Gas Future Scenarios Project – Final Report

A report on a study for the Energy Networks Association Gas Futures Group, October 2010

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Background

When looking out to 2050 there is huge uncertainty surrounding how gas will be consumed, transported and sourced in Great Britain (GB). The extent of the climate change challenge is now widely accepted, and the UK Government has introduced a legislative requirement for aggressive reductions in carbon dioxide (CO_2) emissions out to 2050. In addition, at European Union (EU) level a package of measures has been implemented to reduce greenhouse gas emissions, improve energy efficiency and significantly increase the share of energy produced from renewable sources by 2020. These policy developments naturally raise the question of what role gas has to play in the future energy mix.

To help inform this debate, the Energy Networks Association Gas Futures Group (ENA GFG) commissioned Redpoint and Trilemma to undertake a long-range scenario-based modelling study of the future utilisation of gas out to 2050, and the consequential impacts of this for gas networks. Our modelling assumptions draw heavily on the Department of Energy and Climate Change (DECC) 2050 Pathways analysis, and we consider that our conclusions are fully compatible with both DECC's work and current EU policy objectives.

Key messages

The key findings from our modelling are as follows:

- **There are credible and robust scenarios in which gas could play a major ongoing role in the GB energy mix while meeting both the 2050 carbon targets and the 2020 renewable energy targets**. Managing CO_2 emissions under these scenarios would require the successful development and roll-out of Carbon Capture and Storage (CCS) technology, supported by the deployment of biomethane injection into the gas distribution network, roll-out of district heating, and / or the usage of combined electricity and gas 'dual fuel' systems for domestic heating.
- **Pathways with ongoing gas use could offer a cost-effective solution for a low-carbon transition relative to scenarios with higher levels of electrification**. Our baseline assumptions indicate potential savings of more than £700bn over the 2010 to 2050 period – around £20,000 per household or £10,000 per person – with consequential benefits for consumers, the economy, and the competitiveness of GB industry. Sensitivity analysis indicates that cost savings are still present under assumptions of higher commodity price trajectories and faster technology learning rates, although the difference in costs is reduced relative to the baseline.
- **All potential pathways to a low-carbon future will involve significant investment in new technology, with its associated risks[1]. Given the level of uncertainty regarding these issues, there appears to be significant value in retaining the option for a 'high gas' future**.
- **The costs of maintaining the existing gas transmission and distribution networks are relatively small in comparison to the other system costs associated with a low-carbon transition. Together these findings suggest a compelling economic rationale for maintaining the operation of the GB gas transmission and distribution networks for the foreseeable future**.

[1] These include risks around the pace of technology development and feasibility of deployment, consumer behaviour in relation to uptake of new technologies, and policy / regulatory risk.

Methodology

We have developed a fully-costed supply / demand balance model of the energy sector incorporating assumptions from a range of publically-available sources, including the DECC 2050 Pathways analysis, the UK Energy Research Council (UKERC) 2050 modelling, and research undertaken for the Committee on Climate Change. The model has been used to examine four different scenarios characterised by varying levels of gas and electrification in the energy mix.

To develop our four scenarios, we initially identified two key drivers of future gas utilisation out to 2050. These drivers were selected on the basis that they would generate a diverse but plausible set of scenario outcomes for future gas utilisation, which captured the dimensions of particular interest to the ENA GFG – namely, the demand for network-delivered gas on the transmission and distribution systems respectively. Our key scenario drivers were:

- **Commercialisation of Carbon Capture and Storage (CCS) Technologies**. Successful deployment of CCS is likely to be the key driver of future demand for transmission-delivered gas for baseload generation, since it would allow gas to maintain or even increase its share of the generation mix while still meeting carbon reduction targets.
- **Commercialisation of Electricity and Heat Storage Technologies**. Energy storage technologies – ie, diurnal electricity storage together with seasonal heat storage – are likely to play a key role in facilitating electrification of the heating and transport sectors at reasonable cost, by reducing requirements for diurnal and seasonal peaking capacity. Conversely, slow or unsuccessful deployment of these technologies is likely to be a key driver of ongoing demand for distribution-delivered gas for seasonal / peak heating, as well as transmission-delivered gas for diurnal electricity balancing.

Figure 1 shows how our key scenario drivers map onto the scenarios developed for the study, with 'high / rapid' and 'low / slow' settings on each driver giving a 2x2 matrix of four scenarios in total:

- **Green Gas** – a scenario with a significant and ongoing role for gas, both at the transmission and distribution level. Global gas prices remain relatively low in this scenario due to the discovery of large reserves of commercially extractable unconventional gas, and the development of efficient CCS technology enables gas to retain its share of the generation sector. In addition, a lack of development in storage technologies means that gas remains a key provider of both heating and electricity balancing services. New homes, together with an increasing share of the existing housing stock, move towards a 'dual fuel' heating model with electric heat pumps providing baseload heat and gas providing seasonal peaking requirements. Biomethane injection into the distribution grid, together with extensive use of CHP district heating (some of it also fitted with CCS), is used to help manage emissions in the heat sector. In addition, there is some take-up of Compressed Natural Gas (CNG) as a transport fuel, particularly for Heavy Goods Vehicles (HGVs).
- **Storage Solution** – a scenario with ongoing use of gas primarily delivered at the transmission level for generation, rather than at the distribution level for heating. Breakthroughs in unconventional gas supplies mean that gas prices remain relatively cheap and efficient CCS technology rapidly emerges allowing gas to become the key source of low carbon power generation. At the same time, rapid development of electricity and heat storage technologies allows the heat and transport sectors to be decarbonised cost-effectively through electrification, reducing the need for distribution-delivered gas for heating and unabated gas for electricity balancing. New connections to the gas network fall sharply after 2020, and by 2050 two-thirds of the distribution grid has been decommissioned.
- **Gas Versatility** – in this scenario, CCS is unsuccessful and the requirement for large quantities of direct transmission-delivered gas for baseload generation largely disappears by 2050, to be

replaced by renewables and nuclear. However, a lack of development in electricity and heat storage technologies means that gas continues to provide balancing services in the power market, as well as retaining a significant share in the heating sector, with most new homes continuing to connect to the gas grid through to at least 2030. There is also some take-up of CNG for HGVs in the transport sector at levels similar to the Green Gas scenario. Emissions from gas-fired heating in the Gas Versatility scenario are managed predominantly through maximising the potential of biomethane injection into the gas distribution grid.

- **Electrical Revolution** – this scenario describes a future in which the use of gas is effectively eliminated over a 30 to 40 year period. Global gas prices rise steadily over time in response to dwindling reserves and a failure to effectively exploit unconventional sources, and CCS technology does not develop to the extent that it presents a competitive option compared with renewables and nuclear generation. In addition, developments in storage technologies and flexible nuclear generation, combined with a high level of interconnection with other European countries, mean that gas is no longer required to provide balancing services, while heat demand can be met cost-effectively through zero carbon electricity. New housing connections to the gas grid cease in around 2025 and by 2050 both the gas transmission and distribution networks have been fully decommissioned.

Figure 1 Scenario summary table

		DIMENSION 2: Commercialisation of Electricity and Heat Storage Technologies	
		Low / Slow	**High / Rapid**
DIMENSION 1: Commercialisation of Carbon Capture and Storage Technologies	**High / Rapid**	**GREEN GAS** ***Transmission-delivered gas 2050: HIGH*** - gas + CCS - some unabated gas for balancing ***Distribution-delivered gas 2050: HIGH*** - 'dual fuel' world for domestic heating - biomethane injection - district heating + CCS - some use of CNG in transport	**STORAGE SOLUTION** ***Transmission-delivered gas 2050: HIGH*** - gas + CCS - small amount of unabated gas - additional balancing via electricity storage and demand-side response (DSR) ***Distribution-delivered gas 2050: LOW*** - heating and transport largely electrified - heat storage used to balance seasonal heat
	Low / Slow	**GAS VERSATILITY** ***Transmission-delivered gas 2050: LOW*** - renewables / nuclear dominate - some unabated gas for balancing ***Distribution-delivered gas 2050: MED*** - biomethane at max potential - some use of CNG in transport	**ELECTRICAL REVOLUTION** ***Transmission-delivered gas 2050: NONE*** - renewables / nuclear dominate - balancing via electricity storage, flexible nuclear, interconnection and DSR ***Distribution-delivered gas 2050: NONE*** - heating and transport largely electrified - heat storage used to balance seasonal heat

Results

A summary of the key results from our modelling is set out in Table 1 below. It can be seen from the annual and peak demand figures in 2050 that our four scenarios capture a broad range of trajectories of future gas utilisation, from levels similar to today in Green Gas down to zero in the Electrical Revolution scenario. On the electricity side, all scenarios show a significant increase in output relative to today's levels, reflecting the effects of electrification combined with population and economic growth. However, electricity output and installed capacity in the Electrical Revolution scenario are close to double that in Green Gas by 2050.

All of our scenarios meet both the 2050 carbon targets and the 2020 renewable targets, indicating that an ongoing role for gas in the GB energy mix could be fully compatible with achieving the Government's environmental objectives[2]. Moreover, our results suggest that pathways with ongoing use of gas could offer a cost-effective solution for a low-carbon transition. For example, under our baseline assumptions total costs under Green Gas are more than £700bn lower than Electrical Revolution over the 2010 to 2050 period – around £20,000 per household or £10,000 per person. The bulk of the difference in costs is driven by the additional investment requirements associated with greater electrification, including additional generation capacity, further expansion of the electricity transmission and distribution networks, and greater investment in demand-side electric heating and transport technologies.

While investment costs are higher in the Electrical Revolution scenario, fuel costs represent a higher share of system costs under scenarios with ongoing gas use. Our cost comparisons are therefore potentially sensitive to assumptions around commodity prices. We have tested a number of sensitivities to explore the impact of different commodity price trajectories as well as differences in assumed technology learning rates on our modelling results. These sensitivities suggest that even under assumptions that are less favourable to gas (ie, higher commodity prices and faster learning rates for new technologies), pathways with greater gas use could still be lower cost than scenarios that rely more heavily on electrification[3].

Energy efficiency, through system improvements, heat loss minimisation and augmentation with micro renewable sources, has a key role to play in reducing heating service demands over time[4] and flattening the seasonal heat profile. However, our results suggest that even with significant improvements in insulation technology there remains a significant peak heat demand that varies between seasons. Delivering this requirement via the gas distribution network can save on requirements for additional electricity generation capacity.

Our modelling indicates that managing CO_2 emissions under scenarios with high ongoing use of gas will require the successful development and roll-out of CCS technology, allowing gas to maintain its current share of electricity generation, supported by the deployment of biomethane injection into the gas distribution network, allowing gas to maintain a significant role in domestic and industrial heating. Other important factors in constraining emissions – particularly in the Green Gas scenario – include roll-out of CHP district heating (some of it also fitted with CCS), and the usage of combined electricity and gas 'dual fuel' systems for domestic heating. In transport, all of our scenarios assume significant roll out of hybrids and then plug-in electric battery vehicles, but the use of CNG can contribute to lowering the emissions for the HGV fleet.

[2] We have assumed that a 90% reduction in CO_2 emissions below 1990 levels would be required in the modelled sectors to achieve the Government's target of an 80% reduction in emissions overall. In terms of CO_2 volumes this entails a reduction from 530 Mt of CO_2 to 53 Mt or lower.

[3] As can be seen in the table, Gas Versatility rather than Green Gas is the cheapest scenario in the High Commodity Price sensitivity. This reflects the fact that Gas Versatility has the lowest total investment costs of the four scenarios.

[4] The impact of warmer weather due to climate change is also relevant here, with average temperatures assumed to rise by 2°C over the study period.

Other potential benefits of maintaining gas within the energy mix include enhancing the diversity of the energy supply mix in 2050 and providing additional flexibility with respect to energy balancing particularly at times of low renewable output, with our results suggesting that even in the Electrical Revolution scenario some unabated generation plant may be needed to operate alongside demand-side management and storage systems for balancing electricity. As the cleanest-burning fossil fuel, gas can also play an important transition role in minimising emissions in the short term while new technologies are developed.

Conclusions

Technological development – and consumer uptake of new technologies – is critical to any low-carbon future. Both time and funding are needed to ensure that technology options are fully explored. As noted in the key messages, all potential pathways to a low-carbon future will involve significant investment in new technology. Under high gas scenarios, key technologies are likely to include CCS, biomethane, dual fuel and / or district heating systems, combined with at least some electrification of heating and transport. Under scenarios with low or no ongoing use of gas, investment in electric heating and transport technologies will be critical, alongside electricity and heat storage, demand-side response (DSR), interconnection and / or flexible nuclear to balance the electricity system. All of these technologies have potential risks and uncertainties associated with them, including the pace of technological development and learning, the willingness of consumers to alter their behaviour and preferences, and policy / regulatory risk.

Given the level of uncertainty that exists regarding all of these issues, there appears to be significant value in retaining the option for a 'high gas' future. This is particularly relevant given that our modelling indicates that pathways with ongoing gas use could yield cost savings relative to those with higher levels of electrification, particularly under scenarios with low growth in commodity prices and / or slower rates of technology learning. Our cost analysis suggests that, while the costs of maintaining the gas networks are not insignificant, they are relatively small in comparison to the other system costs that will be incurred in the transition to a low-carbon future. Furthermore, since the capital costs of the existing gas network are largely sunk, decommissioning of the gas network provides limited scope for cost savings. Together these findings suggest a compelling economic rationale for maintaining the operation of the GB gas transmission and distribution networks for the foreseeable future.

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Table 1 Summary of key results

	2010	2050			
	All scenarios	Green Gas	Storage Solution	Gas Versatility	Electrical Revolution
Future gas utilisation					
Annual gas demand (TWh)	1057	1182	719	511	0
Peak day gas demand (TWh) [5]	5.0	4.7	3.5	2.5	0.0
Electricity supply / demand					
Annual electricity demand (TWh)	331	529	605	588	819
Peak electricity demand[6] (GW)	65	99	131	122	168
Installed generation capacity (GW)	87	168	191	230	297
Heating and transport					
Annual delivered energy – heating (TWh)	889	933	785	838	751
Annual delivered energy – transport[7] (TWh)	548	255	270	284	215
Environment					
CO_2 emissions (Mt)	420	48	49	40	38
Biofuel use (incl imports) (TWh)	36	525	530	652	345
Costs[8]					
NPV of system costs 2010 to 2050 – Baseline (£bn)	n/a	4,550	4,766	4,668	5,276
NPV of system costs 2010 to 2050 – High Commodity Prices (£bn)	n/a	5,277	5,221	5,118	5,485
NPV of system costs 2010 to 2050 – High Technology Learning (£bn)	n/a	4,338	4,533	4,455	5,020

[5] Note that our methodology for calculating peak demand is a simplified version of that used by National Grid, and therefore the modelled peak demand for 2010 cannot be directly compared with historic data.

[6] The summary figures for peak electricity demand are presented prior to any demand-side response or electricity storage being applied.

[7] Including both passenger and freight travel across all modes – road, rail, domestic aviation and domestic maritime.

[8] Note that our analysis focuses purely on costs – we have not made any assumptions regarding potential offsetting revenues, for example associated with auctioning of carbon emission allowances or electricity exports.

1 Introduction

1.1 Background

The Energy Networks Association Gas Futures Group (ENA GFG) represents the principal gas network companies in Great Britain (GB), covering the regulated transmission and distribution network operators as well as Inexus, an independent gas transporter (IGT). In February 2010, the ENA GFG issued an Invitation to Tender for the provision of a long-range scenario-based study to "examine potential scenarios within each decade up to 2050 to better understand the future utilisation of gas and fit this into a wider context of climate change transition and impact, including the broader energy influence in relation to generation, heat and transport". Redpoint Energy Limited and Trilemma UK were appointed to carry out this project in April 2010. This report sets out the final results of our scenario modelling.

1.2 Policy context

There is little doubt that the GB energy sector faces a period of considerable change over the coming decades. The extent of the challenge of climate change is now widely accepted. The need for change has been embraced by the UK Government and this means that we cannot continue to produce and consume energy in the same way for much longer. Legislation was introduced in 2008 to create a legally binding, long-term framework to cut greenhouse gas emissions. This requires the UK to cut overall emissions to at least 80% below 1990 levels by 2050[9] and sets out a process for establishing shorter term emissions limits (now fixed out to 2022).

This UK based legislation comes in addition to that set at EU level where a package of measures has been implemented to reduce greenhouse gas emissions, improve energy efficiency and accelerate the roll-out of renewable energy technologies by 2020. In particular, the requirement for the UK to produce 15% of overall energy from renewable sources by 2020 represents a considerable change from the current situation.

These new legal requirements have led policy makers to review the existing policy, regulatory and market framework and to consider where changes might be necessary to deliver the required outcomes. This has involved a combination of scenario analysis, which seeks to identify what investments might be required, along with a review of the market and regulatory arrangements, to consider whether the correct incentives are in place to attract and deliver the necessary investments.

Scenario studies have been undertaken by Ofgem, to help inform the future need for network investment, and, more recently, by DECC, which has undertaken a 2050 Pathways analysis to provide the background for overall policy development. These studies, along with others produced by independent bodies, have highlighted the range of possible future pathways, with a particular emphasis on energy efficiency, biofuels, and electrification as promising routes for decarbonisation of the heating and transport sectors.

In parallel with these scenario studies, both DECC and Ofgem have undertaken reviews of the market arrangements and DECC is currently preparing to consult on proposals for market reform. In addition, Ofgem has conducted a fundamental review of the network regulatory framework (RPI-X@20) and has

[9] As noted previously, we have assumed that a 90% cut in emissions in the modelled sectors would be required to meet the target of 80%. This entails a reduction in CO_2 from 530 Mt of CO_2 to 53 Mt or lower.

proposed that the regime should be revised to increase focus on incentives for innovation and delivery of key outputs. It is envisaged that this revised regulatory framework will be adopted in time for the next price controls for gas distribution and gas and electricity transmission which are due to start in 2013.

Although extensive policy work has been undertaken in the UK, relatively little attention has been paid to the potential long-term future for gas and the role it can play in meeting decarbonisation targets. In addition, there has not yet been a full analysis of the cost implications of different decarbonisation pathways. This study therefore seeks to broaden the range of investment scenarios to 2050 which are being considered by policy makers and seek to quantify their cost implications, with a view to ensuring that short-term policy choices are better understood and more robust policy decisions can be made. Our modelling assumptions draw heavily on the DECC 2050 Pathways analysis, and we consider that our conclusions are fully compatible with both DECC's work and current EU policy objectives.

1.3 Conventions

All modelled results are shown in real 2010 terms.

Net Present Values (NPVs) are calculated using a real social discount rate of 3.5%, as recommended in the HM Treasury Green Book.

1.4 Structure of report

Section 2 of this report explains the study methodology and key assumptions, and discusses the scenario development process and scenario narratives. Section 3 presents the main results of our modelling in relation to primary energy demand, future gas utilisation, electricity supply / demand, environmental targets, and system costs. Section 4 summarises our conclusions and key messages.

More detailed information on the model design and methodology is included in Appendix A, while Appendix B summarises the key data sources for the assumptions used in our model. Supplementary modelling results are presented in Appendix C.

2 Methodology and assumptions

2.1 Overview of modelling approach

In order to answer the questions posed by the ENA GFG, we have developed a fully costed supply / demand balance model of the energy sector. A schematic of the key elements of the model is shown in Figure 2.

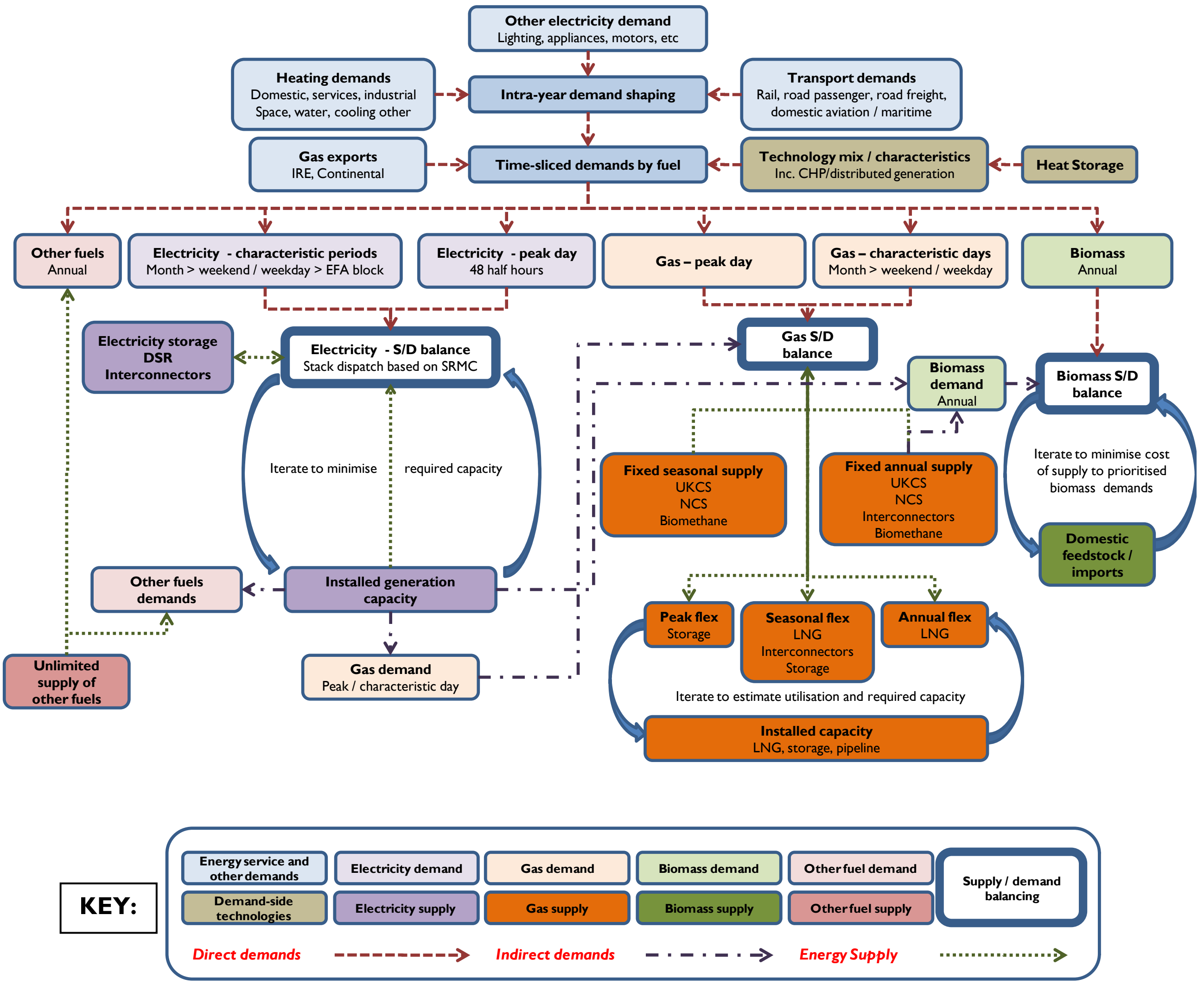
Conceptually, the model is divided into four main segments as follows.

- **Demand-side modules** – incorporating domestic heating, services heating, industrial heating, transport heating and other electricity demand. The starting point for each module is the annual end-use energy service demand by year[10], which is then shaped based on characteristic periods or time slices. The profiled service demands are then supplied by a scenario specific mix of technologies (eg heat pumps, gas boilers etc for domestic heating) with various characteristics such as efficiency, seasonal availability or performance factors and different input energy requirements. From the combination of profiled demand and technologies a series of energy / fuel demands are calculated for each time slice, which must be met within the model.
- **Supply Balancing modules** – including gas, electricity, biomass and other fuels. These provide the required energy to balance the demands in each time slice across the years 2010 to 2050.
    - for *gas*, the supply balancing model contains data on the availability and cost of supply sources at both an annual and monthly level, with LNG acting as the swing supply at an annual level and storage and interconnectors providing swing on a monthly basis.
    - for *electricity*, the module contains a simple representation of an electricity stack which is dispatched based on short-run marginal cost (SRMC) to ensure that demand equals supply in each period, and
    - for *biomass*, the module contains data on the availability and cost tranches of a range of indigenous biomass feedstocks and imports, and calculates the lowest cost way to meet biomass demand across sectors.
- **Cost modules** (not shown in the diagram) – for each section of the model, cost sub-modules are overlaid to calculate the total system costs in each year, including capital costs, fixed and variable operating costs, and fuel prices. The costs of gas and electricity network investment and operation[11] are calculated and allocated to end-use sectors according to their share of energy demand. Primary commodity prices are set as user inputs.
- **Environmental Reporting and other modules** – these include calculations to track CO_2 emissions and across sectors and the overall share of renewables within the energy supply mix.

[10] For example, space heating, water heating, and cooling in the domestic sector or vehicle kilometres travelled by mode (rail, car, HGVs etc) in transport.

[11] With separate modules for gas transmission, gas distribution, electricity transmission and electricity distribution.

Figure 2 Overview of supply / demand model (excluding cost modules)



Note: Direct demands are calculated from fixed user input assumptions. Indirect fuel demands for electricity generation are calculated by the model endogenously based on the operation of the electricity stack.

2.2 Scenario development process

In projecting patterns of gas consumption out to 2050 there is clearly a huge amount of uncertainty and a wide range of potential drivers of future gas demand. The use of scenarios is a widely-accepted technique for assessing long-term uncertainty, particularly where there is a high degree of interdependency between drivers and a desire to represent outcomes in a clear and internally consistent manner.

To develop the scenarios used for this study, we worked closely with the ENA GFG using a four-stage approach as follows:

1. **compile the drivers** of future gas utilisation and assess the materiality of each
2. **identify two key drivers** that can frame four different scenarios in the form of a 2x2 matrix
3. **develop a narrative and assumptions** for each of the four scenarios, and

4. **test and iterate** the scenarios as required.

The two key drivers we identified in the course of the scenario development process were as follows:

- **Commercialisation of Carbon Capture and Storage (CCS) Technologies**. Successful deployment of CCS is likely to be the key driver of future demand for transmission-delivered gas for baseload generation, since it would allow gas to maintain or even increase its share of the generation mix while still meeting carbon reduction targets.
- **Commercialisation of Electricity and Heat Storage Technologies**. Energy storage technologies – ie, diurnal electricity storage together with seasonal heat storage – could play a key role in facilitating electrification of the heating and transport sectors at reasonable cost, by reducing requirements for diurnal and seasonal peaking capacity. Conversely, slow or unsuccessful deployment of these technologies is likely to be a key driver of ongoing demand for distribution-delivered gas for seasonal / peak heating, as well as transmission-delivered gas for diurnal electricity balancing.

These drivers were selected on the basis that they would generate a diverse but plausible set of scenario outcomes for future gas utilisation, which captured the dimensions of particular interest to the ENA GFG members – namely, the demand for network-delivered gas on the transmission and distribution systems respectively.

Figure 3 shows how the two key scenario drivers map onto the scenarios developed for the study. It can be seen that a rapid roll-out of CCS technologies is associated with a high future utilisation of transmission-delivered gas, since CCS can be used to manage the emissions from gas-fired generation plant. Conversely, a rapid roll-out of electricity and heat storage technologies is associated with a lower level of distribution-delivered gas, as well as unabated transmission-delivered gas. This is because storage technologies allow for more rapid electrification of the heat sector (by reducing the resulting seasonal requirement for electricity), and can be used in place of unabated gas for electricity balancing.

The key drivers give a 2x2 matrix of four scenarios in total, with the highest overall gas utilisation in the Green Gas scenario and the lowest overall utilisation in the Electrical Revolution scenario. Storage Solution and Gas Versatility represent intermediate outcomes, with transmission-delivered gas higher in the former scenario and distribution-delivered gas higher in the latter.

Figure 3 Scenario summary table – 2050

		DIMENSION 2: Commercialisation of Electricity and Heat Storage Technologies	
		Low / Slow	**High / Rapid**
DIMENSION 1: Commercialisation of Carbon Capture and Storage Technologies	**High / Rapid**	**GREEN GAS** ***Transmission-delivered gas 2050: HIGH*** - gas + CCS - some unabated gas for balancing ***Distribution-delivered gas 2050: HIGH*** - 'dual fuel' world for domestic heating - biomethane injection - district heating + CCS - some use of CNG in transport	**STORAGE SOLUTION** ***Transmission-delivered gas 2050: HIGH*** - gas + CCS - small amount of unabated gas - additional balancing via electricity storage and demand-side response (DSR) ***Distribution-delivered gas 2050: LOW*** - heating and transport largely electrified - heat storage used to balance seasonal heat
	Low / Slow	**GAS VERSATILITY** ***Transmission-delivered gas 2050: LOW*** - renewables / nuclear dominate - some unabated gas for balancing ***Distribution-delivered gas 2050: MED*** - biomethane at max potential - some use of CNG in transport	**ELECTRICAL REVOLUTION** ***Transmission-delivered gas 2050: NONE*** - renewables / nuclear dominate - balancing via electricity storage, flexible nuclear, interconnection and DSR ***Distribution-delivered gas 2050: NONE*** - heating and transport largely electrified - heat storage used to balance seasonal heat

2.3 Scenario narratives

Building off the scenario driver framework set out above, we developed a set of narratives for the four scenarios in the study. These narratives describe, for each of the four decades between 2010 and 2050, the key expected developments in terms of policy, technology and commodity prices which underpin the assumptions and outcomes for the scenario in question. Table 2 summarises the key features of each scenario in 2050 relative to today's levels with respect to energy demands, the generation mix, heating and transport respectively, while the full written narratives are set out below.

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Table 2 Scenario narratives summary table – 2050 vs current levels

		Green Gas	Storage Solution	Gas Versatility	Electrical Revolution
ENERGY DEMANDS	Gas – transmission delivered	↔	↔	↓↓	↓↓↓
	Gas – distribution delivered	↔	↓↓	↓	↓↓↓
	Electricity	↑	↑↑	↑↑	↑↑↑
	Biofuel	↑↑↑	↑↑	↑↑↑	↑
GENERATION MIX	Gas + CCS	↑↑↑	↑↑↑	↔	↔
	Coal + CCS	↑	↑↑	↑	↑
	Unabated Gas	↓↓	↓↓	↓↓	↓↓↓
	Nuclear	↓	↓	↑	↑↑↑
	Renewables	↑	↑	↑↑↑	↑↑↑
	Imports	↔	↑	↑↑	↑↑↑
	CHP	↑↑	↑	↔	↔
HEATING	Baseload heating – summary	'Dual fuel' world High use of heat pumps for baseload High biomethane High gas district heating Medium solar thermal	Very high heat pumps High solar thermal Medium district heating Biomass for industrial use	Very high biomethane (max potential) Medium heat pumps Low district heating High solar thermal	Very high heat pumps Very high solar thermal Biomass for industrial use
	Peak heating – summary	Conventional gas boilers with biogas injection District heating	Diurnal heat via electricity load and electricity storage Seasonal heat via heat storage plus excess capacity on solar thermal and heat pumps	Conventional gas boilers with biogas injection	Diurnal heat via electricity load and electricity storage Seasonal heat via heat storage plus excess capacity on solar thermal and heat pumps
TRANSPORT	Petrol / diesel	↓↓	↓↓↓	↓↓	↓↓↓
	Biofuel	↑↑	↑↑↑	↑↑	↑
	CNG	↑↑	↔	↑↑	↔
	Electric / PHEV	↑	↑↑	↑	↑↑↑
	Hydrogen	↔	↔	↔	↑↑

2.3.1 Green Gas

Summary

The Green Gas scenario describes a future that involves a significant ongoing role for gas, both at the transmission and distribution level. The costs of gas remain relatively low in this scenario and efficient CCS technology ensures that gas remains a key source of power generation. In addition, the lack of development in electricity storage technologies ensures that gas remains a key provider of balancing services in the power market. In heating, this scenario can be described as a 'dual fuel' world, with baseload heating provided via electrification and gas district heating, and domestic peak heating continuing to be delivered via distribution-delivered gas with a high level of biomethane injection directly into the local grid.

2010-2020

Traditional views of rapidly escalating fossil fuel prices begin to change as vast new reserves of unconventional gas are discovered and the technology to extract these sources competitively is rapidly developed. Energy policy remains focused on decarbonising power through renewables, nuclear and the development of CCS, but relatively low fossil fuel prices coupled with steadily rising costs of renewable subsidies leads to an increasing drive towards CCS. Demonstration of CCS technology is taken forward and the technology is quickly proven, well before the end of the decade, and the relatively cheap costs of gas ensures that CCS with gas plant is increasingly favoured over CCS with coal plant.

In heating, incentives such as Green Deal / Pay-as-you-Save (PAYS) designed to overcome capital costs for residential consumers are well-received and lead to increasing uptake of solar thermal augmentation systems being installed, alongside some heat pumps retrofitted to existing central heating systems – resulting in an effective dual heating system. New housing projects adopt district heat if this is geographically economic or electrification for baseload heat elsewhere. Similarly, attention is focused towards developing the potential to deploy CHP district heating solutions and developing CNG vehicles for large commercial vehicle stocks. Anaerobic digestion and biomethane injection into gas networks begins to develop and increasingly becomes the favoured approach for waste management along with other commercial operations. Renewables targets for 2020 are met, but the EU increasingly turns its focus towards emission reductions being met through other means. Accordingly, explicit renewable targets are not extended beyond 2020 levels. The EU continues to focus infrastructure policy on ensuring secure supplies of gas from a range of sources.

2020-2030

Relatively cheap and abundant supplies of gas continue to be delivered and gas is now accepted as having a central and ongoing role in a 'balanced' energy policy. Economic conditions improve and Government begins to introduce an aggressive 'standards-led' approach to reducing carbon emissions. This includes an Emissions Performance Standard (EPS) that progressively phases out all but low load-factor back-up generation plant from operating without CCS technology and, in transport, a virtual phase-out of petrol and diesel passenger vehicles over a 20 year period. In addition, a programme is initiated to increase the proportion of gas supply which is produced from renewable sources. Commercially operational large scale gasification plant commences during the period increasing the supply of biomethane to distribution networks. CCS technology continues to improve, both in terms of overall cost and capture efficiency and remains competitive with nuclear and all but the cheapest renewable technologies, although renewable volumes still continue to increase as support mechanisms are retained.

Several large CHP district heating projects utilising waste heat from generation plant are undertaken, alongside dedicated gas-fired CHP district heating, informing the long term potential to deliver heating to new housing stock through this route. DSR remains relatively low and intermittency of renewable energy is managed through both unabated and CCS gas plant. Electrification of vehicles progresses relatively slowly, but the Government sets policy to develop street level charging points throughout the UK towards the end of the decade.

2030-2040

The impact of the new and tightening standards dominates outcomes during this decade. CCS technology becomes the industry standard and only back-up capacity continues to operate unabated by the end of the decade. Motor manufacturers employ a range of strategies to comply with new road transport emissions standards and a diverse mix of CNG (for larger vehicles), electric vehicles, and biofuel powered combustion engines emerge. Off-peak electricity is directed toward plug-in hybrid electric vehicles (PHEVs) and the heating / cooling of larger commercial property. The heating sector sees the deployment of a number of major district heating schemes and electrification for all new housing and commercial buildings. However a significant residual gas heating load remains, for both peak heating and process heat in industry. Emissions from these sources are managed through increased biomethane deployment as well as the application of CCS technology to CHP / district heating schemes wherever possible.

2040-2050

The standards-led approach continues to be developed and the scope to generate output from unabated fossil fuel plant continues to reduce. Similarly in transport, conventional petrol / diesel passenger cars are largely eliminated from mainstream use, but there is however some ongoing use of CNG for HGVs as well as petroleum for domestic shipping and aviation. The majority of housing utilises electricity or district heating for baseload heat combined with distribution delivered gas for peak heating.

2.3.2 Storage Solution

Summary

The Storage Solution scenario describes a future with significant ongoing usage of gas, primarily delivered at the transmission level for generation rather than via distribution networks for heating. Gas prices remain relatively cheap and efficient CCS technology rapidly emerges allowing gas to remain the key source of low carbon power generation. In addition, the development of power and heat storage technologies that help to manage seasonal and diurnal swings in heating load allows the heat and transport sectors to be cost effectively decarbonised through electrification.

2010-2020

Traditional views of escalating fossil fuel prices begin to change as vast new reserves of unconventional gas are discovered and the technology to extract these sources competitively is rapidly developed. Coupled with increasing economic pressures on Governments, energy policy moves away from decarbonising power through renewables and nuclear, which are proving high cost and difficult to finance respectively. However, international determination remains strong to address the climate challenge and aggressive long-term carbon reduction targets are agreed. A decarbonised power system is seen to be the least cost route to decarbonising the overall economy and, given the perceived long-term role for gas, significant effort is put into the demonstration of CCS technology. The EU remains focused on delivering carbon reduction and tough new targets are agreed and extended to the heating and transport sectors, leading to an increase in carbon price. Renewables targets for 2020 are just met, but the EU increasingly turns its focus towards emission reductions through a broader range of low-carbon technologies. Accordingly, explicit renewable targets are not extended beyond 2020 levels.

Electrification is now increasingly seen as the solution for the heating sector and a major nationwide programme is initiated to install heat pump technology. Trials are also established to demonstrate the feasibility of large scale electrification of transport. Street level charge points increase in urban centres enabling early adopters to charge their vehicles away from the home. Incentives such as Green Deal / PAYS are well-received and lead to increasing uptake of heat pumps, solar thermal and some photo-voltaic systems being installed.

2020-2030

As power demand begins to grow through the deployment of electric vehicles and heat pumps, the challenges of maintaining energy system balance become apparent. Significant effort is put into developing storage technologies for both power and heat and these R&D efforts prove successful with deployment commencing before the end of the decade. In the meantime, commercial deployment of CCS is well underway and by 2030 the use of unabated fossil plant is rapidly reducing. However, gas prices remain relatively low and renewable technologies continue to prove expensive and therefore gas and the continually improving CCS technology remain the generally preferred generation investment of choice. Most existing nuclear capability is maintained or replaced, but there are no plans to significantly increase the number of nuclear generation plants in the future. Renewable generation continues to increase slowly however as financial incentives are maintained.

Government and EU policies introduce increasing carbon prices for any unabated emissions including residential gas consumption sales. In the heating sector, the use of natural gas for heating is beginning to dramatically reduce through a consumer-led transition to electric heating, thus calling into question the need to maintain existing gas distribution networks. However, efforts to move towards full electrification of heat are delayed due to the need to upgrade low voltage electric distribution systems to existing consumers and the country embarks on a regional electrification roll out programme. Incentives are widely employed to enable remaining consumers to transition from existing heat energy delivery systems to electrified heating appliances, and subsidies are given to offset carbon prices for residents forced to wait. Towards the end of the decade, legislation is introduced preventing new housing and commercial building projects from connecting to gas distribution networks. Meanwhile, motor manufactures adopt strategies for complying with emissions standards based around electricity and biofuels.

2030-2040

Sophisticated electricity and heat storage technology is now being widely deployed and the robustness of a power system based around fossil fuels with CCS has been convincingly demonstrated. Policy therefore continues to drive forward the electrification agenda, both in heat and increasingly in transport as well. Tightening emissions standards ensure that electricity and biofuel are the only long term transport options. Around the middle of the decade, work begins on decommissioning parts of the low pressure gas network. Higher pressure networks are utilised for larger commercial and industrial loads connected to CCS systems. Heating needs are progressively delivered through reactive heating systems and heat pumps, solar thermal and some district heating schemes, together with CHP + CCS for industrial heat. DSR is widely utilised to minimise within-day peaks with network / tariff controlled electric vehicle charging and heating / cooling systems. Peak heating is delivered via additional electricity generation capacity and some district heating.

2040-2050

This decade sees the continuation of the trend to eliminate the use of gas for heating and fossil fuels for transport. The majority of the gas distribution low pressure network is decommissioned and only CCS and large-scale industry connected gas loads remain. Similarly, the programme to replace all UK electricity distribution networks has been completed. The electricity load has increased significantly and a large proportion of this demand is now met using gas with CCS technology. Heating in the domestic and service sectors, and to a lesser extent industry, has transformed through through electrification, and seasonal heat storage and recovery systems are also in widespread use. Power system balancing services are provided primarily through electricity storage and DSR, with some unabated gas peaking plant as backup.

2.3.3 Gas Versatility

Summary

The Gas Versatility scenario describes a future in which gas remains a significant component of the energy system but the requirement for large quantities of gas for baseload generation largely disappears, to be replaced by renewables and nuclear. The key driver for this scenario is that gas does not remain a cost-competitive provider of baseload power, but the lack of development in electricity and heat storage technologies ensures that it remains a provider of both balancing services in the power market and domestic heating (both baseload and peak). Gas also makes a contribution to the transport sector via CNG. Emissions from gas-fired heating are managed predominantly through maximising the potential of biomethane out to 2050.

2010-2020

Energy policy remains focused on delivering the EU's 2020 targets and those relating to renewable energy in particular. However, success is limited outside the power sector where the cost of offshore wind in particular begins to reduce significantly, aided by ongoing government subsidies via the Renewables Obligation (RO) and / or the introduction of a long term feed-in-tariff. The programme to deploy a new fleet of nuclear power plant also proceeds well but serious attempts to demonstrate CCS technology are given lower priority and deferred following problems with early demonstration projects. Ongoing challenges in agreeing aggressive and long term international carbon reduction targets reduces the political appetite to transform the heating sector where early efforts have proven to be extremely difficult. The transport sector, however, presents more fertile ground given developments in biofuel technology and, by the end of the decade, as programme of progressively tightening vehicle emissions standards is introduced.

Incentives such as Green Deal / PAYS lead to uptake of solar thermal augmentation, some heat pump / electrical conversion, photovoltaic and other micro generation systems being installed. New housing and commercial projects adopt a mixture of district heat, electric or conventional delivered gas boilers depending on regional availability.

2020-2030

Renewable and nuclear power generation deployment programmes are now well underway and the share of generation from these sources continues to increase throughout the decade. However, the extent of the deployment is restricted by the need to use gas-fired power plant for system balancing purposes. High costs ensure that efforts to demonstrate CCS are restricted to a limited number of coal plant and by the end of the decade a combination of increasing carbon prices and new plant standards are introduced to eliminate unabated coal by the end of the following decade other than for back-up purposes. Domestic (and to a lesser extent service sector) heat demand continues to be augmented by solar thermal systems and new properties are increasingly electrified, but gas remains the dominant fuel for space heating through the decade. By 2030, a substantial initiative to develop biomethane capacity is seen as a crucial long-term route to decarbonise the heat sector for existing gas consuming properties.

Progress in introducing alternatives to petrol / diesel vehicles is also steady but slower than anticipated with lack of advancement in battery technology proving a significant obstacle to the roll out of electric vehicles. Motor manufactures adopt a variety of strategies for complying with emissions standards including a significant number of vehicles powered by CNG and the development of PHEVs. Renewed political determination to tackle carbon emissions by the end of the decade leads to a 20-year plan to replace remaining petrol / diesel passenger vehicles, primarily through the use of advanced biofuels and electricity.

2030–2040

Ongoing decarbonisation of the power sector proves successful with deployment of nuclear and renewables continuing at pace and all remaining coal-fired plant are fitted with CCS technology. Complete decarbonisation is only prevented by the continuing need for flexible gas back-up plant and the lack of an economic option to abate carbon from plant operating in this mode. A number of new power interconnectors are developed with Europe in an effort to broaden the supply of system balancing services. In the heating sector, extensive development and deployment programmes are underway to maximise the potential to deploy biomethane and, throughout the decade, steady progress is made in increasing the share of the market supplied through this means. Commercially operational large scale gasification plant commences during the period increasing the supply of biomethane to distribution networks. Furthermore, with increasing nuclear and renewable power, gas-fired micro CHP starts to replace conventional boilers and provide a substantive demand-side response while utilising smart-grid technologies. Similarly in road transport, slow but steady progress is made in the penetration of biofuel powered vehicles coupled with increasing use of hybrid electric cars and some ongoing use of CNG.

2040–2050

International efforts to minimise carbon emissions continue to increase as a political priority and, domestically, the UK approach is focused on a strategy to minimise the need for unabated back-up gas-fired power generation through the development of interconnectors into the European network. A significant proportion of properties continue to rely predominantly on single source heating, ie condensing boilers, but emissions are managed through maximising the potential of biomethane, which accounts for over 50% of the annual delivered gas load. The gas transmission system is partly decommissioned and there is talk of it being fully discontinued in the near future as and when distribution networks become self-sufficient in biomethane. Conventional petrol / diesel is entirely replaced by electric and biofuels for road transport, with some continued use of CNG for HGVs as well as petroleum for domestic aviation and shipping.

2.3.4 Electrical Revolution

Summary

The Electrical Revolution scenario describes a future in which the use of gas is effectively eliminated over a 30 to 40 year period. Gas costs remain relatively high and CCS technology does not develop to the extent that it presents a competitive option compared with renewables and nuclear generation. In addition, developments in balancing services technologies ensure that gas is no longer essential for providing flexible generation, while heat demand can be met cost effectively through zero carbon electricity.

2010-2020

As the world emerges from recession, fossil fuel prices begin to increase rapidly as new unconventional sources of fossil fuels prove costly to extract. The international community quickly agree to legally binding and challenging long term carbon reduction targets and the EU extends the emissions trading scheme to the heating and transport sectors with the price of carbon increasing accordingly. The UK Government develops an aggressive long term decarbonisation strategy based around the early decarbonisation of the power sector and the electrification of the heat and transport sectors. Legislation prevents any new building consuming fossil energy and existing incentives are ramped up to promote energy conservation.

By the end of the decade, substantial deployment of renewables has occurred (exceeding the 2020 targets), the first new nuclear power plants are in operation, and CCS demonstration technology has been applied to some coal-fired plant. Initial deployment trials have been completed for a range of decarbonisation options in the heating sector and a long-term deployment plan is agreed for the large-scale electrification of the heat load. Similarly, in road vehicle transport, a national strategy is agreed for the deployment of electric vehicles including the construction of the necessary power infrastructure. By the end of the decade, projects deliver street level charging points to encourage urban electrification of transport and a programme of electric distribution network replacement has begun. The government embarks on a centralised programme of heat sector electrification which requires the coordination of new power capacity, distribution replacement and home / building appliance conversion. Conversion costs are met partly by subsidisation and the Green Deal / PAYS investment frameworks. Individual properties are required under the legislation to convert as and when the infrastructure is delivered.

2020-2030

The success deploying renewables and nuclear in the power sector, coupled with the progressive electrification of the heat and transport sectors, leads to significant effort being devoted to technology development in energy system balancing. Extensive trials are undertaken of heat and power storage and European regulators agree a major programme to integrate the European power network. In addition, smart power networks ensure that the demand side of the market is increasingly able to provide system balancing services. These developments enable the deployment of renewables and nuclear to continue and, by the end of the decade, significant progress has also be made in the deployment of electric vehicles and electric heating. A significant market is also emerging in solar thermal products.

2030-2040

International political commitment to tackle climate change remains strong and the energy system revolution continues at pace through the decade. By the end of the decade, effective decarbonisation is almost complete with only a few back-up gas fired plant remaining along with a residual number of conventional petrol / diesel passenger cars. In the heating sector, developments in biomethane technology allow some aspects of the gas infrastructure to be maintained primarily for industrial applications, but the bulk of heating requirements are being progressively transferred to electrification solutions. Electric vehicles now dominate the transport sector and a nationwide fast charging infrastructure is completed during the decade, although some motor manufacturer are developing alternatives such as hydrogen powered vehicles. Growth in power demand continues to be met by a combination of renewables and nuclear and the European power network is becoming increasingly interconnected. Towards the end of the decade the first imports of concentrated solar power from the Sahara begin to arrive. The UK continues to construct sizeable nuclear power generation in support of the electrification of transport and heating sectors, and nuclear waste management systems and reprocessing infrastructure are developed in support of the programme.

2040-2050

The energy system has now been completely revolutionised with close to zero use of unabated fossil fuels in the power, heating and transport sectors. The UK region is now heavily dependent on renewable and nuclear energy for baseload power, with smart-grid / DSR, electricity storage and interconnectors to maintain a balanced system. Both the gas transmission and gas distribution networks are fully decommissioned by the end of the decade along with all CCGT plant, but a few gasoil-fired Open-Cycle Gas Turbine (OCGT) generation stations remain on the system for emergency back-up to maintain security of supply. Full alignment of European regulation has been enshrined in national legislation and industry codes ensuring that the EU power network is effectively operated as a single super-grid. There are no petrol or diesel passenger cars left in regular use although some petroleum is still used for HGVs, domestic shipping and aviation. An extensive smart distribution network, including advanced power storage capability, enables the convenient fast charging of the large fleet of electric vehicles. Heating is predominantly provided through heat pumps and resistive heaters, supported by significant use of solar thermal. Fluctuating demand for heat is met through seasonal heat storage and recovery systems, operating at both household and district levels, coupled with flexibility on the electricity system to meet diurnal fluctuations alongside DSR to help reduce peak electricity requirements in winter. Collectively power demand has increased by a factor of more than two.

2.4 Assumptions

In order to assess impacts and outcomes under the different scenarios developed for the study, assumptions on a wide range of underlying variables and inputs were incorporated in the model, including:

- energy service demands
- technology penetration rates by sector and technology
- technology learning rates by sector and technology
- capital and operating costs by sector and technology, and
- commodity prices.

Wherever possible, we drew on the latest available information from public UK sources – including DECC's 2050 Pathways analysis[12], research commissioned by the CCC[13], Ofgem's Project Discovery[14], and the UKERC Energy 2050 study[15] – to provide us with a credible value or range of values for each input assumption.

For scenario variables (ie, those that varied across scenarios), we used the range suggested by available research and then selected values within that range in order to align with the scenario narratives described in Section 2.3[16]. We also calibrated our assumptions to ensure that all scenarios met or exceeded the EU 2020 renewable energy targets and the UK Government's 2050 carbon targets[17].

Given the number and complexity of assumptions involved in the modelling, we have not attempted to provide a full breakdown of all our modelling assumptions in this report. However, Table 3 below summarises our assumptions for key input parameters and how these compare to the DECC 2050 Pathways analysis. In addition, reference tables for the main sources used to derive the study assumptions are included in Appendix B of the report.

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[12] http://www.decc.gov.uk/en/content/cms/what_we_do/lc_uk/2050/2050.aspx

[13] Eg http://theccc.org.uk/reports/1st-progress-report/supporting-research-

[14] http://www.ofgem.gov.uk/MARKETS/WHLMKTS/DISCOVERY/Pages/ProjectDiscovery.aspx

[15] http://www.ukerc.ac.uk/support/tiki-index.php?page=Energy+2050+Overview

[16] As an example, in the Green Gas scenario the technology penetration and learning rates for renewable and nuclear generation were set towards the low end of the available range, while those for gas + CCS were set at a high level. The reverse set of assumptions (ie, high penetration and learning rates for renewable and nuclear, low for gas + CCS) applied in the Electrical Revolution scenario.

[17] A 90% reduction in carbon emissions in the modelled sectors was assumed to be required by 2050 in order to meet an 80% target overall. This is because emissions from certain sectors of the economy, such as agriculture and international aviation, were not covered by the model.

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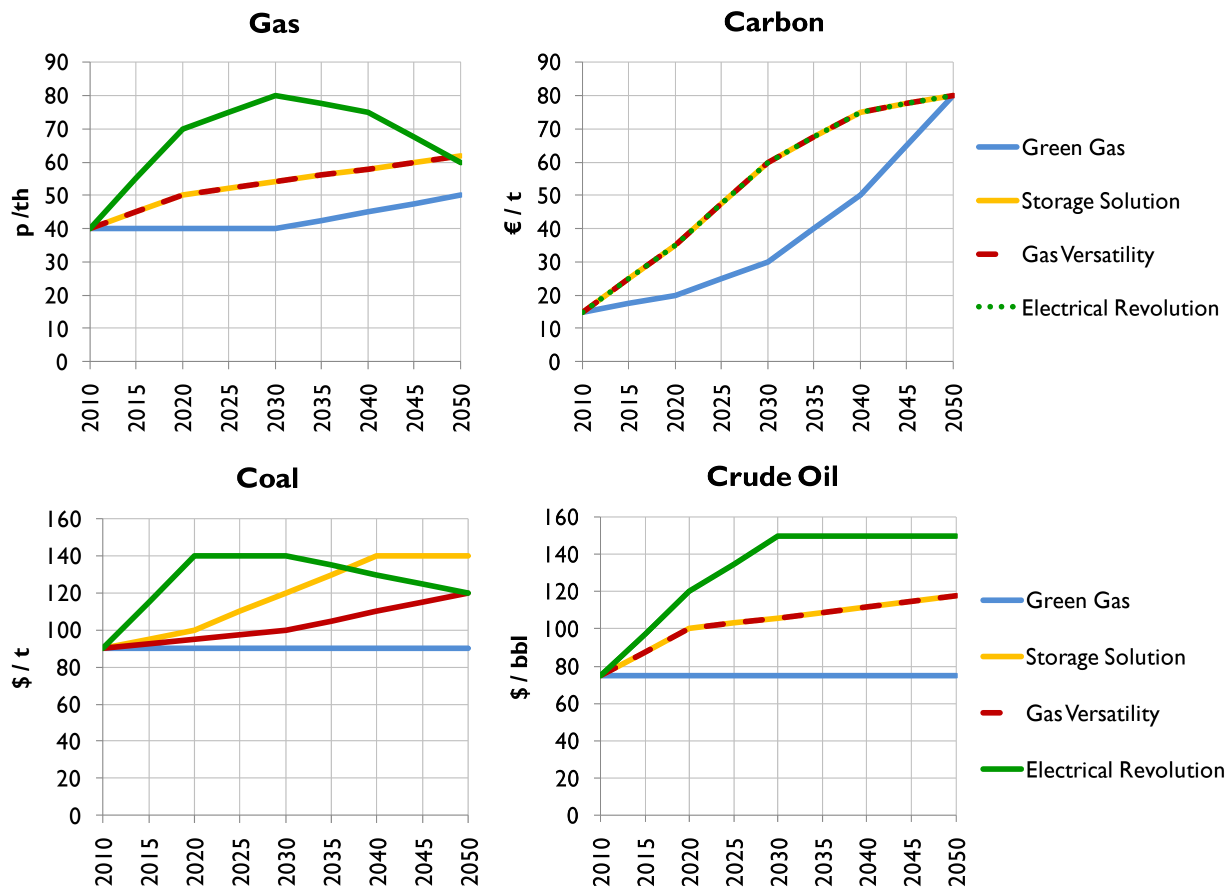
Table 3 Summary of key assumptions

Category	ENA Gas Futures Assumptions	Notes
End-use Service Demands for Heating / Cooling, Transport, Other	All based on DECC 2050 Pathways Level 2	DECC 2050 includes Levels 1 to 4 reflecting increasing levels of ambition. Level 2 is described as "ambitious but reasonable by most experts".
Population and housing growth	Taken from DECC 2050 Population = 76.8 mn by 2050 Households = 39.9 mn by 2050	DECC 2050 assumptions based on Office of National Statistics (ONS) population projections and Department of Communities and Local Government (DCLG) Household projections, extrapolated out to 2050.
Generation technology penetration trajectories	Similar to DECC's mid-range levels for renewables and nuclear In contrast to DECC we assume gas + CCS dominates over coal + CCS	We assume gas + CCS is favoured for emissions reduction purposes and because unabated gas is a cleaner-burning transitional fuel.
Heating technology trajectories	Similar to DECC's mid-range levels for electrification We assume a lower level of industrial heat electrification and solar PV	Our assumptions on industrial heating and solar PV are based on cost considerations and the difficulty of electrifying some industrial heat processes.
Transport technology trajectories	Similar to DECC's mid-range levels for transport electrification (EVs and PHEVs) We assume less use of hydrogen and more use of CNG	Our assumptions reflect the experimental nature of hydrogen technology and the difficulty of powering HGVs with batteries.
Biofuel resource	Similar to DECC assumptions We assume a slightly higher level of indigenous biomass resource (420 TWh vs ~400 TWh) and a higher level of imports	Indigenous resource potential was held constant across scenarios, with end-uses for the resource varying between scenarios. Additional requirements over and above domestic potential were assumed to be met via imports, which vary by scenario.
Commodity prices	Scenario views – see Figure 4	Commodity price assumptions are designed to be consistent with the scenario narratives. Under the commodity price sensitivities the same fuel and carbon prices are applied to all four scenarios.

Figure 4 Baseline commodity price trajectories[18]



2.4.1 Sensitivities

In addition to the core modelling analysis based on the scenario variables and constant assumptions, we undertook sensitivity analysis for two key parameters in the model – **commodity prices** (high, medium and low) and **technology learning rates** for key technologies (high, medium and low). The results of this analysis are included in Section 3. Commodity prices and technology learning rates vary across scenarios in the baseline, but by equating these in the sensitivities direct cost comparisons are made easier.

[18] Note that where overlapping lines are shown in the charts this indicates that commodity prices follow the same trajectory in two or more scenarios.

3 Results

3.1 Overview

This section of the report presents the main results from the scenario modelling, structured under the following headings:

- **primary energy demand** for all scenarios in 2050 vs today
- **future gas utilisation** – including annual and peak day gas demand by scenario, gas flows on the transmission vs distribution networks, and annual / monthly gas supply
- **electricity supply / demand** – including annual demand by scenario, annual supply by generation source, installed capacity, peak day profiles and supply duration curves
- **heating and transport** – including annual and monthly heat output by fuel type and technology, peak heat demand, and annual transport output by fuel type
- **performance against environmental targets** – including the EU 2020 renewable energy targets and the 2050 carbon targets, and
- **system costs** – including capital, operating, fuel and network costs allocated to the main end-use sectors (heating, transport, and other electricity).

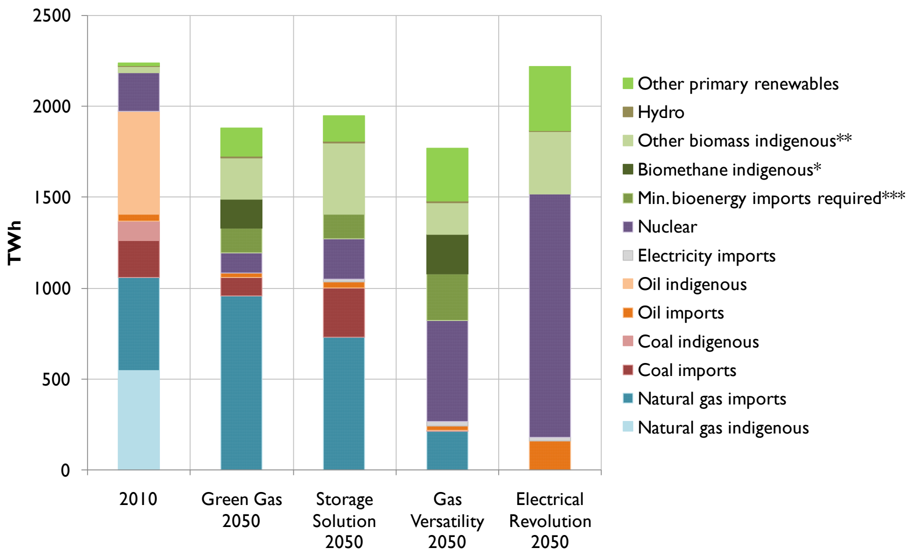
Results from the sensitivity runs for the commodity price and technology learning sensitivities are discussed under System Costs, while an additional sensitivity on the potential impact of low heat pump performance is presented at the conclusion of the section.

3.2 Primary energy

Figure 5 shows total primary energy demands by source for the four scenarios in 2050 and how this compares to the current situation in 2010. Several points are worth noting from this chart.

- In all scenarios, primary energy demand in 2050 is below 2010 levels, reflecting the impact of improvements in technology and energy efficiency, which outweigh the effects of rising population and GDP.
- However, primary energy demand in Electrical Revolution is the highest of the four scenarios in 2050, and is very close to 2010 levels. This reflects the very high level of electricity output, much of it met by nuclear. Gas Versatility has the lowest primary energy demand, followed by Green Gas and then Storage Solution.
- The differences in the primary energy mix, both over time and across scenarios, are also clearly visible in the chart. For example, the use of oil drops sharply in all scenarios, while nuclear rises significantly in the Electrical Revolution and Storage Solution scenarios. Biofuels are a key part of the energy mix in 2050, with much of the indigenous resource devoted to biomethane production in the Gas Versatility and Green Gas scenarios. Use of natural gas falls in all scenarios relative to today, but in the Green Gas scenario the share of natural gas plus biomethane in the energy mix in 2050 is above the share of natural gas in 2010.

Figure 5 Primary energy demand by scenario



* Assumes indigenous resource prioritised for biomethane
** Remaining indigenous resource goes to other biomass demands
*** Minimum level of imported bioenergy required to meet all biomass demands
2010 represents modelled results not actuals

3.3 Future gas utilisation

3.3.1 Annual gas demand

Figure 6 shows the modelled annual gas demand by scenario (including biomethane) at five-yearly intervals out to 2050. It can be seen that our four scenarios capture a broad range of trajectories of future gas demand, from levels similar to today in the Green Gas scenario down to zero by 2050 in the Electrical Revolution scenario. The other scenarios fall in between these two extremes, with annual gas demand of 719 TWh in the Storage Solution scenario and 511 TWh in the Gas Versatility scenario by 2050. The higher levels of future gas demand in the Storage Solution scenario (relative to Gas Versatility) reflect the greater potential that exists for managing carbon emissions via CCS technology in the generation sector, by comparison with the heating sector where there are limits to the potential deployment of biomethane and district heating.

Charts showing the sectoral breakdown of annual gas demand across the heating, transport, and generation sectors (plus Irish and continental exports) can be found in Appendix C. These follow the pattern that would be expected given the scenario narratives, with relatively high ongoing gas demand for heating in the Green Gas and Gas Versatility scenarios, and high ongoing gas demand for generation in the Green Gas and Storage Solution scenarios. Gas demand for transport (in the form of CNG) emerges from 2020 onwards in the Green Gas and Gas Versatility scenarios, but is only a small proportion of the total.

Figure 6 Annual gas demand by scenario

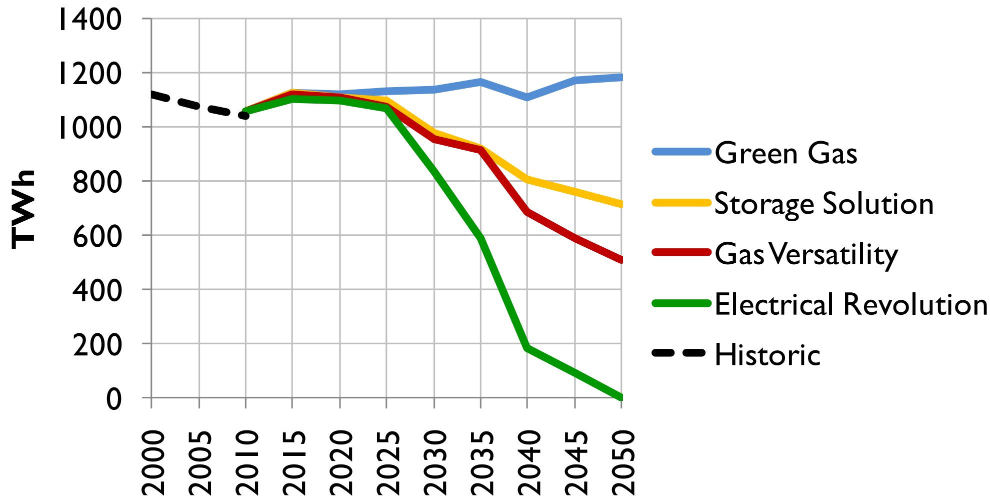


Figure 7 and Figure 8 show how the modelled annual gas flows break out between the gas transmission network (National Transmission System or NTS) and the gas distribution networks (GDNs). As expected given our scenario assumptions, flows on both parts of the network are highest in the Green Gas scenario. In the Storage Solution scenario flows are higher on the NTS than the GDNs, while the reverse pattern is observable in the Gas Versatility scenario. In the Electrical Revolution scenario, flows fall to zero on both parts of the network.

It should be noted that because much of the gas flowing on the GDNs must first flow through the NTS, the flows shown in Figure 7 and Figure 8 sum to a greater total than the annual demand shown in Figure 6. For modelling purposes we have assumed that biomethane is injected directly into the GDNs (and therefore does not flow through the NTS), while all other sources of gas supply are injected initially into the NTS.

Figure 7 Annual gas flows – NTS

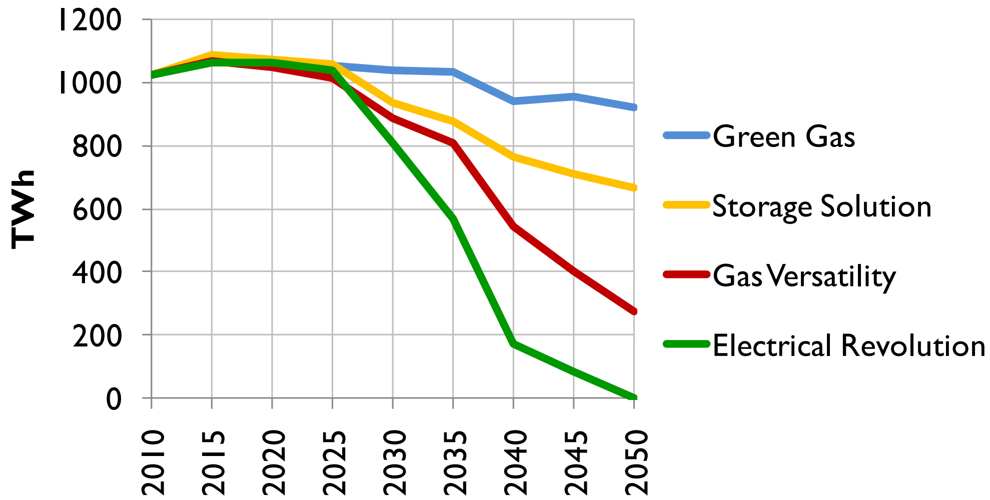
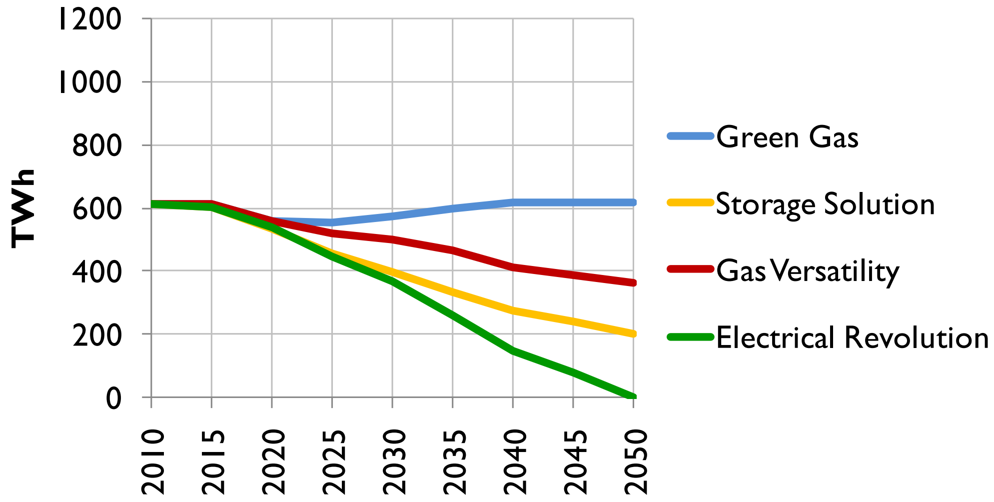


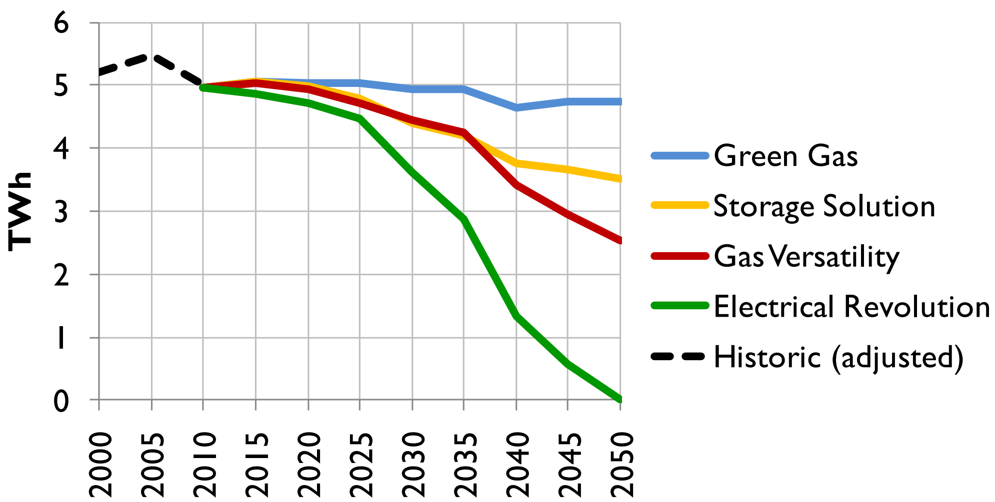
Figure 8 Annual gas flows – GDNs



3.3.2 Peak day gas demand

Peak day gas flows (based on a 1-in-20 year peak day[19]) show a broadly similar pattern to annual flows, as can be seen in Figure 9, Figure 10 and Figure 11 below. However, the spread in outcomes is somewhat narrower than that for annual gas demand, with peak demand in the Green Gas scenario falling by around 5% by 2050, rather than rising slightly. This reflects factors such as the roll-out of energy efficiency and insulation technologies, which reduce peak demand by a greater extent than annual demand particularly for heating, and the greater proportion of baseload gas used in the generation sector.

Figure 9 Peak day gas demand by scenario



[19] It should be noted that we have used a simplified methodology for calculating peak day demand which does not correspond exactly to the methodology used by National Grid. The historic values shown on the chart have been adjusted (downwards) to reflect this difference in methodology, and therefore do not exactly match the figures published in the National Grid Ten Year Statement.

Figure 10 Peak day gas flows – NTS

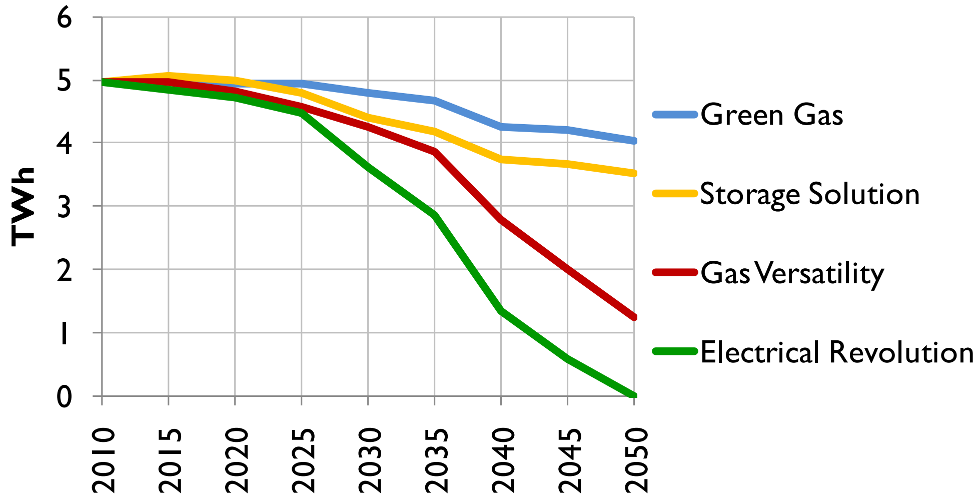
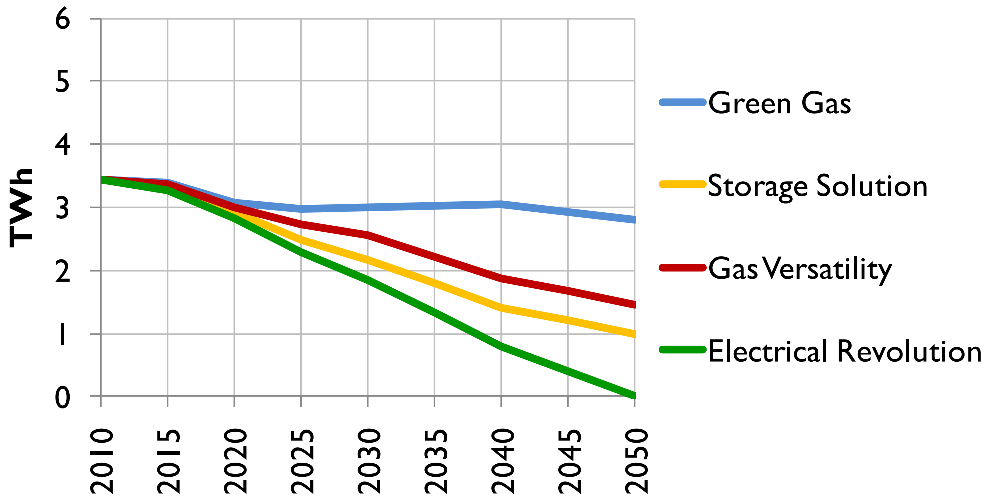


Figure 11 Peak day gas flows – GDNs

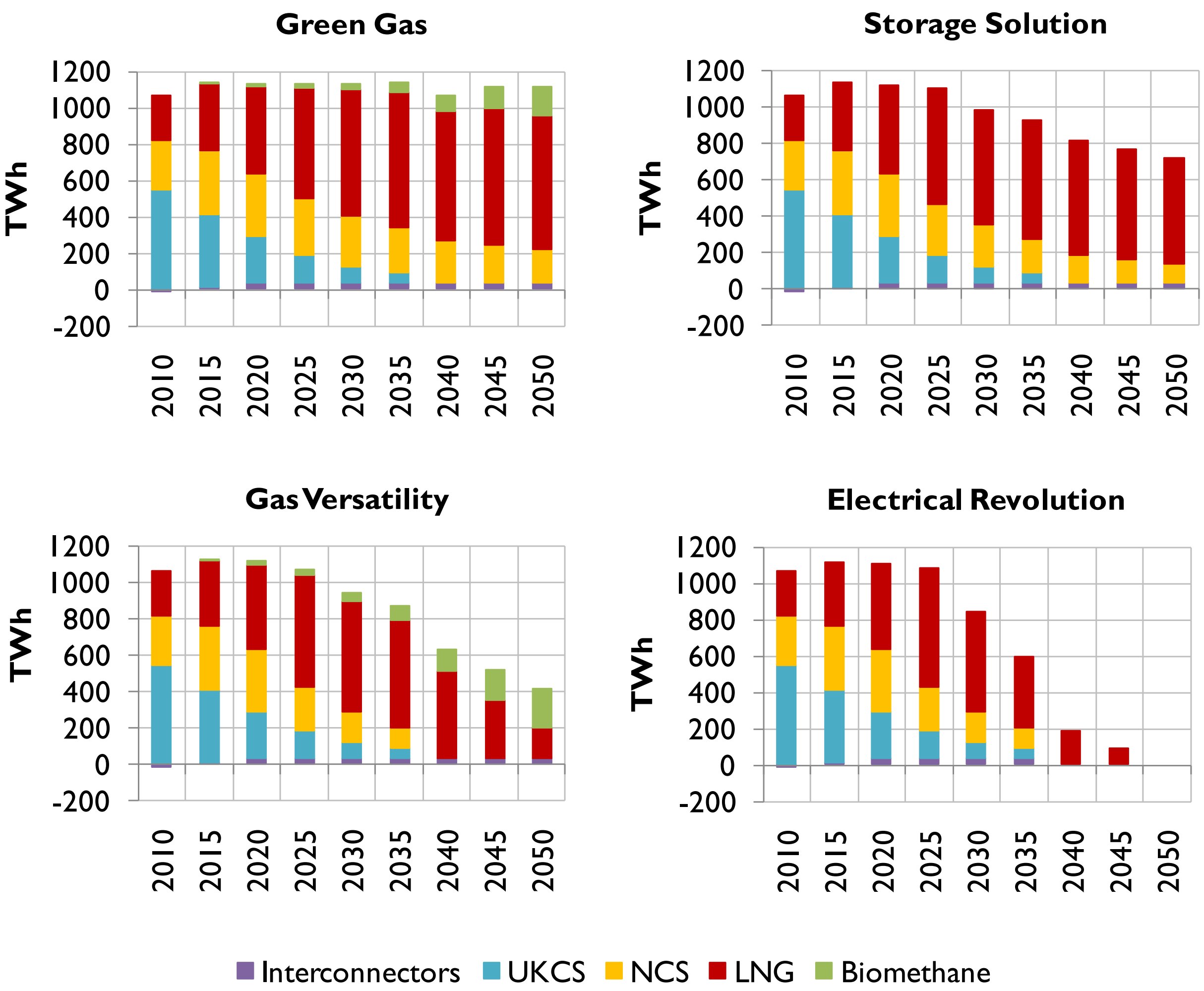


3.3.3 Gas supply

Figure 12 shows the annual gas supply by source for each scenario. Supplies from the UK Continental Shelf (UKCS) and to a lesser extent the Norwegian Continental Shelf (NCS) decline steadily over time, while Liquefied Natural Gas (LNG) makes up an increasing share. The growing importance of biomethane in the gas supply mix is evident in the Green Gas and Gas Versatility scenarios.

Charts showing the monthly gas supply by source for the spot years 2010, 2030, and 2050 can be found in Appendix C. These charts indicate a general flattening of the seasonal gas supply / demand profile over time, which reflects firstly the impact of insulation and more efficient building technologies, and secondly the fact that gas demand for industrial processes – which is largely flat across the year – falls more slowly than domestic gas demand, which is more seasonal. However, there remains a significant peak heat demand that varies between seasons.

Figure 12 Annual gas supply



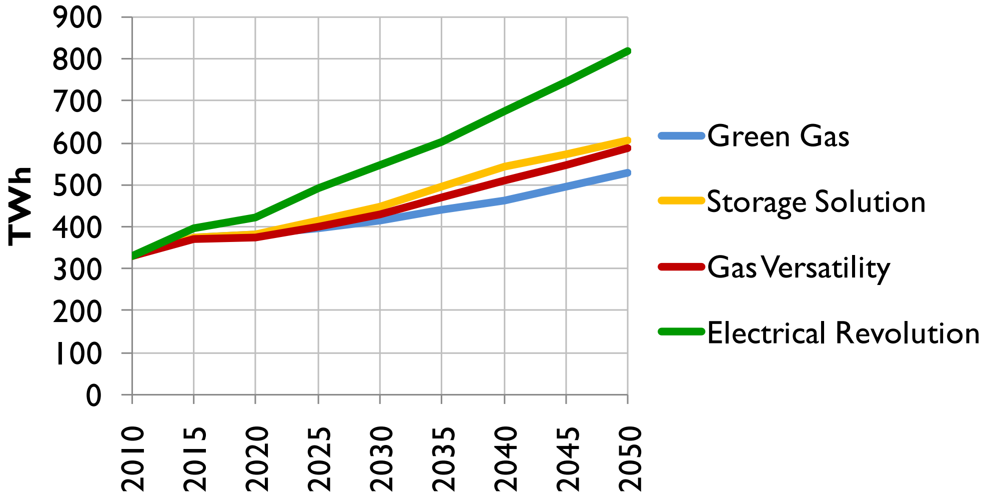
3.4 Electricity supply and demand

3.4.1 Annual electricity demand

Figure 13 shows the annual electricity demand by scenario, in TWh, at five-yearly intervals out to 2050. As expected the chart indicates that demand is highest in the Electrical Revolution scenario, rising to 819 TWh in 2050. Demand is lowest in the Green Gas scenario – 529 TWh by 2050 – but still shows a significant increase above current levels, reflecting growth in electricity demand due to population and economic growth, as well as some electrification of heating and transport.

Sectoral breakdowns of annual electricity demand – split into heating, transport, lighting / appliances and exports – can be found in Appendix C. These charts indicate that electrification of the heat sector is the primary driver of increased electricity demand over time. Electrification of transport accounts for a much smaller share of demand growth, reflecting the large efficiency gains achieved via transition to battery-powered vehicles as well as large efficiency gains in the conventional fleet. Electricity exports are also significant in the Electrical Revolution scenario[20].

Figure 13 Annual electricity demand



3.4.2 Peak day electricity demand profiles

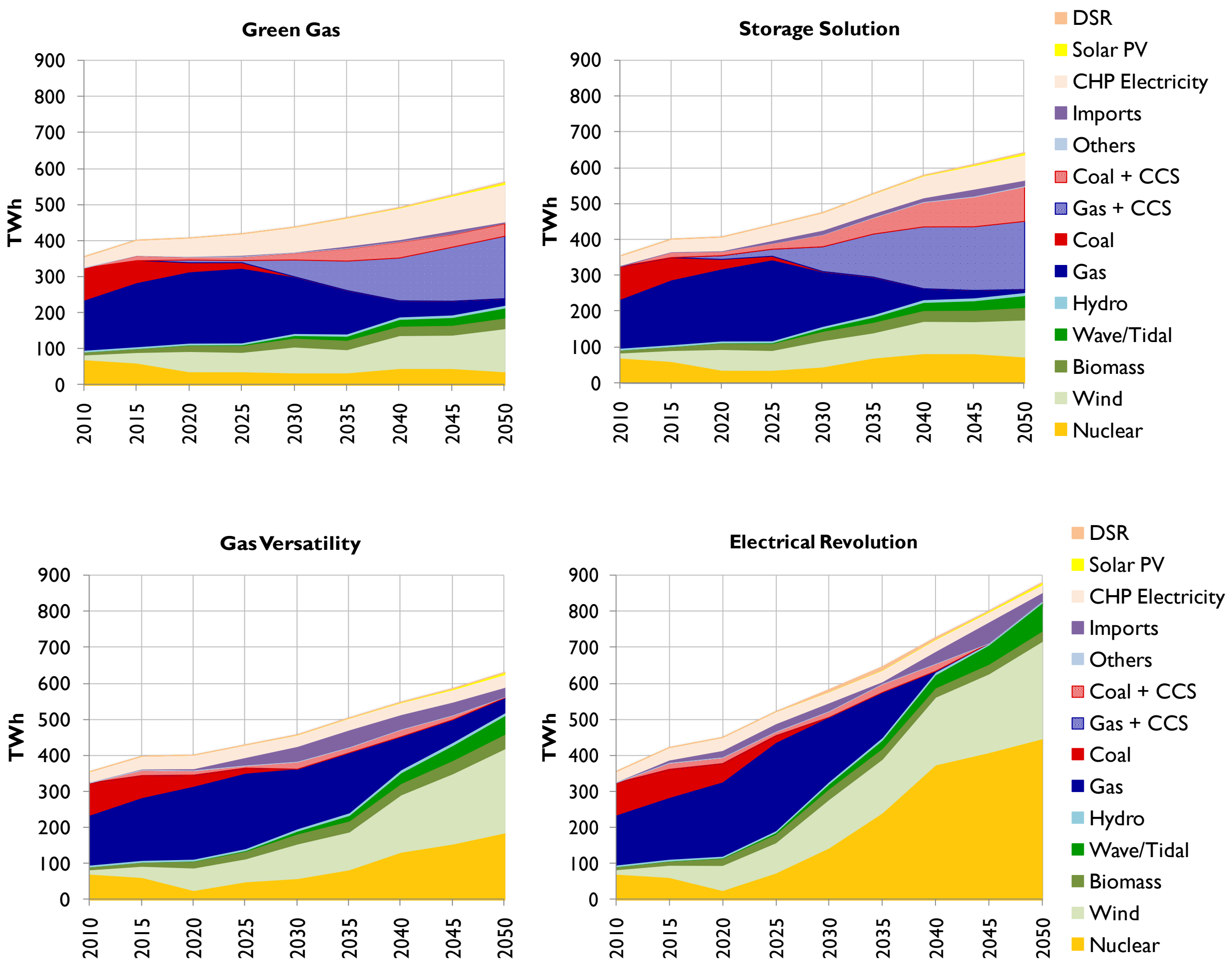
Appendix C also shows peak day electricity demand profiles for the spot years 2010, 2030, and 2050, both with and without electricity storage and DSR. Similar to annual demand, peak demand increases over time in all scenarios, but is greatest in the Electrical Revolution scenario with a peak of just under 170 GW in 2050. The addition of electricity storage and DSR flattens the load profile and reduces peak demand by around 10 GW in the Storage Solution and Electrical Revolution scenarios.

3.4.3 Annual electricity supply by technology

Annual electricity output by generation technology for each of the four scenarios is presented in Figure 14. Penetration levels of the different generation technologies across scenarios can be seen clearly in the charts. In line with the scenario drivers and narratives, CCS technology (both gas and coal-fired) plays a key role in the Green Gas and Storage Solution scenarios, while Gas Versatility and Electrical Revolution rely to a much greater extent on renewable generation and nuclear power. In addition, CHP generation (some of which is also assumed to be fitted with CCS) plays an important role in the Green Gas scenario, reflecting the rapid roll-out of district heating in this scenario.

[20] It should be noted that interconnection allows for large swings in imports and exports associated with varying levels of intermittent renewables – in other words, it is possible to have high levels of both imports and exports. Imports are not shown as a separate category within the sectoral breakdown as they are a source of supply rather than demand.

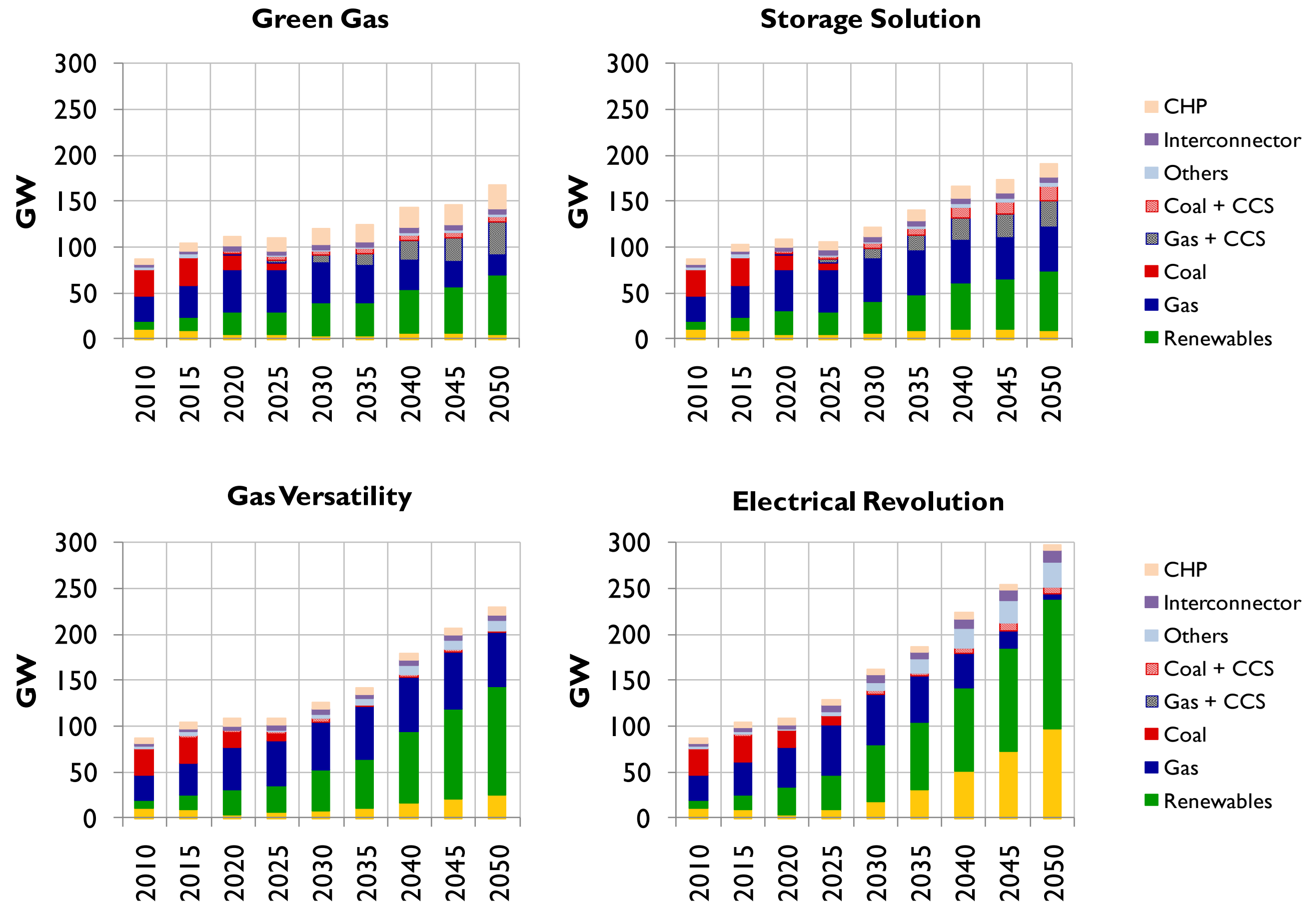
Figure 14 Annual electricity output



3.4.4 Installed generation capacity

A similar picture can be observed for installed generation capacity, shown in Figure 15 below. By 2050, installed capacity in the Electrical Revolution scenario – at 297 GW – is close to double the level in the Green Gas scenario of 168 GW. Storage Solution and Gas Versatility fall in between these two extremes, with installed capacity of 191 GW and 230 GW respectively.

Figure 15 Installed capacity

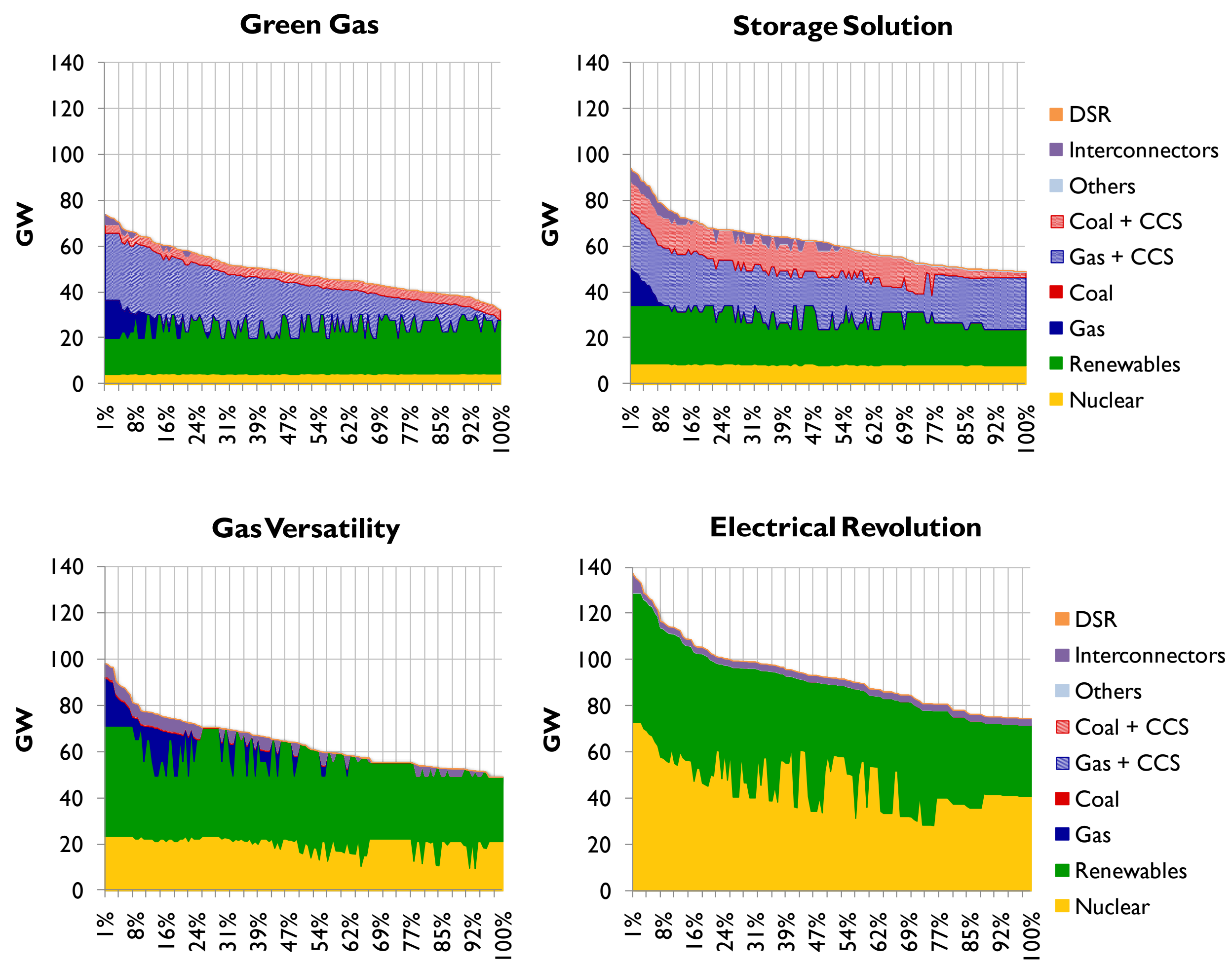


3.4.5 Supply duration curves

Electricity supply duration curves for the four scenarios in 2050 are set out in Figure 16, while additional charts for 2010 and 2030 are included in Appendix C. The duration curves indicate that, as expected, thermal generation with CCS plays a key role in the Green Gas and Storage Solution scenarios, with a small amount of nuclear baseloading throughout the year as well as a reasonable level of intermittent renewable generation. At peak periods in these two scenarios unabated gas plays an important role in balancing the system alongside interconnectors and some use of DSR. It should be noted that the charts assume average availabilities for renewables plant, and hence the required output from back-up plant and response from storage, the demand side and interconnectors could be much greater in periods of very low renewables output. Unabated gas also plays a role in peak periods in the Gas Versatility scenario, but the bulk of output in other times of the year is met from nuclear and renewables.

In the Electrical Revolution scenario, virtually all of the (considerably higher) electricity output comes from nuclear and renewables, with some use of interconnectors, DSR and ‘other’ generation – primarily OCGT plant – in peak periods. Nuclear output fluctuates substantially between periods in this scenario rather than running at a flat baseload profile, indicating the importance of flexible nuclear technology in meeting balancing requirements in scenarios with little or no thermal generation on the system. Analysis of load factors indicates that by 2050 nuclear plant in the Electrical Revolution scenario would need to run at an annual load factor of just over 50% (notwithstanding the high amounts of electricity storage, DSR and interconnection), as compared with 80 to 90% in the remaining three scenarios. Nuclear technology would need to very flexible to achieve this.

Figure 16 Electricity supply duration – 2050



3.5 Heating and transport

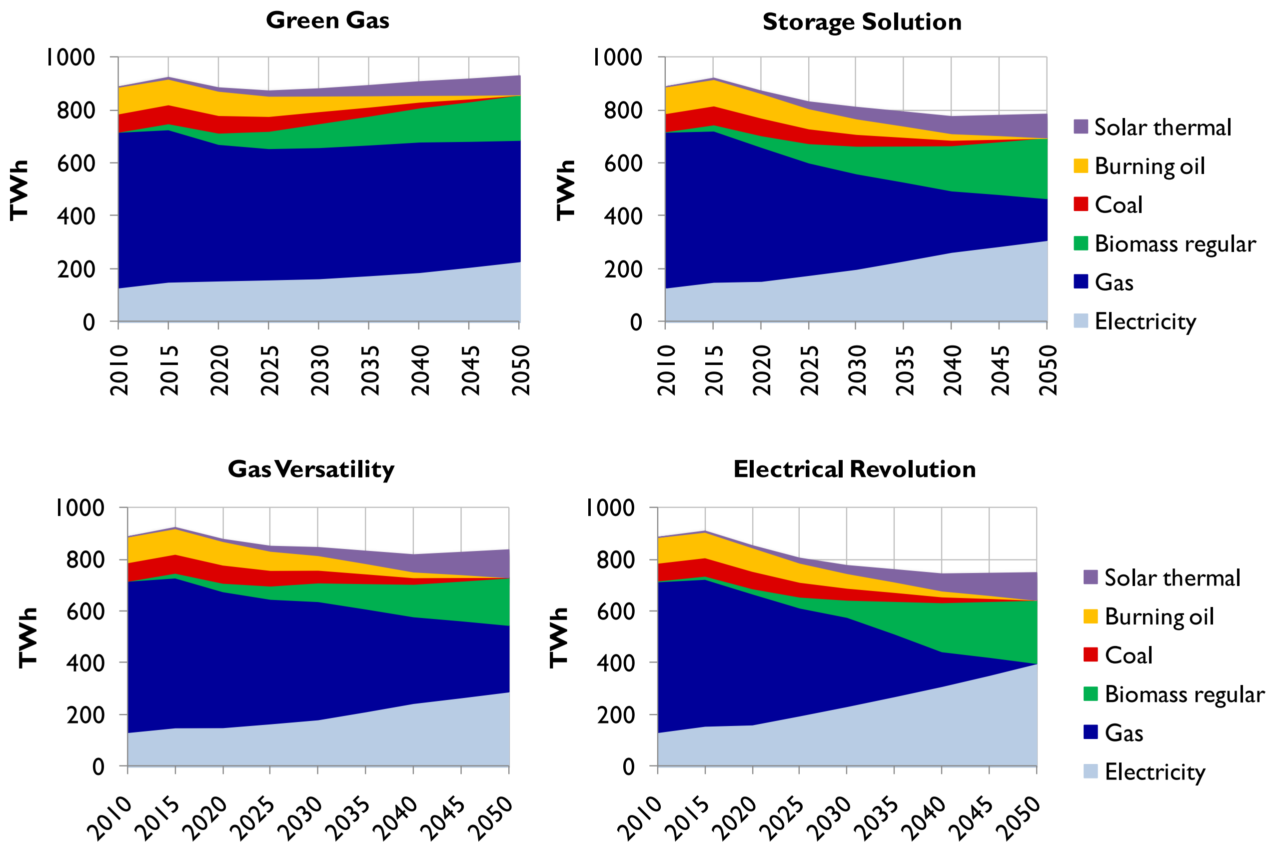
3.5.1 Heating / cooling delivered energy demands

Figure 17 shows the delivered energy demands for heating and cooling by fuel type – covering all sectors including domestic, services and industry – at five-yearly intervals out to 2050. It can be seen that energy demand rises in all four scenarios initially, but then begins to fall in most cases as electrification of heat increases, due to the greater efficiency of heat pumps relative to conventional gas boilers. The exception to this is the Green Gas scenario, in which delivered energy demands in 2050 are five percent above 2010 levels. In general, reductions in heating energy demand come primarily from the domestic sector, while the industrial sector shows steady growth over the period.

It should be noted that while energy demands generally fall over time, the actual heat output grows in all scenarios, reflecting our service demand assumptions for heating and cooling, which are held constant across scenarios and aligned with Level 2 in the DECC 2050 work. Appendix C contains a breakdown of annual heat output and how this is met by different heating technologies.

Monthly delivered energy demands by fuel type for the spot years 2010, 2030 and 2050 are also included in Appendix C. These charts show that, in addition to the decline in heating energy demands over time in most scenarios, there is a general flattening of the seasonal heat shape. This is particularly evident in the Electrical Revolution scenario, where a significant amount of seasonal heat storage technology has been incorporated into the scenario assumptions.

Figure 17 Delivered energy demand for heating / cooling by fuel type

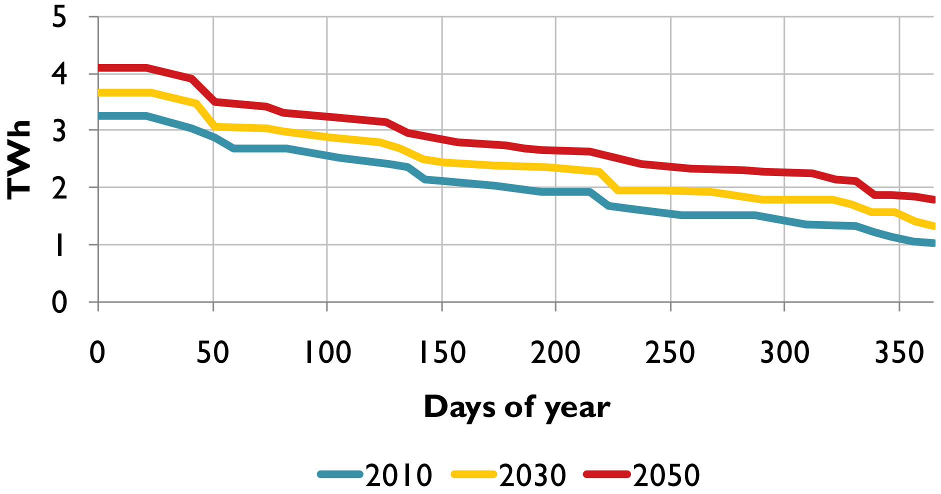


3.5.2 Heating service demand duration curves

Heating service demand duration curves for the spot years 2010, 2030, and 2050 (based on daily demand for each of the 365 days of the year) are shown in Figure 18 below[21]. The steady increase in heating service demand over time can be seen in the chart, which contrasts with the fall in delivered energy demand seen in Figure 17. In addition (although the changes are small and therefore somewhat difficult to see in the chart), the shape of the demand duration curve flattens slightly over time. For example, the ratio of the highest to lowest demand day falls from 3.15 in 2010 to 2.3 in 2050.

[21] Because this chart is based on underlying serviced demands rather than delivered energy demands, the profiles are invariant across scenarios.

Figure 18 Heating service demand duration curves – 2010, 2030 and 2050



3.5.3 Transport delivered energy demands

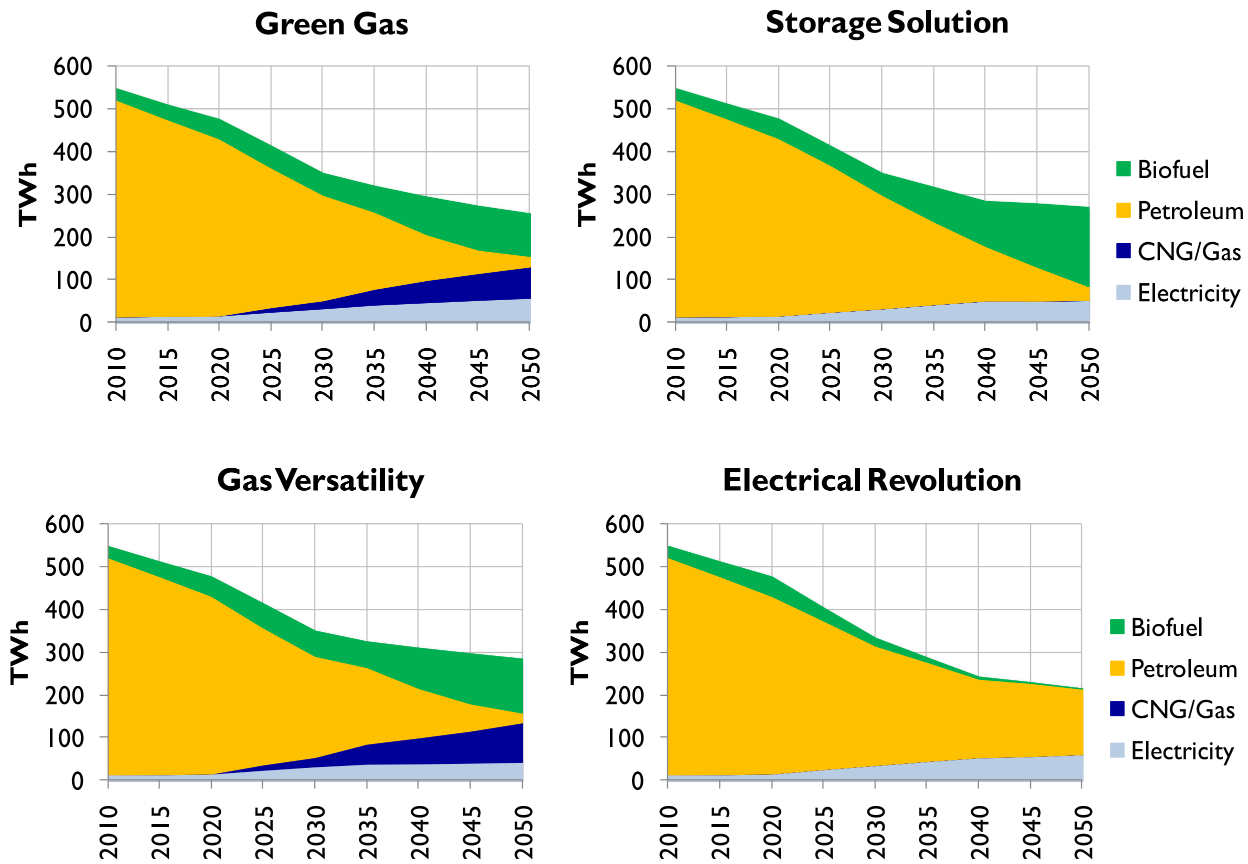
The delivered transport energy demand by fuel type (covering all modes including road, rail, heavy goods vehicles, and domestic maritime and aviation) is shown in Figure 19. Several points of interest are worth noting from these charts, including:

- the level of delivered transport energy demand falls substantially over time in all scenarios, reflecting efficiency gains in the conventional vehicle fleet as well as the increasing penetration of electric battery-powered vehicles – which account for up to 75% of vehicle kilometres travelled in the Electrical Revolution scenario and are three to four times more efficient than internal combustion engines[22]
- biofuels play an important role in reducing emissions from the transport sector, particularly for aviation and heavy goods vehicles given the difficulty of electrifying these modes, and
- there remains some use of fossil fuels in all four scenarios in 2050, but in the Green Gas and Gas Versatility scenarios petroleum is increasingly supplanted by compressed natural gas (CNG).

A breakdown of transport service demands in terms of vehicle kilometres travelled by technology type (conceptually similar to the delivered heat output discussed in the previous section) is shown in Appendix C, for cars / light goods vehicles and HGVs respectively. These charts show that while the delivered energy to the sector falls over time, the number of vehicle km travelled continues to rise for all vehicle types. Also, due to the efficiency effects mentioned above, electric vehicles account for a much larger share of vehicle km travelled than delivered energy.

[22] It should be noted however that the charts do not incorporate efficiency losses in converting fuel to electricity for the battery-powered fleet, since these are accounted for within the generation sector.

Figure 19 Delivered energy demand for transport by fuel type



3.6 Environmental targets

Figure 20 and Figure 21 show how the scenarios compare against key environmental targets, namely the EU 2020 Renewable Energy (RES) target and the UK Government's 2050 carbon target. We have assumed that a 90% reduction in CO_2 emissions below 1990 levels would be required in the modelled sectors to achieve the Government's target of an 80% reduction in emissions overall. In terms of CO_2 volumes this entails a reduction from 530 Mt of CO_2 to 53 Mt or lower.

As discussed in Section 2 of the report, all scenarios have been calibrated to meet both of these targets, but there remains some minor variation across scenarios as can be seen in Figure 21. Interestingly, Storage Solution has the lowest level of cumulative emissions over the period (2129 Mt), closely followed by Electrical Revolution with 2137 Mt. Green Gas, with 2221 Mt, has the highest. In terms of renewable penetration, while all scenarios meet the 2020 RES target, by 2030 there is considerable divergence in outcomes with Electrical Revolution having the highest share of renewables and Green Gas the lowest.

Figure 20 Share of renewables in final energy demand – 2010 to 2030

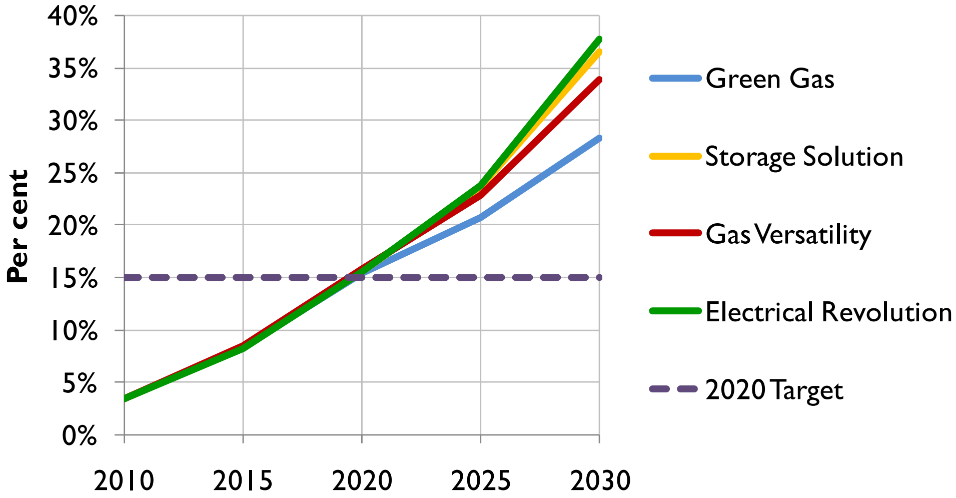
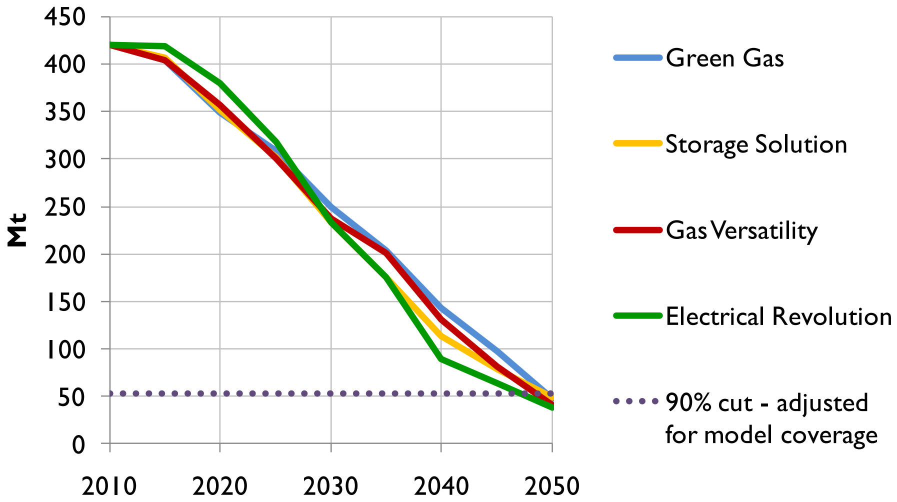


Figure 21 Annual CO_2 emissions – 2010 to 2050



As discussed previously, deployment of CCS technology and / or biomethane injection into the gas distribution grid are likely to be critical to manage CO_2 emissions under scenarios with high ongoing use of gas. The importance of these two technologies is demonstrated in Figure 22 – which shows the annual amount of CO_2 captured by scenario – and Figure 23, which shows the share of biomethane in total delivered gas supply. It can be seen that the Green Gas scenario relies on a relatively high level of both carbon capture and biomethane, as would be expected given the ongoing use of gas in both the generation and heating sectors in this scenario. Gas Versatility has the highest share of biomethane overall but a very low level of carbon capture, while the reverse applies in the Storage Solution scenario.

Figure 22 CO₂ captured by scenario

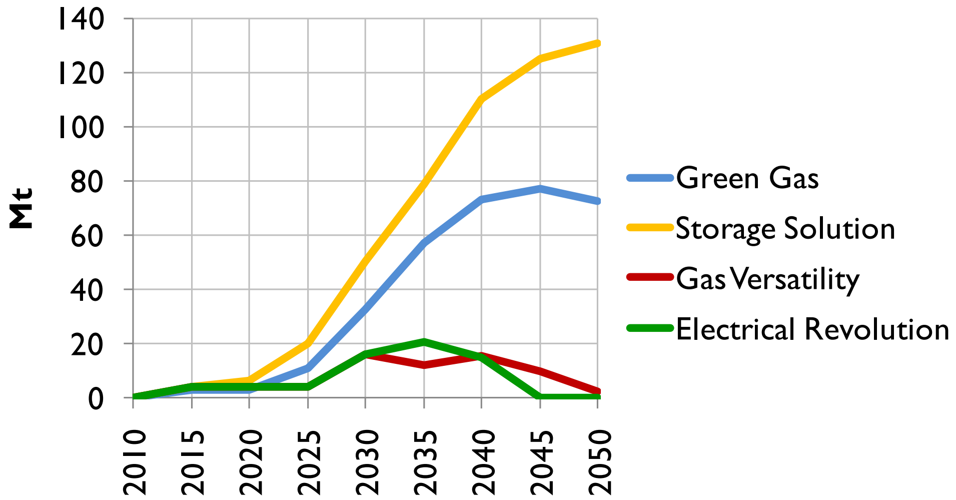
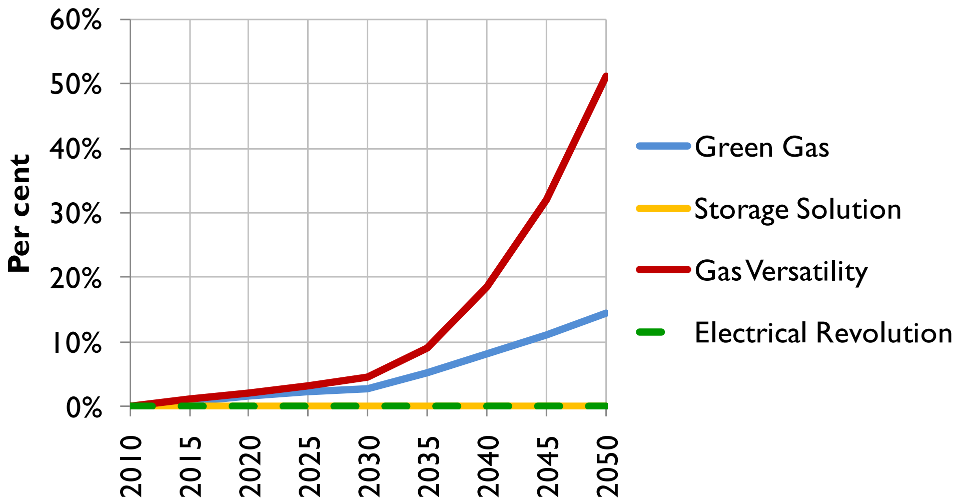


Figure 23 Share of biomethane in all delivered gas



3.7 System costs

As discussed in Section 2, the model developed for this study is fully costed and incorporates assumptions on capital investment costs, operating and maintenance costs (both fixed operating and maintenance (FOM) and variable operating and maintenance (VOM)) and fuel costs by technology for all of the modelled sectors and end-uses[23]. It also incorporates assumptions on transmission and distribution network capital costs (capex) and operating costs (opex) for both gas and electricity, including costs associated with gas network decommissioning. In all cases, investment costs have been annualised using sectoral assumptions on the Weighted Average Cost of Capital (WACC), and overall costs have been discounted at the HM Treasury Green Book social discount rate of 3.5% real.

[23] Cost assumptions for non-road transport modes – ie, aviation, rail and maritime – have been excluded. These do not vary by scenario however and hence would not impact on the overall cost comparisons.

There are various ways in which system costs could be segmented for the purpose of communicating the modelling results. In this report we have initially allocated costs on a sectoral end-use basis between transport, heating and other electricity end-uses, with heating costs divided further into domestic, services and industrial. Within each sector, costs are categorised as follows:

- **end-use investment** – the capital costs associated with end-use technologies such as boilers, heat pumps, electric vehicles, and appliances
- **end-use FOM / VOM** – the fixed and variable operating and maintenance (O&M) costs associated with the end-use capital stock
- **end-use fuel and carbon** – the direct fuel and carbon costs[24] associated with the end-use sectors, for example natural gas for heating and petrol for conventional vehicles, excluding electricity
- **electricity supply and storage** – the combined capital, FOM / VOM, fuel and carbon costs associated with electricity supply (ie, generation) and electricity storage
- **electricity and gas transmission and distribution (T&D)** – the combined capital and operating costs (including business rates and new connections) associated with electricity and gas T&D, and
- **LNG and gas storage** – the combined capital and operating costs associated with LNG terminals and gas storage facilities.

The costs associated with electricity supply and storage, electricity and gas T&D, and LNG and gas storage facilities have been allocated across the end-use sectors on a straightforward pro-rata basis, based on the share of gas and electricity in delivered energy demand for each service[25].

In addition to the presentation of system costs on a sectoral basis, we have also included a separate section setting out and discussing the network cost elements of the results in more detail, given the ENA's particular interest in impacts on gas and electricity network operators.

3.7.1 Baseline cost results by sector

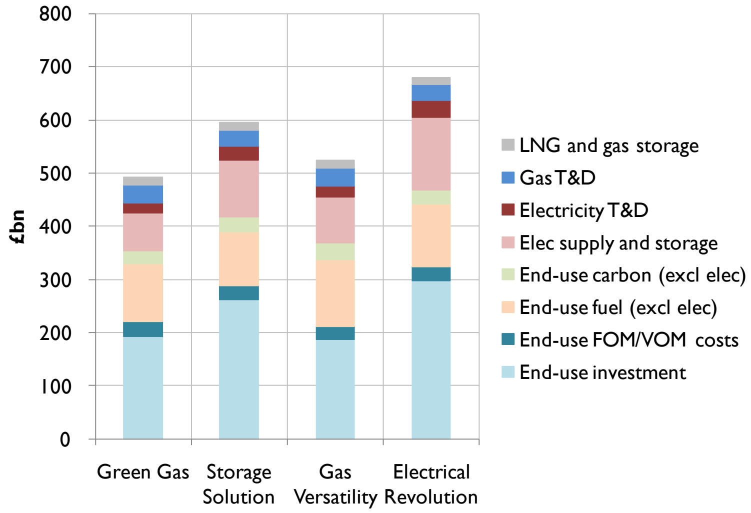
Heating – domestic

Figure 24 shows the Net Present Value (NPV) of modelled domestic heating costs for each scenario over the full 2010 to 2050 study period. It can be seen that the costs of heating in scenarios with ongoing use of delivered gas in the home (Green Gas and Gas Versatility) are significantly lower than in scenarios where heating is largely electrified (Storage Solution and Electrical Revolution). The total cost difference between Green Gas and Electrical Revolution over the period is £188 bn. The main driver of the difference in costs is investment – which covers the purchase costs of new heat pumps, boilers etc – followed by the cost of electricity supply.

[24] Carbon costs have been calculated based on the relevant scenario market price and volume of emissions. No assumptions have been made regarding offsetting revenues from carbon auctions.

[25] In reality, certain cost elements – in particular, the costs of additional electricity generation and network capacity to meet peak demand – are likely to be spread unevenly across sectors, since for example load shifting in the transport sector may allow additional demand to be met with less investment in peaking capacity than the equivalent demand for electricity in the heating sector. We have not attempted to account for this effect in our cost comparisons given the complexity of the analysis and assumptions that would be required, and because it would not affect the total system cost comparisons in any case. However, in general the heating sector would be likely to account for a higher share of system costs relative to the transport sector due to the peakier nature of heating demand.

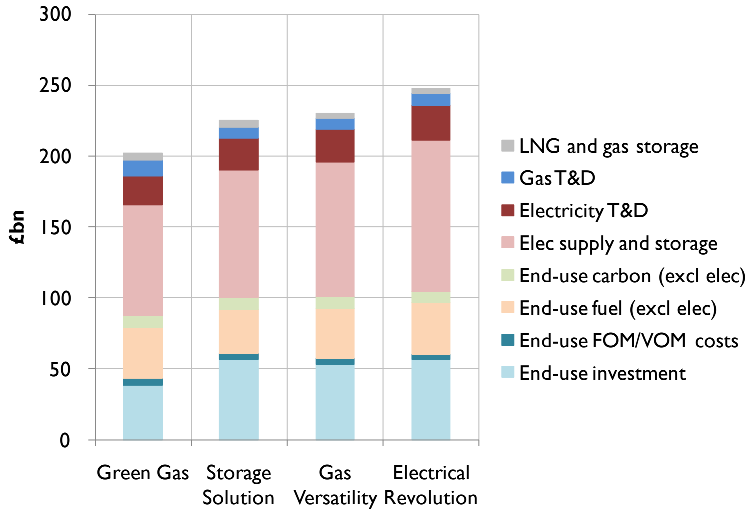
Figure 24 NPV of system costs – domestic sector heating



Heating – services

The NPVs of heating costs in the services sector by scenario are shown in Figure 25. Green Gas is again the lowest cost scenario and Electrical Revolution the highest, with a difference between the two of £46 bn. However, in this sector the costs in the Gas Versatility scenario are slightly above those in the Storage Solution scenario. Heating costs in the services sector are slightly less than half those in the domestic sector overall (note the difference in scale on the chart).

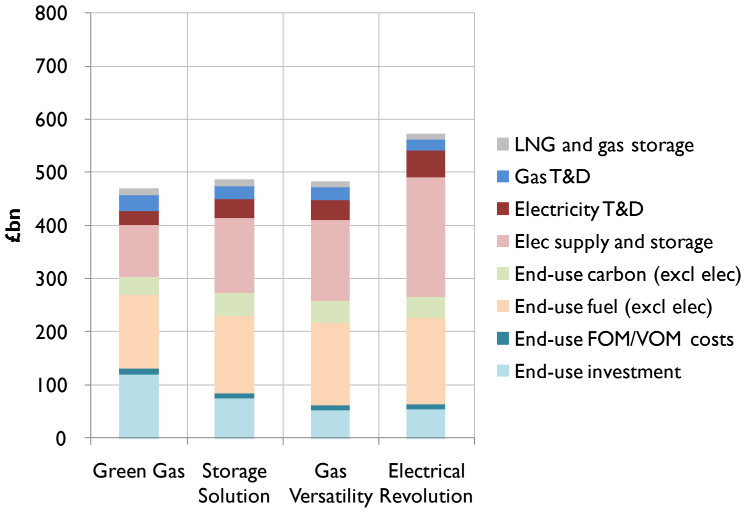
Figure 25 NPV of system costs – services sector heating



Heating – industrial

Comparison of heating costs by scenario for the industrial heating sector shows a similar pattern to the services sector, as can be seen in Figure 26 below. Green Gas (£470 bn) is again the cheapest scenario overall while Electrical Revolution (£573 bn) is the most expensive. However, in this sector the costs associated with Gas Versatility are marginally lower than for Storage Solution. Costs in the industrial heating sector are larger overall than for services, but lower than in the domestic sector.

Figure 26 NPV of system costs – industrial sector heating

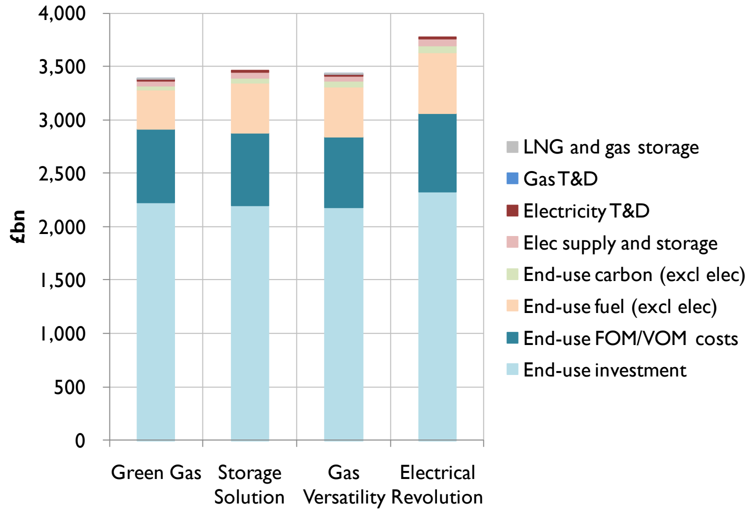


Transport

We now turn to look at transport sector costs, which are presented in Figure 27. The first point to note from this chart is the scale of the costs involved, which range from close to £3,400 bn £3.4 tn) in the Green Gas scenario up to £3,800 bn (£3.8 tn) in the Electrical Revolution scenario over the study period – three to four times the total costs associated with heating. This is predominantly a reflection of the very large capital investment costs incurred in replacing the entire UK vehicle fleet several times over the period. (It should be noted that even if 'no change' to existing vehicle technologies was assumed – ie, continued use of internal combustion vehicles with no shift towards the use of battery electric, plug-in hybrids or CNG vehicles – the total costs of transport over the period would still amount to over £2.8 tn.)

The differences in costs between scenarios are also substantial however, with an additional £400 bn incurred in Electrical Revolution by comparison with Green Gas. Storage Solution and Gas Versatility are also more expensive than Green Gas over the period, by approximately £75 bn and £45 bn respectively. Again, differences in end-use investment costs – such as the costs of electric vehicles and associated infrastructure in the higher electrification scenarios – are the main driver of differences in costs, together with the costs of electricity supply.

Figure 27 NPV of system costs – transport

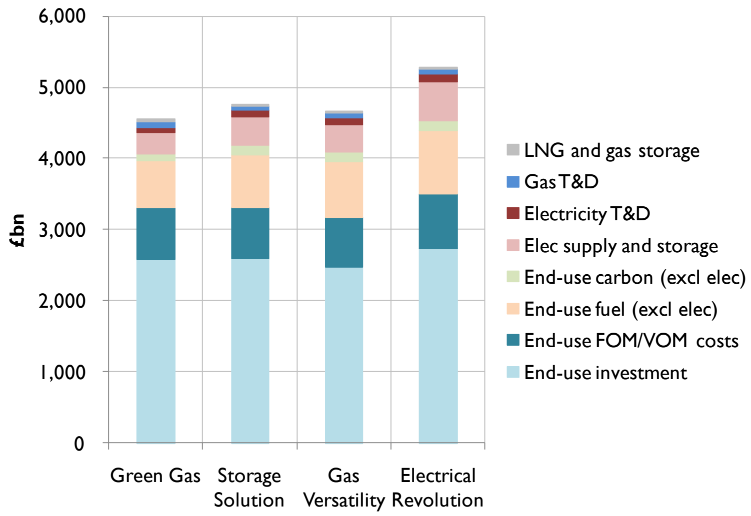


Total system costs

A summary of the total system costs by scenario – including the sectors discussed above together with other electricity end-uses such as lighting and appliances – is shown in Figure 28. This chart confirms that total costs over the period are highest in the Electrical Revolution scenario at £5.3 tn – more than £700 bn above the equivalent figure for the Green Gas scenario. Costs for the other two scenarios fall in between these two extremes, with Storage Solution totalling £4.8 tn and Gas Versatility £4.7 tn.

The chart also shows that capital investment (excluding investment in networks and delivery infrastructure) makes up by far the largest share of overall costs, followed by fuel costs and O&M costs. Network and delivery costs make up a very small proportion of the total in all scenarios – averaging around 2% for electricity transmission / distribution (£77 bn to £122 bn), 1.5% for gas transmission / distribution (£60 bn to £79 bn), and less than 0.5% for LNG and gas storage (£26 bn to £33 bn).

Figure 28 NPV of system costs – total for all sectors



3.7.2 Network costs

Although network costs make up only a small proportion of total system costs, they are still significant in absolute terms, and modelling of these costs is clearly of critical interest to the ENA member companies. As discussed in Section 2 and Appendix C, we have undertaken a full analysis of network costs for each scenario, incorporating assumptions on capex (both new and replacement), opex, depreciation on the existing asset base, business rates and new connections.

For scenarios other than Green Gas, we have also included an estimate of the costs (and savings) associated with partial or total gas network decommissioning. Specifically, we have assumed that by 2050:

- two-thirds of the distribution network is decommissioned in the Storage Solution scenario
- half of the transmission network and one-third of the distribution network is decommissioned in the Gas Versatility scenario, and
- both the transmission and distribution networks are fully decommissioned in the Electrical Revolution scenario.

In all cases we assume that half the decommissioning required is undertaken via grouting and the other half via injection with inert gas.

Figure 29 and Figure 30 show the total annual network costs for electricity T&D and gas T&D respectively, at five-yearly intervals out to 2050. It can be seen that annual electricity network costs rise significantly in all scenarios, but are highest in the Electrical Revolution scenario – more than double Green Gas by 2050 – reflecting the very high levels of electrification of both heating and transport in this scenario. Gas network costs on the other hand rise slightly in the early part of the period, but then begin to fall in all scenarios, with Electrical Revolution dropping to zero by the end of the period reflecting our assumption of full decommissioning in this scenario. The range of costs is much narrower for gas T&D than electricity T&D, which reflects the fact that no new capital investment in gas pipelines (aside from connections and the current gas distribution replacement programme) is assumed to be required over the study period even in the Green Gas scenario.

Figure 29 Modelled annual network costs – electricity T&D

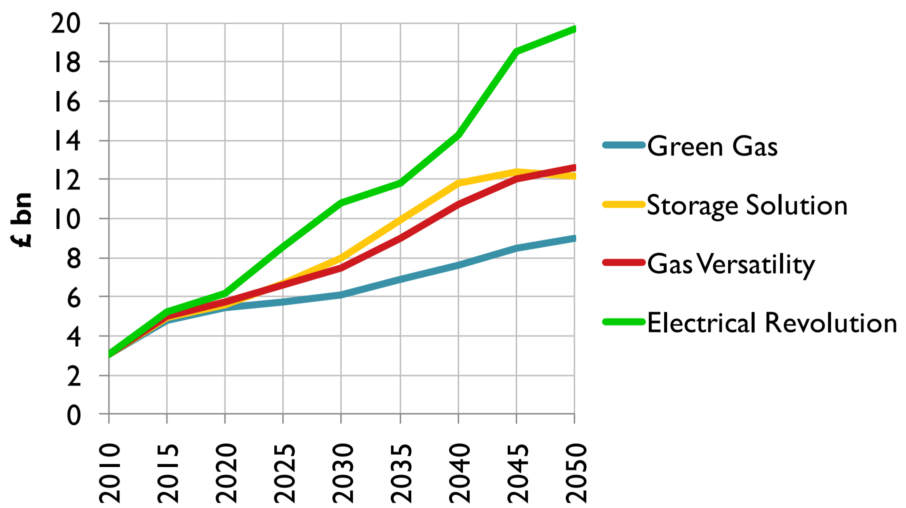
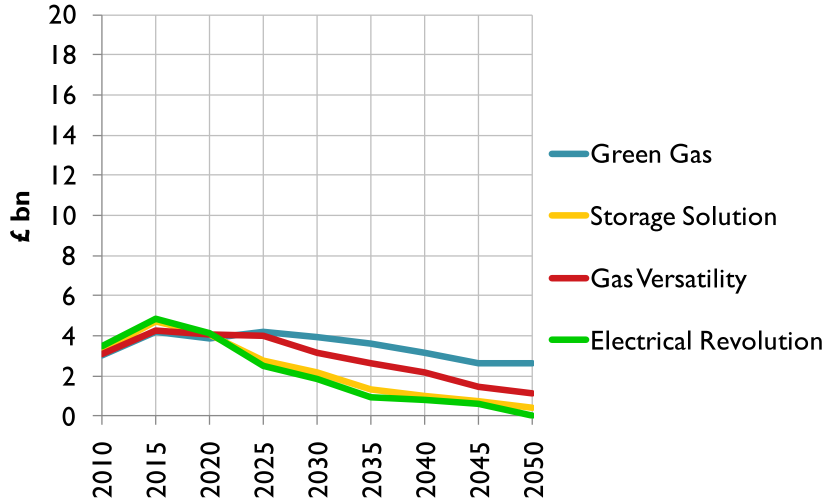


Figure 30 Modelled annual network costs – gas T&D



A more detailed breakdown of the electricity and gas network costs for each scenario, showing the split between the different elements – depreciation, return on capital, opex, rates, connections and decommissioning – can be found in Appendix C.

3.7.3 Cost sensitivities – commodity prices

As noted in Section 2 of the report, our scenario narratives assume different commodity price trajectories over time under the four scenarios – for example, gas prices track lowest in the Green Gas scenario and highest in Electrical Revolution. We have undertaken sensitivity runs applying the same 'Low', 'Medium' and 'High' levels to each scenario. The results from these sensitivities in terms of total system costs by scenario are shown in Figure 31, Figure 32, and Figure 33, while the commodity price trajectory assumptions used for the sensitivity analysis can be found in Figure 34.

Two key points of interest are worth highlighting from these sensitivity comparisons. The first is that applying the same commodity prices to all scenarios reduces, but does not eliminate, the cost differential between Electrical Revolution and Green Gas. For example, even in the High Commodity Price sensitivity the differential still stands at over £200 bn (as compared to £728 bn previously). Secondly however, in all three of the commodity price sensitivities it is now Gas Versatility that is the lowest cost scenario overall rather than Green Gas. This reflects the fact that Gas Versatility has the lowest end-use investment costs of the four scenarios, so once commodity price differentials are eliminated this scenario compares favourably in terms of overall costs.

Figure 31 NPV of total system costs – Low Commodity Prices

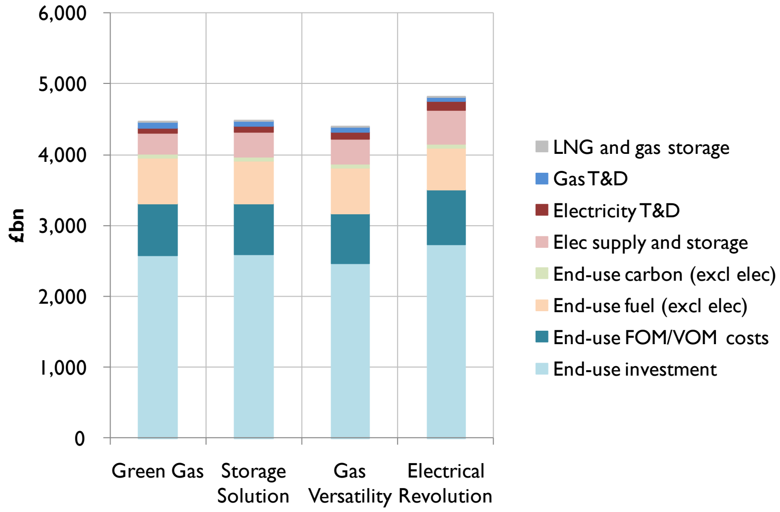


Figure 32 NPV of total system costs – Medium Commodity Prices

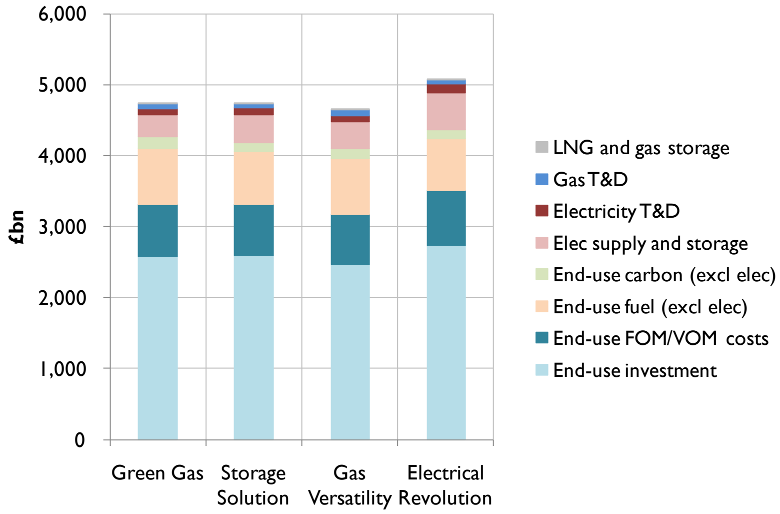


Figure 33 NPV of system costs – High Commodity Prices

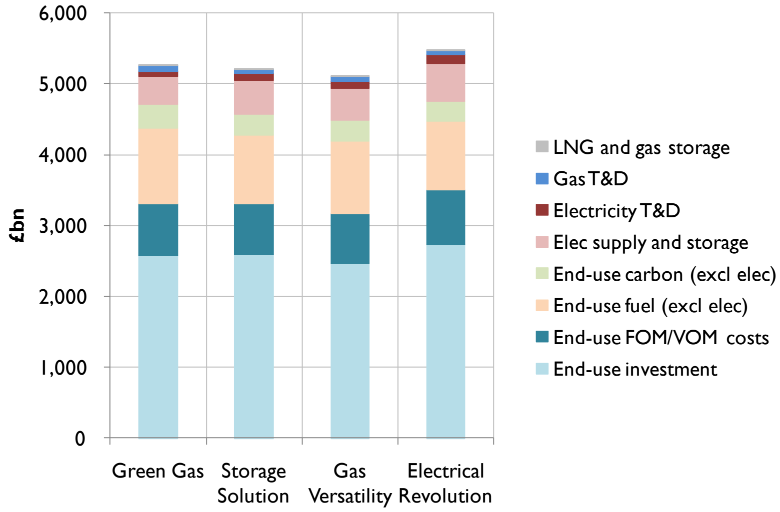
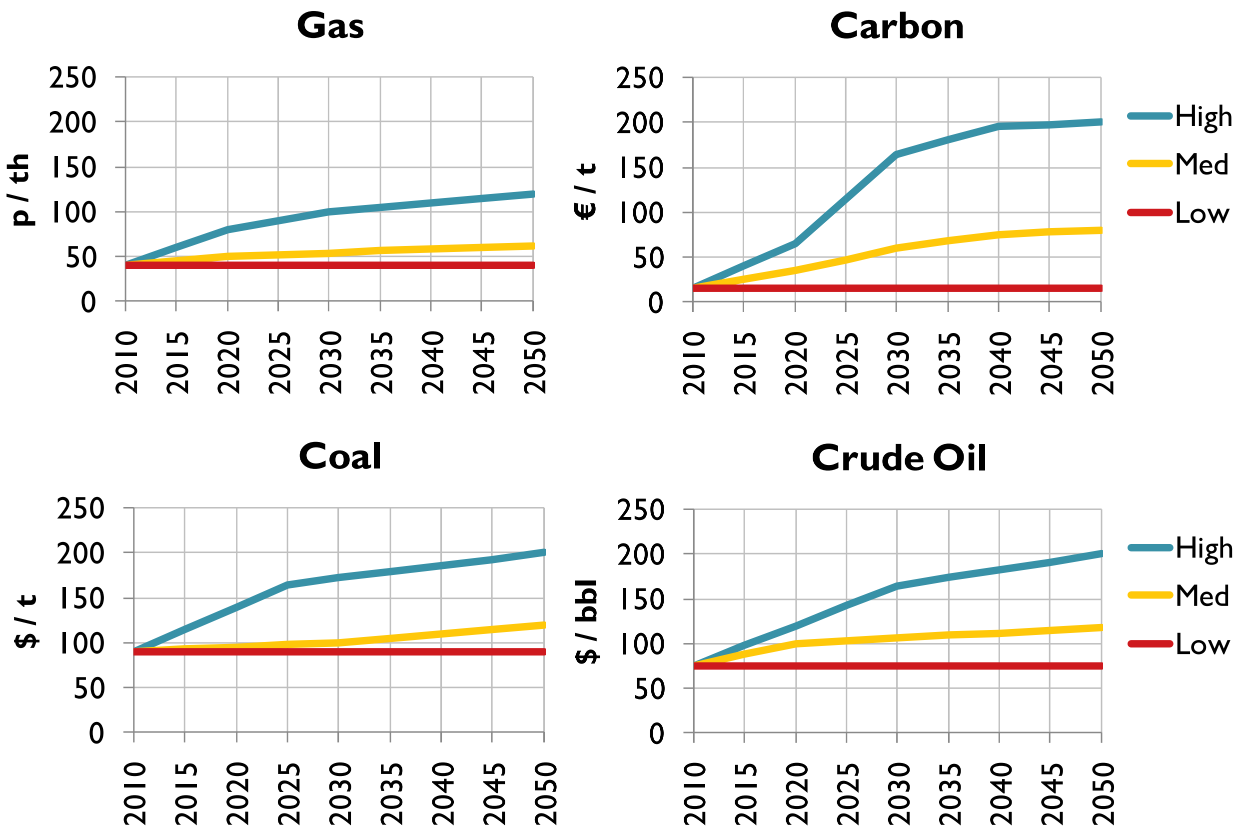


Figure 34 Commodity price trajectories for sensitivity analysis



3.7.4 Cost sensitivities – technology learning rates

In addition to the commodity price sensitivities, we have also undertaken sensitivities around the speed of technology learning (Low / None, Medium, and High). The results from this analysis are shown in Figure

35, Figure 36, and Figure 37 below. It should be noted that in most cases, technology learning rates apply only to new technologies such as offshore wind turbines, tidal / marine generation, heat pumps, CCS, and electric vehicles. In the High Learning sensitivity however we have also assumed a small amount of learning for mature technologies such as CCGT plant, onshore wind, gas boilers and petrol cars.

In general, changes to technology learning rates do not alter the overall pattern of results – in all of the sensitivities, Electrical Revolution remains the most costly scenario and Green Gas the least expensive. However, slow technology learning rates increase the cost differential between Green Gas and Electrical Revolution relative to the baseline (the differential is £843 bn in the Low / No Learning scenario vs £728 bn in the baseline), whereas faster learning rates decrease it (the differential in the High learning scenario is £681 bn). This is to be expected given the more extensive use of new technologies such as heat pumps and electric vehicles in the Electrical Revolution scenario.

Figure 35 NPV of total system costs – Low / No Technology Learning

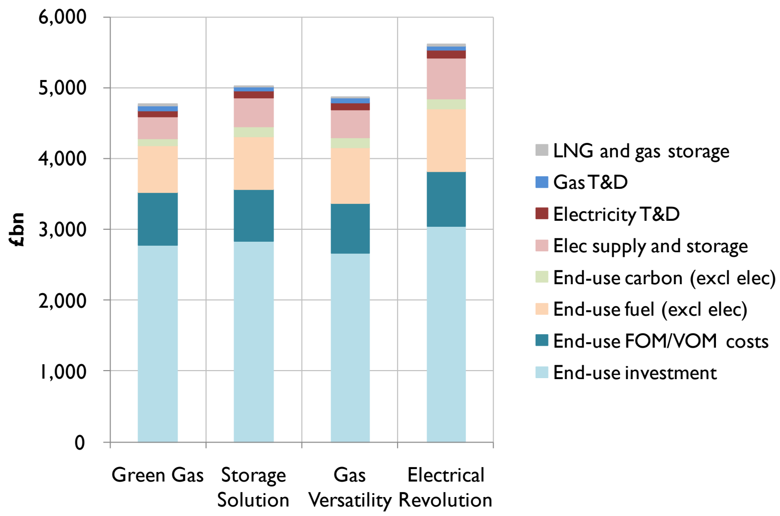


Figure 36 NPV of total system costs – Medium Technology Learning

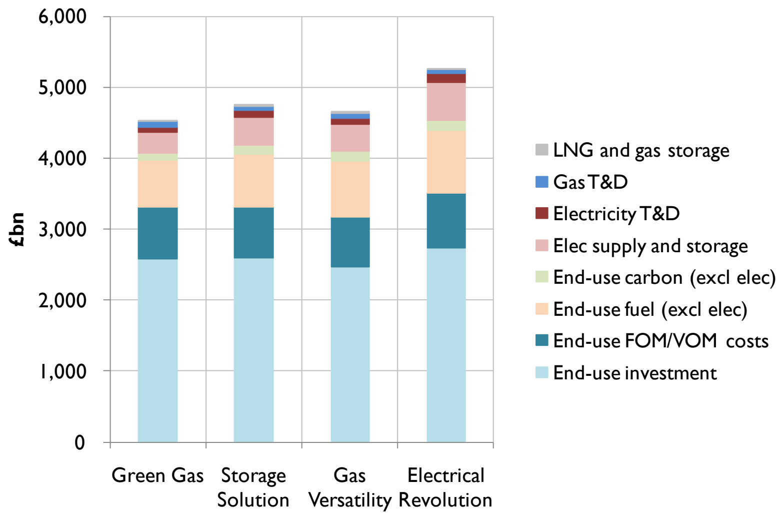
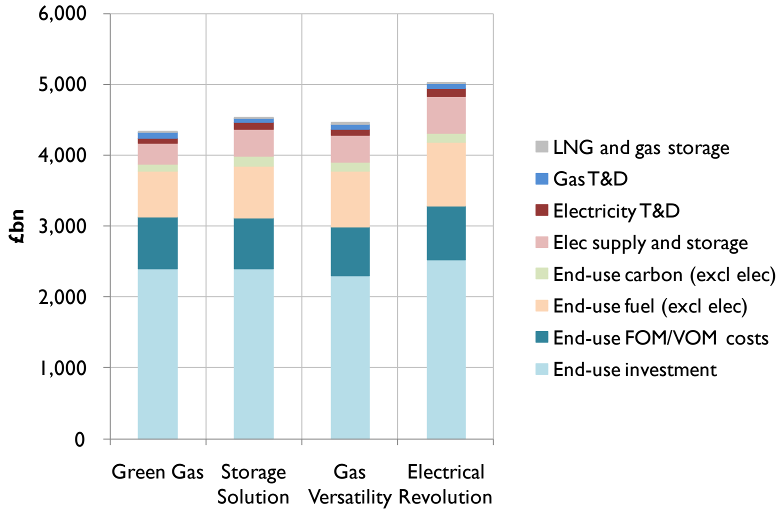


Figure 37 NPV of system costs – High Technology Learning



3.7.5 Cost sensitivities – heat pump performance

In addition to the commodity price and technology learning rate sensitivities, we also undertook a further bespoke sensitivity run to test the impact of lower performance of heat pumps, using a Coefficient of Performance (CoP) set at half the level assumed in our baseline analysis. This sensitivity has the effect of raising the costs of electrification and widening the overall cost gap between Electrical Revolution and the scenarios with ongoing utilisation of gas. This is because additional generation capacity as well as electricity network capacity must be built in the model to cope with the increase in electricity peak demand.

In the low heat pump performance sensitivity, an additional 95 GW of installed capacity is required by 2050 in the Electrical Revolution scenario relative to the baseline. The cost differential between Electrical Revolution and Green Gas in this sensitivity widens to £881 bn (versus £728 bn in the baseline).

4 Conclusions

The results of our modelling indicate that there is a wide range of potential outcomes for future gas utilisation by 2050, a from scenario in which gas continues to be used at levels similar today through to a scenario in which gas is largely eliminated from the energy mix and the existing transmission and distribution networks are decommissioned. On the electricity side, all scenarios show a significant increase in output relative to today's levels, reflecting the effects of electrification combined with population and economic growth. However, electricity output and installed capacity in the Electrical Revolution scenario are close to double that in Green Gas by 2050.

All of our scenarios meet both the 2050 carbon targets and the 2020 renewable targets, indicating that an ongoing role for gas in the GB energy mix could be fully compatible with achieving the Government's environmental objectives. Moreover, our results suggest that pathways with ongoing use of gas could offer a cost-effective solution for a low-carbon transition, with savings of up to £700 bn over the period under our baseline assumptions. This conclusion holds both in our baseline analysis as well as in sensitivity runs with high commodity price trajectories which are held constant across scenarios, and with faster technology learning rates. The difference in costs does however narrow under both of these sensitivities.

Aside from the potential cost savings, other benefits of maintaining gas within the energy mix include enhancing the diversity of the primary energy mix in 2050 and providing additional flexibility with respect to storage and energy balancing particularly at times of low renewable output – our results suggest that even in the Electrical Revolution scenario some unabated generation plant may be needed to operate alongside demand-side management and storage systems for balancing electricity. As the cleanest-burning fossil fuel, gas could also play an important transition role in minimising emissions in the short term while new technologies are developed.

Our modelling indicates that managing CO_2 emissions under scenarios with high ongoing use of gas will however require the successful development and roll-out of CCS technology, allowing gas to maintain its current share of electricity generation, supported by the deployment of biomethane injection into the gas distribution network, allowing gas to maintain a significant role in domestic and industrial heating. Other important factors in constraining emissions – particularly in the Green Gas scenario – include roll-out of CHP district heating, and the usage of combined electricity and gas 'dual fuel' systems for domestic heating. In transport, all of our scenarios assume significant roll out of hybrids and then plug-in electric battery vehicles, but the use of CNG can contribute to lowering the emissions for the heavy goods vehicle fleet.

Technological development – and consumer uptake of new technologies – is critical to any low-carbon future. Both time and funding are needed to ensure that technology options are fully explored. As noted in the key messages, all potential pathways to a low-carbon future will involve significant investment in new technology. Under high gas scenarios, key technologies are likely to include CCS, biomethane, dual fuel and / or district heating systems, combined with at least some electrification of heating and transport. Under scenarios with low or no ongoing use of gas, investment in electric heating and transport technologies will be critical, alongside electricity and heat storage, demand-side response (DSR), interconnection and / or flexible nuclear to balance the electricity system. All of these technologies have potential risks and uncertainties associated with them, including the pace of technological development and learning, the willingness of consumers to alter their behaviour and preferences, and policy / regulatory risk.

Given the level of uncertainty that exists regarding all of these issues, there appears to be significant value in retaining the option for a 'high gas' future. This is particularly relevant given that our modelling indicates that pathways with ongoing gas use could yield cost savings relative to those with higher levels of electrification, particularly under scenarios with low growth in commodity prices and / or slower rates of technology learning. While all of our scenarios anticipate a significant increase in the use of electricity by

2050, a balance between fuel sources may help to reduce the risk of over-reliance on particular technologies.

Our cost analysis also suggests that, while the costs of maintaining the gas networks are not insignificant, they are relatively small in comparison to the other system costs that will be incurred in the transition to a low-carbon future. Furthermore, since the capital costs of the existing gas network are largely sunk, decommissioning of the gas network provides limited scope for cost savings. Together these findings suggest a compelling economic rationale for maintaining the operation of the GB gas transmission and distribution networks for the foreseeable future.

A Model design and structure

A.1 Demand modules

The model contains five main demand modules: domestic heating, services heating, industrial heating, transport, and other electricity demand (covering lighting, appliances, etc). The starting point in each module is the annual energy service demand in each year from 2010 to 2050 by end-use, taken from the DECC 2050 Pathways analysis. For example, space heating, water heating, and cooling in the domestic heat sector or vehicle kilometres travelled by mode (rail, cars, HGVs etc) in transport.

Intra-year profiles are then applied to shape the demands to various characteristic periods, or time slices, across the year. The intra-year energy service demands are then supplied by a scenario specific mix of technologies (eg, heat pumps and gas boilers for domestic heating) with various characteristics such as efficiency, seasonal availability or performance factors and different input energy requirements.

From the combination of time-sliced demand and technologies a series of energy / fuel demands are calculated for each time slice which must be met within the model. CHP and other embedded generation (such as solar PV) are treated at the demand side and any electricity production from these technologies is netted off from electricity demand before the residual is passed to the relevant supply / demand balance module. Demand for gas exports is also considered exogenously at the demand side.

The level of time slicing varies depending on the type of energy/fuel:

- Electricity is the most detailed and is split into 144 characteristic periods over the course of the year – 12 months by two day types (weekday / weekend) and six four-hourly Electricity Forward Agreement (EFA) blocks within each day[26]. An individual peak day is also calculated and is split into 48 half hourly blocks.
- Gas is represented via 24 characteristic days (weekday / weekend for each month in the year) as well as a peak day.
- All other fuels are considered at the annual level only.

Peak day demand is calculated by scaling the space heating requirements on the highest characteristic heating day based on a 1-in-20 winter.

Heat storage is also considered as part of the demand side. At present this is focused on inter-seasonal heat storage whereby solar thermal technology is used to charge a heat bank during the summer periods for discharge in the winter. Given the low grade-heat associated with the storage a ground-source heat pump (GSHP) is required to make optimal use of it and hence this storage form is associated with a significant efficiency gain (subject to additional cost).

CCS for heating, focused on large CHP and boilers primarily for industry, is also considered at the demand side. This is implemented as a proportion of CO_2 emissions captured from selected technologies, with an associated £/tCO_2 cost.

A.2 Supply balancing modules

The supply side modules provide the required energy / fuel to balance the demands in each time slice across the years 2010 to 2050.

[26] These blocks are: 11pm-3am, 3am-7am, 7am-11am, 11am-3pm, 3pm-7pm, and 7pm-11pm.

A.2.1 Gas

The gas supply module contains data on the availability and cost of fixed supply sources of gas at both an annual level and intra year. At more disaggregated levels of time slicing different fixed sources of gas are available, with other sources acting as a 'flexible' supply. The requirements for this additional supply (eg, capacity of gas storage) are then calculated as part of the gas supply / demand balancing to ensure that supply equals demand in each characteristic day and also on the peak day.

At an annual level fixed sources are UKCS, NCS, continental interconnectors and biomethane, with LNG acting as a long-range swing supply. Within the monthly time slices, LNG, storage and interconnectors can act as a flexible supply while on the peak day only storage is available as short-range swing.

The gas supply module may also create indirect demand for biomass to produce distribution network injected biomethane. It is assumed that no biomethane is injected into the transmission network given energy losses associated with pressurising the gas.

A.2.2 Electricity

For electricity the module contains a simple representation of an electricity stack. The module tracks installed capacity of various technology types (based on user specified scenarios) with associated data on efficiency, intra-year seasonal availability, etc.

This installed capacity is then dispatched based on SRMC (short run marginal costs) as part of the electricity supply / demand balance module to ensure that demand equals supply for each of the 144 characteristic periods over the year as well as each half hour on the peak day.

The core electricity stack is also linked to three other sub-modules which play a role in the supply / demand balancing:

- An **electricity storage** module takes the aggregated electricity demand and 'smoothes' it before passing it back to the electricity stack, against which the installed electricity capacity is then dispatched. Electricity storage is only considered at an intra-day level, but considers the total volume of storage available, the maximum instantaneous charge / discharge rate, and the requirement to balance injection/withdrawal from storage (subject to efficiency losses).
  - Within each characteristic day the model undertakes pro-rata smoothing on each of the six EFA blocks to move them towards the overall average for the day, subject to the limitations on storage described above. The aggregate installed storage capacity is limited to one full charge/discharge cycle per day.
  - For the peak day the logic is slightly different and assumes that the system operator has a full volume of storage available for that day (ie injection requirements are ignored). In addition, rather than pro-rata smoothing across all half hours the model undertakes peak shaving to minimise the maximum half-hourly demand seen by the stack.
- A **demand-side response** (DSR) sub-module effectively adds tranches of load shedding technologies (with associated capacities and increasing price levels) into the electricity stack where they can potentially be utilised. Load profile shifting is undertaken separately as part of the intra-year shaping within the demand-side modules.
- **Interconnectors** are similarly considered as technologies in the electricity stack with given levels of capacity. However, the interconnectors have the ability to both import and export according to a separate price profile for each function and so may provide a source of supply or additional demand that needs to be met. The model calculates the level of imports / exports and the subsequent implications for the electricity stack in each of the 144 characteristic periods as well as for each half hour within the peak day.

The electricity supply system also creates its own indirect fuel requirements for gas, biomass and other fuels which are then fed back to the relevant supply / demand balance modules.

A.2.3 Biomass

For biomass the module contains data on the availability and cost tranches of a range of indigenous biomass feedstocks and imports, as well as the different processing routes by which the primary feedstocks can be converted to satisfy different energy service demands.

For example, energy crops could be combusted directly by different sectors to generate heat or electricity, gasified and injected into the gas network to meet a portion of overall gas demand, or converted via various different intermediate routes to create road transport biofuels.

The biomass supply / demand balance module is provided with a set of biomass demands from each sector[27], which are prioritised by the user. The model then calculates the lowest cost way to meet the highest priority demand (given applicable primary feedstock combinations and processing routes) before moving to the next priority biomass demand, while keeping track of cumulative primary feedstock to ensure no double usage. For most demands an unlimited import option (generally at higher cost) is available[28] to meet the delivered demand.

There is also a feedback loop between the delivered bioenergy price calculated within the biomass module and the demand for biomass from the electricity module, as the dispatch of relevant plant is based on its SRMC, which is affected by the fuel price. An iterative process is then needed to ensure the bioenergy price and demand for biomass reach an approximate equilibrium position.

A.2.4 Other fuels

For all other fuels an unlimited supply is assumed to be available at a given unit cost.

A.3 Cost modules

For each section of the model cost sub-modules are overlaid to calculate the total system costs in each year. Primary commodity prices are set as user inputs.

A.3.1 Demand cost modules

For each of the domestic, services, industrial and transport sectors the model calculates the total installed capacity of each technology required to meet the highest demand for output from the technology seen over the course of the year (where this coincides with the peak day it assumes the peak requirement can be met). The model then calculates the level of existing capacity and new capacity requirements accounting for retirements over the 40 year time horizon[29].

Based on the capacity and operational requirements of each technology, investment costs, fixed operating costs, non-electricity fuel input costs and carbon costs are calculated. This includes costs for heat storage and non-electricity related CCS and all costs associated with CHP capacity as this is predominantly heat-led (ie, there is no apportioning of costs related to CHP electricity to the electricity sector).

[27] Eg, domestic direct combustion (separated into large and small), biomethane, electricity biomass regular, electricity from anaerobic digestion (AD), biodiesel, etc.

[28] Excluding landfill gas for electricity, and waste products (which can eg be combusted directly or processed via an AD or gasification route)

[29] For existing capacity in 2010 it is assumed that (1 / lifetime of the technology) is retired in each year from this point onwards.

The costs associated with electricity (generation and networks), gas networks and other gas delivery infrastructure (LNG and gas storage) are calculated separately and then apportioned to the end-use sectors based on their share of final energy consumption of electricity and gas. Delivered bioenergy costs are taken from the biomass supply / demand balance module with biomethane costs split pro-rata based on each sectors' share of gas in delivered energy.

A.3.2 Electricity

In a similar manner to the above, the model calculates the existing and new requirements for generation capacity and the relevant investment costs. Dispatch of installed capacity is determined endogenously based on SRMC within the electricity stack and hence operating costs (fixed and variable), fuel costs and carbon costs are calculated from this. Electricity supply costs also cover interconnectors and costs associated with micro-renewable electricity (only solar PV has been included in the model at present).

Electricity storage costs (investment and fixed operating) are calculated separately. No variable costs are assumed, but the electricity generation costs associated with storage losses are captured within the main electricity system costs.

DSR is incorporated in cost tranches within the electricity stack to determine utilisation, but no system costs have been included within the model.

A.3.3 Gas delivery infrastructure (LNG and Storage)

The gas supply balancing module calculates the operational and capacity requirements for LNG and gas storage, based on the amount of flexible supply needed within each year. From this investment costs and operating costs (fixed and variable) are calculated.

A.3.4 Network costs

The network costs module calculates the capacity requirements for electricity and gas transmission and distribution (T&D) based on the level of peak demand in each year[30] and, for electricity T&D, the installed capacity of new generation by technology type. From this investment costs (capex) and operating costs (opex) are calculated, incorporating depreciation, rates, and new connections to the grid.

[30] For gas T&D, since peak demand does not rise over the period in any of the scenarios, we have assumed no expansion to the existing pipeline network although replacement expenditure is undertaken on the distribution network.

B Data sources for input assumptions

Table 4 Key data sources for heating demand input assumptions

Category	Key sources
Energy service demand	Calibrated directly to DECC 2050 Pathways Analysis (Level 2) from 2015 onwards with the exception of industry where the changes in energy intensity are used to scale the base year data.
Time slicing	National Grid (2009) 10 year statement[31] Eurostat[32] – historic heating degree days for peak ELEXON data on characteristic seasonal profiles by different end-user classes[33]
Technology penetration trajectories	Scenario specific but maximum % and near term penetrations (to 2020) informed by existing literature (see below)
Technology characteristics (efficiency, costs, etc)	Various NERA and AEA work (2009-2010) for DECC related to the RHI (Renewable Heat Incentive)[34] BRE (2005) Reducing UK housing emissions[35] Poyry (2009) Potential and costs of district heating for DECC[36] Element Energy (2008) The growth potential for microgeneration[37]

Table 5 Data sources for transport demand input assumptions

Category	Key sources
Energy service demand	Calibrated directly to DECC 2050 Pathways Analysis (Level 2) vehicle km
Time slicing	Redpoint in-house analysis on electric vehicle load profile shapes (significant degree of load shifting assumed as default)
Technology penetration trajectories	Scenario specific
Technology characteristics (efficiency, costs, etc)	UKERC Energy 2050

[31] http://www.nationalgrid.com/uk/Gas/TYS/

[32] http://epp.eurostat.ec.europa.eu/portal/page/portal/statistics/search_database

[33] http://data.ukedc.rl.ac.uk/cgi-bin/dataset_catalogue/view.cgi.py?id=6

[34] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/renewable_heat/incentive/incentive.aspx

[35] http://projects.bre.co.uk/PDF_files/ReducingCarbonEmissionsHousingv3.pdf

[36] http://www.decc.gov.uk/publications/DirectoryListing.aspx?tags=12

[37] www.berr.gov.uk/files/file46003.pdf

	DECC 2050 Pathways Analysis

Table 6 Key data sources for other electricity demand

Category	Key sources
Energy service demand	Calibrated directly to DECC 2050 Pathways Analysis (Level 2) from 2015 onwards (domestic/services appliances and lighting) with the exception of industry where the changes in energy intensity are used to scale the base year data.
Time slicing	National Grid in-house analysis ELEXON data on characteristic seasonal profiles by different end-user classes

Table 7 Key data sources for electricity generation and CCS

Category	Key sources
Existing generation plant	Ofgem Project Discovery Model Redpoint in-house assumptions (eg on impact of Industrial Emissions Directive)
Technology penetration trajectories	Technology penetration trajectories for new build are scenario specific subject to Upper bounds eg from DECC 2050 Pathways Analysis Near term to 2020 from Ofgem Project Discovery
Technology characteristics (efficiency, etc)	Technology data is based primarily on Project Discovery and Mott MacDonald (2010) UK Electricity Generation Costs Update for DECC[38]

Table 8 Key data sources for gas supply assumptions

Category	Key sources
Supply capacity (UKCS, NCS, Interconnectors, LNG) annual and intra-year	National Grid (2009) 10 year statement Ofgem Project Discovery
Biomethane penetration and costs	Scenario specific but subject to limits identified in eg National Grid (2009) Potential for Renewable Gas in the UK[39] E4Tech (2010) The potential for bioSNG production in the UK[40] report for NNFCC

[38] http://www.decc.gov.uk/en/content/cms/statistics/projections/projections.aspx

[39] http://www.nationalgrid.com/uk/Media+Centre/Documents/biogas.htm

[40] http://www.nnfcc.co.uk/metadot/index.pl?id=10754;isa=DBRow;op=show;dbview_id=2457

Gas delivery infrastructure costs (LNG and storage)	Redpoint in-house assumptions Ofgem Project Discovery

Table 9 Key data sources for electricity and gas network assumptions

Category	Key sources
Cost of capital (WACC)	Ofgem price control documents
Network asset lives	Ofgem price control documents, National Grid
Gas and electricity connection costs	Ofgem price control documents and connections market reporting
Capital costs of electricity network expansion	National Grid
Business rates	National Grid
Costs of gas distribution replacement programme	National Grid
Costs of gas T&D decommissioning per km	National Grid
Relationship between network size and opex	Redpoint regression analysis based on historic information from Ofgem price control documents

Table 10 Key data sources for other input assumptions

Category	Key sources
Biomass availability and costs	E4Tech (2009) Biomass supply curve for the UK[41] for DECC E4Tech (2009) Review of the potential for biomass in aviation report for the CCC[42] DECC 2050 Pathways Analysis E4Tech (2010) The potential for bioSNG production in the UK
Fossil fuel commodity prices	Near term to 2020 from Ofgem Project Discovery Longer term scenario specific

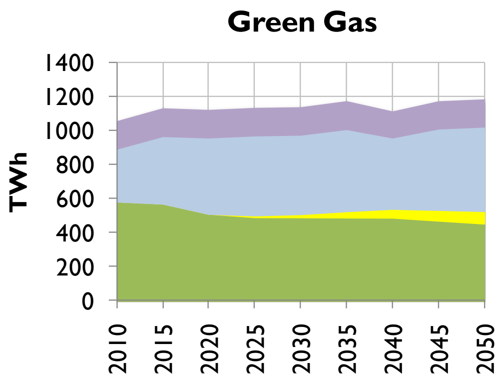
[41] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx

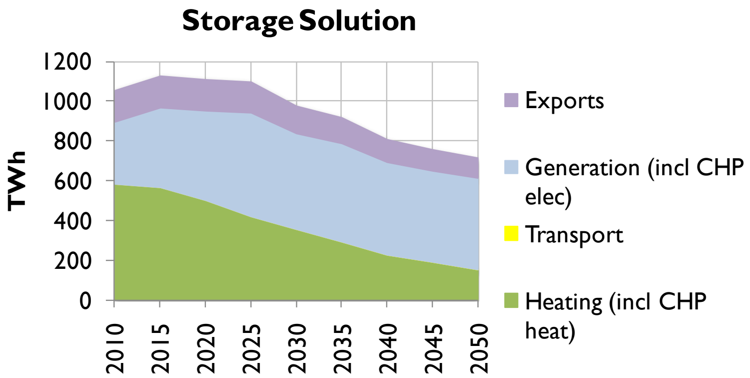
[42] http://www.theccc.org.uk/reports/aviation-report/supporting-research

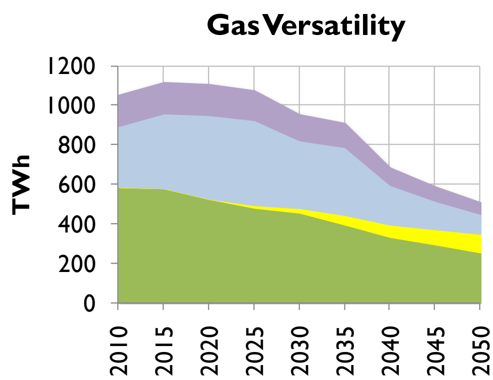
C Additional modelling results

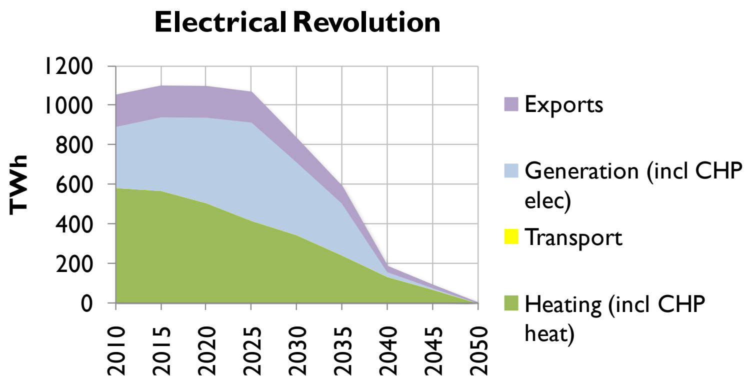
C.1 Future gas utilisation

C.1.1 Annual gas demand by sector

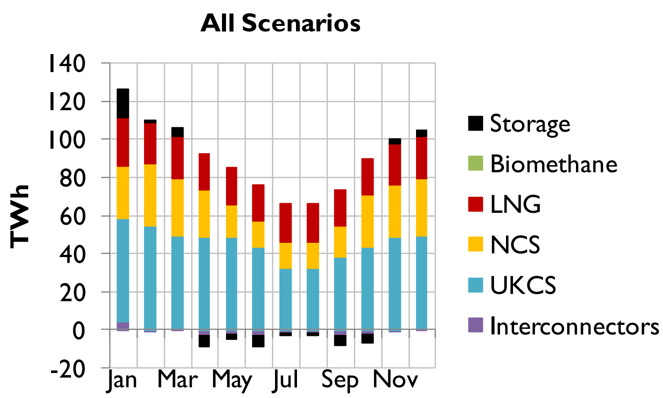




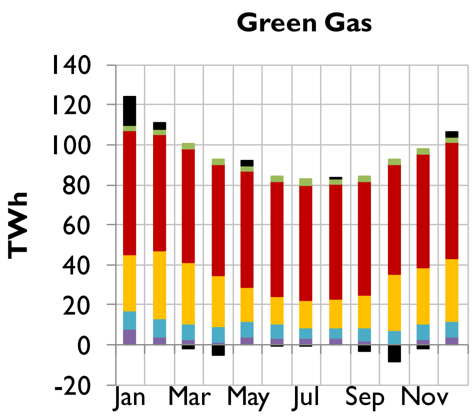


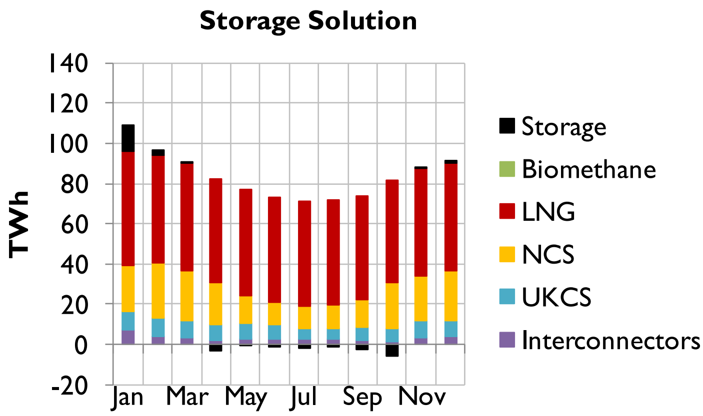


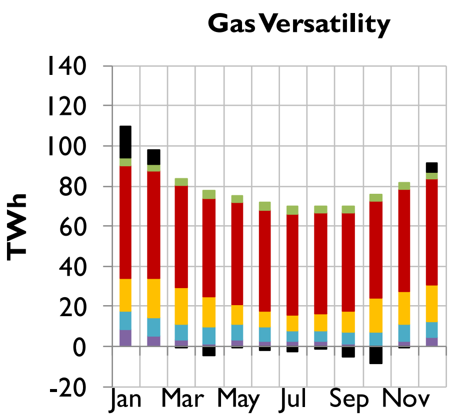
C.1.2 Monthly gas supply by source – 2010

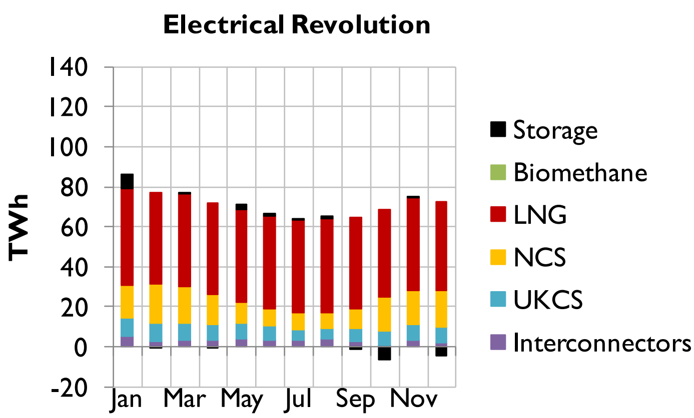


C.1.3 Monthly gas supply by source – 2030

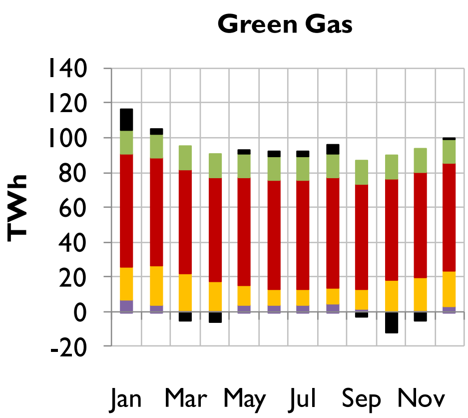


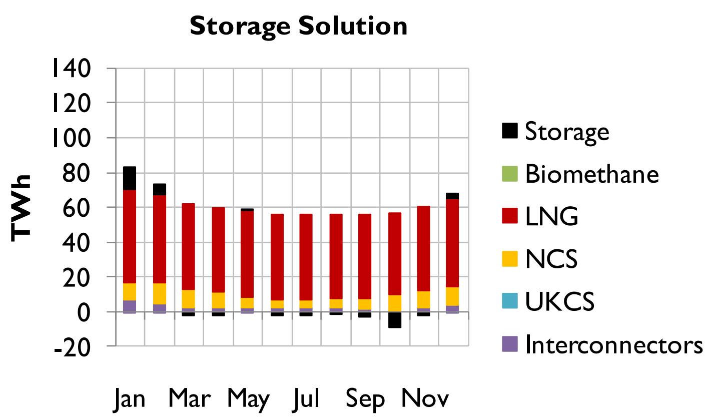


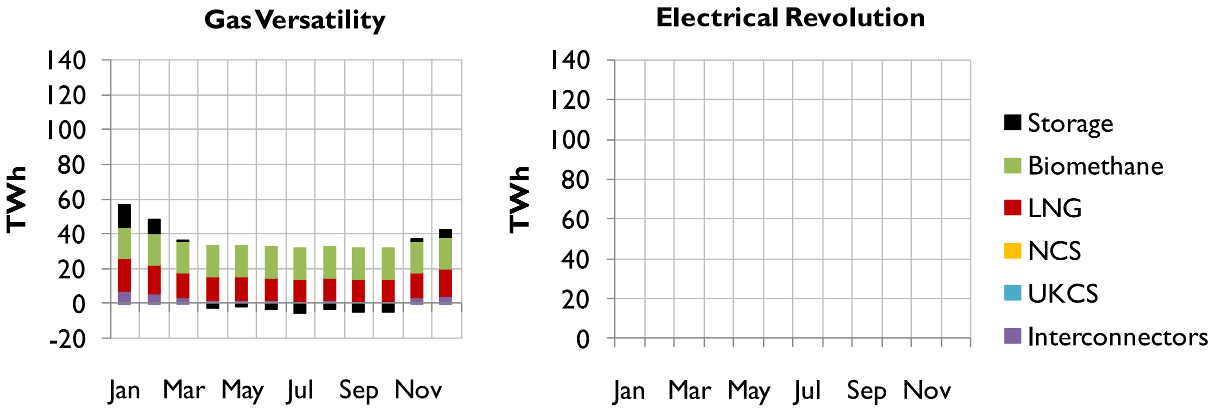




C.1.4 Monthly gas supply by source – 2050

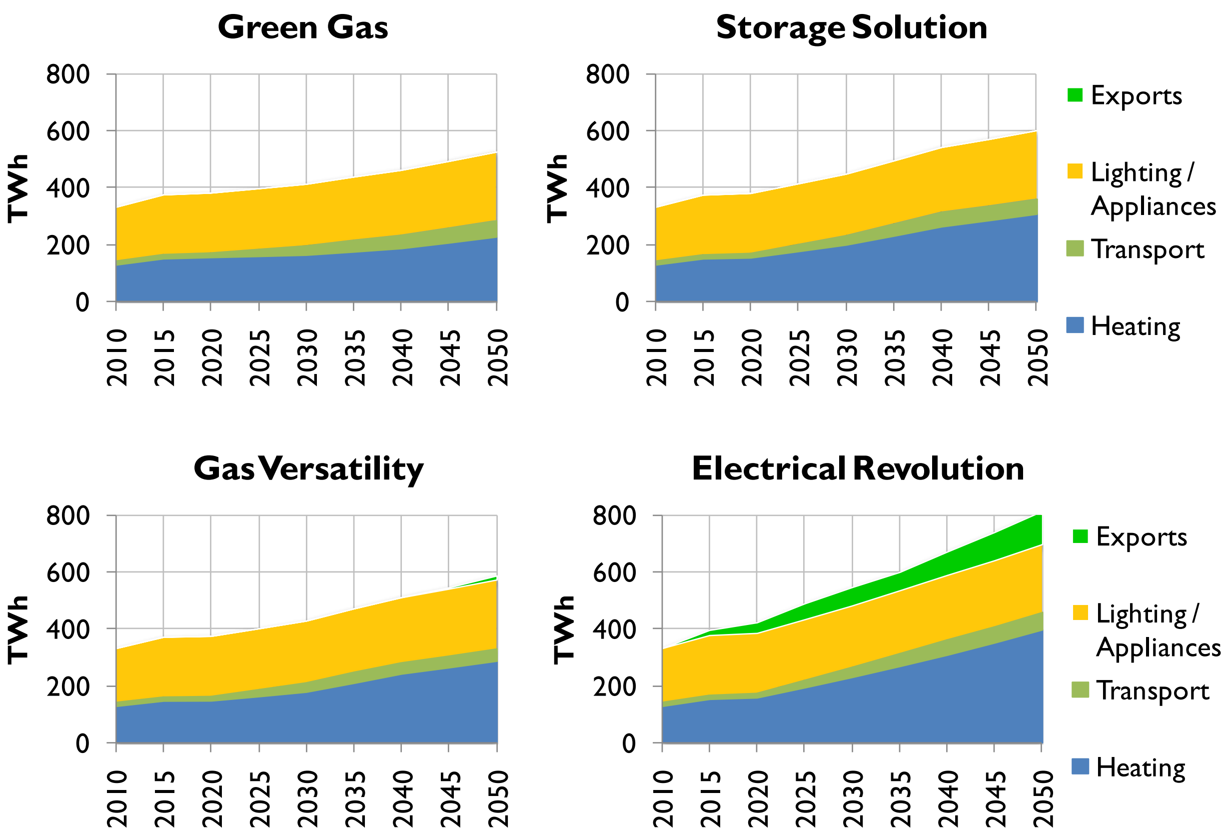






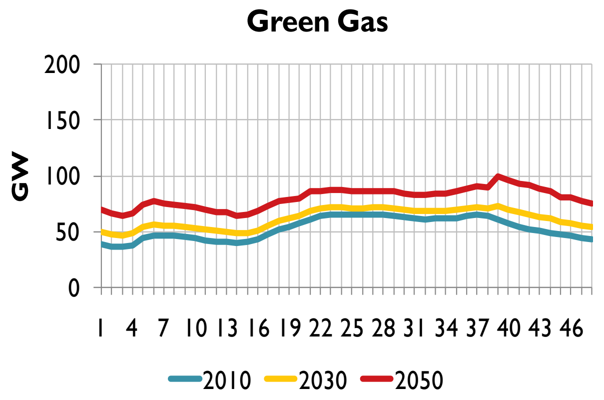
C.2 Electricity supply and demand

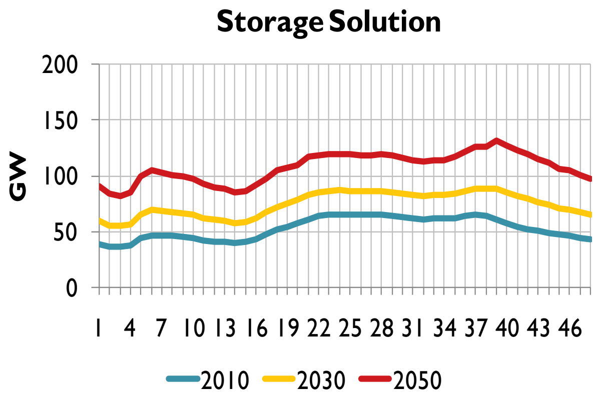
C.2.1 Annual electricity demand by sector

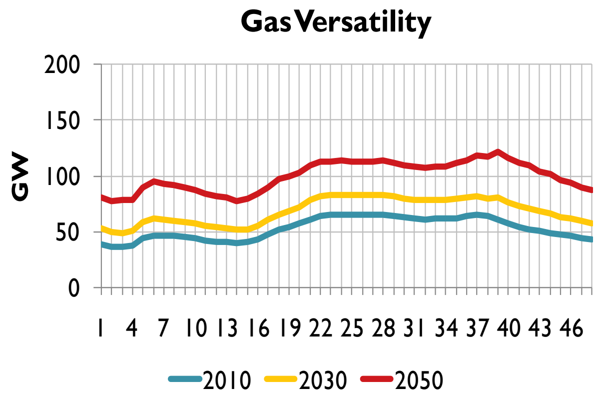


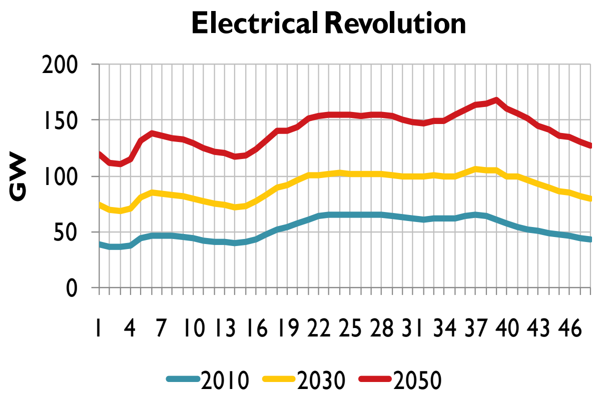
REDPOINT

C.2.2 Peak day electricity demand profiles (without storage / DSR)

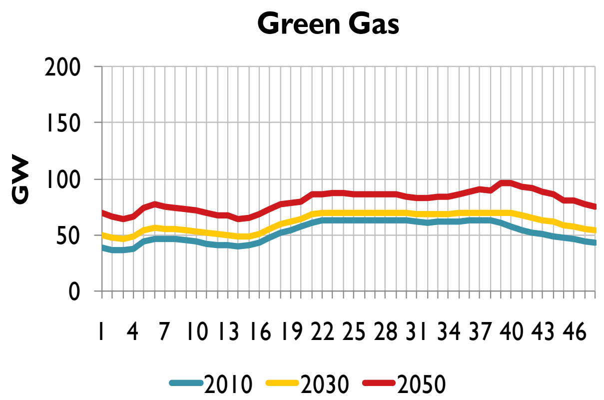


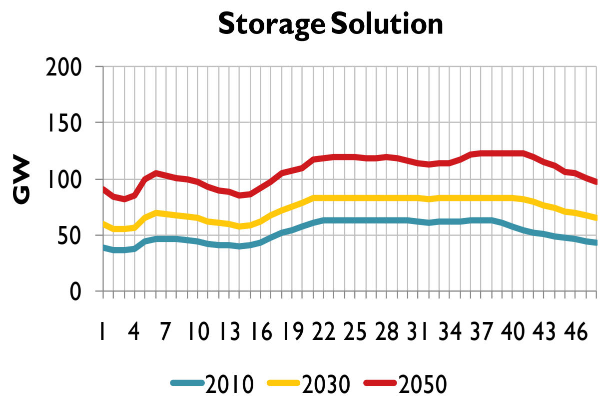


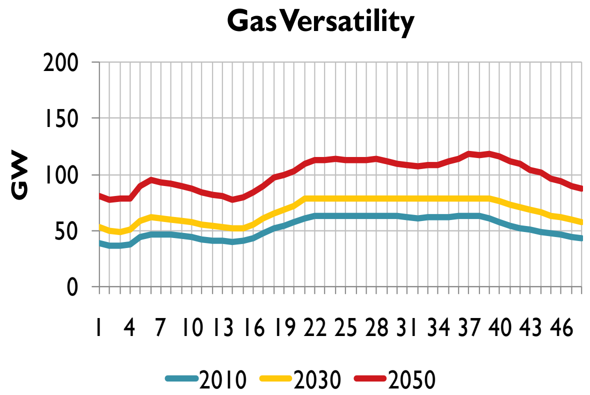


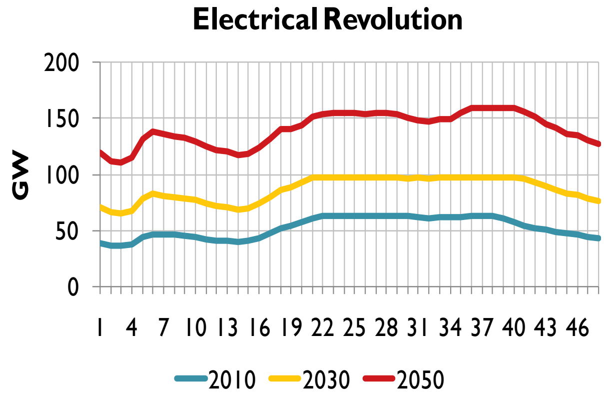


C.2.3 Peak day electricity demand profile (with storage / DSR)



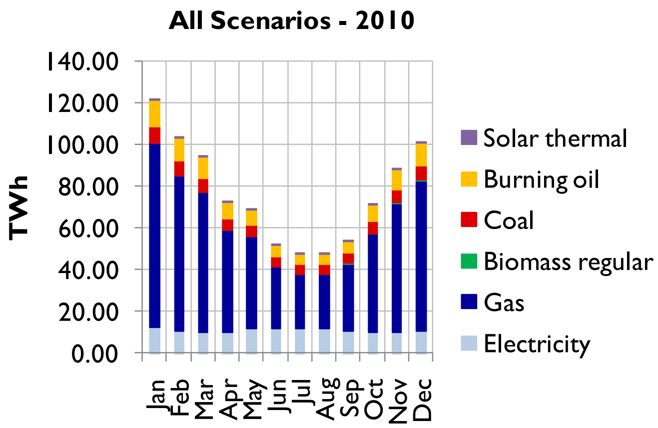




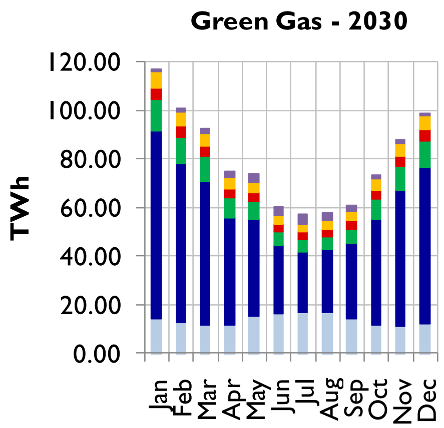


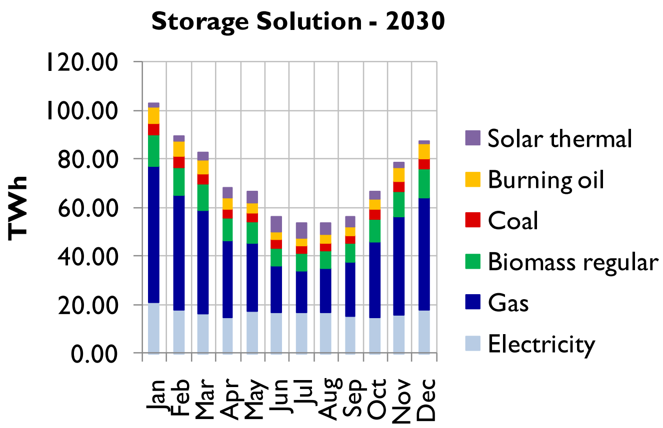
C.3 Heating and transport

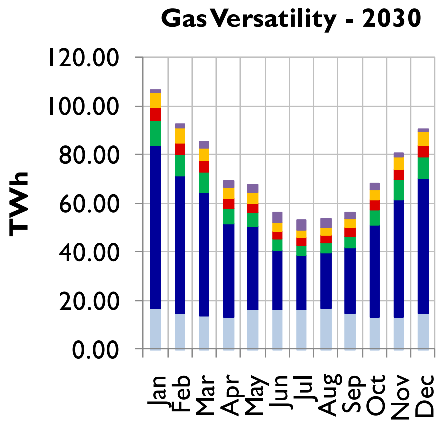
C.3.1 Heating monthly delivered energy demands – all sectors – 2010

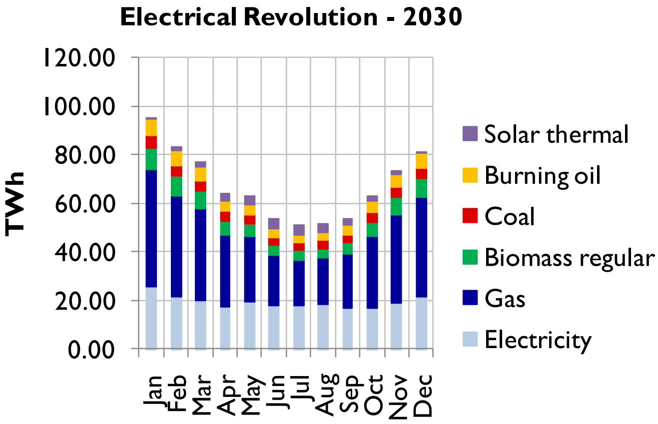


C.3.2 Heating monthly delivered energy demands – all sectors – 2030

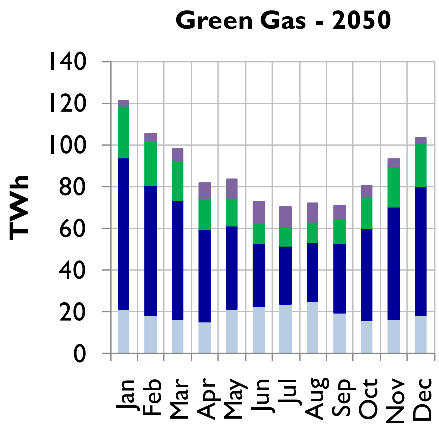


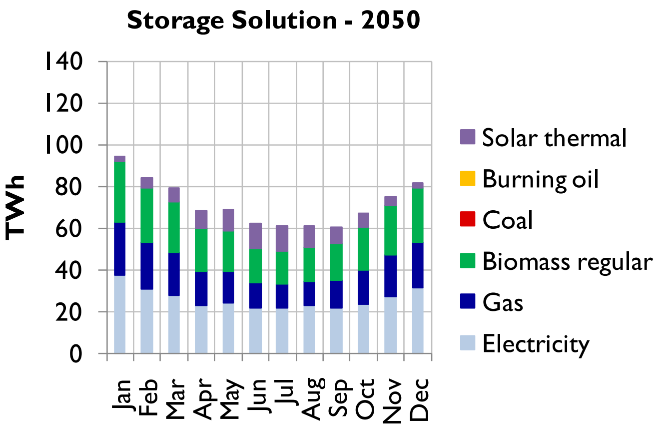


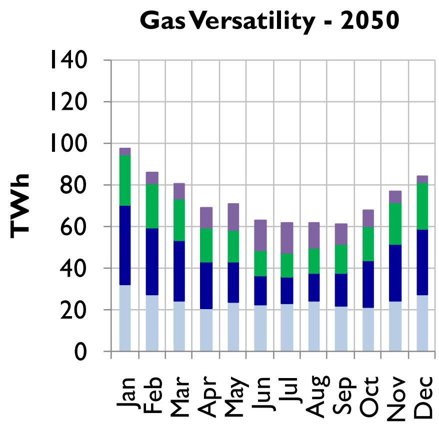


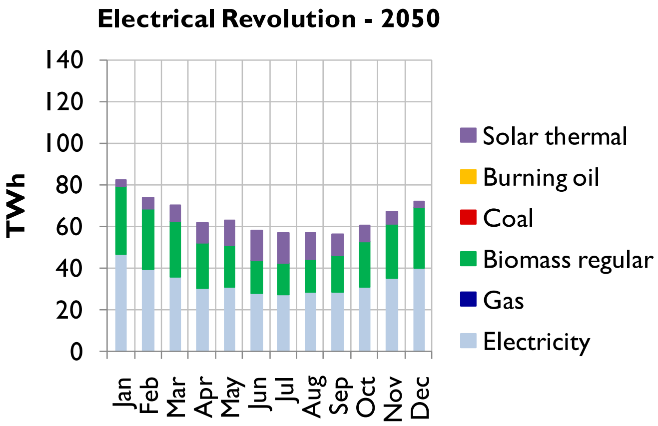


C.3.3 Heating monthly delivered energy demands – all sectors – 2050



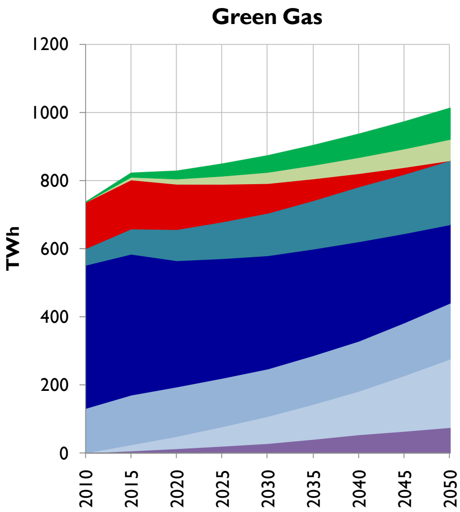


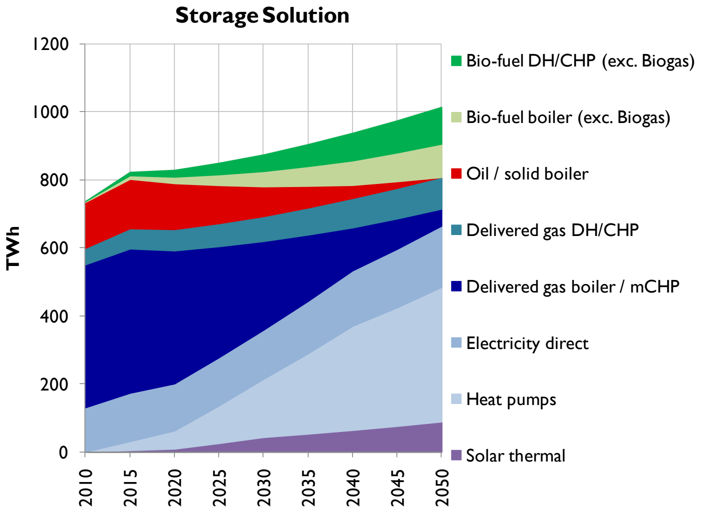


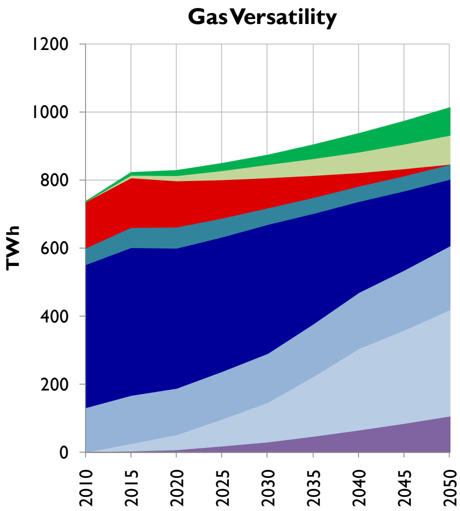


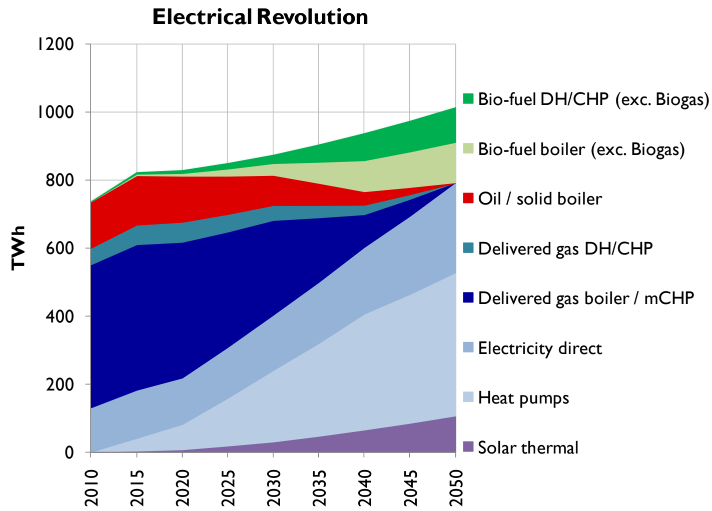
REDPOINT

C.3.4 Heating service demand / output by technology

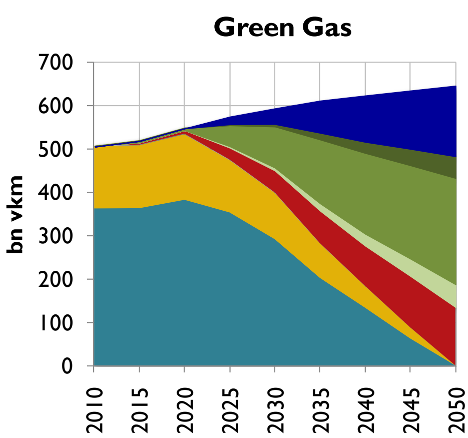


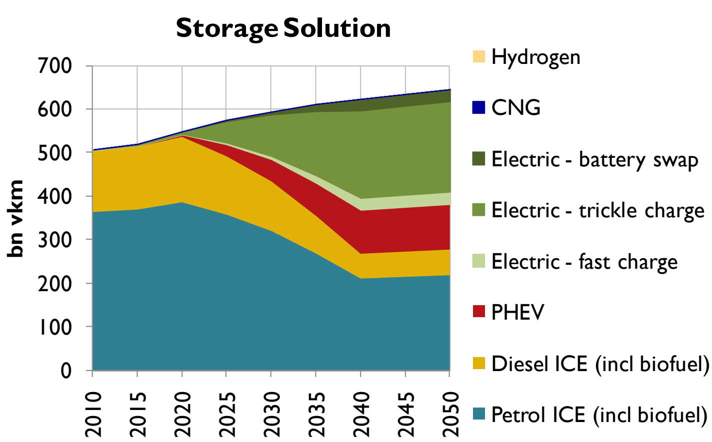


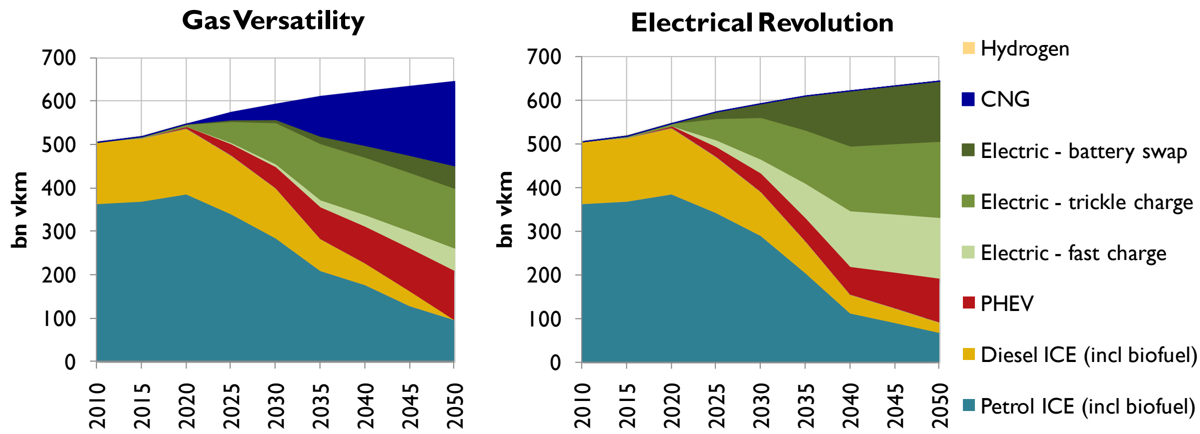




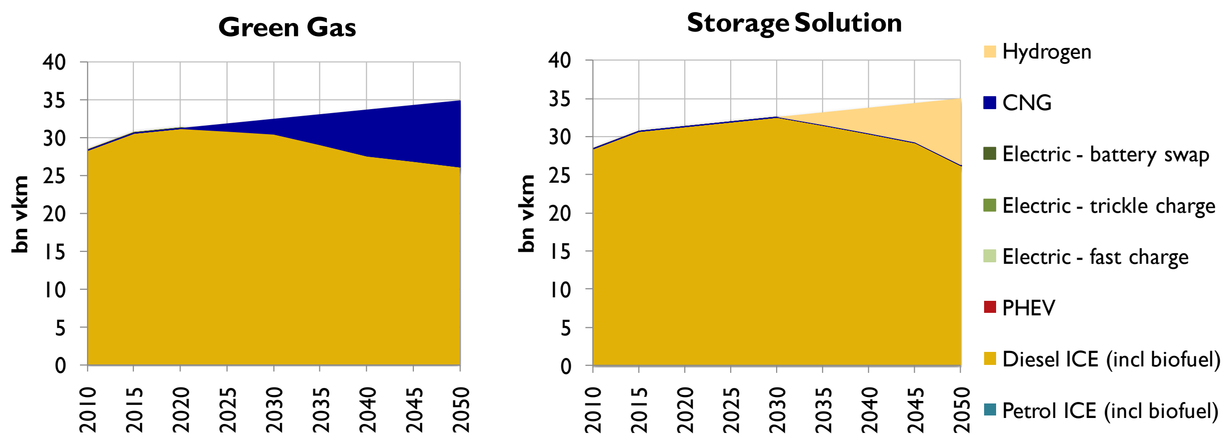
C.3.5 Transport service demands by technology – cars, buses, light goods vehicles (LGVs)

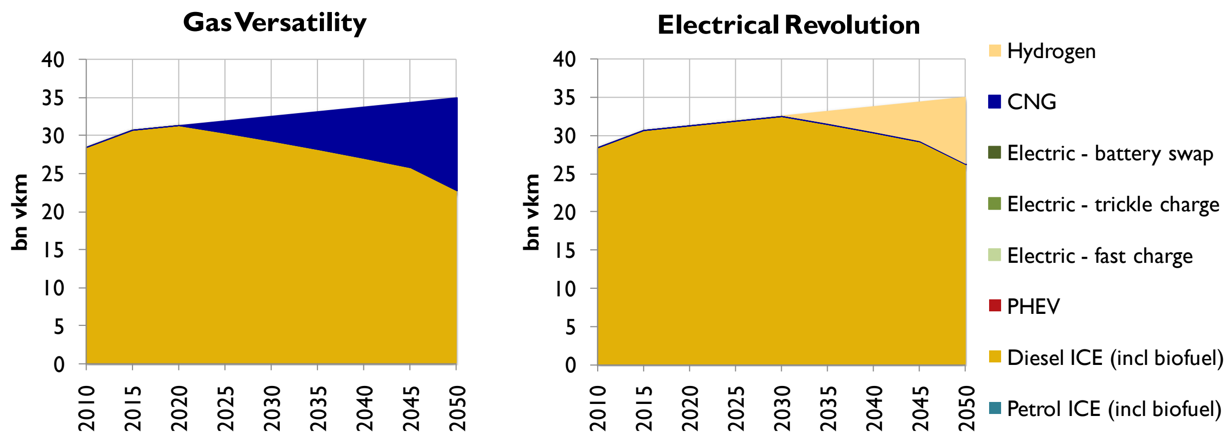






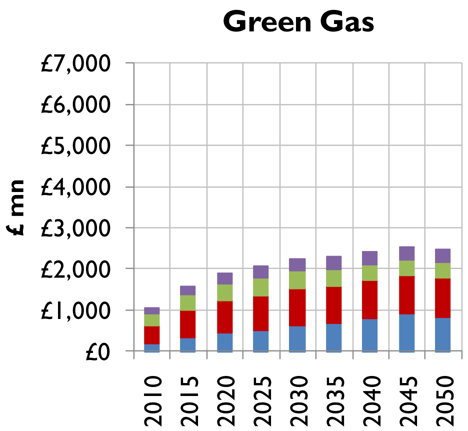
C.3.6 Transport service demands by technology – heavy goods vehicles (HGVs)

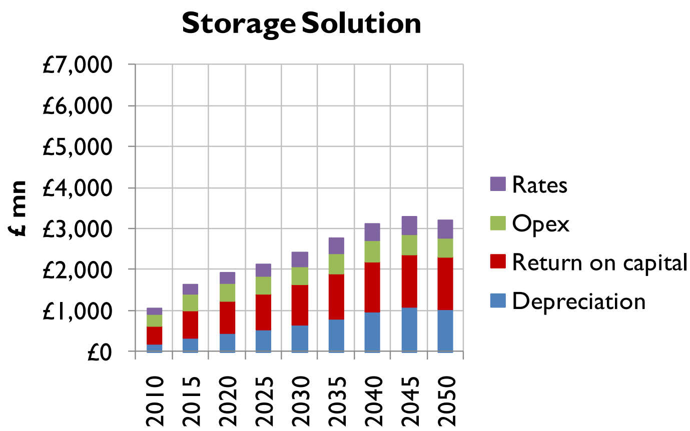


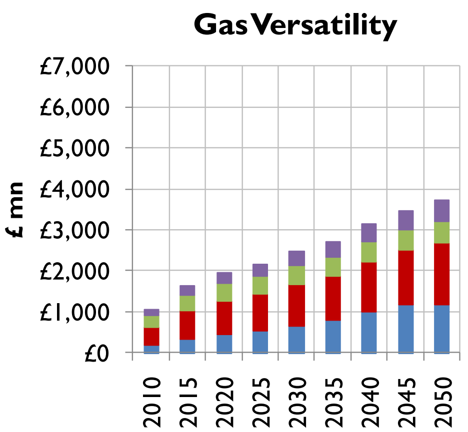


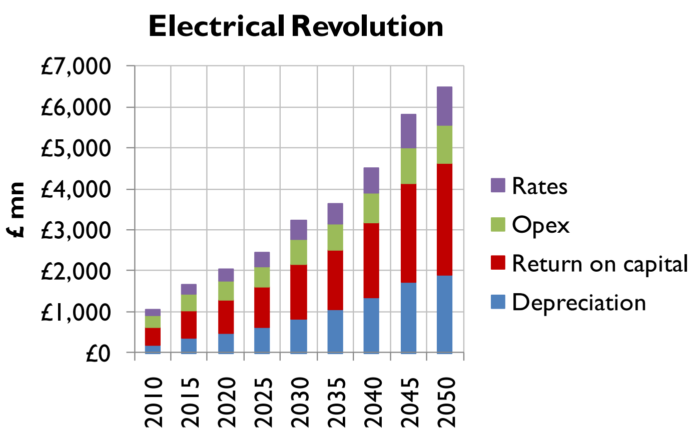
C.4 System costs

C.4.1 Annual electricity transmission costs by scenario

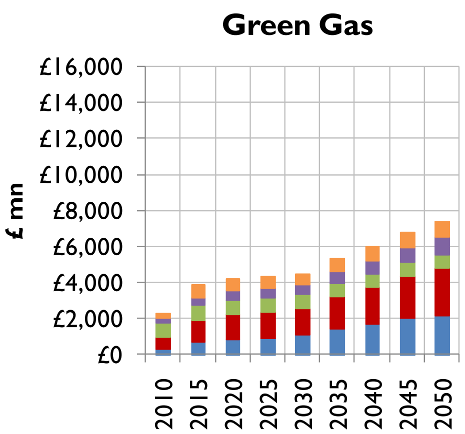


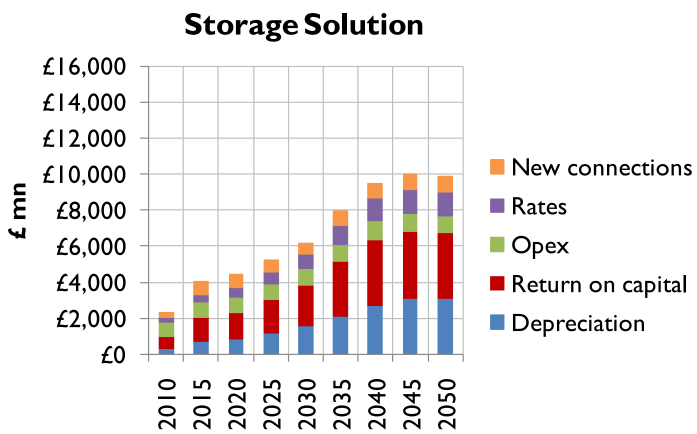


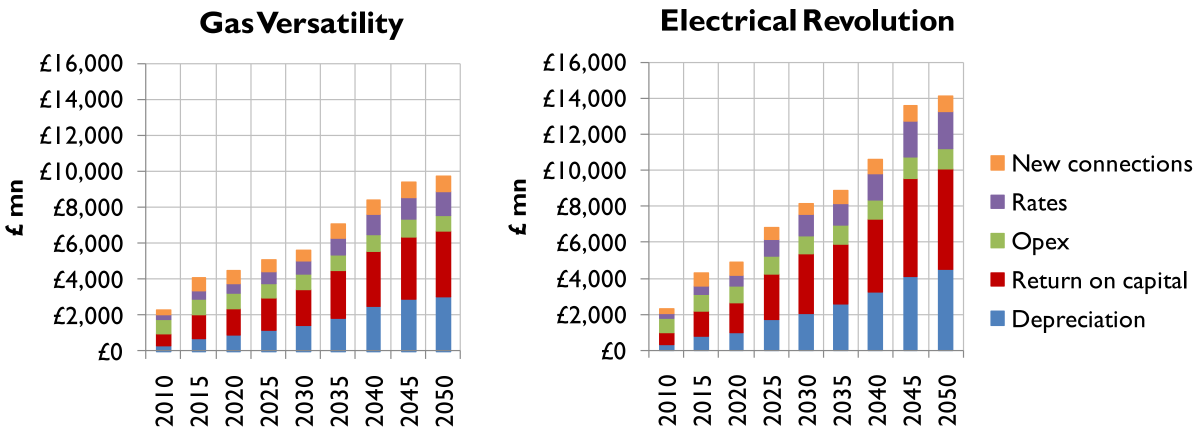




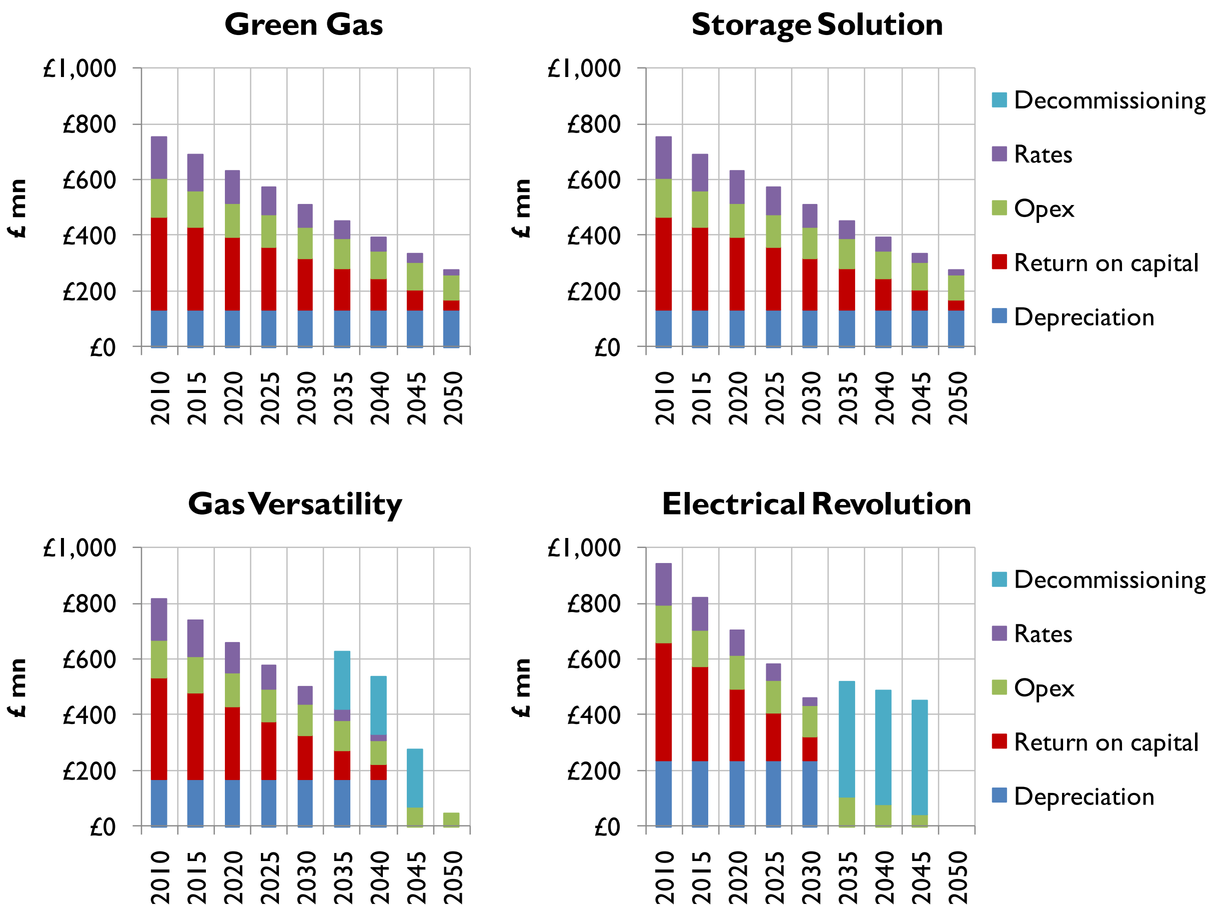
C.4.2 Annual electricity distribution costs by scenario







C.4.3 Annual gas transmission costs by scenario



C.4.4 Annual gas distribution costs by scenario