Sustainability First

GB Electricity Demand Project – *realising the resource*

Paper 9

GB Electricity Demand – 2012 and 2025.

Impacts of demand reduction and demand shifting on wholesale prices and carbon emissions. Results of Brattle modelling.

Authors

Serena Hesmondhalgh. The Brattle Group.

Gill Owen, Maria Pooley & Judith Ward. Sustainability First.

January 2014
Published by Sustainability First

Sustainability First

GB Electricity Demand Project – ***realising the resource***

Paper 9

GB Electricity Demand – 2012 and 2025.

Impacts of demand reduction and demand shifting on wholesale prices and carbon emissions. Results of Brattle modelling.

Authors

Serena Hesmondhalgh. The Brattle Group.

Gill Owen, Maria Pooley and Judith Ward. Sustainability First.

January 2014
Published by Sustainability First

Sponsored by : BEAMA ; British Gas ; Consumer Futures ; EDF Energy; Elexon ;
e-Meter Siemens ; E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ;
Scottish Power Energy Networks ; UK Power Networks ; Vodafone.

Smart Demand Forum Participants : Sponsor Group ; Energy Intensive Users' Group ;
Consumer Futures ; Which ? ; National Energy Action ; Ofgem ; DECC ; Sustainability First.

Preface

Sustainability First

Sustainability First is a UK environment think-tank with a focus on practical policy development in the areas of sustainable energy, waste and water. Sustainability First undertakes research, publishes papers and organises policy seminars. It is a registered charity with independent trustees – http://www.sustainabilityfirst.org.uk.

Since 2006, Sustainability First has produced a series of major multi-sponsor studies on GB household smart energy meters and brings significant knowledge and insight in the fields of energy efficiency, smart metering, smart energy tariffs and demand response.[1]

The Sustainability First project '**GB Electricity Demand – *realising the resource***' is a three-year multi-partner project (2011-2014) focusing on the potential resource which the electricity demand side (industrial, commercial and household customers) could bring to the GB electricity market, through both demand response and demand reduction.

Key themes for the project include:

- Customer Response and Consumer Issues.
- Commercial and Regulatory Issues.
- Public Policy Issues.

The project was supported in its first year under the Northern Powergrid Low Carbon Network Fund project - and thereafter for a further two years to 2014 via a multi-sponsor group.

Sponsors include : BEAMA ; British Gas ; Consumer Futures ; EDF Energy; Elexon; e-Meter Siemens ; E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ; Scottish Power Energy Networks ; UK Power Networks ; Vodafone.

Work is coordinated through a **Smart Demand Forum,** whose participants include the sponsor group together with Ofgem, DECC and key consumer bodies: Energy Intensive Users Group, Consumer Futures, Which? and National Energy Action.

The project is:

- Evaluating and understanding the potential GB electricity demand-side resource across all economic sectors (including the role of distributed generation and micro-generation) ;
- Developing a clearer understanding of the economic value of this resource to different market actors and to different customers over the next 10-15 years ;
- Evaluating the key customer, consumer, commercial, regulatory and policy issues and interactions.

[1] Sustainability First published smart meter papers are available on the website – www.sustainabilityfirst.org.uk

The project is developing a substantive knowledge-base, and provides visibility and thought-leadership for GB electricity demand-side issues. The project is undertaking work relevant to:

- GB smart meter deployment.
- Low Carbon Network Fund and Network Innovation Competition projects.
- Electricity Market Reform proposals for the electricity demand-side (DSR & electricity demand reduction).

The work programme is being delivered through the Smart Demand Forum, through wider stakeholder events, and through twelve published papers. Additional expertise and input is being provided by Serena Hesmondhalgh of The Brattle Group who has developed a quantitative all-sector electricity end-use demand model.

The project also draws upon relevant information from demand side developments in other countries to inform its work (notably the EU, US and Australia).

Sustainability First
January 2014

GB Electricity Demand – 2012 and 2025.

Impacts of demand reduction and demand shifting on wholesale prices and carbon emissions. Results of Brattle modelling.

Table of Contents

List of Figures and Tables

1. Executive summary

This paper outlines the results of combining :

- A model of end-use demand by sector (domestic, commercial and industrial) and usage within those sectors (heating, lighting, hot water, appliances etc); and

- A model of electricity wholesale market dispatch

to investigate the likely impacts on wholesale prices and carbon emissions of assumed levels of demand reduction (including energy efficiency) and demand shifting (shifting demand from one time of day to another.

The paper does not consider the networks perspective – except to note briefly the degree of convergence or divergence between wholesale and network side costs and impacts. We will address network issues further in Paper 12.

1.1. Key findings from the modelling

Key findings from the modelling described in this paper can be summarised as follows:

Before '2020'

Winter evening peak-related load will continue to drive wholesale electricity costs and prices. This means that:

- Reductions in peak demand – be that temporarily from peak shifting or permanently from demand reductions – will deliver cost savings and greater efficiency in the electricity system as a whole.
- If the current merit-order persists, with the operating costs of coal plants *below* those of gas plants, most carbon reduction will be achieved during the summer months.
- Network and wholesale cost drivers are well aligned since both will wish to reduce costs in the electricity system at traditional peak times (winter weekday evenings).
- As intermittent generation increases there may be a need to better align load (demand) with low carbon generation. Electric vehicles, heat pumps and storage heaters could all be used to help align load with generation.
- On the retail side, static time-of-use tariffs (e.g. for households) might therefore be useful in this period to support cost-efficiency in the electricity system. However, the practicality of these tariffs *before* 2020 may be limited, particularly in the household sector, as smart meters will not be fully rolled out until 2020.

After '2020'

- Our modelling indicates that after 2020, wind and other low carbon generation will increasingly start to determine wholesale prices at times of low demand. The prices these generators offer into the wholesale markets will reflect the support which they also receive via feed-in-tariffs (FiTs), or Contracts for Difference (CfDs) or the Renewables Obligation (RO) (i.e. they are likely to have less need for full long-run cost-recovery via short-run wholesale market prices). In addition, the introduction of the capacity mechanism is likely to reduce the need for conventional generation to recover all of its costs from wholesale market prices alone. The combination of these two effects is likely to create a general downward pressure on short-run wholesale market prices, even though total wholesale costs passed through to retailers will include recovery of *all* costs (i.e. including CfD, RO and FiTs). Winter evenings may no longer always be the highest priced period for the wholesale side of the electricity system : low wind output can occur at any time, and hence the potential at any time for demand to be high but supply relatively low.[2]
- Our modelling indicates that post-2020, the incentives of networks and suppliers to reduce peak-loads may increasingly diverge. Network costs will continue to be driven by evening peaks in demand whilst wholesale prices will increasingly have more variability throughout the day, depending upon wind output. Generators will also become somewhat less dependent on high peak prices to recover their fixed costs, if they receive capacity payments.
- Electricity demand reduction (at any time not just peak) could reduce the need for new generation capacity and hence reduce the costs to customers of the RO, FiT / CfDs and the capacity mechanism. Both demand side shifting and demand reduction are likely to have increasingly less impact on carbon emissions as electricity generation decarbonises.

1.2. Policy implications

As well as considering the impact of demand reductions and demand response on wholesale prices and carbon emissions, our modelling also considers the impact of electricity market reform on the potential value of the demand side in the electricity system. We conclude that key electricity market reform initiatives (capacity mechanism, FiTs / CfDs) could reduce the potential value of demand reduction and shifting to suppliers and end-customers. If this reduces the role of the demand side in the electricity system, this could lead to higher costs for consumers than would otherwise be the case with more demand reduction and demand response, because consumers will have to pay (via the capacity mechanism and FiTs / CfDs) to support more generation than they otherwise might have done. However, we note that aspects of the electricity market reform package may support some demand side response initiatives (e.g. via the scope for demand side bidding into the capacity mechanism).

---

[2] although work by Pöyry suggested low wind speeds may be more likely in the morning than the evening

[3] This is not entirely certain, since the output of embedded generation could reduce net flows at this time in certain locations below those at other times.

[4] 'Consultation on options to reduce electricity demand – Government Response' May 2013, DECC. See www.gov.uk/government/consultations/options-to-encourage-permanent-reductions-in-electricity-use-electricity-demand-reduction

[5] By Pöyry Energy Consulting and University of Bath, for DECC. Published November 2010.

1.3. Recommendations

These conclusions lead us to a number of policy recommendations:

- The potential impact of the capacity mechanism and FiTs / CfDs on wholesale prices increases the need for substantial early action (over the next few years) to reduce demand overall and to improve electricity load factors (demand shifting and peak smoothing).
- Policies already in place such as Green Deal and ECO should be used effectively to support electricity demand reduction and demand smoothing.
- Tariff initiatives such as wind-twinning and other measures to support dynamic tariffs such as customer and grid level storage and flexible load could be useful to support efficiency in the electricity wholesale market for suppliers. Dynamic critical peak pricing tariffs could be relevant both for capacity support and / or to the networks but half-hourly settlement would be needed.
- Automation may be required to support both supplier demand-side response needs and also dynamic peak pricing at scale. Measures to increase the scope for automated response (such as product standards) therefore merit early attention.

Introduction

2.1. Scene-setting

The GB Electricity Demand project has sought to understand the potential for demand reduction at peak times, and shifting of demand away from peak times, for reasons of:

- Electricity system cost efficiency;
- Carbon reductions;
- Affordability;
- Security of supply – resilience at least cost.

Today's GB electricity system is planned, designed, built and operated to serve the maximum peak in demand. Therefore, distribution networks, transmission networks, and installed generation capacity are all sized to be able to cope with the maximum winter peak demand (generally winter week-day between 5-7pm). Whilst this is likely to remain the case for the networks[3], it may change on the wholesale side. In future, the peak requirement for conventional generation (coal, oil, gas, nuclear) may not necessarily coincide with the evening peak – increasing levels of intermittent generation, primarily wind and solar, may lead to the maximum requirement for conventional generation occurring at almost any time. Consequently, in thinking about the importance of peak demand going forward, it will be necessary to separately consider network and wholesale (generation) issues. DECC have recognised the importance of the higher costs associated with delivering peak demand in their recent response to the Electricity Demand Reduction Consultation[4], where it outlined its preferred incentive mechanism for delivery of energy reduction potential as being through the Capacity Market**.**

This paper examines the generation (wholesale market) issues. We will consider the network issues in Paper 12.

[3] This is not entirely certain, since the output of embedded generation could reduce net flows at this time in certain locations below those at other times.
[4] 'Consultation on options to reduce electricity demand – Government Response' May 2013, DECC. See www.gov.uk/government/consultations/options-to-encourage-permanent-reductions-in-electricity-use-electricity-demand-reduction

Capacity Market and other Electricity Market Reforms (EMR)

The Government is legislating for a Capacity Market to ensure security of electricity supply because many older power plants are closing and the investment case for reliable capacity is considered to be uncertain. The Government will run the first Capacity Market auction in 2014 for delivery of capacity from the winter of 2018/19. The Capacity Market will provide a predictable revenue stream to capacity providers. The level of revenue will be set through a competitive auction process and in return for payment, successful providers must commit to deliver energy when needed or face penalties. It is intended that demand side response, demand reduction and storage should be able to participate in the capacity mechanism as well as generation. Capacity receiving support through the Renewables Obligation (RO), Contracts for Difference (CfDs), or small scale Feed in Tariffs (FiTs) will not be eligible to participate in the capacity market – this is to avoid over-compensation.

The Capacity Market, CfDs, FiTs and RO will operate alongside the electricity wholesale markets where participants will continue to earn revenues. However, as participants will have these other sources of revenue, it is expected that the Capacity Market, CfDs, FiTs and RO will have a dampening effect on wholesale electricity prices.

2.2. What this paper does

This paper outlines the results of combining:

- A model of end-use demand by sector (domestic, commercial and industrial) and usage within those sectors (heating, lighting, hot water, appliances etc). This model was originally developed by Brattle for Sustainability First in 2011 and has now been updated by Brattle to take account of some more recent data.
- A model of electricity wholesale market dispatch (the Brattle Annual Model)

to investigate the likely impacts of assumed levels of demand reduction and demand shifting on wholesale prices and carbon emissions.

The main aims of the paper are to:

- Identify the different impacts of demand reduction and demand shifting on wholesale prices and carbon emissions in the electricity wholesale markets in 2020 and 2025.
- Assess whether in the future the traditional evening peak may no longer be the highest-cost time of day in the wholesale markets, assuming a highly electrified future

and a high level of wind generation in the system, We use the model to explore whether and when this change may be likely to occur.

Assess what impact a high proportion of wind in the generation mix might have on wholesale market prices at different times of day and at different times of the year. The paper also briefly considers a number of other issues including:

- The potential impact of some aspects of electricity market reform (EMR) on demand response;
- What types of demand response tariffs might best be suited to the pre-2020 and post 2020 electricity markets;
- What types of demand might be most suitable for demand reduction or demand shifting.

We will return to these issues in more detail in Paper 12.

The paper does not consider the networks perspective – except to note briefly the degree of convergence or divergence between wholesale and network-side costs and impacts. We will address network issues further in Paper 12.

We provide an important health warning on this paper. As with all modelling, it relies on assumptions. We recognise that other models may utilise other assumptions and therefore reach different conclusions. We have aimed to be as clear as possible about what assumptions we have made.

2.3. Previous studies

This paper aims to build on research already carried out for DECC, Ofgem and by consultants. Two key research papers in this area are briefly summarised below.

'**Demand side response : conflict between supply and network driven optimisation'**[5] (2010).

This paper debates whether in a future where wind output and consumer demand at winter evening peak are assumed not to correlate, it would be most efficient to (1) maximise wholesale cost savings by wind-balancing (shifting demand into high-wind low-priced periods) and building networks to meet peak demand, or (2) maximise cost-savings through peak-avoidance, and build networks to meet a level of demand which is inflexible.

The report concludes that there is no difference in likely costs between the two different approaches, but security of supply goals could be achieved by shifting demand away from low-wind periods and building networks to meet peak demand. In contrast, the paper

[5] By Pöyry Energy Consulting and University of Bath, for DECC. Published November 2010.

concludes that focusing only on peak-avoidance could risk security of supply if there was a failure to deliver firm demand side response (DSR) at peak times.

'Electricity System Analysis – future system benefits from selected DSR scenarios' (August 2012) Baringa, Redpoint, Element Energy for DECC.

This study assessed the benefits of DSR in terms of avoided distribution network investment, avoided generation investment and avoided operational generation costs. The scope of the study was limited to domestic and small and medium enterprise (SME) demand – the domestic sector was fully modelled using a GB electricity market model, while the SME sector was explored at a high level. Three types of DSR approaches were considered: Static Time of Use pricing, Critical Peak Pricing and Load Control. The study also modelled four different levels of electrification of demand (heat and transport): low, central, high and high heat pump penetration.

The greatest potential for savings was identified as being from reduced investment in open cycle gas turbine (OCGT) peaking plant and avoided distribution network reinforcement costs, as well as reduced operational generation costs, by adopting the Load Control 2[6] tariff under the High electrification scenario.

Potential benefits were observed to increase over time due to the assumed increase in both flexible loads and the uptake of more dynamic DSR tariffs (load control, critical peak pricing).

The dynamic DSR tariffs in the Redpoint model began to show material incremental benefits over Static Time of Use tariffs in 2025 under Central and High electrification scenarios.

Notably, with increasingly high penetration of flexible domestic load (particularly heat pumps), the potential for peak demand reduction via DSR load shifting was found to become limited by an increasing overlap with the non-domestic load peak. Additionally, modelling results were observed to be highly sensitive to assumptions regarding heat pump penetration, dynamic tariff uptake, DSR peak window definition among others.

3. Data sources as modelling inputs

Subject to the necessary safety and privacy safeguards, data on electricity end-use can help unlock many different ways of engaging with customers on the demand-side by:

- Understanding realistic demand-side potential;
- Targeting particular end-uses – for demand reduction and shifting;
- Targeting particular customer groups;
- Targeting particular appliances (heat pumps, electric vehicles).

[6] Load Control applied on all days of the year.

3.1. Empirical electricity end-use - what data sources are available?

As noted in our earlier GB Electricity Demand project papers, there is presently a lack of empirical data on electricity end-use by process, by appliance and by time of day. Consequently, we concluded that it is difficult to target peak demand without better insight into what demand mostly contributes to peak.

Our Paper 1[7] and the Sustainability First note on 'DECC Electricity Demand Data Sources'[8] further explored the issues of data. The latter found that the models used by DECC to provide disaggregated data on electricity end-use were somewhat historic.

The GB Electricity Demand project's second paper[9] was centred around the development of an electricity end-use model. However, this initial model was limited by the available data inputs. The model used available data sources to develop a picture of electricity demand end-use in time: by time-of-day (24 hours), by weekday/weekend day and seasonally. This allowed us to identify some of the key electricity end-uses, and begin to identify which end-uses could potentially be shifted away from peak or reduced. These included peak time lighting in the commercial and domestic sectors (particularly the commercial sector), which could be reduced through the use of more efficient lighting technology such as LEDs.

3.2. New data to inform our model

We begin with a caveat. Whilst there have been a number of new reports published, there are still important limitations in the data available. Most notably there is a lack of empirical data on electricity use within the industry sector – by time-of-use and by appliance/process. The Energy Efficiency Strategy[10] (November 2012), noted the kind of data gaps Sustainability First had identified, namely data on industrial load disaggregation.[11]

---

[7] Paper 1 'GB Electricity Demand – Context and 2010 Baseline Data (2011), Gill Owen, Judith Ward and Maria Pooley, Sustainability First, www.sustainabilityfirst.org.uk/publications.htm

[8] 'DECC Electricity Demand Data Sources – Summary Note' (March 2012), Richard Hoggett. See www.sustainabilityfirst.org.uk/publications.htm

[9] Paper 2 'GB Electricity Demand – 2010 and 2025. Initial Brattle Electricity Demand-side Model – Scope for Demand Reduction and Flexible Response' (2012), Serena Hesmondhalgh and Sustainability First. See www.sustainabilityfirst.org.uk/publications.htm

[10] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65602/6927-energy-efficiency-strategy--the-energy-efficiency.pdf

[11] Hoggett, R. op cit

The new and updated data that we have used to inform the model are as follows.

'Household Electricity Survey – A study of domestic electrical product usage' (2012).[12]

Commissioned by DECC, Defra and the EST, this report was the result of the first detailed electricity end-use survey in the domestic sector for over 20 years (since the demise of the Electricity Association). The survey monitored electricity demand within households, by appliance including: refrigeration, cooking, lighting, audio-visual, ICT, washing/drying, water heating.

The survey included 251 households in England. However, only **25 were monitored for a whole year**, with the remainder being monitored **for one-month periods** at intervals throughout the year. The report depicts demand profiles for different types of household and end-use streams, over the course of a day, weekly and seasonally.

The first research report **- 'Early findings – demand side management'**[13] presents 24-hour demand profiles for the 250 households, examining peak power and demand shifting, standby power, baseload power, secondary electric heating, and 24/7 appliances. Our model incorporates data on household electricity consumption by appliance from this study.

Demand side response in the non-domestic sector'(2012). Element Energy and DeMonfort University for Ofgem.

This report characterised electricity demand in the commercial and services sector and estimated the potential for DSR across different sub-sectors and by end-use. It includes 24-hour estimated demand profiles for a number of sub-sectors, such as Education, Retail, Sports and Leisure, Health, Warehouses and Commercial Offices, and a breakdown of their electricity demand by end-uses, grouped into Catering, Computing, AC & Ventilation, Heating, Hot Water, Lighting and Other. The report also characterised different types of end-uses as to their suitability for different DSR measures (including current DSR services and potential measures such as Critical Peak Pricing). Our model incorporates some of the estimated commercial sub-sector load profile data from this study.

Updated data – data sets which were used in the development of the original model in 2011, and have been updated with more recent data for this 2013 model:

- Elexon - load profile coefficients by half-hour.
- March 2013 Energy Trends. DECC. Quarterly demand data by sector (domestic, commercial, industrial) for 2012.
- Energy Consumption in the UK – annual breakdown by end use and sector for 2011 (DUKES).
- National Grid Electricity Transmission – total demand data for each half-hour between 1 April 2012 and 31 March 2013.

[12] Household Electricity Survey: A study of domestic electrical product usage, Intertek Report R66141, May 2012
[13] Further Analysis of the Household Electricity Use Survey, Early Findings: Demand side management, Element Energy & Loughborough University, June 2013

3.3. Additional forthcoming data

There are a number of projects which will in future assist us in gaining a better insight into electricity end-use.

Cambridge Architectural Research, Element Energy and Loughborough University are carrying out further work on the '**Household electricity survey'** data set. This includes :

- 'Appliances ownership and usage patterns'
- The 'Scoping study for a National Monitoring Survey using Smart Meters'
- Reports on 'Extreme users', 'Social studies and Policy' 'Updating modelling', and 'Updating electricity use statistics by appliance'

In addition, data and reports from low carbon network fund (LCNF) projects will increasingly become publicly available in the next two years.

4. Brattle Modelling Methodology

4.1. Demand Model - methodology and assumptions

The Brattle end-use demand model (used to produce Sustainability First Paper 2) has been updated to take into account more up-to-date high-level consumption data and to adjust the hourly end-use profiles for the commercial and domestic sectors on the basis of new survey work. The hourly data for the industrial sector remains the *residual demand* i.e. the difference between total consumption and the sum of commercial and domestic demand. Similarly, the hourly breakdowns by industrial process remain 'informed guesses', because no new data is available to improve this analysis.

The overall shape of domestic demand provided by the Household Electric Survey (HES) did not precisely match the Elexon load profiles for domestic demand. This is not particularly surprising since the HES covered only relatively few households (see description in preceding section). To overcome this problem, we scaled the HES end-use data to match the Elexon profiles and then calculated, for each end use, the percentage of the day's consumption falling into each hour. These percentages were then applied to the estimated monthly end-use demands, which we continue to derive so as to match the DECC quarterly sector estimates. We recognise that there may be some limitations in this due to the small sample sizes in the HES. The HES data also showed significant unidentified consumption – the 'other' and 'unknown' categories. This demand has been included in the 'other space heating' category since it has been suggested that at least part of the demand might relate to running electric pumps for gas boilers.[14]

[14] Currently, approximately 0.2 kW per boiler.

The two scenarios that we use for 2025 remain unchanged – a 'Business-as-Usual' and a 'Greenest' case, taken from the data in the DECC 2050 Pathways analysis. We take the assumptions of uptake and usage of heat pumps and electric vehicles from this analysis. In particular this means an assumption on our part that :

- Heat pump demand is treated as constant across each day and non-flexible - and
- Electric vehicle demand does not alter by season and its daily profile assumes that charging begins when drivers return home (consistent with Figure 17 from the Energy White Paper, which is stated to be derived from the 2050 Pathways 'Spread Effort' pathway).

4.2. Electricity System Modelling

An important new element has been added to this updated model to our previous demand-side analysis : namely, modelling of the likely impact of demand reductions and demand shifting on wholesale prices and carbon emissions both now and in the future (2025).

The electricity system modelling relies on the Brattle Annual Model (BAM), which is a proprietary generation dispatch model developed by The Brattle Group.

The model schedules the output of plant to meet demand at lowest cost over the course of a year, taking into account constraints on the availability of plant and their running flexibility.[15] We run the generation dispatch model stochastically, sampling from distributions for wind output and forced outages and focus our attention on the *mean* results. We adopt this approach to take account of the increasing impact of wind intermittency on the GB electricity market. The model outputs that are relevant for the analysis in this paper are : (1) hourly wholesale prices and (2) carbon emissions. Consequently, the dispatch model can be used to investigate the impact of changing demand assumptions whilst holding all other assumptions constant. Further details regarding BAM can be found in Appendix 2.

[15] On the one hand, plants, such as nuclear and CHP plants, can be designated as 'must run' and the model will ensure that they generate at a user-specified minimum load factor. On the other hand, the model can limit the output of intermittent plants, such as wind or solar plants, so that they do not produce more than a specified level for any given half hour. In addition, the monthly output of hydro can be constrained between minimum and maximum levels.

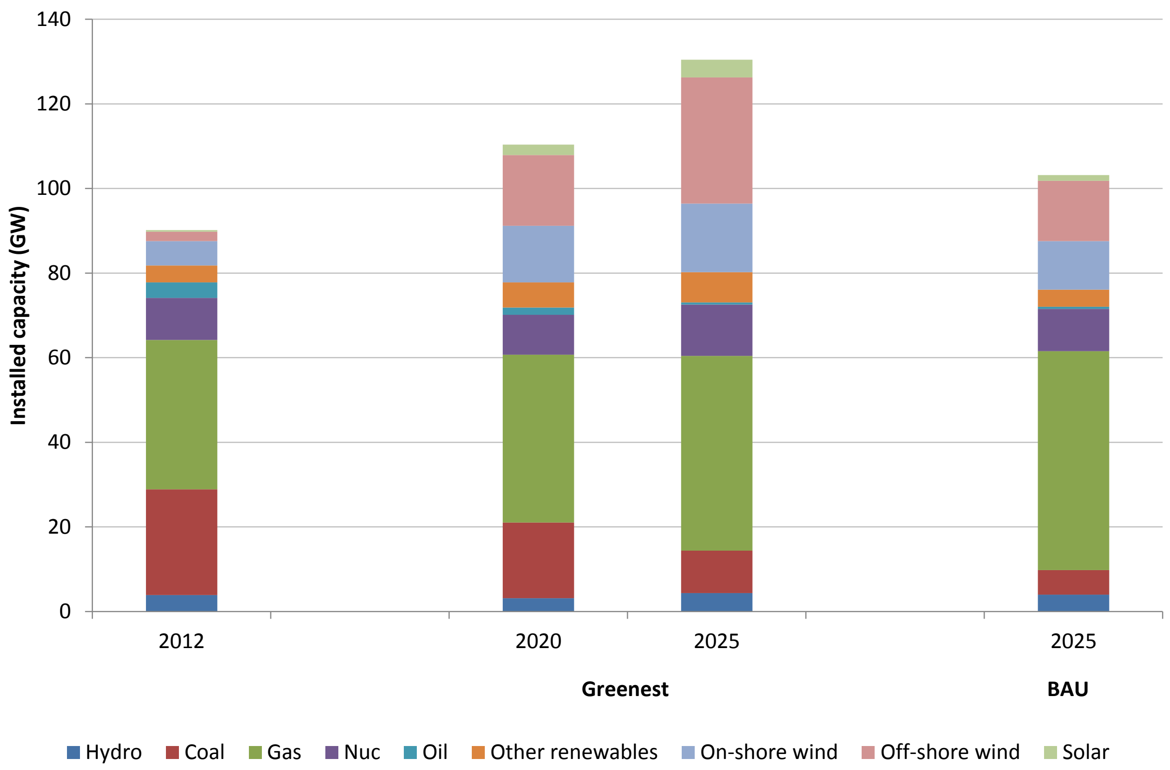
The key feature of the modelling results reported in this paper is the combination of electricity wholesale market dispatch modelling and bottom-up demand modelling, to assess impacts of demand shifting and demand reduction on wholesale prices (and vice versa) and on emissions.

As with any dispatch model, it is necessary to provide data on : the plant on the system (capacity, efficiency, fuel source, and availability) ; demand (in the case of BAM, hourly demand for 4 characteristic days per month) ; fuel ; and carbon prices.

We have relied upon the assumptions in National Grid's 2012 Ten Year Statement for the plant data. Specifically, we have assumed that the 'Business-as-Usual' scenario is consistent with National Grid's 'Slow Progression' case and the 'Greenest' scenario with its 'Gone Green' case. The resulting plant mixes are shown in **Figure 1** below.

The total installed capacity in 2025 is higher under the Gone Green scenario than the Slow Progression scenario because of the low load factor of wind plants. This means that more capacity is required to generate the same volume of electricity as the share of wind generation increases. It is also important to note that although the fossil-fuelled capacity in 2025 is comparable in both scenarios, these plants run at much lower load factors in the Gone Green scenario and hence fossil fuel use (and emissions) are lower in this scenario than in the Slow Progression case.

Figure 1: Plant Mix Assumptions



Our fuel price assumptions for 2020 and 2025 have been taken from the latest DECC projections and converted from real to nominal prices on the assumption of an inflation rate of 2% per annum. For the 'Greenest' scenario we have relied on DECC's Low projections, on the assumption that such a case incorporates relatively lower levels of fossil fuel consumption and hence is likely to lead to lower prices for these fuels. For the 'Business-as-usual' scenario we have used DECC's Central projections : fossil fuel consumption is higher under this case but not as high as under National Grid's Accelerated Growth case. Our carbon price assumptions for these years are consistent with the stated aims of the Government's Carbon Price Floor mechanism. Consequently, we have assumed a carbon price of 30 £/t in 2020 and 50 £/t in 2025[16] (these figures are both in 2009 prices, in nominal terms we have used prices of 37.3 £/t and 68.6 £/t respectively).

For 2012, we have relied on actual fuel and carbon prices, as published by Platts (for gas prices) and EEX (for coal and carbon prices).

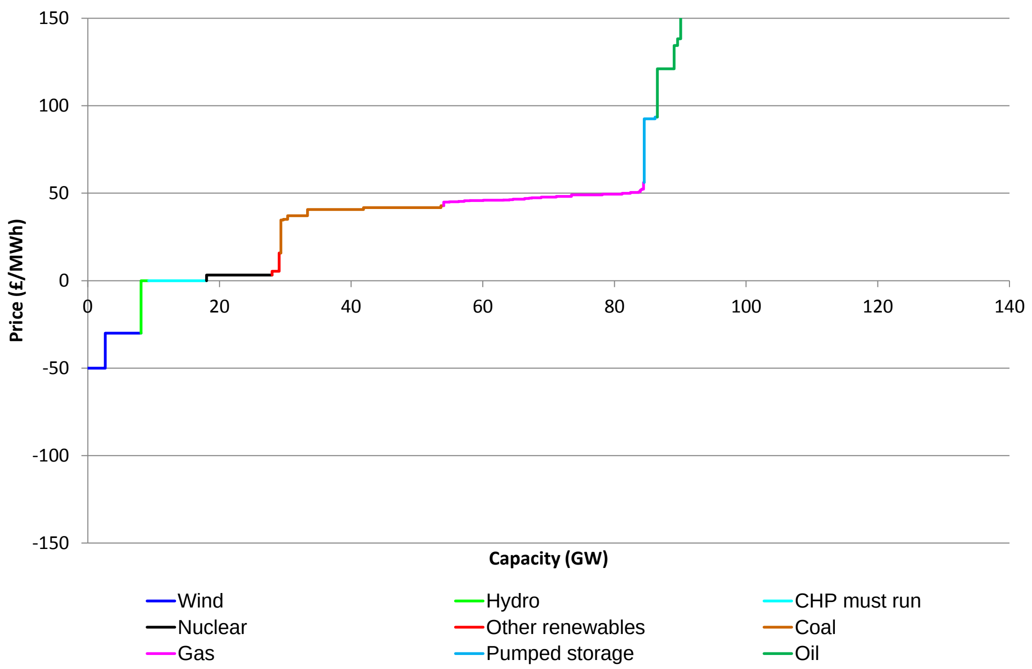
Since our modelling was completed National Grid has updated its scenarios to include higher levels of renewables in both cases, particularly in respect of onshore wind and other renewables.[17] In addition, it has included fuel price views with its new scenarios, including an assumption that the carbon price floor is not achieved under the slow progression scenario. Were we to repeat our analysis using these new assumptions, we anticipate that the 'Business-as-usual' results would then be closer to our current 'Greenest' results and our 'Greenest' results would show even more pronounced effects on prices and emissions from demand reductions. This means that our modelling is *conservative* in the sense that it may under-estimate the likely dampening effect that intermittent generation will have on prices. On the other hand, more wind sooner is likely to lead to a more rapid reduction in the value to suppliers of demand shifting and reduction, as we explain in the next section.

[16] The Government's stated aim is for the Carbon Price Floor to rise linearly from 20 £/t in 2020 to 70 £/t in 2030. This implies a price of 50 £/t in 2025.
[17] National Grid, Future Energy, Future Energy Scenarios (2013). www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/

The merit orders resulting from our assumptions are shown in **Figure 2 to Figure 4** below. We have included negative price offers for wind plants (and nuclear from 2020 onwards) to reflect the fact that the long-run costs of these plants will be (mostly) recovered via the RO mechanism via FiTs/CfDs, rather than directly via wholesale market prices.

Of particular relevance for our modelling results is the fact that in 2012, the marginal costs of coal plant are below those of gas plant. However, under both scenarios, the situation is reversed for both 2020 and 2025.[18] The crucial point is what type of plant is at the margin: if coal is at the margin then demand reductions generate *higher* carbon reductions than when gas is at the margin. This can vary between season and day-types - even for the same merit order. Thus, in 2012, gas is at the margin on winter weekdays but coal is at the margin for at least some of the time on summer weekends.

Figure 2: Merit Order for 2012



[18] For Scenario 1/Slow Progression, there is some intermingling of coal and gas plants but, in general, gas plants are cheaper than coal plants.

Figure 3: Greenest Merit Order for 2020

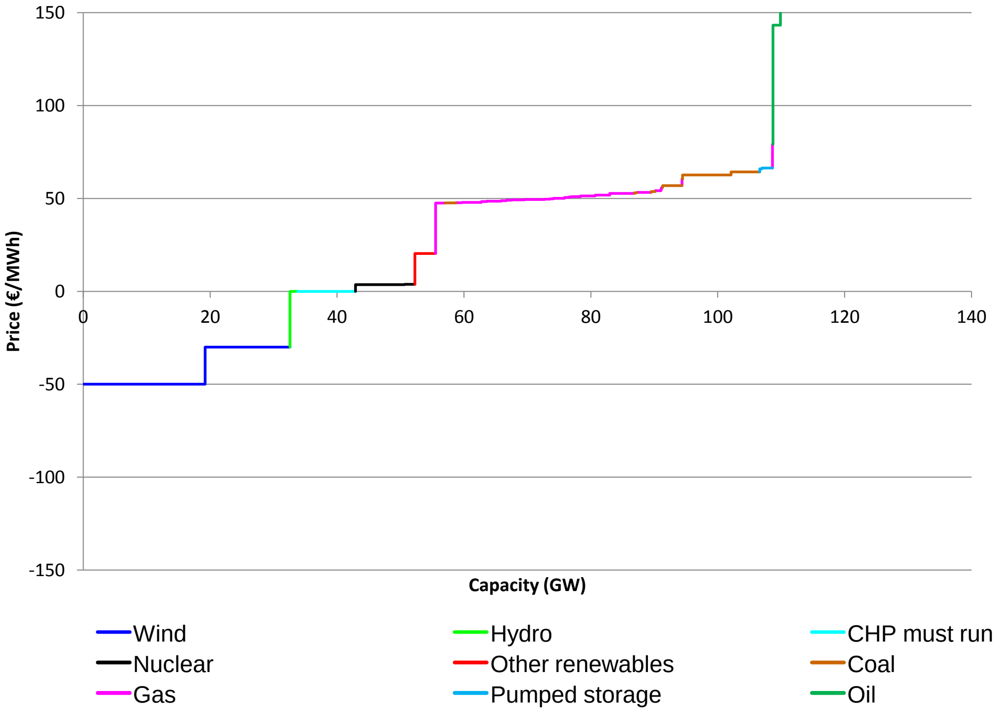
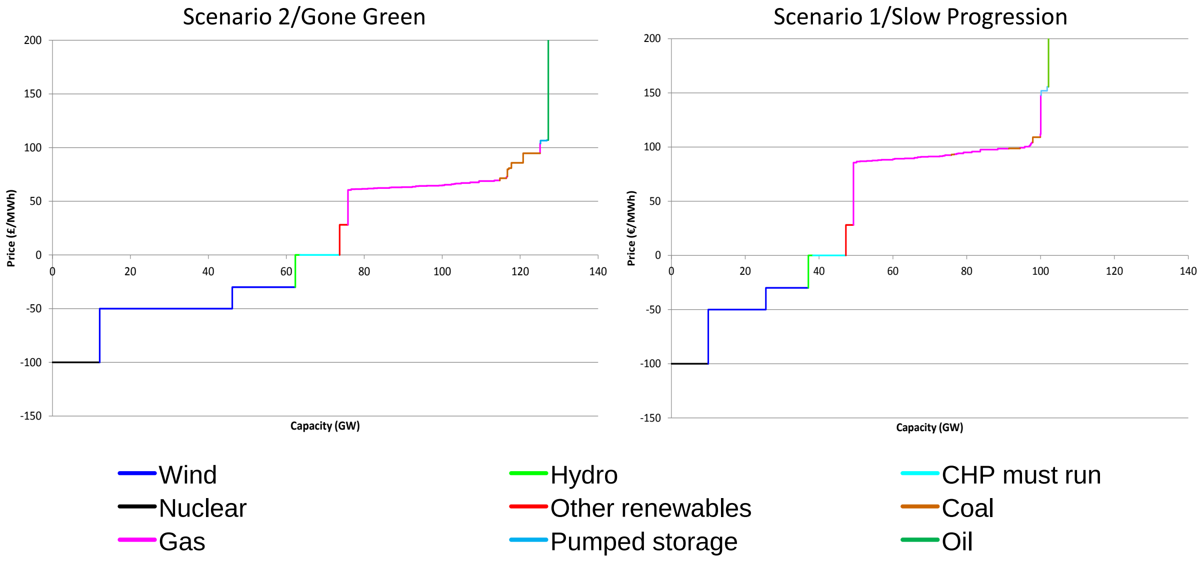
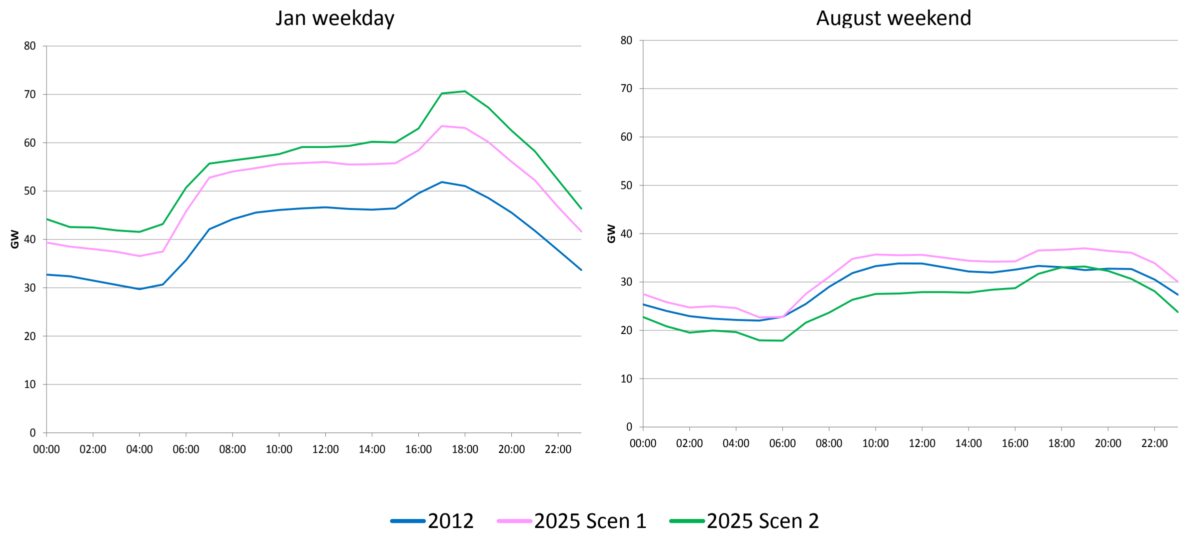


Figure 4: 2025 Merit Orders



The demand assumptions are taken from the Brattle end-use demand model. As **Figure 5** shows, under both scenarios the shape of demand remains broadly similar. However, across January weekdays the combination of electric vehicle recharging and increased electric heating (both heat pumps and conventional heating) results in the 'Greenest' demand being higher than the 'Business-as-Usual' demand, despite the scenario incorporating more aggressive assumptions regarding improvements in lighting and appliance efficiency. However, across August weekends, when there is little heat load, the 2025 'Greenest' demand is both lower than the 'Business-as-Usual' demand and also generally lower than today's 2012 demand.

Figure 5: Comparison of Demand Profiles for 2012 and 2025



5. GB Electricity Demand in 2012 and 2025 - Modelling Results

We have explored the results of demand reductions across the board of 5% and 10% both for the current market and for 2025. Given the results for the 'Greenest' scenario in 2025, we decided that it was also worth investigating the situation in 2020 under this case, to try and determine *when* the level of low carbon generation under such a case might be sufficient to alter the outcomes in terms of price profiles across the course of the day. We also assess the impact of 5% demand shifting on top of a 5% demand reduction.

It is important to note that we have modelled the impacts of **across the board** reductions or shifting – we have not attempted to model shifting or reduction of particular uses (e.g. lighting, heating, wet appliances). We therefore have not incorporated any assumptions into our modelling as to which uses might be most likely to be reduced or shifted.[19]

5.1. Demand reduction and demand shifting possibilities

As in our previous paper, we have used the Brattle end-use demand model to explore what the potential for demand reduction (or demand shifting) might be by sector at different times of the day. We assume that consumption for 'other' space heating (i.e. not remotely tele-switched storage heating), hot water, refrigeration, compressed air and wet domestic appliances may all provide potential for demand reduction or shifting. We have not included lighting because the DECC scenarios already incorporate assumptions on efficiency improvements, including the impact of low energy light bulbs on household demand.

The results from our updated model are shown in **Figure 6** to **Figure 8** below. The potential share of the domestic sector has increased compared to our previous analysis because we have grouped demand which was classified as 'other demand' *together with* 'other space heating'. We made this adjustment because it seemed likely that such unclassified demand was likely to correspond to some form of spot heating (e.g. electric bar heaters or fan heaters) or gas boiler pumps, given that the HES data does not include any electric heating for the majority of the houses surveyed.

[19] We considered this at some length in Paper 2. GB Electricity Demand – 2010 and 2025, Initial Brattle Electricity Demand-Side Model – Scope for Demand Reduction and Flexible Response, Serena Hesmondhalgh, The Brattle Group & Sustainability First, February 2012

Figure 6: Potential for Demand Reduction or Shifting by Sector in 2012

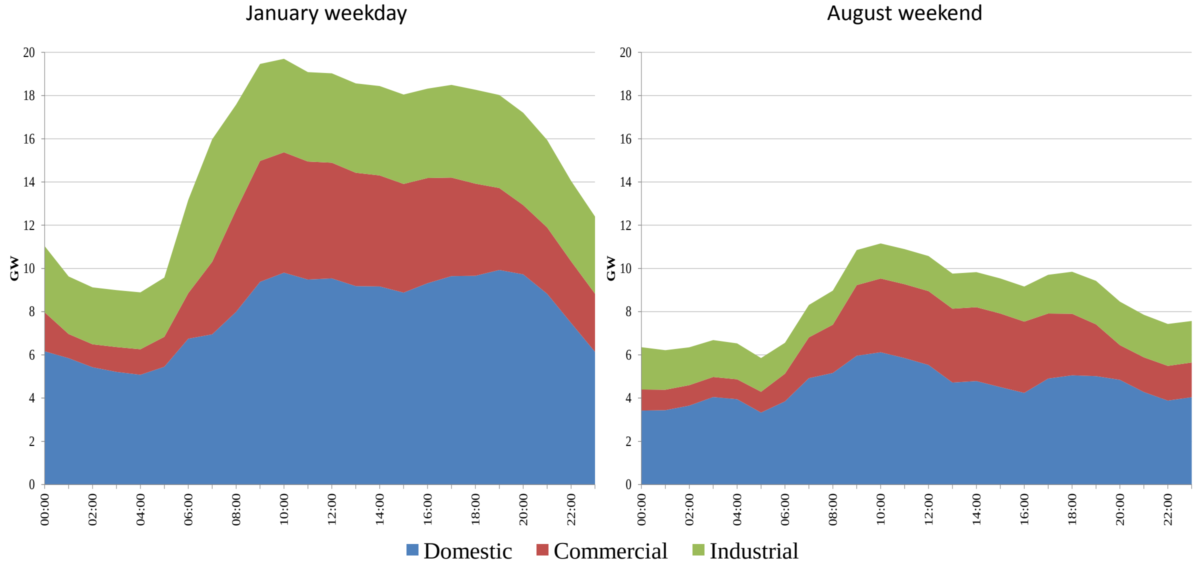


Figure 7: Potential for Demand Shifting in 2025 under Scenario 1. 'Business-as-Usual'

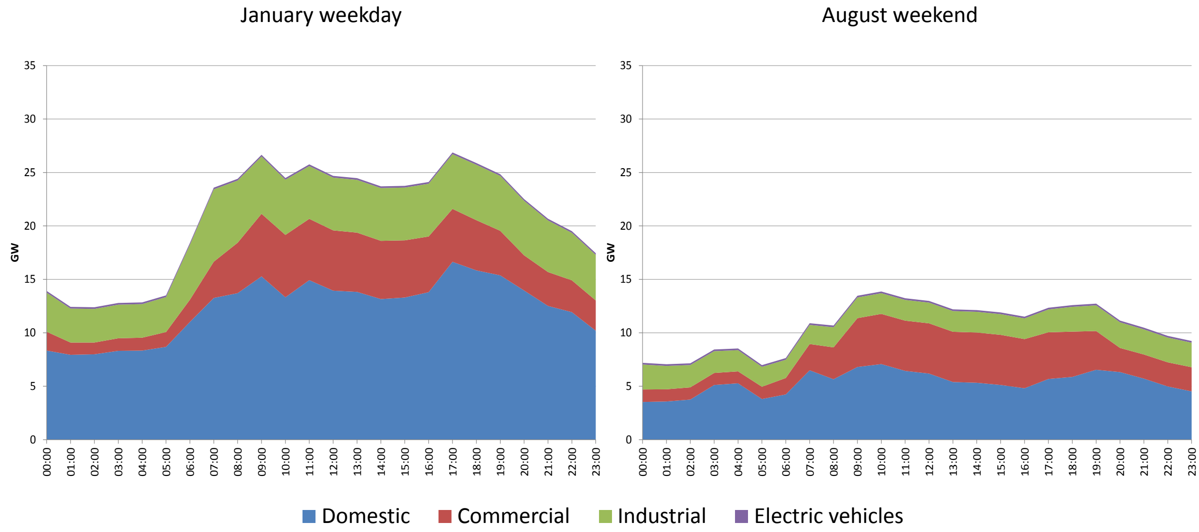
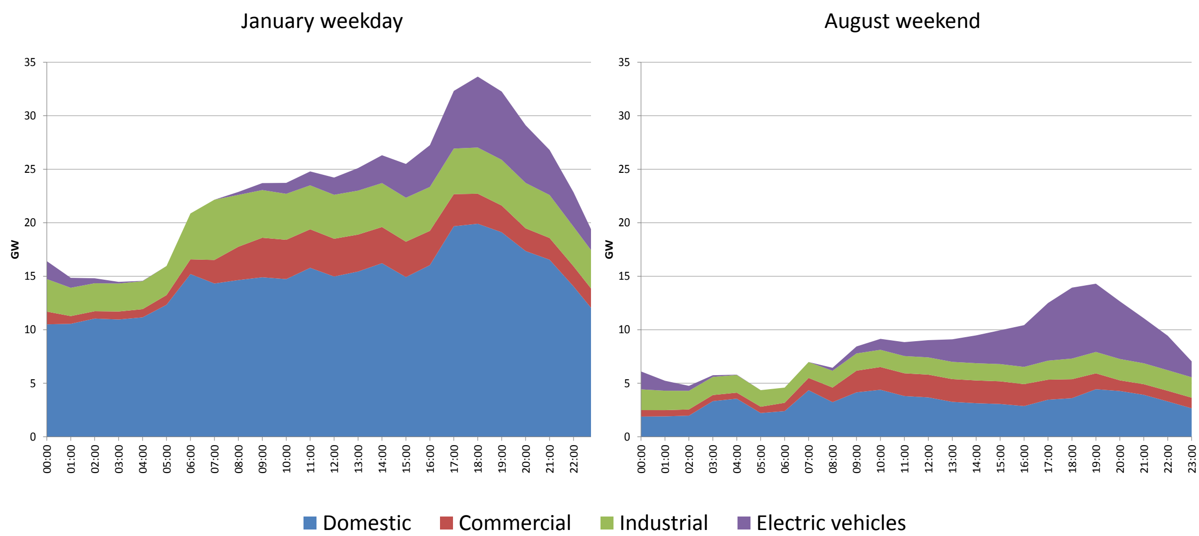


Figure 8: Potential for Demand Shifting in 2025 under Scenario 2. 'Greenest'



5.2. Electricity System Modelling

Having identified the potential for demand reduction and demand shifting, we then explore the impact on installed capacity of reducing electricity demand by 5% and 10% *across all hours of the day*. In this way, we can determine during which periods it may be possible to achieve the greatest impact in terms of reductions in wholesale prices and carbon emissions. We chose these levels of demand reduction because they were broadly consistent with the shift / reduction levels seen in the CLNR time of use trials.

These demand reduction levels fall well inside the range of demand that we estimate to be shiftable or reducible. This can be seen in **Figure 9 to Figure 11** below, which compare the sources of *flexible* demand that we identified in our previous Paper 2, with the levels of overall demand reduction that we have modelled here.

Figure 9: 2012 Demand Reduction Scenarios versus Flexible Demand

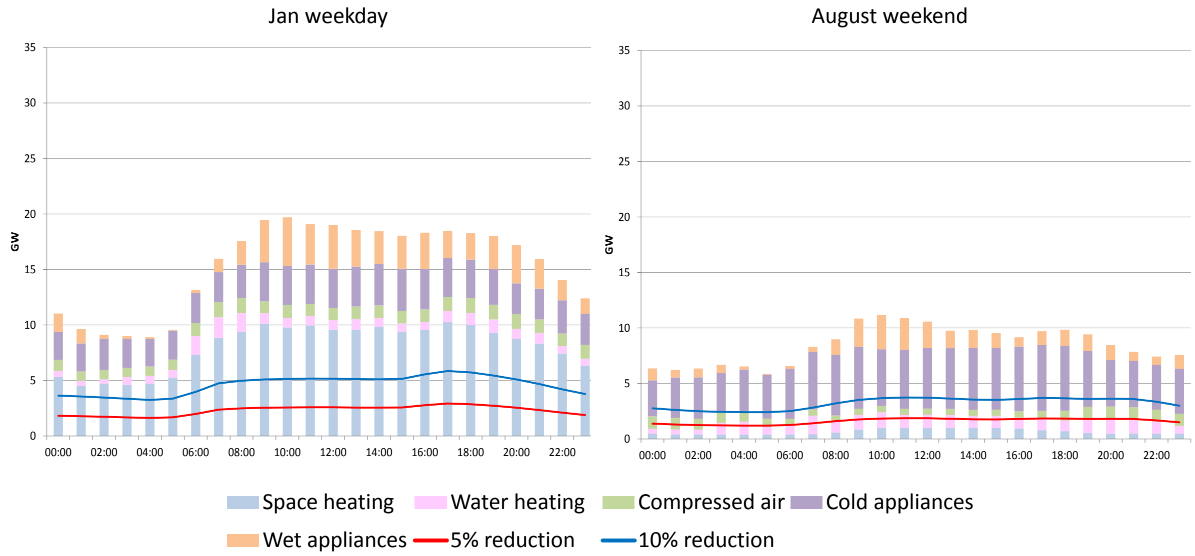


Figure 10: 2025 Demand Reduction Scenarios versus Flexible Demand. Scenario 1. Business-as-Usual.

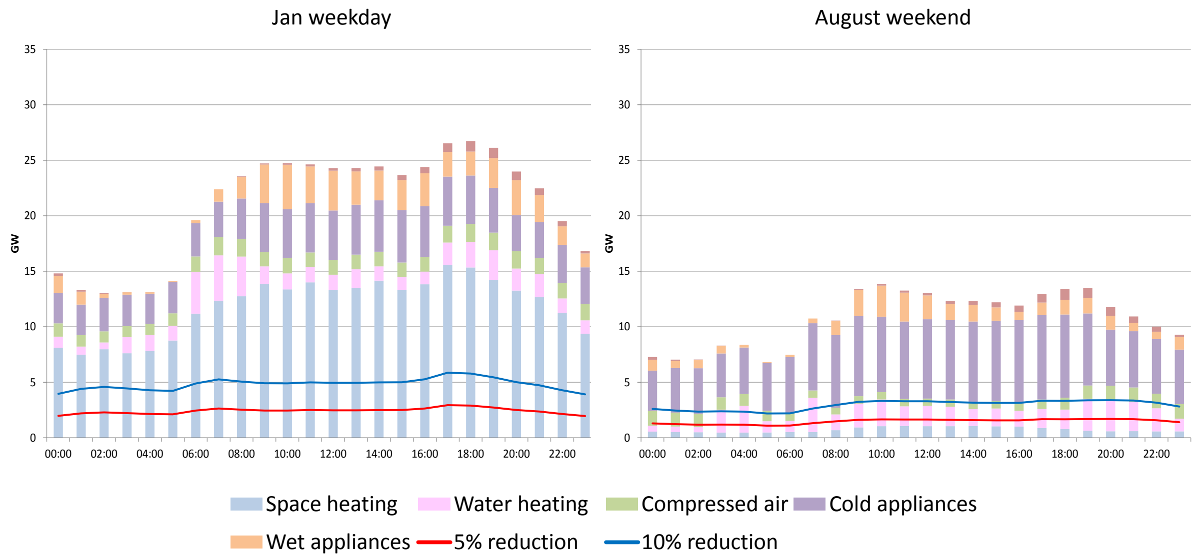
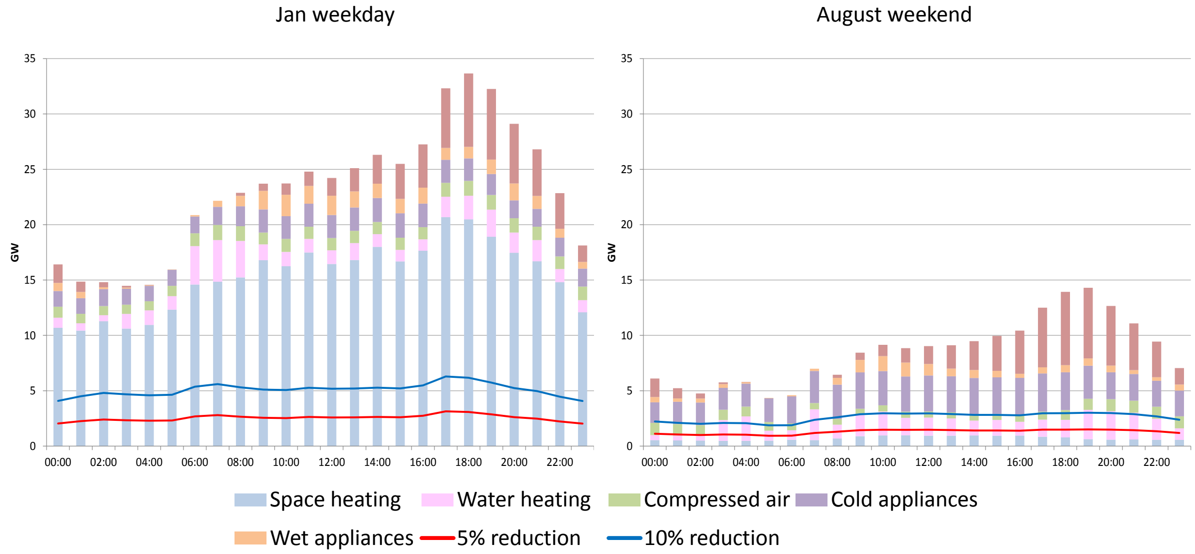


Figure 11: 2025 Demand Reduction Scenarios versus Flexible Demand. Scenario 2. Greenest.



To test the impact that demand ***shifting*** (rather than demand reduction) might have on wholesale prices, we have also run a 2025 case for scenario 2 (Greenest) where there is a basic 5% demand reduction in all hours *with a further 5% demand shift from the peak hours* (16:00 to 20:00) to :

(a) between 00:00 and 06:00 (‘overnight DSR’) and

(b) 12:00-15:00 and 21:00 (‘shoulder DSR’).

The first case could arise as a result of shifting electric vehicle re-charging from peak to off-peak periods. The second case is a more general example of DSR. **Figure 12** shows the resulting demand curves for January weekdays. **Figure 13** shows that :

(1) if the *demand shift is from peak to overnight periods*, then the effect is to *remove* the overnight price reductions that had resulted from demand reduction - whilst having relatively little impact on prices at other times – i.e. including not leading to corresponding price reductions at peak times. In terms of overall CO_2 emissions, the demand shifting results are broadly similar to the 5% demand reduction results – showing that the decrease in peak emissions is broadly matched by an increase in off-peak emissions.

and (2) on the other hand, if the *demand shift is from peak to shoulder periods* then prices (and short run marginal costs) in the periods immediately adjacent to the peak are slightly higher than those under the base case. The changes in CO_2 emissions show a similar pattern but are somewhat lower, as the higher shoulder periods encourage more use of pumped storage, which reduces emissions.

There are clearly many other patterns of DSR that could be considered, for example shifts away from the evening peak to the daytime period, to cope with variable solar output. Such a pattern is to some extent captured by the shoulder DSR example, but the daytime pricing effect could be smaller but of longer duration if extra demand was needed throughout the daylight hours.

Figure 12: Demand Curves for the DSR Examples

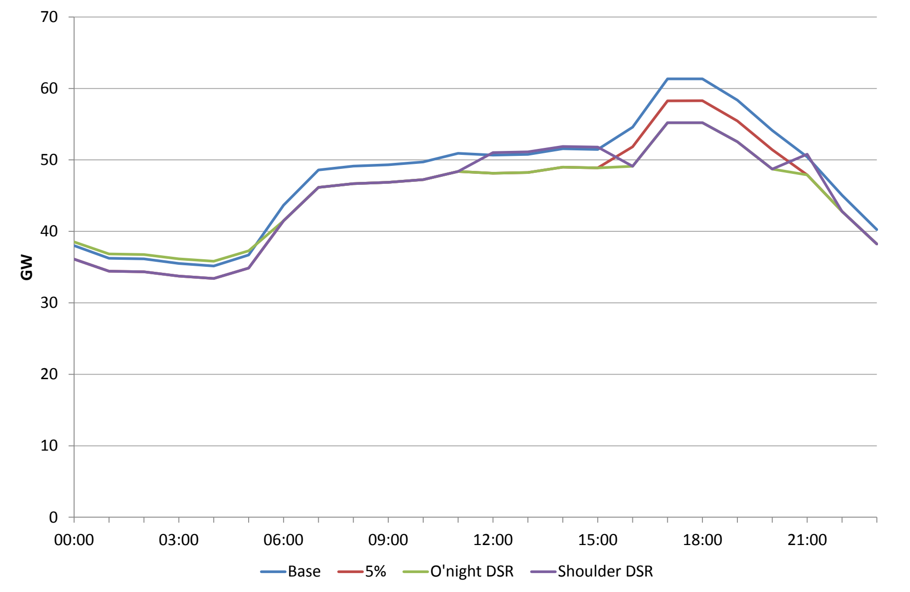
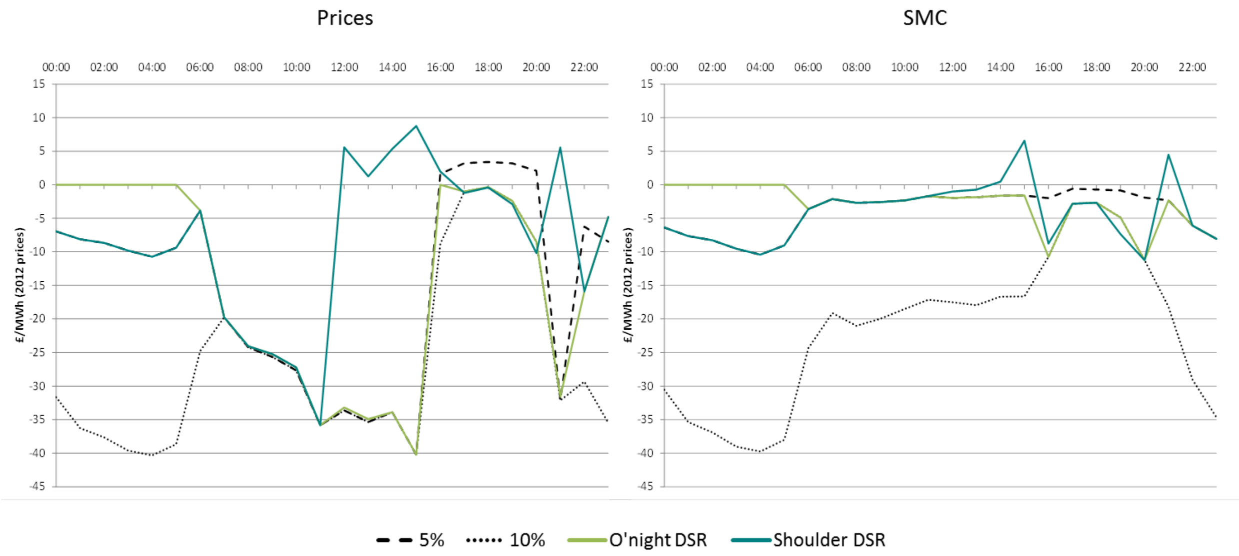


Figure 13 below shows how forecast wholesale prices change in response to demand reduction or demand shifting. A negative figure equals a price reduction and a positive figure equals a price increase.

Figure 13: 5% Demand reduction in combination with a further 5% demand shifting. 2025 Scenario 2 (Greenest). January Weekdays



5.3. Impact of demand reduction and demand shift on wholesale electricity prices

In modelling the likely impact of demand-side reductions and demand shifting on wholesale prices we also assess the implications of increasing the proportion of wind plants in the generation mix and explore the possible impacts of certain policies in the electricity markets (FiT CfDs/ROCs and the capacity market).

Short Run Marginal Costs (SRMC)

The short-run is a period of time where at least one input variable remains fixed. In the case of power generation, the short-run is typically a period where generation capacity remains fixed. In this case, therefore, the SRMC is the incremental cost incurred from producing a unit of output (i.e. 1 MWh) from the existing generation fleet. The main component of SRMC for power plants is fuel costs – therefore wind power (and other renewables) tend naturally to have significantly lower SRMCs than fossil fuel plant. This inherent cost advantage is enhanced in our modelling because we reflect the impact of the FiT CfDs/ROCs by assigning renewable plants *negative* SRMCs at levels designed to reflect the anticipated FiT CfD strike prices. For plants receiving ROCs, it is still worthwhile operating until the combined price they receive (wholesale price + ROC) is less than their operating cost – hence they will wish to generate when SRMCs are negative. Whilst plants with FiT CfDs are not exposed to wholesale prices in the same way, our assumption is a convenient way of capturing the fact that they will wish to generate until they could earn more in the Balancing Mechanism from reducing their output. SRMCs also vary for each power plant depending upon whether the plant is already operating and its level of output. For example, a plant that needs to be started incurs additional costs in terms of fuel and other inputs. A plant operating at 60% output will have a different SRMC than if it was operating at 80% because of different thermal efficiencies at different levels of output.

Figure 14 shows the impact of a 5% reduction in demand on wholesale prices, assuming full recovery of fixed and capital costs via wholesale prices. **Figure 15** shows the impact of a 5% reduction in demand on wholesale prices assuming recovery of short-run marginal costs (SRMC) only. Both figures show the impacts for January weekdays and August weekends.

We have provided this separate modelling for cost recovery via wholesale prices of only SRMCs, because the combination of EMR proposals for capacity auctions (for fossil fuel generation) and the support available for renewable and nuclear plant, make it likely that future electricity wholesale prices will become dampened. This dampening effect is likely to occur because some (possibly most) of fixed and capital costs will be recovered via the separate support mechanisms. Thus, for suppliers considering demand shifting or demand reduction options from their end-customers, it seems possible that after 2018,[20] wholesale prices which reflect only SRMCs could become a more relevant consideration to them than the full costs of generation – as many long-run costs will be payable by suppliers to generators via FiTs/CfDs or capacity payments. This could lead to something of a 'disconnect' between the total underlying costs faced by suppliers (and hence end users) - and - the energy prices payable to generators by suppliers via the wholesale markets - a point we will discuss further, later in this paper.

Since our modelling was completed, the government has indicated that the costs of the capacity payments to generators will be recovered from suppliers on the basis of their customers' contribution to peak demand. This means that suppliers could, in theory, reduce their exposure to capacity payments by reducing their customers' demand at peak. However, the extent to which suppliers could realise this benefit would depend upon (a) whether they were more successful in doing so than other suppliers[21] and (b) the extent to which such reductions are firm (certain).

Furthermore, if capacity auction volumes were adjusted downwards in expectation of demand reductions - but then these demand reductions were not achieved - then there could be negative consequences for security of supply. This implies that the maximum benefits from demand reduction (or shifting at peak) are likely to occur in the period *before* the capacity auction costs start being recovered and when the capacity margin is expected to be tight i.e. in the period up to 2018/19.

We conclude that the possible effect upon wholesale prices of a number of electricity market reform measures (capacity mechanism, FiTs/CfDs) could dampen the potential value of demand reduction and shifting available to suppliers and therefore to end-customers too. However, we note that aspects of the electricity market reform package may support some demand side response initiatives (e.g. via the scope for demand side participation in the capacity market).

[20] When capacity contracts are due to begin.
[21] If all suppliers achieve the same demand reductions, then the costs faced by each supplier may not change unless the number of capacity contracts awarded and/or the price paid for them was also reduced.

Figure 14: Impact of a 5% Reduction in Demand on Wholesale Prices (assuming full cost recovery)

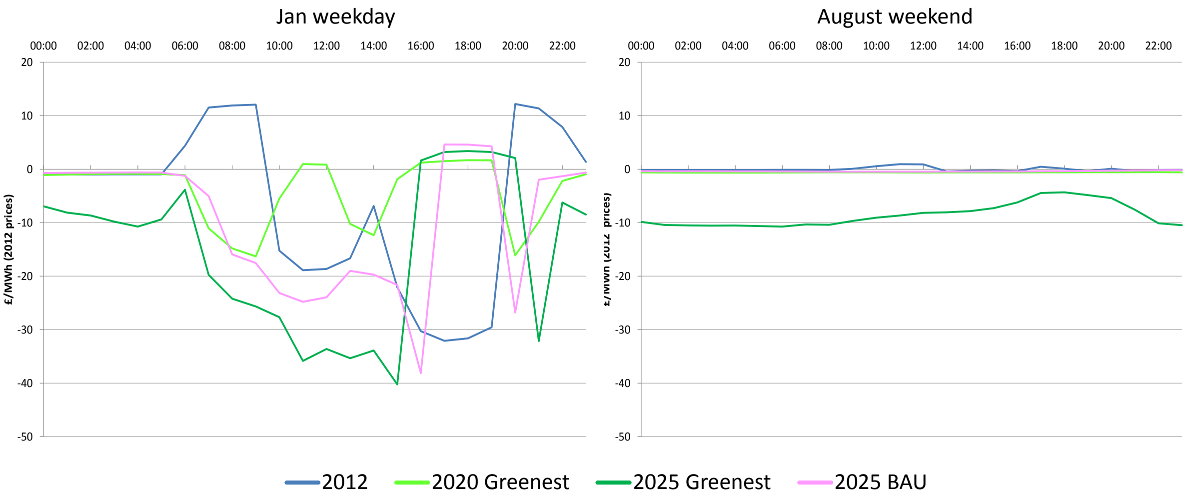
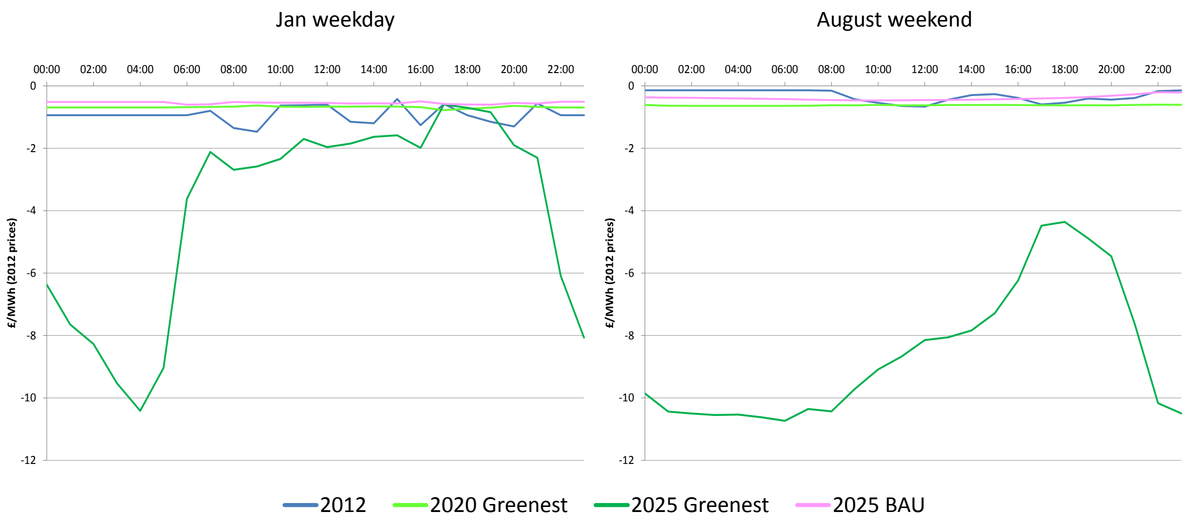


Figure 15: Impact of a 5% Reduction in Demand on Wholesale Prices (assuming recovery of SRMCs only)



One might expect wholesale prices to decrease as a result of demand reductions. However, the impacts of demand reductions on wholesale prices can be rather complex as revealed in our modelling. Demand reductions may only cause very small (if any) reductions in generators' fixed costs, but they can reduce the ability of generators to recover those costs, since they increase the competition between plants to generate electricity. There are many different ways in which this competitive dynamic can be captured. In our modelling, we include an 'uplift' which is designed to allow a new plant to recover its fixed and capital costs, providing that new plants are required. If the additional revenues above those earned at SRMC prices - required to cover fixed and capital costs - are higher for a peaking plant than a base load plant, then it is these additional revenues that are used to determine the uplift and vice versa. However, as the capacity margin increases, we assume that the ability of new generators to recover their fixed/capital costs - and hence the 'uplift' - decreases. Thus, the percentage of fixed and capital costs which we assume can be recovered - varies with the minimum assumed capacity margin - as does the number of hours in which an uplift is included - and the percentage of the uplift recovered in any particular hour. The modelling parameters which determine both the allowed level of fixed/capital cost recovery and the number of hours in which an uplift is applied have been determined from an analysis of the historic relationship of SRMCs, prices and capacity margins. Further information on our modelling approach can be found in Appendix 1.

The effect of these modelling assumptions is that *the number of periods in which fixed cost recovery occurs can also fall*, since, in broad terms, the ability of a generator to recover fixed costs in any hour depends on the tightness of the supply-demand gap in that hour. Due to the interactions between the overall level of fixed cost-recovery allowed by the model and the changes in the supply-demand gap as a result of demand reductions, the 'uplift' in some hours can be greater in the demand reduction cases than that included in the 'Base' case.[22] This can happen, for example, if the uplift in the 'Base' case is determined from the additional revenues required by a new base load plant, which are spread in ever decreasing percentages over the top 60-70% of hours, but the uplift in the demand reduction case is determined from the additional revenues required by a new peaking plant, which are only spread over the top 20% of hours.

Whilst different approaches to modelling fixed/capital cost recovery would give rise to somewhat different outcomes, the general point that wholesale prices are likely to be supported by such cost-recovery at times of low capacity margins is a more generally applicable. Thus, while price rises might not be seen in a demand reduction scenario, it is plausible that the major impacts on wholesale prices would be seen *away* from the hours of lowest capacity margins.

---

[22] These effects are further complicated by the impact that demand reduction has on the use of pumped storage. Some of the increases in prices away from the evening peak are associated with additional pumping prompted by the profitability associated with the higher peak prices generated by the uplift effect just described. This is particularly noticeable for 2012 but also occurs over the evening peak in 2020 and 2025.

The impact of demand reduction on wholesale prices differs between (1) the 'full' cost-recovery case and (2) the SRMC cost-recovery case, primarily because, as just discussed, the modelling assumes that fixed-cost recovery occurs mainly in hours when the supply-demand gap is lower – i.e. during winter daytime periods. With 'full' cost recovery, there is scope for demand reductions to produce significant wholesale price reductions during winter daytime periods as a result of the reduced assumption on fixed cost recovery. By contrast, with SRMC cost-recovery, a 5% demand reduction during winter weekdays is not sufficient to change the marginal generation technology and hence the price impact is modest.

Under the 'Greenest' scenario in 2025, a 5% reduction in demand is sufficient to lead to curtailment of wind output during August weekends and January weekday nights on some occasions - and hence there are comparable price reductions under both the 'full' cost recovery case and the SRMC cost recovery case. However, these price reductions are lower than those for winter day times under the 'full' cost recovery case.

For the other cases (2012, 2020 'Greenest' scenario; 2025 'Business-as-Usual' scenario), a 5% demand reduction is *not* sufficient to lead to wind curtailments. Hence, in those cases the impact of a 5% demand reduction on SRMC based wholesale prices is modest.

In terms of a 10% modelled reduction in demand, the impacts on wholesale prices are similar (although generally larger) to those for 5% reductions in demand, as can be seen from **Figure 16** and **Figure 17**. Of course, all these results depend on the scenario assumptions that have been made. For example, exports to other markets or increased storage capabilities could remove the need to curtail wind output and hence reduce the impact of demand reductions. Nonetheless, the general thrust of the results – that price impacts will be greatest when they lead to changes in the marginal technology – seems robust.

Figure 16: Impact of a 10% demand reduction on wholesale prices (assuming full cost recovery)

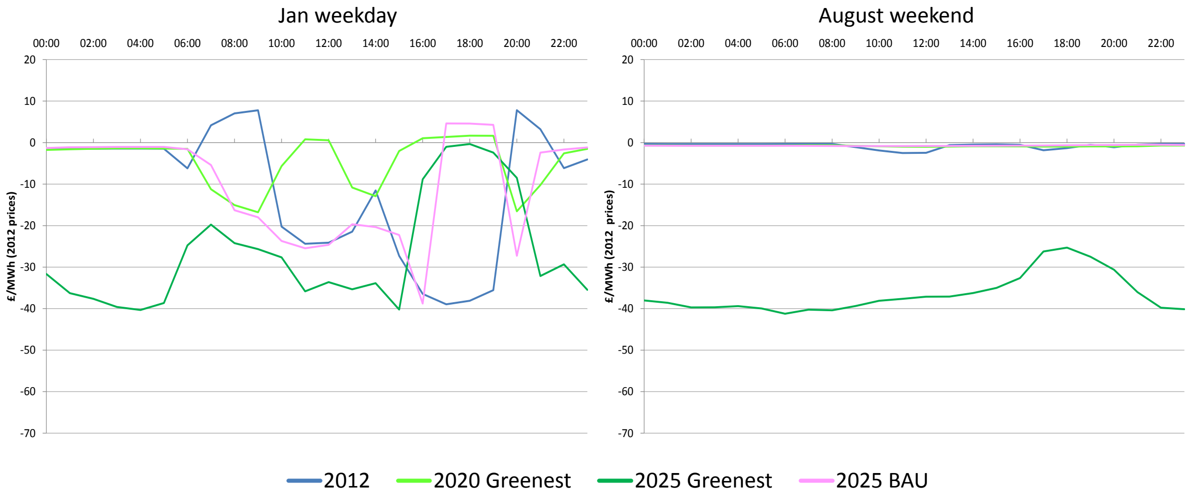
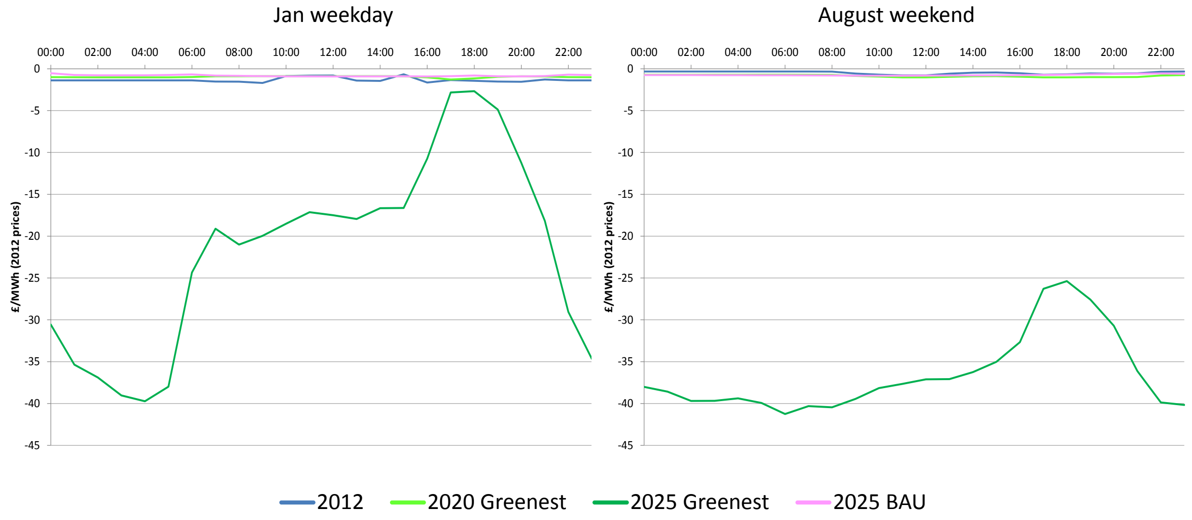


Figure 17: Impact of a 10% demand reduction on wholesale prices (assuming recovery of SRMCs only)



5.4. Impact of demand reduction and demand shift on CO_2 emissions

We have also assessed the impact of demand reduction and demand shift on CO_2 emissions, today and in the future. **Figure 18 and Figure 19** below illustrate some of these impacts.

In 2012, the impact of demand reductions on CO_2 emissions is *greater* over weekday evening peaks, as might be expected. It is also relatively high during the morning pick-up because demand reduction is sufficient to start reducing coal output at these times. Similarly, demand reduction has more impact on CO_2 emissions off-peak in summer than in winter because in coal SRMCs are lower than gas SRMC costs. Consequently, on January weekdays off-peak demand reductions tend only to affect the number of gas plants running and hence have relatively little impact on emissions. By contrast, on August weekdays there are few, if any, gas plants running off-peak and so demand reductions affect the level of coal-fired output and thus have a more significant impact.

In 2025, the scope for carbon reductions is similar under both scenarios but the starting level of emissions is different. On average, the emissions per hour under the 'Business-as-Usual' scenario are higher than emissions under the 'Greenest' scenario by around 1.5 ktonnes/hour on January weekdays and 4 ktonnes/hour on August weekend days. The shape of CO_2 reductions is also different: under the 'Business-as-Usual' scenario there are more opportunities for off-peak reductions than under the 'Greenest' scenario, whereas the reductions are similar for both scenarios during daytime hours. This reflects the fact that the 'Greenest' scenario only has relatively few fossil-fuelled plants (gas plants) running off-peak, so CO_2 reduction possibilities are more limited. With more gas plants running during the daytime the scope for CO_2 reductions increases.

Figure 18: Impact of a 5% Demand Reduction on CO_2 Emissions

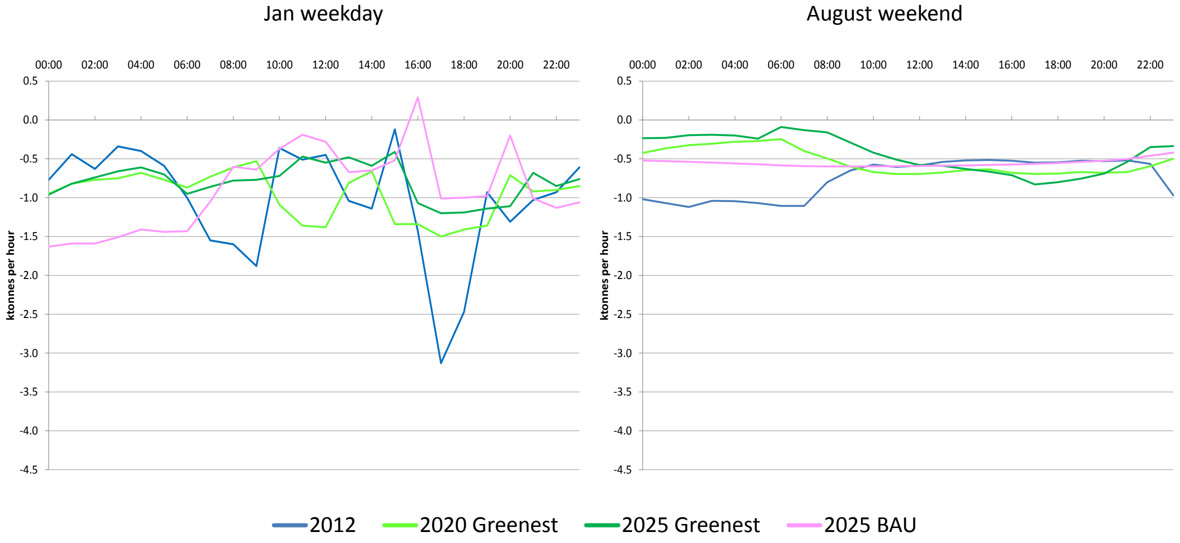
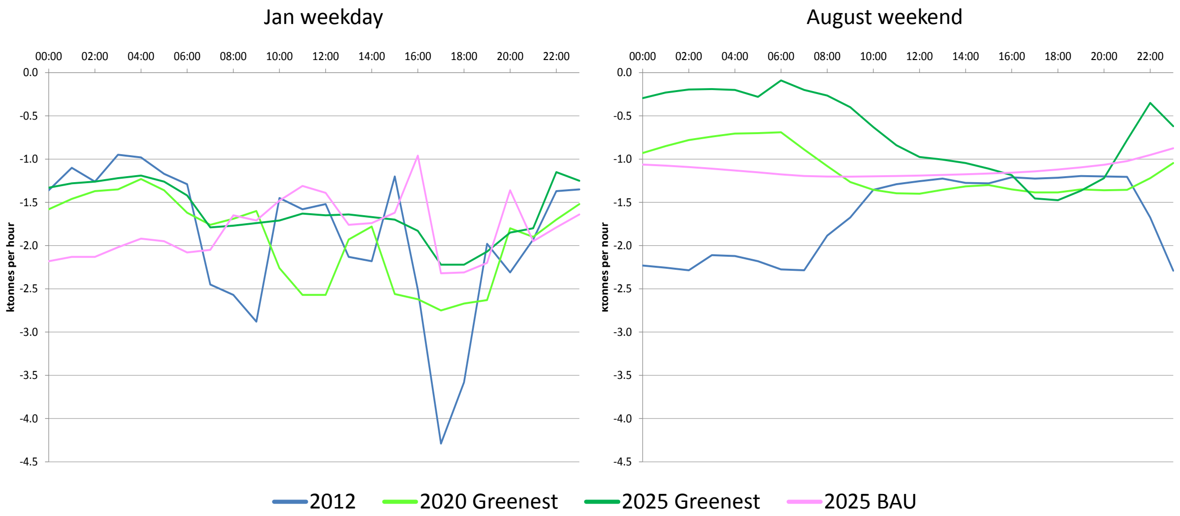


Figure 19: Impact of a 10% Demand Reduction on CO_2 Emissions



5.5. Potential Implications for Retail Tariff Development

This paper is primarily concerned with wholesale prices - rather than the way in which these pass through into retail prices. We have however, briefly considered what the potential implications may be for retail tariff development, given the model findings on the impact of demand reduction on wholesale prices. We will return to these issues in Paper 12 where we will examine both wholesale and network issues.

Table 1 and Figure 20 below show how the uncertainty in wholesale price levels increases as the level of intermittent generation increases. This naturally arises because when the wind blows, wind plants will increasingly set low or negative wholesale prices - whereas when there is little wind, conventional plants will set prices. The variation between FiT/CfD driven offers from wind plants and the SRMCs of conventional plant - is much larger than the variation in the SRMCs for conventional plant. This suggests that on windy days, demand reduction may offer relatively little value in terms of savings of wholesale prices, particularly if these are SRMC-driven. By contrast, when the wind does not blow, demand reduction may still offer material benefits. So far as demand-response is concerned, static retail tariffs (e.g static time-of-day) may not necessarily offer the best *retail* price signal in periods when the wind blows if the aim is to encourage 'efficient' end-customer response.

On average, it appears from the modelling that demand reductions at times *other than the evening peak* might have the greatest cost benefit for suppliers over the longer term, although in the short term, peak reductions will continue to have the greatest effect. Our analysis of modelled demand end-use shows that off-peak demand reductions may be achievable in both the domestic and industrial segments, with interventions focused on 'other' electric space heating[23] in winter - and on cold appliances throughout the year. (However, the scope for off-peak space-heating demand reductions is uncertain – it appears high in **Figure 6** to **Figure 11** largely because it includes electricity demand that was unidentified in the HES survey). During the morning period, reductions in demand from domestic wet appliances could also contribute to load reduction.

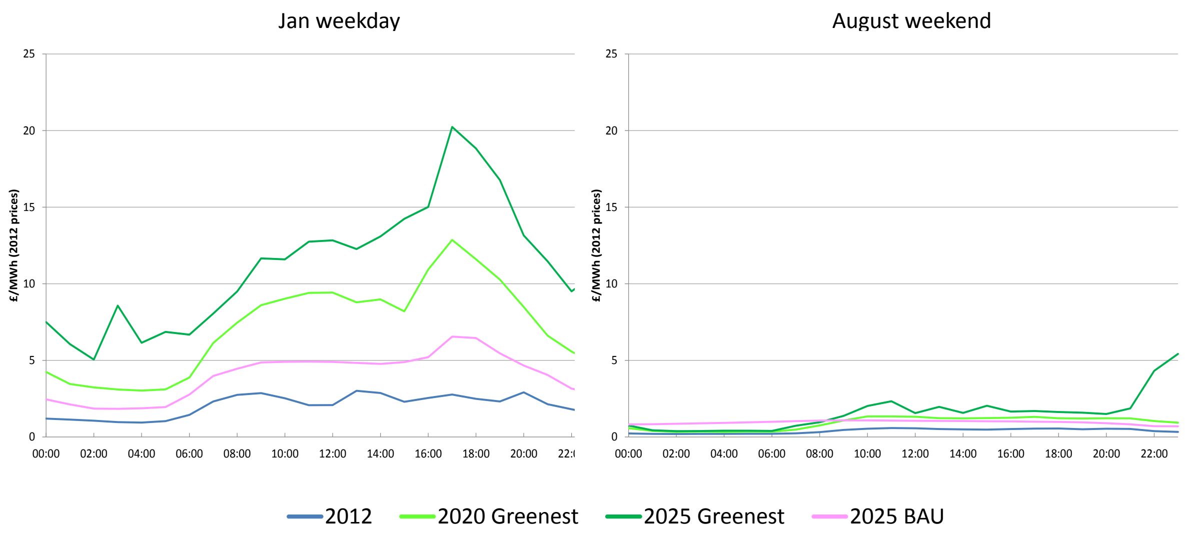
Thus, in the longer term, automatic load control via smart appliances may be the most effective method of providing reliable demand response at short notice and which could respond to the considerable uncertainty noted around potential available savings on wholesale prices. However, the widespread deployment of smart appliances will not happen quickly, particularly as many consumers may view them as 'big-brother' interventions. In the short to medium term some form of dynamic pricing, such as critical peak pricing, may be helpful in delivering demand flexibility provided that it does not have to be invoked too often to be sustainable.[24] Whilst consumers may be willing to respond to critical price signals a few times a year, they may be less enthusiastic if the signals occur more frequently e.g. several times a month throughout the year. More efficient and smarter appliances may therefore start to make an impact before such a point was reached – therefore product policy will be influential in the mid-to-long term.

[23] So, not Economy 7
[24] Half-hourly settlement would be needed to deliver household-level dynamic prices.

Table 1: Percentage price standard deviations

Case	Prices: Baseload	Prices: Off-peak	Prices: Peak	SRMCs: Baseload	SRMCs: Off-peak	SRMCs: Peak
2012	3%	3%	3%	0.5%	0.4%	0.5%
2020 Greenest	12%	9%	14%	0.2%	0.1%	0.3%
2025 Greenest	14%	14%	15%	3.9%	5.8%	2.1%
2025 BAU	4%	4%	5%	0.2%	0.2%	0.2%
2012	1%	1%	1%	0.3%	0.2%	0.4%
2020 Greenest	2%	2%	3%	0.4%	0.3%	0.6%
2025 Greenest	3%	3%	4%	1.8%	2.1%	1.4%
2025 BAU	1%	1%	2%	0.5%	0.4%	0.5%

Figure 20: Price uncertainty (standard deviation) under the electricity market scenarios modelled



6. Policy implications and recommendations

We reiterate that in this paper we have only examined the wholesale side. Issues in the networks will be different and will be explored in Paper 12.

Demand reduction and demand shifting measures will likely have most scope to reduce wholesale prices and CO_2 emissions in the short to medium term. Most conventional generation technologies operate at their maximum efficiency when operating at baseload. Consequently, using demand side measures to achieve higher load factors for conventional plants may deliver significant variable cost savings and emission reductions. Demand side measures could also potentially reduce the need for new capacity, thereby reducing fixed costs as well (including the costs of policies such as the capacity mechanism, FiTs/CfDs and the RO).

In the future, as the electricity market is decarbonised and EMR takes effect, the likely effects are more complex and hence more difficult to predict.

Post-2020 the main effect of demand-side measures is likely to be to reduce the need for new capacity and, hence, to reduce the costs of capacity auctions and the FiTs/CfDs, therefore reducing the overall costs faced by suppliers. The more ‘firm’ the demand side measures, the greater their potential ability to reduce the amount of generation needed by suppliers. As more renewables come on to the system, our modelling suggests that a second peak in prices begins to emerge around the morning pick-up - since wind output is understood to tend to being lower at this time of day than at others. Reducing demand at this time could therefore have significant value in the medium term i.e. in the intermediate stage between low and high decarbonisation.

The value of demand reduction and demand shift in the medium term (2020 - 2025), in terms both of carbon emissions, will be dependent upon the speed of progress in decarbonising the electricity system. As generation is decarbonised, there will be less scope for demand reduction and demand shifting to lead to lower carbon emissions. In a ‘Greenest’ scenario in 2025, significant decarbonisation would be in place, and there would be limited value in demand reduction or demand shift, whereas under a ‘Business-as-usual’ scenario in the same year, demand reduction and demand shift would have much greater value.

It follows from these findings that policies to stimulate demand reduction and demand shifting in the near-and-medium term could help to reduce the amount of generation required in the future and hence the costs to consumers of the electricity market reform measures – capacity mechanism, FiTs/CfDs. This may inform which types of demand reduction measures are targeted by policies, favouring measures with faster returns/more immediate demand reduction effects.

As well as considering the impact of demand reductions and demand response on wholesale prices and carbon emissions, we have also considered the impact of electricity market reform measures on the potential value of the demand side in the electricity system. We conclude that key measures (capacity mechanism, FiTs/CfDs) may reduce some of the potential value available to suppliers and their end-customers from demand reduction and shifting due to the increasingly short-run nature of wholesale prices. In turn, should this effect reduce the role of the demand side in the electricity system, this could lead to higher costs for consumers than would otherwise be the case with more demand reduction and demand response, because consumers will have to pay (via the capacity mechanism and FiTs/CfDs) to support more generation than they otherwise would have done.

These conclusions lead us to a number of policy recommendations:

- The potential impact of the capacity mechanism and FiTs / CfDs on wholesale prices increases the need for substantial early action (over the next few years) to reduce demand overall and to improve electricity load factors (demand shifting and peak smoothing).
- Policies already in place such as the Green Deal and ECO need to be used effectively to support electricity demand reduction and demand smoothing.
- Tariff initiatives such as wind-twinning and other measures to support dynamic tariffs such as customer and grid level storage and flexible load could be useful to support efficiency in the electricity wholesale market for suppliers. Dynamic critical peak pricing tariffs could be relevant both to the networks and/or for capacity support, but half-hourly settlement would be needed.
- Automation may be required to support both supplier demand side response needs and also dynamic peak pricing at scale. Measures to increase the scope for automated response (such as product standards) therefore merit early attention.

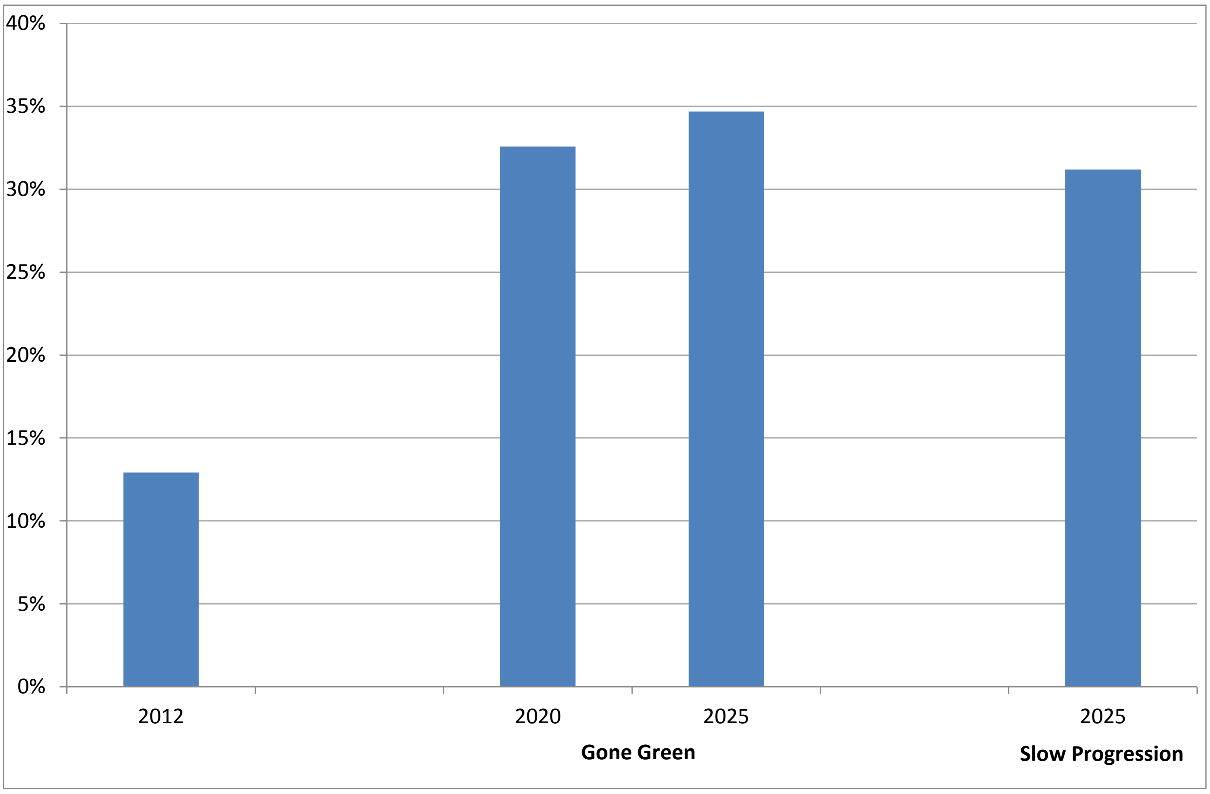
7. Conclusions

This paper outlines the results of modelling to identify the different impacts of demand reduction and demand shifting on wholesale prices and carbon emissions in the electricity wholesale market in 2012, 2020 and 2025. It assesses whether in the future the traditional evening peak may no longer be the highest priced time of day in the wholesale market, assuming a highly electrified future with a high level of wind generation in the system. The paper also considers the potential impact of some aspects of EMR on demand response.

We find that demand reduction and demand shifting measures will likely have most scope to reduce wholesale prices and CO_2 emissions in the short to medium term and before many of the EMR measures come into effect. This reinforces the imperative for substantial early action (over the next few years) to reduce demand overall and to improve electricity load factors.

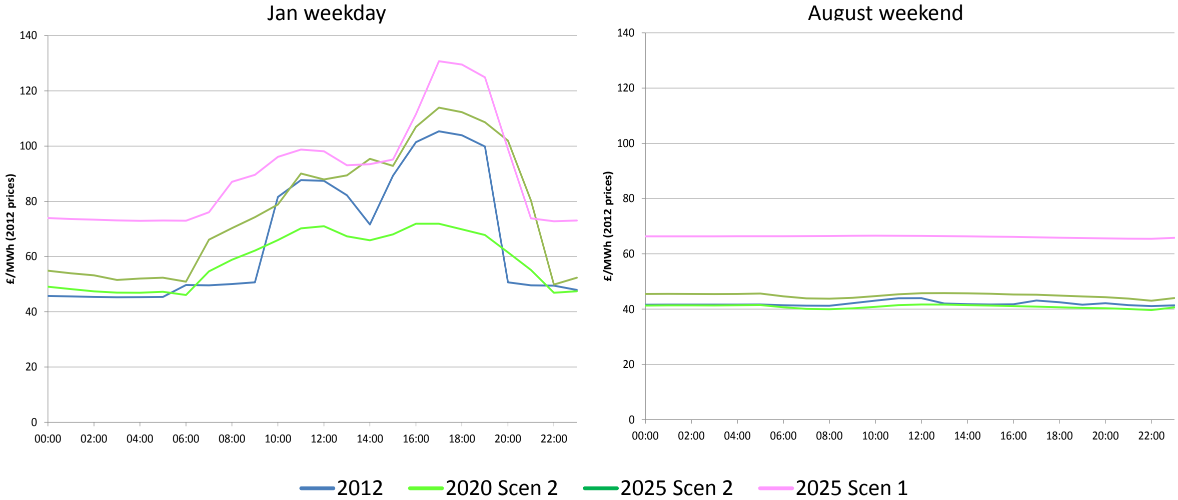
Appendix 1: Additional Results

Figure 21: Capacity Margins under the Base Demand Assumptions[25]



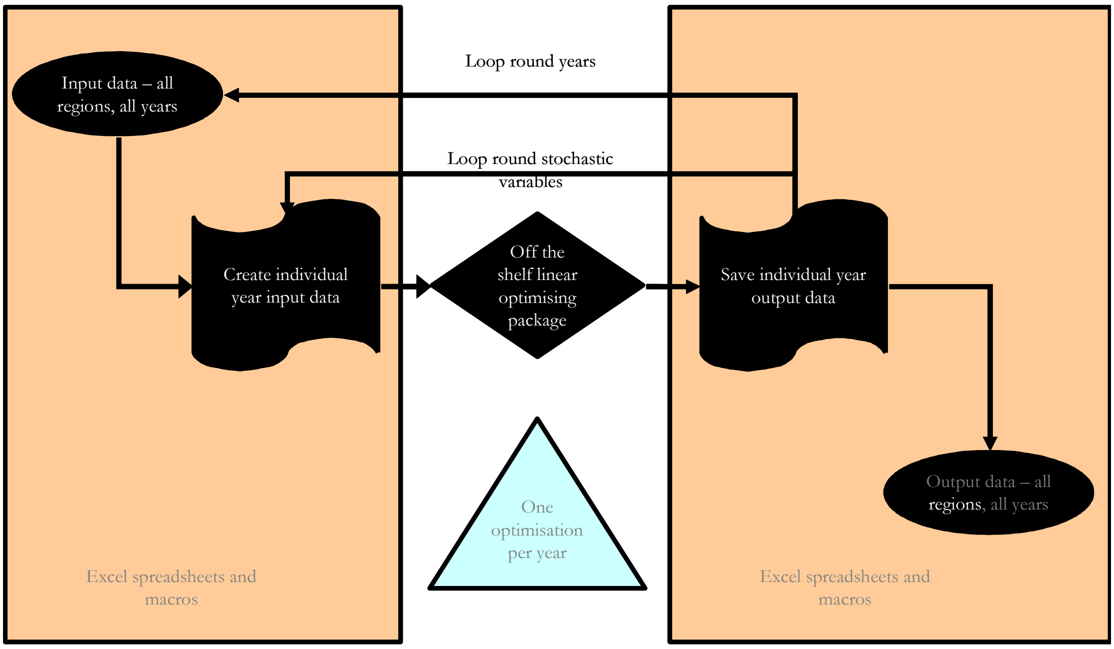
[25] The capacity margins are calculated as the difference between the reliably available capacity (installed capacity for conventional plants, 25% of installed capacity for wind and solar) and peak demand expressed as a percentage of peak demand. We note that National Grid assumes much lower availability of wind at peak (a 7% firm capacity figure). However, changing our assumption would have no impact on our results, since the de-rating factor is only used to calculate the capacity margins and not directly in our modelling of wholesale prices.

Figure 22: Wholesale Market Prices under the Base Demand Assumptions



Appendix 2: Further Details on the Brattle Annual Model

At the heart of BAM is a cost-minimising plant scheduler that, in conjunction with a sophisticated fixed-cost recovery module, enables marginal costs and prices for any number of interconnected countries (or regions) to be modelled. The model can be run in two modes: (a) fast – deterministic runs with simplified approaches to forced outages, to demand variations and to wind output patterns to provide initial indications of prices or to model longer periods and (b) detailed – stochastic representation of these variables using a random number generator to give a more detailed insight into prices and their volatility but taking longer to run. This is illustrated below.



Model inputs

The generic types of required input data include

- Fuel prices: generic international prices for coal and oil products and country specific domestic fuel prices; including gas contract prices, and taxes;
- Fuel characteristics: calorific values, carbon, sulphur and nitrogen content;
- Current plant capacities, retirement of existing plant and entry of new capacity, including renewables;
- Other plant characteristics (fuel blending requirements, maintenance requirements, environmental measures e.g. flue gas desulphurisation levels, forced outage levels, thermal efficiency etc.);

- Plant costs: fuel transport costs, non-fuel variable costs (e.g. coal milling costs, variable O&M costs, market power uplifts etc.), fixed costs; transmission loss factors;
- Electricity demand profiles and growth;
- Contractual arrangements (physical bilateral contracts, must-take fuel contracts);
- Environmental constraints and costs: plant and country/regional emissions limits and costs,
- Financial parameters: exchange rates and inflation rates;
- Inter-regional data: monthly capacities in both directions, losses etc;

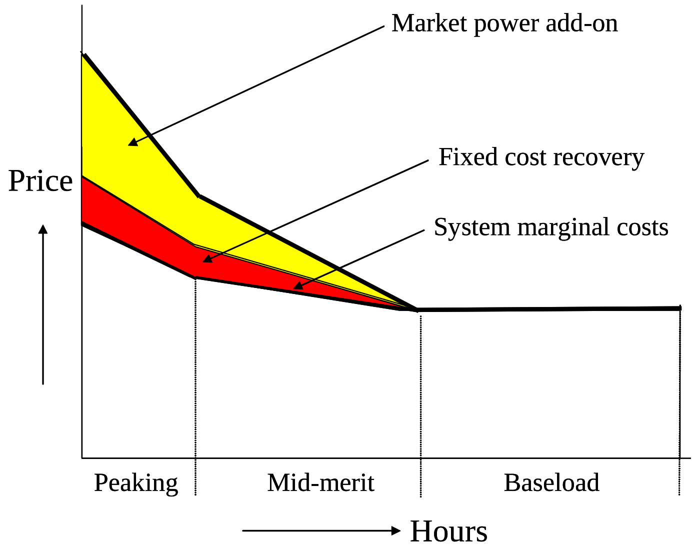
These data are required for each country (or region within a country where market splitting occurs) to be included within the model. The model can accommodate varying numbers of countries, with all the data specific to a particular country grouped into an individual Excel spreadsheet.

Price determination

Cost-based scheduling is a well-established method of estimating short-run marginal costs (SRMCs) for an electricity system. In common with other dispatch models based on linear optimization, BAM uses the dual values associated with meeting hourly demand to represent the SRMCs. This means that the SRMC for an hour does not necessarily directly correspond to the fuel costs of the most expensive generator operating in that hour. This is because the dual values measure the cost of a marginal change in output: if increasing the output of a plant in one hour means that its output has to be reduced in another hour (due to output restrictions) then the SRMC will reflect the *net* effect of both changes.

SRMCs do not necessarily reflect prevailing market prices since SRMC prices would not enable many plants, particularly peaking plant, to recover their fixed costs. In addition, the actions of dominant generators may also affect prices. Our model allows the addition of "uplifts" to SRMCs to enable typical peaking, mid-merit and running plant to recover their fixed costs as well as their variable (short-run) costs. The figure below illustrates this schematically.

Schematic of pricing methodology



The hourly SRMCs produced by the scheduler are sorted into descending price order. The model then estimates the revenues that a typical peaking plant would earn. For example, suppose a peaking plant operates during the highest 10% of prices. The revenues from the top 10% of prices are compared with all of the costs of a peaking plant, and the model increases prices in the top 10% of hours until the plant can just cover its fixed and variable costs. The price increases are structured so that the highest increases are applied to the highest SRMCs – in effect they are added on in a triangular fashion. The user can specify how prices are modified, and the 'shape' of the price recovery is determined by the 'backcasting' exercise described in Stage 2.

Once the calculations have been completed for the peaking plant, the same approach is taken for the mid-merit plant, taking into account the price increases applied to the peak prices. This prevents mid-merit plant earning excessive profits. Finally, the process is repeated for baseload plant. All the parameters used in these calculations are under the control of the user, including the extent to which fixed cost recovery is allowed.

In addition to allowing the recovery of fixed costs, the model also allows market power add-ons to be incorporated. These market-power add-ons can be negative as well as positive, to allow, for example, for plants submitting offers below their SRMC overnight to avoid having to switch off. Historically, this has been particularly important in seeking to replicate Dutch power prices. Appropriate market power add-ons can be determined by calibrating the model against historic market prices.

The model also allows the percentage of fixed costs recovered to vary with the reserve margin. At high reserve margins – when there is an 'excess' of plant – less fixed costs will be recovered, and more fixed costs will be recovered when the market is tight. However, while this approach is theoretically valid, we have found with other interconnector studies that it is better to adopt a 'long-run equilibrium' approach and model a set percentage of fixed cost recovery in each year. Otherwise, variability between fixed cost recovery in the years modelled can introduce significant ‘noise’ which makes the results of the study harder to interpret. By default we model 100% fixed costs recovery, since this is what plants must earn on average to stay in business. In other words, this situation represents a long-run equilibrium.

Probabilistic modelling

Since most of the value associated with interconnectors is associated with price volatility, which leads to price differences across interconnectors, it is important to use a modelling technique that allows the effects of volatility to be appropriately captured. To do this, we use a stochastic modelling approach. We run the BAM model for each year about 100 times. In these runs, we model each day of the year separately, rather than using characteristic days. For each run and for each hour, the model picks random values for:

- Unplanned plant outages; and
- Wind power output;

Unplanned plant outages

For conventional plant, we model unplanned outages and planned maintenance separately. For deterministic BAM runs, unplanned outages are modelled by de-rating the installed capacity of the plant to reflect the likely level of outage. Each plant technology has its own level of unplanned outages – and indeed in BAM it is possible to specify this variable for each plant.

The user specifies the length of planned maintenance – again this can be done down to the plant level, but the model determines when this maintenance takes place based on prices and the planned outages of other plant.

For wind generation, we specify capacity factors by characteristic hour, and apply different, higher load factors for offshore wind. We base our load factors for wind on published academic research and public reports (see discussion below). For hydro plants, we specify minimum and maximum monthly output levels (and, if required, hourly minimum output levels for run-of-river plants). The model then optimises the scheduling of the hydro plants subject to these constraints.

When running the model in its probabilistic mode instead of simply downrating the available capacity of each plant by its forced outage rate throughout the year, we randomly choose whether the plant is fully available or not on each day for each run that we perform. For example, suppose that a plant has a forced outage rate of 5% and we are interested in its availability on March weekdays, of which there are 20. We assume that once a plant is unavailable it will be unavailable for two days. Consequently, we make ten draws of a random number between 0 and 1. Every time the random number is equal to or below 0.025 i.e. half its forced outage rate, we assume that the plant is totally unavailable for two days. Otherwise we assume it is fully available for the two-day period we are considering. We then add up all the days that it is available and divide by the total number of days considered to calculate the percentage availability to apply to the plant's installed capacity for that characteristic day. As an example, suppose that the plant was unavailable on 6 out of the 20 days, then the available capacity of the plant for that characteristic day will be 0.7 (=[20-6]/20).

Wind Power Output

Ideally, to model randomised wind output one would like to have sets of historical hourly wind Capacity Factors (CFs) for each country, determine the distribution of hourly changes in CFs and study the correlations between countries' CFs. Unfortunately, hourly CF data are not readily available, particularly over significant time scales, since these data are usually regarded as commercially sensitive by wind-farm developers and the capacity of wind farms is changing rapidly so aggregated data is difficult to interpret. Instead we use published data on hourly wind speed data in each market (or sub-region of a market) in combination with power curve data from wind turbine manufacturers to generate an initial set of CFs. To create the simulated output from a wider area of wind farms from wind speeds at a single point, we used a technique described in an academic paper and presented at the 2004 Nordic wind power conference. In essence, the technique calculates a rolling average wind speed, with the period over which the average is taken being a function of the wind speed itself. This simulates the average wind speed over the entire area being considered, based on the wind speed measured at a single point within the area. The technique also assumes that there is some random variation of wind speed within the area being considered, so that wind speeds can be both more or less than for the point measurement with a known probability. Using the rolling average effect and a distribution of wind speeds around the point measurement combine to 'smooth' the change in wind speeds and capacity factors. The estimated electricity production is more representative of an area of wind farms. We calibrate our results by comparing monthly average capacity factors from the multi-turbine approach to actual historic CFs - effectively this corresponds to taking into account the impact of the height of the turbines above the ground.

The final step is to characterise the time-series of CFs in a way that we can model probabilistically. We do this by having a function that can generate a random series of CFs, which still respect average historic CFs and changes in a realistic way. Our random series recognises that the change in electricity production from wind from one hour to the next will depend on the current level of wind output, and the output in the previous hour. For example, if wind is producing at a CF of 90% (i.e. near maximum capacity), it is more likely that future changes will reduce rather than increase output. Similarly, if wind production is increasing, it is more likely to continue to increase in the next hour because a weather front is moving in.

To capture these effects, we use separate distributions for each 10% interval of CF (0%-10%, 10%-20% etc.), with separate distributions for the cases where the previous hour had a higher or lower CF. In this way we generate 20 distributions of hourly CF changes. For example, we have a distribution of the hourly changes in CF when the CF in hour t was between 0 and 10% and the CF in hour t-1 was less than the CF in hour t. Similarly, we have a distribution of the hourly changes in CF when the CF in hour t was between 0 and 10% and the CF in hour t-1 was more than the CF in hour t. Depending on the CF in any hour, and the CF in the previous hour, we will draw an hourly change in CF from the relevant distribution.

While we assume that the volatility of the wind CFs is the same for all the countries, we adjust the average CF to approximate the monthly average CFs for each country seen in the historic data. We do this by applying mean reversion to the random series, to ensure that the mean of the random distributions does not vary too much from the average CFs used in the deterministic runs. For example, suppose the average CF is 35%, and the CF in hour t is 50% i.e. above the average. If the random draw suggests that the CF should increase by +20%, which is further away from the average CF, then we apply a factor that will reduce the suggested change in CF to e.g. +10%. The adjustment to the randomly drawn change in CF gets larger the further the CF in hour t is from the desired average CF.

We use different mean reversions for each month and for daytime periods (defined as 08:00 to 20:00 inclusive) and for nightime periods. This means that the higher average wind production in daytime hours is accounted for in the probabilistic modelling.

Correlation between wind farms

Correlations between the wind farm output are important and reduce the overall variability in wind output.

To ensure we get realistic outcomes, we take the approach of generating a ‘seed’ time series and then generating other time series of CFs from the seed series, ensuring that the two series have the correct correlation. Specifically, we generate a random wind time series for a core market, using the distributions described above. We then generate further time-series for wind farms situated in different locations. For each hour, we take the CF of the seed series and add to it a random change in the CF. The random change is drawn from a distribution, the parameters of which are set so that the correlation between the first and second time series are as required. We repeat this process to generate several series, corresponding to different regional patterns across GB based on published data regarding how the correlation of wind output varies with distance.

Sustainability First