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Modelling the impacts of additional Gas CHP capacity in the GB electricity market

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Modelling the impacts of additional Gas CHP capacity in the GB electricity market

This report has been prepared by Lane Clark and Peacock LLP ("LCP") for the Department of Energy and Climate Change ("DECC"). It presents the results of our analysis on the impacts of additional gas-fired Combined Heat and Power ("CHP") capacity in the GB electricity market.

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Executive Summary

This report presents the results of modelling and analysis carried out by LCP for DECC on the impacts of additional gas-fired CHP capacity in the GB electricity market. This work formed one strand of the analysis informing DECC investigation of the case for a subsidy to support new Gas CHP capacity. Two other analysis strands also fed in to DECC's investigations, qualitative research on Gas CHP investment decision-making and modelling of Gas CHP capacity brought forward in response to incentives using the Ricardo-AEA/DECC CHP models.

The purpose of the analysis is to help policy makers understand the interactions between Gas CHP generation and the wider electricity market. It provides DECC with an estimate of the impacts associated with introducing policies that incentivise a greater level of Gas CHP deployment, particularly the impact on carbon emissions. Gas CHP has the potential to play an important role in reducing carbon emissions, particularly during the period in which the GB power sector transitions to a lower carbon generation mix.

The assumptions underpinning the analysis were all provided by DECC. On a number of the assumptions used in this analysis Mott MacDonald provided a view on the suitability of inputs and advised on areas where revisions could be made. In some cases DECC retained existing assumptions to ensure consistency with the other analysis strands referred to above.

The analysis was divided into three main parts:

1. **Carbon displacement**. Modelling the carbon intensity of the generation displaced by additional Gas CHP capacity. The purpose of this analysis was to determine the type of generation displaced by the operation of Gas CHP and the resulting impact on net carbon emissions over the 2018-45 period. Different Gas CHP deployments were modelled, within DECC's selected range of 0.5GW to 3.0GW of additional capacity.
2. **Incremental (endogenous) build**. Modelling the amount of new Gas CHP capacity build over the 2018-2025 period. This analysis modelled the investment decisions of new Gas CHP capacity that might be brought forward under different proposed CHP policy support options. Five proposed policy options were supplied to LCP by DECC, who also provided the eligibility criteria and calculated the support levels for each option. This analysis was conducted to provide DECC with a second set of estimates, using a different approach to their internal CHP build modelling, but under a consistent set of assumptions.
3. **Social NPV.** Modelling the Social Net Present Value (NPV) of the five proposed policy support options for Gas CHP. The Social NPV of each option was estimated in order to provide a view of the overall cost/benefit to society of additional CHP capacity brought forward under each policy scenario, over the 2018-45 period. The analysis was conducted using DECC's Dynamic Dispatch Model (the DDM),

with Gas CHP capacity build assumptions provided from DECC and Ricardo-AEA's modelling.

The five potential Gas CHP policies evaluated as part of this analysis were as follows:

1. **Premium Feed in Tariff (PFiT).** A payment per MWh of electricity generated.
2. **Capital Grant.** Grants awarded for investment in new natural Gas CHP. The level of grant would be based on the projected primary energy saving, based on the plant's design and certified heat load.
3. **Primary Energy Saving (PES) incentive.** A payment per MWh of primary energy saving (i.e. the fuel input saved relative to generating the same heat and power output separately from the same fuel), based on the annual performance of the plant.
4. **Quality Index (QI) weighted heat incentive.** A payment per MWh of heat supplied, weighted according to the quality index of the plant, a measure of overall efficiency.
5. **QI weighted capacity incentive**. A payment per kW of installed electrical capacity, weighted according to the quality index of the plant.

Each policy is applied to new Gas CHP capacity coming online from 2018 to 2025, which is considered to be "good quality" CHP (i.e. the plant certified against the CHP Quality Assurance programme requirements[1]), and exports at least 20% of its power generated to the grid. With the exception of the Capital Grant, which is a one-off upfront payment, support is applied during the first 5 years of operation. This policy formulation is intended to improve the investment case for gas CHP whilst avoiding long term distortion of the electricity market dispatch merit order.

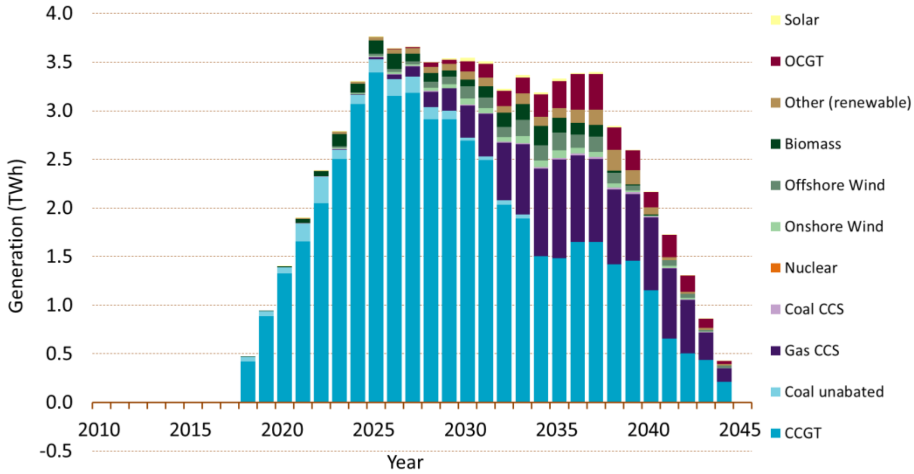
As part of this project, significant updates were made to DECC's existing electricity market model (the DDM), so that the operation of Gas CHP could be modelled in greater detail. Using the DDM, the analysis was able to capture the interactions between Gas CHP and the wider electricity market. The DDM was used in all three parts of the analysis. In the DDM model, potential CHP plant were characterised in 38 representative clusters. The characteristics of the 38 clusters were based on aggregating the 298 base categories in the Ricardo-AEA/DECC CHP models. This number of clusters was selected based on a balance between improved granularity and the availability of representative data, and agreed with Mott MacDonald as appropriate. The clusters grouped together CHP plant with similar characteristics, such as unit size, technical characteristics, policy exposure and heat load profiles. These clusters were defined by DECC and reviewed by Mott MacDonald.

[1] Which aim to ensure that CHP plant deliver at least 10% primary energy saving in line with the requirements of Article 14(11) of Directive 2012/17/EU

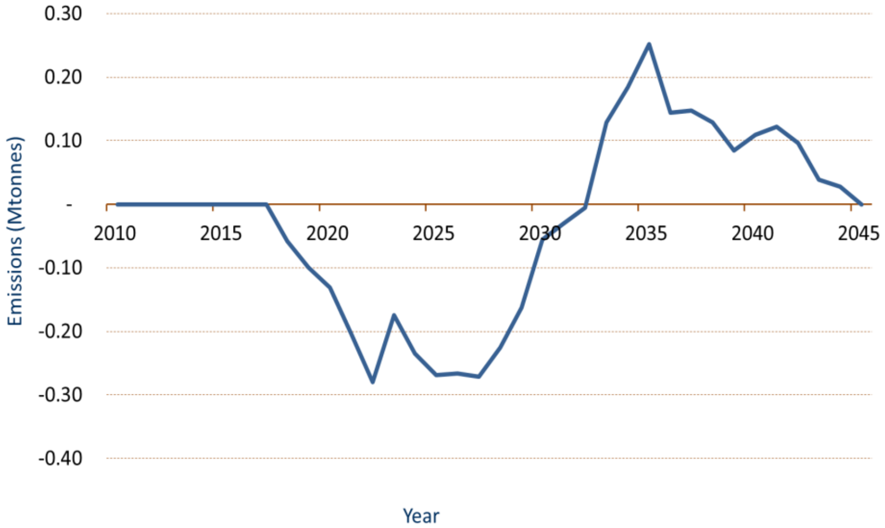
The **carbon displacement analysis** shows that additional Gas CHP provides annual carbon savings through to 2032 under DECC's central grid decarbonisation trajectory assumptions[2], after which additional CHP leads to a net increase in annual emissions. This is due to the type of generation displaced. In early years Gas CHP predominantly displaces conventional Combined Cycle Gas Turbine (CCGT) plant, but from the late 2020s it displaces an increasing proportion of low-carbon generation, including Wind and, in particular, Gas Carbon Capture and Storage (CCS) plant, which are present in DECC generation mix projections.

The type of generation displaced by an additional 0.5GW of Gas CHP, and the resulting net annual carbon emissions impact, are shown on the following two charts.

Generation displaced by additional Gas CHP capacity, +0.5GW scenario



Net Annual CO2 emissions from the generation displaced by additional Gas CHP capacity, +0.5GW scenario



[2] Assuming 100gCO_2e/kWh grid carbon intensity by 2030

However, the analysis shows that the year from which Gas CHP has an overall negative effect on annual carbon emissions is sensitive to a number of key assumptions. Notably, this result assumes a decarbonisation trajectory under which the GB power sector achieves an average carbon intensity of 100g/kWh in 2030. Under a slower decarbonisation trajectory Gas CHP can provide carbon savings over a longer period of time. Results for a trajectory achieving an average carbon intensity of 200g/kWh in 2030 show the “cross-over” year, in which operation of additional gas CHP switches to net increase in carbon emissions, is delayed by 5 years, to 2037.

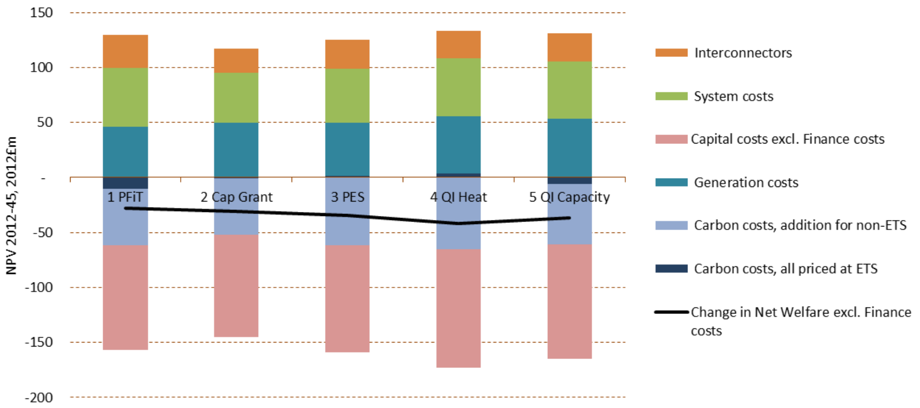
Another key assumption is the commercial arrangements of the Gas CHP plant. Under basecase DECC assumptions, Gas CHP plant does not respond to short-term fluctuations in the wholesale price when generating power for onsite consumption. This is because the avoided cost is assumed to be power imported under a retail tariff. If Gas CHP generating power for onsite consumption had an incentive and the flexibility to respond to wholesale price signals, it should respond to the prices in periods where low carbon generation is on the margin. This should result in greater carbon savings over a longer period of time. A sensitivity case with the majority of plant responsive to the wholesale price showed net carbon savings through to the end of the period modelled, i.e. 2045.

The **incremental endogenous build analysis** shows that very little new Gas CHP capacity is brought forward by the proposed policy options. This is largely consistent with the results from DECC’s own Monte Carlo CHP build modelling. The exception to the low levels of incremental build is District Heating CHP, which is not captured in DECC’s Monte Carlo CHP model. The analysis shows up to 3GW of new District Heating capacity being brought forward over the 2018-2025 period.

One reason that the policy options are shown to bring forward very little incremental build is the high level of modelled build in the baseline. The analysis shows just over 3.1GW of new and replacement Gas CHP deployment under baseline assumptions. One key assumption in the baseline is that all Gas CHP participates in the Capacity Market, which may not occur, particularly in the near term. With Gas CHP not assumed to participate in the Capacity Market at all, modelled deployment is reduced to 2.4GW. There are a number of other key assumptions, such as energy price projections, the number of CHP sites available (technical potential), and the cost of new build, including the hurdle rates required by investors.

Under the **Social NPV analysis**, using DECC's projections of CHP capacity, four of the five policies show a negative net social NPV. The exception is the Capital Grant option, which shows a net benefit due to it reducing private financing costs. However, providing cheap public financing inherently improves the Social NPV of any privately financed investment. When all policies are evaluated on a consistent basis with their financing costs removed, all five policies show similar, negative Social NPVs. This indicates that each of the proposed policies to incentivise Gas CHP would result in a net financial cost to society. The results are summarised on the following chart.

Social NPV of the policy options, excluding Financing costs



It is important to note that like the rest of the analysis presented, there is a significant amount of uncertainty in these results. The analysis is particularly sensitive to the assumptions relating to CHP capital costs and gas prices. Under the sensitivities for lower CHP capital costs and higher fuel prices, the additional policies result in a net positive Social NPV. The amount and type of CHP capacity brought forward is also a key assumption.

The negative Social NPVs under basecase assumptions are a result of additional Gas CHP leading to increases in overall capital and carbon costs that outweigh savings in generation, network and interconnection costs.

The negative monetised carbon impact, despite a reduction in overall emissions, is the result of two factors:

1. The ETS carbon price increases significantly over the modelling period, hence the carbon price is low when carbon savings are delivered, but high when carbon emissions are increased.
2. The emissions from Gas CHP in the non-ETS sector are valued at the non-ETS price, which is higher than the ETS price through to 2030. For example, in 2020 the appraisal value for non-ETS is £64.35/tonne versus £4.77/tonne for ETS. Gas CHP deployed in the non-ETS sector therefore displaces power generation emissions from the ETS sector where they have a low value to the non-ETS sector where they have a higher value. This results in net carbon costs in some years despite a net carbon emissions saving.

The second factor is particularly important. If emissions for all Gas CHP are valued at the ETS price, i.e. using the same price as for the emissions displaced, and finance costs are excluded, the results show a small positive net Social NPV for all policies overall. However, if finance costs are included valuing all emissions at the ETS price still results in a negative Social NPV across all options other than Capital Grants.

The following sections describe the analysis in more detail. Please note that all of the results produced in this report are subject to a wide range of uncertainties associated with long term modelling of power markets and this should be taken into account when drawing conclusions from this analysis. Where appropriate we show a range of scenarios for the key assumptions to show a range for the key results. However, due to the large degree of uncertainty over long term forecasts actual results could be outside of this range.

1. Background

1.1. Purpose of this analysis

LCP and Mott MacDonald were commissioned by DECC to analyse the impacts of additional gas-fired CHP capacity in the GB electricity market. In particular, DECC was looking to understand the types of generation that Gas CHP would be likely to displace, and the net carbon impact resulting from this displacement.

Previous DECC analysis for "*The Future of Heating: Meeting the challenge"*, considered potential policy options to support the deployment of additional Gas CHP capacity. The carbon impacts of the additional CHP deployment was analysed using two approaches. The first approach assumed that generation from additional CHP capacity would displace generation from conventional CCGT plant. The second assumed that it would displace a mix of generation with a carbon intensity equal to the Interdepartmental Analysts Group's (IAG) marginal emissions factor. Over the assessment period (2012-2035) the two different counterfactuals produced very different results. The CCGT counterfactual resulted in significant carbon savings over the period, while the IAG marginal emissions factor resulted in a significant increase in carbon emissions.

In reality additional CHP capacity competes with other generation in the electricity market, either directly or indirectly. The type of generation displaced by additional CHP generation will depend upon factors such as fuel prices, carbon prices and CHP specific factors such as the CHP's operating profiles and commercial arrangements.

As a result, DECC required a more robust analysis to assess the carbon impacts of CHP, taking these various complexities into account.

To achieve this LCP made enhancements to DECC's Dynamic Dispatch Model (the DDM), to allow CHP dispatch to be modelled in greater detail to more accurately reflect how it will interact with the wider generation fleet. Previously, with the exception of a few very large CHP schemes, CHP capacity was not directly modelled in the DDM, with projected CHP generation simply being netted off from demand. The enhanced DDM was used to model the types of generation displaced under scenarios with a range of additional gas CHP capacity, with a focus on the carbon intensity of the generation displaced.

DECC's established in-house CHP model uses Monte Carlo simulation to project the level of CHP capacity which would be economic to build in the modelled year if there were no existing capacity. The second part of the analysis reported here provides an independent set of results for comparison with the Monte Carlo model's results, using the updated DDM to model the impact of the potential CHP support policies on the level of Gas CHP deployment.

DECC's final requirement, to assist in the policy-decision making process, was to provide a more complete picture of the costs and benefits associated with each policy option.

Again, the updated DDM was utilised, to assess the overall costs and benefits to society of DECC's policy options and provide a "Social NPV" for each option. This was carried out using a consistent approach to that used for DECC's Electricity Market Reform policy assessments, and included an evaluation of the impact of the additional Gas CHP capacity on system-wide generation, capital and carbon costs. The additional Gas CHP capacity assumed to be brought forward under each policy option was provided from separate analysis using the Ricardo-AEA/DECC CHP models[3].

1.2. The case for supporting Gas CHP

"Gas CHP" are natural gas-fired power plant that can provide both power and useful heat. Where there is a demand available for the heat they produce, Gas CHP has the potential to provide significant benefits over conventional power-only gas plant.

Gas CHP can provide an overall energy saving when producing heat and power simultaneously, relative to the alternative of satisfying the heat and power through separate conventional sources. In this report we assume that the useful heat provided by Gas CHP would have otherwise been satisfied through a traditional natural gas fired boiler. When the alternative power source is a conventional gas-fired power station, such as an Open Cycle Gas Turbine (OCGT) or CCGT, the efficiency benefit results in savings in fuel and carbon emissions. This means that additional Gas CHP capacity has the potential to play an important role in the decarbonisation of the GB power sector.

However, it is worth noting that unlike power, which can be easily exported to the wider network, heat can only be used by local customers. This requires CHP to be deployed where there are heat loads and configured to meet those heat loads. Risks associated with Gas CHP projects, due to the possibility of either a reduction in future onsite heat demand, or the complete loss of the heat customer can reduce the benefits delivered and may contribute to higher finance costs than conventional powerplant. The requirement for a local customer also means that there may not be a demand for Gas CHP's heat during all periods of the year. This provides a limitation on Gas CHP's potential efficiency and carbon emission savings.

Gas CHP can also provide what are known as embedded benefits. As Gas CHP is generally connected directly to the distribution network, and supplies a proportion of its power for onsite consumption, it can avoid some of the transmission and distribution losses incurred when supplying power from centralised large-scale conventional generation. This means that Gas CHP can reduce total electricity generation, which can also lead to fuel and carbon savings.

Due to the potential role that Gas CHP can play in reducing carbon emissions, particularly during the period in which the GB power sector transitions to a lower carbon

[3] Bespoke Gas CHP Policy – Cost Curves and Analysis of Impacts on Deployment, Ricardo-AEA December 2014

generation mix, DECC is interested in exploring the options available to support greater investment in Gas CHP.

1.3. Options to support Gas CHP

Five potential Gas CHP policies are evaluated as part of this analysis as defined by DECC. Each policy is applied to new, "good quality"[4] Gas CHP capacity coming online from 2018 to 2025, and which exports at least 20% of its power generated to the grid. The 20% export criterion was based on cost curve analysis conducted by Ricardo-AEA and is intended to minimise "deadweight" costs by excluding from support CHP plant which are modelled as being cost effective under current policy:

1. **Premium Feed in Tariff (PFiT).** A payment per MWh of electricity generated.
2. **Capital Grant.** Grants awarded for investment in new natural Gas CHP. The level of grant would be based on the projected primary energy saving, according to the plant's design and certified heat load.
3. **Primary Energy Saving (PES) incentive.** A payment per MWh of primary energy saving, based on the annual performance of the plant.
4. **Quality Index (QI) weighted heat incentive.** A payment per MWh of heat supplied, weighted according to the Quality Index of the plant, a measure of overall efficiency, as determined by annual CHPQA certification.
5. **QI weighted capacity incentive**. A payment per kW of installed electrical capacity, weighted according to the Quality Index of the plant, as determined by annual CHPQA certification.

These policies, with the exception of the Capital Grant, are to be applied only in the first 5 years of operation for qualifying new plant. This policy design decision was taken in order to maximise the impact of the policies on investment decisions and avoid long-term distortions to electricity dispatch decisions.

In focussing solely on incentives for new plant, the analysis does not explore the possible benefit of incentives to extend the useful operation of existing plant that might otherwise shut, or increase the load factors of existing plant.

[4] i.e. CHP plant certified as meeting CHP Quality Assurance (CHPQA) programme efficiency requirements which are based around delivering a minimum of 10% primary energy saving compared to separate generation of heat and power

2. Methodology

2.1. Introduction to the DDM

The analysis presented in this report was conducted using DECC's Dynamic Dispatch Model (DDM).

The DDM is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. It was developed for DECC by LCP in 2011, and is currently used by DECC for its electricity market policy analysis and annual published energy projections.

The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity over the next 40 years. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are modelled based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. This includes the impact of the Government's Electricity Market Reform (EMR) policies, such as the Capacity Market and Contracts for Difference (CfDs), which are modelled in detail as part of the DDM's core simulation.

The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions, and also outputs comprehensive and consistent Cost-Benefit Analysis results.

More information on the DDM can be found on Gov.UK[5].

2.2. Modelling Gas CHP using the DDM

As part of this project, enhancements were made to the DDM to capture the characteristics of Gas CHP generation.

CHP generation possesses a number of unique characteristics when compared to conventional generation. These make the modelling of their operation more complex. In particular:

- For a CHP plant, the marginal cost per MWh of generating electricity depends on the revenue or avoided costs in respect of the heat it generates.
- Depending on its commercial arrangements, a CHP plant may be exposed to either a retail electricity tariff or the wholesale power prices, or both. The portion exposed to the wholesale price is the portion which is exporting power to trade in the wholesale market and therefore respond to real-time changes in market prices. The retail exposed portion i.e. the portion generating to supply on-site electrical

5 https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm

demand, will make operating decisions based on a predetermined retail price and therefore its economic running regime can be determined ahead of time.

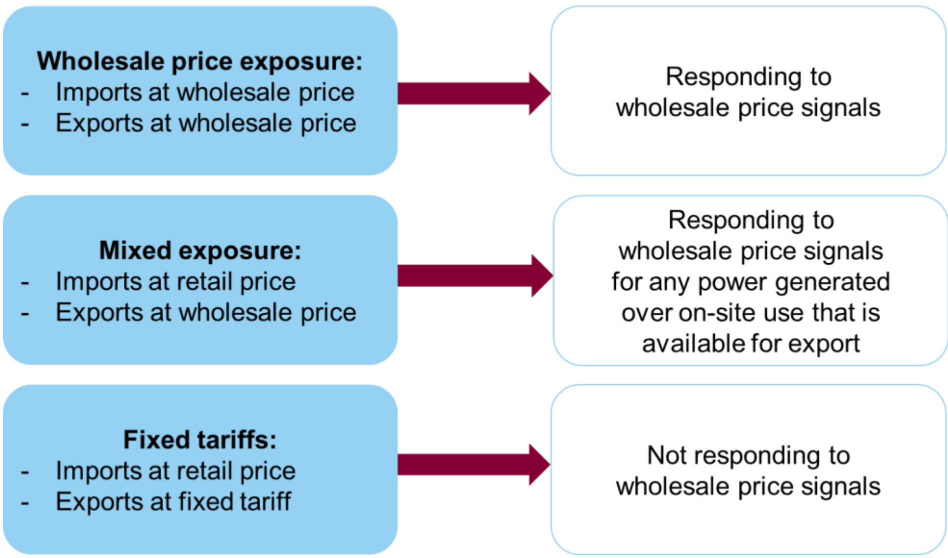
- A CHP plant's operation will also depend on its onsite demand for heat and power at any time. At any given point in time, a CHP plant is in one of four distinct operating modes:

  1. Off
  2. Heat-following
  3. Power-following
  4. Maximum output

The decision between these operating regimes will depend on the value of the power generated relative to the net cost of generation from the CHP plant.

Based on a plant's commercial arrangements and the associated price, the plant operator or control system will decide what mode to run in and what capacity to bid into the wholesale market.

Potential commercial arrangements of a Gas CHP plant:



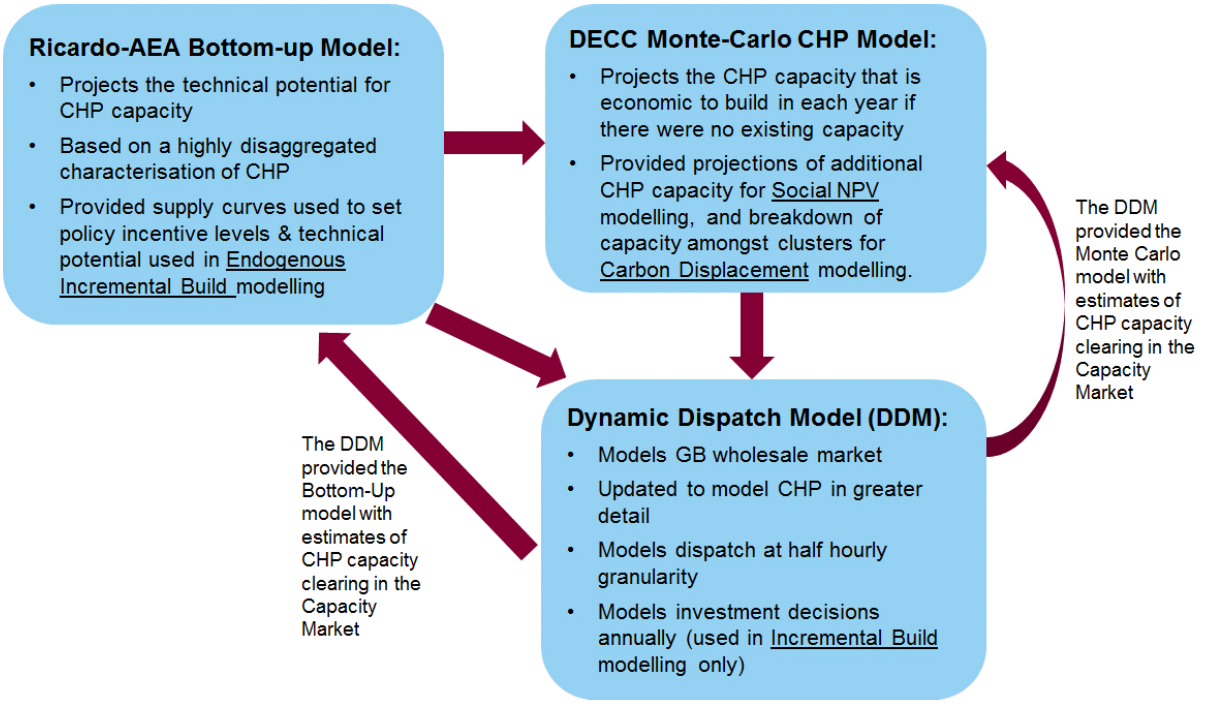
A more detailed description of the modelling methodology can be found in Appendix 1.

3. Overview of the analysis

There were three distinct parts to this analysis:

1. **Carbon displacement**. Modelling the carbon intensity of the generation displaced by additional Gas CHP. The purpose of this analysis was to determine the type of generation displaced by the operation of Gas CHP and the resulting impact on net carbon emissions over the 2018-45 period (covering the full lifetime of CHP plant deployed up to 2025).
2. **Incremental endogenous build**. Modelling the amount of new Gas CHP capacity built over the 2018-2025 period. This analysis used the DDM to model the investment decisions of new Gas CHP capacity that could be brought forward under different CHP policy support options. This analysis was conducted to provide DECC with a second set of estimates, under a different modelling approach to the DECC/Ricardo-AEA CHP capacity modelling, but with a consistent set of assumptions.
3. **Social NPV.** Modelling the Social Net Present Value (NPV) of different policy support options for Gas CHP. The Social NPV of each option was estimated in order to provide a view of the overall cost/benefit to society of additional CHP capacity brought forward under each policy scenario, over the 2018-45 period. The analysis was conducted using the DDM, with Gas CHP capacity build assumptions provided from DECC and Ricardo-AEA's modelling.

This analysis, using the DDM, was part of a larger framework of three models, as shown in the diagram below.



Mott MacDonald's role

LCP led on the analysis, while Mott MacDonald provided expertise and technical assistance. In particular Mott MacDonald:

- Provided review and challenge on CHP technical characteristics and other modelling assumptions including:
  - Technology electrical efficiency expectations
  - Technology heat yield and heat quality expectations
  - Technology Heat to Power (H:P) ratios
  - Variations in H:P ratios with unit size
  - Reliability and availability expectations and maintenance requirements
  - Maintenance costs, and their variations with size and type
- Provided a view on the most representative level of aggregation for the modelling of CHP, balancing granularity with available data and processing requirements for model runs.
- Assisted in developing the methodology for modelling the operation and dispatch of CHP units.
- Provided additional, granular data on CHP operating profiles (heat and power demand) and assumptions on sizing of CHP plant.
- Provided additional input to expected Heat to Power demand ratios for representative target application clusters.
- Provided "sense check" and interpretation of CHP dispatch and build results.
- Engagement with stakeholders, e.g. CHPA

- Providing inputs to “context issues” such as regulatory and legislative issues surrounding the commercial (rather than economic) viability of types of CHP application.

4. Data and Assumptions

4.1. Wider GB market assumptions

The wider market assumptions are consistent with DECC’s December 2013 EMR delivery plan analysis. More detail on the assumptions used in this analysis can be found on Gov.uk[6]. This includes the demand and fuel price assumptions, which are consistent with DECC’s UEP 2013 projections, and a decarbonisation trajectory that achieves approximately 100g of CO_2 per kWh in 2030 for total GB generation.

As the EMR delivery plan analysis was also conducted using the DDM, we were able to utilise the same model input files in this analysis. This ensures complete consistency.

A limited number of updates were made to the delivery plan assumptions:

- Carbon price floor freeze applied, based on the 2014 Budget announcement. Carbon price support limited to £18/tonne in 2016-2020.
- Good-quality autogeneration capacity replaced with detailed representation of Gas CHP capacity (see next section)
- More granular representation of intra-day wind profiles was applied.

4.2. Gas CHP assumptions

CHP technical characteristics

- Gas CHP plant were modelled in the DDM using 38 representative “clusters”, each with its own set of technical characteristics.
- The clustering definitions were provided by DECC, based on CHP plant size, technical characteristics, policy exposure, load profiles and percentage power exported. This is a higher level of aggregation than is used in the Ricardo-AEA and DECC CHP models, which use 298 tranches of CHP, but represents a consistent view.
- The technical and operating assumptions for each cluster were provided by DECC, and reviewed by Mott MacDonald. In cases where Mott MacDonald suggested changes, some were accepted while others were noted, but rejected in order to maintain consistency with assumptions in the Ricardo-AEA and DECC models.

More detail on the technical characteristics of the clusters can be found in Appendix 2.

[6] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan

CHP commercial arrangements

Arguably the key assumption in this analysis is the commercial arrangements that new CHP capacity will be exposed to. It is this that determines how CHP make dispatch decisions and therefore how they interact with the rest of the market.

The modelling assumes the following commercial arrangements for the different Gas CHP clusters, as provided by DECC. Many of the results that follow are summarised by these three size groupings.

Group	Cluster unit size	Import power price	Export power price	Gas price
CHP Small	< 2MW	Retail tariff	80% of Wholesale	Retail
CHP Medium	2 – 25 MW	Retail tariff	80% of Wholesale	Retail
CHP Large	> 25 MW	Retail tariff	Wholesale price	Retail

The retail power tariff is calculated within the DDM based on a fixed multiple of the wholesale price (as projected one season ahead within the DDM). This relationship ensures the modelled retail power price is internally consistent with long term changes in wholesale power prices. A multiple of 1.55 was used, calculated from the average when comparing the industrial retail power price (excluding policy cost elements that are modelled separately in the DDM) and the wholesale price in DECC's published projections (for 2013-2030). Four different retail price bands are determined: Day, Evening Peak, Evening & Night. The price also varies by season and between weekend and weekday.

The 80% of wholesale price export power price assumption for plant below 25MW was taken from the Ricardo-AEA/DECC CHP models. This is intended to represent the discount incurred by small, independent generators for selling though a Power Purchase Agreement.

The gas retail price is the industrial price from DECC's Energy Demand / UEP model excluding Climate Change Levy (CCL) policy costs from which Good Quality CHP is exempt.

Gas CHP plant connected to the distribution network benefit from providing power to consumers with a reduced level of network losses. Avoided transmission and distribution losses are assumed for each cluster were provided by DECC, and range from 5.5% to 9.5% depending on plant size, as a proxy for network connection voltage.

Heat & onsite power use profiles

The operation of CHP units is dependent on the level of onsite heat and power demand at any one time. When there is a demand for the heat, the CHP unit benefits from the additional efficiency gained from providing useful heat and power simultaneously. When there is no onsite need for the heat, the heat must be dumped if the plant operates and the overall efficiency of the plant decreases. The onsite power demand is also important, as CHP units are generally exposed to different commercial arrangements based on whether they are importing or exporting their power. For more detail on how this is modelled and part of this project please see Appendix 1.

Granular, half hourly heat and onsite power use profiles for a range of typical Gas CHP plant hosts were provided by Mott MacDonald and Ricardo-AEA. Where these profiles were available for the sectors covered by a CHP cluster, the granular profiles were used in the modelling.

Where no suitable granular profile was available, six-point energy load index profiles provided by Ricardo-AEA were used. These profiles provide heat and onsite power use for 3 blocks in a typical Summer and a typical Winter day.

Build-out assumptions

In the Carbon Displacement and Social NPV modelling, the assumptions for the build-out of Gas CHP were provided by DECC and Ricardo-AEA. This included:

- Total capacity under baseline (2012, 2020, 2025)
- Build under each CHP bespoke policy scenario (2020, 2025)
- Breakdown of the capacity across the 38 modelled Gas CHP clusters

All CHP plant were assumed to have a 20 year lifetime, with a major overhaul after 10 years Existing capacity (as of 2012) was assumed to retire at a uniform rate, reflecting an even distribution of ages in the initial fleet between 0 and 20 years. These assumptions were translated to give an annual capacity for each cluster over the full modelling period (2013-45).

In the Incremental Build modelling, DECC and Ricardo-AEA provided assumptions on the Maximum Technical Potential of Gas CHP build. These were provided for each cluster (in 2020 and 2025), and were used as an upper limit on the amount of Gas CHP capacity brought forward in our modelling.

Policy exposure

In all of the DDM modelling, a number of existing policies were applied to Gas CHP plant. These include:

- Climate Change Levy (CCL).
- Carbon Reduction Commitment (CRC).

- Carbon price support (CPS) including CHP heat relief & on-site consumption exemption.
- ETS Phase III.

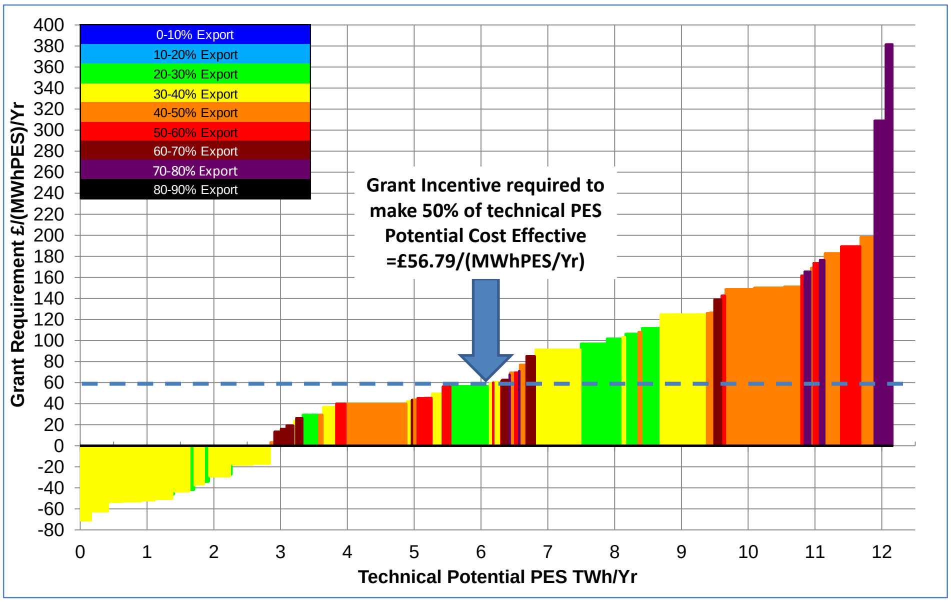
For the Incremental Build and Social NPV analysis, five bespoke Gas CHP policies were evaluated. Each policy was applied to qualifying new plant coming online between 2018 and 2025 with the following levels of support (all in real £2012):

1. Premium Feed in Tariff (FiT), £17.55 per MWh of electricity.
2. Capital Grant, £56.79 per MWh of annual Primary Energy Saving (PES).
3. PES incentive, £19.30 per MWh of PES.
4. Quality Index (QI) weighted heat incentive, £12.31 per MWh of heat x QI/100. QI is a measure of overall efficiency.
5. QI weighted capacity incentive, £89.48 per kW x QI/100.

These policies, with the exception of the Capital Grant, were applied to the first 5 years of operation for qualifying plant. Qualifying plant are new Gas CHP capacity coming online from 2018 to 2025, which is considered to be “good quality” CHP i.e. the plant is certified as meeting the requirements of CHPQA, and exports at least 20% of its power generated to the grid.

The support levels were calculated by DECC based on supply curves representing all qualifying potential CHP excluding existing capacity. The baseline support levels were set so that the 50th percentile of potential CHP would be cost effective under each policy.

DECC Gas CHP Potential 2020 Supply Curve for qualifying CHP



5. Carbon intensity of the generation displaced by Gas CHP

5.1. Overview and key assumptions

The purpose of this part of the analysis was to model the carbon intensity of generation displaced by additional Gas CHP generation. This enables an assessment of the net impact of additional Gas CHP on total carbon emissions.

Modelling was carried out using a version of the Dynamic Dispatch Model (DDM), which has been upgraded to model Gas CHP in detail. Carbon displacement was assessed over the 2018-45 period.

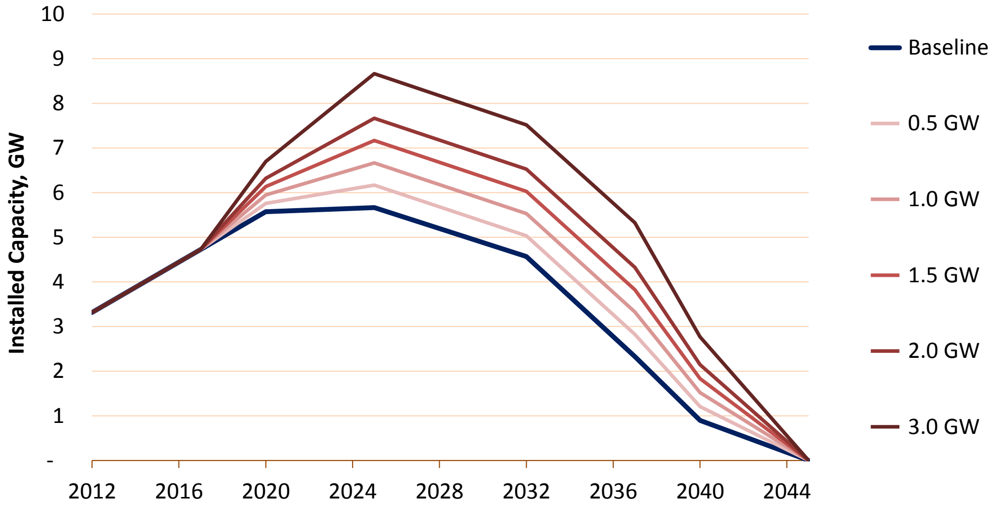
The baseline Gas CHP build profile was provided from DECC's Monte Carlo CHP model analysis. This included the breakdown of the build amongst the 38 clusters of CHP modelled. The exceptions to this were the clusters representing Oil & Gas and District Heating, which are not covered by DECC's Monte Carlo CHP model. Off-model assessments for these were provided by Ricardo-AEA.

To examine the generation displaced by Gas CHP, scenarios were modelled containing different levels of additional CHP capacity above the baseline: +0.5GW, 1.0 GW, 1.5GW, 2.0GW, 3.0GW. The additional build is modelled as coming online over the 2018-2025 period where the new policy support options would be available.

The trajectories for the baseline and scenario build profiles are shown on the chart below. In the baseline used for this part of the modelling, CHP capacity was projected by DECC's then current Monte Carlo analysis to grow from its 2012 level capacity of 3.3GW to 5.7GW in 2025. It should be noted that in addition to the CHP capacity in the 38 clusters the DDM already includes two large (c.1.2MW) CCGT CHP plant and biomass CHP capacity. These are excluded from the chart below.

For a detailed breakdown of the baseline and scenario capacity by cluster please see Appendix 2.

Installed Gas CHP capacity modelled, by build scenario



In addition to the range of CHP build scenarios, scenarios were run on the development of the wider GB electricity market. These scenarios each represented a different "background" capacity and generation mix, meaning different types of generation will be displaced by additional Gas CHP.

They are based on pre-existing DECC scenarios, and have been set up to ensure the assumptions within each scenario are internally consistent. For each scenario a baseline and a +1.5GW new Gas CHP build profile was run. The scenarios run were:

- High fossil fuel prices
- Low fossil fuel Prices
- High demand
- Low demand
- 50g/kWh carbon intensity in 2030
- 200g/kWh carbon intensity in 2030
- High offshore wind build

Circumstances under which Gas CHP may displace low-carbon generation

One of the key questions this analysis attempts to answer is at what point Gas CHP starts to displace low-carbon generation, and if and when this displacement results in a net increase in overall carbon emissions.

First, it is important to understand the circumstances under which Gas CHP could displace low-carbon generation, and what the key assumptions driving this are.

Low-carbon generation operating in the wholesale market will tend to occupy the lower end of the merit order stack, operating as baseload generation. This is because a combination of low fuel costs, low carbon costs and policy support incentives mean that the Short Run Marginal Cost ("SRMC") of most low-carbon generation will be near or below zero (e.g. wind, solar). Even low-carbon generation with significant fuel costs (e.g. Biomass, CCS), will tend to operate at lower SRMCs than Gas CHP, due to the policy support they receive under the ROC and CfD regimes and lower carbon price exposure.

This means that Gas CHP operating in the wholesale market should not displace low-carbon generation, as it will respond to real-time wholesale price signals whenever low-carbon generation is marginal, and turn its CHP unit off (switching to backup boilers to satisfy any heat load).

However, our central assumption is that, for the proportion of their power output which is used to satisfy onsite electricity demand, Gas CHP plant do not respond perfectly to wholesale price signals. They are assumed to pay a retail price for onsite electricity demand if the CHP is not operating, a banded tariff (4 time bands per day) varying in proportion to the average wholesale price predicted for each time band. Gas CHP may reduce its output to avoid exporting electricity when wholesale prices are low, but it will continue to generate to satisfy onsite demand whenever the cost of operating is lower than the site's retail tariff.

This assumption was provided by DECC and tested with, and confirmed as being reasonable by CHP and industrial stakeholders. We have assumed that they will continue to operate in this manner over the full modelling horizon (2015-45), which is more uncertain.

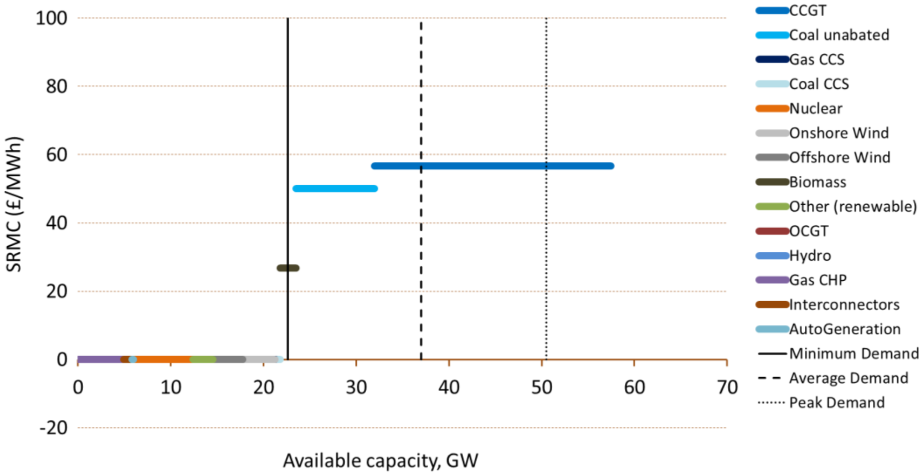
As a result of on-site demand, Gas CHP will displace marginal low-carbon generation. In DECC's central case there is a significant amount of low-carbon generation on the margin from the late 2020s onwards, in particular Gas CCS.

The following two charts show approximate representations for how the merit order stack may look in 2020 and 2035, relative to the range of demand levels. In reality, the stack will change throughout the year, and even within a single day, due to factors such as intermittent availability, plant outage schedules, limited running hour constraints (e.g. IED constrained coal plant) and fuel price seasonality.

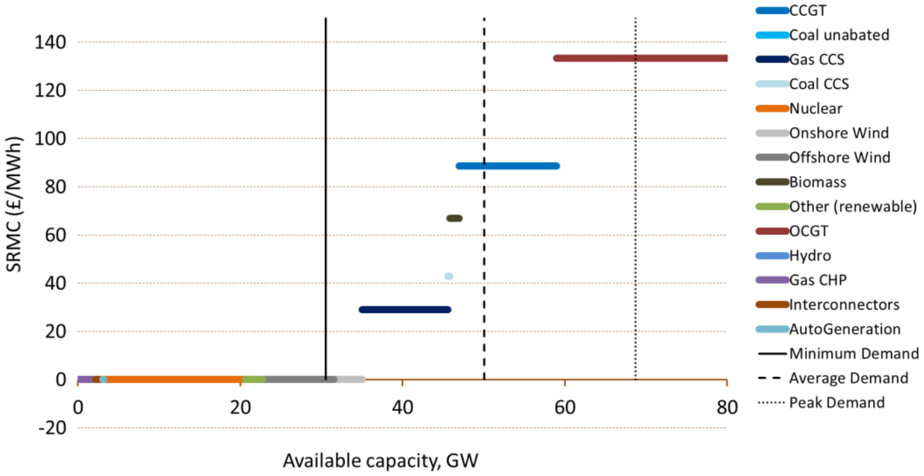
In 2020, CCGT is on the margin most of the year, with coal occupying the margin in some periods of lower demand. In this case, Gas CHP will only be displacing generation that has a higher carbon intensity than its own, resulting in emission savings.

By 2035, however, the generation mix on the system has changed considerably. There is a significant increase in low carbon generation, including Gas CCS, which sits below CCGT in the merit order due to its CfD policy support and the high carbon price. CCGT still occupies the margin during periods with average levels of demand, but during low demand periods low-carbon generation such as Gas CCS, Biomass and Wind may occupy the margin. In these low demand periods, Gas CHP that is not responding to wholesale prices will displace this generation, resulting in additional CO_2 emissions.

Illustrative merit order, 2020



Illustrative merit order, 2035



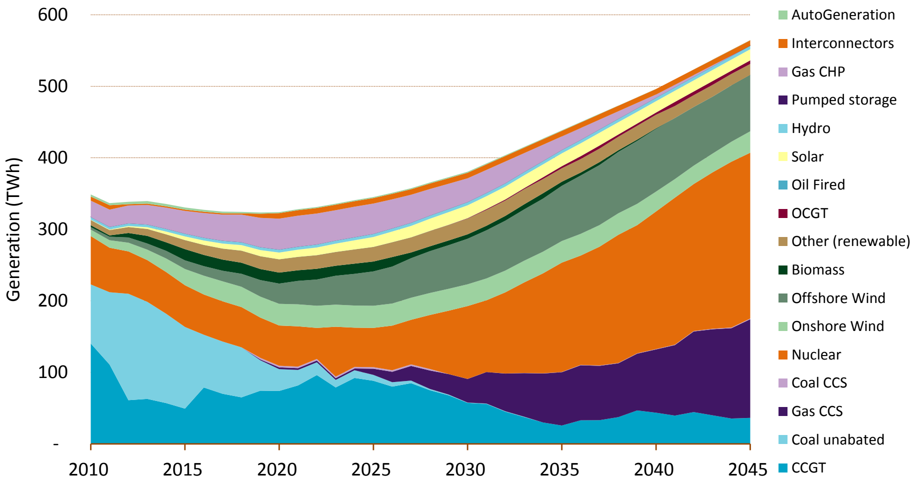
5.2. Summary of results

5.2.1. Reference case

The baseline for this analysis is consistent with DECC's central "Reference case" used in its December 2013 EMR delivery plan analysis. Under these assumptions, the GB power sector achieves a carbon intensity of approximately 100g/kWh in 2030.

The following chart shows the baseline generation mix over the modelling period. There is a significant increase in the proportion from low carbon sources over this period.

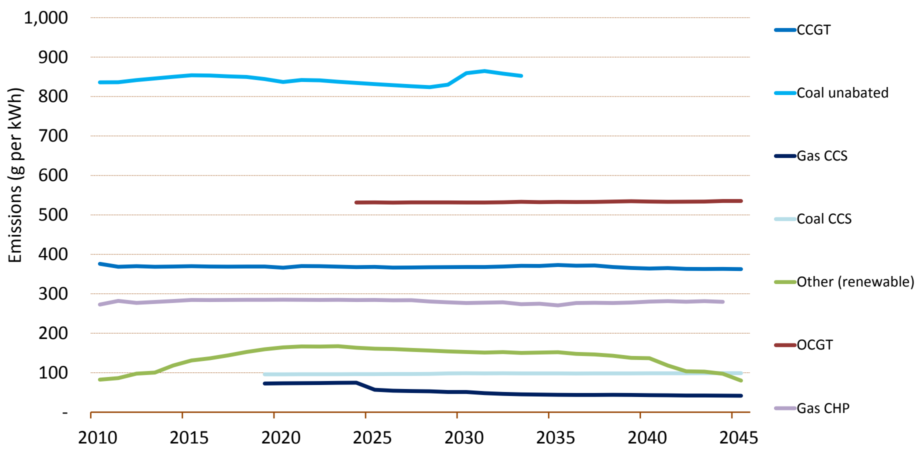
Baseline generation mix under DECC central grid decarbonisation trajectory



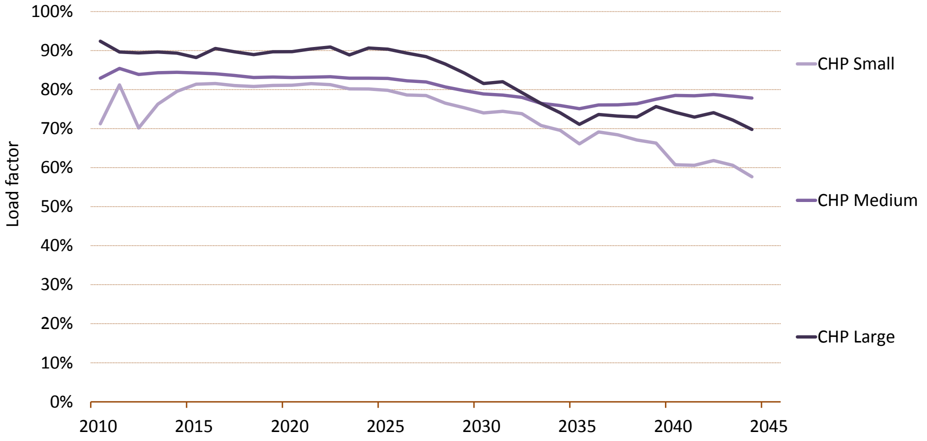
The next chart shows the relative CO_2 emission intensities of the various technologies modelled. The emission figure for Gas CHP represents emissions produced in addition to a counterfactual alternative heat source, i.e. the emissions produced in supplying heat and power through CHP are discounted by the emissions that would have been produced in supplying the heat source with gas boilers.

When displacing 1kWh of CCGT generation Gas CHP saves around 100g of CO_2. But displacing Gas CCS generation will result in a 250g/kWh increase, and displacing renewable generation will result in an increase of almost 300g/kWh.

CO_2 emission rates of different technologies



Load factors – Gas CHP



CHP load factors are relatively stable over the modelling period, with only a small drop-off after about 2030. This is largely driven by the assumptions for the heat and power use profiles and the commercial arrangements of the representative clusters modelled. When there is demand for a CHP's heat, it will be able to operate very efficiently and therefore tend to operate up to at least its full heat load. This is seen in the load factors prior to 2030.

From around 2030, there are significant periods of low prices, due to the penetration of low carbon technologies, such as wind, on the system. During these periods, CHP reduces its exports to the grid, for which it receives a proportion of the wholesale price. CHP also reduces its generation in response to lower retail tariffs in low demand periods. Wholesale prices, and subsequently retail tariffs, are likely to show more "shape" in the future, with off-peak, overnight prices depressed by the high levels of low carbon generation.

5.2.2. CHP build scenarios

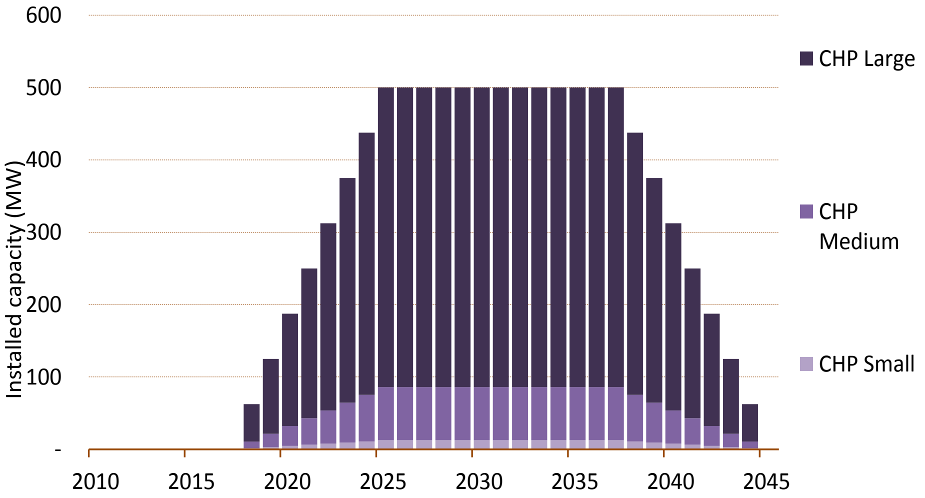
The impact of a range of different levels of Gas CHP capacity was modelled. Additional capacity was assumed to be deployed from 2018 until 2025, after which it was assumed that additional Gas CHP would no longer be incentivised by the policy options.

The scenarios covered additional new Gas CHP build over the 2018-2025 period of +0.5GW, 1.0 GW, 1.5GW, 2.0GW and 3.0GW.

For this modelling of generation displaced, the capacity mix on the rest of the system was "locked" across the baseline and all scenarios. This avoids the additional Gas CHP affecting the build or retirement decisions of other plant, which could result in step-changes in the modelling results (e.g. a change in the online date of a large CCGT or nuclear plant), and allows the generation displacement to be viewed in isolation. This assumption was viewed as appropriate given the relatively low levels of additional Gas CHP capacity modelled.

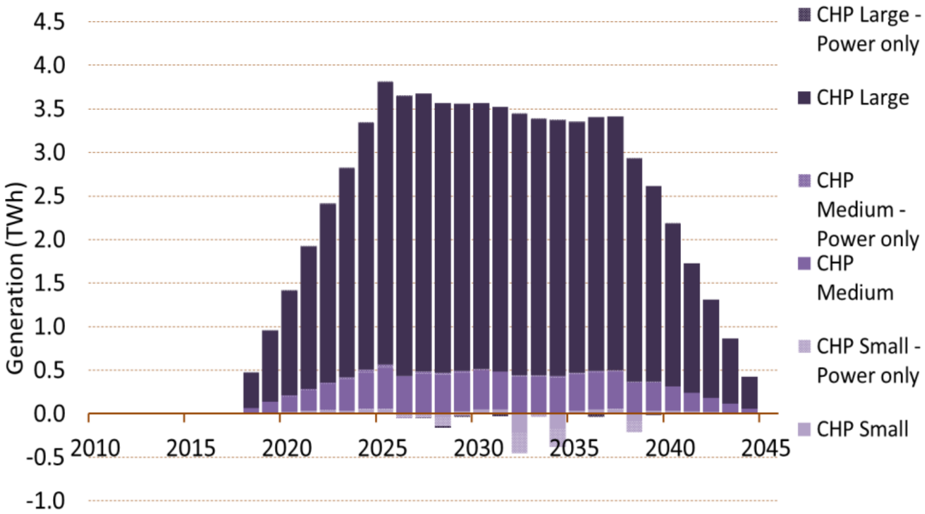
The assumption on the mix of the additional CHP capacity amongst the 38 clusters was provided by DECC based on Ricardo-AEA and DECC's baseline Monte Carlo CHP capacity projections. The majority fell in the larger clusters, i.e. those with unit sizes of more than 25 MW. (Note that updated baseline capacity projections were provided by DECC/Ricardo-AEA for the Social NPV modelling.)

Additional Gas CHP capacity, +0.5GW scenario



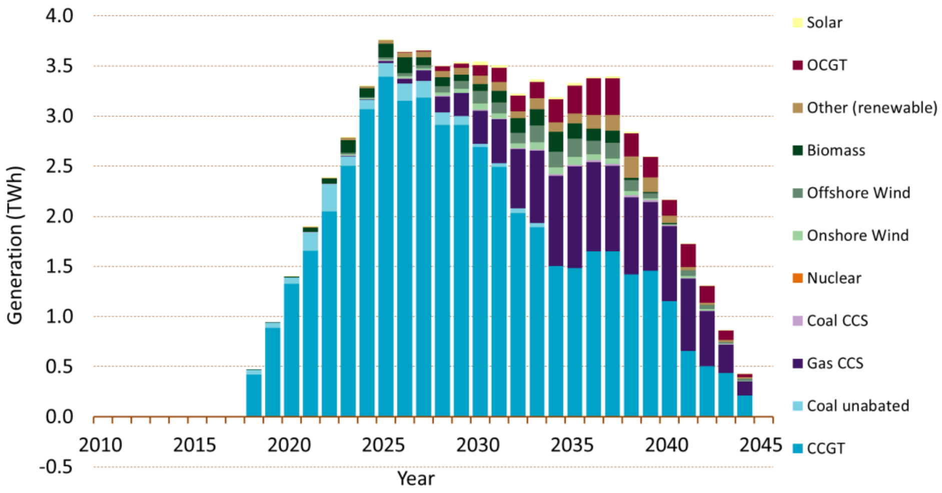
The chart below shows the net change in Gas CHP generation resulting from the additional Gas CHP capacity. In some years there is a small reduction in Gas CHP generation in the smallest category, as the prices it is exposed to reduce, and it is displaced by the Medium and Large categories of Gas CHP.

Generation from additional Gas CHP capacity, +0.5GW scenario



The chart below shows the breakdown of the generation that the additional Gas CHP capacity displaces.

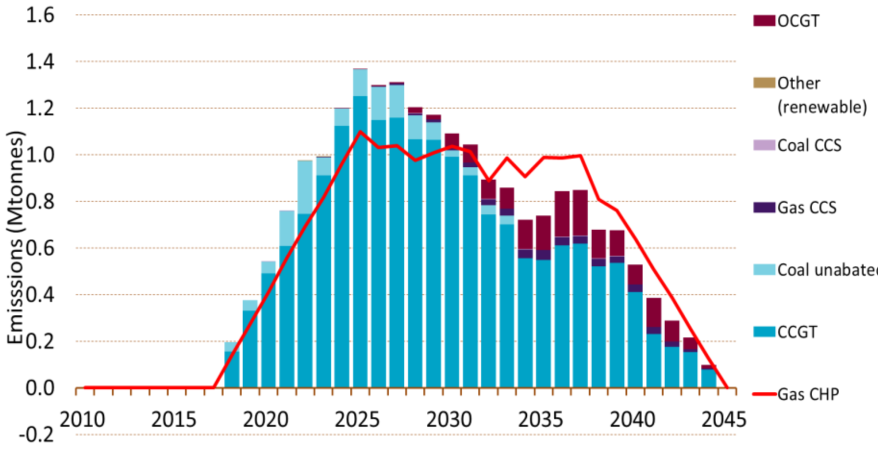
Generation displaced by additional Gas CHP capacity, +0.5GW scenario



Initially, over the 2018-2025 period, displacement is almost entirely of CCGT (which is the marginal plant), and small amounts of unabated coal.

From the late 2020s, small amounts of low-carbon generation are displaced, including Biomass, Gas CCS and wind. From around 2030 onwards, significant amounts of low-carbon generation, in particular Gas CCS are displaced. There is also some displacement of OCGT, which has significant amounts of capacity brought forward through the new system-wide Capacity Market in DECC's basecase.

CO_2 emissions from the generation displaced by additional Gas CHP capacity, +0.5GW scenario

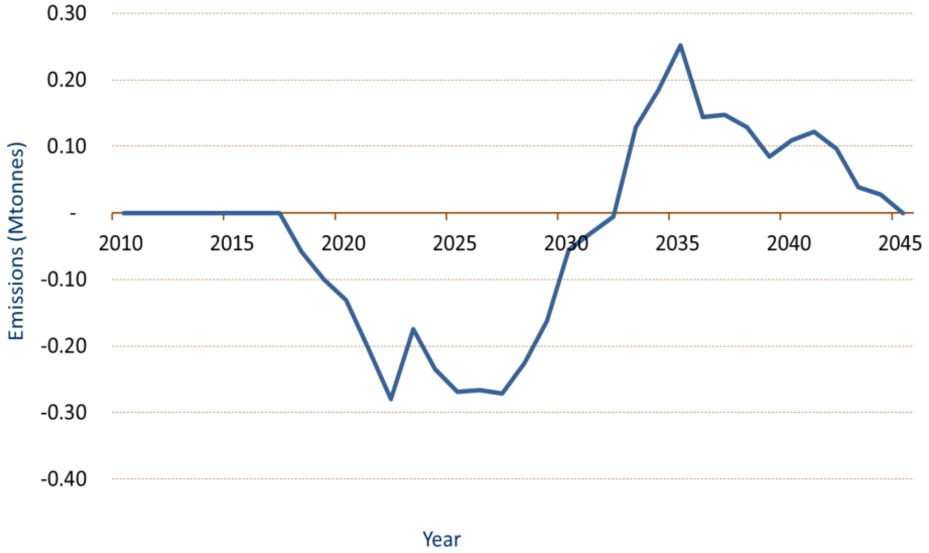


The chart above shows the carbon emissions avoided from the displaced generation. The red line shows the carbon emissions produced by the additional Gas CHP generation minus counterfactual boiler emissions, and the bars show the carbon emissions it displaces.

Prior to 2032, the emissions saved outweigh the emissions incurred, resulting in a net saving. From 2032, the additional Gas CHP results in an increase in emissions. This is primarily due to the increased penetration of low carbon generation on the system.

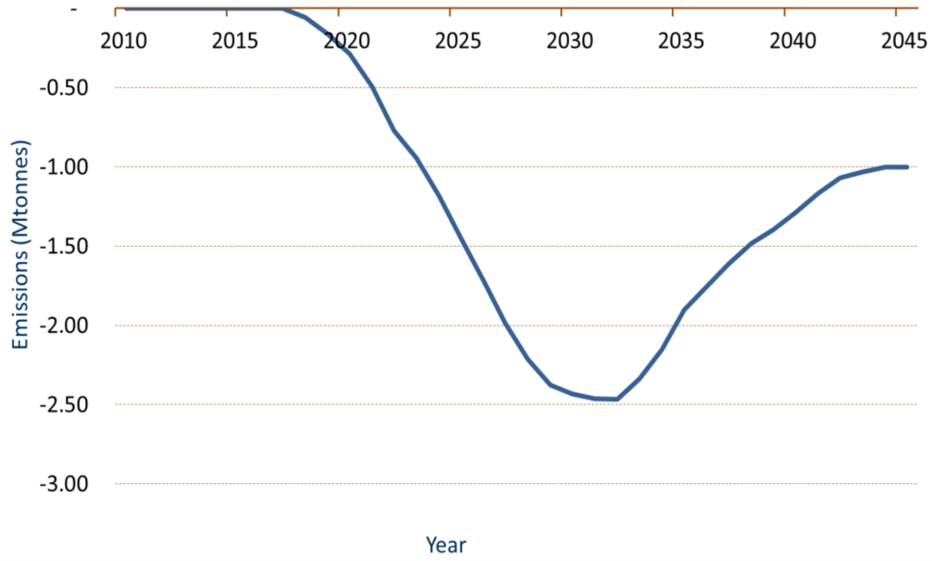
The net carbon impact is shown on the next chart.

Net CO_2 emissions from the generation displaced by additional Gas CHP capacity, +0.5GW scenario



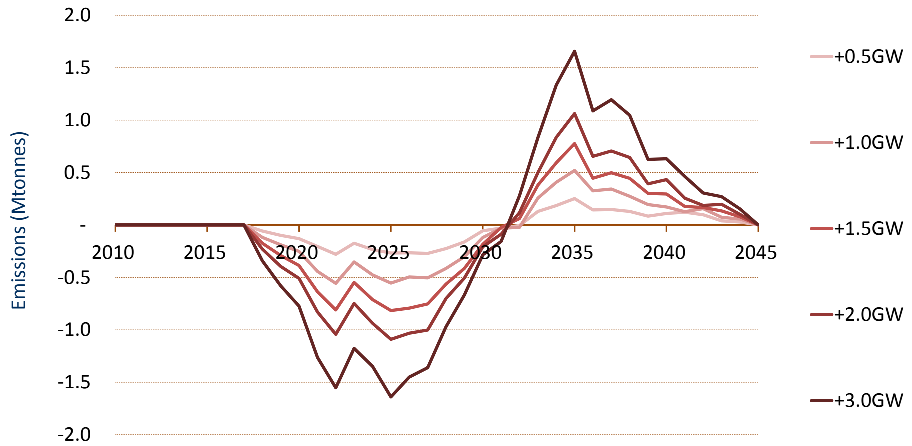
When shown cumulatively we see that over the full modelling horizon, the additional Gas CHP results in a net saving in emissions. The additional 0.5GW of Gas CHP capacity results in around 1Mtonne of emissions saved over the whole period, peaking at around 2.5Mtonne in 2032.

Cumulative net CO_2 emissions from the generation displaced by additional Gas CHP capacity, +0.5GW scenario



The following chart shows the net impact on emissions of all the build scenarios.

Net CO_2 emissions due to additional Gas CHP, all build scenarios



In general, the results are proportional to the level of CHP capacity deployed. There is no evidence of any obvious point above which additional Gas CHP capacity results in a significantly different net carbon impact. The net carbon profile, including the 2032 cross-over point, is driven almost entirely by what is marginal within the wider generation fleet, and the gas CHP capacities are not sufficiently large to materially affect when this switchover occurs.

The capacity mix on the rest of the system is “locked” in all these scenarios so it is worth noting that this observation may not hold true if the level of deployment was sufficient to result in a significant change to the capacity mix on the system. However, given the relatively low levels of deployment in response to policy incentives shown in the endogenous build modelling and DECC Monte Carlo modelling (see subsequent sections), we would not expect the additional Gas CHP to have a material effect on the overall system capacity mix. For example, the DECC Monte Carlo modelling only shows 150-200MW of additional deployment.

5.2.3. Generation background scenarios

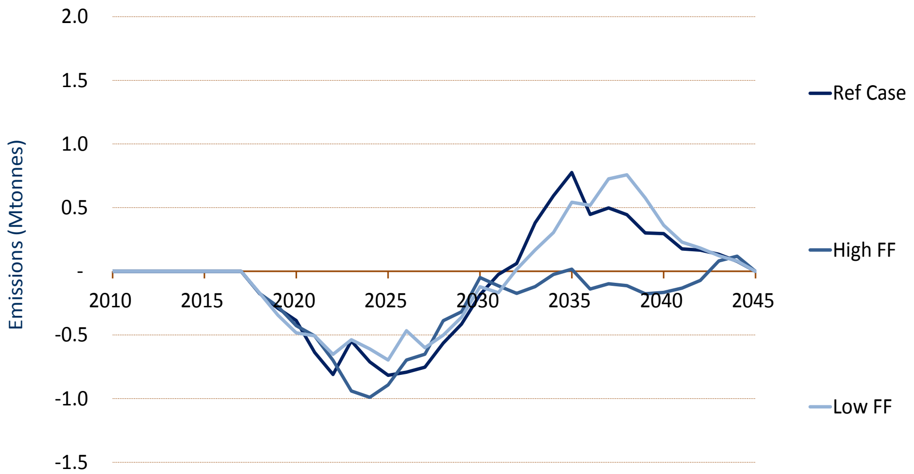
In addition to the build scenarios, we also explored several scenarios with a different underlying capacity mix on the system.

The scenarios were based on DECC assumptions, and are consistent with those used in the EMR delivery plan analysis:

- High fossil fuel prices
- Low fossil fuel Prices
- High electricity demand
- Low electricity demand
- 50g/kWh carbon intensity in 2030
- 200g/kWh carbon intensity in 2030
- High offshore wind build

Each sensitivity scenario was run on a case with an additional 1.5GW of Gas CHP build over the scenario's baseline. The system capacity mix between the sensitivity scenario and its baseline was locked in each case.

Fossil Fuel Price scenarios: net carbon impact due to additional 1.5GW of Gas CHP

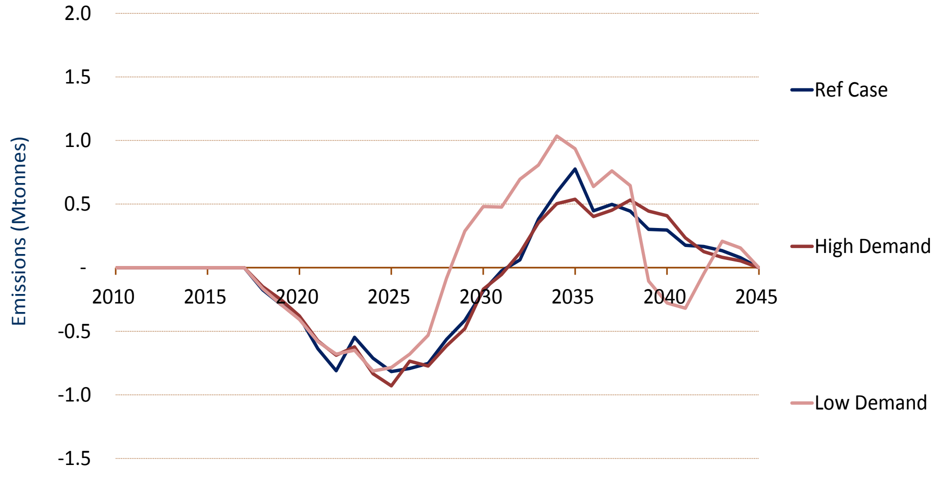


The Low Fossil Fuel Price scenario shows only minor differences in net carbon impact relative to the Reference case. This is because the lower fossil fuel price scenario does not show a significant impact on the capacity or generation mix on the system. One reason for this is that DECC's Low Fossil Fuel Price scenario is set up to achieve the same decarbonisation trajectory as the central case.

The High Fossil Fuel scenario, however, shows a significant impact. In the 2030s there is no longer a net increase in emissions. The primary reason for this is the deployment level of Gas CCS. Under the High Fossil Fuel scenario, there is a much lower level of Gas CCS deployment, resulting in a lower level of low-carbon generation displacement.

This scenario illustrates how sensitive the analysis is to assumptions that may affect the evolution of the GB energy mix over the next 30 years. In particular, the analysis is sensitive to assumptions that affect the timings for the commercialisation of large-scale CCS deployment.

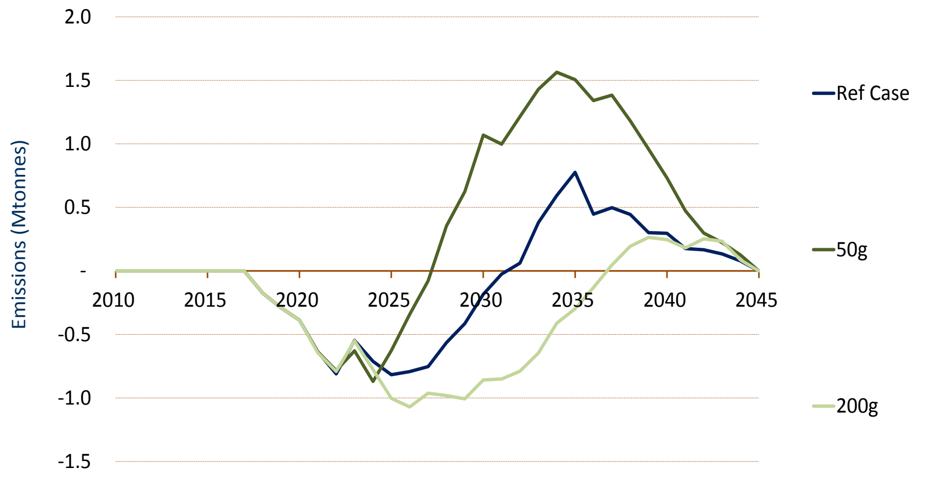
Demand scenarios: net carbon impact due to additional 1.5GW of Gas CHP



The High Demand scenario shows only minor differences in the net carbon impact relative to the Reference case. This is because this scenario does not significantly impact the system's generation mix, at least near the margin.

The Low Demand scenario shows a net increase in emissions occurring several years earlier, with the cross-over point now occurring around 2028. The primary reason for this is that low-carbon generation represents a greater proportion of total demand. Under a scenario with lower demand there are more periods during the year where low-carbon generation is marginal, resulting in a higher level of low-carbon displacement. There is, however, a period in 2039-2042, where net annual emissions are reduced. This is due to lower displacement of CCS generation, and demonstrates that the sensitivity of the results to assumptions on the penetration of low-carbon technologies.

Decarbonisation scenarios: net carbon impact due to additional 1.5GW of Gas CHP



As would be expected, both the carbon intensity scenarios show a significant impact on net CO_2 emissions impacts of additional Gas CHP capacity. The cross-over point (where net CO_2 impact switches from a decrease to an increase) occurs around 5 years earlier in the 50g scenario and around 5 years later in the 200g scenario,

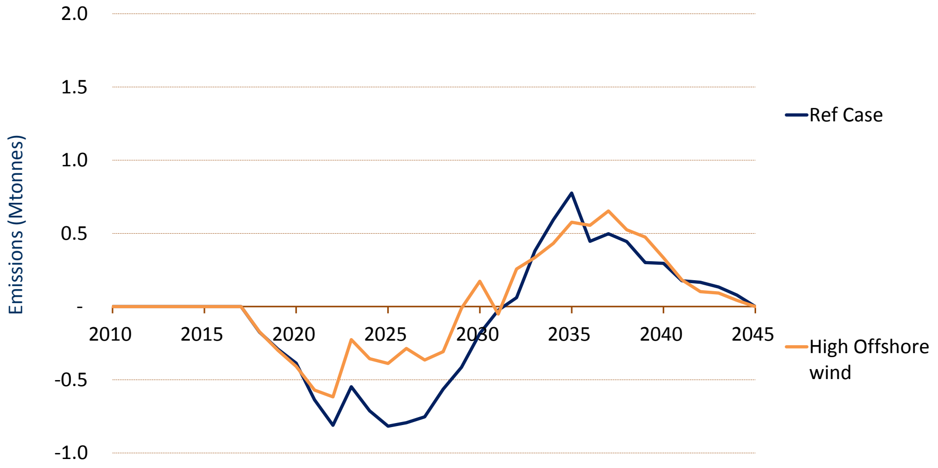
Under the scenario where the GB power sector achieves a CO_2 intensity of 50g/kWh in 2030, the benefit of Gas CHP is greatly reduced. This is because of the significant amounts of low-carbon generation on the system.

In contrast, the 200g/kWh CO_2 intensity scenario shows a significant increase in the benefit of additional Gas CHP.

Like the High Fossil fuel scenario, these two scenarios illustrate how sensitive the analysis is to assumptions on the evolution of the GB energy mix. If the decarbonisation trajectory is considerably slower than under the central 100g/kWh assumption, then Gas CHP could provide significantly increased carbon savings.

The final generation background scenario explored was one with High Offshore Wind build. In this scenario there is almost 40GW of Offshore Wind capacity online in 2030, almost double the amount projected in the central case. This results in decreased carbon savings in the 2020s, and minimal impact post 2030. The decreased savings in the 2020s are a result of more low-carbon generation being displaced, due to the large amounts of Offshore Wind generation.

High Offshore Wind scenario: net carbon impact due to additional 1.5GW of Gas CHP

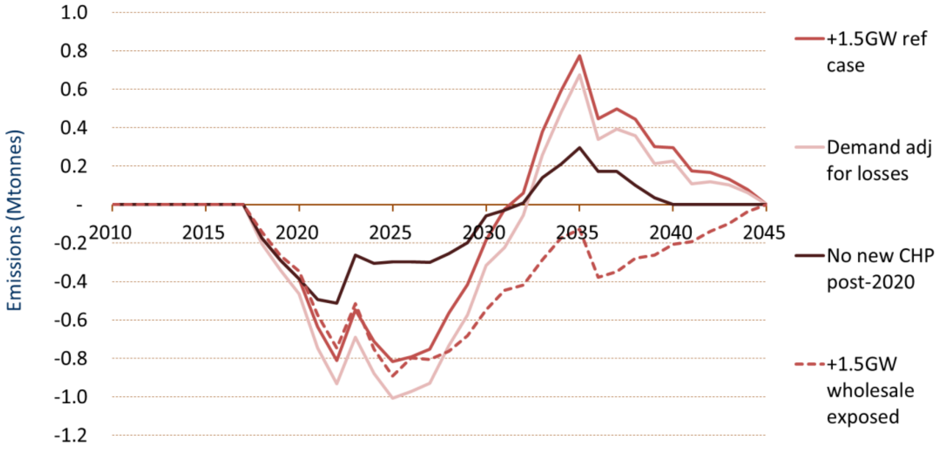


5.2.4. Additional sensitivities

Additional sensitivities were run on the +1.5GW scenario to explore the effects of:

- Modelling all of the electrical output of large CHP units (>25MW), which make up the majority of the additional capacity modelled, as competing directly in the wholesale market, rather than a proportion being retail price exposed.
- Adjusting the demand to account for the transmission losses avoided by Gas CHP
- No new Gas CHP being deployed post-2020

Additional sensitivities: net carbon impact due to additional 1.5GW of Gas CHP



As outlined in previous sections, the commercial arrangement for new CHP plant is a key factor in how the plant interact in the market. In the first sensitivity, we consider an extreme case where the large new CHP plant, which make up the majority of the capacity, respond to the wholesale price over the whole modelling period for all of their power output, rather than just for exported power. If new CHP had the technical capability and exposure to the commercial arrangements enabling them to respond to wholesale prices from the late 2020s onwards, then we would see a similar effect.

In this sensitivity the wholesale-exposed large CHP respond to price signals when low carbon generation is on the margin and turn off their CHP unit so they can import cheap power from the grid. As a result, in this case, there is no “cross-over” point in 2032 when net emissions previously became positive. In fact, the Gas CHP shows a net saving in emissions throughout the modelling period, i.e. through to 2045.

This shows the sensitivity of the results to the assumptions around the commercial arrangements of the plant. If CHP plant are responding to low wholesale prices, by turning off their CHP unit and satisfying their heat demand through back-up boilers, there is a significant gain in terms of carbon savings.

Mott MacDonald has noted that a number of commercial CHP contracts previously operated in this way. Short term power market price fluctuations could result in wide swings from shut down of power generation coupled with power import, to full power generation with less than full use of heat. However, CHPA and industrial stakeholder's input on typical electricity retail pricing arrangements indicated that current commercial arrangements do not operate in this way.

It should be recognised that frequent stop-starts of gas turbines are costly in terms of maintenance and degradation impacts, but these effects only dampen the ability of CHP plant operation to fully follow wholesale power prices. Mott MacDonald suggests that a significant portion of the full benefit of following the wholesale price could be technically available in practice, particularly for medium sized machines, who have the ability to rapidly ramp up and ramp down. A collateral benefit of this operating mode is that CHP plant output could be incentivised to contribute to system balance mechanisms rather than exacerbating the impacts of non-dispatchable renewable generation. However, commercial arrangements favour generation to satisfy on-site power demand over export to the wholesale market.

Adjusting demand to account for the electricity transmission and distribution losses avoided results in greater carbon savings, and shifts the cross-over point back one year to 2033. In the subsequent Social NPV analysis (see section 7) this adjustment is made for all cases.

With no new deployment post-2020 the lower level of carbon savings in the 2020s is offset by lower carbon additions in the 2030s. The cumulative impact of this is a result very similar to the baseline.

5.3. Conclusions

This analysis estimates the impact of additional Gas CHP capacity on total carbon emissions.

Under baseline assumptions, additional Gas CHP provides carbon savings through to 2032, after which it results in a net increase in emissions. This is due to the type of generation displaced. In early years Gas CHP primarily displaces CCGT, but from the late 2020s onwards it displaces an increasing proportion of low-carbon generation, such as Gas CCS and Wind.

This result is sensitive to a number of assumptions. In particular, the decarbonisation trajectory of the GB power sector and the deployment levels of Gas CCS. The baseline, based on DECC's central assumptions, assumes the GB power sector achieves an average carbon intensity of 100g/kWh in 2030. Under a slower decarbonisation trajectory, Gas CHP has the potential to provide carbon savings for a longer period of time.

Another key assumption is around the commercial arrangements of the Gas CHP plant. In particular, the responsiveness of Gas CHP plant to wholesale price fluctuations. If sites served by Gas CHP bought their power in the wholesale market, and assuming the CHP unit had the flexibility to respond to wholesale price signals, then CHP units will not operate when wholesale prices are low and low carbon generation is on the margin.

6. Endogenous modelling of incremental Gas CHP build

6.1. Overview and key assumptions

This analysis was conducted to provide DECC with a second set of estimates on the amount of new Gas CHP deployment under different policy support options. It adopts a different approach to DECC's internal modelling, but with a consistent set of assumptions.

Like the carbon displacement analysis, this modelling was carried out using the upgraded version of the DDM, which contained the functionality to model Gas CHP in greater detail.

There are a number of areas where the approach used in the DDM differs from that used in the DECC's existing CHP models:

Advantages of the DDM modelling approach:

- Models the interactions with the rest of the electricity market. For example, any effect that additional Gas CHP capacity has on the wholesale price, and how this feeds back into Gas CHP investment decisions.
- Models the operation of Gas CHP units at a granular, half hourly level. The operating regime can vary in each half hour depending on the CHP plant's heat and power demand, commercial arrangements, and market power prices.
- Models EMR policy in detail, in particular the deployment of Gas CHP through the Capacity Market.
- Models the dependence from one year to the next, modelling existing capacity and new capacity separately. DECC's Monte Carlo CHP model determines the total capacity which it would be economic to build in any one year if there was no pre-existing capacity.

Disadvantages of the DDM modelling approach

- For practical purposes, the DDM analysis modelled Gas CHP using 38 representative clusters. This is a significantly higher level of aggregation than the 298 tranches used in DECC's Monte Carlo CHP model. This represents a good compromise between adequate representation of behavioural variation and processing efficiency, and a better balance between granular characterisation and available data.
- The DDM does not include the DECC Monte Carlo CHP model's investment probability element, rather it models build as a go/no-go decision based on projects meeting a minimum hurdle rate.
- The DDM modelling did not include detailed modelling of biomass CHP. In the DECC Monte Carlo CHP model biomass CHP competes with Gas CHP investment decisions.

Key assumptions

CHP incremental build was modelled over the 2018-2025 period, the period over which it was assumed any potential policy support would be available.

- Hurdle rate, by cluster, ranging from 12.0% to 23.5% (post-tax real). Gas CHP has significantly higher hurdle rates than conventional gas plant such as OCGT and CCGTs. This may be due to higher perceived risks associated with CHP investment or opportunity cost.
- Capex, by cluster, ranging from £780/kw to £1,530/kW.
- Investment decision for all Gas CHP plant based on an assessment of the returns projected over the first 10 years of plant operation.
- Separate refurbishment decision made 10 years into all Gas CHP plant's lifetime, providing option to extend plant life to 20 years.
- Gas CHP build constrained by maximum technical potential, provided by Ricardo-AEA for each cluster.
- Risk of loss of heat load represented by degradation in the onsite heat demand over the Gas CHP plant's lifetime. Available heat load was reduced by 7.5% over 10 year period. This assumption was supplied from Ricardo-AEA, based on analysis of premature closures of CHPQA certified plant over the 2003-2012 period.
- DECC's December 2013 Reference Case assumptions are still used to define the market-wide assumptions, but the capacity mix is no longer locked between the baseline and scenario runs. Instead, plant investment decisions are modelled, including those for Gas CHP.
- In the baseline, all Gas CHP were eligible to compete in the Capacity Market. In the Capacity Market, plant capacities are reduced to reflect average historical rates of availability. The adjustments applied are known as derating factors, and are generally applied at the technology level. In the modelling, Gas CHP's derating factor was applied as either the generation of the cluster during winter peak, or a standard derating factor assumption for Gas CHP (assumed to be 85% when the analysis was conducted, slightly more conservative than the 90% derating factor confirmed for CHP in the first auction) – whichever was smaller. For the majority of clusters this meant a standard derating factor of 85% was applied. An alternative baseline scenario was also run with no Gas CHP participating in the Capacity Market.
- In policy scenarios all Gas CHP participates in the Capacity Marker other than the plant that qualify for the policy support option.

More detail on the data and assumptions can be found in Appendix 2.

6.2. Summary of results

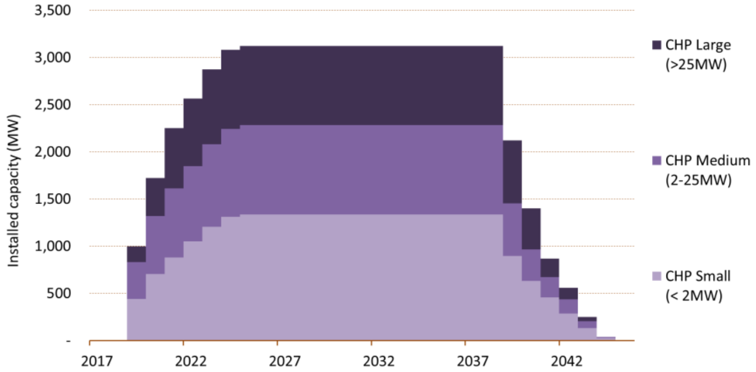
6.2.1. Baseline

Under baseline assumptions, modelling shows 3.1GW of CHP new and replacement capacity coming online over the 2018-2025 period.

There is a relatively even spread amongst the three unit size groups (< 2MW, 2-25 MW, >25MW), with 1.3GW coming from CHP plant smaller than 2MW.

All the new CHP plant brought forward take the option to refurbish their plant after 10 years, resulting in a 20 year lifetime.

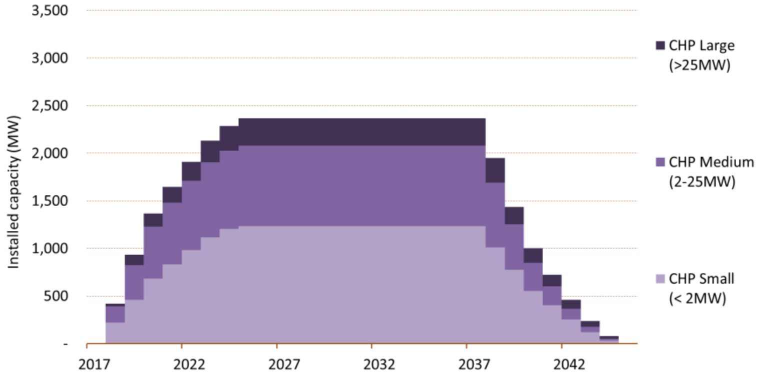
Incremental CHP capacity brought forward in the baseline



Under the same baseline assumptions, but with no Capacity Market participation, modelling shows approximately 2.4GW of CHP capacity coming online over the 2018-2025 period.

This is around 700MW less than with Capacity Market participation, with the main difference coming in the larger units (>25MW), who benefit the most from the Capacity Market incentive.

Incremental CHP capacity brought forward in the baseline, with no Capacity Market participation



Detailed incremental build results at a cluster level can be found in Appendix 3.

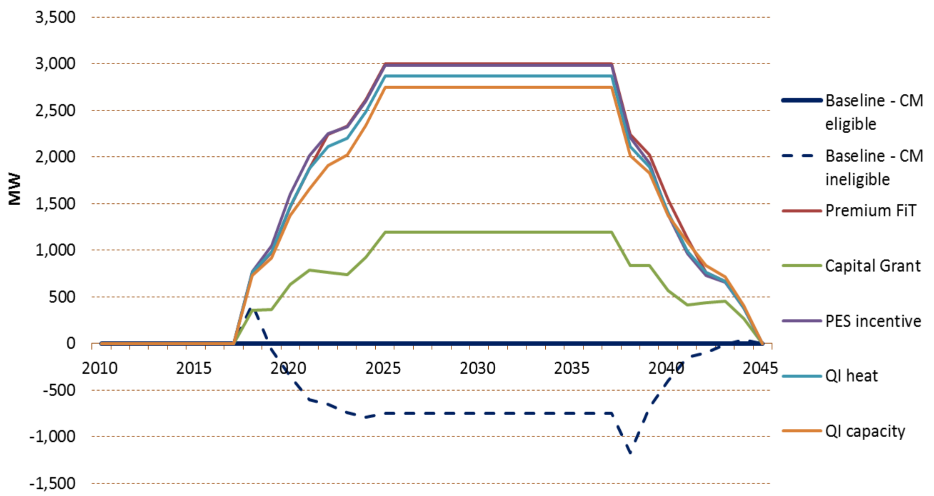
6.2.2. Bespoke policy scenarios

Each of the five bespoke policies were modelled under the same general assumptions as the basecase, to determine the amount of additional CHP capacity which would be brought forward over the 2018-2025 period.

The bespoke policies only apply to CHP plant exporting more than 20% of their power to the grid. In this modelling, eligibility was assigned at a cluster level based on the export assumptions used in Ricardo-AEA/DECC's modelling, to ensure consistency between the two approaches. Those clusters that are eligible for bespoke policy are not able to participate in the Capacity Market.

Four of the bespoke policies show around 2.7-3.0GW of additional capacity over the baseline, with the Capital Grant bringing forward 1.2GW.

Additional capacity brought forward over the baseline

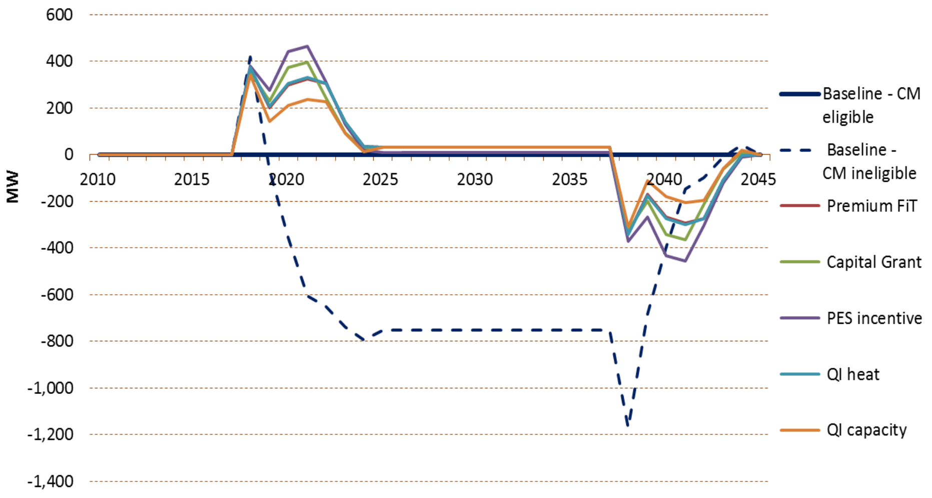


However, the vast majority of this additional capacity comes from the cluster representing District Heating (DH) capacity. With DH excluded, there is only a negligible amount of total additional capacity brought forward, about 30MW total by 2025. DECC's own modelling also shows a relatively small amount of capacity coming online as a result of each of the bespoke policies, around 150-200MW.

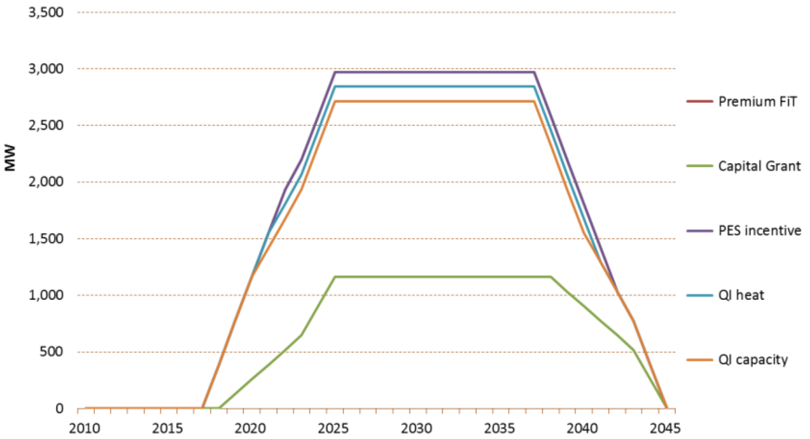
There is, however, around 400MW of capacity that is being brought online earlier than in the basecase. As the carbon displacement modelling demonstrates, this early deployment should provide a net carbon benefit.

The results described are in comparison to the baseline where Gas CHP participates in the Capacity Market. Under the alternative baseline, where Gas CHP does not participate in the Capacity Market, the bespoke policies still bring forward almost 800MW of additional capacity (excluding DH). Section 6.2.3 below, examines the prospects of Gas CHP participation in the Capacity Market.

Additional capacity brought forward over the baseline, excluding District Heating cluster



Additional capacity brought forward over the baseline, District Heating only



The main point of difference between the DDM and Ricardo-AEA/DECC CHP capacity results was in the baseline assessments. The DDM modelling showed no DH capacity brought forward in the baseline, whereas Ricardo-AEA's assessment showed 2.7GW brought forward by 2025, which is roughly in line with the amount brought forward in the DDM's policy support scenarios. However it should be noted that both sets of results for District Heating CHP model the economic viability of the CHP only, and do not consider the wider costs of building the heat network as a whole. The DH results therefore need to be treated with caution.

Mott MacDonald has noted that this level of development should be available from the supply chain, but that significant potential barriers remain in the legal and regulatory domains. In particular, the long term contractibility of heat load (exclusion of alternate, future, cheaper supplies) and compulsory inclusion of DH mains in all new developments, would materially assist exploitation of DH based CHP schemes.

One thing to note on this chart is that the Capital Grant policy has a significantly smaller impact on the District Heating build out than the other 4 bespoke policies.

The main reason for this is the low hurdle rate assumed for District Heating relative to the other clusters. Its hurdle rate of 12% (post tax real), is significantly lower than the other clusters, which are generally within the range of 18 to 23%.

The other 4 policies provide support further into the plant's lifetime, so a lower hurdle rate – relative to that used in setting the incentive levels – will mean the benefits are not as heavily discounted. The benefits from the other 4 policies are accrued across the first 5 years of operation, whereas the Capital Grant benefit is accrued up front. Modelled incentive levels were set by DECC with each policy being of equivalent present value for CHP in the sectors included in the Ricardo-AEA/DECC CHP models when discounted at the hurdle rate for the relevant sectors. These sectors all have hurdle rates in the 18-25% range and do not include District Heating. Due to the low hurdle rate of District Heating CHP the FiT, PES incentive and QI incentive levels are in practice of greater value for District Heating CHP than the Capital Grant.

6.2.3. Gas CHP participation in the Capacity Market

At the time this analysis was carried out, it was unclear to what degree Gas CHP would participate in the first Capacity Market auction, and it is still unknown to what degree it will compete in subsequent auctions. The majority of Gas CHP capacity modelled in our incremental build baseline is above 2 MW and would be able to participate in the Capacity Market directly, but 16% is smaller CHP (i.e. unit sizes below 2MW) which would need to combine with other small units through an aggregation service in order to participate.

DECC has noted that the Combined Heat and Power Association (CHPA) are sceptical regarding the amount of new build CHP that will participate in the Capacity Market because:

- Participation is non-mandatory for Distribution Network connected capacity.
- Capacity Market complexity will deter participation of small CHP.
- Developers will be reluctant to commit to long-term capacity agreements.
- Capacity Market revenue will be regarded as risky.
- CHP developers will be less able to spread this risk across a portfolio of assets or by trading.

DECC has also noted that in their qualitative research[7] most interviewees expressed unwillingness to engage in complex energy contracts, seeing this as outside their core expertise and limiting flexibility to respond to the needs of their core business activity.

This may support CHPA's view that participation of new CHP projects in the Capacity Market will be low, at least initially.

The argument in favour of Gas CHP participation includes the following points:

- Penalties are capped at 2 x monthly capacity payments and 1 x annual capacity payments. System stress events, requiring response from contracted plant, are likely to be rare if the market operates as expected and achieves the targeted level of system security.
- New plant have the flexibility to bid for a contract of any length between 1 and 15 years, meaning new Gas CHP does not have to lock into longer term contracts.
- OCGT and CCGT based CHP are able to operate in power-only mode if required without additional hardware or capital expenditure. Reciprocating engine CHP would need to be equipped with a heat exchangers/dump radiators to operate in power only mode. This is a straightforward modification which would only increase capex costs by around 3%, based on DECC estimates.
- Over time, the systems needed to facilitate the participation of small developers should develop, including the establishment of aggregators.
- The first auction is due to be run in December 2014. If this clears successfully at an attractive price, it will demonstrate the benefits that are available.
- In years where additional capacity is required the auction clearing prices are likely to be sufficient for new Gas CHP to be competitive.
- Long term capacity contracts could potentially reduce the hurdle rates required for new Gas CHP investment.

For the reasons stated above, we would expect Gas CHP participation to increase over time, as the opportunity for additional revenue streams begins to outweigh the cost of participation.

For the purposes of this modelling Gas CHP has been assumed to participate in the Capacity Market and its competitiveness against other capacity has been modelled. Most of the additional Gas CHP capacity brought forward in our incremental build baseline as a result of the Capacity Market are in 2019, 2020 and 2021 i.e. auctions held in 2015, 2016 and 2017. This is because capacity in clusters which are most economically viable are brought forward in early years, up to a point where the technical potential of the cluster is reached.

[7] Factors affecting the uptake of gas CHP, November 2014

6.2.4. Sensitivities

Given the large amount of District Heating capacity brought forward, the sensitivity of this result was tested using two of the key assumptions driving District Heating's high level of build. The two assumptions were DH's hurdle rate, i.e. the required rate of return on investment, and its level of "onsite" power demand i.e. supply of power to buildings on the heat network.

The central case Hurdle Rate assumption of 12% (post tax real) provided for the DH cluster is significantly lower than any of the other 37 clusters. Two increases to this assumption were explored, 15% and 18%.

The central case onsite power demand profile resulted in exports from DH of around 27%, which is in line with the export levels of the DH capacity brought forward in Ricardo-AEA's basecase. However, the tranches of DH CHP not brought forward in Ricardo-AEA's modelling had much higher levels of export. To test this assumption we looked at reducing the onsite power demand to achieve levels of export of approximately 50% and 68%, the latter of which represents the average export level of the DH tranches not brought forward in Ricardo-AEA's assessment.

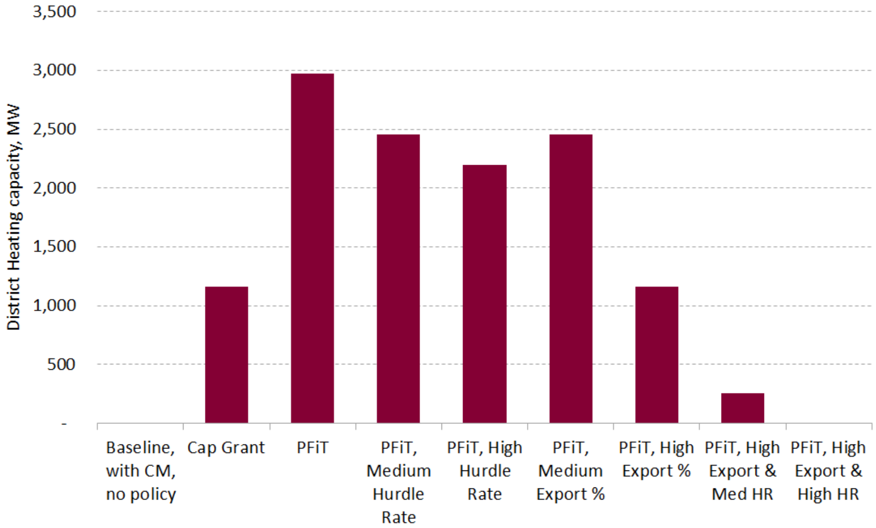
Sensitivity assumptions

Assumption	Hurdle rate (post tax real)	Export % (outturn)
Basecase	12%	~ 27%
Medium	15%	~ 50%
High	18%	~ 68%

The Premium FiT, which shows almost 3GW of additional capacity under baseline assumptions, was used to run these sensitivities.

The following chart summarises the results. Increasing the level of export, in particular, considerably decreases the amount of DH capacity brought forward under the PFiT policy option.

Sensitivity results, new build capacity brought forward in District Heating CHP



A higher hurdle rate means that the investor requires a greater rate of return from the CHP investment, therefore less capacity is brought forward when the hurdle rate requirement is increased.

The commercial arrangements assumed for CHP plant mean that they receive a lower level of income for exports relative to the avoided costs of power consumed onsite (proportion of wholesale price vs. a retail tariff). A higher level of export will mean lower income is attributed to the CHP unit, and the investment is less attractive. The sensitivities with high levels of assumed export showed significantly lower amounts of DH capacity brought forward. With high levels of export and a high required hurdle rate, no DH capacity was brought forward.

6.3. Conclusions

This analysis provides DECC with a second set of estimates on the amount of new Gas CHP deployment under different policy support options, as a cross-check to its internal projections. It adopts a different approach to DECC's internal modelling, using an updated version of the DDM model, but uses a consistent set of assumptions.

The results of the analysis show the policy options bringing forward very little incremental capacity over the 2018-2025 period. The one notable exception is in District Heating CHP, where up to 3GW of additional capacity is brought forward. This modelling result is based purely on evaluating the economics of the CHP investment, in line with the focus of this project, and ignores other factors, in particular the costs associated with developing the District Heating network itself and the associated regulatory and legal barriers. It therefore represents an assessment of the maximum economic CHP potential provided the networks are developed and is likely to overstate actual deployment.

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One reason that the policy options are shown to bring forward very little incremental build outside of District Heating is the high level of build in the baseline. The baseline shows just over 3GW of new CHP being brought forward over the 2018-2025 period (equivalent to about half of all existing CHP capacity), spread relatively evenly amongst different sizes of CHP. The baseline assumes all Gas CHP participates in the Capacity Market, which CHPA believes is unlikely. If Gas CHP does not participate in the Capacity Market, then this reduces the baseline new build to 2.4GW.

7. Social NPV of bespoke policy options for Gas CHP

7.1. Overview and key assumptions

The third and final part of the analysis is an appraisal of the social costs and benefits associated with each CHP policy support option.

The methodology used is consistent with that used in DECC's assessments of Electricity Market Reform policy options, which also utilise the Dynamic Dispatch Model.

Like the carbon displacement and incremental build analysis, this modelling was carried out using an upgraded version of the DDM, which contained the functionality to model Gas CHP in greater detail.

The Social NPV analysis assesses the costs and benefits to society over the 2018-2044 period, due to the additional capacity brought forward under each policy option. The Social NPV has been assessed over the operational lifetime (assumed to be 20 years) of the additional CHP plant which is built over the baseline in response to policy support. The assumption for how much new Gas CHP capacity is brought forward under each option was provided by DECC based on their own Monte Carlo CHP modelling and Ricardo-AEA's estimates for the District Heating and Oil & Gas sectors (which are not included within the Monte Carlo model), and is an input to this analysis.

For each policy option, the costs associated with the additional Gas CHP are assessed relative to a baseline with no policy options in place.

The costs for the policy options and the baseline are calculated for the following elements:

- **Capital costs** – capital expenditure and finance costs assessed over the relevant debt lifetime of the plant, which was assumed to be 10 years for Gas CHP smaller than 25MW and 15 years for Gas CHP larger than 25MW.
- **Generation costs** – fuel, operation and maintenance expenditure.
- **Monetised carbon costs** – the carbon emissions displaced are assessed using the traded ETS price, while the Gas CHP carbon emissions are assessed using either the ETS price or non-ETS price, depending on which sector the CHP operates. Note that the emissions modelled for Gas CHP in both the counterfactual and policy scenario are net of those associated with providing heat. In the counterfactual, the heat is assumed to be provided from an alternative heat source: specifically a gas boiler with thermal efficiency of 81% (on a Gross Calorific Value basis). In the policy scenario, only emissions in addition to those produced by the alternative heat source are modelled, i.e. the marginal emissions increase associated with producing power from CHP.
- **System costs –** costs associated with operating the electricity system. Assessment covers transmission network use costs, i.e. the costs involved with upgrading and maintaining the transmission system, and the cost of providing

spinning reserve, i.e. ensuring that enough capacity is held back by operating plant so that they can respond with additional output at short notice. The spinning reserve requirement is set at a level to cover the loss of the largest single generator on the system.

- **Interconnection costs** – cost of electricity imported from outside Great Britain via interconnectors to Ireland and continental Europe. Calculated as imports less exports, valued at the wholesale price.
- **Unserved energy costs** – negligible, Gas CHP is assumed to displace an equivalent amount of secure conventional gas capacity.

The Social NPV is calculated as: *Total costs under the baseline – Total costs under the policy option* (both discounted to net present value terms in 2012£).

For all of the core scenarios, it is assumed that the additional Gas CHP capacity will displace an equivalent amount of derated new CCGT capacity as CCGT is consistently the marginal plant in Capacity Market auctions over this period. Using the equivalent derated amount is consistent with the presence of a Capacity Market, which targets a certain level of derated capacity in each year. CCGT was chosen because DDM modelling suggests that it is the technology likely to be displaced by additional Gas CHP capacity of this magnitude over the 2018-2025 deployment period.

The rest of the capacity on the system was "locked" between the baseline and all scenarios. This avoids the additional Gas CHP capacity affecting the build or retirement decisions of other plant, which could result in step-changes in the modelling results (e.g. a change in the online date of a large nuclear plant), and allows the Social NPV to be assessed using a case where only the derated equivalent capacity is displaced. This assumption was viewed as appropriate given the relatively low levels of additional Gas CHP capacity modelled.

The same five policy support options were assessed as in the incremental build analysis, with the support levels defined by DECC (all in real £2012):

- Premium FiTs, £17.55/MWhe
- Capital Grant, £56.79/MWh/Yr PES
- PES incentive, £19.30/MWh PES
- QI weighted heat incentive, £12.31/(MWh heat x QI/100)
- QI weighted capacity incentive, £89.48/(kWe x QI/100)

A summary of key assumptions:

- Gas CHP build profile for baseline and scenarios provided from DECC's CHP model.
- Capacity on the system is locked, other than the additional Gas CHP displacing an equivalent derated amount of CCGT capacity.
- The Social NPV is evaluated over the 2018-2044 modelled period.
- Social discount rate of 3.5% used.
- Hurdle rates, by CHP cluster, range from 12.0% to 23.5% (post-tax real). The full value of these was applied when assessing the financing costs for additional CHP capacity.
- Capex, by CHP cluster, range from £780/kw to £1,530/kW.
- DDM team's December Reference Case assumptions are used to define the market-wide assumptions.
- In the baseline, all Gas CHP are eligible to compete in the Capacity Market, using deratings based on the generation of each cluster during winter peak.
- In policy scenarios all Gas CHP participates in the Capacity Marker other than the plant that qualify for the policy support option.

More detail on the data and assumptions can be found in Appendix 2.

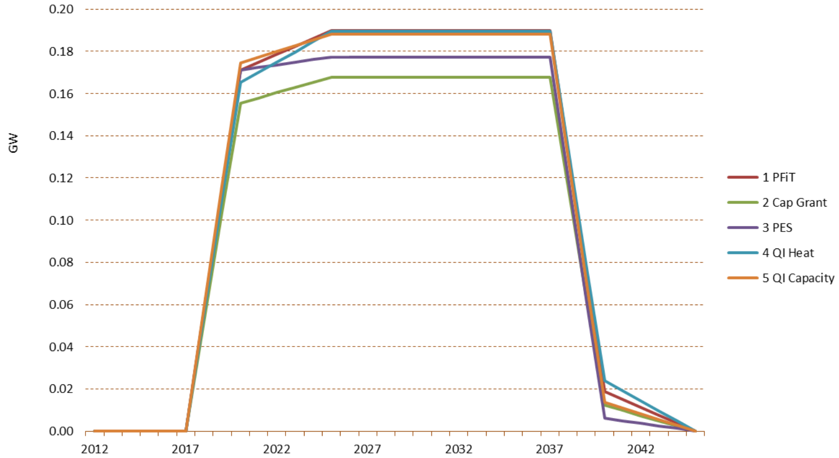
7.2. Summary of results

7.2.1. Bespoke policy scenario Social NPV results

The CHP capacity results provided by DECC showed between 160MW and 190MW of additional new Gas CHP capacity being brought forward by each of the 5 policy options.

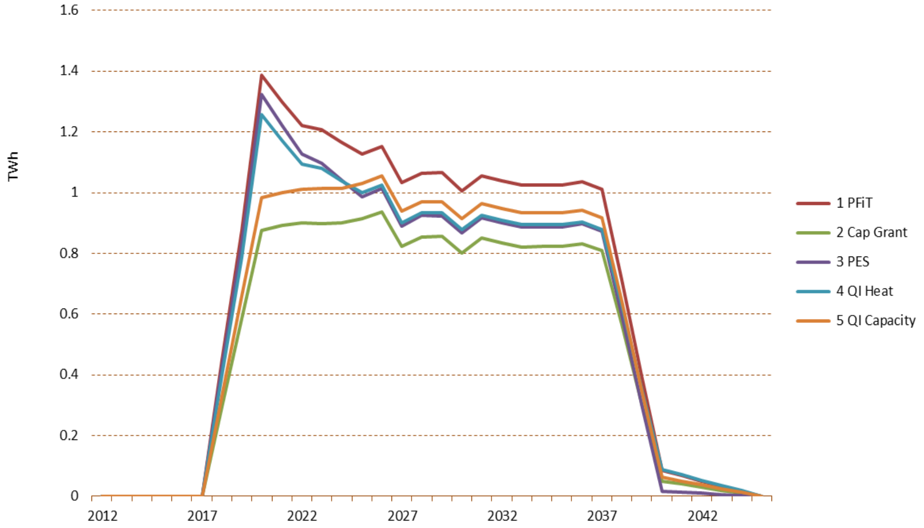
These build profiles are used as an input to the modelling results that follow.

Additional Gas CHP capacity over the baseline under each policy support option



The generation results shown below are outputs from the DDM based on the above build profiles inputs.

Additional Gas CHP generation over the baseline under each policy support option



The three policies that incentivise operation (PFiT, PES incentive and QI Heat incentive) all show an increase in generation over the first 5 years of operation. This increase in generation is not only a result of the additional capacity brought forward by the policies, but also any qualifying new build Gas CHP capacity already present in the baseline that is being incentivised to operate when it would otherwise not have done so.

The difference in the overall level of generation between policies is a result of both the total amount of capacity being brought forward, and the mix of CHP clusters that make up this additional capacity. For example, the QI capacity incentive brings forward a lower amount of overall capacity and hence provides a lower amount of additional CHP generation. The Premium FiT brings forward a similar amount of capacity to other policy options but provides a higher amount of generation due to higher load factors within the mix of capacity it brings forward. This is due to capacity with lower H:P ratios being brought forward under the PFiT incentive.

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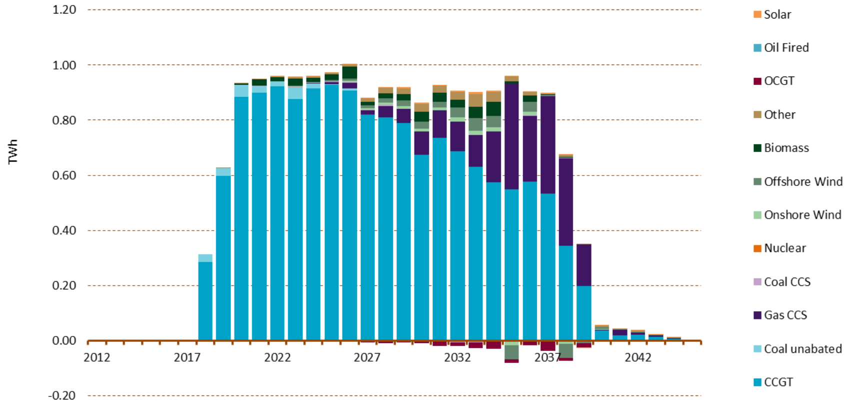
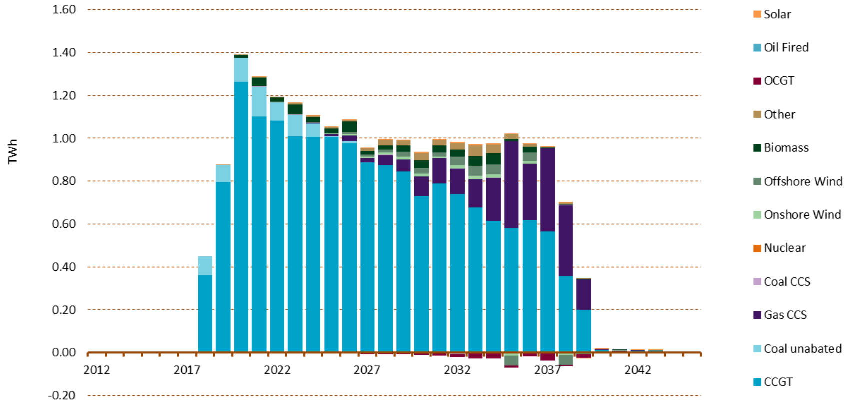
The following two charts show the type of generation displaced by the additional capacity brought forward by the Capital Grant and PES incentive options.

Generation displaced by additional Gas CHP generation over the baseline under Capital Grant option



Generation displaced by additional Gas CHP generation over the baseline under PES incentive option



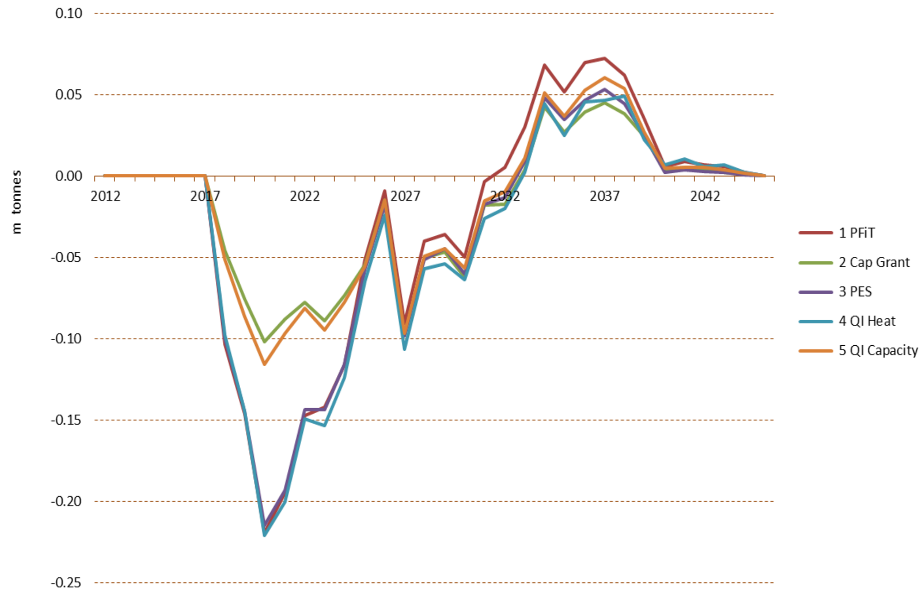
In general, the breakdown is similar to that seen in the carbon displacement modelling. The majority of displacement is of CCGT generation, but from the late 2020s onwards there is an increasing amount of displacement of low-carbon generation, particularly Gas CCS.

The PES incentive, which incentivises additional operation in the first 5 years of the plant's lifetime provides additional displacement over this early period, and more displacement of coal.

Note that the amount of generation being displaced is slightly higher than the additional Gas CHP generation. This is due to the transmission and in some cases distribution losses that are avoided by Gas CHP generation (see Appendix 2 for detailed assumptions) as this will be more distributed. By avoiding losses, the same amount of end-user demand can be satisfied with a lower level of generation. Also note that for some technologies in the 2030s we see negative displacement, i.e. an increase in generation as a result of additional Gas CHP capacity. One reason for this is that the Gas CHP plant have a different generation profile to the CCGT capacity they displace, as they do not operate under the same commercial arrangements. This is why we see an increase in OCGT generation in some cases, as OCGT is filling the gap left by the displaced CCGT in hours that the Gas CHP does not operate.

The net carbon impacts of each policy option are shown on the next chart. These show a similar result to the carbon displacement modelling, with CHP generation providing carbon savings up until around 2032.

Net CO_2 impact of additional Gas CHP generation under policy support option



The five policies show a similar carbon impact over the period modelled, with the exception of the 2018-2025 period, where the three policy options that incentivise operation show a much greater carbon saving than the other two options. PFiTs also show a greater increase in emissions in the 2030s due to the plant running with higher load factors.

These net carbon results do feed into the Social NPV calculation.

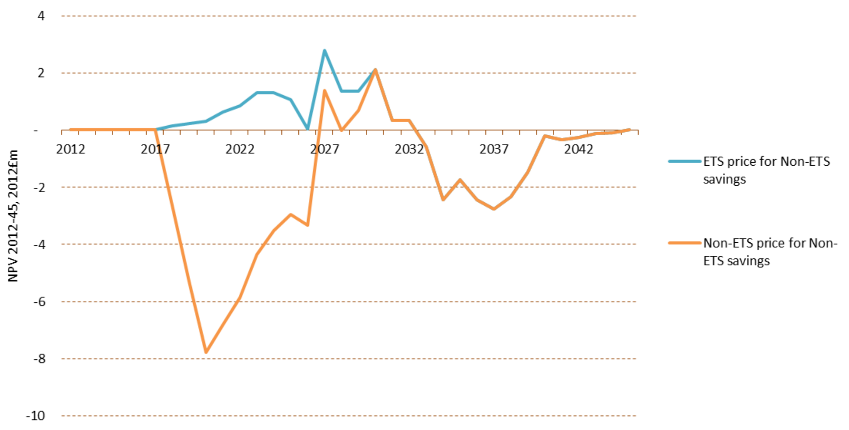
However, to translate these results into the monetised impact the CO_2 is priced depending upon the sector in which the emissions occur:

- Carbon emissions displaced from conventional power generation are assessed using the traded ETS price.
- Gas CHP carbon emissions associated with power generation are assessed using either the ETS price or non-ETS price, depending on which sector the CHP plant operates in.

This follows the UK approach to accounting for physical point of carbon CO_2 emissions as shown in the National Inventory of GHG emissions.

On the chart below, the orange line shows the monetised impact of the net carbon emissions. The blue line shows the impact if all emissions were priced at the ETS price (even those Gas CHP emissions in the non-ETS sector). The two lines overlap from 2030, when the ETS and non-ETS price are assumed to converge.

Monetised CO_2 saving under Capital Grant option



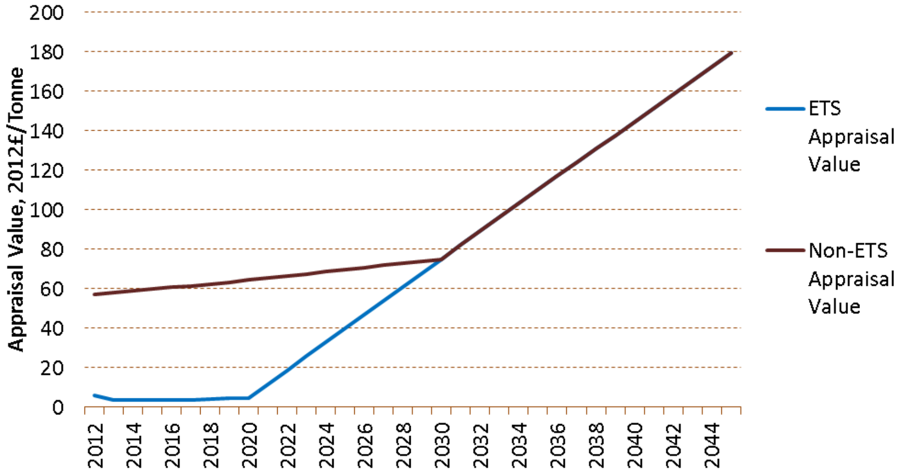
There are two main factors driving these results:

- The carbon price increases significantly over time. This is why, with all emissions evaluated at the same price (the blue line), we see a larger relative impact in later years.
- The non-ETS price is significantly higher than the ETS price in early years. This is because the ETS price is currently very low and any emissions in the non-ETS sector are considered more expensive to abate.

The second of these factors, in particular, has a significant impact. Despite a net saving in overall emissions over the 2018-2027 period, the monetised impact for the purposes of the Social NPV calculation is a net cost. This is because the majority of additional Gas CHP generation is in the non-ETS sector, and their emissions, although lower, are considered more expensive to abate than the emissions they displace from conventional power stations in the traded sector.

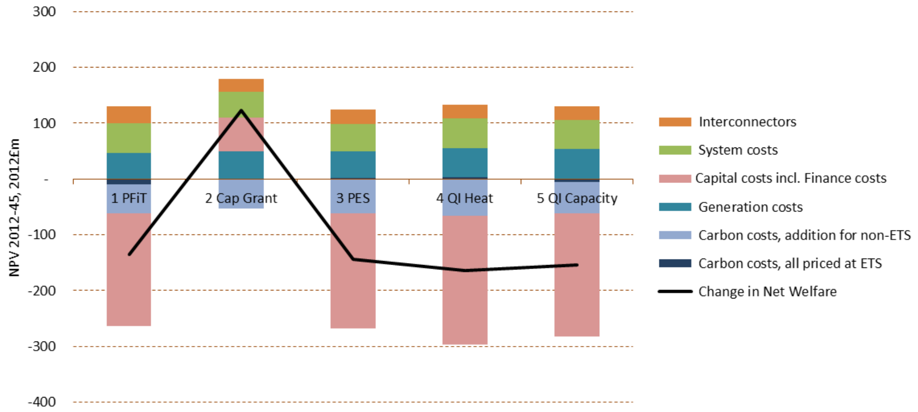
The two prices (appraisal values) are shown on the following chart.

CO_2 appraisal values for ETS and non-ETS sectors



The Social NPV for each of the policy support options is shown on the following chart. The bars show the breakdown of the different components, with a positive value representing a net benefit to society and a negative value representing a cost. The black line shows the overall net position of each of the options. For monetised carbon costs, the dark blue bar represents the cost with all emissions valued at the ETS price and the pale blue bar represents the incremental cost of displacement of emissions from ETS to non-ETS.

Social NPV of the policy options

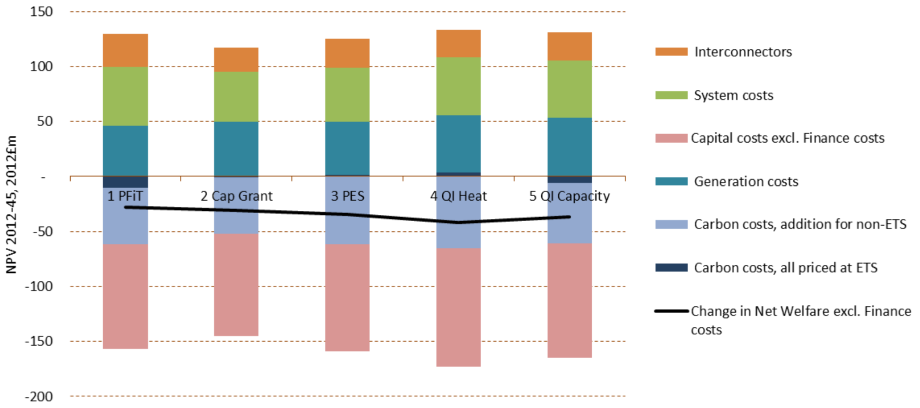


With the exception of the Capital Grant, all policies show a net cost to society, ranging from £120-170m (2012 real). The Capital Grant shows a net benefit of over £100m.

The reason for this difference is primarily down to the finance cost component. In most cases, the higher capex and higher required hurdle rates of Gas CHP, relative to the conventional gas plant they displace, will mean that additional CHP capacity leads to higher capital repayment and financing costs. However, under the Capital Grant option the method of financing differs, with some of the financing cost for supported CHP transferred from the private sector to the public sector. The low cost of public sector financing for the additional capacity brought forward under Capital Grants and also for eligible new build capacity in the baseline ("deadweight") results in a net reduction in financing costs. The costs to society of the public financing are not included in the Social NPV calculation, meaning any comparisons between policy support options will tend to favour the Capital Grant. It should be noted that, within a social NPV assessment, public sector financing would always show a net social benefit compared to private financing, irrespective of the technology it were applied to.

For these reasons, it is considered more appropriate to make comparisons of the relative Social NPVs of different policy options with the financing cost element removed. This comparison is shown on the following chart. It should however, be remembered that the higher hurdle rates required to finance CHP do represent an additional cost to society in absolute terms relative to the baseline.

Social NPV of the policy options, excluding Financing costs



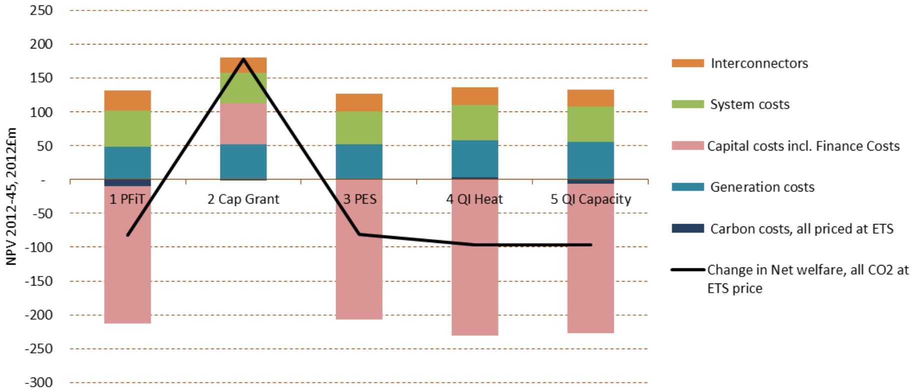
With the financing costs removed, the five policy support options show similar net Social NPV results, ranging from -£93m to -£108m. The different options also show a similar breakdown between the different components. The reasons for each component's contribution are detailed below.

- ***Generation costs.*** CHP plant tend to be more efficient than the conventional plant they displace, so tend to have lower fuel costs overall (all gas is valued at DECC's Long-run Variable Cost (LRVC) of supply for the purposes of the Social NPV calculation). The LRVC of gas represents the net welfare impact upon society of an increase or decrease of a kWh of gas supplied for consumption. Gas CHP also reduces the total generation required, due to avoiding a proportion of transmission and distribution losses. These fuel savings are partly offset by higher operation and maintenance costs relative to the conventional generation displaced. Overall, Gas CHP provides lower Generation costs compared to the baseline, contributing a net benefit to the Social NPV.

- ***Capital costs.*** Construction and finance costs (reflected by their high hurdle rates) of Gas CHP are significantly higher than the counterfactual conventional gas plant. This means that the capital and financing cost of additional Gas CHP capacity contributes a net cost to society, despite the CCGT capital and finance costs displaced.
- ***System costs.*** Gas CHP is largely distribution connected, meaning transmission network use costs are reduced relative to the baseline. This contributes a net benefit to the Social NPV.
- ***Interconnectors.*** Interconnection is valued at the wholesale price of electricity, so any reduction in wholesale price (without the equivalent increase in interconnector flows) contributes a net benefit to the Social NPV.
- ***Carbon costs, all priced at ETS price.*** Gas CHP saves emissions prior to 2032, and has a net saving over its lifetime. However, the carbon ETS price is projected to rise significantly over this period. This means that emissions saved in the early 2020s are valued at a much lower price than those added in the late 2030s. The net Social NPV impact of the net carbon emissions saving, valued at the ETS price, is around zero for most options, and a small cost for some options, despite an overall saving in emissions.
- ***Carbon costs, additional for non-ETS.*** As explained above, the Gas CHP emissions that occur in the non-ETS sector are monetised at a different, and in the period up to 2030 much higher, price than the ETS emissions they displace. This is because they are considered much harder and more costly to abate. A large portion of the additional Gas CHP generation is non-ETS, displacing power generation emissions from the ETS sector where they have a low value to the non-ETS sector where they will be more costly to further abate. This contributes a net cost to the Social NPV.

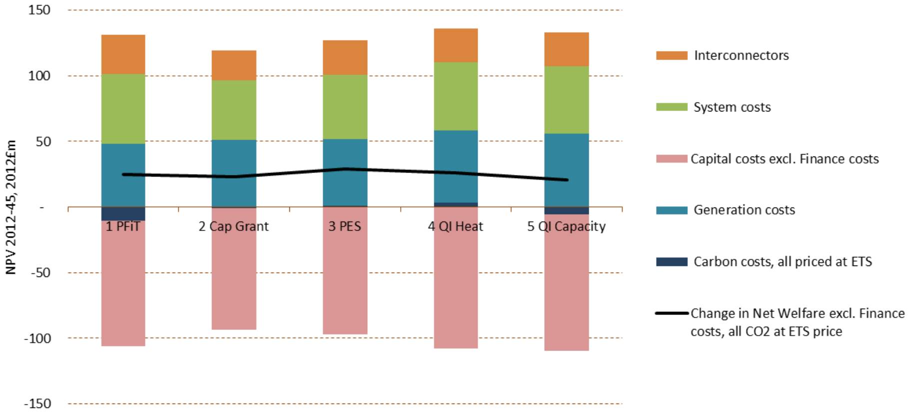
The results above show a large net monetised carbon cost, despite a reduction in overall emissions. The following chart shows the net Social NPV position if all carbon emissions were valued at the ETS price.

Social NPV of the policy options, including Financing costs, all carbon valued at the ETS price



With all emissions valued at the ETS the policies still show a net cost to society in all cases except Capital Grants. If finance costs were excluded and all emissions valued using the same price, there would be a net benefit to society under all five policy options, as shown below.

Social NPV of the policy options, excluding Financing costs, all carbon valued at the ETS price



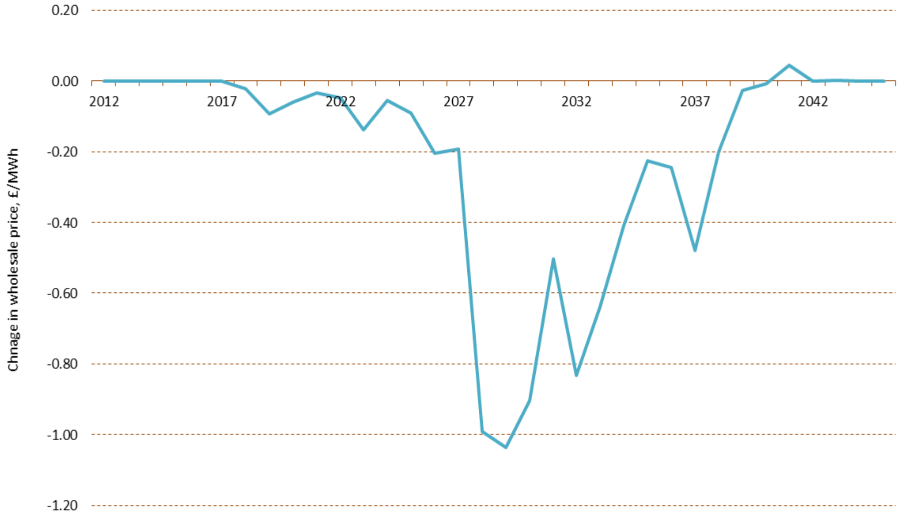
7.2.2. Bespoke policy scenarios – non-monetised impacts

There are several additional costs and benefits of the policy support options that cannot be directly captured in the Social NPV calculation. These are outlined in the following sections.

7.2.2.1. Wholesale price and bill impact

The additional Gas CHP has an impact on the wholesale electricity price, as shown in the chart below. In principle this will feed through to a reduction in consumer bills (although this is partially offset by increased payments to CfD generators). This does not directly feed into the Social NPV calculation, as it is considered a transfer from producers to consumers, though it is captured in the valuation of interconnection benefits.

Wholesale price impact of the Capital Grant support option



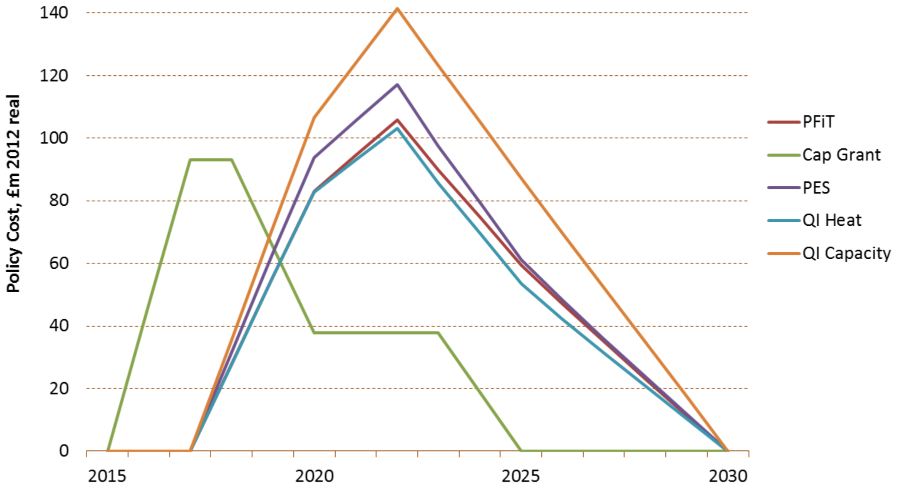
The wholesale price decreases as a result of the additional Gas CHP, with the biggest reduction occurring in the late 2020s and early 2030s. This is despite the fact that only a proportion of Gas CHP electrical output competes in the wholesale market.

Instead, most of the Gas CHP generation modelled is operating outside of the wholesale market, responding to retail tariffs. When operating, Gas CHP reduces the net demand for generation in the wholesale market, and shifts the margin to a lower point on the merit order. The late 2020s and early 2030s are periods where there are large price “steps” in the merit order near the margin (see the illustrative merit order chart for 2035 in section 5.1) , which means small shifts can result in large changes to the marginal price. For example, stepping from CCGT on the margin to Gas CCS, or from Gas CCS to Wind.

7.2.2.2. Policy cost impacts

The cost profile of each policy support option is shown on the chart below. Policy costs are not included in the Social NPV as these are regarded as a transfer rather than a net cost to society. The policies show a similar trajectory, with the exception of the Capital Grant option, where the majority of the costs are incurred up front. The last year of CHP support payments is in 2029, as we are modelling capacity brought online over the 2018-2025, with incentives only applied during the first five years of operation.

Policy support costs over time

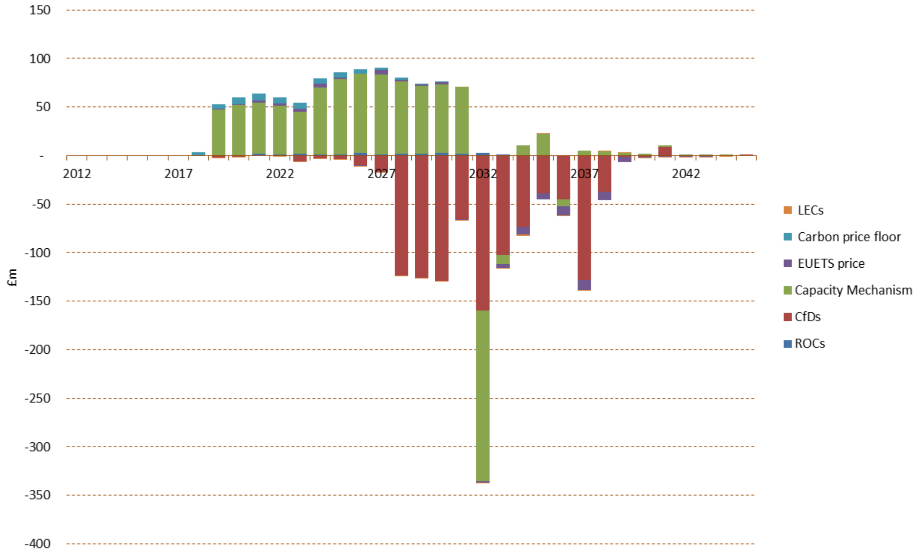


These cost profiles result in the following overall policy costs. These are presented in 2012 £ present value terms, using the 3.5% social discount rate applied in the Social NPV calculation.

£m 2012 PV	Bespoke CHP policy cost
Capital Grant	£355m
P-FiTs	£476m
PES incentive	£519m
QI heat incentive	£456m
QI capacity payment	£648m

The additional Gas CHP brought forward through the policy options also has an impact on the costs associated with other electricity market policies. Particularly the Capacity Market, which provides support for much of the eligible Gas CHP in the baseline and also supports the displaced CCGT capacity. The chart below shows the impact on this and other wider-market policies.

Policy cost impact of the Capital Grant support option



There are two main policies affected:

- **Capacity Market.** In most years, Capacity Market costs are reduced due to Capacity Market-supported CCGTs being displaced by CHP that is supported through the CHP policy support options. This reduction will feed through into a decrease in consumer bills. The large increase in Capacity Market costs in 2032 is a result of an increase in the bid of the marginal plant setting the clearing price in that year. The plant is projecting lower wholesale market returns as a result of the additional Gas CHP on the system. It should be noted that these impacts are small relative to total Capacity Market costs.
- **CfDs.** Lower wholesale prices will result in higher CfD top-up payments. Under the CfD regime, low-carbon generation is paid the difference between a reference price (based on the wholesale market price) and their strike price. The impact on consumer bills of an increase in CfD top-up payments should be more than offset by the decrease in wholesale prices that cause them as the wholesale price reduction applies across all generation not just CfD generation.

The table below shows a comparison between the costs associated with the CHP policy options and the savings in Capacity Market payments, in present value terms. In most cases, the two are of comparable magnitude. The Capital Grant option shows a net saving, of £90m over the 2018-2045 assessment period.

£m 2012 PV	Bespoke CHP policy cost	Capacity Market saving
Capital Grant	£355m	£445m
P-FiTs	£476m	£442m
PES incentive	£519m	£470m
QI heat incentive	£456m	£468m
QI capacity payment	£648m	£423m

7.2.3. Additional sensitivities

In addition to assessing the Social NPV of the five policy support options, a number of sensitivities were run to explore the impact of various assumptions.

The following sensitivities were run, under the Capital Grant support option unless otherwise stated:

1. **Low FF.** Using fossil fuel prices (gas and coal) based on DECC's UEP 2013 Low projection.
2. **High FF.** Using DECC's equivalent high fossil fuel price projection.
3. **50g**. High decarbonisation trajectory, achieving 50g/kWh by 2030
4. **200g**. Low decarbonisation trajectory, achieving 200g/kWh by 2030
5. **Low Capex.** A 30% reduction in CHP capex assumptions. This case results in CCGT CHP capex figures which are more in line with those published by PB Power in their levelised cost assumptions[8].
6. **High capex.** A 30% increase in CHP capex assumptions.
7. **De-NOx.** Selective Catalytic Reduction NOx abatement equipment required to be fitted to all reciprocating engine CHP to control local air quality impacts. This is modelled as an increase in capex of 3.4% and an increase in operating cost (for consumable reagent) equivalent to a 7.6% increase in fuel cost across all the reciprocating engine clusters. These assumptions were provided by DECC and Ricardo-AEA.
8. **No new CHP post 2020.** Assuming no new Gas CHP is supported after 2020.
9. **75th percentile support.** Additional CHP capacity is deployed, based on the 75th percentile of DECC's Capital Grant supply curve. This represents an increase in the Capital Grant support level from £56.79/MWh of PES (baseline, 50th percentile) to £124.79/MWh of PES. This results in 447MW of additional Gas CHP capacity brought forward under the Capital Grant, vs. 169MW in the baseline 50th percentile Capital Grant scenario.
10. **OCGT displaced.** Gas CHP is assumed to displace the equivalent amount of derated new OCGT capacity rather than CCGT capacity. OCGT has lower capex costs but higher generation costs than CCGT.
11. **DDM incremental build.** Using the incremental CHP build projected in the DDM analysis (results detailed in section 6 and Appendix 3). This build profile is made up of a high level of District Heating deployment.

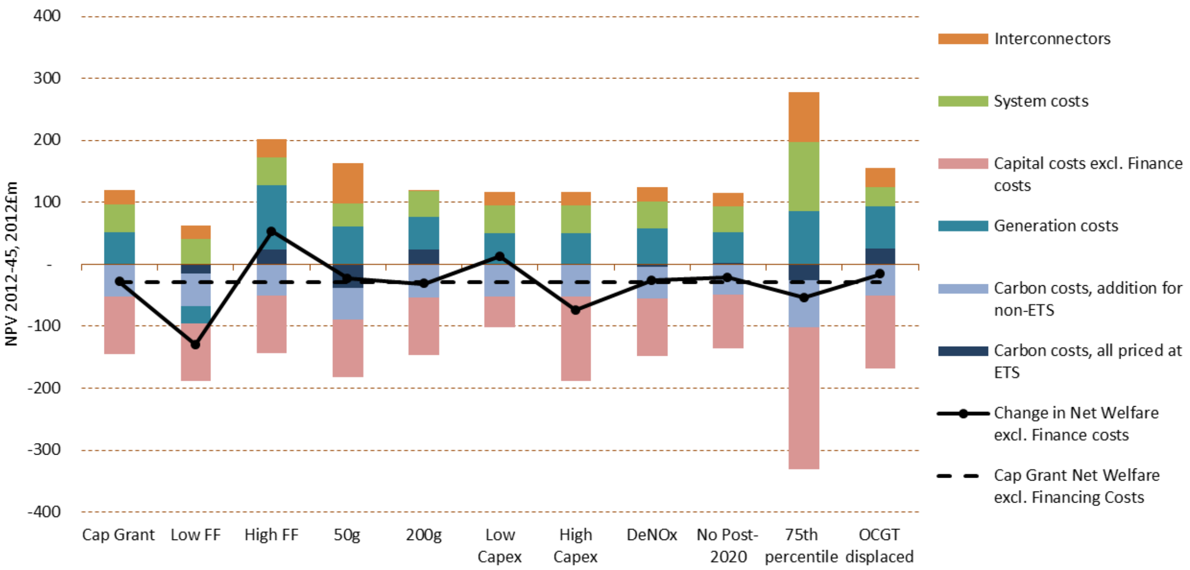
[8] https://www.gov.uk/government/publications/parsons-brinkerhoff-electricity-generation-model-2013-update-of-non-renewable-technologies

12. **CCGT hurdle rate.** Using an assumed 7.5% (pre-tax real) hurdle rate as the finance cost rather than the full CHP hurdle rate. As the high hurdle rate is partly responsible for the positive Capital cost results in the Capital Grant option (when Finance costs are included) this sensitivity has been assessed against the PES incentive scenario.

The chart below shows the Social NPV result for the first ten sensitivities outlined above. The results show the net Social NPV impact under the Capital Grant policy scenario. The core Capital Grant scenario is shown on the left for comparison.

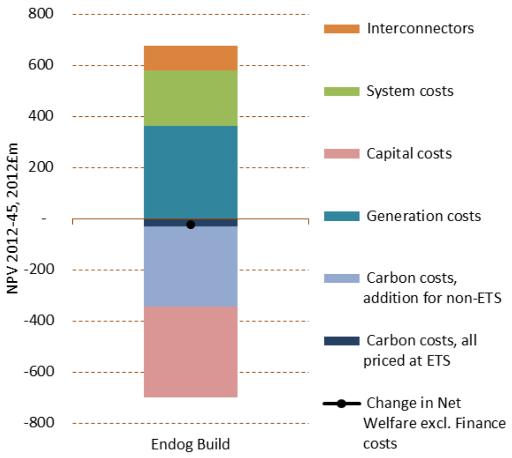
For most sensitivities, the counterfactual also needed to be updated and run with the change in assumption. For example, the High FF result shows the impact of the Capital Grant policy option under high fossil fuel prices relative to a counterfactual which also has high fossil fuel prices.

Social NPV of sensitivities 1-10, excluding Financing costs



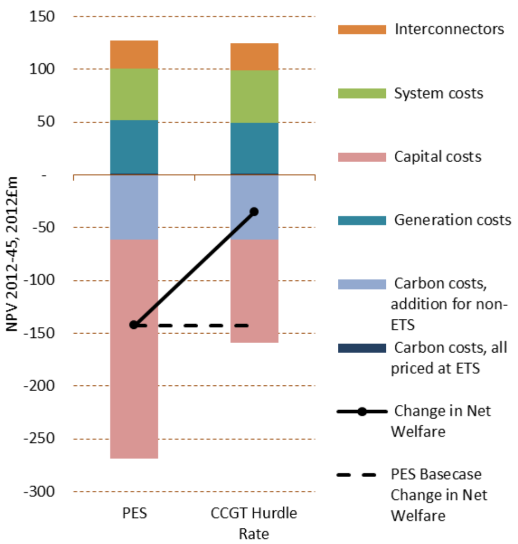
The DDM incremental endogenous build sensitivity result is shown below. It was also run under the Capital Grant policy but delivers a significantly different CHP build profile.

Social NPV of DDM incremental endogenous build sensitivity, excluding financing costs



The final sensitivity, exploring the impacts of a lower hurdle rate, is shown below. It was run under the PES incentive support option, and the core PES scenario result is shown for comparison. Unlike the other results shown above, the financing costs are included here, as they represent the component being explored by this sensitivity.

Social NPV of lower hurdle rate sensitivity, financing costs included



The reasons for the impacts on Social NPV under each sensitivity are detailed below.

- **Low FF.** The main impact is a reduction is the generation cost benefits, which are now a net cost rather than a net saving. The lower gas price means that the benefits in fuel saving are smaller relative to the costs due to additional opex.

- **High FF.** In contrast to the Low FF sensitivity, the High FF shows an increase in generation cost savings. Higher gas prices means fuel savings from Gas CHP have a greater benefit relative to the additional opex costs. There is also a small increase in ETS carbon cost savings, as there is reduced displacement of low-carbon generation.
- **50g / 200g.** The decarbonisation trajectory sensitivities show relatively little impact in the overall Social NPV. The impact on carbon costs is largely offset by the impact on interconnection costs, as more displacement of low carbon generation will result in reductions in the wholesale price.
- **Low / High Capex.** The change in capital costs under these sensitivities directly feeds through into a change in the net Social NPV position. The low capex sensitivity, which represents an assessment of CHP capex more in line with that published by PB Power, gives a small positive Social NPV result overall.
- **De-NOx.** Negligible impact. The generation from Gas CHP is reduced, but this occurs in both baseline & scenario, resulting in little impact on the net Social NPV position.
- **No new CHP post 2020.** Negligible impact. Majority of additional capacity was previously being brought forward over the 2018-2020 period.
- **75th percentile.** The 75th percentile Capital Grant brings forward significantly more CHP capacity than the central case. Overall there is a slight decrease in the Social NPV. This is because the additional capital and carbon costs of the new capacity outweigh the benefits from reduced generation, system and interconnection costs. The additional capacity brought forward is not as efficient as that brought forward in the central (50th percentile grant) case, meaning the generation cost savings are relatively low.
- **OCGT displaced.** Overall there is a slight improvement in Social NPV over the central case, which assumes CCGT is displaced. The additional capital costs, due to the lower capex of OCGT, are more than offset by savings in generation costs.
- **DDM incremental build.** The DDM incremental build brings forward significantly more CHP capacity than in the central case (1.2 GW vs. 169MW), though almost all of this is in the District Heating sector. The additional capacity results in significant reductions in the generation, system and interconnection costs, but significant increases in carbon and capital costs. However, relative to the amount of capacity brought forward, the capital costs are lower than in the central case. This is primarily because the District Heating cluster has a lower capex assumption than most other CHP clusters. Overall this means the net Social NPV position is only very slightly negative.
- **CCGT hurdle rate.** Comparing the lower hurdle rate sensitivity to the central PES incentive scenario shows a significant decrease in capital and finance costs and an improvement in the Social NPV. The decrease is due to decreased financing costs, which are included in this comparison. The hurdle rate of 7.5% (pre-tax real) used in this sensitivity (in line with the assumption used for CCGTs) is significantly

less than those assumed for CHP in the central case, which typically range from 14% to 18% (pre-tax real).

7.3. Conclusions

This analysis provides an assessment of the social costs and benefits associated with the additional CHP capacity brought forward by each policy support option.

The results show four of the five policies with a negative net Social NPV, i.e. social costs outweighing the benefits. The exception is the Capital Grant option, which shows a net benefit due to the reduced private financing costs of both additional and eligible baseline new build (deadweight). However, when evaluated on a consistent basis as the other four policies, excluding the financing costs, the Capital Grant result falls into line with the other policies.

In general, Gas CHP provides savings in generation costs (due to fuel savings from running Gas CHP over conventional plant), network costs and interconnection costs. These savings are offset by increases in capital & finance costs (due to the higher capex and hurdle rates associated with Gas CHP over conventional plant), and carbon costs.

The increase in carbon costs is the least intuitive result, and is caused by two factors. The first is that the carbon price increases substantially over the evaluation period (2015-2045), meaning the emissions that Gas CHP adds in later years are priced much higher than the emissions it saves in early years. The second factor is that the emissions produced by Gas CHP in the non-ETS sector are price substantially higher than the emissions they displace in the ETS sector. This evaluation of the emissions at these two prices is a key assumption, and with all emissions monetised at the same price, the Social NPVs for all policies improve, by £57m on average. With financing costs excluded, monetising all emissions at the same price switches the Social NPV for all five policies from net negative to net positive.

The sensitivities run show that the Social NPV results are sensitive to a number of key assumptions. In particular, the analysis is sensitive to assumptions relating to CHP capital costs, the gas price and the hurdle rate applied to CHP. Under the sensitivities for lower CHP capital costs and higher fuel prices, the additional policies result in a net positive NPV. The amount and type of CHP capacity brought forward is also a key assumption, as seen in the incremental endogenous build result, where almost all the additional capacity was concentrated in a single cluster, and the net cost was proportionally much smaller than in the basecase.

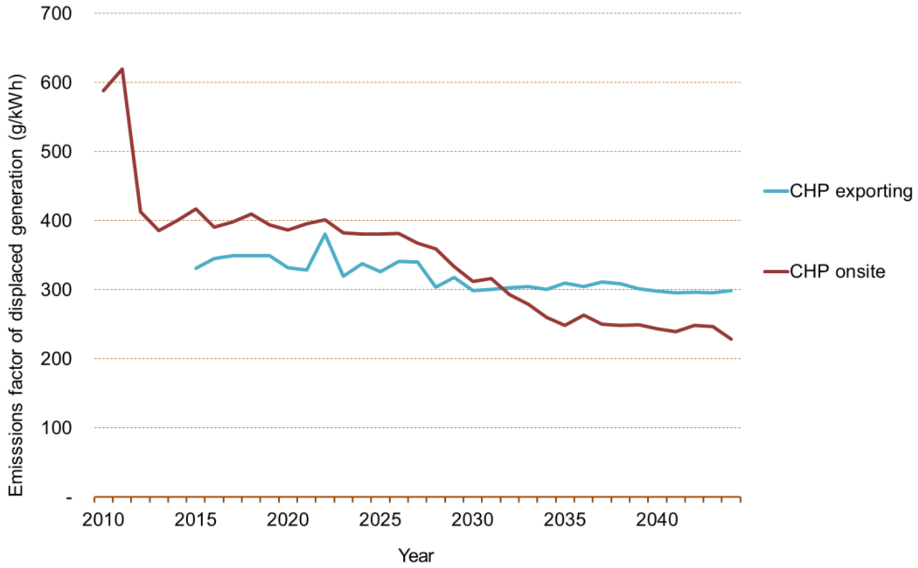
The Social NPV results are not, however, as sensitive to the decarbonisation trajectory as the displacement results, as the displacement of low carbon technologies does not have a major impact on the Social NPV.

8. Marginal Emissions Factors

As part of the Social NPV analysis, Marginal Emissions Factors were calculated for Gas CHP. These were calculated using the Social NPV basecase, i.e. with no bespoke policies in place.

The Marginal Emission Factor (MEF) represents the CO_2 intensity of the marginal unit of generation displaced by additional Gas CHP generation. Separate MEFs were calculated for both CHP generation satisfying onsite demand and CHP generation exporting. Results are shown in the following chart.

Marginal emissions factor for generation displaced by Gas CHP when exporting and importing



CHP satisfying onsite power demand does not respond to wholesale price fluctuations under our modelling assumptions. As a result, its average annual MEF will be similar to that for the whole system, differing slightly due to the operating profiles of Gas CHP. For most of the period gas-fired CCGT is the predominant technology on the margin, with generation from coal representing a smaller proportion. Consequently, the MEF is approximately 400g/kWh from 2012 through to 2025. From the late 2020s onwards the penetration of low-carbon technologies increases, to the point where they occupy the margin in some periods of the year, and this reduces the annual MEF to 250g/kWh and below.

CHP generation that is exported to the grid is assumed to receive 80% of the wholesale price, and will only export when it is economic to do so. We therefore do not see the MEF for CHP exports drop off in the late 2020s to the same degree, as it does not displace low-carbon technologies. The MEF is also not as high in the earlier years, due to it being uneconomic for CHP to export when coal, with high emissions but a lower marginal cost, generates at the margin.

CHP modelling methodology in the DDM

This section outlines how we model the dispatch of Gas CHP plant using the DDM.

In each half hour modelled, we determine the capacity the plant will commit to running that is independent of the wholesale price. We also determine the capacity and price that each CHP plant will bid into the wholesale market.

In order to establish the dispatch bids and predetermined running regimes, we must understand the commercial and operational characteristics of the plant. This includes the plant's operating characteristics, its heat value and own power use profiles, and the commercial arrangements for import and export of power. From these factors we can determine which of the four possible operating modes the plant will run in, and what its dispatch bid will be. The rest of this section outlines this process in more detail.

1. Marginal cost of power

For a CHP plant, the marginal cost per MWh of generating electricity is dependent upon the revenue or avoided costs in respect of heat generated. This could either be through a commercial contract for sale of the heat or represent the equivalent cost of running a boiler. A CHP plant can therefore be viewed as having different marginal power costs depending on the heat required:

- **SRMC_P:** The marginal cost of power when there is no need for the heat. It is calculated from the electrical efficiency of the CHP plant when running in power-only mode in the same way as a conventional power plant, taking into account the fuel price, carbon price and any variable O&M costs.
- **SRMC_H**: The marginal cost of power when there is a required heat load. It is calculated in the same way as SRMC_P, but uses the "effective electrical efficiency" of the CHP plant when running in CHP mode. This measure allows for a direct comparison of CHP plant to conventional plant, by allocating a portion of the total fuel input to the thermal output, based on the fuel requirement of the alternative heat source which would otherwise need to be operated. It is calculated as follows:

$E_{EE} = E_E / (1 – E_T / E_{TA})$

where

E_{EE} = effective electrical efficiency of the CHP plant (%)

E_E = electrical efficiency of the CHP plant, when running in CHP mode (%)

E_T = thermal efficiency of the CHP plant (%)

E_{TA} = thermal efficiency of the alternative heat source, eg the replacement boiler (%)

Figure 1 shows the profile of the heat requirement for a CHP plant with a maximum power output of 1000MW.

The light blue area represents the volume of power that can be generated at the marginal cost SRMC_H, the shape of this area represents the power that would be produced when the plant meets the heat requirement and so follows the shape of the heat load.

The dark blue area represents the volume of power that can be generated at the marginal cost of SRMC_P. This is the residual capacity.

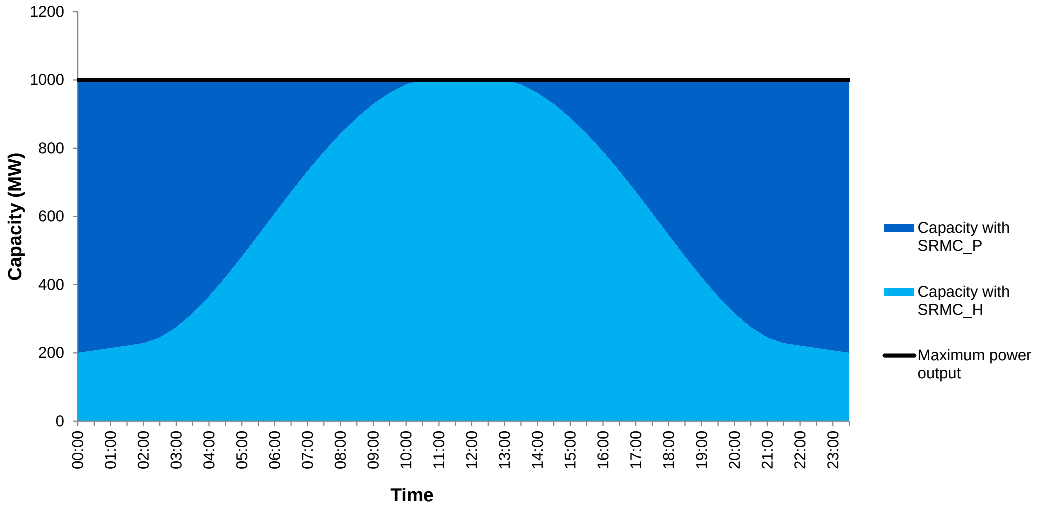


Figure 1: Marginal cost of power.

2. Operating modes

At any given point in time, a CHP plant is in one of four distinct operating modes:

- **Off**: The plant does not generate. It imports any on-site power required and uses a boiler for the heat required.
- **Heat-following**: The plant operates in CHP mode at a power output that generates just enough heat to meet the required heat load. The amount of power generated is determined by the Heat:Power ratio and might be more or less than the site's own power use. All of this power is produced at a marginal cost of SRMC_H.
- **Power-following**: The plant generates an amount of power equal to its own power use. We assume that any excess heat above the required heat volume can be dumped at no cost. Any heat shortfall is made up by a replacement boiler. The marginal cost of this power depends on the heat load.

- **Maximum-power**: The plant generates power at its maximum electrical capacity. The short run marginal cost for the capacity above the power generated to meet the heat load is given by SRMC_P (> SRMC_H). We assume that any excess heat produced above the required heat volume can be dumped at no cost.

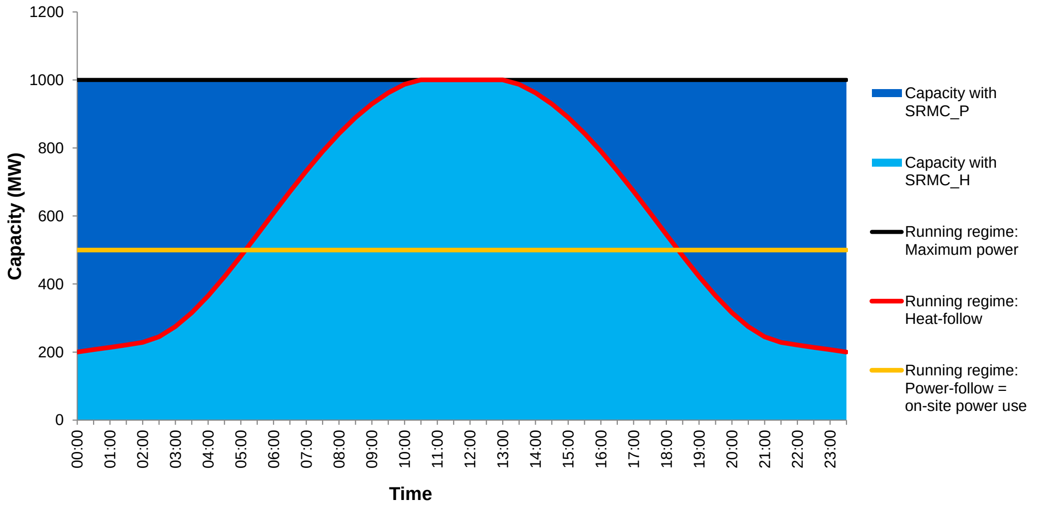


Figure 2: Operating modes.

3. Commercial arrangements

The decision between these operating regimes will depend on the value of the power generated (£/MWh) relative to the net cost of generation from the CHP plant. At any point in time there are two relevant prices:

- **Import power price:** The price paid to import power. If there is on-site demand for power the operator can avoid paying this price by generating power from the CHP plant. This has been assumed to be a retail tariff based on time-of-use for all sizes of CHP plant.
- **Export power price**: The price paid to export power. The price received for power generated above on-site power requirements which can be exported to the grid. As with the import price this could range from a fixed tariff to the wholesale price.

As the terms for export are likely to be less favourable than that paid for import the DDM was updated to allow for three types of commercial arrangement. Which of these applies significantly affects how the plant operates in the market.

- **Wholesale price exposure**: The plant imports and exports electricity at the wholesale price. The plant should therefore respond to wholesale price signals.
- **Mixed exposure**: The plant imports electricity at the retail price, and exports at the wholesale price. The plant will respond to wholesale price signals for any power generated over on-site use that is available for export.
- **Fixed tariffs**: The plant imports at the retail price and exports at a fixed tariff. The plant will not respond to wholesale market signals.

4. Operating mode decision and dispatch bid

Based on a plant's commercial arrangement and the associated price, the plant operator or control system will decide what mode to run in and what capacity to "bid" into the wholesale market.

As the modelling in this report assumes that all Gas CHP plant have mixed exposure, we will consider this commercial type in detail.

4.1 Mixed exposure

At a given point in time, the operating mode will be decided as follows, based on values of the retail price (RP):

- If SRMC_H > RP: Do not run
- If SRMC_P < WP: Maximum-power

At periods where own power use exceeds the heat follow generation:

- If SRMC_H < RP < SRMC_P: Heat-follow
- If WP < SRMC_P < RP: Power-follow

At periods where heat follow generation exceeds own power use:

- If SRMC_H < WP < SRMC_P: Heat-follow
- If SRMC_H > WP: Power-follow

We model this regime by bidding two "plant" into the wholesale price market, one at a price of SRMC_H, the other at a price of SRMC_P:

At periods where own power would exceed heat follow generation:

- **Bid 1:** Zero capacity at a price of SRMC_H
- **Bid 2:** A capacity C at a price of SRMC_P. In order to decide C, we first determine how much capacity C_0, up to own power use, the plant should generate according to the above running regime.
    - If C_0 = heat follow generation, then C = maximum capacity minus heat follow generation
    - If C_0 = own power use, then C = maximum capacity minus own power use

At periods where heat follow generation would exceed own power use:

- **Bid 1:** A capacity of heat follow generation minus own power use at a price of SRMC_H
- **Bid 2:** A capacity of maximum capacity minus heat follow generation at a price of SRMC_P

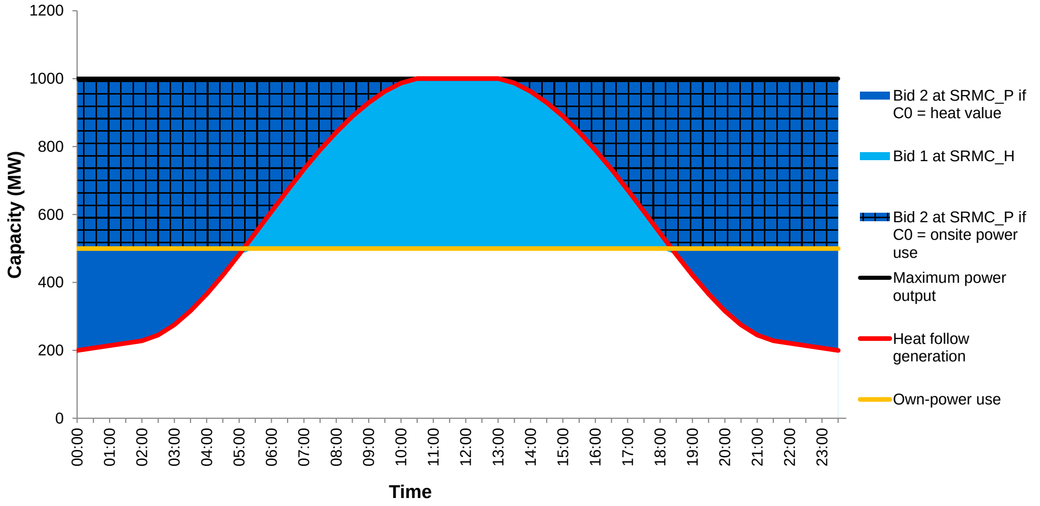


Figure 4: Bids when exposed to retail price for imports and wholesale price for exports. Bid 1 in light blue, Bid 2 in dark blue if C_0 = heat follow generation, Bid 2 cross-hatched if C_0 = own power use.

Data and Assumption tables

Appendix 2

CHP clusters: technical characteristics (Social NPV analysis)

Cluster #	Weighted average capacity per site (MW)	Tech type *	Total transmission and distribution losses avoided (%)	Electrical Efficiency % (fully condensing mode)	Electrical Efficiency (CHP mode)	Thermal Efficiency (CHP mode) ****	Heat: power ratio	Opex: £/MWhe	CapEx: £/kWe	Hurdle Rate % (post-tax real)
1	1.0	1	5.5	38.0	38.0	45.6	1.20	11.74	953	23.04
2	1.0	1	7.5	38.0	38.0	45.6	1.20	10.31	956	20.00
3	1.8	1	7.5	38.0	38.0	45.6	1.20	10.20	882	20.00
4	4.6	2	7.5	34.9	34.9	45.8	1.31	9.74	967	21.02
5	3.5	2	5.5	38.0	38.0	45.6	1.20	10.20	793	20.15
6	2.7	2	7.5	38.0	38.0	45.6	1.20	10.20	828	20.00
7	2.9	1	5.5	38.0	38.0	45.6	1.20	10.20	817	22.40
8	5.4	3	5.5	32.0	32.0	45.7	1.43	9.21	1,153	20.84
9	10.5	3	5.5	35.0	35.0	42.0	1.20	8.54	999	20.40
10	4.2	2	5.5	34.6	34.6	45.7	1.32	9.66	1,000	19.27
11	19.4	4	5.5	34.8	34.8	42.2	1.21	8.58	855	20.45
12	30.7	4	5.5	35.0	35.0	42.0	1.20	8.54	780	20.74
13	45.1	4	5.5	43.0	37.8	31.9	0.84	7.71	989	19.50
14	130.1	4	5.5	45.1	38.6	29.3	0.76	7.49	950	20.02
15	262.4	4	5.5	45.1	38.6	29.3	0.76	7.49	924	18.00
16	2.1	1	7.5	38.0	38.0	45.6	1.20	10.20	857	20.00
17	6.0	3	5.5	34.5	34.5	43.6	1.26	8.98	1,067	21.85
18	2.0	2	5.5	38.0	38.0	45.6	1.20	10.20	863	20.00
19	0.4	1	5.5	37.6	37.6	45.6	1.21	12.22	1,063	20.99
20	0.2	1	5.5	36.2	36.2	45.1	1.25	12.86	1,225	20.00
21	0.2	1	5.5	37.1	37.1	45.6	1.23	12.72	1,164	21.21
22	0.6	1	5.5	38.0	38.0	45.6	1.20	12.21	1,022	23.52
23	0.0	1	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
24	0.0	1	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
25	0.0	1	7.5	33.6	33.6	46.9	1.40	12.86	1,458	20.00
26	0.2	1	5.5	36.8	36.8	46.0	1.25	12.14	1,134	18.00
27	0.0	1	7.5	31.7	31.7	47.7	1.50	12.86	1,545	20.00
28	0.0	1	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
29	1.8	1	5.5	38.0	38.0	45.6	1.20	10.20	883	18.00
30	1.0	1	5.5	38.0	38.0	45.6	1.20	11.40	962	19.82
31	2.6	1	5.5	38.0	38.0	45.6	1.20	10.20	831	21.55
32	2.7	1	5.5	38.0	38.0	45.6	1.20	10.20	827	20.81
33	3.2	2	5.5	37.0	37.0	45.9	1.24	10.13	858	18.47

Cluster #	Weighted average capacity per site (MW)	Tech type *	Total transmission and distribution losses avoided (%)	Electrical Efficiency % (fully condensing mode)	Electrical Efficiency (CHP mode)	Thermal Efficiency (CHP mode) ****	Heat: power ratio	Opex: £/MWhe	CapEx: £/kWe	Hurdle Rate % (post-tax real)
34	6.2	3	5.5	33.6	33.6	43.6	1.30	8.84	1,116	21.84
35	2.4	1	5.5	38.0	38.0	45.6	1.20	10.20	843	18.00
36	1.3	1	5.5	38.0	38.0	45.6	1.20	11.63	901	21.27
37**	177.0	4	5.5	45.0	39.0	27.3	0.76	7.49	923	18.00
38***	2.8	1	9.5	38.0	38.0	40.8	1.20	10.20	784	12.00

** 1 = gas reciprocating engine, 2 = small OCGT, 3 = large OCGT, 4 = CCGT*

*** Oil and Refinery sector cluster, not modelled in the DECC Monte Carlo CHP model*

**** District Heating sector cluster, not modelled in the DECC Monte Carlo CHP model*

***** An alternative boiler efficiency of 81% (GCV basis) was assumed for all clusters*

Source: DECC

CHP clusters: existing policy exposure

	Policies eligible for:				
	CCL				
	base gas rate (£/MWCCLh)=	base elec rate (£/MWh)=			
	1.77	5.09			
Cluster #	top up heat rate, % of base rate (weighted average %)	top up electricity rate, % of base rate (weighted average %)	Liable for CPS on power exported? (% of cluster = "yes")	CRC on electricity generation and top up heat? (% of cluster = "yes")	ETS membership
1	35	10	100	0	y
2	100	100	0	0	y
3	100	100	100	0	y
4	100	100	100	0	y
5	35	10	100	0	y
6	100	100	100	0	y
7	35	10	100	0	y
8	35	10	100	0	y
9	35	10	100	0	y
10	35	10	100	0	y
11	35	10	100	0	y
12	35	10	100	0	y
13	35	10	100	0	y
14	35	10	100	0	y
15	35	10	100	0	y
16	100	100	100	0	y
17	35	10	100	0	y
18	35	10	0	0	y
19	35	10	0	0	n
20	35	10	0	0	n
21	35	10	0	0	n
22	35	10	0	0	n
23	0	0	0	0	n
24	0	0	0	0	n
25	100	100	0	100	n
26	35	10	0	0	n
27	100	100	0	100	n
28	0	0	0	0	n
29	35	10	0	0	n

30	35	10	100	0	n
31	35	10	100	0	n
32	35	10	100	0	n
33	35	10	100	0	n
34	35	10	100	0	n
35	35	10	100	0	n
36	35	10	100	0	n
37*	0	0	100	0	y
38**	0	0	0	0	n

** Oil and Refinery sector cluster, not modelled in the DECC Monte Carlo CHP model*

*** District Heating sector cluster, not modelled in the DECC Monte Carlo CHP model*

Source: DECC

CHP clusters: Build profile inputs for Generation Displaced modelling

	2012	2020 Baseline	2025 Baseline	2020, +0.5 GW Scenario	2025, +0.5GW Scenario
Cluster No.	MWe	MWe	MWe	MWe	MWe
1	2.0	21	25	22.0	27.3
2	63.9	35	34	35.6	34.3
3	15.6	55	56	55.5	56.4
4	62.5	1	2	2.0	4.3
5	24.7	21	21	22.5	25.8
6	13.2	14	17	14.5	17.2
7	31.6	82	78	82.4	79.5
8	103.4	124	141	124.3	141.0
9	304.0	128	146	128.3	146.1
10	9.8	35	46	35.2	46.2
11	0.0	5	5	9.3	15.6
12	319.8	156	76	185.8	155.3
13	417.2	251	182	290.5	286.3
14	624.4	457	380	505.0	508.6
15	0.0	432	448	432.5	449.4
16	31.4	48	56	51.4	65.8
17	56.1	6	27	11.4	40.5
18	0.0	0	0	0.7	1.9
19	0.0	633	655	632.7	655.5
20	0.0	104	171	103.8	170.7
21	1.8	149	283	152.6	293.2
22	0.4	31	31	31.3	31.3
23	21.3	0	0	0.0	0.0
24	0.0	0	0	0.0	0.0
25	27.7	108	112	107.5	112.3
26	0.0	37	37	37.1	37.1
27	85.6	749	727	748.6	727.2
28	2.8	0	0	0.0	0.0
29	1.8	41	41	40.7	40.6
30	1.8	99	100	99.9	103.6
31	25.7	157	151	157.2	150.8
32	18.3	124	119	123.5	118.9
33	20.9	43	49	46.8	58.1
34	223.1	71	85	72.2	87.9
35	0.0	13	13	12.8	12.8
36	4.5	107	118	108.9	122.3
37*	758.0	1,139	1,139	1176.7	1239.5
38**	43.0	95	95	98.1	103.4

** Oil and Gas sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*

*** District Heating sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*

Source: DECC and Ricardo-AEA

CHP clusters: Build profile inputs for Incremental and Social NPV modelling, 2020

	2020						
	Baseline		Policies				
	Technical potential	DECC CHP Model Capacity	Premium FiT	Capital Grant	PES Incentive	QI Heat	QI Capacity
Cluster No.	MWe	MWe	MWe	MWe	MWe	MWe	MWe
1	16	5	5	5	5	5	5
2	38	9	11	11	12	11	12
3	50	20	20	20	20	20	20
4	61	14	21	20	20	23	21
5	63	44	45	45	45	45	45
6	45	18	18	18	18	18	18
7	103	32	33	34	33	33	34
8	225	122	117	121	122	117	122
9	224	136	137	134	133	136	135
10	103	52	56	55	56	57	55
11	117	47	51	53	51	51	50
12	473	265	273	268	270	272	270
13	591	222	220	226	223	220	222
14	931	367	403	374	368	366	373
15	523	227	224	217	232	221	230
16	61	20	25	25	25	25	25
17	39	26	26	26	25	26	26
18	10	6	6	6	6	6	6
19	1,055	302	321	326	330	328	325
20	104	20	20	20	21	20	20
21	243	46	47	48	48	49	48
22	63	15	15	15	15	15	15
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
25	114	30	30	31	31	30	30
26	59	26	26	26	26	26	26
27	2,145	70	148	159	164	169	172
28	0	0	0	0	0	0	0
29	59	22	23	23	23	23	23
30	66	30	30	30	30	30	30
31	230	115	115	115	115	115	115
32	142	75	75	75	75	75	75
33	132	87	87	87	87	87	87
34	188	102	106	107	107	109	105
35	9	5	5	5	5	5	5
36	111	37	42	42	42	42	42

37*	2,576	177	177	177	177	177	177
38**	3,191	1,975	1,975	1,975	1,975	1,975	1,975

** Oil and Gas sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*
*** District Heating sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*

Source: DECC and Ricardo-AEA

CHP clusters: Build profile inputs for Incremental and Social NPV modelling, 2025

	2025						
	Baseline		Policies				
	BU Capacity	MC capacity	Premium FiT	Capital Grant	PES Incentive	QI Heat	QI Capacity
Cluster No.	MWe	MWe	MWe	MWe	MWe	MWe	MWe
1	16	4	4	5	4	4	4
2	38	8	10	10	11	11	11
3	50	20	20	20	20	20	20
4	61	10	14	13	13	16	14
5	63	43	44	44	44	44	44
6	45	17	18	18	18	18	18
7	103	28	30	31	31	31	31
8	225	85	84	83	83	84	82
9	224	112	107	108	105	107	105
10	103	42	44	42	44	43	43
11	117	34	37	38	38	38	38
12	473	226	232	232	227	230	229
13	591	106	108	106	103	109	106
14	931	190	194	195	195	190	193
15	523	96	97	95	84	99	96
16	61	16	24	24	24	23	24
17	39	21	21	21	21	21	21
18	10	6	6	6	6	6	6
19	1,108	325	347	351	353	355	349
20	104	23	23	23	23	23	23
21	243	53	56	56	57	57	57
22	63	17	16	16	16	17	16
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
25	114	40	39	40	39	39	40
26	59	27	27	27	27	27	27
27	2,145	97	189	197	199	220	208
28	0	0	0	0	0	0	0
29	59	23	23	23	23	23	23
30	66	29	29	29	29	29	29
31	230	113	114	113	113	114	114
32	142	73	73	73	73	73	73
33	132	87	87	87	87	87	87
34	188	109	115	114	113	115	114
35	9	5	5	5	5	5	5

36	127	41	47	47	46	47	46
37*	2,576	0	177	177	177	177	177
38**	4,392	2,718	2,718	2,718	2,718	2,718	2,718

** Oil and Gas sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*
*** District Heating sector cluster, not modelled in the DECC Monte Carlo CHP model, assessments provided by Ricardo-AEA*

Source: DECC and Ricardo-AEA

CHP clusters: Six-point Heat Demand assumptions

Cluster	Winter day, MW Per Site	Winter evening, MW Per Site	Winter night, MW Per Site	Summer day, MW Per Site	Summer evening, MW Per Site	Summer night, MW Per Site
1	4.65	2.70	2.79	1.40	1.21	1.26
2	3.08	3.02	2.85	1.24	1.23	1.15
3*	5.31	5.31	5.31	2.12	2.12	2.12
4*	17.89	7.71	4.44	6.14	3.61	2.09
5	9.67	6.35	6.24	4.32	3.80	3.65
6*	8.36	7.09	6.31	3.23	3.02	2.53
7	4.74	4.26	4.24	3.51	3.39	3.37
8	11.41	10.66	10.54	8.60	8.22	8.10
9	19.37	17.40	17.51	15.08	14.42	13.77
10	12.19	12.19	12.19	6.95	6.95	6.95
11	38.45	36.30	35.96	30.76	29.64	29.02
12	53.25	49.90	49.44	41.37	41.18	38.65
13	61.34	57.89	56.38	49.46	48.25	44.80
14	152.39	143.79	139.77	124.82	122.77	114.17
15	270.07	265.30	260.53	199.41	229.56	189.87
16*	7.75	3.61	1.69	2.53	1.72	0.82
17	40.23	17.17	17.17	7.63	5.19	5.19
18	12.28	6.14	6.14	2.46	1.84	1.84
19	0.62	0.59	0.58	0.45	0.44	0.42
20	0.65	0.59	0.59	0.23	0.20	0.20
21	1.46	0.68	0.68	0.28	0.20	0.20
22	0.79	0.79	0.79	0.71	0.71	0.71
23	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00
25	0.18	0.18	0.18	0.07	0.07	0.07
26	0.33	0.23	0.26	0.26	0.21	0.21
27*	0.27	0.09	0.08	0.05	0.03	0.03
28	0.00	0.00	0.00	0.00	0.00	0.00
29	2.89	2.86	2.83	2.11	2.08	2.05
30	2.36	2.21	2.21	1.18	1.11	1.11
31	4.09	3.69	3.76	3.11	2.95	2.88
32	3.81	3.70	3.58	3.18	3.17	2.96
33	9.58	6.18	6.05	4.06	3.71	3.41
34	9.80	9.28	9.09	8.21	8.00	7.55
35	3.41	3.29	3.17	2.82	2.70	2.58
36	5.32	3.18	3.18	1.59	1.38	1.38

** Six-point profile not used in DDM modelling. A representative granular, half hourly profile was applied. Cluster 38 (District Heating) also used a granular profile.*

Source: Ricardo-AEA

The risk of some CHP units losing their Heat demand was modelled by reducing Heat Demand by 7.5% over every 10 years of operation. The source of this assumption was supplied from Ricardo-AEA analysis of premature cessation of CHP operation of CHPQA certified plant over the 2003-2012 period.

CHP clusters: Six-point On-site Power Demand assumptions.

Cluster	Winter day, MW Per Site	Winter evening, MW Per Site	Winter night, MW Per Site	Summer day, MW Per Site	Summer evening, MW Per Site	Summer night, MW Per Site
1	2.47	1.40	1.40	2.35	1.27	1.28
2	1.17	1.13	0.60	1.07	1.02	0.50
3*	1.91	1.91	1.05	1.72	1.72	0.86
4*	7.66	2.76	1.53	7.54	2.76	1.53
5	6.01	4.51	4.21	5.67	4.17	3.91
6*	3.18	2.66	1.32	2.95	2.43	1.12
7	3.61	3.27	3.18	3.41	3.06	3.03
8	7.11	6.92	6.83	6.62	6.48	6.41
9	12.55	12.26	11.73	11.62	10.89	10.89
10	5.74	5.26	4.17	5.49	4.44	3.35
11	16.97	16.34	16.20	15.52	14.90	14.76
12	35.13	34.27	32.77	32.51	30.85	30.39
13	56.06	53.68	50.75	53.53	48.43	47.12
14	139.59	135.69	127.96	132.61	127.50	123.60
15	359.91	350.00	340.09	341.91	341.91	332.00
16	3.41	1.54	0.73	3.37	1.51	0.72
17	26.71	9.83	9.83	25.38	9.00	9.00
18	5.68	2.84	2.84	5.40	2.56	2.56
19	0.40	0.38	0.37	0.38	0.35	0.35
20	0.54	0.27	0.38	0.54	0.27	0.38
21	1.14	0.51	0.51	1.08	0.46	0.46
22	0.69	0.69	0.61	0.65	0.60	0.60
23	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00
25	0.06	0.06	0.03	0.06	0.06	0.03
26	0.26	0.21	0.21	0.21	0.19	0.19
27	0.22	0.07	0.04	0.21	0.07	0.04
28	0.00	0.00	0.00	0.00	0.00	0.00
29	1.38	1.16	1.16	1.36	0.97	0.97
30	2.13	1.47	1.72	2.11	1.47	1.72
31	2.63	2.49	2.39	2.37	2.22	2.21
32	3.89	3.73	3.59	3.75	3.62	3.50
33	5.30	3.84	3.73	5.04	3.67	3.56
34	7.62	7.40	7.00	7.15	6.86	6.69
35	5.99	5.59	5.34	5.74	5.38	5.13
36	2.28	1.29	1.29	2.19	1.12	1.12

** Six-point profile not used in DDM modelling. A representative granular, half hourly profile was applied. Cluster 38 (District Heating) also used a granular profile.*
Source: Ricardo-AEA

Fuel price assumptions

Year	Coal (£/tonne)	Gas (£/therm)	Gas Retail (£/therm)
2010	59.43	0.427	0.518
2011	77.92	0.578	0.701
2012	58.21	0.601	0.729
2013	56.48	0.623	0.756
2014	60.31	0.653	0.792
2015	64.20	0.683	0.827
2016	66.55	0.691	0.839
2017	68.90	0.707	0.859
2018	71.25	0.723	0.879
2019	73.60	0.723	0.881
2020	75.94	0.723	0.883
2021	75.94	0.723	0.885
2022	75.94	0.723	0.887
2023	75.94	0.723	0.889
2024	75.94	0.723	0.892
2025	75.94	0.723	0.894
2026	75.94	0.723	0.896
2027	75.94	0.723	0.898
2028	75.94	0.723	0.900
2029	75.94	0.723	0.902
2030	75.94	0.723	0.904
2031	75.94	0.723	0.904
2032	75.94	0.723	0.904
2033	75.94	0.723	0.904
2034	75.94	0.723	0.904
2035	75.94	0.723	0.904
2036	75.94	0.723	0.904
2037	75.94	0.723	0.904
2038	75.94	0.723	0.904
2039	75.94	0.723	0.904
2040	75.94	0.723	0.904
2041	75.94	0.723	0.904
2042	75.94	0.723	0.904
2043	75.94	0.723	0.904
2044	75.94	0.723	0.904
2045	75.94	0.723	0.904

Year	Coal (£/tonne)	Gas (£/therm)	Gas Retail (£/therm)
2046	75.94	0.723	0.904
2047	75.94	0.723	0.904
2048	75.94	0.723	0.904
2049	75.94	0.723	0.904
2050	75.94	0.723	0.904

Source: DECC, LCP analysis

Additional detail on results

Incremental endogenous build: New capacity brought forward by cluster, Baseline (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	-	10.0	15.0	20.0	25.0	30.0	35.0	40.0
3	-	15.0	20.0	25.0	30.0	35.0	40.0	40.0
4	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	-	15.0	25.0	30.0	35.0	35.0	35.0	35.0
7	-	35.4	55.7	65.8	76.0	86.1	86.1	86.1
8	-	-	8.5	16.9	25.4	33.9	33.9	33.9
9	-	-	-	-	-	-	10.5	10.5
10	-	30.0	45.0	50.0	55.0	60.0	65.0	70.0
11	-	-	-	-	-	19.4	38.9	38.9
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-
16	-	15.0	20.0	25.0	30.0	35.0	40.0	45.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	-	346.3	519.4	634.9	750.3	865.7	923.4	923.4
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	128.2	142.5	171.0	185.2
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	-	40.3	63.4	74.9	86.4	97.9	103.7	103.7

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
37	-	-	-	-	-	-	-	-
38	-	-	-	-	-	-	-	-

Source: LCP analysis

Incremental endogenous build: Alternative baseline, no CHP participating in the Capacity Market (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	-	-	-	-	-	-	-
2	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
3	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	5.0	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	5.0	10.0	15.0	20.0	25.0	30.0	35.0	35.0
7	15.2	35.4	55.7	65.8	76.0	86.1	86.1	86.1
8	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-
10	10.0	25.0	35.0	40.0	45.0	50.0	55.0	60.0
11	-	-	-	-	-	-	-	-
12	30.6	61.2	91.8	122.4	153.0	183.7	214.3	244.9
13	-	44.9	44.9	44.9	44.9	44.9	44.9	44.9
14	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	173.1	346.3	519.4	634.9	750.3	865.7	923.4	923.4
20	-	-	-	-	-	-	6.1	12.1
21	14.2	42.7	57.0	71.2	85.5	85.5	99.7	114.0
22	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	10.0	20.0	30.0	35.0	40.0	45.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	10.0	20.0	30.0	35.0	40.0	45.0	45.0	45.0
30	10.0	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	40.6	81.2	121.8	142.1	162.4	162.4	162.4	162.4
32	24.2	54.5	78.7	90.8	96.8	96.8	96.8	96.8
33	20.0	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
36	17.3	40.3	57.6	69.1	80.7	92.2	103.7	103.7
37	-	-	-	-	-	-	-	-
38	-	-	-	-	-	-	-	-

Source: LCP analysis

Incremental build: Premium Fit incentive (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
3	10.0	20.0	30.0	35.0	40.0	40.0	40.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	10.0	20.0	30.0	35.0	35.0	35.0	35.0	35.0
7	25.3	50.6	76.0	86.1	86.1	86.1	86.1	86.1
8	-	-	8.5	16.9	16.9	25.4	25.4	25.4
9	-	-	-	-	-	-	10.5	10.5
10	15.0	35.0	50.0	55.0	60.0	65.0	70.0	70.0
11	19.4	38.9	58.3	77.8	97.2	97.2	97.2	97.2
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	230.9	461.7	692.6	808.0	923.4	923.4	923.4	923.4
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	128.2	142.5	156.7	171.0
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	10.0	25.0	40.0	45.0	45.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	28.8	57.6	86.4	103.7	103.7	103.7	103.7	103.7
37	-	-	-	-	-	-	-	-
38	387.4	774.8	1,162.2	1,549.7	1,937.1	2,195.4	2,582.8	2,970.2

Source: LCP analysis

Incremental build: Capital Grant incentive (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	5.0	15.0	25.0	30.0	35.0	40.0	40.0	40.0
3	5.0	15.0	20.0	25.0	30.0	35.0	40.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	10.0	20.0	30.0	35.0	35.0	35.0	35.0	35.0
7	25.3	50.6	76.0	86.1	86.1	86.1	86.1	86.1
8	-	-	8.5	16.9	16.9	25.4	25.4	25.4
9	-	-	-	-	-	-	10.5	10.5
10	20.0	40.0	60.0	70.0	70.0	70.0	70.0	70.0
11	-	-	-	19.4	38.9	58.3	77.8	97.2
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	230.9	519.4	808.0	923.4	923.4	923.4	923.4	923.4
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	114.0	128.2	156.7	171.0
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
28	-	-	-	-	-	-	-	-
29	15.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	28.8	57.6	86.4	103.7	103.7	103.7	103.7	103.7
37	-	-	-	-	-	-	-	-
38	-	129.1	258.3	387.4	516.6	645.7	904.0	1,162.2

Source: LCP analysis

Incremental build: PES incentive (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	5.0	15.0	25.0	30.0	35.0	40.0	40.0	40.0
3	10.0	20.0	30.0	35.0	40.0	40.0	40.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	10.0	20.0	30.0	35.0	35.0	35.0	35.0	35.0
7	25.3	50.6	76.0	86.1	86.1	86.1	86.1	86.1
8	-	-	8.5	16.9	16.9	16.9	16.9	16.9
9	-	-	-	-	-	-	10.5	10.5
10	20.0	40.0	60.0	70.0	70.0	70.0	70.0	70.0
11	19.4	38.9	58.3	77.8	97.2	97.2	97.2	97.2
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	230.9	519.4	808.0	923.4	923.4	923.4	923.4	923.4
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	114.0	128.2	142.5	156.7
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	15.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	28.8	57.6	86.4	103.7	103.7	103.7	103.7	103.7
37	-	-	-	-	-	-	-	-
38	387.4	774.8	1,162.2	1,549.7	1,937.1	2,195.4	2,582.8	2,970.2

Source: LCP analysis

Incremental build: QI weighted heat incentive (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
3	5.0	15.0	20.0	25.0	30.0	35.0	40.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	10.0	20.0	30.0	35.0	35.0	35.0	35.0	35.0
7	25.3	50.6	76.0	86.1	86.1	86.1	86.1	86.1
8	-	-	8.5	16.9	16.9	25.4	25.4	25.4
9	-	-	-	-	-	-	10.5	10.5
10	20.0	40.0	60.0	70.0	70.0	70.0	70.0	70.0
11	19.4	38.9	58.3	77.8	97.2	97.2	97.2	97.2
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	230.9	461.7	692.6	808.0	923.4	923.4	923.4	923.4

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	128.2	142.5	156.7	171.0
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	15.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	28.8	57.6	86.4	103.7	103.7	103.7	103.7	103.7
37	-	-	-	-	-	-	-	-
38	387.4	774.8	1,162.2	1,549.7	1,807.9	2,066.2	2,453.6	2,841.0

Source: LCP analysis

Incremental build: QI weighted capacity incentive (MWe)

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
1	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
3	5.0	15.0	20.0	25.0	30.0	35.0	40.0	40.0
4	10.0	20.0	30.0	35.0	40.0	45.0	50.0	55.0
5	-	15.0	25.0	30.0	35.0	40.0	40.0	40.0
6	10.0	20.0	30.0	35.0	35.0	35.0	35.0	35.0
7	25.3	50.6	76.0	86.1	86.1	86.1	86.1	86.1
8	-	-	8.5	16.9	16.9	25.4	25.4	25.4
9	-	-	-	-	-	-	10.5	10.5
10	15.0	30.0	45.0	50.0	55.0	60.0	65.0	70.0
11	-	-	-	19.4	38.9	58.3	77.8	97.2
12	-	122.4	183.7	244.9	275.5	306.1	306.1	306.1
13	-	44.9	89.9	134.8	179.7	224.7	269.6	269.6
14	-	-	130.6	261.2	261.2	261.2	261.2	261.2
15	-	-	-	-	-	-	-	-

Cluster No.	2018	2019	2020	2021	2022	2023	2024	2025 .. 2037
16	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0
17	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-
19	230.9	461.7	692.6	808.0	923.4	923.4	923.4	923.4
20	-	-	12.1	24.2	30.3	36.3	42.4	42.4
21	-	28.5	71.2	99.7	128.2	142.5	156.7	171.0
22	-	20.0	30.0	35.0	40.0	45.0	50.0	55.0
23	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	-	15.0	25.0	30.0	35.0	40.0	45.0	45.0
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	10.0	20.0	30.0	35.0	40.0	45.0	45.0	45.0
30	-	20.0	30.0	35.0	40.0	45.0	45.0	45.0
31	-	81.2	132.0	162.4	162.4	162.4	162.4	162.4
32	-	54.5	84.7	96.8	96.8	96.8	96.8	96.8
33	-	45.0	70.0	80.0	80.0	80.0	80.0	80.0
34	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-
36	23.0	51.9	80.7	97.9	103.7	103.7	103.7	103.7
37	-	-	-	-	-	-	-	-
38	387.4	774.8	1,162.2	1,420.5	1,678.8	1,937.1	2,324.5	2,711.9

Source: LCP analysis

Quality assurance of the modelling

Dynamic Dispatch Model

The DDM is used for electricity system modelling within DECC and was developed by LCP. The model is well known to DECC and has been through considerable quality assurance and external peer review. These reviews have found no fundamental problems with the underlying methodology and results produced from the[9] model.

The model has been upgraded to enable the detailed modelling of Gas CHP to be carried out within the model. The upgraded model has been subject to testing and validation to ensure fitness for purpose.

Modelling assumptions review

The CHP models contain a number of assumptions such as on capital costs and heat demand. These assumptions are under constant review and a number of operating characteristics were changed to improve the accuracy of modelling results. Quality assurance of assumptions has involved a number of steps as outlined below:

- The key assumptions requiring review were identified, following this a review was undertaken to identify with stakeholders such as Mott Macdonald, Ricardo AEA and the CHPA appropriate assumptions.
- CHP operators have also been given sight of the key modelling assumptions used within the model and provided an opportunity to comment. Where evidence suggested that an assumption was now out of date or incorrect this was changed by DECC if warranted by evidence. Where possible, sensitivities have also been carried out on key modelling assumptions to examine the impact of changes in these assumptions on overall modelling results and these have been reported within the submission.
- The changes made to modelling assumptions were made in order to improve the accuracy of modelling results and ensure that modelling inputs are based on the most appropriate and up to date sources.

LCP Quality Assurance

The carbon displacement modelling and Social NPV results have been produced using the upgraded DDM. LCP have undertaken QA of results which have been sent to DECC. The QA processes used depend upon the nature of the project and the type of deliverable. During this project two of LCP's QA processes have been applied.

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[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48385/5427-ddm-peer-review.pdf

Model analysis: This is the QA process applied when LCP provide model results and analysis. It falls into a number of stages which include the following:

- **Review of approach.** With any modelling exercise there are decisions on exactly how certain aspects should be modelled. On this project the approach used in each area of the modelling by LCP was reviewed by Mott MacDonald and DECC.
- **Input data and assumptions**. The input data used for any run is entered and then independently reviewed by a different member of the LCP team.
- **Model setup and execution.** As for input data, the model is set up by one member of the LCP team and independently reviewed by a different team member. This includes basic checks that the right data files have been used and the model has been run with the correct options (e.g. granularity, projection period etc.*)*
- **Sense check of results.** The results of each model run are reviewed by a member of the senior team. This includes sense checks on all of the results that will be reported. In doing this key calculations are roughly checked based on the change in input assumptions.

Model development testing/validation: This is the process LCP go through when developing any new model functionality. The upgrades to the DDM model to incorporate Gas CHP have followed this process and have been agreed with relevant DECC modelling and analytical colleagues.

DECC Quality Assurance

DECC's quality assurance of CHP modelling results has involved several steps as described below:

- Internal QA: Modelling results have been quality assured by heat team economists and policy officials. This has involved checking the consistency of overall results, doing off-model calculations to check against modelled results and understanding the key drivers of results.
- Central modelling results have also been subject to sensitivity analysis testing the results to changes in key input assumptions and decarbonisation trajectories. Any results requiring further investigation have then been followed up with contractors to resolve and correct any errors.
- Peer review: The modelling results from the CHP models have been subject to peer review from other DECC analysts. In particular modelling results have been reviewed by economists in the electricity markets team to ensure consistency with EMR modelling and check the robustness of results. Modelling results have also been reviewed by modellers in the Dynamic Dispatch Modelling team to ensure that results make sense.
- IAG: Modelling results on carbon displacement, additional capacity incentivised by policy support and Social NPVs have also been presented at the DECC

Interdepartmental Analysts Group. This group is composed of analysts from across DECC and OGD's and serves as a quality assurance body for analysis. Key suggested recommendations from these meetings have been taken on board and reflected in our analysis and modelling.

- Economist clearance: Modelling results have been cleared by the senior heat team economist. Results have also been discussed with senior economists and the Chief Economist and their views reflected in the modelling and valuation approach adopted.

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