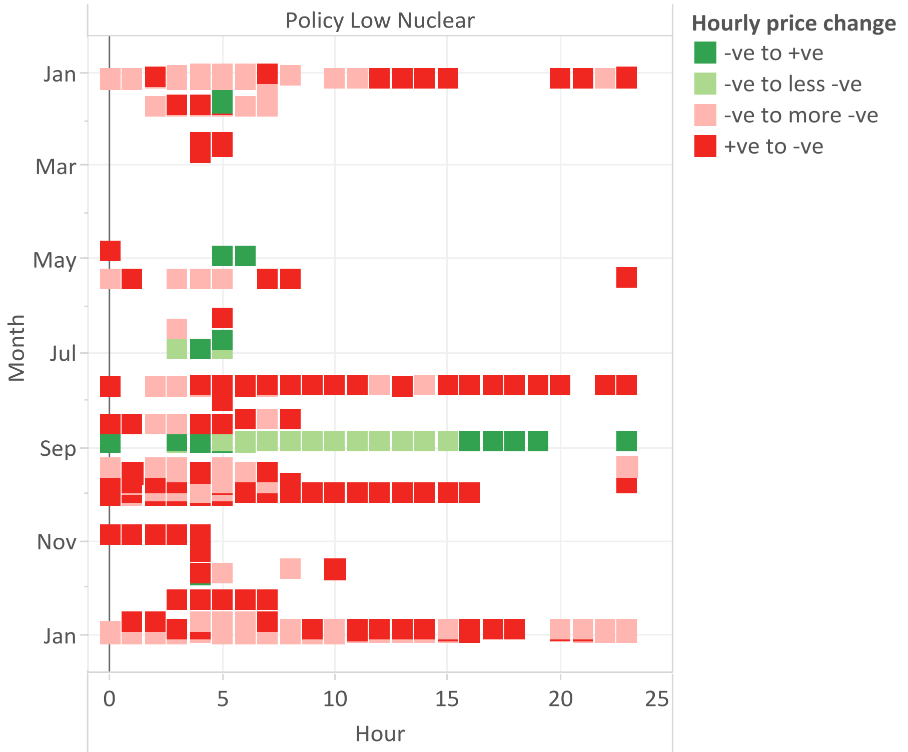
The results show that even if nuclear operates inflexibly and bids into the day-ahead market at a very negative level, replacing nuclear with wind while maintaining the same capacity margin and / or system carbon intensity could result in more negative price events because of the greater installed capacity of wind required.

Figure 34 Frequency of negative price events by duration

Duration of negative price event (hours)	Policy DA						Policy Low Nuclear					
	2020	2025	2028	2030	2035	2040	2020	2025	2028	2030	2035	2040
1	1	2	18	11	11	1	2	4	20	11	9	3
2	2	1	8	4	2		1	2	3	6	4	1
3			4	6	1	1		1	4	6	1	
4	1		6	1	7	1	1	1	2	4	6	1
5		1	1	1	3		2	1	3	1	1	1
6			3	4	1	1		3	7	7	2	2
7					1				2	3	1	
8			1	1				1	3			
9				1	1					1		
10					1				1	1	2	
11									1			
12			1									
13												
14			1						1			
15			1									
16									3			
17			1	1					2			
18			1							1		
19												
20												
21									1			
22												
23												
24												
>24												

Some price increases do occur in this sensitivity, as shown by the green and pale green squares in Figure 35. However the number of negative to positive price movements is outweighed by negative price movements in aggregate such that there is a net increase in negative prices. From this chart it can also be seen that there is a greater concentration of positive to negative price changes overnight, coinciding with the low price off-peak periods in the core Policy scenario.

Figure 35   Distribution of price change hours



6.4 Increased Storage sensitivity

6.4.1 Introduction

The Increased Storage sensitivity probes the impact of a higher build-out of flexible electricity storage in the Policy scenario (day-ahead) on negative prices. Future expectations of a greater frequency of negative prices could be a potential driver for increased electricity storage volumes. We also note that the Policy scenario assumes significant electrification of transport and heating in the long-term, and that this is likely to provide opportunities for flexible storage, for example in the form of batteries. The effects of this sensitivity would also be qualitatively similar to greater demand-side response to negative prices or more flexible nuclear operation.

6.4.2 Input assumptions

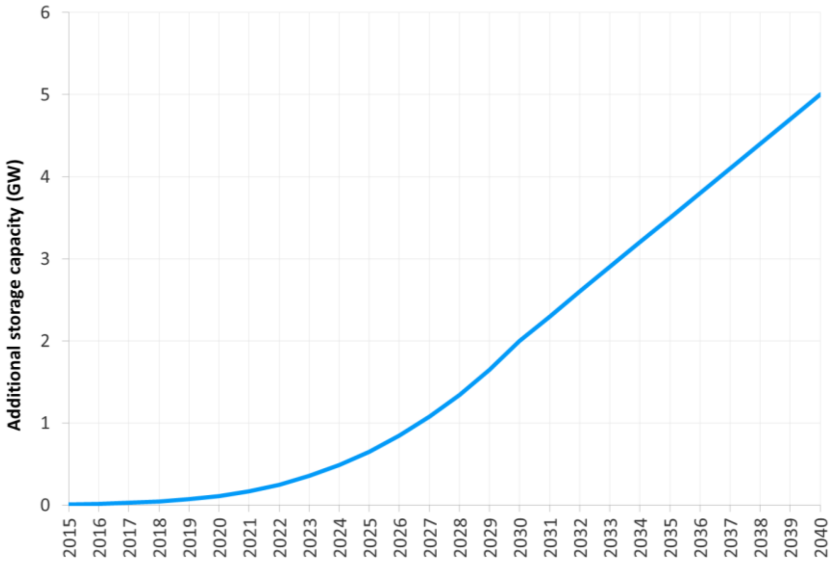
We have assumed an additional 2 GW of storage capacity by 2030 compared to the core Policy scenario, and a further 5 GW of storage by 2040, as shown in Figure 36. We have based this trajectory on the following sources:

- 'Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future', report by Imperial College London for the Carbon Trust, 2012.
- The Electricity Storage Network's (ESN) pathway to 2020, but delayed by ten years so that the 2020 estimate of a further 2 GW is actually reached by 2030 in this sensitivity.
- For the pathway between 2030 and 2040 we have assumed a linear trajectory.

- All other assumptions are unchanged from the Policy scenario.

In this sensitivity we have assumed that the additional storage is relatively ‘quick-cycle’, which is capable of operating at maximum output for less than five hours.

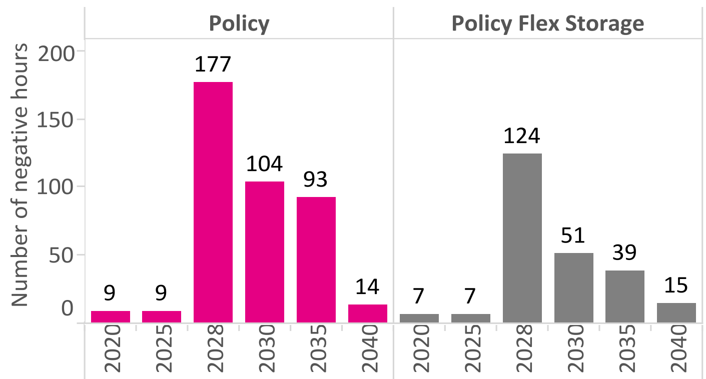
Figure 36 Additional electricity storage capacity in the Increased Storage sensitivity



6.4.3 Results

With the introduction of this level of additional electricity storage we see a notable reduction in the incidence of negative prices, particularly over the period 2028-2035, as shown in Figure 37.

Figure 37 Annual negatively priced hours



The greatest absolute reduction in negative price hours occurs in 2035, with 54 fewer hours compared to the core Policy scenario.

Figure 38 compares the frequency of negative price events by duration for the core Policy scenario and the Increased Storage sensitivity. The reduction in the frequency of shorter duration events is particularly notable by the reduction in red-shaded squares in the sensitivity (right hand side of the chart).

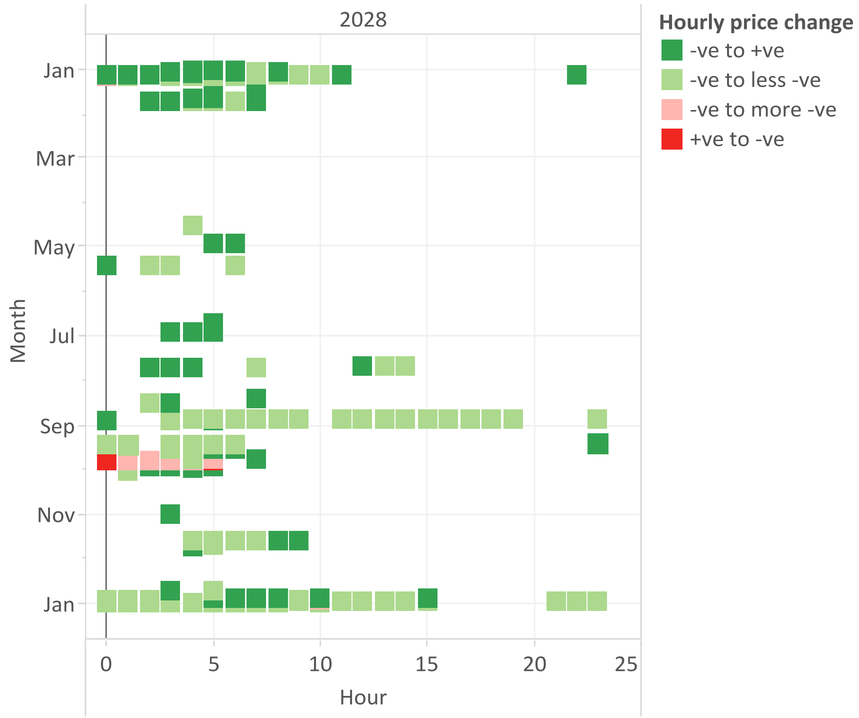
Figure 38 Frequency of negative price events by duration

Duration of negative price event (hours)	Policy DA 2020	Policy DA 2025	Policy DA 2028	Policy DA 2030	Policy DA 2035	Policy DA 2040	Policy Increased Storage 2020	Policy Increased Storage 2025	Policy Increased Storage 2028	Policy Increased Storage 2030	Policy Increased Storage 2035	Policy Increased Storage 2040
1	1	2	18	11	11	1	1	2	12	10	6	2
2	2	1	8	4	2		1		4	1		1
3			4	6	1	1			2	1		
4	1		6	1	7	1	1		2	3	2	
5		1	1	1	3			1	1		1	1
6			3	4	1	1			1	2	2	1
7					1				1			
8			1	1					1		1	
9				1	1							
10					1							
11												
12			1							1		
13												
14			1						1			
15			1						1			
16												
17			1	1					1			
18			1						1			
19												
20												
21												
22												
23												
24												
>24												

This reduction in shorter-duration negative price events is a consequence of the relatively 'short-cycle' storage we have modelled which cannot generate / charge for extended periods. It is possible that if we were to model relatively 'longer cycle' storage units we could see a reduction in the frequency and duration of longer duration negative price events.

For this sensitivity we have also looked at the distribution of price movements, calculating the change in each hourly price in the sensitivity versus the core Policy scenario. We have plotted the hours of material price change as shown in Figure 39. Here we show the results for the 2028 spot year. The dominance of green-shaded areas highlights the strong weighting towards prices moving from negative to positive in the increased storages sensitivity. This occurs overnight in the majority of cases when the additional storage capacity will take advantage of the overnight negative prices, optimising value from the greater peak / off-peak price ratio.

Figure 39 Distribution of price-change hours



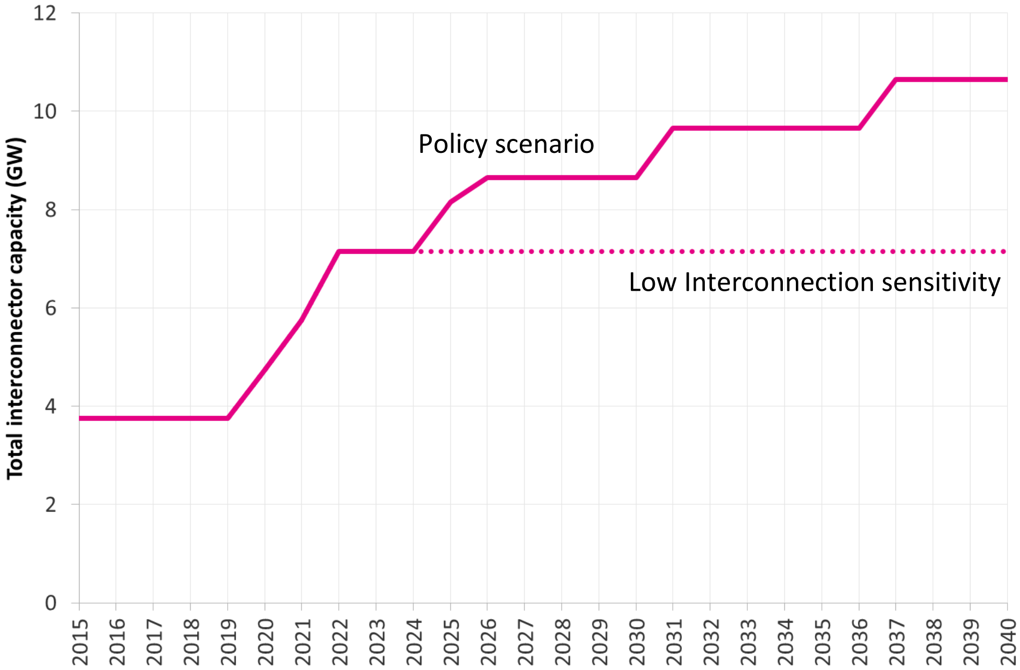
6.5 Low Interconnection sensitivity

The Low Interconnection sensitivity explores the impact of both lower interconnector capacity in the day-ahead and intra-day timeframes, and the impact of lower intra-day interconnector flexibility. This sensitivity is performed on the Policy scenario.

6.5.1 Input assumptions

Figure 40 outlines the aggregate interconnector capacity assumed in this sensitivity compared to the core Policy scenario. We have assumed that interconnector capacity flat-lines at 7.2 GW from 2022 onwards.

Figure 40 Interconnector capacity



In the day-ahead timeframe, we assume that interconnectors are free to dispatch based on interconnected market price arbitrage in the day-ahead timeframe, as per our base case assumption in the core scenarios.

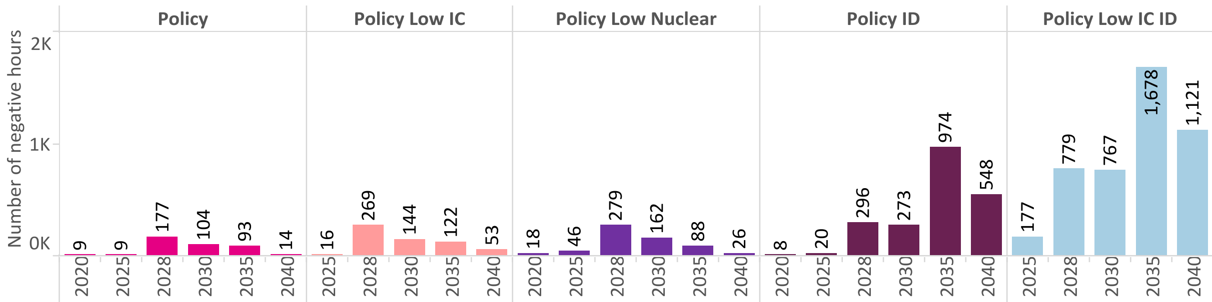
In the intra-day timeframe in this sensitivity, we assume that hourly interconnector flows determined at the day-ahead stage are 'frozen' and cannot be changed or re-optimised intra-day. This is in contrast to the core Policy and Market scenarios in which we allowed full flexibility for re-dispatch of interconnection intra-day – which is in line with the principles of the EU Target Model.

While day-ahead market coupling is now operational across North-West European electricity markets, most intra-day markets are not coupled and the details of the implementation of the EU Target Model in the intra-day timeframe have not been finalised. There is therefore uncertainty around the degree of flexibility interconnectors will have to respond to market developments intra-day. This Low Interconnection sensitivity models the extreme of complete intra-day interconnector inflexibility and therefore allows the full range of potential outcomes to be explored[40].

6.5.2 Results

Reducing the available interconnector capacity increases the number of negative prices at the day-ahead stage relative to the Policy scenario, as shown in the two left hand panels of Figure 41. The annual increase in negative price hours, which occurs across all modelled spot years, is relatively modest in the day-ahead timeframe, with negative prices occurring in only 3% of total hours in the peak year (2028), compared to 2% in the core Policy scenario.

Figure 41 Annual negative price hours by scenario/sensitivity



In the intra-day timeframe we see significantly more negative prices occurring in each of the modelled years compared to the intra-day timeframe in the core Policy scenario (right hand panels in Figure 41), particularly in the longer term. The impact of reduced overall interconnector capacity combined with interconnector inflexibility at the intra-day stage increases not only the frequency of negative price events but also the duration of these events. We illustrate this outcome in Figure 42. These events can reach up to 70 hours in duration in this sensitivity.

This sensitivity underlines the role of flexible interconnector capacity in mitigating against negative prices, and the importance of full EU Target Model implementation which allows interconnectors to respond optimally to changing market price signals.

[40] Note that the intention of this sensitivity was to establish the ‘range’ of outcomes by considering the extreme case of zero intra-day flexibility for interconnection. This should not necessarily be taken as a realistic outcome as it would not comply with the requirements of the EU Target Model.

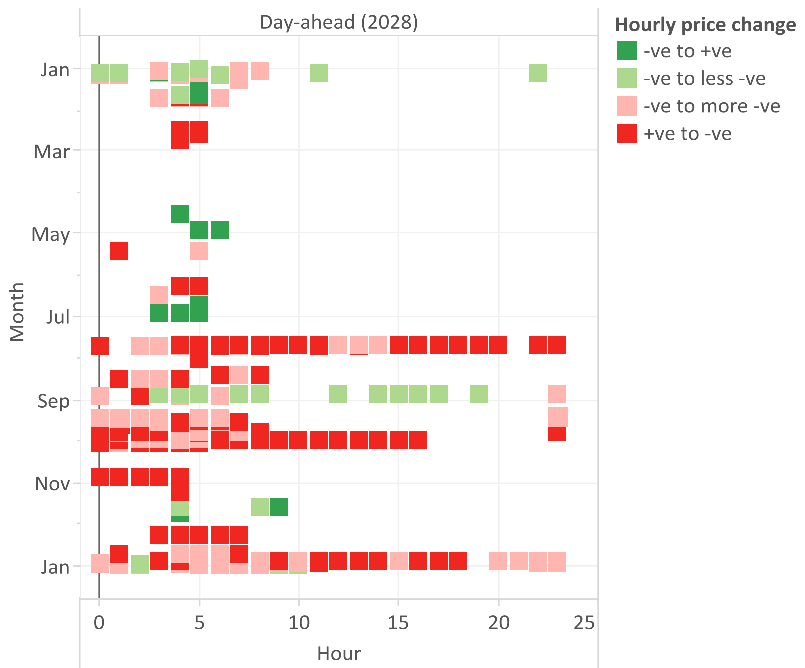
Figure 42 Frequency of negative price events by duration

Duration of negative price event (hours)	Policy DA						Policy Low IC DA					Policy ID						Policy Low IC ID				
	2020	2025	2028	2030	2035	2040	2025	2028	2030	2035	2040	2020	2025	2028	2030	2035	2040	2025	2028	2030	2035	2040
1	1	2	18	11	11	1		16	11	13	9	2	2	11	13	36	36	29	15	18	42	22
2	2	1	8	4	2		3	8	8	6	4	1	1	6	8	16	11	8	10	13	11	12
3			4	6	1	1	1	3	4	4	3		1	9	3	8	9	4	7	12	12	5
4	1		6	1	7	1		2	1	6	3	1		2	6	4	8	8	9	4	7	5
5		1	1	1	3			5	4	3	3			2	1	5	4	3	8	5	6	6
6			3	4	1	1		4	4	3			1	7	9	11	10	7	12	9	24	14
7					1		1	3	2				1	2	5	13	4	1	15	15	18	16
8			1	1				3	2					2	5	6	5	3	3	12	9	12
9				1	1				1	2				1	2	12	6		8	7	15	11
10					1					1				2		7	2		1	8	7	5
11															1	4	4				8	1
12			1					1						1	1	2	1		1	1	5	1
13																4	1		2	1	3	1
14			1					1						2		3	1				3	3
15			1											1	1				1	3	2	4
16								3						1		1			1	1	4	2
17			1	1				2						1		2			1	2	3	1
18			1					1	1					1		2	1			2	3	2
19																1			1	1	1	2
20																1	1		1		3	3
21														1	1				1	1		
22																				1	2	2
23																						1
24																1						1
>24																4	3		6	1	11	6

At the day-ahead stage more hours change from positive to negative prices than vice versa, as shown in

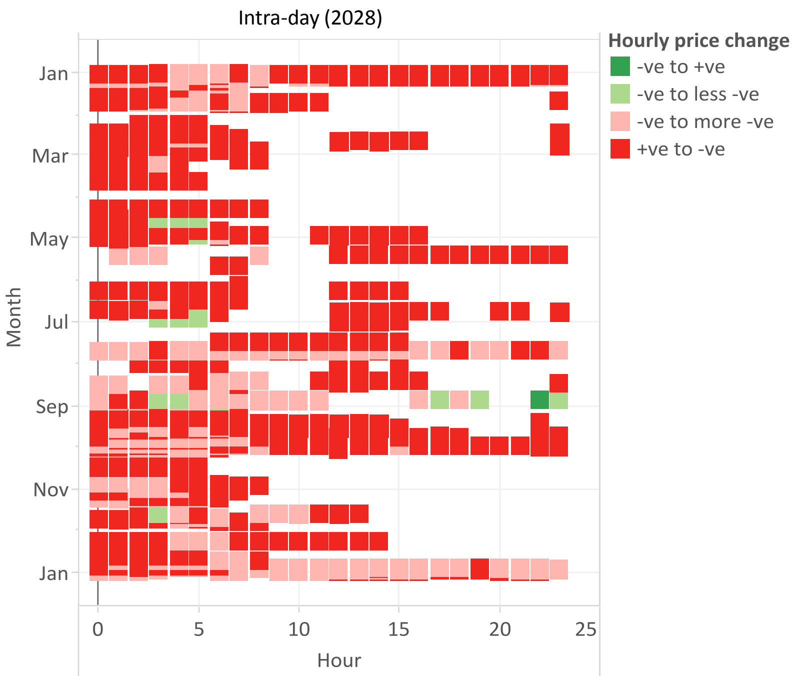
Figure 43.

Figure 43 Distribution of price-change hours



This is because GB is usually exporting during low price events in the core Policy scenario, and by reducing the interconnector capacity in this sensitivity we are effectively reducing the demand from interconnected markets to which GB exports. This decreases the point on the GB supply curve at which demand and supply intersect, pushing prices from positive to negative in these hours. Restricting intra-day interconnector flexibility significantly increases this impact, as further illustrated in Figure 44.

Figure 44 Distribution of price-change hours (intra-day)



7 Conclusions

7.1 Summary of key messages

1. **In the Market scenario, with moderate long-term decarbonisation and electricity demand, negative prices are not a significant feature of the GB day-ahead electricity market over the next 25 years.**
   - In this scenario, we do not observe any 6+ hour negative price events in any year through to 2040 at the day-ahead stage.
   - The policy setting CfD support payments to zero would not be triggered.
   - Some negative prices occur, mainly in the period 2020-2030, with an average of 2.5 negative price hours per year, and a maximum in any one year of twelve hours in 2020.
   - The substantial majority (94%) of negative price events last between one and three hours.
2. **The number of negative price hours is closely linked to the amount of low carbon generating capacity in receipt of support payments – higher low carbon build supported under CfDs for Renewables or the RO could lead to occurrences of 6+ hour negative price events.**
   - In the Policy scenario, which has higher deployment of subsidised low carbon capacity – consistent with a long-term system carbon intensity of <100 gCO_2/kWh by 2030 – negative price events lasting 6+ hours occur at the day-ahead stage in most years from 2023 onwards.
   - The policy setting CfD support payments to zero would be triggered around 80 times from 2023-2040.
   - We project an average of 58 negative price hours per year in the period 2020-2040, and the peak year for negative prices in this scenario is 2028 with a total of 177 hours.
3. **Low carbon support payments, including both CfDs for Renewables and Renewable Obligation Certificates (ROCs) are an important driver of negative prices.**
   - The opportunity cost of low carbon support which is paid based on output generation is one of the most important drivers of negative bidding.
   - The amount of low carbon capacity in receipt of support payments may be more important in determining the number of negative prices than the total low carbon capacity in itself.
   - This means that as more low carbon generating capacity reaches the end of the term of its support payments, the incidence of negative prices could decrease – even though the overall quantity of installed low carbon capacity might not.
   - For example, in the Policy scenario the incidence of day-ahead negative prices falls from 2033 onwards with four or fewer 6+ hour events per year over the period 2035-2040, even though the total installed low carbon capacity increases.
   - The bidding incentives and support levels are such that RO-supported plant are likely to offer less negatively than equivalent CfD-supported plant.

- This means that when negative prices occur in the period to 2037, the marginal power plant which sets the price is likely to be one which is supported under the RO and not CfDs for Renewables.

4. **The number of negatively priced hours is very sensitive to the assumed bidding behaviour of low carbon generators.**
   - The above messages are dependent on the assumption that generators offer into the day-ahead market based on their strictly variable operating costs minus the opportunity cost of support payments.
   - There is evidence from historical negative pricing which has been observed in the balancing market that low carbon generators could offer lower than this, particularly closer to real time in the intra-day and balancing markets.
   - If low carbon generators did price a further discount in to their offers, for example to avoid incurring technical or commercial shut-down or start-up costs, then the number of negative prices could be substantially higher.
   - In our modelling of the intra-day timeframe, we assumed that wind generators did further discount their offers – this combined with lower system flexibility to respond to changes in forecast generation and demand resulted in an increase in the number of negative price hours in the Policy scenario from 93 (day-ahead) to 974 (intra-day) in 2035, and an increase from 14 to 548 in 2040.
   - The 6+ hour trigger for subsidy payments to fall to zero under CfDs for Renewables is based on day-ahead prices, and so further changes to prices closer to real time would not affect CfD payments.
5. **Flexible interconnection to other markets plays an important role in mitigating against day-ahead negative prices in GB, in both the day-ahead and intra-day timeframes.**
   - Our detailed modelling of both GB and wider European markets captures the impact of interconnection with other countries on negative price outcomes in GB.
   - GB is predominantly exporting during periods of low GB prices, and when GB prices are negative, in both core scenarios.
   - Lower future new build of interconnection could significantly increase the frequency and duration of negative price events.
   - Capping interconnector capacity at 7.2 GW in the Policy scenario results in an increase in the number of negative price hours from 104 to 144 in 2030 and from 14 to 53 in 2040.
   - In our intra-day modelling we assumed that interconnectors were fully flexible to re-optimise their import / export position in response to market developments – this is consistent with aims of the European Target Model for electricity markets.
   - If GB interconnection is not flexible to change its import / export position intra-day, this is likely to substantially increase the number of negative prices.

- For example, in a sensitivity on the Policy scenario with no interconnector flexibility post-day-ahead trading, the number of negative price hours increased from 273 to 767 in 2030 and from 974 to 1678 in 2035[41].

6. **More electricity storage could help reduce the future incidence of negative prices in GB.**
   - We have investigated the effect of a greater quantity of electricity storage, such as batteries, on the number of day-ahead negative prices in the Policy scenario.
   - An extra 2 GW of electricity storage reduced the number of negative price hours from 104 to 51 in 2030 and the number of 6+ hour negative price events from seven to three.
   - Additional 'quick cycle' storage (with output duration of less than five hours) is more effective at reducing the incidence of short-duration price events of less than six hours than those lasting many hours.

7.2 Caveats and limitations

There are a number of features and of the analysis we have carried out and the assumptions we have used which may affect the negative price outcomes, including:

- Renewable re-powering:
  - We have made the implicit assumption that old wind capacity is re-powered and stays on the system once it reaches the end of its lifetime, and that the re-powered capacity does not receive support payments.
  - If old capacity was simply closed, or additional brand new capacity built, this could affect negative price outcomes in the long term.
  - Based on the bidding assumptions we have made in our day-ahead scenario modelling:
    - An outcome which resulted in less renewable / wind capacity on the system in receipt of subsidy payments would, all else being equal, reduce the frequency and duration of negative price events.
    - An outcome which resulted in more renewable / wind capacity on the system in receipt of subsidy payments would, all else being equal, increase the frequency and duration of negative price events.
- Future availability of CfD contracts:
  - We have assumed new CfD contracts are available to all technologies to the end of the modelled timeframe.
  - If CfD support ended sooner for some technologies, this could reduce the frequency and duration of negative price events (all else being equal).
- We have taken a single 'snapshot' of the intra-day timeframe:
  - Our intra-day analysis effectively models a single intra-day 'auction'.

[41] Note that the intention of this sensitivity was to establish the 'range' of outcomes by considering the extreme case of zero intra-day flexibility for interconnection. This should not necessarily be taken as a realistic outcome as it would not comply with the requirements of the EU Target Model.

- We have not attempted to capture the ‘continuous’ nature of the intra-day timeframe.

- Historical basis for scarcity rent calculation:
  - Our scarcity pricing methodology is based on analysis of historical price outcomes.
  - If bidding behaviour changed in the future market – for example, prompted by changed in the generation mix or the introduction of the capacity market – actual outcomes could differ.
  - However, we note that the principal periods of interest in this study – those with low or negative prices – have no positive scarcity value, so would be unlikely to be affected.
- We have not attempted to model reactionary bidding behaviour:
  - If CfD-supported generators aware of the 6+ hour negative price event rule foresee 4-5 hours of negative prices in the day-ahead reference market, this may influence their bidding behaviour, or that of their wider portfolio.
  - Behaviour of this nature is very difficult to model, requiring the application of game theory, and we have not attempted to do so in the current study.

Appendix A Modelling inputs

Commodity Price Assumptions

Figure 45 Brent crude oil assumptions

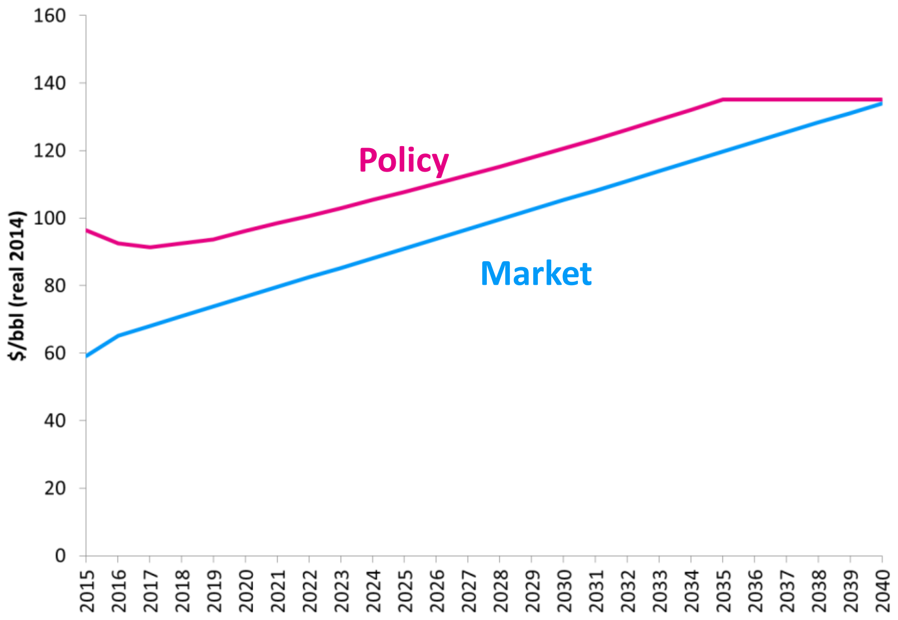


Figure 46 NBP gas price assumptions

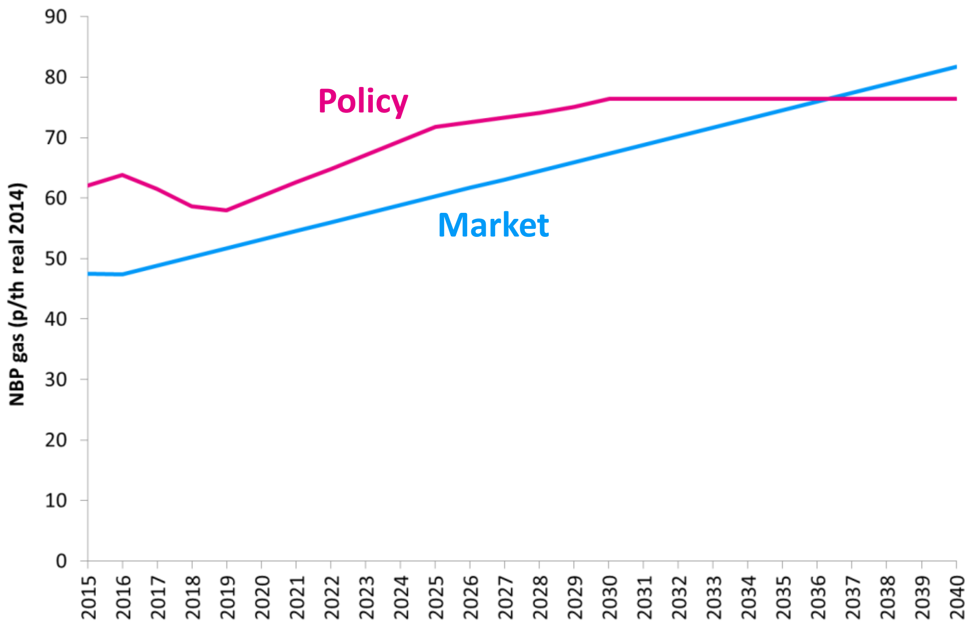


Figure 47 Coal price assumptions (ARA CIF)

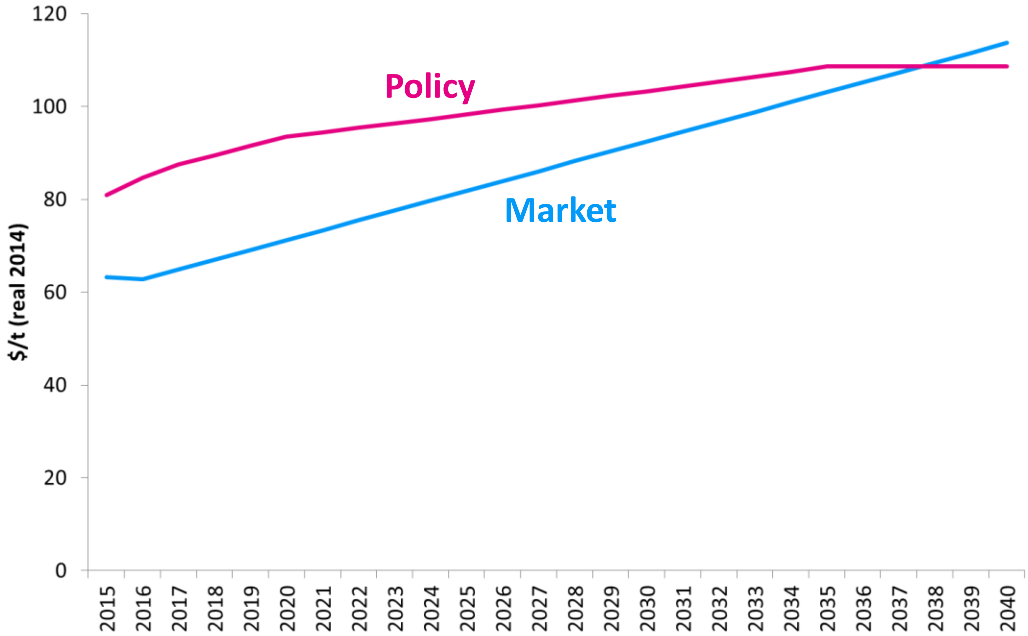


Figure 48 EUA carbon price assumptions

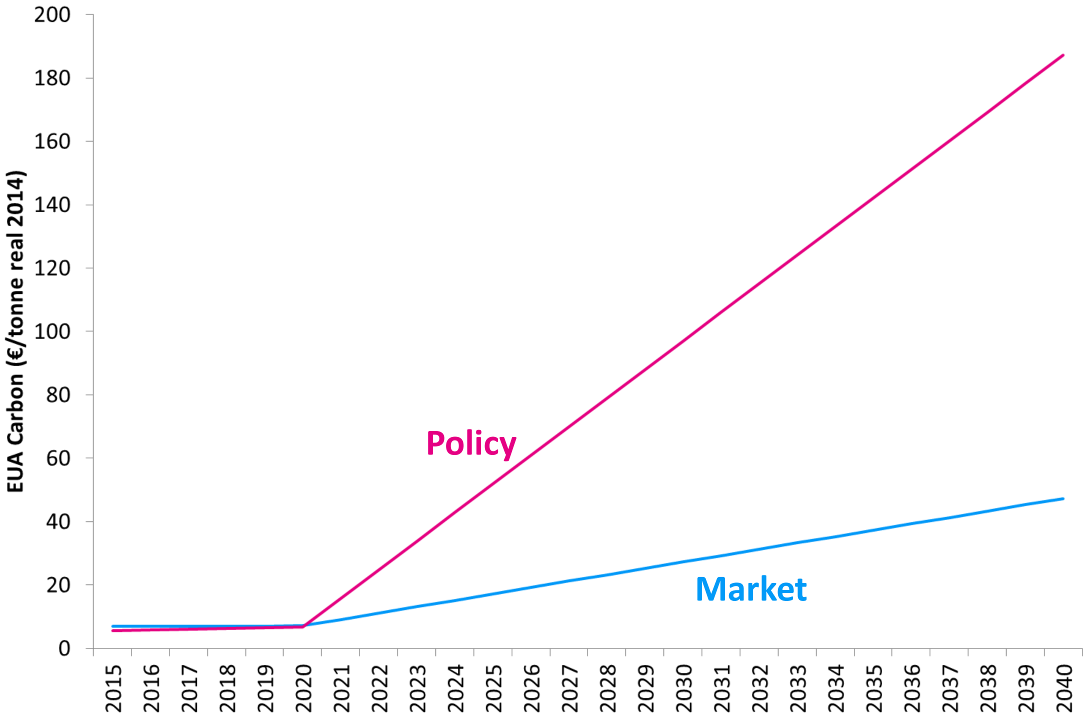


Figure 49 GB all-in carbon price assumptions