Imperial College London

Analysis of Alternative UK Heat Decarbonisation Pathways

For the Committee on Climate Change

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Imperial College London

Project Team

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Contents

Abbreviations

ATR	Auto Thermal Reformer
BECCS	Bioenergy plant with Carbon Capture and Storage
BEIS	Department for Business, Energy & Industrial Strategy
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
DH	District heating
EE	Element Energy
H_2	Hydrogen
HHP	Hybrid Heat Pump
HP	Heat pump
IWES	Integrated whole energy system model
LDZ	Local Distribution Zones
NG	Natural gas
NIC	Network Innovation Competition
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PEM	Proton Exchange Membrane
PV	Photovoltaics
RES	Renewable Energy Sources
RH	Resistive heating
SGI	Sustainable Gas Institute
SMR	Steam Methane Reformer
SOE	Solid Oxide Electrolyser
LT-TES	Long-term Thermal Energy Storage

Extended Executive Summary

Context and objective of the studies

Addressing the challenges related to decarbonisation of gas and heat, the Committee on Climate Change (CCC) has identified multiple decarbonisation pathways for low-carbon heating as proposed in the CCC's October 2016 report, "Next Steps for UK Heat Policy"[1]. Three central pathways have been identified: i.e. (i) by 'greening' the gas supply by shifting to low-carbon hydrogen (H2), (ii) electrification of heat supported by low-carbon power generation, or (iii) by potential hybrid solutions, with the bulk of heat demand, met by electricity, and peak demands met by green gas[2]. Each pathway brings significant challenges, and it was unclear whether there is a dominant solution and what the implications are on the future infrastructure requirements and operational coordination across energy systems in the UK.

In this context, the Integrated Whole-Energy System (IWES) model developed by Imperial College London, has been applied to assess the technical and cost performance of alternative decarbonisation scenarios for low-carbon heating in 2050 with the aim to:

- Understand the implications of alternative heat decarbonisation pathways on electricity and gas infrastructures in the UK energy system in 2050 by:
  - Analysing the interactions between the electricity and heat systems (including various forms of storage)
  - Optimising the interactions across different energy vectors to maximise the whole-system benefits;
- Understand the economic performance and drivers of various pathways by:
  - Comparing the whole system costs of alternative heat decarbonisation scenarios in 2050, and beyond towards a zero-emissions energy system. For example, comparing the costs of retaining gas distribution networks that are re-purposed for hydrogen transport, against reinforcing the electricity grid under various low-carbon heating scenarios
  - Analysing the impact of uncertainties in technologies and costs;
- Provide fundamental evidence to support the development of policies for decarbonisation of heating and the electricity system.

Comprehensive studies have been carried out to quantify the investment and operational requirements as well as the costs of alternative heat decarbonisation pathways for a representative energy system for Great Britain in 2050. These studies

[1] Available at: https://www.theccc.org.uk/wp-content/uploads/2016/10/Next-steps-for-UK-heat-policy-Committee-on-Climate-Change-October-2016.pdf

[2] A bioenergy focused pathway was not considered a core option, as the CCC's 2011 Bioenergy Review suggested a limit of around 135 TWh of primary bioenergy that could be available to the UK power and gas systems.

were carried out in the context of related activities in this area, including research carried out by the Department for Business, Energy & Industrial Strategy (BEIS) research on Heat and Strategic Options, research into the costs of future heat infrastructure for the National Infrastructure Commission[3], Network Innovation Competition (NIC) trials etc.

The interactions across different energy vectors, i.e. electricity, gas, and heat systems including different types of energy storage (electricity, hydrogen, thermal) have been optimised using the IWES model to maximise whole-system benefits. In summary, the IWES model minimises the total cost of long-term infrastructure investment and short-term operating cost while considering the flexibility provided by different technologies and advanced demand control, and meeting carbon targets. The IWES model includes electricity, gas, hydrogen and heat systems, simultaneously considering both short-term operation and long-term investment decisions[4] covering both local district and national/international level energy infrastructure, including carbon emissions and security constraints.

Scope of the studies

The CCC's approach to low-carbon heat is presented in Figure E. 1. The scope of this particular study includes quantification of the system costs of different heat decarbonisation pathways, consistent with the CCC's approach to low-carbon heat. The CCC's previous analysis has identified that converting all off-gas grid homes and some direct electric heating to heat pumps, representing 18% of households[5], and 13% of households in urban areas to district heating is cost-effective. This modelling, therefore, considers the costs of converting the remaining 71% of households to a low-carbon heating technology.
The studies focus on:

- The cost performance of each decarbonisation pathway and cross-cutting analysis across pathways;
- The interaction and optimal capacity portfolios of power system infrastructure (generation, electricity network, electricity storage), hydrogen infrastructure (production capacity, hydrogen network, storage), carbon capture and storage infrastructure and heating infrastructure;
- The impact of uncertainties in key modelling assumptions and input parameters;
- The role and benefits of enabling technologies that can improve system flexibility

[3] Element Energy and E4tech," Cost analysis of future heat infrastructure," a report for National Infrastructure Commission, March 2018.

[4] This study focuses on the optimal investment needed to meet the 2050 system requirements and carbon target. The transition from the present to the optimised 2050 system warrants further studies.

[5] Assuming 34.3m households by 2050

across all energy vectors and reduce emissions;
- The impact of energy efficiency and climate change;
- Technical feasibility of the existing gas distribution infrastructure to transport hydrogen.

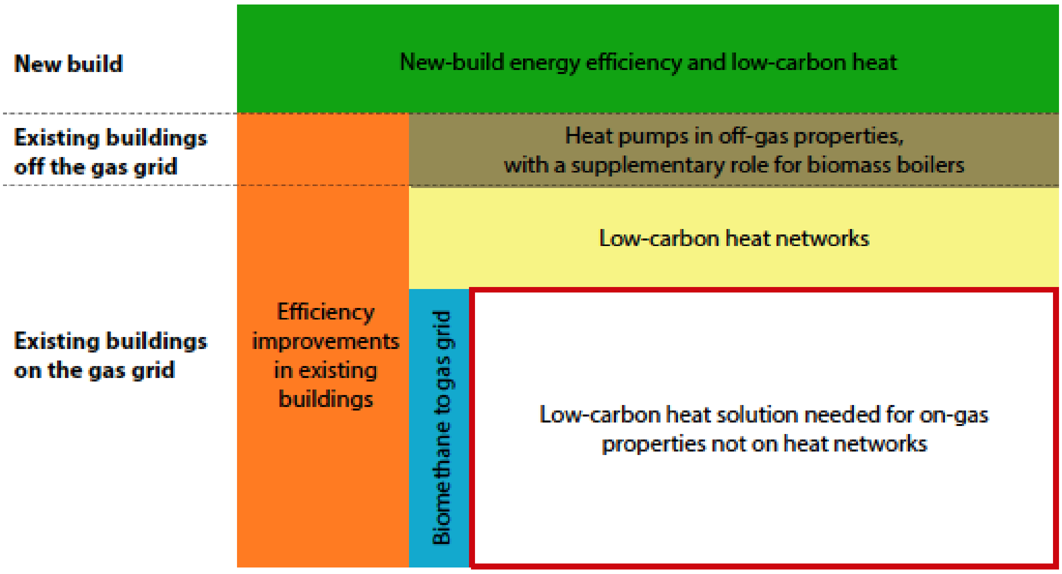


Figure E. 1 Low-regrets measures and the remaining challenge for existing buildings on the gas grid[6]

The analysis is based on an optimised system constructed by the IWES model, which assumes that full coordination across all system components (i.e. gas, electricity, heat infrastructure) can be achieved. This will require further development of appropriate regulatory and commercial frameworks as well as cooperation across all market stakeholders and deployment of appropriate technologies and control systems necessary to enable cost effective decarbonisation of the GB energy system, which is beyond the scope of this report.

Overview of the investigated heat decarbonisation strategies

The study focuses on three core heat decarbonisation pathways:

- ***Hydrogen pathway***
  The core Hydrogen pathway is based on the application of end-use hydrogen boilers at consumer premises to decarbonise heat demand. It is assumed that consumers that do not have access to gas would use electric heating.

- ***Electric pathway***
  In this pathway, heat demand is met by the optimal deployment of end-use electric heating appliances including heat pumps (HP) and resistive heating (RH).

[6] CCC (2016) Next Steps for UK Heat Policy

- ***Hybrid pathway***
  This pathway is based on the application of combining the use of gas and electric heating systems, i.e. hybrid heat pump (HHP). The gas heating system in the Hybrid system uses natural gas or carbon-neutral gas such as biogas or hydrogen to reduce emissions from gas.

The study uses two main annual carbon emissions targets, i.e. 30Mt and 0Mt to identify the implications of going to zero carbon; 10Mt is used in some studies to investigate the system changes in the transition from 30Mt to 0Mt. Sensitivities of the results against different assumptions (e.g. financing cost, heat demand, system flexibility, hydrogen import, unavailability of nuclear) have also been studied and analysed.

A range of alternative strategies has also been investigated, with the core heat decarbonisation pathways. This includes the implementation of:

- ***Regional decarbonisation strategies***
  The strategies combine one decarbonisation pathway with a different pathway with the aim to find lower cost solutions:
  - Use of hydrogen in the North of GB[7] while the rest of the system is decarbonised through HHP, in order to minimise investment in hydrogen networks.
  - Use of hydrogen in urban areas while rural areas are decarbonised through HHP.
  - Use of industrial HP-based district heating in urban areas.
- ***District heating***
  This consists of two scenarios including:
  - National deployment of industrial-scale hydrogen boilers in district heating networks (H2+DH);
  - National deployment of industrial HP in district heating networks (Elec+DH);
- ***Micro-CHP***
  In this scenario, 10GW of micro-CHP is deployed in the Hybrid system that can displace end-use HHPs and power generation.

The key results of the studies are described as follows.

Cost performance of core decarbonisation pathways

The annual system costs of different decarbonisation pathways were considered in this study across three different annual carbon emissions targets, i.e. 30 Mt, 10 Mt, and 0 Mt[8] are presented in Figure E. 2.

[7] Scotland, North of England and North of Wales
[8] H2[30], H2[10], and H2[0] refer to the H2 pathway with 30Mt, 10Mt, and 0Mt target respectively. The same notation is used to identify the decarbonisation pathways (H2, Elec, Hybrid) and the carbon targets ([30],[10],[0]).

Key assumptions

- Auto Thermal Reformer (ATR) combined with Carbon Capture and Storage (CCS) is considered as the default technology for producing hydrogen from natural gas[9]; otherwise, hydrogen is produced using electrolysis.
- Hydrogen is produced from gas in a centralised manner, in the regions which have access to gas and carbon storage terminals, to maximise the benefits of economies of scale and eliminate the need for national CCS infrastructure.
- 21 TWh of biogas and 135 TWh of primary bioenergy are used in all pathways.
- The assumed maximum capacity of low-carbon generation that can be deployed by 2050 for wind, PV, CCS, and nuclear is 120 GW, 150 GW, 45 GW, and 45 GW respectively.
- 50% of the potential flexible technologies across electricity, heat and transport sectors is assumed to be available to provide various system services. These include controllable industrial and commercial loads, electric vehicles, smart domestic appliances and preheating.
- Optimised energy storage including electricity, thermal, and hydrogen storage
- Household level energy efficiency measures (including insulation) are assumed to be deployed consistent with the CCC's scenarios for 2050. There are no costs associated with energy efficiency in the modelling.
- Light vehicle transport is assumed to be electrified in all scenarios, leading to 111 TWh of electricity demand by 2050.
- 135 TWh of industrial space heating demand is assumed to be either electrified or hydrogenated in the respective pathways.

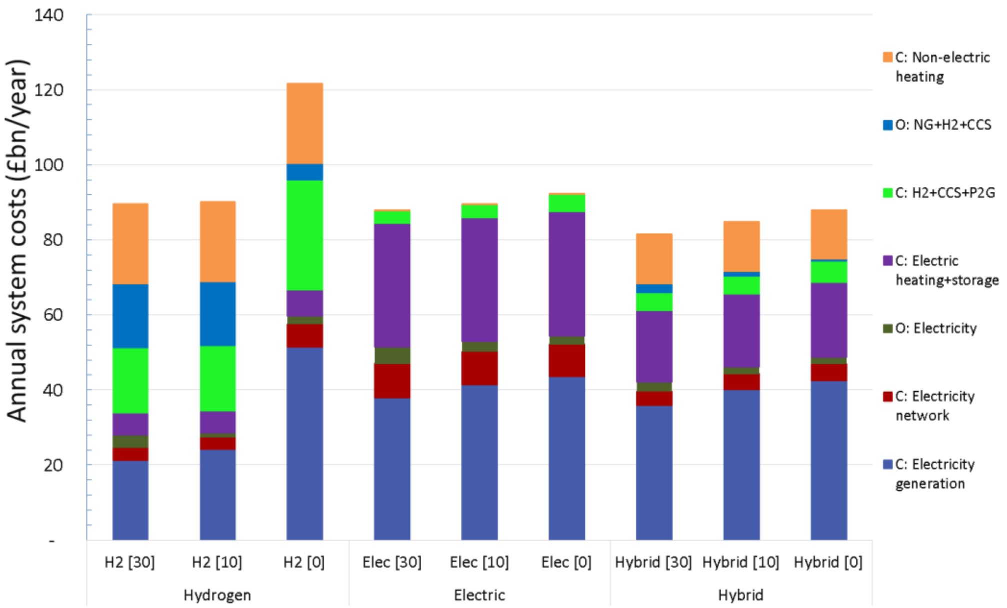


Figure E. 2 Annual system cost of core decarbonisation pathways

9 Assumed natural gas price: 67p/therm

The IWES model optimises 29 system cost components[10] which are grouped into five capex (C) and two opex (O) categories as follows:

a. ***C: Electricity generation*** – annuitised capital cost of electricity generation that encompasses both low-carbon and non-low carbon generation.
b. ***C: Electricity networks –*** annuitised capital cost of the electricity network that consists of the cost of the distribution network, transmission network and interconnectors.
c. ***O: Electricity*** – annual operating cost of electricity that includes all the variable operating costs (e.g. fuel, O&M) as well as start-up, and fixed operating costs. Carbon prices are excluded from this analysis.
d. ***C: Electric heating +storage*** – annuitised capital cost of electric heating and energy storage in electric scenario includes the capital cost of the heat pump (domestic and industrial), resistive heating, electric storage, thermal energy storage, cost of end-use conversion (replacing gas-based heating to electric), cost of appliances and cost of decommissioning gas distribution due to electrification.
e. ***C: H2+CCS+P2G*** – annuitised capital cost of hydrogen and CCS infrastructure, including the cost of all hydrogen production technologies, cost of hydrogen and CCS networks, cost of hydrogen storage and carbon storage.
f. ***O: NG+H2+CCS*** – annual operating cost of the natural gas system that includes fuel cost of gas-based hydrogen production technologies, e.g. SMR and ATR, cost of hydrogen import, operating cost of hydrogen storage and the fuel cost of the natural gas (NG)-based boiler.
g. ***C: Non-electric heating –*** annuitised capital cost of non-electric heating includes the capital cost of natural gas (NG) and hydrogen-based boilers, cost of district heating infrastructure, conversion cost and the cost of maintaining the existing gas distribution network.

The key findings are summarised as follows:

1. Costs of alternative decarbonisation pathways are relatively similar for 30Mt, but the cost differences increase for the H2 pathway in 0 Mt case

As shown in Table E. 1, the system costs of the decarbonisation pathways at the carbon emissions target of 30Mt/year are broadly similar; the cost difference between core pathways, i.e. Hybrid, Electric and H2 is within 10%, and hence the ranking may change when different assumptions apply. The costs marginally increase at 0Mt/year, except in H2 pathways as the hydrogen production shifts from gas to electricity, which significantly increases the cost of hydrogen infrastructure (due to the shift from ATR to electrolysers).

[10] More description of the cost components used in the IWES model can be found in Appendix A.

Table E. 1 Cost performance of different decarbonisation pathways

Pathways	Cost (£bn/year)		
	30Mt	10Mt	0Mt
Hybrid	81.6	84.8	88.0
Elec	87.8	89.5	92.2
H2	89.6	90.2	121.7

In the H2 pathways, the cost of hydrogen infrastructure is dominated by the cost of gas reforming plants and hydrogen storage, which is optimised in the study. The function of hydrogen storage[11] is to improve the utilisation of the hydrogen infrastructure by reducing the capacity of hydrogen production plants. For example, the peak demand of hydrogen in the H2 30Mt case reaches 260 GW while the total capacity of hydrogen production proposed by the model is only 103 GW (costs £8bn/year). In order to meet such demand, there is a need for around 20 TWh of hydrogen storage (costing £6.4 bn/year). Without storage, the hydrogen production capacity would be 2.6 times larger which would increase the cost of the H2 pathway by £13 bn/year).

2. **The Hybrid pathway is the least-cost under central assumptions while the cost of the H2 pathway is found to be the highest cost, compared to the other pathways.**

The cost of each of the core pathways is presented in merit order in Table E. 1. The Hybrid scenario is identified as the most cost-effective decarbonisation pathway, with the hydrogen pathway being the most expensive. All of these cost results involve a broad range of uncertainty (see page 20).

There are several key drivers contributing to the cost performance of different decarbonisation pathways:

- The Hybrid pathway is based on high-efficiency HHPs that supply the baseload of heat demand while providing the flexibility to use gas during peak demand[12] conditions or low renewable output. This flexibility reduces the capacity requirement of the power system infrastructure required to meet peak demand compared to the capacity required in the Electric pathway. This also reduces the capacity required for security of supply reasons and the corresponding costs. It is important to highlight that the model determines the level of capacity needed to maintain the same level of security in all pathways.
- In general, the Electric pathway requires the highest investment in electricity

[11] Combination of underground storage, e.g. salt caverns as is currently used in Teesside and medium pressure over ground storage

[12] In order to test the adequacy of the system capacity to deal with the extreme weather conditions, 1-in-20 years events are considered, i.e. extreme cold winter week coinciding with low output of renewables.

networks, particularly at the distribution level, due to a significant increase in peak demand driven by heat electrification. Network costs in the Hybrid pathway are significantly lower than in the Electric pathway as the use of the gas boiler component of a hybrid heat pump during peak demand can efficiently reduce the need for distribution network reinforcement (although some network reinforcement is required to accommodate renewable generation). The H2 pathway tends to require significantly lower electricity distribution network reinforcements, when compared to the other pathways, except in the 0Mt case where significant reinforcement is needed to accommodate demand-side flexibility and integrate more renewable generation to achieve the carbon target cost-effectively (as it is assumed that all hydrogen is produced domestically via electrolysis in the 0Mt case, requiring additional low-carbon electricity generation).

- In the H2 pathway, natural gas is decarbonised through hydrogen production via gas reforming with CCS[13]. This reduces the need for investment in low-carbon electricity generation but requires higher investment in the hydrogen and CCS infrastructure compared to other pathways[14]. However, the overall operation and investment cost associated with the hydrogen system in H2 pathway exceeds the benefits associated with lower investment in electricity generation. The cost difference becomes much more pronounced in 0Mt case as the cost of hydrogen infrastructure increases substantially (as shown in Figure E. 2) due to the shift from ATR to electrolysers (capex of electrolysers is higher than the capex of ATR), although the increase in capex can be partially offset by the reduction in the gas opex.
- The H2 pathway is characterised by the lowest energy efficiency due to a number of energy conversion processes involved: heat pumps are operated between 200% and 300% efficiency (or higher)[15], whereas converting gas to hydrogen for use in domestic gas boilers is 80% efficient or less (depending on the efficiency of hydrogen boilers and efficiency of the hydrogen production). However, the cost of hydrogen boilers is significantly lower than HP or HHP.
- There is a need to replace gas appliances in both the H2 and Electric pathways, which increases the costs of corresponding scenarios. Hydrogen boilers are significantly lower cost than heat pumps[16], at £75/kW$_{th}$ for a boiler and £600/kW$_{th}$ for a heat

[13] Assuming Auto-thermal Reforming, with 88% HHV efficiency and 96% capture rate, based on Element Energy (2018) Hydrogen Infrastructure: Summary of Technical Evidence

[14] The CCC specified that 135 TWh of primary bioenergy should be used to provide 'negative emissions' via Bioenergy plant with Carbon Capture and Storage (BECCS), though these negative emissions are not considered within the carbon constraint in the model as these are accounted for across the economy. The model chose to use BECCS to produce hydrogen in all cases, with the hydrogen being used in either hydrogen-based power plant or gas boilers. The cost of BECCS plant is included in all pathways. Efficiencies for BECCS plant were assumed to be 69% for gasification and 40.6% for electricity generation.

[15] Annual average COP of HP used in the study is 2.7.

[16] More detailed information about household conversion costs can be found in Appendix B.

pump but have higher operating costs. In the Hybrid pathway, on the other hand, there is no need to replace other gas appliances, which minimises the household conversion cost.

3. Electric and Hybrid pathways have greater potential to reduce emissions to close to zero at a reasonable cost, compared to the H2 pathway.

Comparing the system costs of 30Mt, 10Mt and 0Mt cases in Table E. 1, the results demonstrate the following:

- While the cost to meet a 10Mt carbon target in the H2 pathway increases only by £0.6bn/year compared to the cost in 30Mt scenario, there is a significant increase in cost (more than £30bn/year) in H2 pathways when carbon target changes from 30Mt to 0Mt, driven by the change in hydrogen production from ATR to electrolysers. The system costs of electrolysers are higher than ATR as the application of electrolysers also requires a significant increase in investment in the low-carbon electricity generation. Improved carbon capture rates on gas reforming plant or importing low-carbon hydrogen to the UK could allow for reduced emissions in the H2 pathway.
- The costs of the Electric and Hybrid pathways in the 0Mt cases are also 4 - 6 £bn/year higher than the corresponding costs in 30Mt; this is driven by the increase in electricity generation capex as a higher capacity of nuclear is needed to provide a firm low-carbon electricity source. The increased nuclear capacity is also observed in H2 0Mt case. The implication is that fewer emissions are available to the reserve and response plants that are required to back up variable renewables in these pathways, requiring firm low-carbon generation.
- Achieving zero emissions with a hybrid pathway will depend on the availability of low-carbon biogas, as well as consumer usage of the hybrid heat pump.

The analysis demonstrates that:

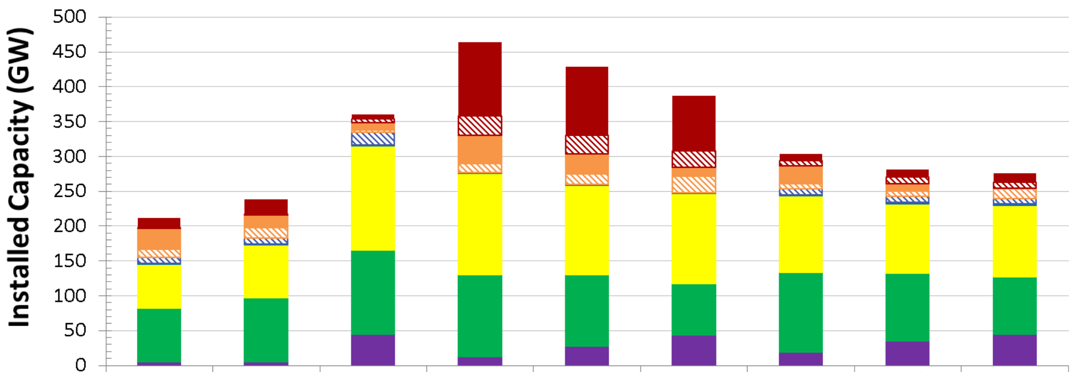
- Systems with more stringent carbon emission targets will lead to higher costs;
- Further decarbonisation beyond 30 Mt is possible at limited additional costs (few billions per year) in the hybrid and Electric pathways; this is also true for deep decarbonisation towards a zero-emissions energy system.
- Electric and Hybrid pathways provide more optionality towards a zero-carbon future compared to the H2 pathway, which is limited up to 10 Mt unless there is an improvement in the capture rate of CCS.

4. The costs of low-carbon systems are dominated by capital expenditure (capex) while operating expenditure (Opex) is significantly lower.

In the 30Mt cases, the ratio between the system opex and total cost is relatively small, i.e. less than 25% in the H2 pathway, 5% in Electric, and 6% in Hybrid. Towards zero carbon, the opex component in all decarbonisation pathways reduces significantly as most of the energy is produced by zero marginal cost renewable resources and low operating cost nuclear generation, while the use of gas is limited to only low-carbon gas (biogas, bioenergy), with any hydrogen being produced by electrolysis supplied by low-carbon electricity generation. This implies that the system costs will be very sensitive to capital and financing cost of infrastructure[17] and much less sensitive to fluctuations in future gas prices.

Impact of heat decarbonisation strategies on the electricity generation portfolio

Different decarbonisation pathways require substantially different electricity generation portfolios, as the choice of heating pathway will have significant implications for gas and electricity systems. Optimal generation portfolios for the core decarbonisation scenarios are presented in Figure E. 3. Coordination of the design and operation of gas, heat and electricity systems is important for minimising the whole-system costs of decarbonisation.



	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
	Hydrogen			Electric			Hybrid		
OCGT	15	21	6	106	98	79	9	11	13
H2 OCGT	0	0	5	27	27	24	8	10	9
CCGT	30	19	11	41	28	13	26	11	0
H2 CCGT	12	14	3	12	15	23	7	8	14
District CHP	8	9	18	0	0	0	8	8	8
Hydro	1	1	1	1	1	1	1	1	1
PV	63	76	150	146	128	129	110	99	103
Wind	77	92	120	117	104	74	115	98	82
Nuclear	5	5	45	13	27	43	19	35	45

Figure E. 3 Optimal generation portfolio in the core decarbonisation pathways

From the optimal generation portfolio proposed by the model, a number of conclusions can be derived:

1. **Maximum capacity of low-carbon generation that is assumed to be available by**

[17] Hurdle rates used in the study are between 3.5% and 11% depending on the technologies.

2050 is sufficient to reach the zero-carbon target[18].

Across all scenarios a significant capacity of low carbon electricity generation PV, wind and nuclear is required, representing an increase of 130-450% of electricity generation capacity on today's levels (of around 100 GW). The optimal generation portfolio also includes hydrogen based CCGT and OCGT plant. There is only one case, i.e. 0Mt H2 pathway, where the capacity of PV, wind and nuclear hit the upper limits of UK deployment potential by 2050[19]. This increase in electricity generation capacity implies significant build rates over the period to 2050, in order to meet the decarbonisation targets. Any constraints on build rates, such as financing, materials or skills issues could reduce the achievable level of energy system decarbonisation by 2050.

2. **Energy system flexibility and interactions across different energy systems significantly influence the power generation portfolio.**

The optimal portfolio of PV, wind, nuclear and hydrogen-based CCGT/OCGT is based not only on the levelized cost of electricity (LCOE) of these generation technologies, but also system integration costs of all technologies are considered. The whole-system cost would depend on the level of flexibility which can be provided by the interaction between the heat and electricity sectors, which will impact deployment rates of low carbon generation technologies, aimed at meeting the carbon target at minimum costs. It is important to note that cross-vector flexibility and the link between local and national levels services across different time-scales are considered by IWES model in all scenarios and that this cross-vector coordination minimises cost of decarbonisation of the whole-energy system; in the absence of cross-vector coordination the overall system costs would significantly increase.

The modelling results demonstrate that providing additional system flexibility (beyond cross-sector flexibility) can further reduce the annual system cost by up to £16 bn/year. The flexibility provided by demand-side management or energy storage across different energy vectors (electricity, gas, heat) can improve the utilisation of low-carbon generation and reduce the overall requirement of production capacity and network infrastructure reinforcement. For example, if heat demand is supplied by electric heating, reducing the peak of heat demand by preheating[20] or using thermal storage can

[18] The CCC defined the upper UK deployment limit for low-carbon electricity generation technologies as wind, PV, CCS and nuclear is 120 GW, 150 GW, 45 GW and 45 GW for wind, PV, CCS and nuclear respectively.

[19] Due to insufficient capacity of low-carbon electricity generation, this case cannot meet the zero-carbon target and the annual carbon emissions were 2 Mt/year.

[20] Preheating involves heating the households earlier than it would be otherwise done while utilising inherent heat storage in the fabric of the houses. This type of flexibility is critical for reducing system peaks, enhancing the value of the provision of balancing services and increasing utilisation of renewables by electric heating, which significantly reduces the cost of decarbonisation.

reduce the required firm generation capacity[21]. The studies demonstrate that most of the value of system flexibility (including preheating) contributes to the savings in the capex of low-carbon electricity generation which is a dominant cost component (Figure E. 1).

3. **A significant capacity of firm low-carbon generation is needed in all pathways with a 0Mt carbon target**

Analysis demonstrated that meeting a zero-emission target cost effectively would require a significant capacity of nuclear generation in all pathways, due to the variability of renewable production and the need to eliminate emissions associated with management of demand-supply balance. Hence, in the 0 Mt case, a significant amount of capacity of variable renewables is replaced by firm low-carbon generation capacity, i.e. nuclear. The results demonstrate that although in the short and medium term the focus can be on deployment of variable RES, in the long-term, to achieve a zero-carbon emissions target, firm low-carbon generation technologies such as nuclear (or alternatives) will be required, e.g. for the 0Mt, in all core pathways, more than 40 GW of nuclear generation is deployed. The appropriate portfolio of power sector technologies, therefore, depends on the desired level of decarbonisation of the energy system.

4. **Pre-combustion CCS generating plant is more attractive than the post-combustion CCS.**

No post-combustion CCS plant is selected due to the high cost of the technology and the presence of residual carbon emissions (it is important to note that post-combustion fossil CCS cannot be used in 0Mt scenario due to residual carbon emissions). There is, however, a significant volume of pre-combustion CCS, i.e. hydrogen-based combined cycle gas turbine and hydrogen-based open cycle gas turbine primarily in the Electric and Hybrid scenarios. Pre-combustion-hydrogen-based generation can be considered as complementary to CCS generation as it enables decarbonisation of traditional gas plant technologies and can provide flexibility while making efficient use of the hydrogen infrastructure.

5. **The total capacity of electricity generation in the Electric pathways is significantly larger than in other pathways.**

Full electrification of heating demand in the Electric pathway will substantially increase peak electricity demand. Hence the corresponding amount of firm-generation capacity in the Electric pathway is about 100 GW larger compared to other pathways. It should be noted that in the Electric pathway there is a significant amount of peaking plant (OCGTs) that are supplied by biogas and operate at very low load factors (operating during high peak demand conditions driven by extremely low external temperatures). In the Hybrid

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[21] In the Electric 0 Mt scenario, the use of preheating can reduce more than 40 GW of firm generating capacity.

pathway, on the other hand, the extreme peak of heat demand is directly supplied by gas boilers using biogas in the gas grid rather than electricity, and hence the capacity requirement for peaking plant is much lower.

Considering the uncertainty across different heat decarbonisation pathways and emissions targets, "low/no regrets"[22] capacity of specific low-carbon generation technologies can be determined by taking the minimum of the proposed capacity for the corresponding generation technology across different pathways (given the costs of different low carbon generation technologies) and across emissions targets. This suggests that a capacity of at least 74 GW of wind generation is useful in all scenarios, given the seasonal profile of both wind generation and energy demand[23]. The modelling also indicates a role for at least 5 GW of nuclear power, and 3 GW of hydrogen-fuelled CCGT capacity, across all pathways.

It is important to highlight that more electricity generation capacity will need to be built, but the optimal generation portfolio will depend on the decarbonisation pathway and the carbon target. For example, in the Elec 30Mt case, there may be a need for 13 GW of nuclear, 117 GW of wind, 146 GW of PV and 12 GW of H2 CCGT while in the H2 30 Mt case, the requirements are 5 GW of nuclear, 77 GW of wind, 63 GW of PV, 12 GW of H2 CCGT. However, in the H2 0 Mt case, the required capacity for nuclear, wind, PV and H2 CCGT are 45 GW, 120 GW, 150 GW, and 3 GW. There is a significant increase in the capacity of nuclear, wind and PV while a reduction in H2 CCGT. In this case, hydrogen is mainly produced from low-carbon generation sources and used for heating instead of for electricity production. The balancing services provided by H2 CCGT can be displaced by the operation flexibility of electrolysers.

Building more or less (i.e. having a sub-optimal generation portfolio) will increase system costs and may lead to less utilisation of low-carbon generation capacity and deteriorate reliability of the system if there is inadequate firm capacity. It is important to note that the optimal generation mix is system specific and depends on the assumptions taken in the model. Therefore, the low/no regret capacity provides a tangible indicator of how much the minimum capacity needed for each low-carbon generation technology across different scenarios. It is important to note that deployment of flexibility technologies and systems will be important to support decarbonisation of electricity generation.

[22] Low/no regrets capacity is defined as the capacity that will be needed irrespective of the decarbonisation pathway adopted in the future.

[23] The results are based on the assumptions and system conditions used in the studies, e.g. it was assumed that the system was supported by flexibility from demand response, energy storages, generators, and interconnectors.

Impact of uncertainties on the cost of decarbonisation

As shown in Figure E. 2, the costs of the core decarbonisation pathways at are relatively similar (cost difference is within 10%) except the H2 0Mt case and hence the overall cost of alternative pathways may change when different assumptions apply. In order to inform this process, a range of sensitivity studies has been carried out to determine the corresponding changes in total system costs in the core H2, Electric and Hybrid decarbonisation pathways. Specifically, the sensitivity studies analyse the impact of (i) H2 technology (using SMR instead of ATR), (ii) low-cost hydrogen imports, (iii) reduced discount rates, (iv) capex of low-carbon generation, (v) carbon emissions targets, (vi) space heating demand, (vii) system flexibility, (viii) heating appliance cost, (ix) fuel prices, and (x) reduced peak of heat demand. The results of the sensitivity studies for 30Mt are presented in Figure E. 4.

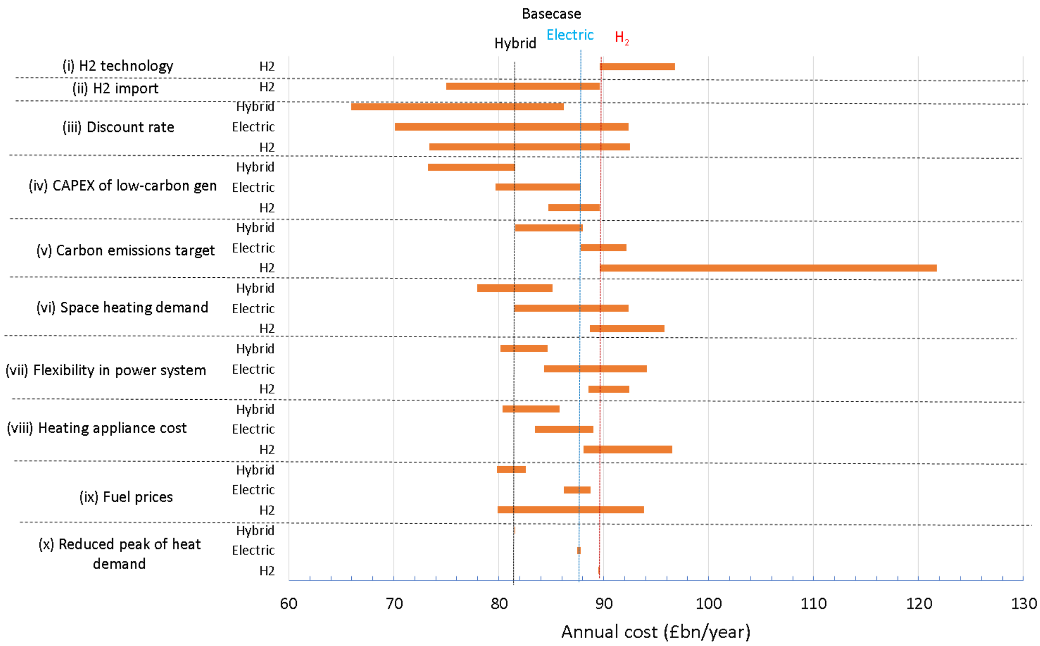

Figure E. 4 Cost changes in core decarbonisation pathways under different scenarios [30Mt]

The results demonstrate that:

- For all pathways, low financing costs would be the primary driver for reducing the system cost as the low-carbon energy system costs are driven by the capital rather than operating costs.
- The 2nd most substantial cost reduction for the H2 scenario is found in the case when low-cost hydrogen import is available (risks associated with significant energy imports are not within the scope of this study). By importing hydrogen, the infrastructure needed to transport, and store hydrogen can be reduced assuming that there is flexibility in managing the import in terms of the timing, and the locations of where

the hydrogen should be delivered to. Consistently low gas prices could also improve the viability of a hydrogen pathway, compared to other pathways.

- In all pathways, meeting a stricter carbon target will increase the system costs. While the increase in costs in Electric and Hybrid is between 4.4 and 7.2 £bn/year, the increase in cost in the H2 pathway is much more substantial (more than £30bn/year); this implies that H2 would be the highest cost pathway towards zero carbon.
- A reduction in annual heating demand, driven by improved energy efficiency, could reduce the total system costs by 0.9 – 6.2 £bn/year. Across the three pathways, the highest impact of heat demand reduction in the Electric pathway.
- The benefits of system flexibility are highest in the Electric scenario and lowest in the H2 pathway, as both H2 and Hybrid scenarios involve some inherent cross-vector flexibility across both gas and electricity systems. Flexibility benefits in this report, present only the value of additional flexibility beyond cross-vector flexibility that is an inherent part of the IWES modelling (which co-optimises electricity, gas, hydrogen and heat systems, simultaneously). This implies that whole-energy system costs would significantly increase in the absence of cross-vector coordination.
- Cost of H2 pathway is more sensitive towards the fuel prices compared to the Electric and Hybrid pathway; the volume of gas used in the last two pathways is much lower compared to the one in the H2 pathway since the heat demand is met primarily by electric heating (HP) and most of the energy comes from low-carbon resources.
- The impact of the reduction in the peak of heat demand is relatively marginal in all pathways, as a significant level of system flexibility is assumed, via pre-heating and thermal storage at a household level. Without this flexibility, the impact on costs of peak heat demand would be much more significant.
- Across the uncertainties listed above the core Hybrid system (£81.6bn/year) remains the least-cost solution, followed by Electric pathway (£87.8bn/year) and H2 pathway (£89.6bn/year). It can, therefore, be concluded that the Hybrid pathway is the most robust decarbonisation pathway to reach the 30Mt carbon target. There are a few conditions where an H2 pathway becomes more competitive, i.e. if large-scale and low-cost imports of hydrogen are available (at £25/MWh), and all other conditions remain the same, or if gas prices are low (at 39p/therm). The cost of the Electric pathway is always higher than the cost of Hybrid. The cost of the Electric pathway is close to the cost of the Hybrid pathway particularly when heating demand is low.

As the impact of different assumptions may get intensified in the zero-carbon cases, the importance of different parameters on the costs of different decarbonisation pathways may also change; the results of the sensitivity study for 0Mt cases are shown in Figure E. 5.

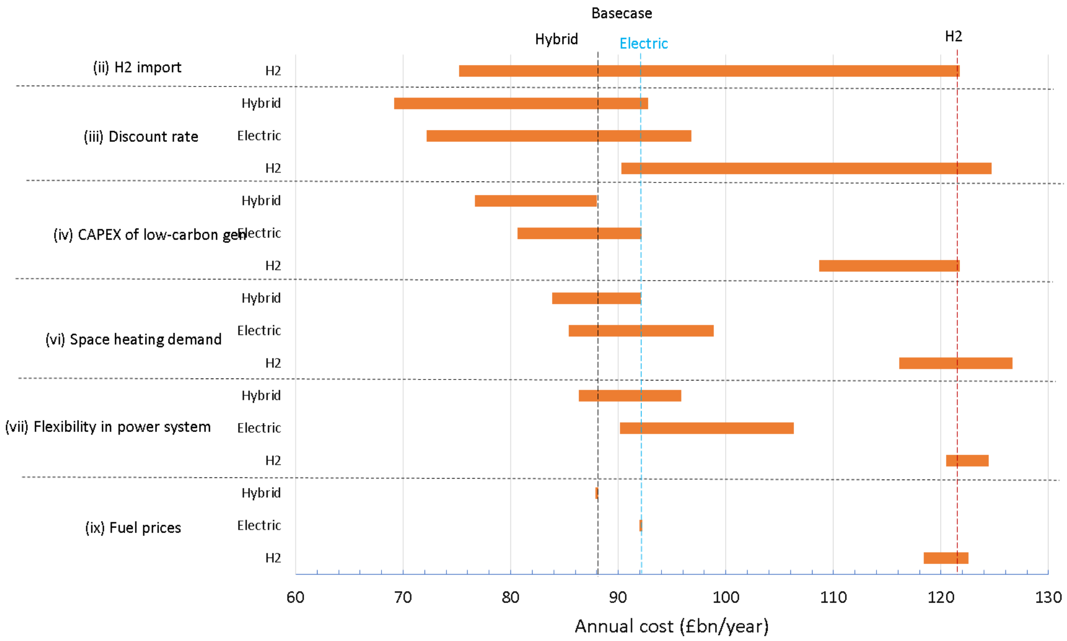

Figure E. 5 Comparison between the costs of different decarbonisation pathways under different scenarios [0Mt]

In most cases, the trends are the same as ones observed in the 30Mt cases with some exceptions such as:

- The impact of reduced financing costs in the H2 pathway is higher than in the other pathways. The results are driven by the need for the 0Mt H2 case to have a much more significant investment in electrolysers and low-carbon generation technologies compared to the other pathways. This is a contrast to the results of the 30Mt cases where the highest impact of having a low discount rate is found in the Electric case.
- For the same reason, the impact of reduced capex of low-carbon generation is the highest in the H2 0Mt case. This is a contrast to the results of the 30Mt case, where the largest impact is found in the Hybrid pathway.
- The value of system flexibility increases significantly in 0Mt scenarios. However, additional flexibility is less important in zero emissions H2 pathways given the presence of electrolysers that can provide system balancing services while generating hydrogen.
- As indicated in Table E2, the cost of the core Hybrid pathway is the lowest (£88.0bn/year) compared with Electric pathway (£92.2bn/year) and H2 pathway (£121.7 bn/year). The cost of the H2 pathway is the highest in most cases, with the exception of potential low-cost hydrogen imports.
- The cost difference between the Hybrid/Electric and H2 pathway increases compared to the cost difference between the corresponding pathways in 30Mt cases. In contrast, the cost differences between the Electric and Hybrid decreases in 0Mt cases. This is expected since the Hybrid system becomes more dependent on electrification to decarbonise the heating and gas systems, as less residual emissions

are allowed for in the gas boiler element of the hybrid heat pump.
Since the Hybrid pathway is the least-cost scenario in both the 30Mt and 0Mt cases, it can be concluded that the Hybrid scenario is the most robust decarbonisation pathway, although the absolute level of decarbonisation that can be achieved through this pathway depends on the availability of biogas, and consumer usage of the heat pump and boiler elements of the hybrid heat pump[24].

Alternative heat decarbonisation strategies: district heating and micro-CHP

Successful implementation of district heating in Denmark (and some other EU countries) and the potential application of end-use micro-CHP technologies have raised questions about the contribution these technologies could make to heat decarbonisation pathways. The results are compared with the core scenarios in the corresponding pathways. The costs and system implications of implementing these alternative strategies are presented in Figure E. 6.

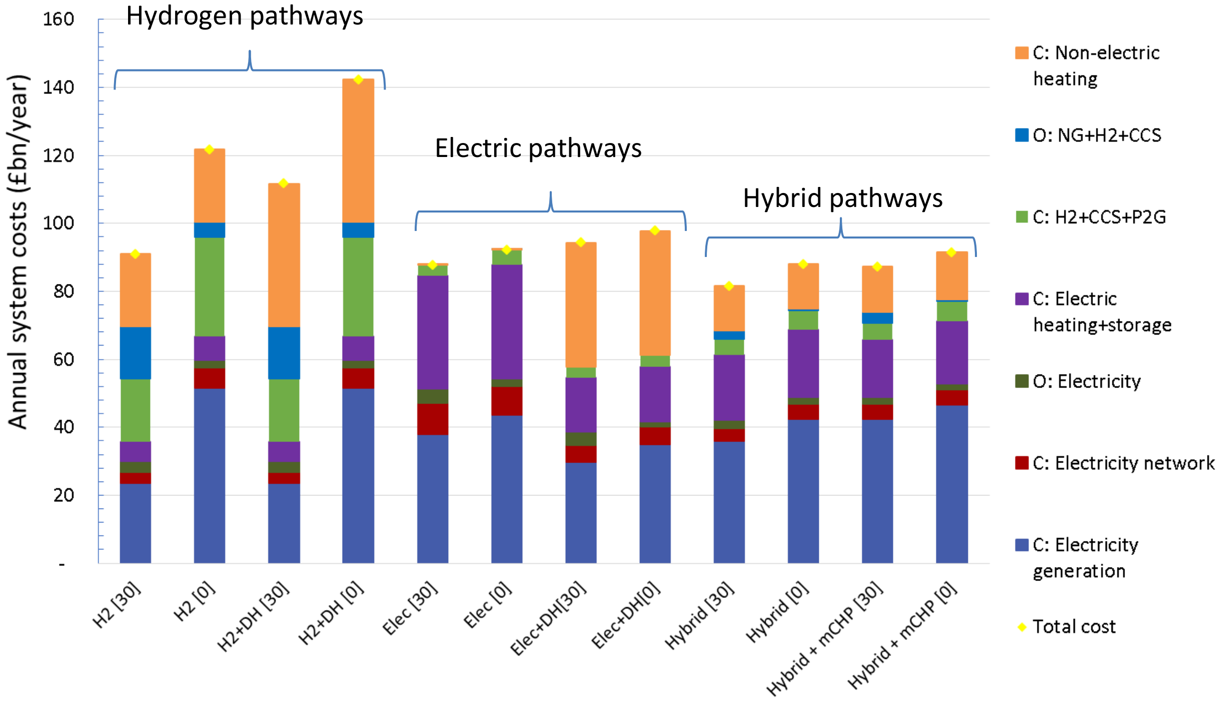

Figure E. 6 Annual system cost of different decarbonisation pathways

The key findings from these studies are:

1. **National district heating pathways are significantly more costly than other heat pathways due to the expenditure associated with the deployment of heat networks.**

[24] Annual use of the boiler component is around 14% in the 30 Mt scenario and 3% in the 0 Mt scenario

The analysis demonstrates that national deployment of district heating incurs a higher cost than the systems with domestic heating appliances, which is primarily driven by the cost of deploying heat networks and the cost of connecting consumers to heat networks, including new assets needed to control heat and the metering in dwellings. On the other hand, due to economies of scale, the cost of heating devices in the district heating networks is significantly lower (35%-50%) compared to the cost of domestic heating. In the Electric pathway, there is also a significant reduction in the capital cost of the electricity generation driven by a higher COP of industrial HP (4 on average) compared to the COP of domestic HP (less than 3 on average) but this cost reduction is still lower compared to the increase in costs associated with heat network deployment and connection.

While the study provides evidence that national deployment of district heating will not be cost-effective, local application of district heating in high-heat-density areas could provide a more cost-effective solution as the cost of heat networks and disruption cost could be minimised. It is estimated that the cost of urban heat networks is less than 25%[25] of the cost of heat networks in non-urban areas while heat demand in urban areas is estimated around 40% of the total heat demand.

2. **Micro-CHP, installed in households, could contribute to reducing the capacity of centralised electricity generation and network reinforcement.**

Small-scale end-use combined heat and power (micro-CHP) can substitute for the capacity of electric heating appliances, reduce distribution network costs and displace the capacity of gas-fired plants including hydrogen power generation, while the impact on RES and the nuclear capacity requirement is marginal. This finding demonstrates that micro-CHP could provide firm capacity (assuming it is able to be managed to provide capacity during peak demand) while significantly enhancing generation efficiency, as the heat produced from thermal electricity generation is not wasted but is used to meet local heat demand. However, given the assumptions related to the cost of micro-CHP[26] and the need for an auxiliary gas / hydrogen boiler, the total cost of the system with micro-CHP is still marginally higher than the cost of the core Hybrid pathway (but slightly lower than the Electric scenario). Furthermore, the physical size of the some micro-CHP technologies may need to be reduced further in order for these to be deployed at scale[27].

Alternative heat decarbonisation strategies: regional scenarios

Deploying hydrogen in the regions where gas terminals are available or in regions with high energy demand density such as urban areas as alternatives decarbonisation

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[25] The total length of urban networks is less than 25% of the overall length of distribution networks.
[26] Cost of micro-CHP used in the studies is £2500/kW.
[27] Micro-CHP based on steel-cell technology is already appropriate for most domestic premises.

pathways, have also been investigated and analysed for the 30Mt and 0Mt carbon emission cases. Three regional scenarios are considered: (i) *Hybrid – H2 North* assumes that the main heating system in the North of GB (Scotland, North of England, North Wales) is fuelled by hydrogen while the other regions use hybrid heat pumps; (ii) *Hybrid – H2 Urban* assumes that hydrogen heating systems are deployed in all urban areas while other regions use hybrid heat pumps for heating; (iii) *Hybrid – Urban DH HP* assumes the use of electric-based district heating with highly-efficient ground-source HP[28]. The results are presented in Figure E. 7, and the annual system costs of the regional scenarios are compared against the costs of non-regional Hybrid systems (the first two bars in the graph).

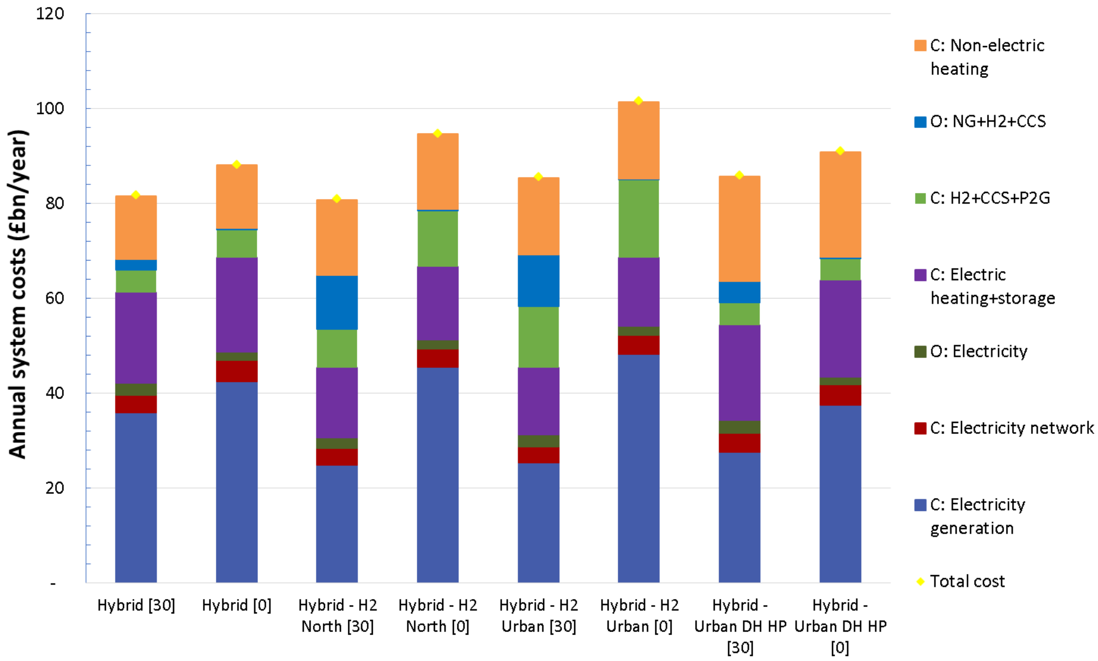


Figure E. 7 Costs of alternative Hybrid pathways

Use of hydrogen in Hybrid regional scenarios can reduce demand for low-carbon generation and reduce the cost of electricity generation at the expense of increased hydrogen infrastructure operating costs. The results demonstrate that for the 30Mt case, deployment of hydrogen in the Northern region could be an attractive alternative to the non-regional scenario; the cost is marginally lower by £0.8bn/year. This implies that for some regions, hydrogen conversion can be a cost-effective heat decarbonisation option. This favours regions in close proximity to existing gas terminals, and carbon storage areas. Towards a zero-carbon energy system, the cost of Hybrid- H2 North [0] is £6.6bn/year higher than the cost of Hybrid [0] due to the need to use electrolysers and low-carbon generation technologies to produce hydrogen. The costs of regional Hybrid – H2 Urban cases, both for 30Mt and 0Mt cases, are higher compared to the cost of the

[28] Annual average COP is 4.

non-regional Hybrid system by 3.9 – 13.4 £bn/year. The cost of producing hydrogen in local district areas is assumed to be 50% higher than the cost of producing hydrogen by large-scale plants located near gas terminals; this increases the capex of hydrogen infrastructure in the Hybrid – H2 Urban scenarios.

One of the main barriers to district heating is the high cost of deploying heat networks. Therefore, the implementation of district heating may be constrained to the high-heat-density areas, e.g. urban areas. The results of Hybrid – Urban DH HP demonstrate that the efficiency of industrial HP can reduce the infrastructure cost of electricity generation compared to the corresponding costs in Hybrid, but the cost of deploying district heating infrastructure offsets the benefits. Overall, the total costs of Hybrid – Urban DH HP are 2.8 – 4.2 £bn/year higher than the costs of the Hybrid pathways.

These results demonstrate the importance of considering regional diversity in national level heat decarbonisation decisions, though the cost optimality of this diversity depends on the desired level of decarbonisation. Converting heat to hydrogen in some regions could be a cost-effective decision as part of a hybrid national level heat decarbonisation strategy.

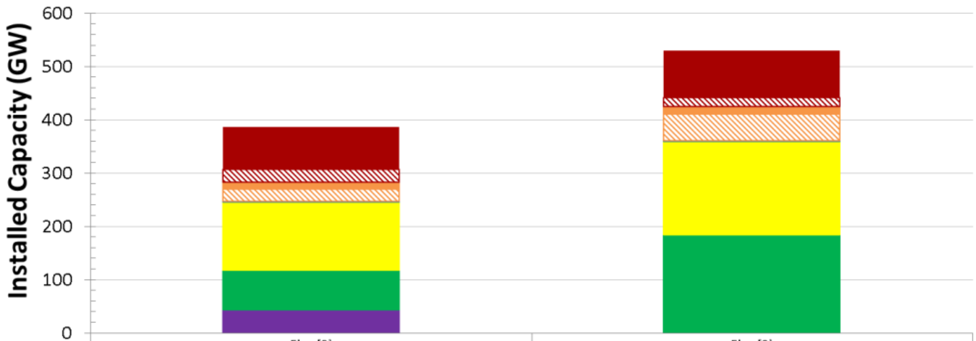
The importance of cross-energy system flexibility and firm low-carbon generation

As discussed previously, improving energy system flexibility is necessary for enabling cost-effective integration of low-carbon electricity generation particularly renewables. Improving flexibility could save around 10 and 16 £bn/year in the 30Mt and 0Mt case respectively. The flexibility should be provided not only in the electricity system but also in the gas, heating, and transport systems as there is a strong coupling across these energy vectors as demonstrated in the studies.

The availability of firm low-carbon resources such as nuclear generation is critical for fully de-carbonising the energy system[29]. As the study demonstrates, firm low-carbon generation is significantly less critical in systems with a less demanding carbon target[30]. Given this finding, the analysis was carried out to investigate the possibility of delivering a zero-carbon energy system without nuclear power. An alternative approach considering a higher RES capacity is studied with the aim to quantify the RES capacity needed to meet zero carbon without nuclear. The study demonstrates that it would feasible to achieve zero-emissions energy system without nuclear generation, subject to the presence of hydrogen storage and corresponding hydrogen-based power generation.

[29] In a 0Mt scenario CCS technologies for producing hydrogen or power generation cannot be used due to residual carbon emissions unless a capture rate of 100% is assumed.
[30] This section hence mostly focuses on 0Mt case.

Figure E. 8 presents the comparison between the optimal generation portfolio for the Electric 0Mt pathway with and without nuclear generation. The capacity of PV and wind needed in a zero-carbon Electric system without nuclear plants are 175 GW and 185 GW respectively, which is above the estimates of UK potential for these technologies[31]. Unless the potential level of PV and wind can be increased to such level, the system will require nuclear to meet the zero-emission target. An alternative solution is to use hydrogen imports, the system can achieve zero-carbon emissions within the built-constraint in PV and wind capacity, but it requires a higher capacity of hydrogen-based power generation.



	Elec [0] Core scenario	Elec [0] No nuclear, high RES
OCGT	79	88
H2 OCGT	24	16
CCGT	13	14
H2 CCGT	23	51
Hydro	1	1
PV	129	175
Wind	74	185
Nuclear	43	0

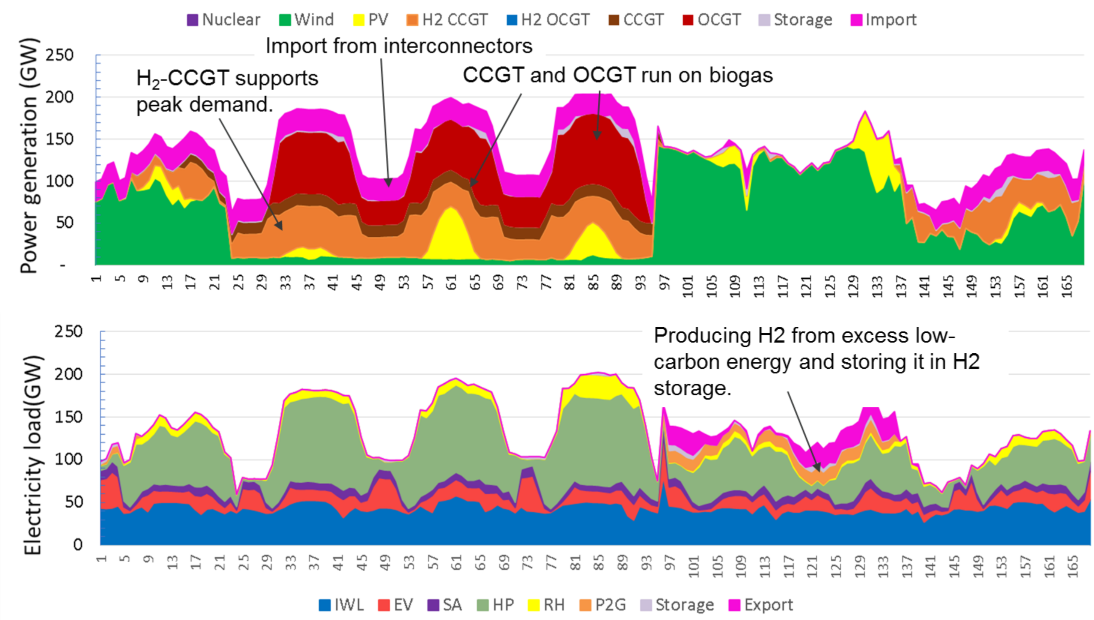
Figure E. 8 Comparison of the generation portfolio for Electric pathway with and without nuclear technology

To achieve zero-carbon emissions without firm low-carbon generation, there is a need for significant long-term energy storage that could be provided by hydrogen. This is in addition to significant short-term energy system flexibility provided by demand shifting via pre-heating and thermal storage in homes (50% of potential demand flexibility is assumed available). As shown in Figure E. 9(a), during periods of high RES output, the excess energy is converted into hydrogen by electrolysers ("Power-to-Gas"). This drives the need for investment in electrolysers[32] to enhance the utilisation of RES. Energy in the form of hydrogen can then be stored across long time horizons as losses in hydrogen storage are assumed to be minor and not time dependent. Electrolysers can also provide balancing services during high RES output, and therefore, reduce the need for these services from other sources (generation, demand-side response, storage, etc.), though

[31] 150 GW for PV and 120 GW for wind

[32] 15 GW of electrolysers is proposed by IWES in the Elec [0] No nuclear, high RES case.

this role absorbs just 5% of total electricity over the year[33]. During low RES output, the stored energy can be used to produce electricity via hydrogen-based power generation. Hence the capacity of hydrogen-based CCGT increases significantly - from 23 GW in the system with nuclear to 51 GW in the system without nuclear. It can be concluded that "Power-to-Gas" and hydrogen-based generation can substitute nuclear generation. It is important to note that electrolysers (as part of the "Power-to-Gas" system), due to higher costs, are not selected by the model in the core Electric pathways when nuclear generation is available, as other technologies, such as demand-side response and energy storage technologies are able to provide system flexibility services at lower cost. It is important to highlight that hydrogen-based CCGTs and OCGTs can also provide system balancing which facilitates the cost-effective integration of other low-carbon generation such as renewables and nuclear.



(a) Elec [0] no nuclear, high RES case

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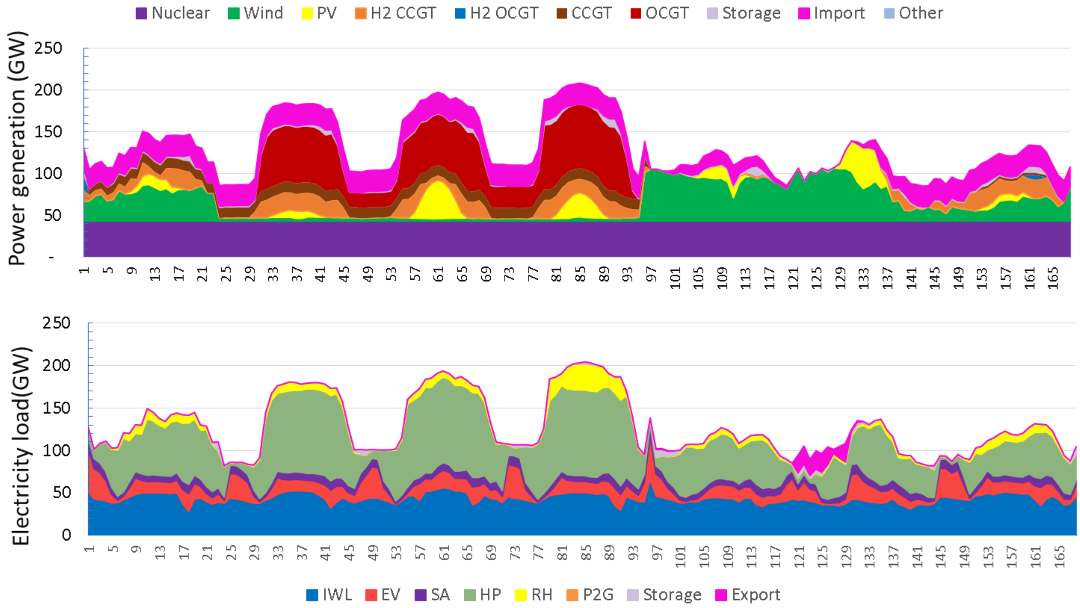
33 Electrolysers also provide grid-balancing services particularly when the system is less flexible (e.g. in H2 0Mt case). In this case, electrolysers are used to save the excess of renewable energy in the form of hydrogen. Since there are losses associated with this process, it is carried out only when it is necessary.



(b) Elec [0] core scenario

IWL: baseload including Industrial and Commercial load, EV: Electric Vehicle, SA: Smart Appliances, HP: Heat Pump, RH: Resistive Heating, P2G: Electrolysers

Figure E. 9 The role of electrolysers, hydrogen storage and generation in balancing the system with large penetration of renewables and the use of biogas for peaking plants

Figure E. 9(b) shows the hourly generation output and load profiles for the same period in the Electric 0Mt core scenario. The availability of nuclear reduces the need for hydrogen-based CCGT and other low-carbon generation such as wind and PV as shown in Figure E. 8.

Given the cost assumptions used in the study, the scenario without nuclear will cost around £10bn/year more than the scenario with nuclear. The comparison between the system costs of the core Electric 0Mt case with and without nuclear is shown in Figure E. 10.

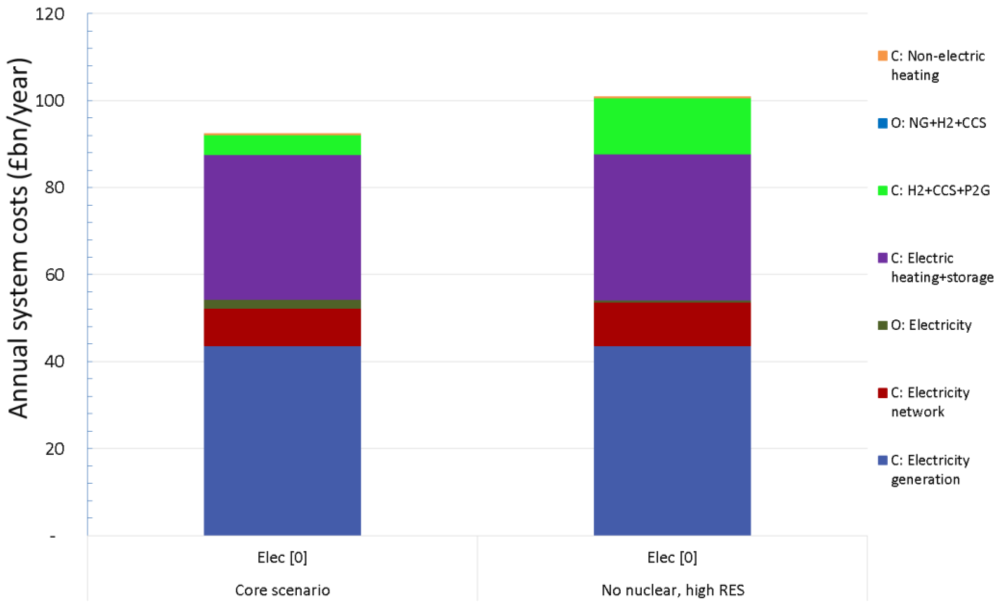


Figure E. 10 System costs of the Electric pathway with and without nuclear technology

The results of the study demonstrate that in the absence of firm low-carbon generation such as nuclear, the system would require long-term storage that could be supplied by hydrogen through investment in the hydrogen electrolysers and storage. The capacities of hydrogen production plant, hydrogen networks and storage are optimised and tailored to system needs in order to minimise the overall system cost.

To achieve zero-carbon emissions without nuclear generation, there is a need for 3.6 TWh hydrogen energy storage (Figure E. 11), that can provide both support in the short-term energy balancing and long-term storage. The volume of hydrogen storage needed is around 1100 mcm, which, for context, is around 30% of the volume of the recently closed Rough gas storage facility. The annuitized investment cost of the hydrogen storage across GB in this scenario is around £3.2 bn/year.

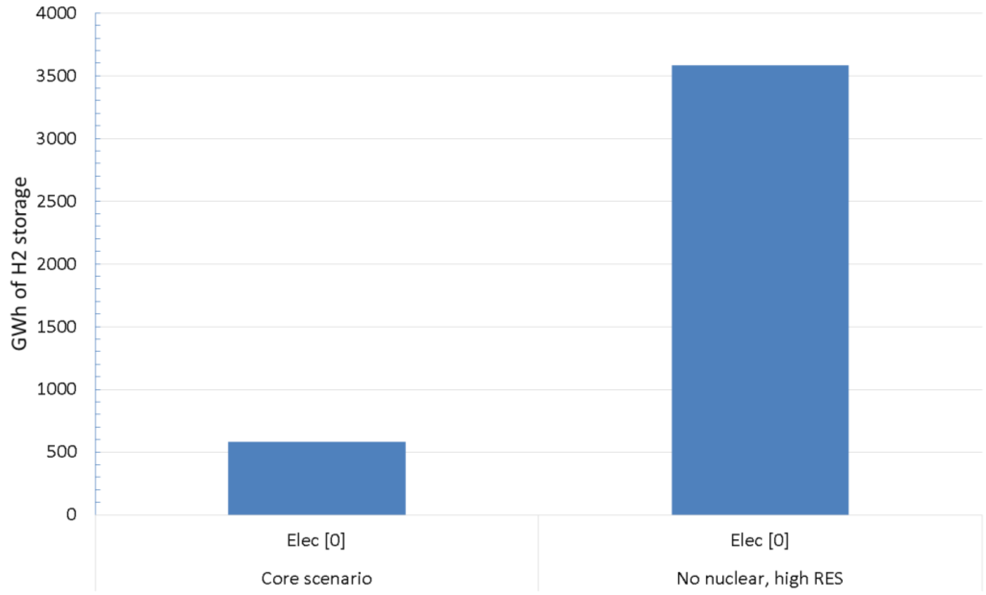


Figure E. 11 Comparison of the hydrogen storage requirement in Electric 0Mt cases

The need for investment in hydrogen infrastructure (production plant, network, and storage) could be reduced by importing hydrogen rather than producing it in GB. Importing hydrogen reduces demand for long-term storage and Power-to-Gas schemes.

The interaction between thermal and electricity storage

Other forms of energy storage investigated in this study include thermal energy storage (TES) and electricity storage. The IWES model optimised the portfolio and size of the energy storage system considering the technical and cost and characteristics of each storage technology. Studies have also been carried out investigating the correlation between the thermal storage and electricity storage; the results are presented in Figure E. 12.

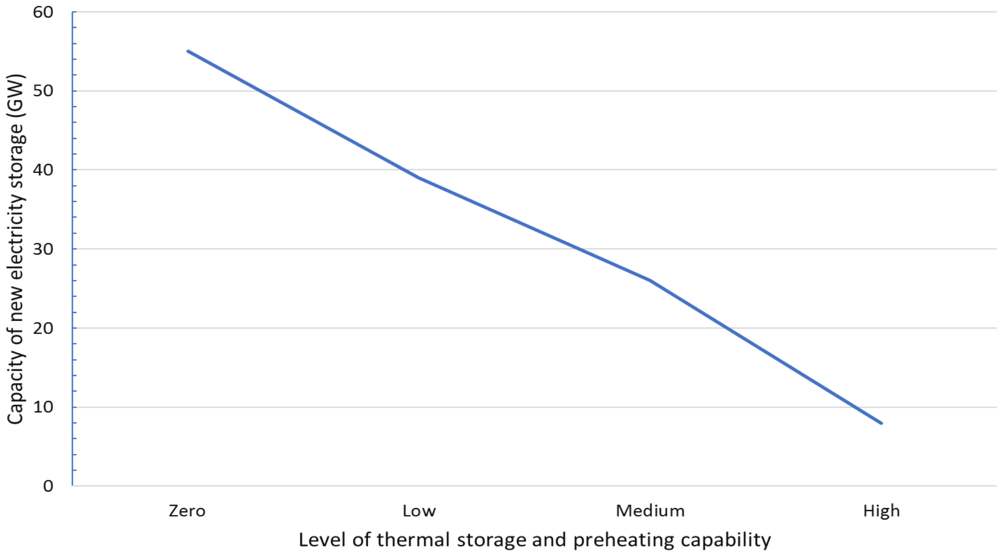


Figure E. 12 Correlation between TES and electricity storage

The modelling results demonstrate that in the absence of thermal storage and other forms of flexibility, there would be a need for more than 55 GW new electricity storage[34] in the Electric scenario; however, if 58 GW_{th} of TES (1.7 kW_{th}/household) and preheating (more than 100 GW_{th}) are available, the need for new electricity storage reduces to below 10 GW, since the cost of thermal storage (e.g. hot water tank, oil or phase-change-material based thermal storage) is considerably lower than the cost of electricity storage while the preheating is assumed to be applied at low cost.

Impact of future development of gas-based hydrogen production technologies

Steam Methane Reforming (SMR) is currently a mature technology for producing hydrogen from natural gas. In the future, this technology could be substituted by Auto Thermal Reforming (ATR), which is expected to have superior performance in terms of cost, energy efficiency and carbon capture rate[35]. The cost performance difference between the two technologies in the H2 30Mt pathways is analysed, and the results are presented in Figure E. 13.

Application of ATR as the primary technology for production of hydrogen in the 30Mt case would reduce system costs by £7.2bn/year compared to the case with SMR. The cost reduction is enabled by (i) savings in low-carbon electricity generation capex due to reduced requirement for decarbonising electricity within a fixed emissions constraint, as the emissions from the gas sector is lower than compared with the SMR case; (ii) a

[34] Total storage capacity is 110 GWh.

[35] See Element Energy (2018) Hydrogen Infrastructure: Summary of Technical Evidence

reduction in the capex of hydrogen infrastructure as the cost of ATR is lower than SMR; and (iii) a substantial reduction in the operating costs as the efficiency of ATR (89%) is higher than SMR (75%).

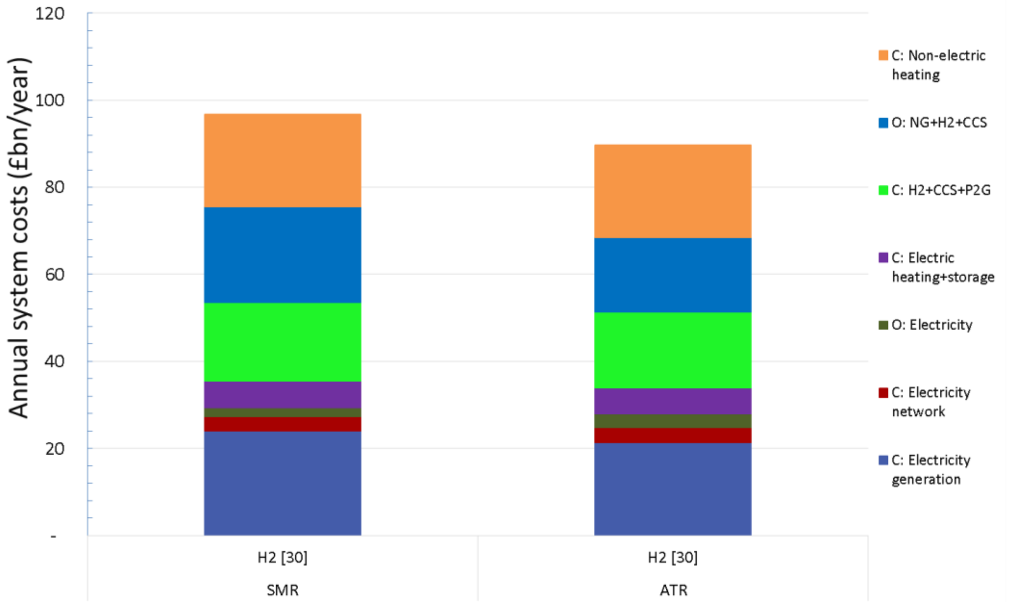


Figure E. 13 Cost performance of H2 pathways based on SMR and ATR

However, significant increases in the cost of the H2 pathway in the zero-carbon scenario are driven by the need to produce hydrogen via electrolysis. In this context, the impact of possible technology enhancements in capturing the carbon emissions of Auto Thermal Reformer (ATR) from 96% (the value used in the base case) to 100% with a marginal increase (10%) in cost has been analysed. This improvement would enable the use of ATR in the zero-carbon scenario, which would significantly reduce the cost of the H2 scenario. The cost performance of the H2 pathway in 0Mt case with electrolysers and enhanced ATR is compared in Figure E. 14.

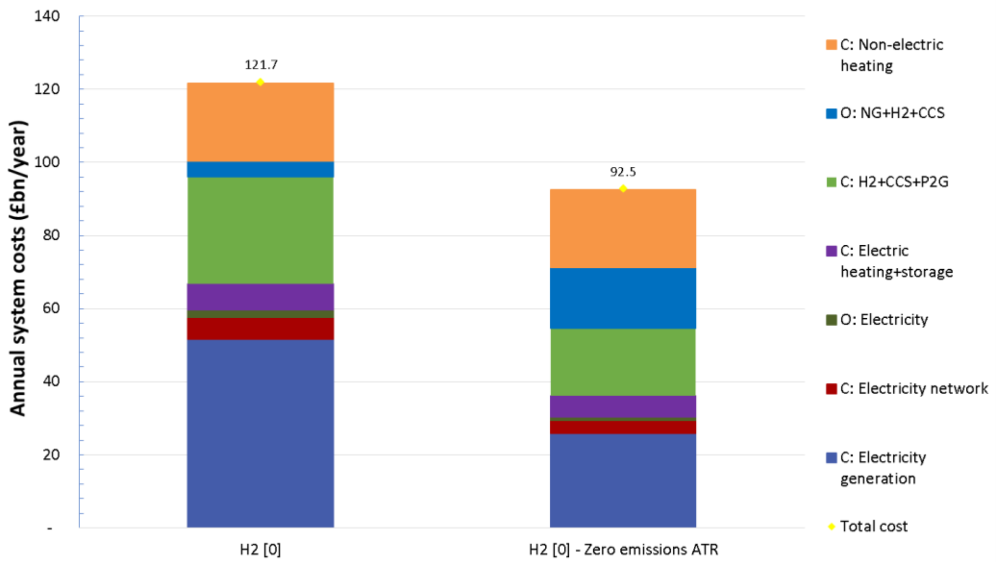


Figure E. 14 Value of enhancing the capture rate of ATR for a zero-carbon system

Enhancing the capture rate of ATR would reduce the cost of H2 0Mt pathway from £121.7bn/year to £92.5bn/year while enabling zero emissions target to be achieved. Since the cost of ATR is also lower than electrolysers, the cost of hydrogen infrastructure would also reduce as well as the cost of low-carbon electricity generation required to produce hydrogen via electrolysis. The use of gas would increase the operating cost of the H2 pathway, offsetting some of the savings obtained in the reduction of hydrogen and electricity infrastructure capex. If a zero-emissions ATR could be developed, this would make hydrogen scenario significantly more cost effective: the cost of H2 0Mt pathway with zero-emissions ATR would be only marginally higher than the cost of Elec 0Mt pathway. Therefore, if a future gas-based hydrogen production technology was able to achieve zero emissions (i.e. capture rate of CCS is towards 100%) at limited additional cost, the system costs of the hydrogen pathway would be comparable to alternative pathways for a zero-emissions energy system.

Impact of improved energy efficiency and climate change

The optimal choice of decarbonising heat may depend on the level of heat demand in the future which could be influenced by many factors, e.g. improved housing insulation and climate change. In this context, the system costs of the core scenarios are compared with the costs of two scenarios with lower heating demand. The first, second, and third sets of three bars in Figure E. 15 correspond to (i) core scenario, (ii) low domestic heating demand scenario, and (iii) low domestic heating demand with climate change adjustment (CCA). The corresponding annual domestic heat demand including both space-heating and water-heating demand used in these three scenarios is (i) 349 TWh_{th}, (ii) 290 TWh_{th}, and (iii) 234 TWh_{th}. The last scenario assumes a 2°C increase in the UK temperature in 2050.[36] The studies were carried out for all three main pathways for 0Mt cases.

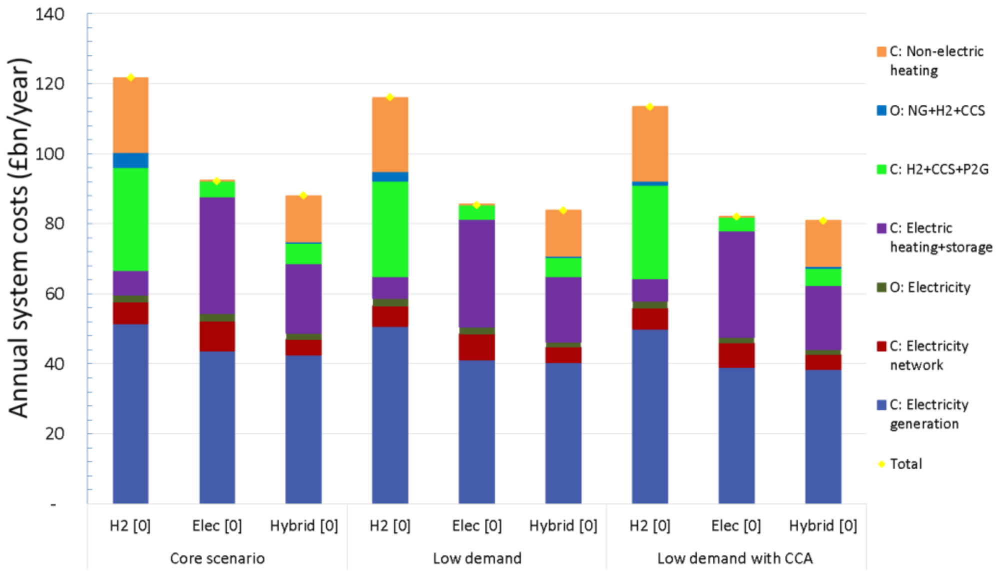
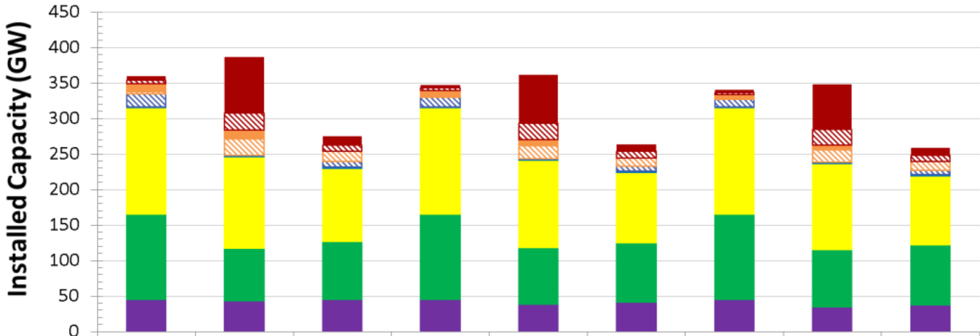


Figure E. 15 Impact of the reduction in heat demand on the system annual costs

The results demonstrate that the annual system costs are lower when domestic heating demand is reduced, though it is worth noting that the results exclude the costs associated with reducing this demand (e.g. investment cost for improving thermal insulation and using the smart-energy system). In addition to demand reductions the results for the "Low demand with CCA" are influenced by the assumed higher annual average temperature in this pathway, resulting in a higher average COP for heat pumps in the Electric and Hybrid pathways. Consequently, this reduces the infrastructure requirements and associated costs. The impact on the power generation capacity requirement is shown in Figure E. 16.

For the Electric and Hybrid pathways, comparing the generation capacity proposed for the core scenario and Low demand with CCA, there is around an 8-9 GW reduction in the capacity of nuclear plant. A substantial 17 GW reduction of peaking capacity (OCGT) in the Electric pathway; in general, there is a substantial reduction in the power generation capacity across all pathways due to a reduction in the heating demand.

[36] The core scenarios use historical temperature data with a few consecutive days of modified demand to simulate extreme weather events, i.e. very cold days with low output of renewable energy.



	Core scenario			Low demand			Low demand with CCA		
	H2 [0]	Elec [0]	Hybrid [0]	H2 [0]	Elec [0]	Hybrid [0]	H2 [0]	Elec [0]	Hybrid [0]
OCGT	6	79	13	4	68	9	4	64	10
H2 OCGT	5	24	9	3	23	10	3	22	9
CCGT	11	13	0	8	8	0	6	7	0
H2 CCGT	3	23	14	2	18	12	1	18	12
District CHP	18	0	8	13	0	6	10	0	6
Hydro	1	1	1	1	1	1	1	1	1
PV	150	129	103	150	124	99	150	121	97
Wind	120	74	82	120	79	84	120	81	85
Nuclear	45	43	45	45	39	41	45	34	37

Figure E. 16 Impact of heating demand reduction on the optimal generation mixes

The costs of the H2 pathways are still the highest in these zero-emissions scenarios, and the least-cost solutions for all scenarios are still the Hybrid pathways although the cost difference between the Electric and Hybrid pathways becomes less with reduced heat demand. The results are not unexpected since increased energy efficiency or increased temperature will reduce peak heat demand and the corresponding benefits of HHPs.

The ability of the existing gas distribution system to transport hydrogen

Modelling was carried out to investigate the technical capability of the existing gas distribution networks to transport hydrogen instead of natural gas, to meet the peak heat demand. Distribution networks operating at different low, medium and high-pressure levels were examined. The results demonstrate that the transportation of hydrogen does not have a significant impact on the pressure profiles for low and medium pressure gas distribution networks, nor their capability to meet peak energy demands. However, in high-pressure networks, the 'linepack' (i.e. the volume of gas that can be stored in a gas pipeline) plays an important role in meeting the energy demand during peak conditions. The lower density of hydrogen compared to natural gas would reduce the available linepack in the high-pressure networks and constrain their energy supply capability. Consequently, a small amount of localised hydrogen storage facilities would be required to enable the distribution networks to transport hydrogen to meet the peak of heat demand. The modelling extrapolates additional hydrogen network storage network requirements across the GB gas distribution system, based on the amount of hydrogen storage capacity required in high-pressure hydrogen distribution test networks that were modelled[37]. The results indicate that in order to enable the existing gas distribution networks to transport hydrogen during peak conditions, between 131 GWh to 333 GWh of hydrogen storage would be required[38], which would increase the cost of H2 pathway for approximately £0.35bn/year to £0.61bn/year, equivalent to 0.4% of the total costs of the hydrogen pathway[39].

Key findings

Based on the cost performance of different pathways with the 30Mt and 0Mt carbon target[40], the cost of each pathway is presented in merit order in Table E. 2.

Table E. 2 Cost performance of different heat decarbonisation pathways

30Mt scenarios	Cost (£bn/year)
Hybrid - H2 North	80.8
Hybrid	81.6
Hybrid - H2 Urban	85.4
Hybrid - Urban DH HP	85.8
Hybrid + micro-CHP	87.2
Elec	87.8
H2	89.6
Elec+DH	94.3
H2+DH	111.6

0Mt scenarios	Cost (£bn/year)
Hybrid	88.0
Hybrid - Urban DH HP	90.8
Hybrid + micro-CHP	91.4
Elec	92.2
Hybrid - H2 North	94.7
Elec+DH	97.7
Hybrid - H2 Urban	101.4
H2	121.7
H2+DH	142.2

For the 10Mt cases, the annual system costs are £84.8bn/year for the Hybrid case, £89.5bn/year for the Electric case, and £90.2bn/year for the Hydrogen case.

It can be concluded that:

- The Hybrid pathway is identified as the most cost-effective decarbonisation pathway, although the costs of the core decarbonisation pathways are relatively similar (the cost difference is within 10%). Though it is worth noting that given the uncertainties involved, the ranking may change when different assumptions apply.
- Systems with lower carbon emission targets will lead to higher costs, though the absolute level of cost depends on the emissions reduction target. In all scenarios, further emission abatement, from 30Mt to 10Mt, is available at limited additional cost (the increased cost is between by 0.6 - 3.2 £bn/year). However, this will change when

[37] Based on modelling results of high-pressure test networks and peak heat demand for various Local Distribution Zones (LDZ) across GB, the regression model was applied to estimate the required hydrogen storage capacity.

[38] In addition to the investment needed in centralised hydrogen storage, e.g. salt-cavern storage.

[39] The cost of distributed storage is included in the costs of all H2 scenarios.

[40] 10 Mt cases were only performed for the core scenarios. In these cases, the Hybrid pathway is the least-cost solution followed by the Electric and the H2 pathway.

moving from 10Mt to 0 Mt, with the cost further increases by £31.5bn/year in the hydrogen scenario, compared to £2.7bn/year in the electric scenario.

- Electric and Hybrid pathways provide more optionality towards deep levels of decarbonisation compared to the H2 pathway, given the shift in hydrogen production from gas (ATRs) to electricity (electrolysers), which significantly increases the cost of hydrogen infrastructure.
- Regional scenarios for deploying hydrogen and district heating are more attractive than national deployment for these specific solutions. In some cases, regional heat decarbonisation choices – such as hydrogen in the North of GB, or district heating in heat dense areas - within a wider national system can reduce overall costs.
- Technologies such as micro-CHP can provide alternatives to electric heating and improve cross-energy flexibility between electricity and gas systems.
- There are significant uncertainties in the assumptions underpinning all scenarios, providing no clear lowest cost solution across the three core decarbonisation pathways.

Considering the uncertainty across different heat decarbonisation pathways and emissions targets, "low/no regrets"[41] capacities of low-carbon generation technologies across different pathways and emissions targets have been derived from the modelling results. It indicates that there will be a minimum requirement of 5 GW of nuclear, 74 GW of wind, and 3 GW of H2 CCGT across all pathways. Additional electricity generation capacity will need to be built as the optimal generation portfolio will depend on many factors such as costs, system flexibility, selected decarbonisation pathway and the carbon target.

A range of sensitivity studies has also been carried out to assess the impact of different assumptions on each decarbonisation scenario and its associated costs. The sensitivity studies consider the influence of different discount rates, system flexibility, carbon emissions targets, capex of low-carbon generation, heating demands, etc. In most of the cases considered in the sensitivity analysis, the Hybrid scenario is identified as the least-cost decarbonisation pathway; although the volume of gas reduces significantly, the value of existing gas infrastructure increases significantly by providing flexibility and reducing significantly investment in electricity infrastructure. The Hybrid pathway is generally more resilient to the sensitivities included in this analysis while the H2 and Electric pathways would cause higher levels of disruption to households (requiring both building upgrades and disruptions related to network reinforcements).

In summary, the key findings of the modelling carried out are as follows:

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[41] Low/no regrets capacity is defined as the capacity that will be needed irrespective of the decarbonisation pathway adopted in the future.

- *Towards a zero-carbon energy system, the cost-effective decarbonisation of heat may require electrification*
  - Unless carbon capture rates involved in the production of hydrogen via gas reforming can reach close to 100%, then decarbonising via hydrogen would require significant investment in zero-carbon electricity generation in order to produce hydrogen via electrolysis, which increases the costs of hydrogen scenario significantly above hybrid and electric pathways.
  - Technology improvement in both carbon capture rates and efficiencies of gas-based hydrogen production technologies would significantly reduce the cost of hydrogen pathways, particularly in a 0Mt scenario.
- *Energy efficiency is of key importance*
  - Reducing heat demand by improving energy efficiency of buildings can reduce system costs across all pathways.
- *Towards a zero-carbon energy system, overall system costs will be dominated by the capital expenditure rather than operating costs*
  - Any measures that may reduce the capex (e.g. lower financing cost) will have a significant impact
  - Energy system pathways will be less sensitive than today's energy systems to fuel price variations, particularly in the Hybrid and Electric pathways.
- *System flexibility is of key importance for cost-effective energy system decarbonisation*
  - In this context, the modelling demonstrated that the lack of additional sources flexibility would further increase system costs by additional £16 billion per year[42]. The study demonstrates that having 50% of potential flexibility would already capture a significant proportion (70%-85%) of the benefits. As the benefits are non-linear, initial improvements in flexibility have the highest value; beyond 50% flexibility the marginal value of additional flexibility reduces.
  - Clearly, co-ordinating system flexibility across electricity and gas systems can reduce system costs, e.g. (i) the use of gas to supply heat during peak demand conditions significantly reduces investment in electricity system infrastructure (ii) hydrogen could be stored over long-term time horizons and hence used in the power system to reduce the need for firm low carbon generation (e.g. nuclear); (iii) household level flexibility around heat demand, facilitated by thermal energy storage and application of preheating, would enhance the utilisation of renewable energy resources and significantly reduce system capacity requirements.
  - Stronger planning coordination between electricity, gas and heating systems is

[42] The maximum value of additional flexibility was obtained in the Electric 0Mt pathway, while the value of additional flexibility in other scenarios is lower as significant flexibility is provided through coordination across different energy vectors. The value of additional flexibility varies across different pathways and carbon targets (presented in section 3.5.1).

needed to minimise whole-system costs.

- o When electrolysers are needed (e.g. to produce hydrogen), electrolysers can provide short-term grid balancing services following the output of renewables. However, such flexibility can also be provided by demand response and storage hence the decision to invest in electrolysers is not primarily driven by the need for grid balancing but by converting energy from low-carbon electricity generation to hydrogen which can then be stored more cost-effectively. Electrolysers have important role in H2 0Mt case but are less critical in other pathways.

- *Energy storage can reduce system capacity requirements and facilitate the cost-effective deployment of renewables.*
  - Energy storage can be used to improve load factors of baseload power generation and hydrogen production plants; the cost of storage is typically lower than the capex of baseload plant, and therefore it can provide capacity at lower cost. The modelling results demonstrate that hydrogen storage is essential to maintain steady production in gas-reforming plants that produce hydrogen[43]. This can reduce the need for hydrogen production capacity and its associated cost and provide cost-effective both short and long-term energy storage as a supplement or an alternative to other energy storage technologies (e.g. electricity storage and thermal storage). Whilst a hydrogen transmission network provides significant 'linepack' storage of hydrogen, hydrogen storage can complement this by providing both short and long-term energy balancing. This can substitute for firm low-carbon generation, which will facilitate more effective integration of RES into the energy system. The model chooses to invest around £6bn/year in hydrogen storage in a H2 [30] Mt scenario, which is lower cost than scenarios with lower amounts of hydrogen storage.
  - o The modelling results demonstrate that in the absence of thermal storage and other flexibility resources, there would be a need for more than 55 GW additional electricity storage in the Electric scenario; however, if 58 GW_{th} of TES (1.7 kW_{th}/household) and preheating (more than 100 GW_{th}) are available, the need for new electricity storage reduces to below 10 GW, since the cost of preheating and thermal storage (e.g. hot water tank, phase-change-material based thermal storage) is lower than the cost of electricity storage.

- *Importing low-cost hydrogen could potentially make the H2 pathway cost competitive against electrification pathways*; although producing hydrogen at the costs assumed in this analysis would require a significant reduction in the cost of electrolysis and shipping hydrogen. Imports of hydrogen could also reduce the need for UK based hydrogen storage.

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43 Current gas-reforming technology operates at steady output. This was therefore included as an assumption in the model.

- *Economies of scale of investment* are also important for achieving minimum overall cost. The modelling assumes that both electricity and hydrogen is produced on a centralised, rather than a distributed basis. More localised production would result in lower economies of scale, increasing system costs.
- *Gas network modelling suggests that additional network level storage of distributed hydrogen (131 – 333 GWh) is required to enable transport of hydrogen through high-pressure distribution gas networks.* This would increase the cost of H2 pathway for approximately £0.35bn/year to £0.61bn/year. While the total volume required is relatively small, the distribution of these storages is important for consideration. Therefore, this investment cost is in addition to significant investment in large-scale storage facilities in the H2 scenarios.

Recommendations

A set of recommendations are outlined below, based on the modelling results and analysis carried out in this study.

Further analysis

In order to provide an in-depth understanding of the transition towards low-carbon heat, a number of areas may warrant further investigation. These could include:

- Detailed analysis of different types of buildings considering typical heat requirements, levels of insulation, the role of thermal storage, etc. Following this, a further assessment of corresponding system performance and costs could be made.
- Further investigation of alternative decarbonisation pathways that involve diversified ("patchwork") heating solutions across different regions in the UK, and the impact these could have on national low-carbon heating choices. In the context of heat-sector decarbonisation it may be appropriate to investigate if the concept of levelized cost of end use heat technologies could be introduced to inform corresponding policy development.
- Development of robust least-worst heat decarbonisation pathways and corresponding policies, while considering explicitly a full range of technologies and system uncertainties.
- The resilience of the future energy systems considering high impact events such as extreme weather conditions, shortage of gas supply, etc.
- Role, value and business cases of emerging technologies such as micro-CHP, Phase Change Material-based thermal energy storage, co-optimisation of energy for cooling and heating, research into long-term thermal energy storage technologies.
- Assessing the significance of the integration of transport and heat sectors through the vehicle-to-home / vehicle-to-grid concepts, and the impact on the need for thermal storage.
- Investigation into the operation and costs of managing the gas grid with significantly reduced flows of gas (i.e. in the hybrid heat pump scenarios).

- Further research into the implications of additional energy efficiency measures, beyond what was assumed in this study, applied across all heat decarbonisation pathways.
- Investigation in greater detail of the scope for H2 imports; this should include consideration of costs of solar generation, electrolysers, water production, etc., marine transport, storage (ammonia versus liquid H2) and different locations (North Africa, Middle East, South Africa, Australia).
- Further research related to the provision of system inertia is needed to investigate the impact on the optimal portfolio of generation technologies, particularly in 0 Mt case, as the provision of synthetic inertia (e.g. by wind generation) could reduce the optimal volume of nuclear, while on the other hand, coordinated de-loading of nuclear generation during low demand and high renewable output conditions would reduce the size of the largest loss and hence enhance the value of nuclear generation.

Decarbonisation of electricity supply and enhancement of system flexibility

The studies demonstrate that the decarbonisation of electricity generation and improvement of system flexibility are essential irrespective of the adopted heat decarbonisation strategy. As the present renewable capacity, around 40 GW in total, is significantly lower than the no-regret capacity, this implies that the decarbonisation of electricity supply should be continued. In the short term, the deployment of low-carbon generation can focus on renewable power. In the medium and long-term, firm low-carbon capacity should be installed to meet low emissions carbon targets. Technologies such as nuclear, CCS, hydrogen-based CCGT/OCGT etc., should be considered. Increased penetration of low-carbon generation capacity should be accompanied with increased flexibility in the system to minimise the system integration costs. Further knowledge and practical experience should be gained by trialling smart control of demand systems to enhance the system flexibility.

Policy development for heat decarbonisation

At present, there is a large-scale programme underway for the decarbonisation of the electricity supply sector (i.e. a support mechanism for investment in low carbon generation). In order to facilitate investment in low-carbon heating appliances such as hydrogen boilers, electric/hybrid heat pumps, micro-CHP, etc., it would be important to review and develop further policy guidance and/or financial incentives including Renewable Heat Incentive (RHI)[44] to individual end-users and/or energy communities to encourage and reward investment in low-carbon heating technologies. Furthermore, the price of electricity reflects the carbon content of the fuel mix, which is not the case for household currently on fossil fuel-based heating systems, so carbon price for heat

[44] RHI provides financial incentive to promote the use of renewable heat including heat pumps.

should be considered. In this context, it will be important to investigate the CO_2 reductions that could be achieved from demand-side focussed strategies, e.g. radical building energy efficiency programs.

Market design for flexibility

As demonstrated in this study, cross-energy system flexibility will be critical for facilitating a cost-effective transition to a low-carbon energy system (i.e. a reduction in investment in low carbon generation and energy conversion technologies, a reduction in system operating costs, a reduction in investment in system capacity needed to meet the peak demand). In the electricity sector, there are several emerging markets focusing on new flexibility products (such as fast frequency response, demand-response reserve services, etc.). These initiatives should be extended through the development of cost-reflective flexibility markets[45] with appropriate spatial and temporal resolutions, that would link all energy vectors and facilitate competition between alternative solutions on a level playing field.

Furthermore, as demonstrated in the modelling, flexibility technologies and systems can reduce the amount of low-carbon generation needed to meet the carbon targets. However, suitable remuneration mechanisms for this value stream do not exist in the current market (and are not considered in the Electricity Market Reform). Such mechanisms should be developed to allow new flexible technologies to access revenues associated with a reduction in investment in low carbon generation through establishing the link between energy market and low-carbon agenda.

Pilot trials

One of the key conclusions from the studies carried out is that none of the heat decarbonisation pathways can be excluded as options for large-scale deployment, due to the proximity of overall system costs across the pathways within a significant level of uncertainty. Therefore, the focus of any action should be to address uncertainties. Knowledge and experience that will be gained from deployment at scale (i.e. 10,000s of households) will provide critical insights into the strengths and weaknesses of alternative approaches to heat decarbonisation and the technologies involved. Hence consideration should be given to a programme of technology deployment on a pilot trial basis. These initiatives should be designed to encompass all aspects of deployment - from production through to end-users - while including all types of representative buildings within the UK.

[45] This is coherent with the recommendation in the Pöyry and Imperial College's report to the CCC: "Roadmap for Flexibility Services to 2030", May 2017.

Carbon emission targets for energy

The studies illustrate the impact of reducing carbon emissions from energy from 30Mt to 0Mt – without decarbonisation of the heating system, residual emissions could be over 100 $MtCO_2$, which is incompatible with the UK's 2050 target. In the long-term, reducing energy system emissions to zero may be required to support other sectors that cannot achieve their share of the required greenhouse gas reductions. The consequence of this would be to substantially reduce natural gas-based technologies such as gas reforming and gas generation and would, therefore, require considerably more zero-carbon electricity generation technologies such as nuclear power and renewables, combined with energy storage. However, progress with importing hydrogen at low costs, or improving the efficiencies and carbon capture rates of gas reforming technologies could mitigate the need to build additional low-carbon electricity generation. This hydrogen production options warrant further investigation.

Hydrogen production demonstration plants

The two hydrogen production technologies for large-scale deployment are currently gas reforming and electrolysis. Although there is considerable experience of gas reforming it is limited to industrial applications. There is insufficient experience of electrolysis. In both cases, there is considerable uncertainty in terms of costs and performance, particularly for large-scale deployment. It would be informative to commit to build gas reforming and electrolysis demonstration plants within the UK to enable experience to be gained prior to making decisions on large-scale deployment.

Chapter 1. Introduction

1.1 Context

The heat sector accounts for more than half of the UK's energy consumption and contributes to more than 30% of the total carbon emissions. Achieving the UK's long-term climate targets will require decarbonisation of electricity, gas, and heat in a coordinated manner. A strategic decision on both gas and heat decarbonisation pathways will require an in-depth understanding of the techno-economic and environmental characteristics of these pathways.

Addressing the challenges related to decarbonisation of gas and heat, the Committee on Climate Change (CCC) has identified multiple decarbonisation pathways for low-carbon heating as proposed in the CCC's October 2016 report, "Next Steps for UK Heat Policy"[46]. Three central pathways have been identified: i.e. (i) by 'greening' the gas supply by shifting to low-carbon hydrogen (H2), (ii) electrification of heat supported by low-carbon power generation, or (iii) by potential hybrid solutions, with the bulk of heat demand, met by electricity, and peak demands met by green gas[47]. Each pathway brings significant challenges, and the CCC concluded that it was unclear whether there is a dominant low-carbon heating solution for the UK, and what the implications are on the future infrastructure requirements and operational coordination across UK energy systems.

Whichever portfolio of technological options for gas and heat decarbonisation prevails in the future, the interaction between various energy vectors – electricity, heat, natural/biogas and hydrogen – will be critical for the cost-effective decarbonisation of the energy system. A higher degree of integration between electricity and other energy vectors, especially heat, presents novel and unique opportunities to make use of cross-vector flexibility to support the integration of low-carbon generation technologies and the potential to reduce the cost of decarbonisation. The interactions across different energy vectors are also likely to affect the choice of technologies and the optimal portfolio of energy infrastructure. This integrated approach will improve the flexibility across different energy vectors, which can substantially reduce the cost of decarbonisation and enhance the integration of low-carbon generation technologies into the electricity system, as demonstrated in several recent studies of the future UK power

[46] Available at: https://www.theccc.org.uk/wp-content/uploads/2016/10/Next-steps-for-UK-heat-policy-Committee-on-Climate-Change-October-2016.pdf

[47] A bioenergy focused pathway was not considered a core option, as the CCC's 2011 Bioenergy Review suggested a limit of around 135 TWh of primary bioenergy that could be available to the UK power and gas systems.

sector[48,49]. Gas decarbonisation through hydrogen may also enable vast quantities of energy to be stored cost-effectively across seasons, which could significantly reduce the system integration cost of variable renewable sources.

As the energy system progresses towards ever more ambitious carbon targets, increased interaction between energy vectors will become more important. In this context, whole-energy system modelling will be central for capturing the complexities of different energy sub-systems as well as specific features of a range of emerging energy conversion and storage technologies (e.g. gas storage, thermal storage, hybrid heat pumps, combined heat and power plant, fuel cells etc.) that would link energy vectors and provide flexibility. Analysing multi-vector energy systems at sufficient temporal and spatial granularity will be essential for assessing the cost-effectiveness of alternative decarbonisation pathways. Furthermore, multi-vector decarbonisation will also need to adequately consider the synergies and conflicts between the local/district level and national level infrastructure requirements. In this context, comprehensive analyses have been undertaken across multiple energy vectors in order to provide an in-depth understanding of the interactions between decarbonised electricity, gas and heating systems, as well as to identify and understand the key uncertainties that affect decisions around low-carbon heat to 2050.

1.2 Key objectives

This project focuses on understanding and quantifying the impact of long-term cost drivers of decarbonising the heat sector. The specific objectives of the project are to:

- Understand the implications of alternative heat decarbonisation pathways on electricity and gas infrastructures in the UK energy system in 2050 by:
  - Analysing the interactions between the electricity and heat systems (including various forms of storage)
  - Optimising the interactions across different energy vectors to maximise whole-system benefits;
- Understand the economic performance and drivers of various pathways by:
  - Comparing the whole system costs of alternative heat decarbonisation scenarios in 2050, and beyond towards a zero-emissions energy system. For example, comparing the costs of retaining gas distribution networks that are re-purposed for transporting hydrogen, against reinforcing the electricity grid under various low-carbon heating scenarios;

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[48] G. Strbac, M. Aunedi, D. Pudjianto, F. Teng, P. Djapic, R. Druce, A. Carmel, and K. Borkowski, “Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies,” Imperial College London and NERA Economic Consulting report for the Climate Change Committee, 2015.

[49] D. Sanders, A. Hart, M. Ravishankar, G. Strbac, M. Aunedi, D. Pudjianto, and J. Brunert, “An analysis of electricity system flexibility for Great Britain,” Report BEIS, 2016.

   - Analysing the impact of uncertainties in technologies and costs;
- Provide fundamental evidence to support the development of policies for decarbonising heating and the electricity system.

Comprehensive studies have been carried out to quantify the investment and operational requirements as well as the costs of alternative heat decarbonisation pathways for a representative energy system for Great Britain in 2050. These studies were carried out in the context of related activities in this area, including the on-going research carried out by Department for Business, Energy & Industrial Strategy (BEIS) on Heat and Strategic Options, research into the costs of future heat infrastructure for the National Infrastructure Commission[50], Network Innovation Competition (NIC) trials, etc.

1.3 Scope of studies

The CCC's approach to low-carbon heat is presented in Figure 1-1. The scope of this particular study includes quantification of the system costs of different heat decarbonisation pathways, consistent with the CCC's approach to low-carbon heat. The CCC's previous analysis has identified that converting all off-gas grid homes and some direct electric heating to heat pumps, representing 18% of households[51], and 13% of households in urban areas to district heating is cost-effective. This modelling, therefore, considers the costs of converting the remaining 71% of households to a low-carbon heating technology. The studies focus on:

- Cost performance of each decarbonisation pathway and cross-cutting analysis across pathways;
- Interaction and optimal capacity portfolios of power system infrastructure (generation, electricity network, electricity storage), hydrogen infrastructure (production capacity, hydrogen network, storage), carbon capture and storage infrastructure and heating infrastructure;
- Impact of uncertainties in key modelling assumptions and input parameters;
- Role and benefits of enabling technologies that can improve system flexibility across all energy vectors and reduce emissions;
- Impact of energy efficiency;
- Technical feasibility of transporting hydrogen in the existing gas distribution infrastructure.

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[50] Element Energy and E4tech," Cost analysis of future heat infrastructure," a report for National Infrastructure Commission, March 2018.

[51] Assuming 34.3m households by 2050

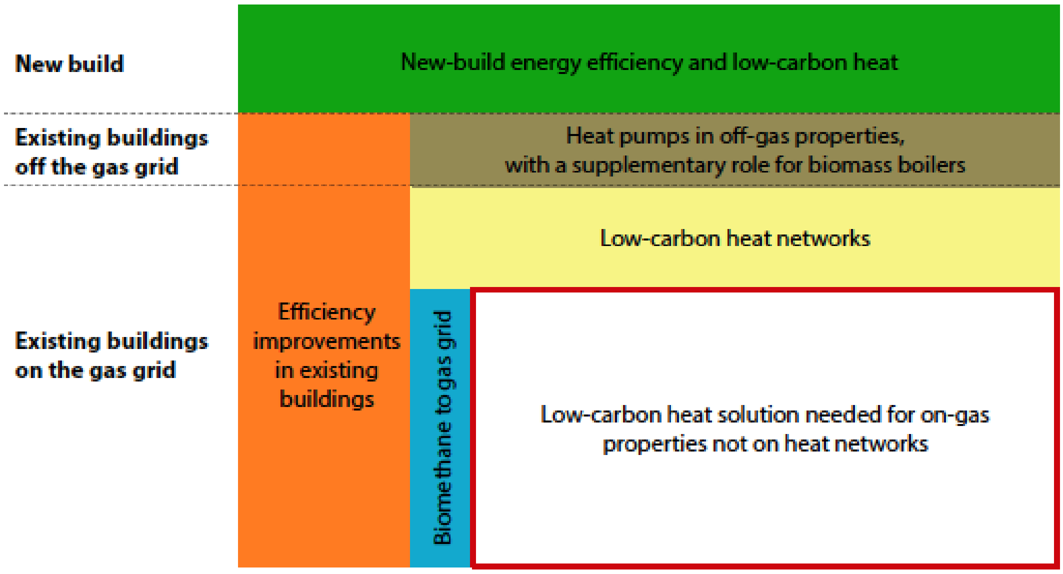

Figure 1-1 Low-regrets measures and the remaining challenge for existing buildings on the gas grid[52]

The analysis is based on an optimised system constructed by the IWES model, which assumes that full coordination across all system components can be achieved. This will require further development of appropriate regulatory and commercial frameworks as well as cooperation across all market stakeholders and deployment of appropriate technologies and control systems necessary to enable cost effective decarbonisation of the GB energy system, which is beyond the scope of this report.

A broad spectrum of studies has been carried out to optimise the future investment and operation of the Great Britain (GB) system[53] focusing on three heat decarbonisation pathways: H2, Electric and Hybrid systems. The study uses future (2050) annual system energy demands of domestic and non-domestic sectors provided by the CCC:

- Total annual non-heat and non-transport electricity demand: 367 TWh;
- Total heat energy demand: 633 TWh;
- Total transport-related-electricity demand: 111 TWh.

The composition of the energy demand used in the study is summarised in Figure 1-2.

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[52] CCC (2016) Next Steps for UK Heat Policy

[53] A 14-regions model is used in these studies; the system is described in Appendix F.

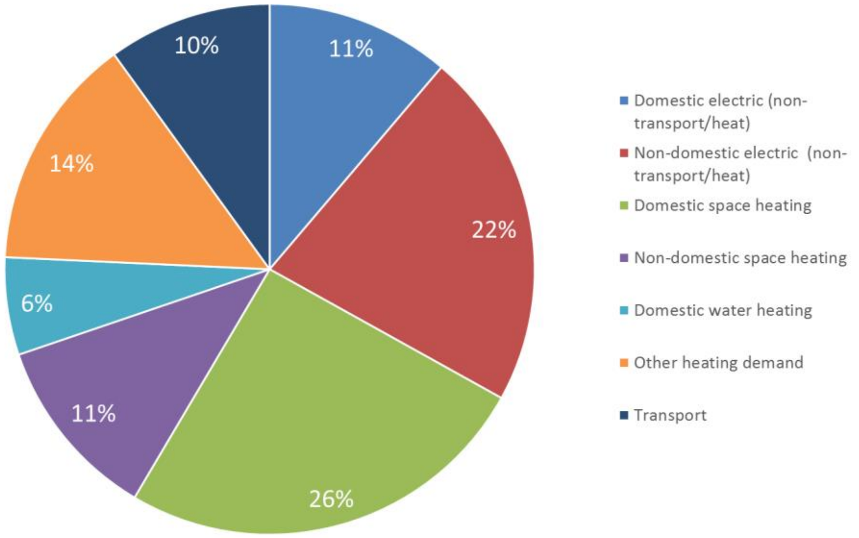

Figure 1-2 Composition of energy demand

Sensitivity studies have been performed on the three core decarbonisation pathways, including:

- Carbon targets: 30, 10, and 0Mt CO_2/year;
- Impact of heat demand reductions driven by energy efficiency improvements in the building stock and climate;
- Impact on the core scenarios of the use of district heating, and micro-CHP technologies,
- Regional scenarios
- Reduced financing costs
- Low-carbon power generation capex;
- Fuel cost;
- Hydrogen import;
- Hydrogen production technologies: SMR, ATR, electrolysers;
- System flexibility which is provided by:
    - Electric system: demand response (including from electrolysers), electricity storage, Interconnectors;
    - Hydrogen storage including long-term and distributed storage;
    - Thermal Energy Storage (TES) including preheating, domestic and district heating thermal storage.
- Constraint on the low-carbon resources including nuclear;
- Availability of technology;
- Heating technologies (e.g. HP/RH only vs optimised HP and RH).
- Interactions between gas and electricity systems.

Discussions of the results and the analysis can be found in Chapter 2 – 4.

1.4 Modelling approach

In order to study the interaction between different energy vectors and analyse the impacts of alternative heat decarbonisation pathways on the UK electricity and gas infrastructure in 2050, a set of pathways have been optimised using the Integrated Whole-Energy System (IWES) model developed by Imperial College. IWES model is an enhancement of the Whole Electricity System Investment Model (WeSIM) model[54] which incorporates modelling of heating technologies including district heating, heat networks, heat pumps (HP) both air/ground source, hybrid heat pump (HHP) and a module that optimises hydrogen infrastructure.

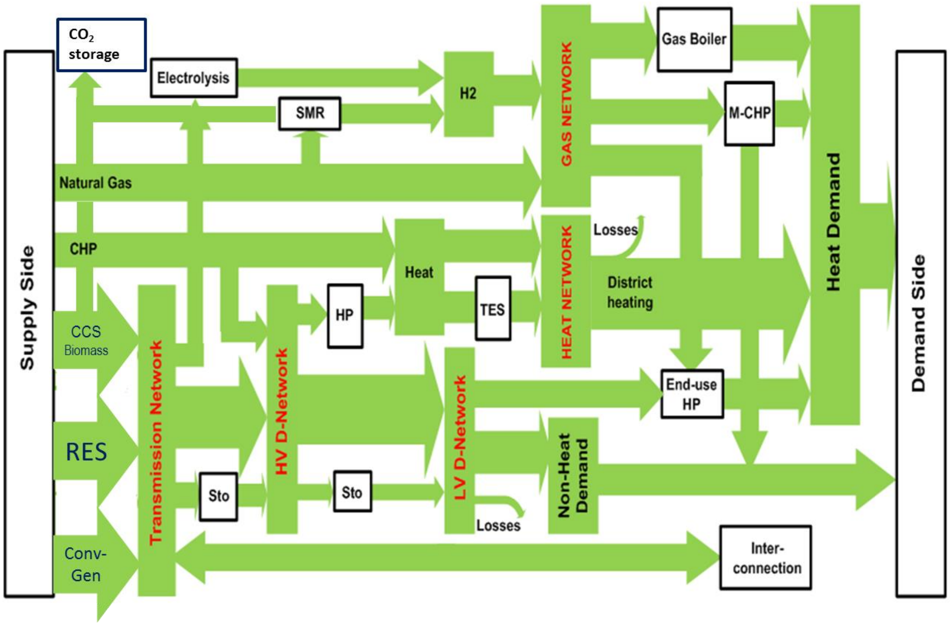

Figure 1-3 Interaction between gas, heat, and electricity systems

In summary, the IWES model minimises the total cost of long-term infrastructure investment and short-term operating cost while considering the flexibility provided by different technologies and advanced demand control, while meeting carbon targets. The IWES model includes electricity, gas, hydrogen and heat systems, simultaneously considering both short-term operation and long-term investment decisions[55] covering both local district and national/international level energy infrastructure, including carbon emissions and security constraints.

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[54] WeSIM is a holistic electricity system optimisation tool developed by Imperial that has been used extensively to analyse the system integration cost of new generation and the value of flexibility sources. Technical description of the model can be found in the following report: G. Strbac, M. Aunedi, D. Pudjianto, P. Djapic, S. Gammons, and R. Druce, "Understanding the balancing challenge," A report for the UK Department of Energy and Climate Change, 2012.

[55] This study focuses on the optimal investment needed to meet the 2050 system requirements and carbon target. The transition from the present to the optimised 2050 system warrants further studies.

The IWES model captures the interaction across different energy carriers, for example: where actions in the heating system (such as retaining hot water stores) can complement measures in the electricity system, the model can use these as opportunities to minimise the overall energy system costs. The IWES model also optimises the energy supply, transmission and distribution infrastructure requirements and additional system (e.g. balancing) services required in each of the above scenarios. Through the IWES model, opportunities for provision of system flexibility are analysed across different vectors, e.g. demonstrating the benefits of hydrogen production processes (power-to-gas and vice versa) and hydrogen storage in providing support to short-term and long-term balancing in the power system.

In the context of hydrogen, the IWES model has been used to optimise the required capacity of hydrogen production from different technologies, e.g. steam methane reforming (SMR) and/or auto thermal reforming (ATR) with CCS, electrolysis, biomass gasification and hydrogen storage, while simultaneously optimising investment and operation of the electricity system. The model considers the cost of hydrogen production in addition to the cost of hydrogen networks, hydrogen storage and CCS facilities. This enables the optimisation and analysis of the cost of different locational distributions of hydrogen sources.

The IWES model has also been used to optimise the mixes and capacities of the heating appliances in different decarbonisation pathways while taking into consideration the cost and efficiency of appliances. For example, in a scenario where the heat sector is decarbonised through electrification, the IWES model optimises the portfolio of heat pumps and resistive heating, installed at the household level, in order to minimise the overall cost. Heat pumps cost more but are more efficient than resistive heating (an average of 270% efficient compared to 100% for resistive heating); therefore, the model is used to determine the optimal portfolio of investments in heat pumps and resistive heating. Generally, heat pumps are used to supply 'baseload' heat while high-temperature heat demand (e.g. hot water) is supplied by resistive heating, as this portfolio of heat devices minimises the overall system investment and operating costs.

In this analysis it is assumed that during extreme cold conditions (1-in-20 years cold winters) the system level peak of heat demand is 80% of the sum of the peak heat demand of individual users, due to diversity effect (as the peak demand of all individual users does not coincide with the system peak demand). Based on that assumption, the cost of heating appliances is derived in the model.

For the purposes of this study, the IWES model has been set up to:

- Take into consideration system variability and optimise the operation of the energy system on an hourly basis;
- Reflect the technical needs of balancing the supply and demand of energy across different time horizons (seconds to years), including maintaining grid frequency

and providing system inertia; while reflecting the dynamic parameters and technical limitations of the selected portfolio of energy sources;

- Have a robust representation of demand and outputs of intermittent technologies on an hourly/half-hourly basis, considering spatial differences, correlation of renewable output and demand; whilst allowing opportunities for demand-side response to be analysed;
- Model electricity systems in GB and Europe to reflect the correlation of both electricity demand and supply with interconnected markets (e.g. benefit from diversity in renewable generation patterns through optimising interconnectors flows);
- Identify operating reserve requirements at different timescales;
- Include all components of system cost, i.e. capital, generation, carbon, operation and maintenance, transmission and distribution, energy storage (thermal, electricity, hydrogen), and transport of gas/hydrogen/carbon to storage;
- Reflect the impact on bulk transmission and distribution infrastructure requirements and costs for different network characteristics (e.g. urban and rural) and
- Incorporate distributed generation (e.g. solar PV, micro-CHP) connected directly to the distribution network.

The key outputs of the model include:

- Optimised energy infrastructure including the capacity and technology choices for power generation, hydrogen and heat sources.
- Capacity of transmission and distribution infrastructure for electricity and gas/hydrogen, including the consideration of grid constraints and required reinforcements
- Energy storage, including electricity, thermal and hydrogen storage;
- Emissions and generation/production by technology, including electricity and hydrogen production.
- Capital and maintenance expenditure of gas and electricity infrastructures;
- Operating costs including fuel costs, and balancing costs for the electricity system and the cost of transporting hydrogen/carbon;
- Other household related costs (e.g. heat pump capital costs, changes to gas appliances due to hydrogen conversion).

The results of the model have been used to analyse the technical and cost implications of different decarbonisation pathways when considering an optimised development and operation of the UK's energy system.

1.5 Key assumptions

The key assumptions used in the study are listed as follows:

Heat decarbonisation pathways

- In the H2 pathway, the majority of domestic heating will use hydrogen-based gas boilers with zero direct carbon emissions. Only households with no access to gas distribution use electric heating (i.e. a combination of heat pump and resistive heating). In hydrogen scenarios which include district heating, industrial gas boilers are used.
- In the Electric pathway, all heating is electrified using a combination of heat pumps and resistive heating. Industrial heat pumps are used for district heating.
- In the Hybrid pathway, a combination of hybrid heat pumps (HHP) and hybrid resistive heating are used to supply heating demands. Customers who do not have access to gas are supplied by electric heating.
- Gas boilers are fuelled by natural gas and/or carbon-neutral gas (biogas or hydrogen). Hydrogen can be added to the natural gas distribution system to up to 20% of the total volume (around 7% of total energy).
- As heat pumps are assumed to supply heat demand up to 55°C, gas boilers or resistive heaters are used to increase the temperature up to 65°C in order to meet higher temperature heat demands (e.g. hot water demand)
- The CCC's previous analysis has identified that converting all off-gas grid homes and some direct electric heating to heat pumps, representing 18% of households[56], and 13% of households in urban areas to district heating is cost-effective. This modelling, therefore, considers the costs of converting the remaining 71% of households to a low-carbon heating technology.
- Light vehicle transport is assumed to be electrified in all scenarios, leading to 111 TWh of electricity demand by 2050. Energy demands for Heavy Goods Vehicles (HGVs) were not considered in this study.
- Industrial process heat demand of 135 TWh/year is assumed to be delivered via hydrogen or electrification in the respective pathways.

Hydrogen production technologies

- Hydrogen production from gas is carried out using Auto Thermal Reformers (ATR) with CCS with expected higher performance, CO2 capture rates and lower cost than traditional Steam Methane Reformers (SMR)[57].
- Hydrogen from gas reforming is produced in a centralised manner to benefit from economies of scale; this implies that the production is located in the regions which have access to gas and carbon storage terminals, which reduces the need for a national CCS network. Furthermore, sensitivity studies have been carried out to investigate the cost performance differences between centralised and distributed

[56] Assuming 34.3m households by 2050

[57] See Element Energy (2018) Hydrogen Infrastructure: Summary of Technical Evidence

approaches for producing hydrogen (demonstrating that the centralised approach is more cost-effective than the distributed approach). This is further discussed in section 2.1.2.

- Hydrogen production from electricity can be performed by two different electrolyser technologies: Solid Oxide Electrolysers (SOE) or Proton Exchange Membranes (PEM). Two variants of PEM technologies, (i) PEM, (ii) PEM (SGI[58]) are modelled to capture different performance in energy conversion efficiency and cost of the technology (Table 1-1).

Table 1-1 Cost, efficiency, and capture rate of different hydrogen production technologies[59]

Technology	Capex (£/kW)	Fixed Opex (£/kW/year)	Efficiency (%)	Capture Rate (%)
ATR + CCS	333	24.4	89%	96%
SMR + CCS	384	24.4	75%	90%
Solid Oxide Electrolyser	800	45.0	92%	
Proton Exchange Membrane	465	29.3	74%	
Proton Exchange Membrane (SGI)	350	29.3	67%	
Biomass Gasification+CCS	1,234	103.4	69%	90%

Availability of bioenergy and biogas

- Another source of hydrogen considered in this study is bioenergy. It is assumed that 135 TWh/year of bioenergy (from purpose-grown feedstock) is available and can be converted into either electricity or hydrogen via biomass gasification with CCS. The capital cost of biomass gasification with CCS infrastructure is considered in modelling, while the cost of bioenergy is not included. Furthermore, negative emissions associated with bioenergy are not included in the modelling.
- In addition to bioenergy, it is assumed that 21 TWh/year of biogas (or biomethane) from anaerobic digestion is available. The biogas can be used to supply traditional gas-fired power generation and/or gas boilers. The cost of biogas is assumed to be the same as the cost of natural gas, while being carbon neutral.

Hydrogen network

- It is assumed that in all scenarios, the national natural-gas transmission network (NTS) will be retained in the future. Biogas (biomethane) could be mixed with natural gas. A limited amount of hydrogen could also be mixed with natural gas; however, the current national gas transmission is not suitable for large-scale transport of hydrogen. Therefore, in the H2 pathway, a new national hydrogen transmission

[58] Source: Sustainable Gas Institute

[59] Source: CCC based on Element Energy (2018) Hydrogen for heat technical evidence project

infrastructure is assumed to be deployed, in addition to the NTS, at additional cost[60].

- For gas distribution, it is assumed that in the H2 pathway, the gas distribution is converted to be 100% hydrogen compliant[61]. In the Hybrid pathway, the natural-gas-based gas distribution network is retained, but a limited volume (e.g. 20%) of hydrogen could be mixed with the natural gas in the gas distribution system.

Hydrogen storage

- Two different hydrogen storage technologies[62] are modelled:
    - Underground storage - it is assumed that underground storage is used as centralised and long-term hydrogen storage. There is a restriction associated with the discharge of the storage (10% of energy stored/day) due to the need for a "gas cushion" for the stability of the storage.
    - Overground medium-pressure storage – it is assumed that this is used as distributed storage close to high energy demand locations to support of the supply of gas to localised peak demands. This storage is flexible as it can be discharged or charged rapidly.

Carbon prices and carbon capture

- No explicit carbon price is assumed in the modelling, as the model is set to achieve a specific carbon target.
- The cost of storing carbon at the carbon storage terminal is assumed to be £15/tCO_2. The cost of a carbon storage network is a separate cost component. If hydrogen is produced centrally near the gas and carbon storage terminals, the cost of carbon storage network is relatively small and included in the CCS infrastructure cost at the plant level. Otherwise, the cost of carbon storage network is optimised in the model; e.g. in the case studies with distributed hydrogen production (section 2.1.2).
- In the H2 scenario, the cost of CCS power generation is reduced by around 5% to reflect the sharing of CCS infrastructure.

Electricity generation

- The levelized cost of electricity generation for low-carbon generation technologies is assumed to be as follows:
    - PV: £40/MWh

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[60] A sensitivity study was also carried out to investigate the cost of producing hydrogen more locally to mitigate the need for building hydrogen transmission networks. This requires CCS networks to be built to transport carbon to storage facilities. The study is discussed in section 2.1.2.

[61] Replacing iron pipes with polyethelene pipes in the Iron Mains Replacement Programme supports the use of hydrogen; in addition, there will be a need for distributed hydrogen storage, meters, sensors, compressors.

[62] Modelling data of the hydrogen storage are obtained from Element Energy (2018) Hydrogen for heat technical evidence project.

  - Wind: £50/MWh
  - Nuclear: £70/MWh
  - CCS: £90/MWh
- The assumed maximum capacity for wind, PV, CCS, and nuclear that can be built by 2050 are 120 GW, 150 GW, 45 GW, and 45 GW respectively[63].
- It is assumed that the UK is energy neutral at the annual level (total annual demand is equal to annual production) while allowing short-term energy/power exchanges with the interconnected countries

Electricity network

- The cost of reinforcing transmission network and interconnection is estimated around £1.5m and £2m per km[64] respectively.
- The cost of reinforcing distribution networks in rural and urban areas is between £95k and £362k per km respectively.
- It is assumed that the existing electricity transmission and distribution networks will be retained in future in all pathways and hence the cost of the existing electricity infrastructure is not explicitly presented.

System flexibility

- Unless otherwise stated, the study assumes a significant level of system flexibility defined as follows:
- 50% of the potential flexibility in demand response is used. Demand flexibility is enabled by controllable Industrial and Commercial loads, smart charging of electric vehicles, demand-side management of smart domestic appliances and frequency responsive, smart fridges, domestic TES and preheating capability. For example, 50% of households can shift their heating demands to reduce peak or to maximise utilisation of low-carbon generation, via preheating or thermal storage in their homes.
- The model can choose to invest in energy storage including distributed electricity storage, domestic thermal energy storage and hydrogen storage.
- Electrolysers also provide flexibility by allowing the output to follow the available low-carbon energy, e.g. from PV or wind; this improves system balancing and reduces the associated operating costs.
- Additional interconnection capacity can be built up to 25 GW.

Energy efficiency

- Household level energy efficiency measures (including insulation) is assumed to be

[63] As defined by the CCC
[64] Based on 1 GW capacity

deployed consistent with the CCC's scenarios for 2050. This includes up to 4 million solid walls, all loft and cavity walls by 2050. The costs of installing this energy efficiency are not included in this analysis, as the CCC estimates this to be cost-effective against a target-consistent carbon price[65].

[65] See CCC (2015) Sectoral Scenarios for the Fifth Carbon Budget

Chapter 2. Analysis of alternative heat decarbonization pathways

This study considered three core pathways for decarbonising electricity and heat demand:

- ***Hydrogen pathway***

  The core Hydrogen pathway [H2] is based on installing hydrogen boilers at consumer premises in order to decarbonise heat demand. It is assumed that the consumers that do not have access to gas would use electric heating.

- ***Electric pathway***

  In the Electric pathway [Elec] heat demand is provided by the optimal deployment of electric heating appliances including heat pumps (HPs) and resistive heating (RH).

- ***Hybrid pathway***

  The Hybrid pathway combines the use of gas and electric heating systems via a hybrid heat pump (HHP), which includes both a heat pump and a gas boiler. The gas heating system in the Hybrid system uses natural gas or carbon-neutral gas such as biogas or hydrogen[66] to reduce emissions from gas.

A range of alternative strategies across the core heat decarbonisation pathways has also been investigated. This includes the implementation of:

- ***Regional decarbonisation strategies***

  This consists of three scenarios, including:
  - Use of hydrogen in the North of GB[67] while the rest of the system is decarbonised through HHP, in order to minimise investment in the transportation of hydrogen.
  - Use of hydrogen in urban areas while rural areas are decarbonised through HHP.
  - Use of large-scale industrial HP-based district heating in urban areas.
- ***District heating***

  This consists of two scenarios including:
  - National deployment of industrial-scale hydrogen boilers in district heating networks (H2+DH);
  - National deployment of industrial HP in district heating networks (Elec+DH);

[66] The volume of hydrogen that can be mixed with natural gas or biogas is limited to up to 20%. A hybrid heat pump with hydrogen boiler was not selected as the cost would be higher than the one with natural/biogas.

[67] Scotland, North of England and North of Wales

- ***Micro-CHP***
  In this scenario, 10GW of micro-CHP is deployed in the Hybrid system, instead of hybrid heat pumps.

The key results of the studies are described as follows.

2.1 Hydrogen pathways

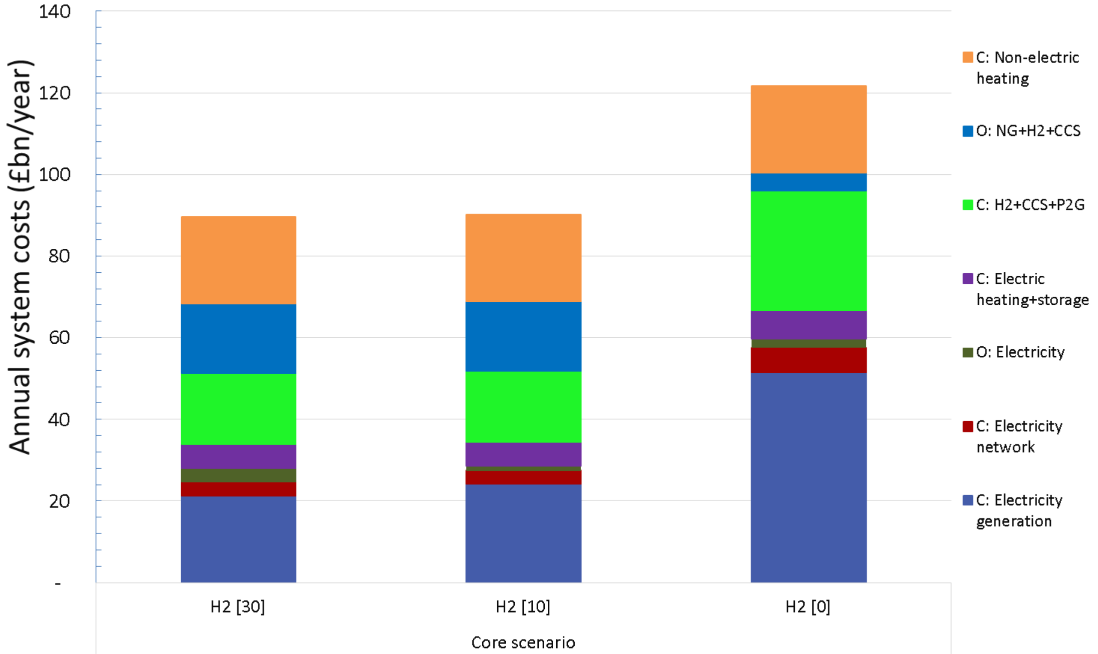
The core H2 pathway evaluated in this study is based on installing hydrogen boilers in households; customers that do not have access to gas will use electric heating (heat pumps and resistive heating). It is also assumed that converting a home to hydrogen use involves changing all gas infrastructure at additional cost (see Appendix B for the description of these costs).

Three carbon targets, i.e. 30Mt, 10Mt and 0Mt are considered to evaluate the cost performance of each H2 pathway creating three cases: H2 [30], H2 [10], H2 [0]. The annual system costs across different cases are presented and compared in Figure 2-1.

There are several cost components of hydrogen pathways:

- The cost of hydrogen infrastructure is dominated by the cost of gas reforming plants and hydrogen storage, the combination of which is optimised in the study. This includes around £15.1bn/year of investment in hydrogen infrastructure, split between investment in production plants (£8bn/year), and around £6.4bn/year in hydrogen storage plants. The cost of hydrogen transmission is less than £1bn/year.
  - The function of hydrogen storage[68] is to improve the utilisation of the hydrogen infrastructure by reducing the capacity of hydrogen production plants. For example, the peak demand of hydrogen in the H2 30Mt case reaches 260 GW while the total capacity of hydrogen production proposed by the model is only 103 GW (costs £8bn/year). In order to meet such demand, there is a need for around 20 TWh of hydrogen storage (costing £6.4bn/year). Without storage, the hydrogen production capacity would be 2.6 times larger which would increase the cost of the H2 pathway by £13bn/year).
- Another major cost component in the hydrogen pathways is the £17.1bn/year cost of the natural gas required to produce hydrogen in a 30Mt case. This cost decreases in 0Mt if the hydrogen is produced by electrolysis, though overall costs are significantly higher.
- The investment cost (£21bn/year) in hydrogen-based gas boilers including the household conversion costs.

[68] Combination of underground storage, e.g. salt caverns as is currently used in Teeside and medium pressure over ground storage



Annual system costs considered in the study

The IWES model considers 29 different cost categories (described in Appendix A), but for simplicity, the annual system costs are presented and grouped into five Capital expenditure (C) and two Operating costs (O) categories described as follows:

a. ***C: Electricity generation*** – annuitised capital cost of electricity generation that encompasses both low-carbon and non-low carbon generation.
b. ***C: Electricity networks*** – annuitised capital cost of the electricity network that consists of the cost of the distribution network, transmission network and interconnectors.
c. ***O: Electricity*** – annual operating cost of electricity that includes all the variable operating costs (e.g. fuel, O&M) as well as start-up, and fixed operating costs. Carbon prices are excluded from this analysis.
d. ***C: Electric heating +storage*** – annuitised capital cost of electric heating and energy storage in electric scenario includes the capital cost of the heat pump (domestic and industrial), resistive heating, electric storage, thermal energy storage, cost of end-use conversion (replacing gas-based heating to electric), cost of appliances and cost of decommissioning gas distribution due to electrification.
e. ***C: H2+CCS+P2G*** – annuitised capital cost of hydrogen and CCS infrastructure, including the cost of all hydrogen production technologies, cost of hydrogen and CCS networks, cost of hydrogen storage and carbon storage.
f. ***O: NG+H2+CCS*** – annual operating cost of the natural gas system that includes fuel cost of gas-based hydrogen production technologies, e.g. SMR and ATR, cost of hydrogen import, operating cost of hydrogen storage and the fuel cost of the natural gas (NG)-based boiler.
g. ***C: Non-electric heating*** – annuitised capital cost of non-electric heating includes the capital cost of natural gas (NG) and hydrogen-based boilers, cost of district heating infrastructure, conversion cost and the cost of maintaining the existing gas distribution network.

Figure 2-1 Annual system cost of hydrogen pathways

The following costs are associated with the costs of decarbonising the electricity sector; some costs could be considered as 'baseline' costs as all pathways consider a decarbonised electricity system:

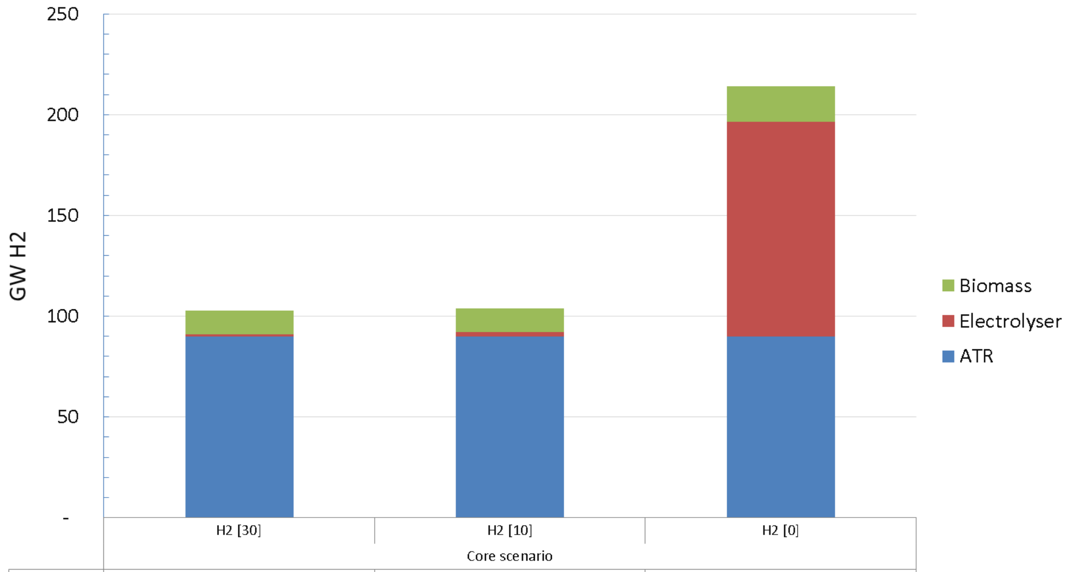
- Investment of more than £18bn/year in new low-carbon electricity generation capacity in the 30Mt and 10Mt cases. The investment required increases to £49bn/year in a 0Mt case due to the need to install additional low-carbon electricity generation to produce zero emissions hydrogen via electrolysis.
- Between £2 - 3bn/year of required electricity network upgrades, mostly at the distribution level;
- The operating costs of the electricity system (i.e. fuel burnt for balancing the system) less than £3.5bn/year (30 Mt case) and becomes less in both the 10Mt and 0 Mt cases as the electricity generation contains more zero-marginal-cost generation;
- Around £6bn/year for installing heat pumps in off-gas grid homes as well as some additional domestic Thermal Energy Storage;

Increasing the carbon constraint in the modelling from 30 Mt/year to 0 Mt/year increases annual system costs by more than £30bn/year. However, the total system costs increase only by £0.6bn/year to reduce the emissions from 30 Mt/year to 10 Mt/year. The additional cost is driven by £2.8bn/year increase in the cost of electricity generation but offset by a £2.2bn/year reduction in the electricity operating cost as more zero-marginal-cost of generation is installed.

The increased costs are driven by:

1. The increased investment in H2 infrastructure in the H2[0] is driven by the need for zero-emission electrolysers to displace gas-based hydrogen production

The optimised hydrogen production capacities proposed by the IWES model are presented in Figure 2-2, across different emissions constraints. Assuming a capture rate of 96% for gas-based ATR production of hydrogen makes this technology unsuitable for a zero-carbon energy system, though gas-based hydrogen production dominates the production mix in both the 30 Mt and 10 Mt scenarios. It is important to highlight that it is not possible to displace ATR entirely by electrolysers in the H2[0] case due to the limited availability of low-carbon energy resources assumed in the study; therefore, a significant capacity of ATR remains but operating at a very low load factors as indicated by the reduced hydrogen production of ATR from 30Mt to 0Mt cases shown in Figure 2-3. The implication of this is that zero-emissions energy system based on domestically produced hydrogen via electrolysis would not be feasible. Meeting zero emissions in a hydrogen-based system will require hydrogen imports and/or zero-emissions gas-based hydrogen production capacity alongside electrolysis. Even if further low-carbon electricity generation resources were available for producing hydrogen via electrolysis, this is significantly more costly than alternative zero carbon energy systems via electrification pathways.

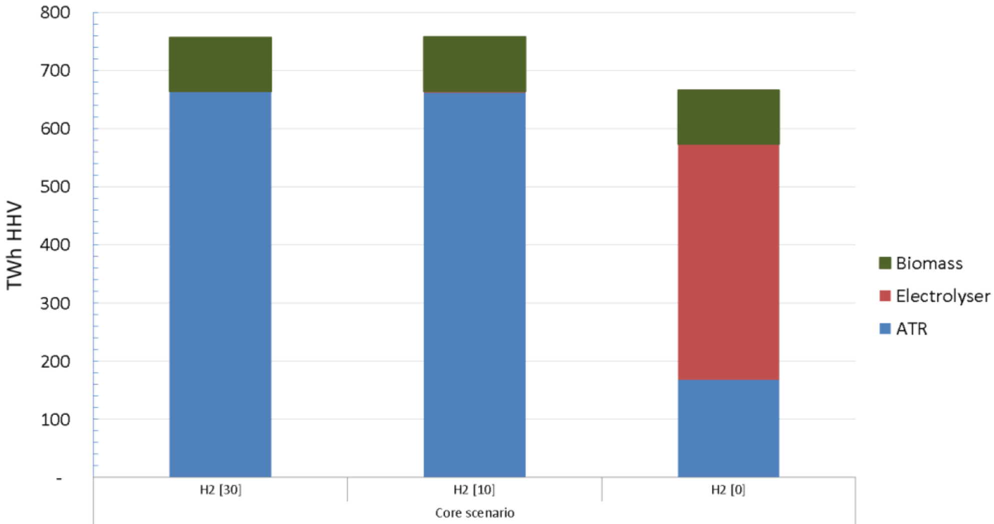


	H2 [30]	H2 [10]	H2 [0]
Biomass	12	12	18
Electrolyser	1	2	106
ATR	90	90	90

Figure 2-2 Optimal portfolios of hydrogen production technologies

Figure 2-2 demonstrates that ATR is selected as the primary technology to produce H2 to meet a low-carbon target of 30Mt and 10Mt, but electrolysers will be needed if a strict zero-carbon target is a long-term objective for the energy system (unless emissions from ATRs can be removed entirely, which is discussed in section 2.1.1.2). The 30Mt and 10Mt cases have the same optimal portfolio of hydrogen production technologies as gas use has been almost fully decarbonised. Therefore, in the 10Mt case, the electricity sector is further decarbonised. At a capture rate of 96%, producing around 600 TWh of hydrogen via ATRs will result in residual emissions of around 5Mt CO_2 per year, with around 120Mt CO_2 per year being sequestered from this process. The shift from ATR to electrolysers implies that a transition towards zero-carbon energy system in the H2 pathways would require change in production of hydrogen from gas to electricity-based.

Figure 2-3 shows the hydrogen production in different cases. It also demonstrates the shift from ATR in a 30Mt scenario to electrolysers in the 0Mt scenario as the primary hydrogen production technology. Hydrogen production in the 30Mt cases is approximately 90 TWh higher than the production in 0Mt cases. In the 30 Mt case, demand for hydrogen is higher than in the 0Mt case as hydrogen is used for both power generation and heating. In the 0Mt case, less hydrogen is allocated for power generation as there is assumed to be a constraint on the total availability of UK based low-carbon energy sources for producing hydrogen via electrolysis.



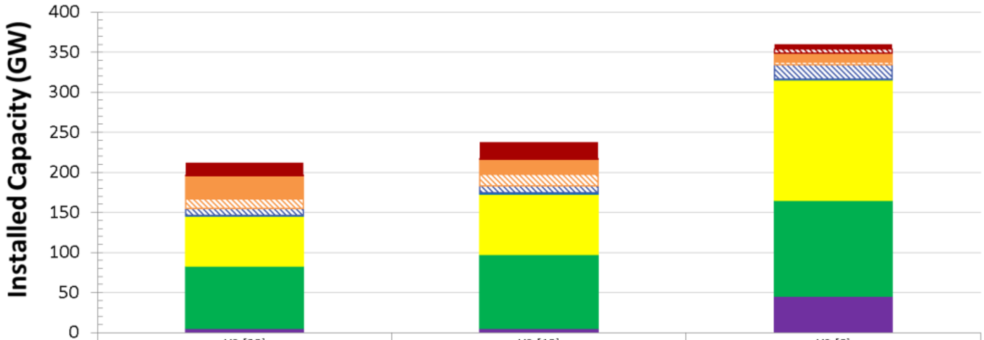
	H2 [30]	H2 [10]	H2 [0]
Biomass	93	93	93
Electrolyser	1	3	406
ATR	663	661	168

Figure 2-3 Hydrogen production from ATR, electrolyser, and biomass gasification

2. The increased cost of electricity system, primarily driven by the increased capacity of low-carbon generation needed to meet a zero-carbon target.

The optimal generation capacity for each pathway proposed by the IWES model is shown in Figure 2-4. For H2[0], the capacity of PV, wind, and nuclear generation increases substantially from the capacity needed in the 30Mt case due to the shift in the optimal hydrogen production mix from ATR to electrolysis (this will be further presented in Figure 2-2). In this case, the capacity of low-carbon generation reaches the maximum limit assumed in this study. There is a need for 45 GW of nuclear to be part of the generation portfolio, in addition to 150 GW of PV and 120 GW of wind generation (in contrast, the need for nuclear capacity is minimum in 30Mt cases as most of the hydrogen is produced by natural gas). As the capacity of renewables increases in the 0Mt case, electricity network costs also increase by £2.7bn/year, mostly at the distribution level[69].

[69] The impact of increased capacity of large-scale renewables on the transmission network is minimised by installing electrolysers near generation sites.



	H2 [30]	H2 [10]	H2 [0]
	Core scenario		
OCGT	15	21	6
H2 OCGT	0	0	5
CCGT	30	19	11
H2 CCGT	12	14	3
District CHP	8	9	18
Hydro	1	1	1
PV	63	76	150
Wind	77	92	120
Nuclear	5	5	45

Figure 2-4 Optimal portfolios of generation capacity in H2 pathways

It is important to highlight that even in a zero-carbon system, traditional fossil-fuel-based generators such as CCGT, and OCGT are still able to operate using biogas to provide system balancing and backup, though the load factors of these plant are limited by the availability of carbon-neutral biogas.

For the core H2 0Mt case, the pre-defined availability of low-carbon generation resources leads to the inability of this pathway to reach zero carbon as shown in Figure 2-5. Therefore; a sensitivity study was carried out allowing higher capacity for renewables to be installed in the H2 pathway to enable this pathway to reach a zero-carbon target. Additional amount of 56 GW of wind (176 GW in total) is installed compared to the base case (120 GW).

	H2 [0]	H2 [0]
	Core scenario	Higher RES limit
OCGT	6	24
H2 OCGT	5	5
CCGT	11	28
H2 CCGT	3	3
District CHP	18	17
Hydro	1	1
PV	150	150
Wind	120	176
Nuclear	45	45

Figure 2-5 Identifying the need for low-carbon generation capacity in H2 [0] case

Increased availability of low-carbon electricity sources enables complete decarbonisation of the core H2 pathway; the system cost will increase to £130.6bn because of the increased capacity requirement of power generation and H2 infrastructure (although some costs are offset by the reduction in the electricity opex, network costs and gas opex). The cost comparison between the base case and the case with a higher RES limit is presented in Figure 2-6.

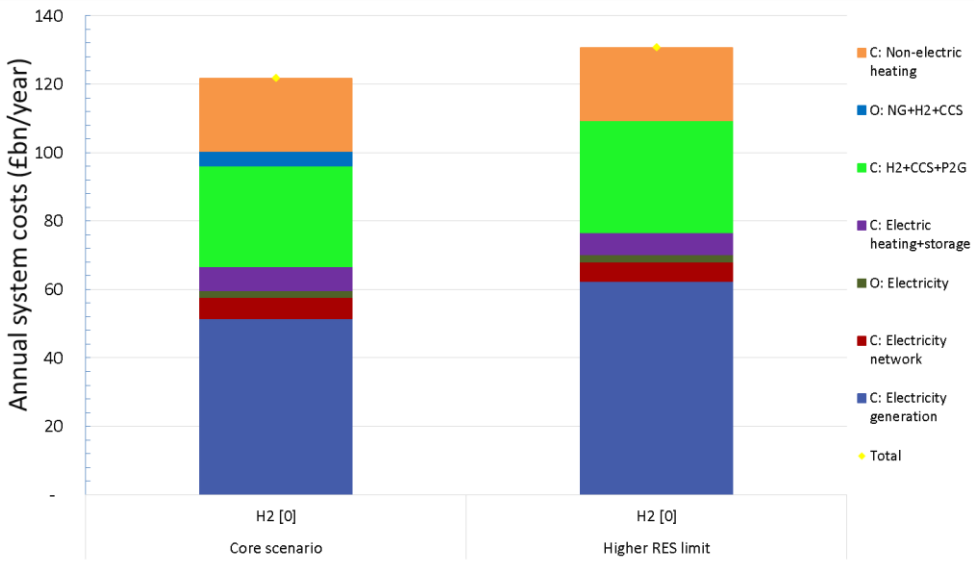


Figure 2-6 Comparison between the system costs in the H2 0Mt base case and the case with higher RES limit

Based on this study, it can be concluded that the H2 0Mt pathway may not meet the carbon target if the constraints related to the deployment volumes of low-carbon generation in the model are genuine UK resource constraints. As noted in section 2.4, the cost of this scenario is also significantly higher than the cost of alternative zero-emissions pathways.

2.1.1 Impact of future developments in gas-based hydrogen production technologies

2.1.1.1 Comparison between Steam Methane Reforming and Auto Thermal Reforming

Steam Methane Reforming (SMR) is currently a mature technology for producing hydrogen from natural gas. Approximately 48% of current global hydrogen production is via SMR[70]. In the future, this technology could be substituted by Auto Thermal Reforming (ATR) which is expected to have superior performance in terms of cost, energy efficiency and carbon capture rate[71]. The cost performance difference between

[70] See Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[71] See Element Energy (2018) Hydrogen for heat technical evidence project

the two technologies in the H2 30Mt pathways is analysed, and the results are presented in Figure 2-7.

Introducing ATR as the primary hydrogen production technology in the 30Mt case would reduce system costs by £7.2bn/year compared to a case with SMR. The cost reduction is enabled by (i) a substantial decrease in the operating costs as the efficiency of ATR (89%) is higher than SMR (75%); (ii) reduction in the capex of hydrogen infrastructure as the cost of ATR is lower than SMR; and (iii) savings in low-carbon electricity generation capex due to reduced requirement for decarbonising electricity within a fixed emissions constraint, as the emissions from the gas sector is lower than compared with the SMR case.

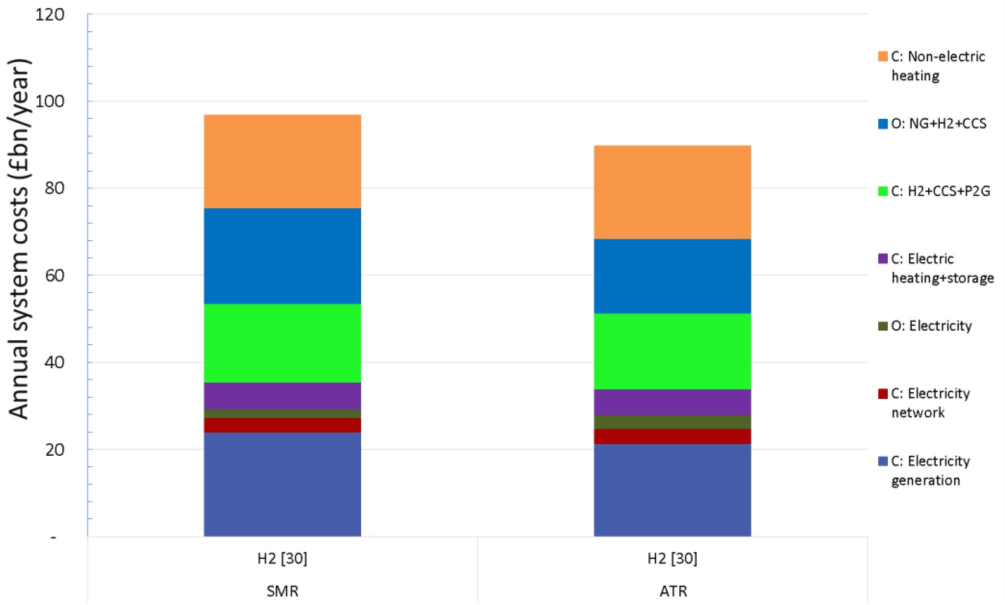


Figure 2-7 Cost performance of H2 pathways based on SMR and ATR

2.1.1.2 Impact of improving Auto Thermal Reformer's capture rate

Significant increases in the cost of the H2 pathway from the 30Mt to the zero-carbon scenario are driven by the need to produce hydrogen via electrolysis. In this context, the impact of possible technology enhancements in capturing the carbon emissions of ATR from 96% (the value used in the base case) to 100% with a marginal increase (10%) in cost has been analysed. This improvement would enable the use of ATR in the zero-carbon scenario, which would significantly reduce the cost of the H2 scenario. The cost performance of the H2 pathway in 0Mt case with electrolysers and enhanced ATR is compared in Figure 2-8.

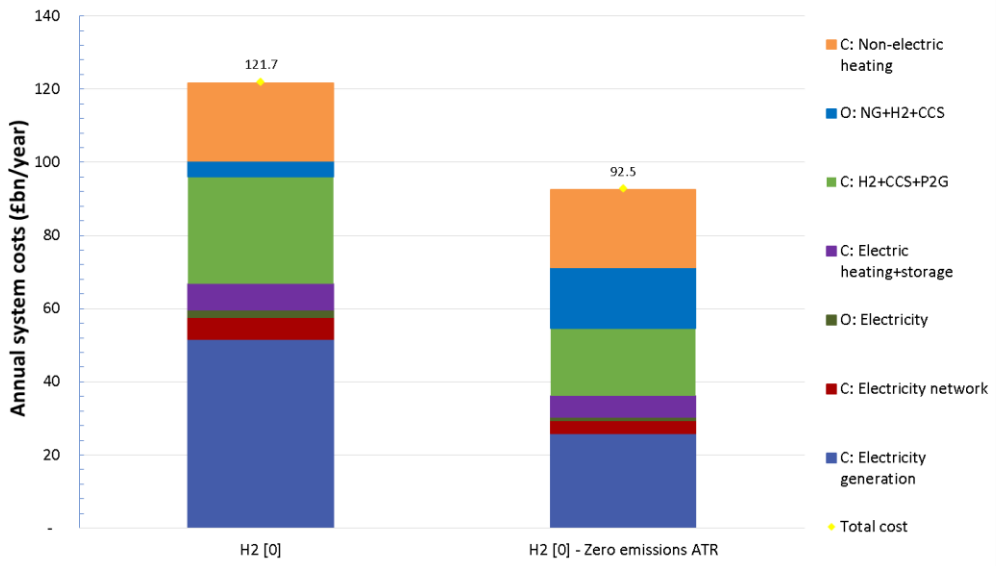


Figure 2-8 Value of enhancing the capture rate of ATR for a zero-carbon system

Enhancing the capture rate of ATR would reduce the cost of H2 0Mt pathway from £121.7bn/year to £92.5bn/year (savings of £29.2bn/year) while enabling zero emissions target to be achieved. Since the cost of ATR is also lower than electrolysers, the cost of hydrogen infrastructure would also reduce as well as the cost of low-carbon electricity generation required to produce hydrogen via electrolysis. The use of gas would increase the operating cost of the H2 pathway, offsetting some of the savings obtained in the reduction of hydrogen and electricity infrastructure capex. If a zero-emissions ATR could be developed, this would make hydrogen scenario significantly more economic: the cost of H2 0Mt pathway with zero-emissions ATR would be only marginally higher than the cost of Elec 0Mt pathway. Therefore, if a future gas-based hydrogen production technology was able to achieve zero emissions (i.e. capture rate of CCS towards 100%) at limited additional cost, the system costs of the hydrogen pathway would be comparable to alternative pathways for a zero-emissions energy system.

2.1.2 Distributed versus centralised hydrogen production

As an alternative to the centralised hydrogen production considered in the core scenarios, where hydrogen is produced close to coastal gas terminals with access to offshore CCS, localised production of hydrogen is also considered. The advantage of this approach would be to eliminate the need for a national hydrogen gas transmission network; the existing gas transmission would be used to transport the natural gas, which would be converted to hydrogen via distributed SMR or ATR located close to demand centres. However, this approach requires infrastructure to transport carbon to the carbon storage terminals on the coast. Though the capital costs of hydrogen and carbon dioxide pipelines are similar, transporting hydrogen around the country is less costly than piping CO_2. This is because hydrogen can be transported via an existing gas distribution network (alongside a new hydrogen transmission network), which is less costly than building a new onshore CO_2 transportation network. It is assumed that distributed hydrogen production would be more costly than centralised large-scale production, due to a loss of economies of scale. Furthermore, the absence of a national hydrogen network would eliminate the opportunity for the transportation of hydrogen between regions, which will drive higher overall capacity requirements for hydrogen production plant and/or storage.

To investigate and compare the performance of distributed and centralised hydrogen production approaches, the system and cost implications of the two approaches were studied for a 30Mt carbon target. Figure 2-9 shows the optimal hydrogen production capacity in both cases.

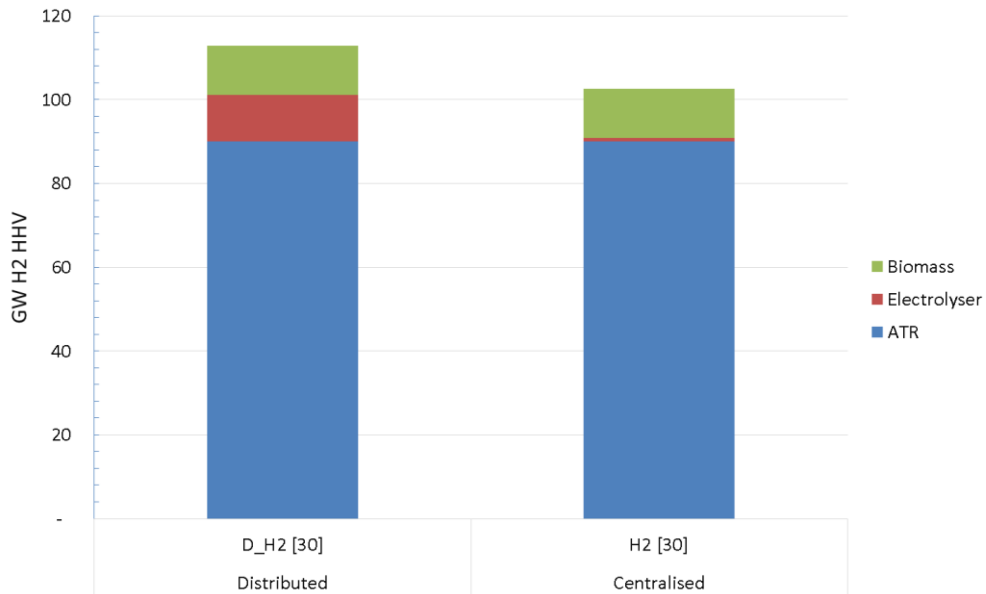


Figure 2-9 Capacity of hydrogen production plant in distributed and centralised scenarios

The studies demonstrate that the distributed approach requires around 10% higher hydrogen production capacity than a centralised approach. Due to the absence of a national hydrogen transmission system, the distributed approach loses the benefits from the diversity of hydrogen demand from both heating and electricity sectors across different regions. An increase in required hydrogen capacity, in addition to the higher unit cost of local hydrogen production plants, lead to an increase in the costs of a distributed approach when compared to a centralised approach, as shown in Figure 2-10.

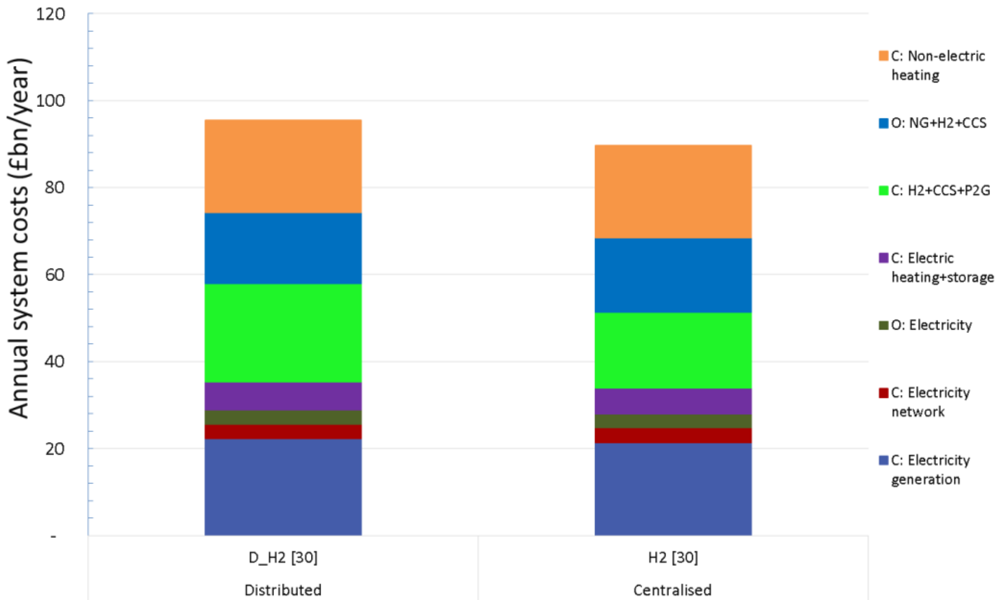


Figure 2-10 Cost comparison between the distributed and centralised hydrogen production scenarios

The modelling suggests that the cost of a distributed approach is about £5.9bn/year higher than the cost of a national, centralised approach, mainly due to the higher cost of hydrogen infrastructure. Based on this result and the conclusion that the centralised approach would be more cost-effective, the core H2 pathways were analysed assuming large-scale, national level hydrogen production.

2.1.3 Hydrogen-based district heating

Successful implementation of district heating in Denmark and other EU countries, motivated a study to assess the system implications and system cost of implementing heat decarbonisation using industrial-scale hydrogen gas boilers and district heating technologies. It is assumed that this district heating strategy is applied nationally to all areas[72]; although this case is slightly hypothetical, it can provide insights in the costs and the implications on both energy infrastructure and system operation. Two cases with 30Mt and 0Mt carbon targets are investigated: (i)H2+DH[30], (ii)H2+DH[0]. The results are compared with the results of the core scenarios in the corresponding pathways. The costs and system implications of implementing these alternative strategies can be observed in Figure 2-11.

[72] The heat demand in high and low density areas can be found in Appendix F

Imperial College London

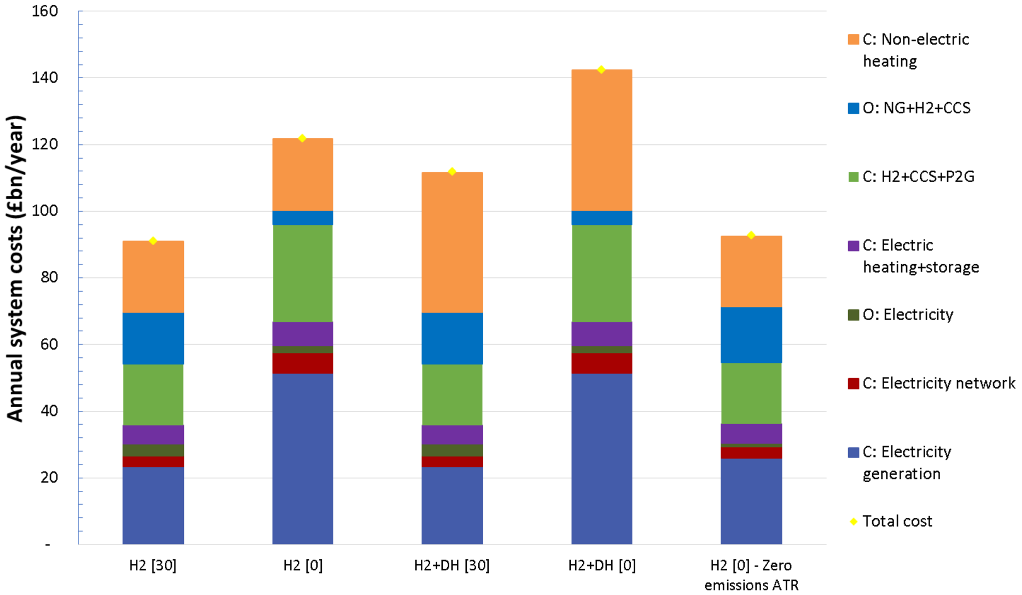


Figure 2-11 Annual system costs of alternative hydrogen pathways

The modelling results demonstrate that hydrogen-based district heating may not be cost-effective as the total cost of H2+DH is more than £20bn/year higher than the cost of core H2 pathways. The key difference between the two cases is that the cost of heating infrastructure in the district heating case is significantly larger than the core H2 pathways (where hydrogen boilers are installed in domestic premises). This increase in cost is primarily driven by the cost of deploying heat networks and the cost of connecting domestic premises to heat networks, including assets needed to meter and control heat in dwellings. The increase in cost is offset by the lower cost (by 35%-50%) of heating devices in district heating systems - due to economies of scale - compared to the cost of smaller, domestic appliances.

2.1.4 The ability of the existing gas distribution system to transport hydrogen

Hydrogen's volumetric energy density is around 30% of the volumetric energy density of natural gas. This implies that more than three times volume of gas (hydrogen) has to be supplied to consumer premises via gas distribution networks to meet the same energy demand. This raises a question about the capability of existing gas distribution networks to transport larger flows of gas if they are converted into hydrogen networks, and whether these networks would require significant reinforcement. In this context, modelling was carried out to investigate the technical capability of the existing gas distribution networks to transport hydrogen instead of natural gas in order to meet peak heat demand. Distribution networks operating at different pressure levels (i.e. low, medium, high) were examined and it was demonstrated that there would be no supply constraint for low and medium pressure networks, while in the high-pressure networks there would be a need for hydrogen storage to avoid unserved energy demand during peak conditions (see Annex D).

The modelling results for the high pressure test networks were used along with a regression method to estimate the relationship between peak energy demand of a high pressure gas distribution network and its required hydrogen storage capacity. Given the peak energy demand for various Local Distribution Zones (LDZ) across GB, the regression model then was applied to estimate the required hydrogen storage capacity for each LDZ.

In summary, the modelling[73] demonstrated that for low and medium pressure distribution networks the transportation of hydrogen does not have a significant impact on the networks' pressure profiles and their capability to meet energy demand at all times. In high-pressure networks, the 'linepack' (i.e. the volume of gas that can be stored in a gas pipeline) plays an important role in meeting energy demand during peak conditions. The lower density of hydrogen compared to natural gas reduces the available linepack in the high-pressure networks and constrain their capability. Consequently, hydrogen storage facilities would be required to enable the distribution networks to transport hydrogen to meet the peak energy demand.

Extrapolating the hydrogen storage requirements for high-pressure test networks to different regions across GB in order to maintain sufficient gas pressure during peak demand leads to additional GB hydrogen storage requirements of 131-333 GWh at the network level, as shown in Table 2-1.

Table 2-1 Hydrogen storage capacity required in different region across GB

Region	H2 storage (GWh) - Low	H2 storage (GWh) - High
Eastern	9.9	25.8
East Midlands	12.2	32.2
North East	7.7	20.2
North	2.9	8.2
North Thames	22.0	47.9
North West	17.6	45.5
Scotland	10.1	26.1
South East	22.7	57.2
South	7.2	19.3
South West	1.7	4.8
West Midlands	11.7	30.6
North Wales	0.6	1.6
South Wales	5.2	13.7
Total	**131.4**	**333.1**

[73] More detailed discussions can be found in Appendix D.

The results indicate that in order to enable the existing gas distribution networks to transport hydrogen during peak conditions, between 131 GWh to 333 GWh of hydrogen storage would be required[74], increasing the costs of the H2 pathway by approximately £0.35bn/year to £0.61bn/year, equivalent to 0.4% of the total costs of the hydrogen pathway. This cost has been included in the costs of all H2 scenarios.

2.1.5 Hydrogen storage

There is a significant investment (£6.4 bn/year) in hydrogen storage plants in the H2 pathways. The storage plants are used to reduce the capacity requirements of hydrogen production plants and networks by flattening out the demand of hydrogen; this improves the utilisation of the hydrogen infrastructure and minimises the hydrogen infrastructure costs. Energy in the form of hydrogen can then be stored across long time horizons as losses in hydrogen storage are assumed to be minor and not time dependent.

Two hydrogen storage technologies are modelled, i.e. (i) overground medium pressure[75] hydrogen storage and (ii) underground storage (e.g. salt caverns hydrogen storage). The per unit cost of underground storage is less than half of the cost of overground storage, but it is less flexible due to the physical attributes[76] of the salt caverns that dictate the maximum discharge rates. Therefore, it is not unexpected that the modelling results suggest using the overground medium pressure hydrogen storages for balancing the demand and supply of hydrogen in the short-term; this is shown in Figure 2-12. It is assumed that there are no dynamic constraints limiting the charging and discharging of the overground hydrogen storage plants.

[74] In addition to the investment needed in centralised hydrogen storage, e.g. salt-cavern storage.

[75] Based on the EE analysis (see Element Energy (2017) Hydrogen supply chain evidence base & modelling tool), the medium pressure would be more cost-effective than compressed/high pressure storage unless the area of demand was a long way from a transmission pipeline.

[76] The rate of change of the gas pressure in the caverns is limited to maintain the cavern wall stability. It is assumed that maximum 10% of the contained volume can be discharged per day.

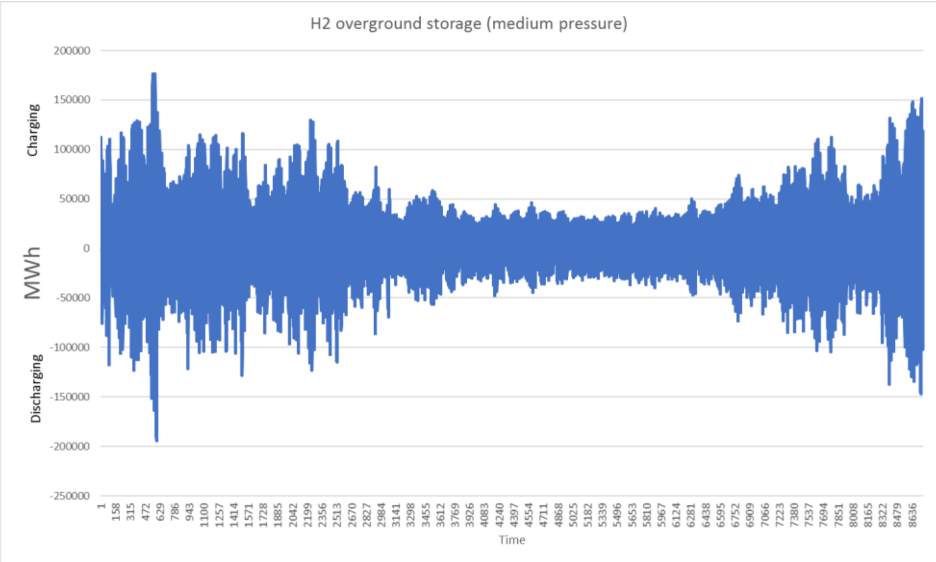


Figure 2-12 Charging/discharging profile of overground hydrogen storage

Underground hydrogen storage is used significantly less frequently than 'linepack' storage, primarily to supply the peak demand periods as indicated in Figure 2-13. The modelling results suggest that the utilisation of the underground storage plants is relatively low, but they come at significant cost. Importing hydrogen, as an alternative strategy, could reduce these costs, but may involve other infrastructure costs

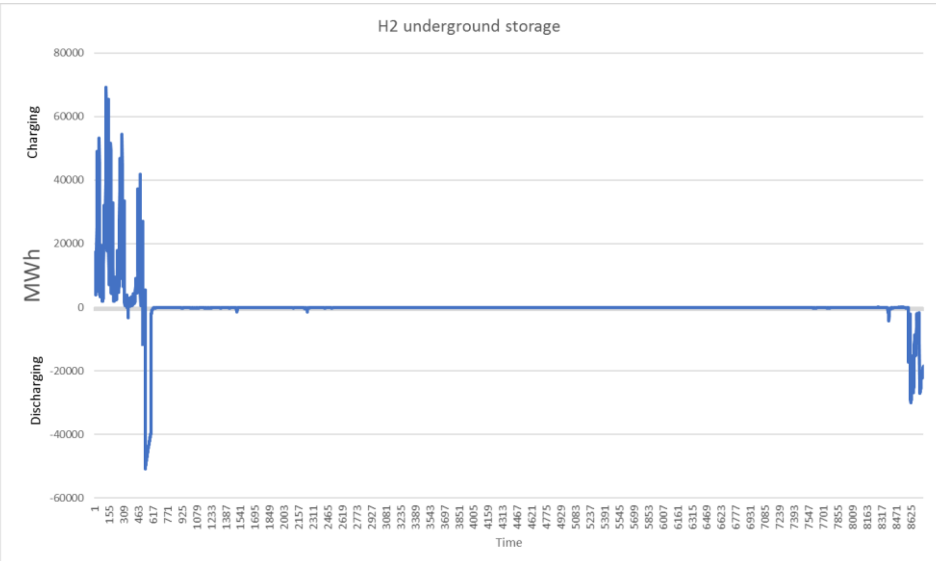


Figure 2-13 Charging/discharging profile of underground hydrogen storage

2.2 Electric pathways

The core Electric pathway evaluated in this study is based on a combination of heat pumps and resistive heating (RH) deployed at the household level[77]. It is assumed that these technologies require decommissioning of all household gas appliances and replacing them with electric appliances. The gas distribution system also needs to be decommissioned.

For each pathway, three carbon targets, i.e. 30Mt, 10Mt, and 0Mt are analysed: Elec [30], Elec [10], Elec [0]. The annual system costs of these pathways are presented in Figure 2-14.

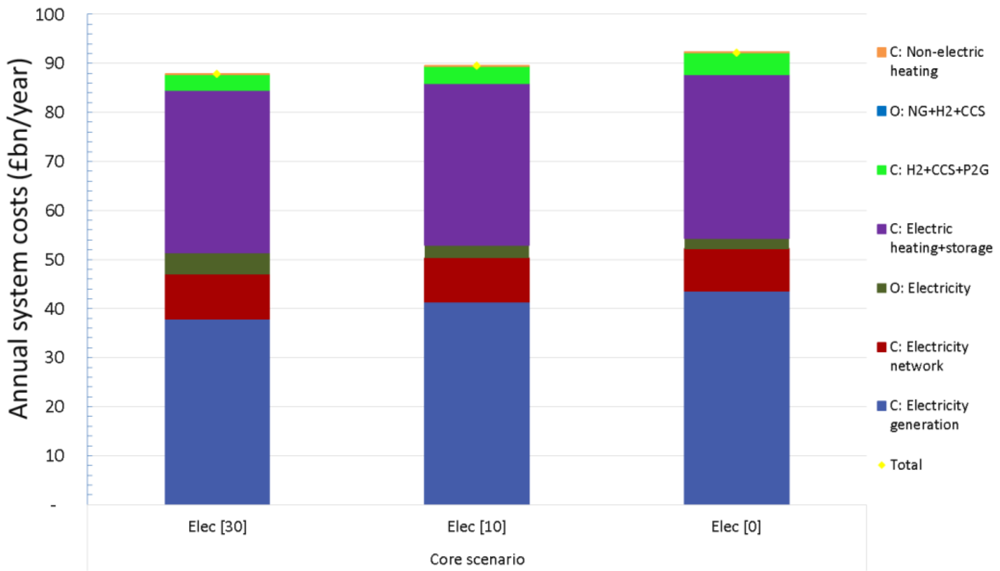


Figure 2-14 Annual system costs in Electric pathways

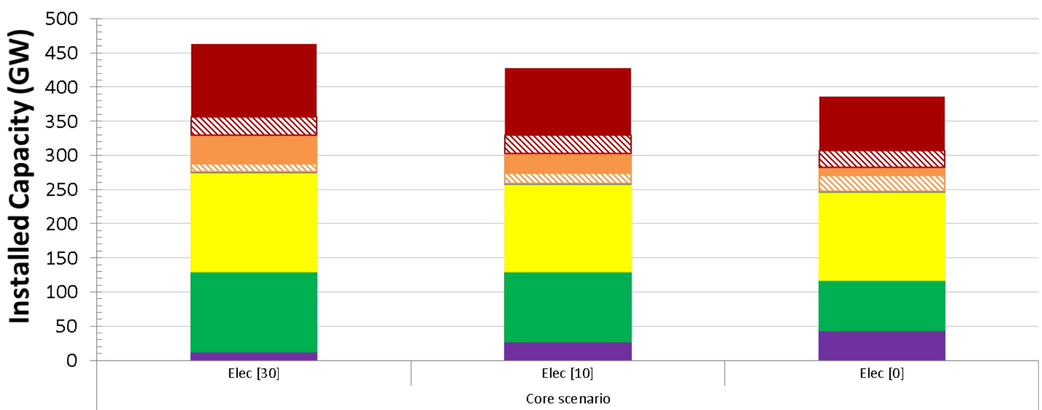
Total system costs are dominated by investment costs at the household level, as well as significant costs in installing low-carbon electricity generation infrastructure and upgrading electricity distribution networks. Operational costs are small as an electrified system is dominated by zero marginal cost low-carbon generation. This implies that this pathway is less sensitive to future variations in fuel prices than a hydrogen pathway (which is further discussed in Chapter 3).

Moving towards a zero-carbon target, total system costs increase primarily due to increased investment in nuclear power as a firm low-carbon generation technology. Most of the electricity generation costs are attributed to the cost of low-carbon generation technologies; a small proportion of the cost is associated with traditional gas-

[77] A 5 kW_{th} HP and 1 kW_{th} RH are installed in all households (excluding non-district heating networks), alongside some domestic thermal storage.

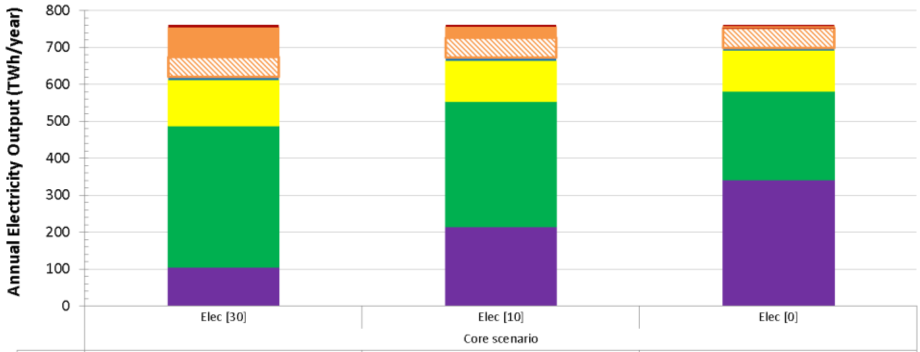
fired plants such as CCGTs and OCGTs, which use biogas in the 0Mt cases. The optimal capacity proposed by the model for each Electric pathway is presented in Figure 2-15.

The increased capacity of nuclear in lower emission scenarios is offset by the reduction in other low-carbon generation capacities such as wind and PV. Increased capacity of nuclear power can also displace traditional capacities such as CCGT and OCGT as nuclear can provide firm capacity, unlike variable RES. There is also an increase in the installed capacity of hydrogen-based CCGT from 12 GW in Elec [30] to 23 GW in Elec [0]; this indicates an increased role for hydrogen-based power generation for a very-low carbon system in order to provide system flexibility and balancing services. In the Elec scenario, hydrogen-based power generation utilises hydrogen produced from bioenergy. As carbon constraints increase, there is a sharp reduction of traditional CCGT capacity from 41 GW in 30Mt to 13 GW in 0Mt as the utilisation of this technology in the zero-carbon system is limited by the lower availability of carbon-neutral biogas.



	Elec [30]	Elec [10]	Elec [0]
OCGT	106	98	79
H2 OCGT	27	27	24
CCGT	41	28	13
H2 CCGT	12	15	23
Hydro	1	1	1
PV	146	128	129
Wind	117	104	74
Nuclear	13	27	43

Figure 2-15 Optimal power generation capacities in Electric pathways



	Elec [30]	Elec [10]	Elec [0]
OCGT	7	5	4
CCGT	80	30	5
H2 OCGT	0	0	0
H2 CCGT	54	54	54
Hydro	8	8	8
PV	124	109	108
Wind	383	340	241
Nuclear	104	213	340

Figure 2-16 Optimised electricity production in Electric pathways

Figure 2-16 shows the electricity production from each generation technology in the Electric pathway, demonstrating several consequences:

- Increased electricity production from nuclear in a 0Mt scenario displaces some production from variable RES shown in the 30Mt cases.
- Increased capacity of hydrogen-based generation in 0Mt cases (shown in Figure 2-15) is limited to running at low load factors as it is deployed to provide short-term system balancing and meet security supply requirements.
- In the 0Mt scenario, the output of traditional fossil generation such as CCGT and OCGT decreases as expected. The amount of electricity that can be produced by CCGTs and OCGTs will depend on the volume of carbon-neutral gas (e.g. biogas) available in the system.

2.2.1 Electric-based district heating

The following study investigates the performance of using electric-based district heating provided by industrial heat pumps. The study uses two carbon targets: 30 Mt (Elec+DH[30]) and 0Mt (Elec+DH[0]). Figure 2-17 demonstrates that the savings in electricity generation capex and lower capex of electric heating due to economies of scale in the district heating system are offset by the increased capex from installing heat networks and district heating appliances. The costs of Elec+DH pathways are therefore higher by £5.5 - £6.5bn/year than the costs of the core Electric pathways that use domestic electric heating. There is a potential application for district heating if the cost of heat networks can be reduced, particularly in high energy density urban areas. This is discussed in more detailed in section 2.6.2.

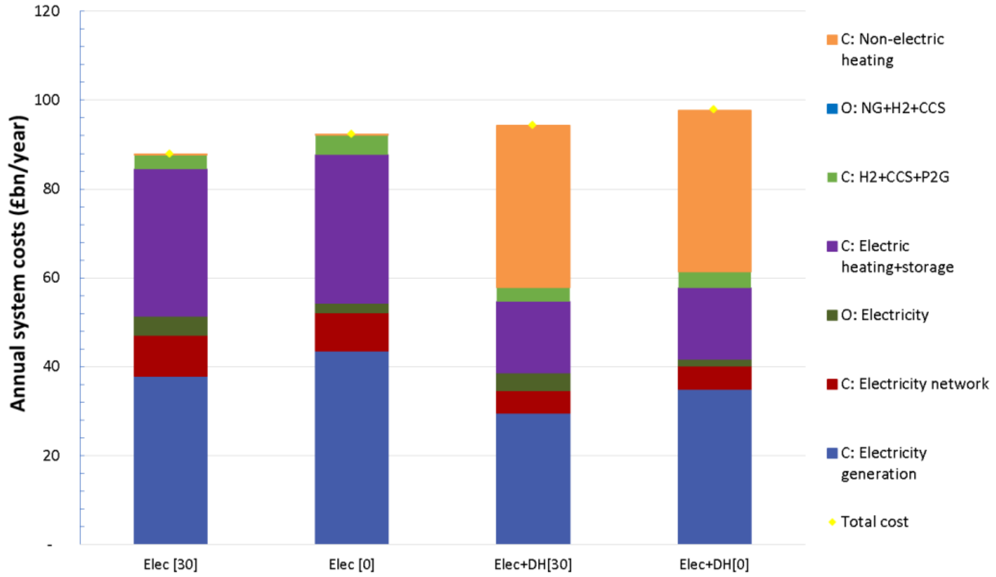
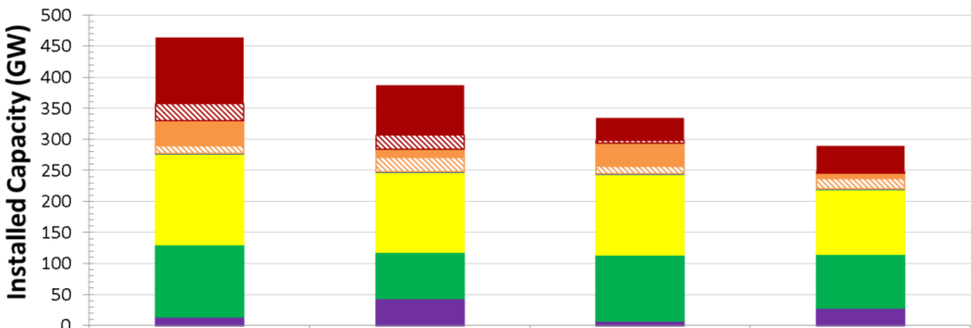


Figure 2-17 Annual system costs in different Electric pathways

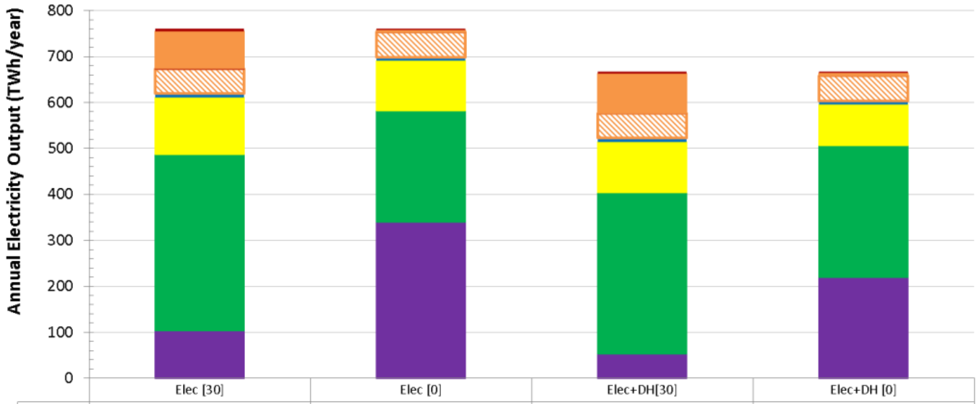
Figure 2-18 shows the proposed generation capacity for the electric-based district heating pathways. The results are compared with the results of the corresponding core Electric pathway.



	Elec [30]	Elec [0]	Elec+DH[30]	Elec+DH [0]
OCGT	106	79	36	42
H2 OCGT	27	24	4	2
CCGT	41	13	38	9
H2 CCGT	12	23	11	16
Hydro	1	1	1	1
PV	146	129	130	104
Wind	117	74	107	87
Nuclear	13	43	7	28

Figure 2-18 Optimal generation portfolio in different Electric pathways including electric-based district heating

Higher COPs of industrial heat pumps (4 on average) compared to residential heat pumps (less than 3) reduce the amount of required electricity capacity and generation on the system. This reduces electricity production by around 100 TWh/year as shown in Figure 2-19. This also leads to a lower electricity system capacity; for example, the proposed nuclear capacity is also 6-15 GW lower than the non-district heating case resulting in lower electricity generation capex.



	Elec [30]	Elec [0]	Elec+DH[30]	Elec+DH [0]
OCGT	7	4	4	3
CCGT	80	5	86	6
H2 OCGT	0	0	0	0
H2 CCGT	54	54	54	54
Hydro	8	8	8	8
PV	124	108	110	89
Wind	383	241	351	287
Nuclear	104	340	53	219

Figure 2-19 Optimised electricity production in different Electric pathways including Electric-based district heating pathway

2.3 Hybrid pathways

In the Hybrid pathway, combinations of electric and gas-based heating appliances (hybrid heat pumps (HHP) and hybrid resistive heating) are used to supply heat demand. The natural gas distribution system is retained despite having a lower utilisation factor[78]. On-going work in the FREEDOM project is investigating the implications of lower flows of gas in a hybrid heat pump scenario on gas distribution network operability[79].

As the gas distribution network is retained, there is no household conversion cost needed associated with the replacement of domestic heating and cooking appliances. The costs of the Hybrid pathways for emissions constraints of 30Mt, 10 Mt, and 0Mt are presented in Figure 2-20[80].

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78 Network costs are assumed to remain the same as in a high utilisation scenario.

79 https://www.westernpower.co.uk/Innovation/Projects/Current-Projects/FREEDOM.aspx

80 It includes the cost of maintaining the gas distribution network.

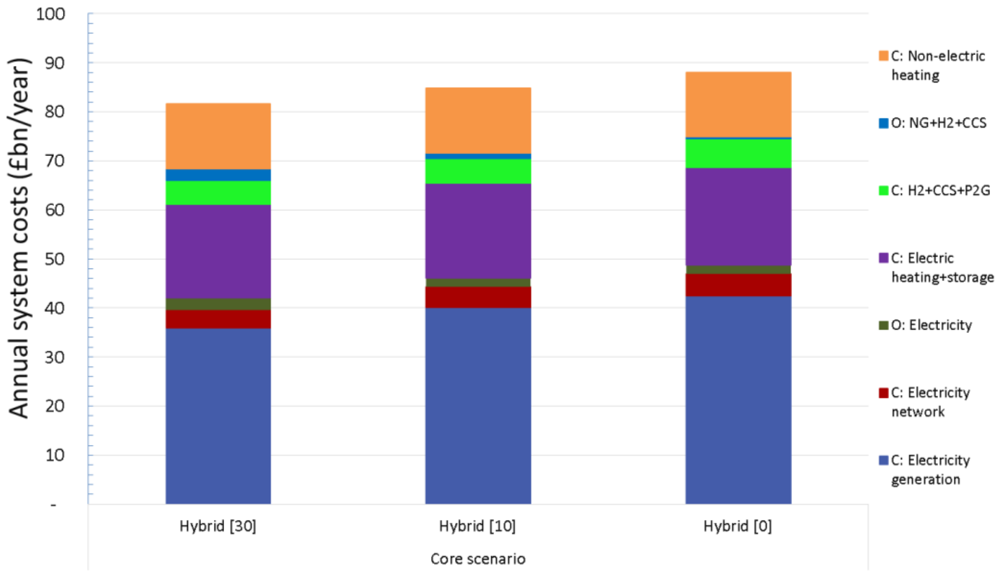
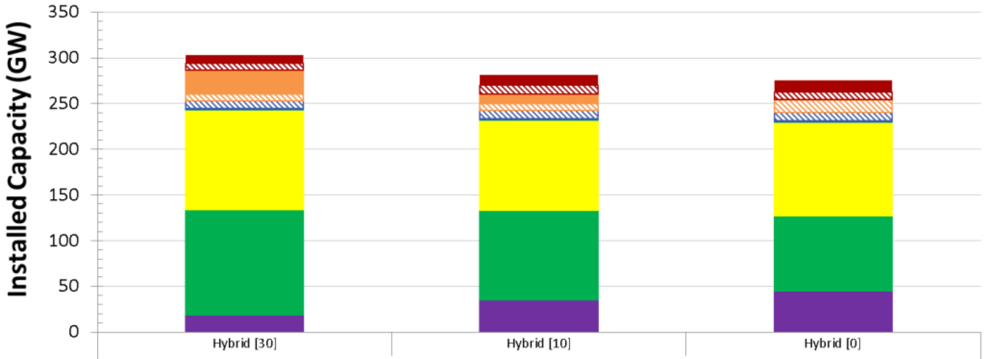


Figure 2-20 Annual system costs in Hybrid pathways

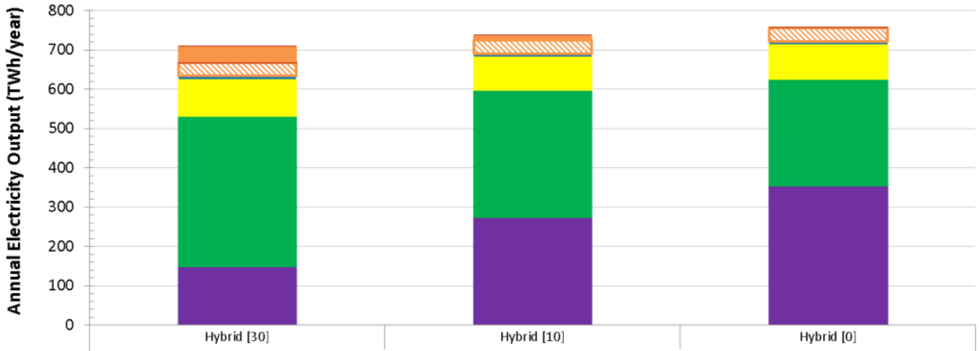
The system costs in the Hybrid pathways are dominated by the following capex components: (i) electricity generation, (ii) electricity networks, (iii) heating appliances including investment in electric (HP,RH) and non-electric (gas) heating, and (iv) hydrogen infrastructure which is needed to supply hydrogen-based district heating customers. The operating cost in the electricity system is similar to the Electric pathway. Gas opex cost (from running the gas boiler element of a hybrid heat pump) is only a small percentage of overall system costs, as the model suggests its optimal for a heat pump to provide 81-90% of household heating requirements, with resistive heating and gas boilers providing the remaining 10-19% (Figure 2-23).

Compared to the costs in a 30Mt case, the system costs in a 0Mt scenario increase by £6.5bn/year. This is driven by the increase in capex of electricity generation as more nuclear power is installed (Figure 2-21) since the 0Mt case requires larger amount of firm low-carbon generation (Figure 2-22). For example, the proposed nuclear capacity in Hybrid [30] is 19 GW, while this increases to 45 GW in Hybrid [0]. The increased nuclear capacity can displace some capacity of wind, PV and other firm capacities such as CCGT and OCGT.



	Hybrid [30]	Hybrid [10] (Core scenario)	Hybrid [0]
OCGT	9	11	13
H2 OCGT	8	10	9
CCGT	26	11	0
H2 CCGT	7	8	14
District CHP	8	8	8
Hydro	1	1	1
PV	110	99	103
Wind	115	98	82
Nuclear	19	35	45

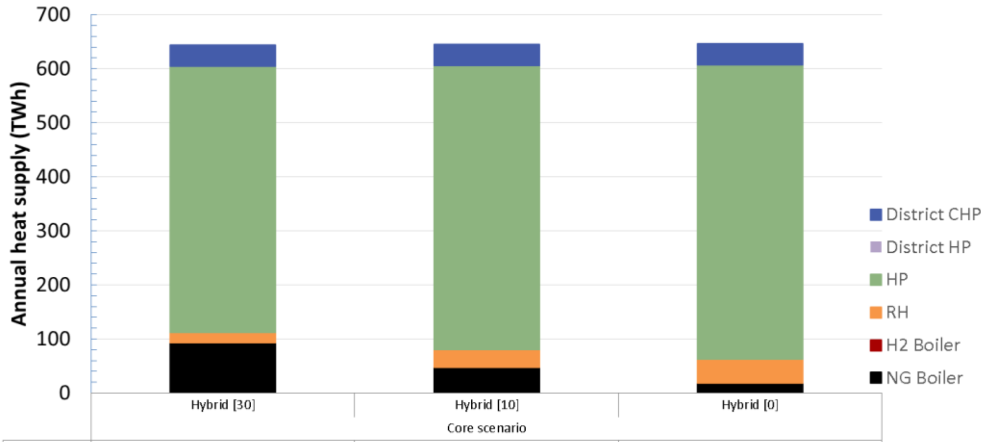
Figure 2-21 Optimal portfolios of electricity generation in Hybrid pathways



	Hybrid [30]	Hybrid [10] (Core scenario)	Hybrid [0]
OCGT	0	0	0
CCGT	41	11	0
H2 OCGT	0	0	0
H2 CCGT	34	34	34
Hydro	8	8	8
PV	95	86	89
Wind	383	323	270
Nuclear	148	273	354

Figure 2-22 Annual electricity production in Hybrid scenarios

Changing from a 30Mt to a 0Mt carbon target would lead to a reduction in gas-related opex as the gas boilers can only use a limited amount of biogas in the 0Mt cases. This reduces the utilisation of the gas boilers which increases the utilisation of electric heating (HP and RH) as demonstrated in Figure 2-23. Heat output from heat pumps in the model is assumed to be limited to 55°C and so higher temperatures ~65°C (e.g. hot water), can only be provided by gas boilers or RH.



	Hybrid [30]	Hybrid [10]	Hybrid [0]
District CHP	39	39	39
District HP	0	0	0
HP	492	525	545
RH	19	32	44
H2 Boiler	0	0	0
NG Boiler	92	48	18

Figure 2-23 Heat delivered in Hybrid scenarios by different heating technologies

The heat delivered by gas boilers constitutes around 14%, 7%, and 3% of the overall heat demand in 30Mt, 10Mt and 0Mt case respectively. There is a risk of sub-optimal usage of gas boilers that may increase the emissions and cost to customers. To prevent sub-optimal usage of gas and improve energy efficiency, the applications of smart-home energy optimisation and automation should be explored in addition to the provision of incentives (or penalties) to customers who can maintain the optimal usage of gas. Emissions in the hybrid pathway could increase substantially if consumers didn't use their hybrid heat pump in a way that is optimal for the overall system (i.e. by using the gas boiler component more than is considered in the model).

2.3.1 Impact of micro-CHP

An alternative domestic heating source could be a micro-Combined Heat and Power (CHP) unit supplemented by an auxiliary gas boiler. Micro-CHP has a high-energy efficiency as it is capable of providing both heat and electricity to consumer premises. The implications of deploying 10 GW of micro-CHP in the Hybrid pathway with a 30Mt and a 0 Mt emissions constraint have been investigated, and the results are compared with the results of the corresponding core Hybrid scenarios.

Given the assumptions related to the cost of micro-CHP (£2500/kW) and the need for an auxiliary gas / hydrogen boiler, the total cost of the system with micro-CHP is still marginally higher than the cost of the core Hybrid pathway (Figure 2-24). Furthermore, the physical size of the current micro-CHP technologies may need to be reduced further in order for them to be deployed at scale[81].

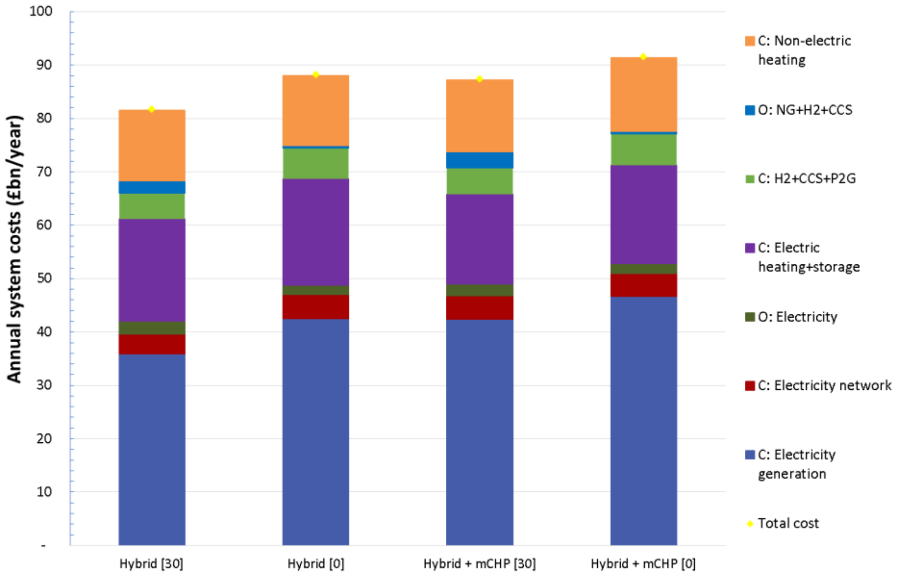
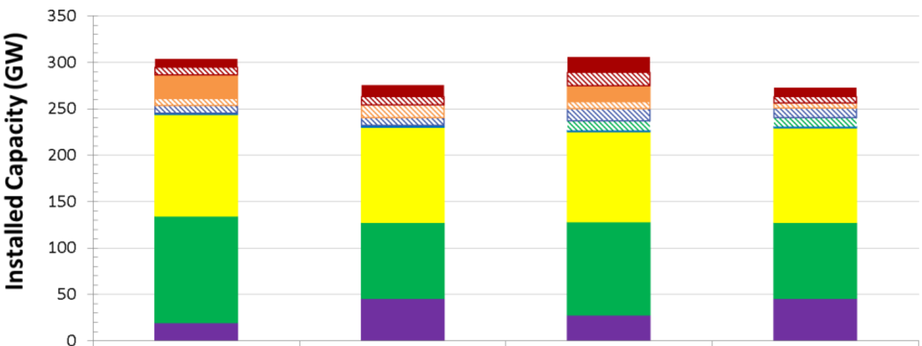


Figure 2-24 Comparing the annual system costs of Hybrid scenarios without and with micro-CHP

The modelling results demonstrate that small-scale end-use combined heat and power (micro-CHP) can displace not only the capacity of domestic electric heating appliances but also the capacity of gas-fired power plants on the system, including hydrogen-based power generation (Figure 2-25).

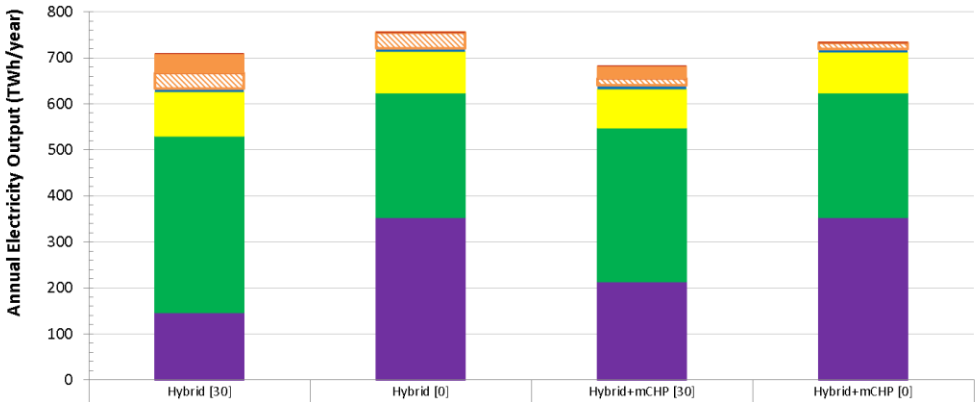


	Hybrid [30]	Hybrid [0]	Hybrid+mCHP [30]	Hybrid+mCHP [0]
OCGT	9	13	16	10
H2 OCGT	8	9	14	7
CCGT	26	0	18	0
H2 CCGT	7	14	7	5
District CHP	8	8	13	10
micro-CHP	-	-	10	10
Hydro	1	1	1	1
PV	110	103	97	102
Wind	115	82	100	82
Nuclear	19	45	27	45

Figure 2-25 Impact of micro-CHP on the optimal portfolios of electricity generation in Hybrid pathways

[81] Micro-CHP based on steel-cell technology is already appropriate for most domestic premises.

However, the impact of micro-CHP on the low-carbon generation capacity requirement is marginal. This finding demonstrates that micro-CHP can provide the equivalent of firm electricity system capacity (assuming it can be controlled to provide capacity during peak demand) while significantly enhancing generation efficiency, as the heat produced is not wasted (as in traditional power stations) but used to meet local heat demand. This reduces annual electricity demand by around 24 TWh. Micro-CHP also displaces the output of hydrogen-based and traditional CCGT as shown in Figure 2-26.



	Hybrid [30]	Hybrid [0]	Hybrid+mCHP [30]	Hybrid+mCHP [0]
OCGT	0	0	0	0
CCGT	41	0	25	0
H2 OCGT	0	0	1	0
H2 CCGT	34	34	16	13
Hydro	8	8	8	8
PV	95	89	83	88
Wind	383	270	334	270
Nuclear	148	354	214	354

Figure 2-26 Impact of micro-CHP on the annual electricity production in Hybrid pathways

2.4 Cost performance of core decarbonisation pathways

The system costs of different decarbonisation pathways are presented in Figure 2-27.

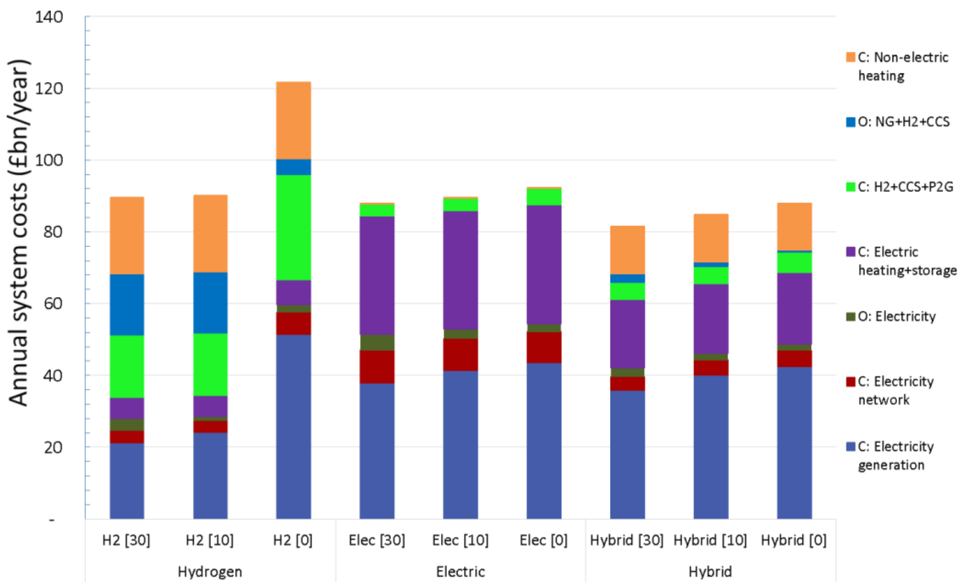


Figure 2-27 Annual system cost of core decarbonisation pathways

The key findings of the comparison of different cost components of alternative decarbonisation pathways are:

1. **The costs of alternative decarbonisation pathways are relatively similar for 30Mt, but the cost differences increase for the H2 pathway in a 0 Mt case**

As shown in Table 2-2, the system costs of the decarbonisation pathways for a carbon emissions target of 30Mt/year are broadly similar; the cost differences between the core pathways (i.e. Hybrid, Electric and H2) is within 10%, and hence the ranking may change when different assumptions apply, given the uncertainties around the assumptions in this analysis.

Table 2-2 Cost performance of different decarbonisation pathways

Pathways	Cost (£bn/year)		
	30Mt	10Mt	0Mt
Hybrid	81.6	84.8	88.0
Elec	87.8	89.5	92.2
H2	89.6	90.2	121.7

The costs marginally increase for a 0Mt/year emissions constraint, except in H2 pathways as hydrogen production shifts from gas to electricity, which significantly increases the cost of hydrogen infrastructure (due to a shift from gas-based production to electrolysers).

2. **The Hybrid pathway is the least-cost pathway while the cost of the H2 pathway is found to be the highest cost, compared to the other pathways.**

The cost of each of the core pathways is presented in order of merit in Table 2-2. The Hybrid scenario is identified as the most cost-effective decarbonisation pathway, with the hydrogen pathway being the most expensive, though it is worth noting that all of these cost results involve a broad range of uncertainty (see Chapter 3).

There are several key drivers contributing to the cost performance of different decarbonisation pathways:

- The Hybrid pathway uses highly efficiency hybrid heat pumps to supply the bulk of heat demand whilst providing the flexibility to use gas during peak demand[82] conditions or low renewable output. This flexibility reduces the power system infrastructure required to meet peak demand (whilst maintaining the security of supply) compared to the capacity required in the Electric pathway. It is important to highlight that the model determines the level of capacity needed to maintain the same level of security in all pathways.

[82] In order to test the adequacy of the system capacity to deal with the extreme weather conditions, 1-in-20 years events have been considered in the modelling; three consecutive cold days (the average daily temperature across GB is -7°C) coinciding with low output of renewables. Figure 3-12 shows the profile of ambient temperature used in the studies.

- The Electric pathway requires the highest investment in electricity networks, particularly at the distribution level, due to a significant increase in peak demand driven by the electrification of heat. Network costs in the Hybrid pathway are significantly lower than the costs in the Electric pathway as the use of the gas boiler component of a hybrid heat pump during peak demand can efficiently reduce the need for distribution network reinforcement although some network reinforcement is required to accommodate the growth of distributed renewable generation and demand response. The H2 pathway tends to require significantly lower electricity distribution network reinforcements, when compared to the other pathways, except in the 0Mt case where significant reinforcement is needed to accommodate demand-side flexibility and integrate more renewable generation into the system, in order to achieve the carbon target cost-effectively (as it is assumed that all hydrogen is produced domestically via electrolysis in the 0Mt case, requiring additional low-carbon electricity generation).
- In the H2 pathway, natural gas is decarbonised through hydrogen production via gas reforming with CCS[83]. This reduces the need for investment in low-carbon electricity generation but requires higher investment in hydrogen and CCS infrastructure. However, the overall operation and investment cost associated with the hydrogen system in H2 pathway outweighs the benefits associated with lower investment in electricity generation. The cost difference becomes much more pronounced in a 0Mt case as the cost of hydrogen infrastructure increases substantially (as shown in Figure 2-27) due to the shift from ATR to electrolysers (the capex of electrolysers is higher than the capex of ATR), although the increase in capex can be partially offset by the reduction in gas opex.
- The H2 pathway is characterised by the lowest energy efficiency due to a number of energy conversion processes involved: heat pumps are assumed to be between 200% - 300% efficient or higher[84], whereas converting gas to hydrogen for use in domestic gas boilers is 80% efficient or less (depending on the efficiency of hydrogen boilers[85] and efficiency of the hydrogen production[86]).
- There is a need to replace gas appliances in both the H2 and Electric pathways, which increases the costs of corresponding scenarios. Hydrogen boilers are significantly lower cost than heat pumps[87], at £75/kW_{th} for a boiler and £600/kW_{th} for a heat pump but are characterised with higher operating costs. On the other hand, in the Hybrid pathway there is assumed to be no need to replace other gas appliances,

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[83] Assuming Auto-thermal Reforming, with 88% HHV efficiency and 96% capture rate, based on Element Energy (2018) Hydrogen Infrastructure: Summary of Technical Evidence

[84] Annual average COP of HP used in the study is 2.7.

[85] Efficiency of hydrogen boilersis assumed to be 90%

[86] Efficiency of ATR is assumed to be 88.5%, based on Element Energy (2018) Hydrogen Infrastructure: Summary of Technical Evidence

[87] More detailed information about household conversion costs can be found in Appendix B.

which minimises the overall household conversion cost.

3. **Electric and Hybrid pathways have greater potential to reduce emissions to close to zero, compared to the H2 pathway.**

Comparing the system costs of the core decarbonisation pathways for emissions constraints of 30Mt, 10Mt and 0Mt cases in Table 2-2 demonstrates the following:

- While the cost of meeting 10Mt carbon target in the H2 pathway increases by only £0.6bn/year compared to the cost in a 30Mt scenario, there is a significant increase in cost (more than £30bn/year) in H2 pathways when the carbon target changes from 30Mt to 0Mt, driven by a change in hydrogen production from ATR to electrolysers. The system costs of electrolysers are higher than ATR plants as the application of electrolysers also requires a significant increase in investment in low-carbon electricity generation. Improved carbon capture rates on gas reforming plant or importing low-carbon hydrogen to the UK could allow for reduced emissions in the H2 pathways.
- The costs of the Electric and Hybrid pathways in 0Mt cases are also 4 - 6 £bn/year higher than the corresponding costs in 30Mt; this is driven by the increase in electricity generation capex as a higher capacity of nuclear is required to provide a firm (non-variable) source of low-carbon electricity. An increase in nuclear capacity is also observed in an H2 0Mt case.
- Achieving zero emissions with a hybrid pathway will depend on the availability of low-carbon biogas, as well as consumer usage of hybrid heat pumps.

The analysis demonstrates that:

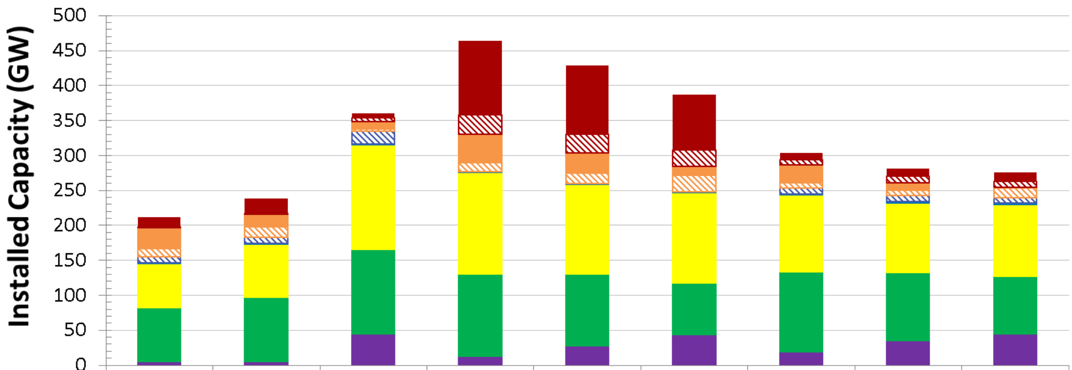
- Systems with more stringent carbon emission targets will lead to higher costs;
- Further decarbonisation beyond 30 Mt is possible at a limited additional cost in the hybrid and Electric pathways, this is also true for deep decarbonisation towards a zero-emissions energy system (costs are 6-7% higher in a 0 Mt case).
- Electric and Hybrid pathways provide more optionality towards a zero-carbon future compared to the H2 pathway, which is limited up to 10 Mt unless there is an improvement in the capture rate of CCS.

4. **The costs of low-carbon systems are dominated by capital expenditure (capex) while operating expenditure (opex) is significantly lower.**

In the 30Mt cases, system operating costs are a relatively small component of overall system costs, i.e. less than 25% in the H2 pathway, 5% in Electric, and 6% in Hybrid. Towards zero carbon, the opex component in all decarbonisation pathways reduces significantly as most of the energy is produced by zero marginal cost renewable resources and low operating cost nuclear generation, while the use of gas is limited to only low-carbon gas (biogas, bioenergy)[88], with any hydrogen being produced by electrolysis supplied by low-carbon electricity generation. This implies that the system costs will be very sensitive to cost of financing the infrastructure[89] in the scenarios and much less sensitive to future fluctuations in gas prices.

2.5 Impact of heat decarbonisation strategies on the electricity generation portfolio

Different decarbonisation pathways require substantially different electricity generation portfolios, as the choice of heating pathway will have significant implications on gas and electricity systems. The coordination of the design and operation of gas, heat and electricity systems is important for minimising the whole-system costs of decarbonisation. Optimised generation portfolios for the core decarbonisation scenarios are presented in Figure 2-28.



	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
	Hydrogen			Electric			Hybrid		
OCGT	15	21	6	106	98	79	9	11	13
H2 OCGT	0	0	5	27	27	24	8	10	9
CCGT	30	19	11	41	28	13	26	11	0
H2 CCGT	12	14	3	12	15	23	7	8	14
District CHP	8	9	18	0	0	0	8	8	8
Hydro	1	1	1	1	1	1	1	1	1
PV	63	76	150	146	128	129	110	99	103
Wind	77	92	120	117	104	74	115	98	82
Nuclear	5	5	45	13	27	43	19	35	45

Figure 2-28 Optimal generation portfolio in different decarbonisation pathways

A number of conclusions can be derived from the optimal generation portfolio proposed by the model:

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88 The CCC specified that 135 TWh of primary bioenergy should be used to provide 'negative emissions' via Bioenergy plant with Carbon Capture and Storage (BECCS), though these negative emissions are not considered within the carbon constraint in the model as they are accounted for across the economy. The model chose to use BECCS to produce hydrogen in all cases, with the hydrogen being used in either hydrogen-based power plant or gas boilers. The cost of BECCS plant is included in all pathways. BECCs were assumed to be zero cost in this analysis. Cost of biogas was assumed to be the same as the cost of natural gas.

89 Financing costs assumed in the study are between 3.5% and 11% depending on the technologies.

1. **Maximum capacity of low-carbon generation that is assumed to be available by 2050 is sufficient to reach the zero-carbon target[90].**

Across all scenarios a significant capacity of low carbon electricity generation is required, representing an increase of 130-450% of electricity generation capacity on today's levels (of around 100 GW). The optimal generation portfolio also includes hydrogen based CCGT and OCGT plant. There is only one case, i.e. 0Mt H2 pathway, where the capacity of PV, wind and nuclear hit the upper limits of UK deployment potential by 2050[91] assumed in the modelling. This increase in electricity generation capacity implies significant build rates (around new 5-9 GW/year of low-carbon generation technology) between now and 2050, in order to meet the decarbonisation targets. Any constraints on build rates, such as financing, materials or skills issues could reduce the achievable level of energy system decarbonisation by 2050.

2. **Energy system flexibility and interactions across different energy systems significantly influence the power generation portfolio.**

The whole-system cost of the scenarios depends on the level of flexibility which can be provided across (and including the interaction between) the heat and electricity sectors, which will impact the deployment rates of low carbon generation technologies, with the aim of meeting the carbon target at minimum costs. The modelling results demonstrate that improving system flexibility can reduce the annual system cost by up to £16.2 bn/year[92] in an Electric 0Mt pathway (£4bn/year in a hydrogen 0 Mt pathway). The flexibility provided by demand-side management or energy storage across different energy vectors (electricity, gas, heat) can improve the utilisation of low-carbon generation and reduce the overall requirement of production capacity and network infrastructure reinforcement[93]. For example, if heat demand is supplied by electric heating, reducing the peak of heat demand by preheating[94] or using thermal storage can reduce the required firm generation capacity (by up to 110 GW)[95]. The studies

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90 Maximum potential capacities of wind, PV, CCS and nuclear provided by the CCC were 120 GW, 150 GW, 45 GW and 45 GW respectively, based on build rate constraints of 4 GW/year for wind technologies, 1.5 GW/year for nuclear/CCS, 5 GW/year for solar, 3 GW/year for ATRs, 3 GW/year for electrolysers, with technologies assumed to be deployed between 2030 and 2050

91 Due to insufficient capacity of low-carbon electricity generation, this case cannot meet the zero-carbon target and the annual carbon emissions were 2 Mt/year.

92 The max system cost difference between the system with full and no flexibility across pathways

93 In a system where no flexibility can be provided at the domestic level, network costs are £5 bn/year higher.

94 Preheating involves heating the households earlier than it would be otherwise done while utilising inherent heat storage in the fabric of the houses. This type of flexibility is critical for reducing system peaks, enhancing the value of the provision of balancing services and increasing utilisation of renewables by electric heating, which significantly reduces the cost of decarbonisation.

95 In the Electric 0 Mt scenario, the use of preheating can reduce more than 40 GW of firm generating capacity.

demonstrate that most of the value of system flexibility (including preheating) comes from reducing spend on low-carbon electricity generation (Figure 2-27).

3. **A significant capacity of firm low-carbon generation is needed in all pathways with 0Mt carbon target**

- Analysis demonstrated that meeting a strict zero-emission target cost-effectively would require a significant capacity of nuclear generation in all pathways, due to the variability of renewable production and the need to eliminate emissions associated with management of demand-supply balance. Hence, in the 0 Mt case, a significant amount of capacity of variable renewables is replaced by firm low-carbon generation capacity, i.e. nuclear. The results demonstrate that although in the short and medium term the focus can be on deployment of variable RES, in the long-term, to achieve a zero-carbon emissions target, firm low-carbon generation technologies such as nuclear (or alternatives) will be required, e.g. for the 0Mt, in all core pathways, more than 40 GW of nuclear generation is deployed. The appropriate portfolio of power sector technologies, therefore, depends on the desired level of decarbonisation of the energy system.
- Further research related to the provision of system inertia is needed to investigate the impact on the optimal portfolio of generation technologies, particularly in 0 Mt case, as the provision of synthetic inertia (e.g. by wind generation) could reduce the volume of nuclear and increase capacity of renewables, while on the other hand, coordinated de-loading of nuclear generation during low demand and high renewable output conditions would reduce the size of the largest loss and hence enhance the value of nuclear generation.

4. **Pre-combustion CCS generating plant is more attractive than post-combustion CCS.**

No post-combustion CCS plant is selected due to presence of residual carbon emissions and higher cost of CCS technology (it is important to note that post-combustion fossil CCS cannot be used in a 0Mt scenario due to residual carbon emissions). There is, however, a significant volume of pre-combustion CCS, i.e. hydrogen-based combined cycle gas turbine and hydrogen-based open cycle gas turbine primarily in the Electric and Hybrid scenarios. Pre-combustion-hydrogen-based generation can be considered as complementary to CCS generation as it enables decarbonisation of traditional gas plant technologies and can provide flexibility while making efficient use of the hydrogen infrastructure.

5. **The installed capacity of electricity generation in the Electric pathways is significantly larger than in other pathways.**

Full electrification of heating demand in the Electric pathway will substantially increase peak electricity demand. Hence the corresponding amount of firm-generation capacity in the Electric pathway is about 100 GW larger compared to other pathways. It should be noted that in the Electric pathway there is a significant amount of peaking plant (OCGTs) that are supplied by biogas and operate at very low load factors (operating during high peak demand conditions driven by extremely low external temperatures). In the Hybrid pathway, on the other hand, the extreme peak of heat demand is directly supplied by gas boilers using biogas in the gas grid rather than electricity, and hence the capacity requirement for peaking plant is much lower.

Considering the uncertainty across different heat decarbonisation pathways and emissions targets, "no regret"[96] capacity of specific low-carbon generation technologies can be determined by taking the minimum of the proposed capacity for the corresponding generation technology across different pathways (given the costs of different low carbon generation technologies) and across emissions targets. This suggests that a capacity of at least 74 GW of wind generation is useful in all scenarios, given the seasonal profile of both wind generation and energy demand[97]. The modelling also indicates a role for at least 5 GW of nuclear power, and 3 GW of hydrogen-fuelled CCGT capacity, across all pathways.

It is important to highlight that more electricity generation capacity will need to be built, but the optimal generation portfolio will depend on both the decarbonisation pathway and the carbon target. A higher capacify of firm low-carbon generation is needed in a system with a very-low emissions target. For example, in the Elec 30Mt case, there is a need for 13 GW of nuclear, 117 GW of wind, 146 GW of PV and 12 GW of H2 CCGT while in the H2 30 Mt case, the requirements are 5 GW of nuclear, 77 GW of wind, 63 GW of PV, 12 GW of H2 CCGT. However, in the H2 0 Mt case, the required capacity for nuclear, wind, PV and H2 CCGT are 45 GW, 120 GW, 150 GW, and 3 GW. There is a significant increase in the capacity of nuclear, wind and PV alongside a reduction in H2 CCGT. In this case, hydrogen is mainly produced from low-carbon generation sources (as the emissions from gas-based hydrogen production are too high in this case) and used for heating instead of for electricity production. In this case significant amount of short and long term flexibility services is provided electrolysers. Sufficient firm power generation capacity is also needed to ensure that peak demand is met when renewable generation production is low.

It is important to note that the optimal generation mix is system specific and depends on the assumptions taken in the model. Therefore, the low/no regret capacities identified by the model provide a tangible indicator of the minimum capacity needed for each low-carbon generation technology across different scenarios.

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[96] Low/no regrets capacity is defined as the capacity that will be needed irrespective of the decarbonisation pathway adopted in the future.

[97] The results are based on the assumptions and system conditions used in the studies, e.g. it was assumed that the system was supported by flexibility from demand response, energy storage, generators, and interconnectors.

2.6 Alternative heat decarbonisation strategies

2.6.1 District heating and micro-CHP

Successful implementation of district heating in Denmark (and other EU countries) and the potential application of end-use micro-CHP technologies have raised questions about the contribution these technologies could make to heat decarbonisation pathways. The results are compared with the results of the core scenarios in the corresponding pathways. The costs and system implications of implementing these alternative strategies can be observed in Figure 2-29.

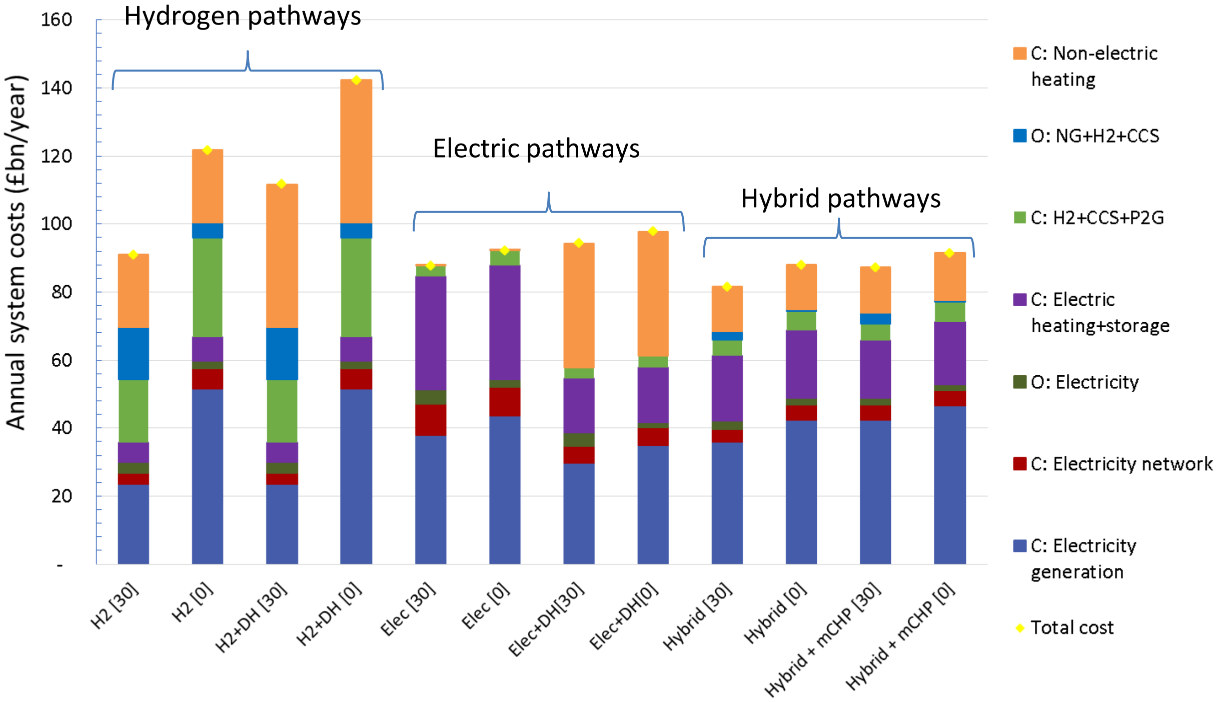

Figure 2-29 Annual system costs of alternative heat decarbonisation pathways through district heating and micro-CHP compared with the costs of core scenarios

The key findings from the study are:

1. **National district heating pathways are significantly more costly than other heat pathways due to the expenditure associated with the deployment of heat networks.**

The analysis demonstrates that national deployment of district heating incurs a higher cost than systems with domestic level heating appliances, which is primarily driven by the cost of deploying heat networks and the cost of connecting consumers to heat networks, including new assets needed to control heat and metering in dwellings. On the other hand, due to economies of scale, the cost of heating devices in district heating networks is significantly lower (35%-50%) than the cost of domestic heating appliances. In the Electric pathway, there is also a significant reduction in the capital cost of the electricity generation driven by a higher COP of industrial heat pumps (4 on average) compared to the COP of domestic heat pumps (less than 3 on average). However, this cost reduction is still outweighed by the increase in costs associated with heat network deployment and connection.

While the study provides evidence that national deployment of district heating will not be cost-effective, local applications of district heating in high-heat-density areas could provide a more cost-effective solution. Heat demand in urban areas makes up around 40% of the total heat demand, whilst the cost of urban heat networks is less than 25%[98] of the cost of heat networks in non-urban areas.

2. **Micro-CHP, installed in households, could contribute to reducing the capacity of centralised electricity generation and network reinforcement.**

Small-scale end-use combined heat and power (micro-CHP) can substitute for / contribute to the capacity of electric heating appliances, reduce distribution network costs and displace the capacity of gas-fired plants including hydrogen power generation, while the impact on RES and the nuclear capacity requirement is marginal. This finding demonstrates that micro-CHP could provide firm capacity (assuming it is able to be managed to provide capacity during peak demand) whilst significantly enhancing generation efficiency, as the heat produced from thermal electricity generation is not wasted but is used to meet local heat demand. However, given the assumptions related to the cost of micro-CHP (£2500/kW) and the need for an auxiliary gas / hydrogen boiler, the total cost of the system with micro-CHP is still marginally higher than the cost of the core Hybrid pathway (but slightly lower than the Electric scenario). Furthermore, a reduction in the physical size of the traditional micro-CHP technologies may also need to be achieved in order for them to be deployed at scale[99].

2.6.2 Regional scenarios

Regional approaches to deploying hydrogen, such as in a group of regions where gas terminals are available or in urban areas with high energy demand density have also been investigated and analysed for the 30Mt and 0Mt carbon emission cases. Three regional scenarios are considered: (i) *Hybrid – H2 North* assumes that the main heating system in the North of GB (Scotland, North of England, North Wales) is fuelled by hydrogen while the other regions use hybrid heat pumps; (ii) *Hybrid – H2 Urban* assumes that hydrogen heating systems are deployed in all urban areas while other regions use hybrid heat pumps for heating; (iii) *Hybrid – Urban DH HP* assumes the use of electric-based district heating with highly-efficient ground-source heat pumps[100]. The results are presented in Figure 2-30, and the annual system costs of the regional scenarios are compared against the costs of non-regional Hybrid systems (the first two bars in the graph).

[98] The total length of urban networks is less than 25% of the overall length of distribution networks.
[99] Micro-CHP units based on steel-cell technology is already appropriate for most domestic premises.
[100] Annual average COP is 4.

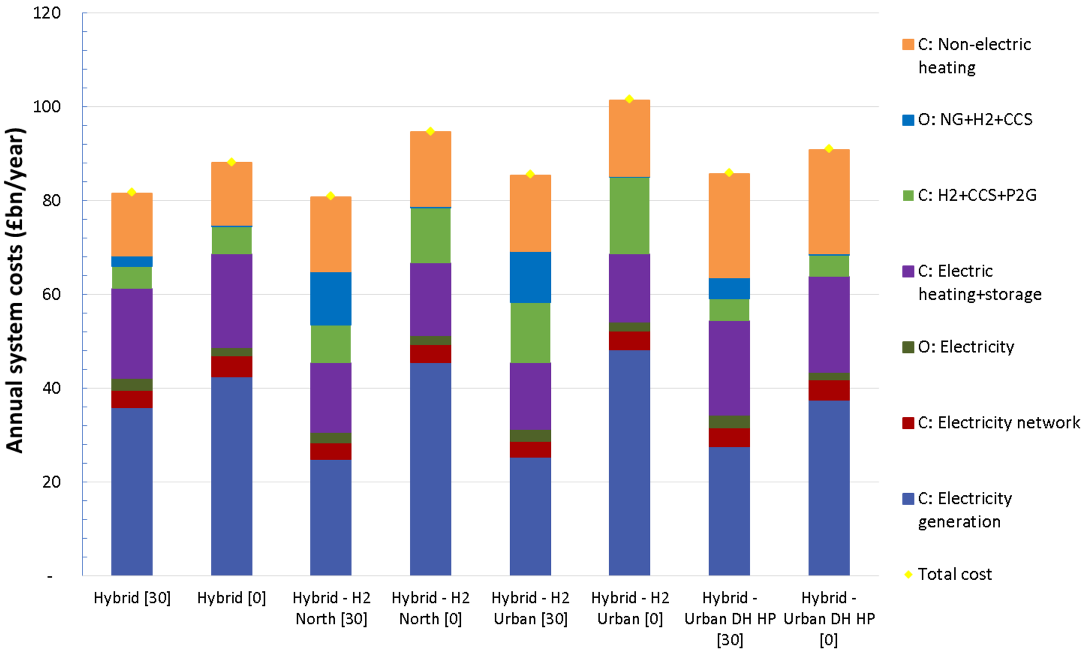

Figure 2-30 Costs of alternative Hybrid pathways

Use of hydrogen in Hybrid regional scenarios can reduce the demand for low-carbon generation capacity at the expense of increased hydrogen infrastructure operating costs. The results demonstrate that for the 30Mt case, deployment of hydrogen in the Northern region could be an attractive alternative to the non-regional scenario as the costs are marginally lower by £0.8bn/year. This implies that for some regions, hydrogen conversion can be a cost-effective heat decarbonisation option. This favours regions in close proximity to existing gas terminals, and carbon storage areas, reducing overall networks costs. Towards a zero-carbon energy system, the cost of Hybrid- H2 North [0] is £6.6bn/year higher than the cost of Hybrid [0] due to the need to use electrolysers and low-carbon generation technologies to produce hydrogen. The costs of regional Hybrid – H2 Urban cases, both for 30Mt and 0Mt cases, are higher than a non-regional Hybrid system by 3.9 – 13.4 £bn/year. The cost of producing hydrogen in proximity to urban areas is assumed to be 50% higher than the cost of producing hydrogen by large-scale plants located near gas terminals; this increases the capex of hydrogen infrastructure in the Hybrid – H2 Urban scenarios.

One of the main barriers to district heating is the high cost of deploying heat networks. Therefore, the implementation of district heating may be constrained to the high-heat-density areas, e.g. urban areas. Heat demand in high-density areas makes up around 40% of the total heat demand (Table F-1 in Appendix F), whilst the corresponding cost of heat networks is less than 25% of the cost of heat networks in low-heat density areas[101]. The results of the Hybrid – Urban DH HP scenario demonstrate that the efficiency of

[101] The total length of urban networks is less than 25% of the overall length of distribution networks.

industrial heat pumps can reduce the infrastructure costs of electricity generation compared to the corresponding costs in a Hybrid scenario, though the cost of deploying district heating infrastructure outweighs these benefits. Overall, the total costs of the Hybrid – Urban DH HP scenario are 2.8 – 4.2 £bn/year higher than the costs of the Hybrid pathways.

These results demonstrate the importance of considering regional diversity in national level heat decarbonisation decisions, though the cost optimality of this diversity depends on the desired level of decarbonisation. Converting heat to hydrogen in some regions could be a cost-effective decision as part of a hybrid national level heat decarbonisation strategy.

Chapter 3. Sensitivity studies on the decarbonization pathways

3.1 Key sensitivity factors

A range of studies has been carried out to understand the impact of different assumptions on the core decarbonisation pathways. The sensitivity studies focus on two carbon targets (30Mt and 0Mt) and are listed and summarised in Table 3-1.

Table 3-1 List of sensitivity studies

Sensitivity	Low	Central	High
H2 technologies	-	ATR	SMR
H2 import	-	No hydrogen Import	There is no constraint on how much hydrogen can be imported at £25/MWh.
Discount rate / cost of finance	3.5% cost of capital for all investments	3.5% cost of capital for heating appliances Networks: 5.7% Generating plants: 5.8%-11%	7.5% cost of capital for heating appliances
CAPEX of low-carbon electricity generation	Wind: £40/MWh PV: £30/MWh Nuclear: £50/MWh	Wind: £50/MWh PV: £40/MWh Nuclear: £70/MWh	-
Carbon emissions target	0 Mt/year	30 Mt/year	-
Space heating demand (domestic)	224 WTh	283 TWh	341 TWh
Flexibility[102]	No demand-side response and no energy storage	50% availability of potential demand-side response and energy storage	High availability and low cost of demand-side response and energy storage
End-use heat appliance cost	H2 boiler: £100/kW_{th} NG boiler: £100/kW_{th} HP: £400/kW_{th} RH: £100/kW_{th}	H2 boiler: £150/kW_{th} NG boiler: £125/kW_{th} HP: £600/kW_{th}	H2 boiler: £250/kW_{th} NG boiler: £125/kW_{th} HP: £800/kW_{th} RH: £200/kW_{th}

[102] System flexibility from flexible electricity demand (industrial and commercial load, smart charging of EV, smart appliances, electricity and heat storage, and preheating measures). No cost is attributed to demand flexibility, but the costs of energy storage are included

Sensitivity	Low	Central	High
		RH: £150/kW_{th}	
Fuel prices (gas)[103]	39 p/therm	67 p/therm	83 p/therm
Heat peak demand (domestic space heating)	173 GW_{th} (10% reduction from the central case)	192 GW_{th}[104]	-

The sensitivity studies are carried out for the 30Mt and 0Mt cases.

3.2 Hydrogen Scenario

Figure 3-1 shows the results of the sensitivity studies on the H2 decarbonisation pathways with a 30Mt carbon target.

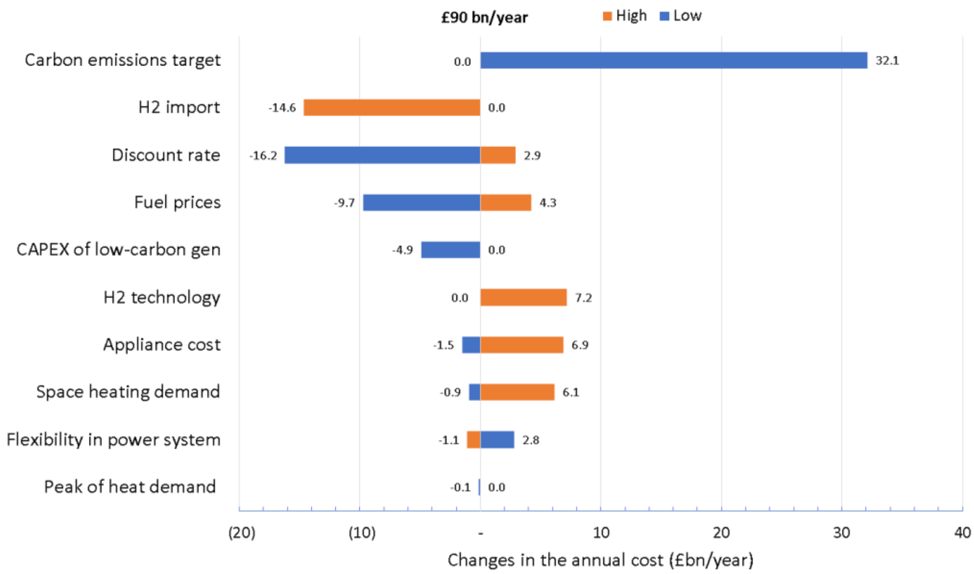

Figure 3-1 Cost sensitivity of H2 decarbonisation pathways [30Mt]

The results demonstrate the following: (from the most sensitive factor towards the less sensitive)

- The cost of H2 decarbonisation pathways is very sensitive to the specified emissions target. To achieve zero emissions, there is a need to use electrolysers to produce hydrogen. The cost of hydrogen production via electrolysis is larger as it requires substantial investment in electrolysis as well as investment in low-carbon electricity generation technologies. Having a stricter carbon target, from 30 Mt to 0 Mt per year,

103 BEIS ,"Updated Energy & Emissions Projections: Annex M," 2017

104 Based on the original heat demand (excluding the impact of preheating and thermal storage plants)

increases the system costs by £32.1bn/year[105].

- Assuming that hydrogen can be imported at low cost (£25/MWh) will lower the system cost of H2 decarbonisation pathway by £14.6bn/year from reducing the investment needed in GB hydrogen production technologies (which is costlier). Additional network and storage will still be needed to enable hydrogen transmission to the demand centres across GB. Importing hydrogen also reduces domestic carbon emissions associated with gas-based hydrogen production, and therefore, less low-carbon electricity generation capacity will be needed for the same emissions target.
- As capital costs dominate the overall system cost, the impact of changes in financing costs will be substantial. The "Low" scenario reduces the cost by £16.2bn/year while the "High" scenario increases the total cost by £2.9bn/year.
- For the H2 30Mt scenario, the system cost is also sensitive to fuel prices as hydrogen production is based on gas consumption. It is also interesting to note that the impact of low and high gas prices is asymmetrical due to two main reasons: (i) the gas price range used is asymmetrical; (ii) the optimal investment and operation of the system proposed by the model changes following the changes in gas prices. The low gas price scenario reduces the system cost by £9.7bn/year while the high gas price scenario increases the cost by £4.3bn/year. If the gas price is low, it will reduce gas opex and more hydrogen could be allocated for electricity production via hydrogen-fuelled power generation; this reduces the required investment in other low-carbon electricity generation plants. If the gas price is high, it will mainly increase gas opex as the use of hydrogen in power production in the Central scenario is less than 4%.
- Having lower capex for low-carbon generation technologies will reduce the system cost by £4.9bn/year. The lower capex could be achieved, e.g. by technological enhancement, improving energy conversion efficiency, and cutting production and installation costs.
- Using SMR instead of ATR to produce hydrogen increases the cost by £7.2bn/year (see the discussion in section 2.1.1.1).
- The cost of heating appliances also affects the overall cost. Lower cost of hydrogen boilers will reduce the cost by £1.5bn/year; on the other hand, a higher cost of hydrogen boilers will increase the overall cost by £6.9bn/year.
- The reduction in space heating demand reduces overall hydrogen production, leading to lower system costs by £0.9bn/year. On the contrary, a higher heating demand will increase hydrogen demand leading to higher system cost – by £6.1bn/year- as more hydrogen needs to be produced. This highlights the benefits that increased energy efficiency could deliver.
- For the H2 30Mt case, the cost of reducing additional system flexibility is

[105] As described in Section 2.1, the increase in system costs is £29bn/year when the carbon emissions reduce from 10Mt to 0Mt.

£2.8bn/year, while improving the system flexibility can save additional £1.1bn/year.

- Given the presence of flexibility that can smooth energy demand profiles (both electricity and heat), the further reduction in peak heat demand (10%) does not lead to significant cost reductions.
- It is important to note that the production and use of hydrogen is optimised in relation to operation and investment requirements of the electricity system and hence and this is not presented as the flexibility service, and hence the benefits of additional flexibility sources as defined in the study are relatively modest.

The studies were extended to the 0Mt cases, and the results are presented in Figure 3-2. The trends are the same, but the sensitivities are intensified as the carbon emissions target is set to 0Mt. For example, assuming full imports of hydrogen reduces costs by £14.6bn in the 30Mt case and £46.5bn in the 0Mt case. These results emphasize the importance of lowering the cost of hydrogen production technologies, especially for a zero-carbon emissions scenario. Similarly, the impact of discount rates is more significant, as a larger capital investment in low-carbon electricity generation is needed in the 0Mt case. In contrast, the sensitivity related to the fuel prices is lower in the 0Mt case as the use of gas is significantly reduced in the 0Mt scenario. The model optimises the operation of electrolysers and hydrogen storage in line with requirements of both the electricity and gas systems. This cross-vector optimisation provides significant flexibility to the electricity system, and hence the benefits of other sources of flexibility presented in these figures are not very significant.

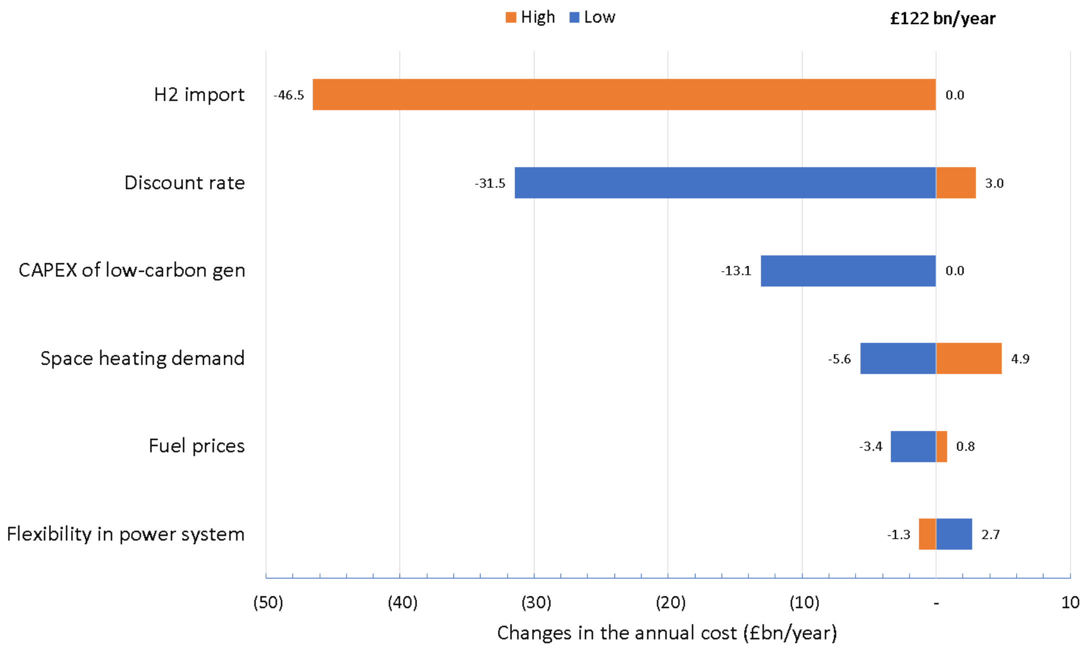

Figure 3-2 Cost sensitivity of H2 decarbonisation pathways [0Mt]

3.3 Electricity Scenario

Figure 3-3 shows the results of the sensitivity studies on the Electric decarbonisation pathways with a 30Mt carbon target. The results indicate that:

- Overall system costs are highly sensitive towards financing costs. This is expected since the majority of the costs, particularly in the Electric pathway, are dominated by capital costs. Thus, reducing the cost of capital for these investments will have a major impact. For the same reason, lower capex of low-carbon generation also leads to lower system costs.
- Having a stricter carbon target will increase system costs by £4.4bn/year.
- Flexibility is important for the Electric pathway. Having low flexibility costs more than £6bn/year while having more flexibility can save additional £3.5bn/year (up to £16bn/year in the 0 Mt pathway). It is important to note that the model optimises the use of hydrogen (produced mostly from BECCS) to support the electricity system, and this cross-vector optimisation delivers very significant flexibility. However, the benefits of flexibility presented in figure below refer only to the value of additional flexibility sources (e.g. pre-heating, smart charging of EVs etc.).
- The costs are also sensitive towards space heating demand; a low heat demand scenario reduces the costs by £6.3bn/year while in the high heat demand scenario the costs increase by £4.6bn/year.
- The high cost of electric heating appliances will increase overall costs by £1.3bn/year while low appliance costs will reduce costs by £4.3bn/year.
- Gas price variations have little impact on overall system costs as the utilisation of gas-fired power generation (CCGT and OCGT) is only about 12% of total annual electricity production.
- The impact of reduced peak heat demand is modest as the system already has a certain amount of flexibility which limits any further benefits of reducing peak demand. Load shifting and energy storage in the system have been used to flatten the daily energy demand profile (see Chapter 4 for more detail on this), and therefore, the 10% reduction of heat peak demand becomes less relevant.

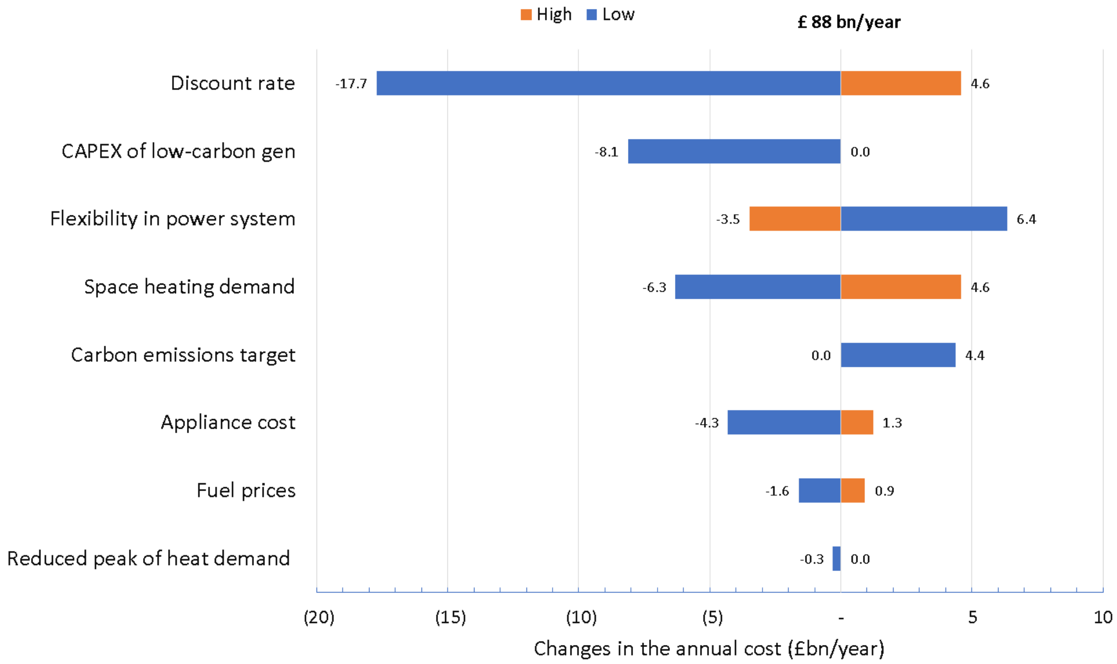

Figure 3-3 Cost sensitivity of Electric decarbonisation pathways [30Mt]

The studies are extended to the 0Mt cases, and the results are presented in Figure 3-4.

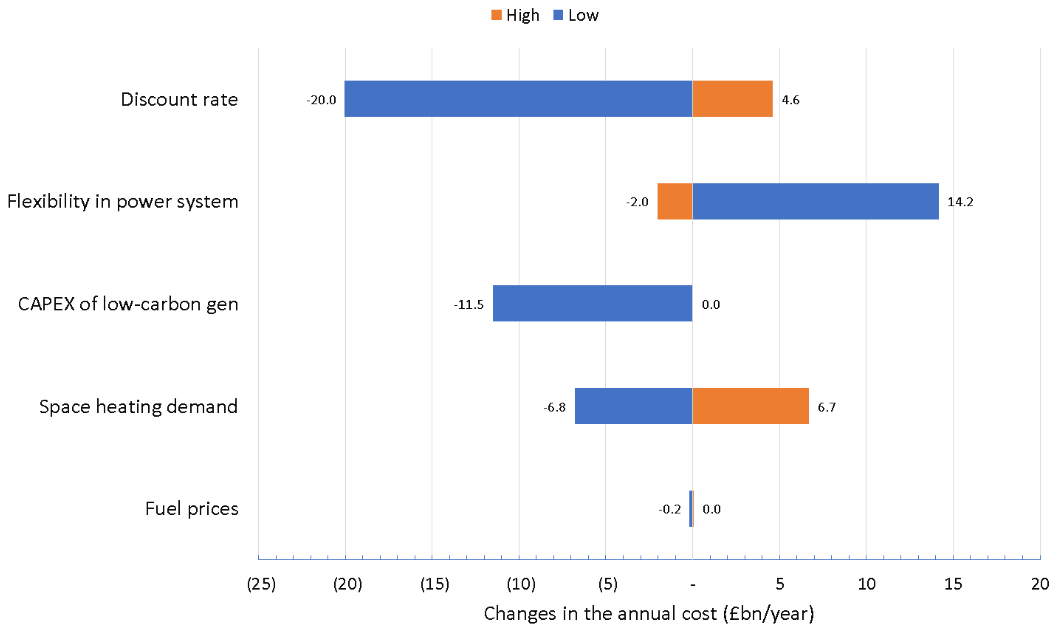

Figure 3-4 Cost sensitivity of Electric decarbonisation pathways [0Mt]

The trends are similar to the ones observed in the 30Mt cases, but the sensitivities are intensified as the carbon emissions target is set to 0Mt. For example, having a lower cost of finance can reduce the cost by around £20bn/year, this value is higher compared to the savings (£17.7bn/year) obtained in the 30Mt case. Similarly, the benefit of having flexibility is also higher in the 0Mt case (£14.2bn/year) compared to the benefit in the

30Mt case (£6.4bn). On the other hand, the sensitivity related to changes in fuel prices becomes much lower, as the use of gas is only limited to carbon-neutral gas in the 0Mt case.

3.4 Hybrid Scenario

Figure 3-5 shows the results of the sensitivity studies on the Hybrid decarbonisation pathways with a 30Mt carbon target. The results indicate the following:

- The system cost of the Hybrid system is also dominated by capital cost, and therefore, the impact of low or high financing costs is high. The low discount rate scenario leads to savings of £15.6bn/year, and the high discount rate leads to higher costs of £4.7bn/year. For the same reason, lowering the capex of low-carbon generation would also lead to a £8.3bn/year reduction in costs compared to the base case.
- Setting a stricter carbon target (i.e. 0Mt) increases annual system costs by £6.5bn/year as more investment in low-carbon generation technologies will be needed.
- The cost increases by £4.2bn/year if the appliance costs are high; the cost decreases by £1.2bn/year in the case of low appliance costs.
- Having lower or higher heat demand will reduce or increase annual system cost by around £3.6bn/year.
- Flexibility is also important in the Hybrid system as it can save £3.1bn/year; improving flexibility can deliver additional savings of £1.4bn/year. It is important to note that use of gas and electricity for heating is inherently optimised by the model, and this is not considered explicitly as a flexibility service. The benefits of flexibility quantified in the study refer to additional flexibility sources, such as pre-heating, smart-charging of EVs, etc.
- Having lower or higher gas prices also leads to lower or higher system costs as gas is still used for both power generation and heating in the Hybrid system.
- Reducing peak heat demand by 10% has a modest impact on system costs as the system already has some flexibility which limits the benefit of reducing peak heat demand as the daily heat demand profile is flattened.

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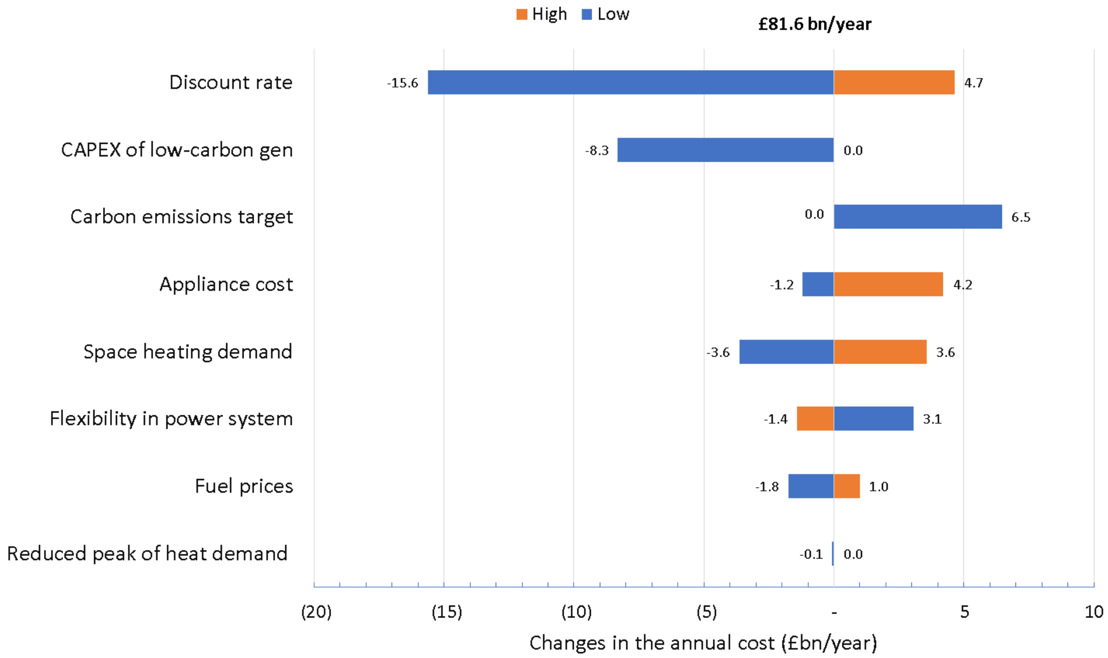

Figure 3-5 Cost sensitivity of Hybrid decarbonisation pathways [30Mt]

Sensitivity studies related to the 0Mt scenario were carried out, and the results are presented in Figure 3-6. The trends are similar, but – as in other pathways - the significance of the sensitivities tends to increase as the carbon emissions target becomes more stringent. For example, lowering financing costs can reduce costs by around £18.9bn/year, this value is higher compared to the savings (£15.6bn/year) obtained in the 30Mt case. Similarly, the benefit of flexibility is also higher in the 0Mt case (£7.8bn/year) compared to the benefit in the 30Mt case (£3.1bn/year). On the other hand, the significance of changes in fuel prices is reduced as the use of gas is reduced in the 0Mt case.

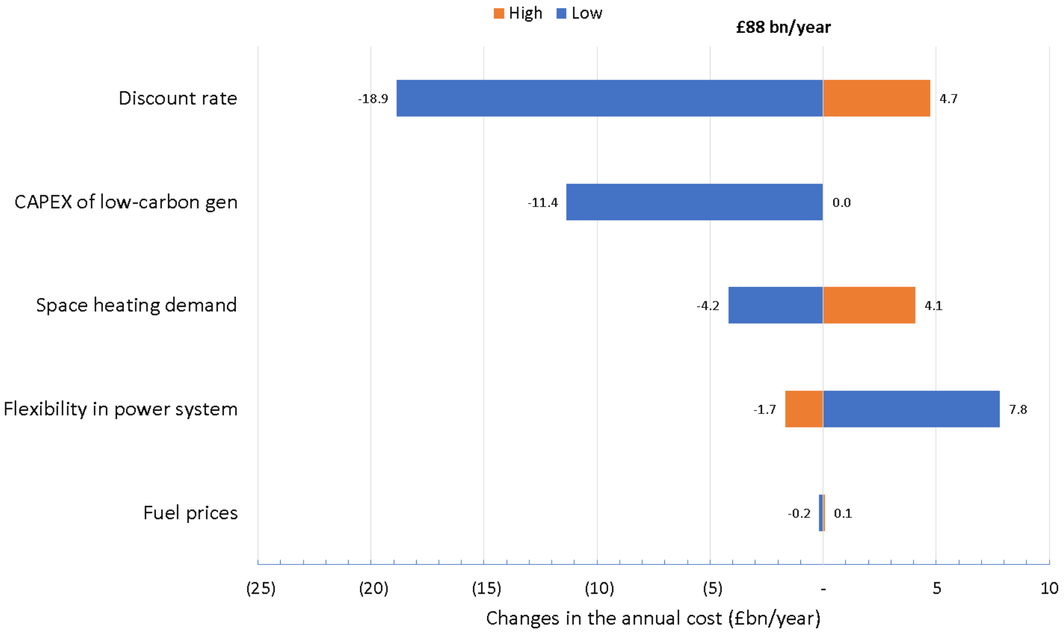

Figure 3-6 Cost sensitivity of Hybrid decarbonisation pathways [0Mt]

3.5 Cross-cutting analysis across alternatives decarbonisation pathways

In this section, a cross-cutting analysis of the sensitivity studies across three decarbonisation pathways is discussed.

3.5.1 Sensitivity across different decarbonisation options

Figure 3-7 shows a comparison of the sensitivity studies discussed in the previous section across the core H2, Electric and Hybrid decarbonisation pathways. The objective of this exercise is to enable a direct comparison across the different decarbonisation pathways considered in this study.

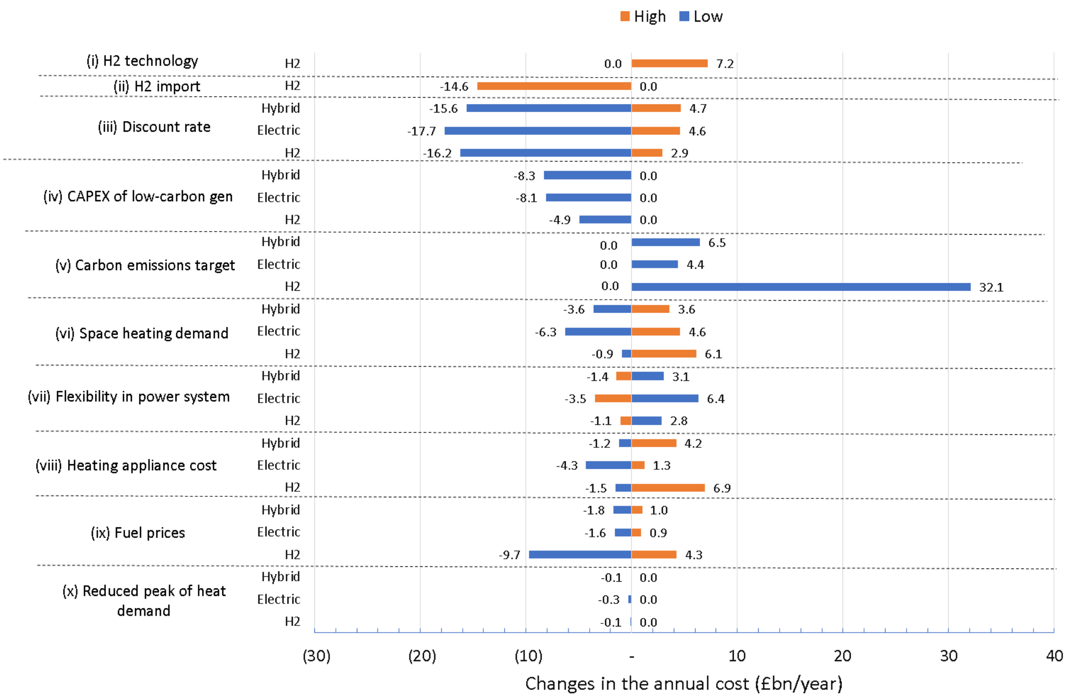

Figure 3-7 Comparison between the cost sensitivity of different decarbonisation pathways [30Mt]

The results of the sensitivity studies presented in Figure 3-7 demonstrate the following:

- For all pathways, low financing costs would be the primary driver for reducing the system cost as the low-carbon energy system costs are driven by the capital rather than operating costs.
- The most significant cost increase in the H2 scenario is primarily driven by the need to change the hydrogen production from gas to low-carbon power generation technologies.
- The 2nd most substantial cost reduction for the H2 scenario is found in a case when low-cost hydrogen imports are available (risks associated with significant energy imports are not within the scope of this study). By importing hydrogen, the infrastructure needed to transport, and store hydrogen can be reduced (assuming that imports can be delivered at all times, and to the right locations). Consistently low gas prices could also improve the viability of a hydrogen pathway, compared to other pathways.
- For the same reason, a reduction in the cost of low-carbon electricity generation reduces the overall cost significantly.
- In all pathways, meeting a stricter carbon target will increase system costs. While the increase in costs in the Electric and Hybrid pathways is between 4.4 and 6.5 £bn/year, the increase in costs in the H2 pathway is much more substantial (more than £30bn/year); this implies that H2 would be the highest cost pathway towards a strict zero carbon emissions target.

- The reduction in annual heating demands, driven by improved energy efficiency reduces total system costs by 0.9 – 6.3 £bn/year. Across the three pathways, the highest impact of heat demand reduction is in the Electric pathway.
- The benefits of additional flexibility are largest in the Electric scenario and lowest in the H2 pathway, as both H2 and Hybrid scenario involve more cross-vector flexibility, which reduces the benefits of other sources flexibility as defined in the study.
- The cost of an H2 pathway is more sensitive towards fuel prices compared to the Electric and Hybrid pathway as the volume of gas used in the last two pathways is much lower compared to the H2 pathway since heat demand is met primarily by electric heating (HP) and most of the energy comes from low-carbon resources.
- The impact of a reduction in peak heat demand is relatively marginal in all pathways, as a significant level of system flexibility is assumed to be delivered at a household level via pre-heating and thermal storage. Without this flexibility, the impact on costs of peak heat demand would be much more significant.

Furthermore, sensitivities across different decarbonisation pathways for the 0Mt cases are presented in Figure 3-8.

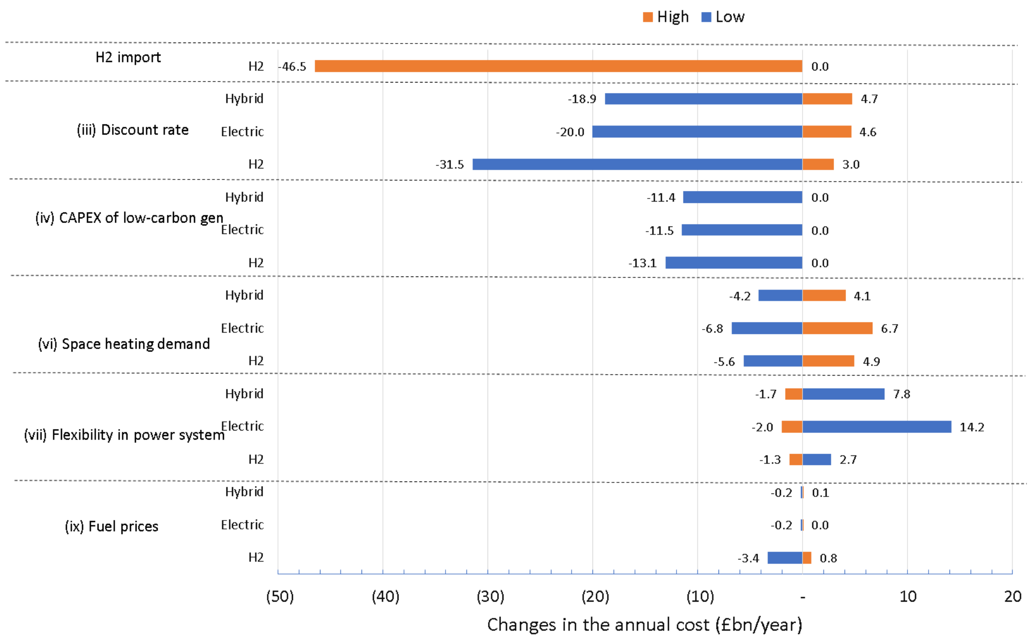

Figure 3-8 Comparison between the cost sensitivity of different decarbonisation pathways [0Mt]

As the impact of different assumptions may get intensified in zero-carbon scenarios, the importance of different parameters on the costs of different decarbonisation pathways may also change. In most cases, the trends are the same as ones observed in the 30Mt cases with some exceptions such as:

- The impact of the reduced cost of finance in the H2 pathway is higher than in the other pathways, as in a 0 Mt scenario domestic hydrogen is produced by electrolysers, requiring an increase in low-carbon electricity generation. This is driven by a need for much larger investment in low-carbon generation technologies compared to the other pathways in a 0Mt H2 case. This is in contrast to the results associated with the 30Mt scenarios where the highest impact of reducing the discount rate is found in the Electric pathway.

- For the same reason, the impact of reducing capex of low-carbon electricity generation technologies is highest for the H2 0Mt case. This is in contrast to the results of the 30Mt case, where the largest impact is found in the Hybrid pathway.

3.5.2 Cost of decarbonisation across different scenarios

The cost range of the core decarbonisation pathways across the sensitivity studies is compared in order to identify the drivers and conditions in which one particular pathway may become significantly more or less cost competitive compared to other pathways. The results are presented for the 30Mt (Figure 3-9) and 0Mt (Figure 3-10) cases.

The results for the 30Mt cases indicate the following:

- Across the uncertainties listed above the core Hybrid system (£81.6bn/year) remains the least-cost solution, followed by the Electric pathway (£87.8bn/year) and H2 pathway (£89.6bn/year). It can, therefore, be concluded that the Hybrid pathway is the most robust decarbonisation pathway to reach a 30Mt carbon target.
- There are a few conditions where an H2 pathway becomes more competitive, i.e. if large-scale low-cost imports of hydrogen are available (at £25/MWh), and all other conditions remain the same, or if gas prices are low (39p/therm).

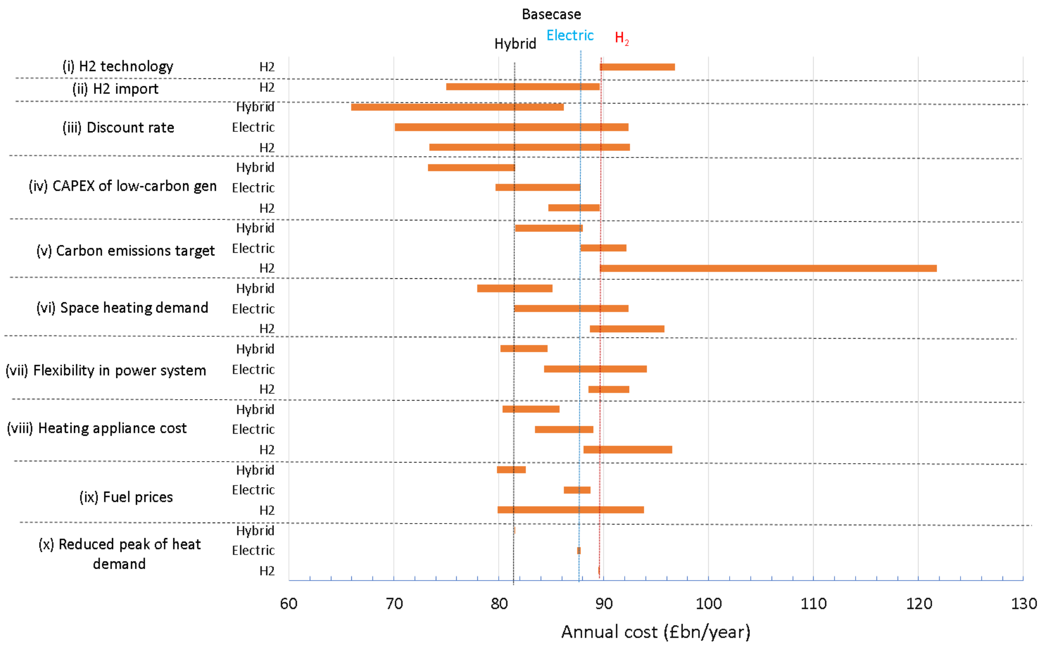

Figure 3-9 Comparison between the cost range of different decarbonisation pathways [30Mt]

- The cost of the Electric pathway is always higher than the cost of a Hybrid pathway, indicating the importance of cross-vector flexibility. The cost of the Electric pathway is close to the cost of the Hybrid pathway particularly when heating demand is low.

For the 0Mt cases, the results are presented in Figure 3-10.

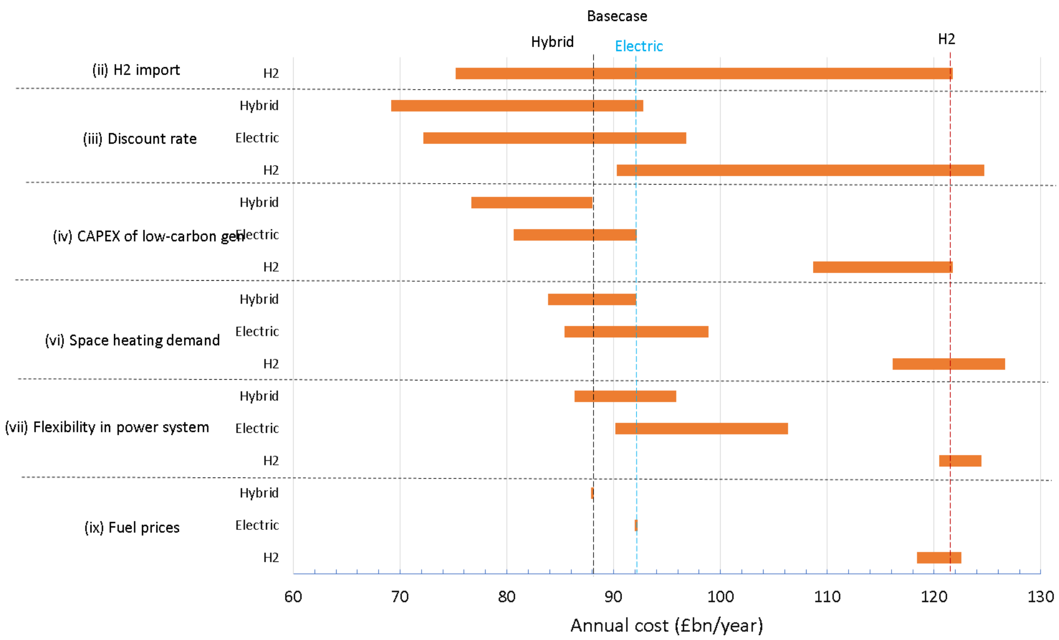

Figure 3-10 Comparison between the cost range of different decarbonisation pathways [0Mt]

The results demonstrate the following:

- The cost of the core Hybrid pathway is the lowest (£88.0bn/year) compared with Electric pathway (£92.2bn/year) and H2 pathway (£121.7bn/year). The cost of the H2 pathway is the highest in most cases, with the exception of hydrogen import at low cost.
- The cost difference between the Hybrid/Electric and H2 pathway increases compared to the cost difference between the corresponding pathways in the 30Mt cases. In contrast, the cost differences between the Electric and Hybrid decreases in the 0Mt cases. This is expected since the Hybrid system becomes more dependent on electrification to decarbonise the heating and gas systems, as less residual emissions are allowed for in the gas boiler element of the hybrid heat pump.

Since the Hybrid pathway is the least-cost scenario in both the 30Mt and 0Mt cases, it can be concluded that the Hybrid scenario is the most robust decarbonisation pathway, although the absolute level of decarbonisation that can be achieved through this pathway depends on the availability of biogas, and consumer usage of the heat pump and boiler elements of the hybrid heat pump[106].

3.6 Impact of improved energy efficiency and changes in heat demand

The optimal choice of decarbonising heat may depend on the level of heat demand in the future which could be influenced by many factors including improved housing insulation and temperature increases due to climate change. In this context, the system costs of the core scenario are compared with the costs of two lower heat demand scenarios[107]. The three scenarios in Figure 3-11 are (i) core scenario, (ii) low demand scenario, and (iii) low demand with climate change adjustment. The corresponding annual domestic heat demands (including both space-heating and water-heating demand) used in these three scenarios is (i) 349 TWh_{th}, (ii) 290 TWh_{th}, and (iii) 234 TWh_{th}. The last scenario assumes a 2°C increase in UK average annual temperature in 2050.[108] The studies were carried out for all three main pathways for the 0Mt cases.

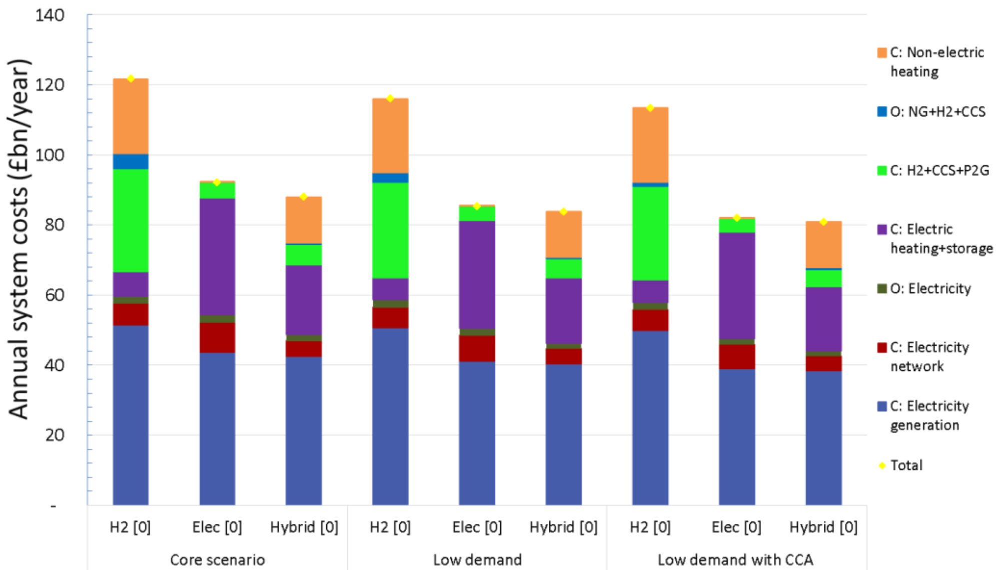

Figure 3-11 Impact of reduced heat demand on the system annual costs

Figure 3-12 shows the daily variation of outdoor temperature used in the study for both the base cases and the cases with increased average temperature due to climate change effect (the annual average of the increased temperature is around 2°C). Based on the temperature profiles in Figure 3-12, the COP of heat pumps is then derived from BEIS's

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[106] Annual use of the boiler component is around 14% in the 30 Mt scenario and 3% in the 0 Mt scenario

[107] The background of these scenarios is described in Appendix C.

[108] The core scenarios use historical temperature data with a few consecutive days of modified demand to simulate extreme weather events, i.e. very cold days with low output of renewable energy.

2016 report on heat pumps[109]. Figure 3-13 shows the COP of heat pumps used in the study.

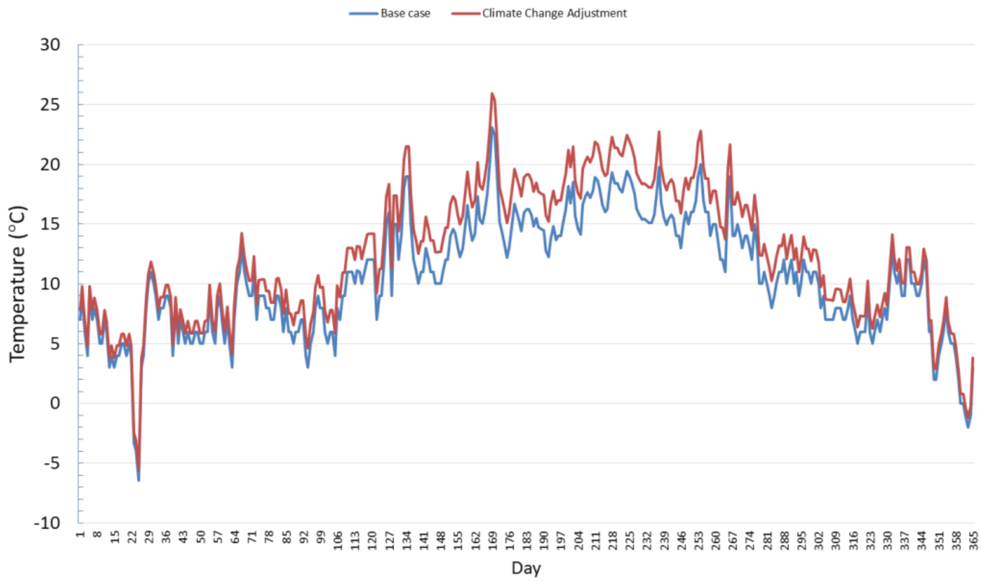


Figure 3-12 Impact of climate change on the ambient temperature

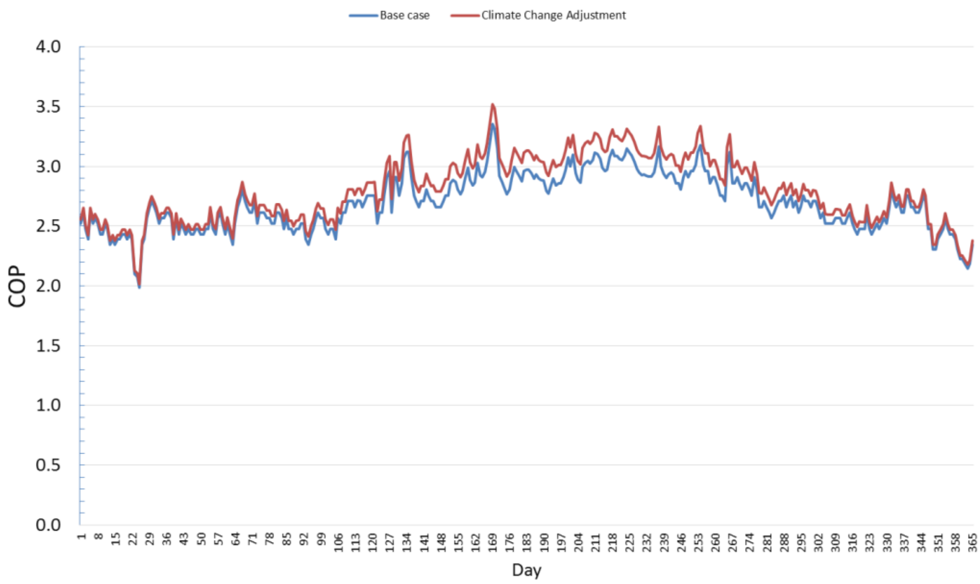


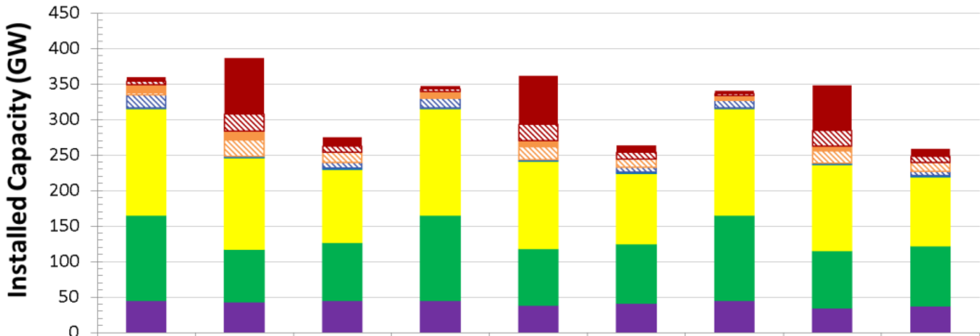
Figure 3-13 Impact of climate change on the COP of HP/HHP

The results demonstrate that annual system costs are lower when domestic heating demand is reduced, though it is worth noting that the results exclude the costs associated with reducing this demand (e.g. investment cost for improving thermal insulation and using the smart-energy system). In addition to demand reductions the

[109] BEIS, "Evidence Gathering – Low Carbon Heating Technologies," November 2016. The COP data are based on the use of air-source HP and water output temperature of 55°C.

results for the “Low demand with CCA” are influenced by the assumed higher annual average temperature in this pathway, resulting in a higher average COP for heat pumps in the Electric and Hybrid pathways. Consequently, this reduces the infrastructure requirements and associated costs.

The impact on power generation capacity requirement is shown in Figure 3-14. In general, there is a substantial reduction in the power generation capacity across all pathways due to reduction in the heating demand. For the Electric and Hybrid pathways, there is an 8-9 GW reduction in the capacity of nuclear plants in the lowest demand scenario. Similarly, there is a substantial (17 GW) reduction of peaking capacity (OCGT) in the Electric pathway.



	H2 [0]	Elec [0]	Hybrid [0]	H2 [0]	Elec [0]	Hybrid [0]	H2 [0]	Elec [0]	Hybrid [0]
	Core scenario			Low demand			Low demand with CCA		
OCGT	6	79	13	4	68	9	4	64	10
H2 OCGT	5	24	9	3	23	10	3	22	9
CCGT	11	13	0	8	8	0	6	7	0
H2 CCGT	3	23	14	2	18	12	1	18	12
District CHP	18	0	8	13	0	6	10	0	6
Hydro	1	1	1	1	1	1	1	1	1
PV	150	129	103	150	124	99	150	121	97
Wind	120	74	82	120	79	84	120	81	85
Nuclear	45	43	45	45	39	41	45	34	37

Figure 3-14 Impact of heating demand reduction on the optimal generation mixes

The costs of the H2 pathways are still the highest in these zero-emissions scenarios, and the least-cost solutions for all scenarios are still the Hybrid pathways although the cost difference between the Electric and Hybrid pathways reduces with lower heat demand.

Chapter 4. The importance of energy system flexibility and alternatives to firm low-carbon generation

4.1 Alternatives to nuclear generation

Improving energy system flexibility is necessary for enabling the cost-effective integration of low-carbon generation into the electricity system. Improving flexibility could save up to 10 and 16 £bn/year in the 30Mt and 0Mt cases respectively. It is important to note that cross-vector flexibility is inherently taken into account in all scenarios, and hence the benefits of flexibility presented refer only to the value of other sources flexibility (e.g. pre-heating, smart charging of EVs, etc.).

The studies suggest that the availability of firm low-carbon resources (such as nuclear, hydrogen CCGT or CCS plant) is critical for fully de-carbonising the energy system[110]. As the study demonstrates, firm low-carbon generation is significantly less critical in systems with less demanding carbon targets[111]. Given this finding, analysis was carried out to investigate the possibility of delivering a zero-carbon energy system without nuclear power. An alternative approach is to quantity of renewable electricity capacity needed to meet a zero-carbon energy system without nuclear. The study demonstrates that it would feasible to achieve a zero-emissions energy system without nuclear generation, subject to the presence of hydrogen storage and corresponding hydrogen-based power generation.

Figure 4-1 presents a comparison between optimal generation portfolios for an Electric 0Mt pathway with and without nuclear generation. The capacity of PV and wind needed in a zero-carbon Electric system without nuclear plants are 175 GW and 185 GW respectively, which is above the estimates of UK potential for these technologies considered in this study[112]. Unless the potential level of PV and wind can be increased to

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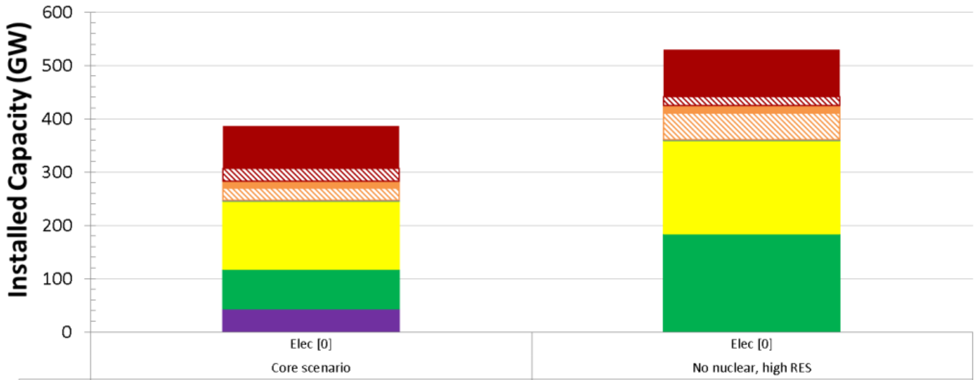
[110] In a 0Mt scenario CCS technologies for producing hydrogen or power generation cannot be used due to residual carbon emissions unless a capture rate of 100% is assumed.

[111] This section hence focuses on 0Mt case.

[112] 150 GW for PV and 120 GW for wind

such level, the system will require nuclear to meet the zero-emission target. An alternative solution is to use hydrogen imports, allowing the system to achieve zero-carbon emissions within the defined constraint of PV and wind capacity, but it requires a higher capacity of hydrogen-based power generation.



	Elec [0] Core scenario	Elec [0] No nuclear, high RES
OCGT	79	88
H2 OCGT	24	16
CCGT	13	14
H2 CCGT	23	51
Hydro	1	1
PV	129	175
Wind	74	185
Nuclear	43	0

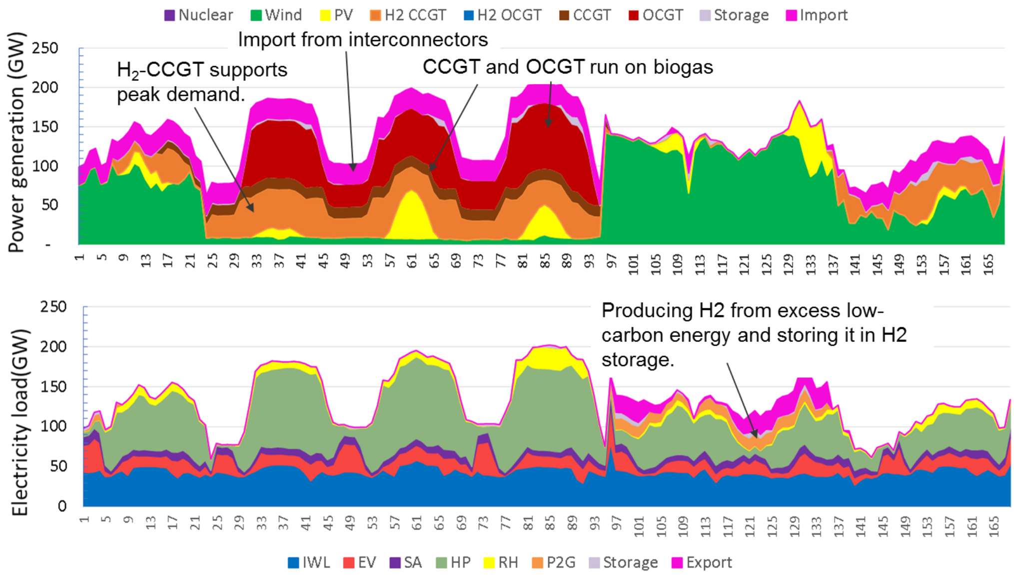
Figure 4-1 Comparison of generation portfolios for the Electric pathway with and without nuclear technology

To achieve zero-carbon emissions without firm low-carbon generation, there is a need for significant long-term energy storage that could be provided by hydrogen. This is in addition to significant short-term energy system flexibility provided by demand shifting via pre-heating and thermal storage in homes (50% of potential demand flexibility is assumed available). As shown in Figure 4-2 (a), during periods of high renewables output, the excess energy is converted into hydrogen by electrolysers ("Power-to-Gas"). This drives the need for investment in electrolysers[113] to enhance the utilisation of renewables. Energy in the form of hydrogen can then be stored across long time horizons as losses in hydrogen storage are assumed to be minor and not time dependent. Electrolysers can also provide balancing services during periods of high renewables output, and therefore, reduce the need for these services from other sources (generation, demand-side response, storage, etc.)[114]. During low renewables output, stored energy can be used to produce electricity via hydrogen-based power generation. Hence the capacity of hydrogen-based CCGT increases significantly - from 23

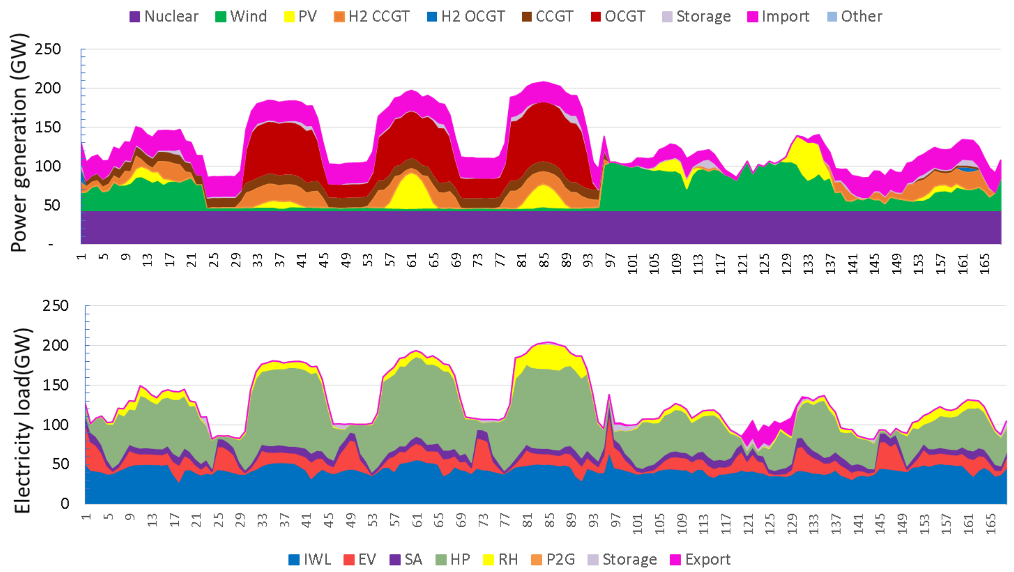
[113] 15 GW of electrolysers were proposed by IWES in the "Elec [0] No nuclear high RES" case.

[114] Electrolysers also provide grid-balancing services particularly when the system is less flexible (e.g. in H2 0Mt case). In this case, electrolysers are used to save the excess of renewable energy in the form of hydrogen. Since there are losses associated with this process, it is carried out only when it is necessary.

GW in the system with nuclear (43 GW) to 51 GW in the system without nuclear. It can be concluded that “Power-to-Gas” and hydrogen-based generation can substitute nuclear generation. It is important to note that electrolysers (as part of the “Power-to-Gas” system), due to higher costs, are not selected by the model in the core Electric pathways when nuclear generation is available, as other technologies, such as demand-side response and battery storage are able to provide system flexibility services at lower cost.



(a) Elec [0] no nuclear, high RES case



(b) Elec [0] core scenario

IWL: baseload including Industrial and Commercial load, EV: Electric Vehicle, SA: Smart Appliances, HP: Heat Pump, RH: Resistive Heating, P2G: Electrolysers

Figure 4-2 The role of electrolysers, hydrogen storage and generation in balancing the system with large penetration of renewables and the use of biogas for peaking plants

It is important to highlight that hydrogen-based CCGTs and OCGTs can provide system balancing services which facilitates cost-effective integration of other low-carbon generation such as renewables and nuclear. Figure 4-2(b) shows the hourly generation output and load profiles for the same period in the Electric 0Mt core scenario. The availability of nuclear reduces the need for hydrogen-based CCGT and other low-carbon generation such as wind and PV as shown in Figure 4-1.

The comparison between the system costs of the core Electric 0Mt case with and without nuclear is shown in Figure 4-3, showing that a scenario without nuclear power (or similar firm low-carbon capacity) costs around £10bn/year more than a scenario with nuclear power generation.

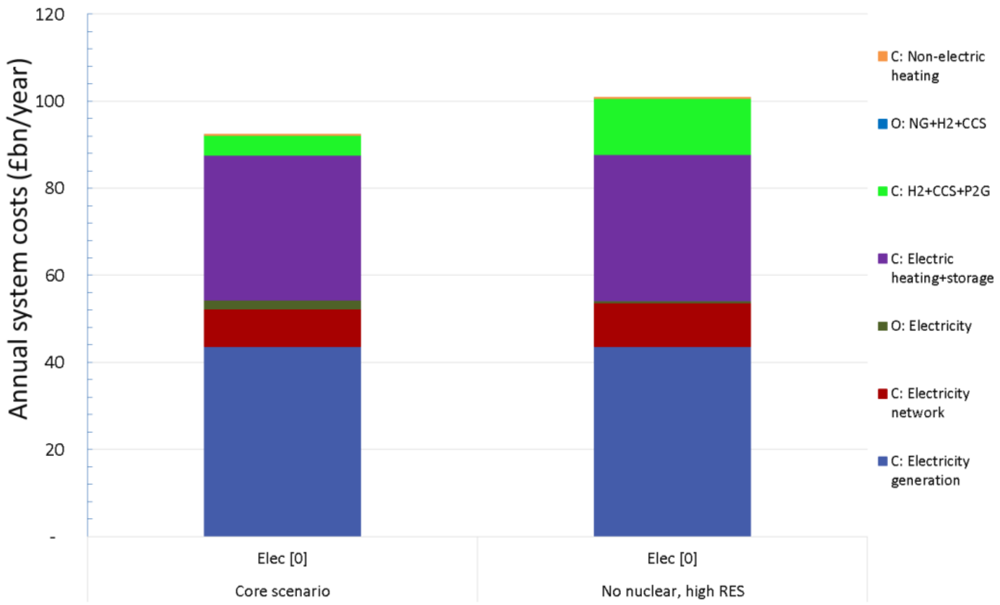


Figure 4-3 System costs of the Electric pathway with and without nuclear technology

The results of the study demonstrate that in the absence of firm low-carbon generation such as nuclear, the system would require long-term storage that could be supplied by hydrogen through investment in the hydrogen electrolysers and storage. The capacities of hydrogen production plant, hydrogen networks and storage are optimised and tailored to system needs in order to minimise the overall system cost.

To achieve zero-carbon emissions without nuclear generation, there is a need for 3.6 TWh hydrogen energy storage (Figure 4-4) that can provide both support in the short-term energy balancing and long-term storage. The volume of hydrogen storage needed is around 1100 mcm, which, for context, is roughly about 30% of the volume of the recently closed Rough gas storage facility. The annuitized investment cost of the hydrogen storage across GB in this scenario is around £3.2 bn/year.

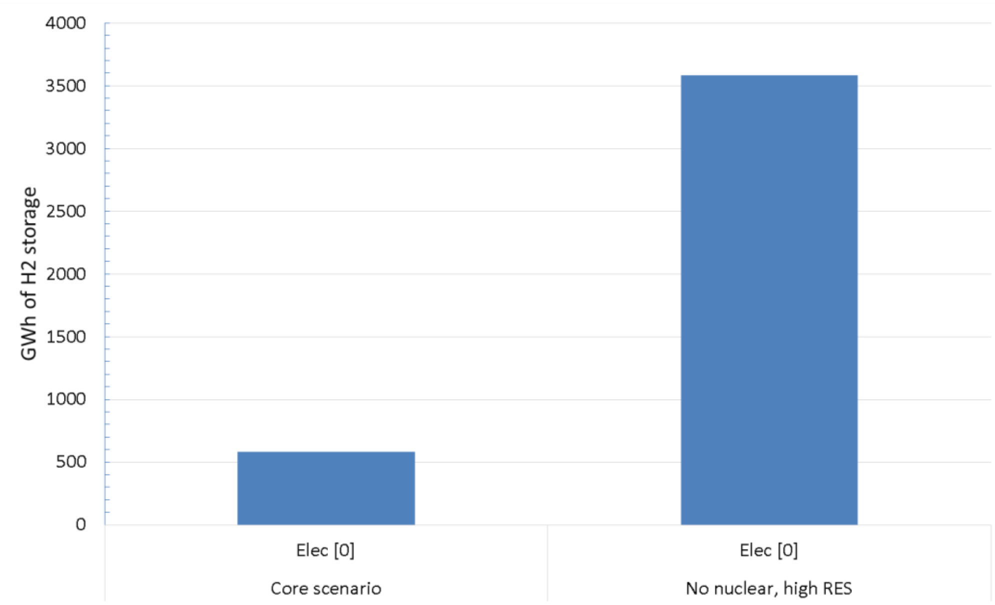


Figure 4-4 Comparison of hydrogen storage requirement in Electric 0Mt cases

The need for investment in hydrogen infrastructure (production plant, networks, and storage) can be reduced by importing hydrogen rather than producing it in GB, as importing hydrogen reduces demand for energy storage and Power-to-Gas schemes.

4.2 The interaction between thermal and electricity storage

Thermal storage and preheating can provide significant flexibility to the system as it can shift thermal loads to off-peak periods, reducing the overall system capacity requirement, improving the utilisation of renewables, and reducing operating costs. The benefits of thermal storage and preheating are illustrated in Figure 4-5. The results show two consecutive days of extremely cold weather[115].

The modelling results demonstrate that thermal storage is charged, and the building is pre-heated during the night. The upper diagram shows the heat output of HP, NG boiler, RH, and thermal storage. Thermal storage is discharged during high demand conditions resulting in a smaller capacity requirement for heat pumps and resistive heating. The ability to shift thermal load provides significant benefits through reducing system peak capacity requirement and the associated costs - 150 GW_{th} of peak load can be reduced by using thermal storage and preheating.

[115] The model considers "1-in-20" winter extreme cold days to ensure there is sufficient infrastructure capacity installed in the system to deal with these conditions.

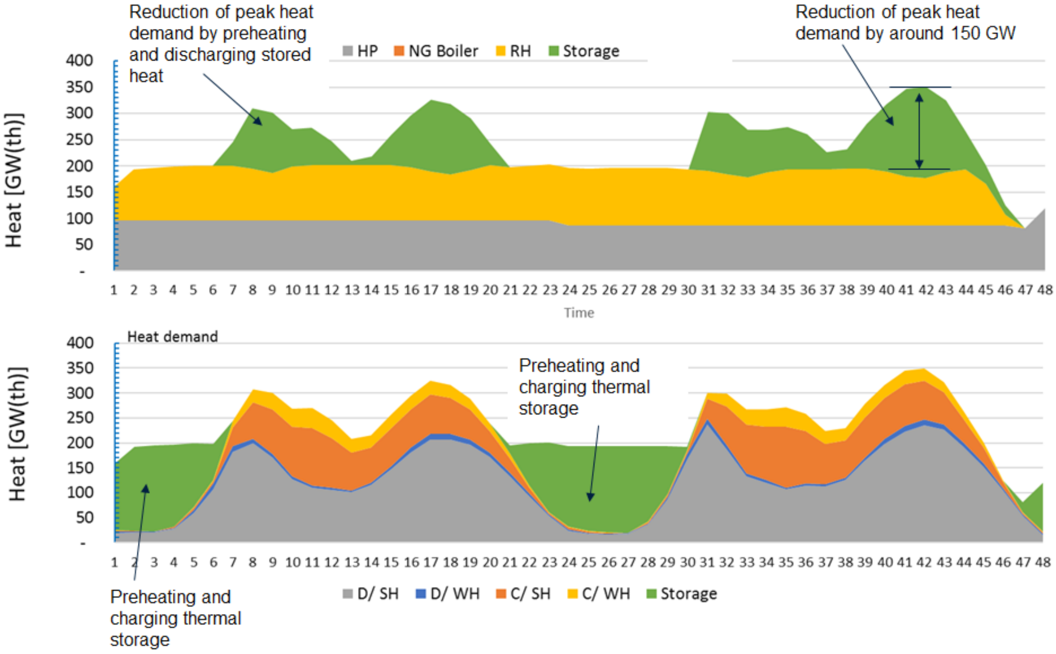


Figure 4-5 Flexibility provided by thermal storage and preheating[116]

Other forms of energy storage investigated in this study include thermal energy storage (TES) and electricity storage. The IWES model optimised the portfolio and size of the energy storage system considering the technical and cost characteristics of each storage technology. Studies have also been carried out investigating the correlation between the thermal storage and electricity storage. The studies involve a number of different levels of predefined thermal storage availability and preheating capability from High to Zero thermal storage. The High scenario represents around 58 GWth of TES and more than 100 GWth preheating[117]. The Medium and Low scenarios are 50% and 25% of the capacity in the High scenario respectively, and the last scenario (Zero) is an extreme scenario where there is no domestic TES and preheating capability available. In this study, the level of thermal storage and preheating is given as an input and not optimised; the IWES model optimises the other infrastructure requirements including electricity storage. The studies show a 0Mt Electric pathway as the role of storage in reducing the infrastructure requirement is high in this scenario. The results are shown in Figure 4-6.

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[116] Figure 4-5 shows hourly heat demand of the system contributed by domestic space heating (D/SH), domestic water heating (D/WH), commercial space heating (C/SH), commercial water heating (C/WH), and thermal storage including preheating.

[117] Preheating involves heating the households earlier than it would be otherwise done while utilising inherent heat storage in the fabric of the houses. This type of flexibility is critical for reducing system peaks, enhancing the value of the provision of balancing services and increasing utilisation of renewables by electric heating, which significantly reduces the cost of decarbonisation.

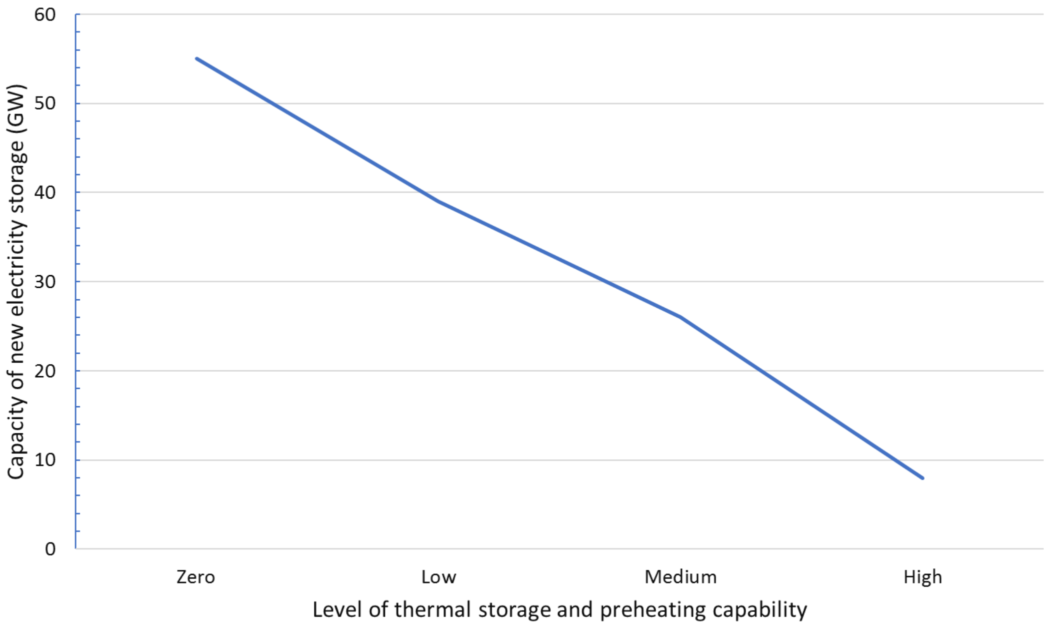


Figure 4-6 Correlation between TES and electricity storage

The modelling results demonstrate that in the absence of thermal storage and other flexibility sources, there would be a need for more than 55 GW of new electricity storage[118] as well as substantial additional power system capacity in the Electric scenario; however, if 58 GW_{th} of TES (1.7 kW_{th}/household) and preheating (more than 100 GW_{th}) is available, the need for new electricity storage reduces to below 10 GW, since the cost of thermal storage is considerably lower than the cost of electricity storage and the cost of preheating is assumed to be applied at low cost. Smart control could be installed to manage the operation of heating appliances and thermal storage including preheating to minimise costs to consumers (and the overall system costs) while maintaining the comfort levels. For example, preheating could be carried out when there is surplus of low-carbon energy production while reducing the heat demand during peak periods. Preheating and thermal storage also reduce the capacity of heating appliances.

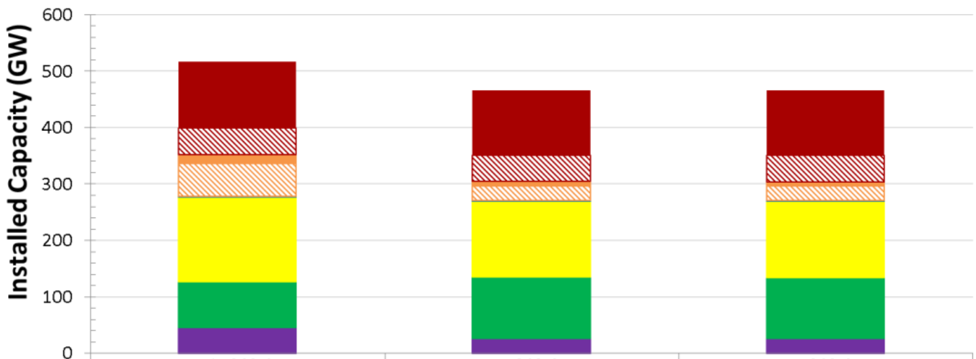
Although there is a strong interaction across different energy storage technologies (electricity, gas, and thermal); these technologies may not be able to fully substitute for the functionalities of other storage technologies. Storing energy in the form of electricity can be more flexible than heat energy storage. For example, the batteries in the electrified transport sector will provide services to local and national grid via the V2G concept. Therefore, electricity storage is still needed (although with less capacity) even with a large capacity of thermal storage.

[118] Total storage capacity is 110 GWh.

Another alternative energy storage is in the form of long-term thermal energy storage (TES) is discussed in the next section.

4.3 Impact of long-term Thermal Energy Storage

The increased penetration of renewables in the UK attracts discussions on the use of long-term thermal energy storage to store excess of renewable output over longer time horizons. There are a number of long-term thermal energy storage technologies such as underground thermal energy storage, pit storages, salt hydrate technology, phase-change materials etc. The benefit and value of thermal energy storage technologies in enabling the use of more variable and lower cost RES instead of higher-cost but firm low-carbon generation such as nuclear has also been investigated through two cases studies assuming the availability of TES that can store 10 and 20 days of heat demand. The capacity of the TES is optimised by the IWES model. The modelling of long-term TES is technology agnostic; it is assumed that there are no significant losses (cycle losses of 10%). The counterfactual (reference) scenario used in this comparison is the Electric 0Mt case[119] with zero flexibility. The results of the study are demonstrated in Figure 4-7.



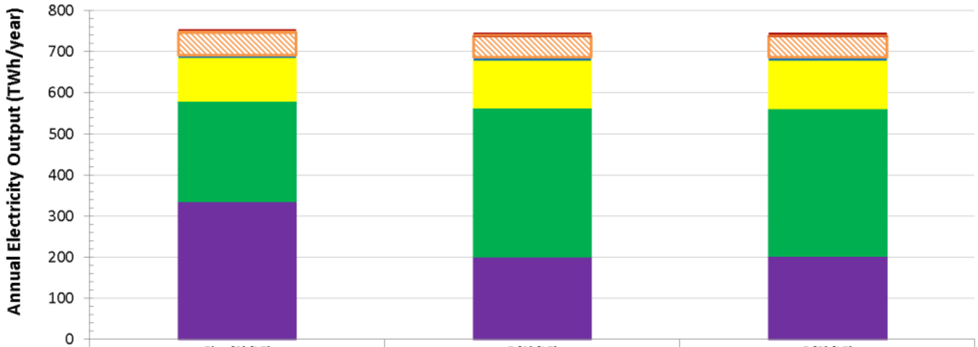
	Elec [0] [LF] No flex	E [0] [LF] TES 10 d	E [0] [LF] TES 20 d
OCGT	118	114	115
H2 OCGT	46	47	48
CCGT	16	8	7
H2 CCGT	57	25	25
Hydro	1	1	1
PV	150	134	136
Wind	82	109	108
Nuclear	45	26	26

Figure 4-7 Long-term thermal energy storage enables the integration of more renewables

The results demonstrate the following:

- Long-term thermal energy storage can facilitate the integration of larger volumes of renewables, such as increased wind capacity. It is important to note that even though the proposed capacity for PV is smaller, the utilisation of PV output is higher as less curtailment will be needed during periods of high output. This is demonstrated in Figure 4-8.

119 In this case, no system flexibility was assumed to be available in 0Mt Electric case



	Elec [0] [LF] No flex	E [0] [LF] TES 10 d	E [0] [LF] TES 20 d
OCGT	3	4	5
CCGT	5	3	3
H2 OCGT	1	2	2
H2 CCGT	53	52	52
Hydro	8	8	8
PV	104	115	116
Wind	245	362	359
Nuclear	336	202	204

Figure 4-8 Long-term thermal energy storage enables higher utilisation of renewables

- The ability to use more RES reduces the need for nuclear power, and therefore, the installed capacity of nuclear in a system with thermal energy storage decreases (from 45 GW to 26 GW). This leads to a reduction in the share of nuclear power in the energy mix as annual production falls from 336 TWh to 202 TWh (out of 748 TWh total).
- There is a marginal difference between the results of a system with 10 days and 20 days of TES, suggesting that there is a limited additional benefit in having longer duration energy storage (though much longer durations have not been considered) The size of TES should be optimised to minimise the system cost.

Further studies investigating design options for long-term thermal storage would allow in-depth understanding on the optimal ratings, energy storage capacities, and the impacts of these technologies on the overall energy system.

Chapter 5. Conclusions and policy recommendations

5.1 Conclusions

The cost of each pathway and core variants are presented in ascending order in Table 5-1, for carbon targets of 30Mt and 0Mt.

Table 5-1 Cost performance of different decarbonisation pathways

30Mt scenarios	Cost (£bn/year)		0Mt scenarios	Cost (£bn/year)
Hybrid - H2 North	80.8		Hybrid	88.0
Hybrid	81.6		Hybrid - Urban DH HP	90.8
Hybrid - H2 Urban	85.4		Hybrid + micro-CHP	91.4
Hybrid - Urban DH HP	85.8		Elec	92.2
Hybrid + micro-CHP	87.2		Hybrid - H2 North	94.7
Elec	87.8		Elec+DH	97.7
H2	89.6		Hybrid - H2 Urban	101.4
Elec+DH	94.3		H2	121.7
H2+DH	111.6		H2+DH	142.2

For the 10Mt cases, the annual system costs are £84.8bn/year for the Hybrid case, £89.5bn/year for the Electric case, and £90.2bn/year for the Hydrogen case.

It can be concluded that:

- A Hybrid pathway is identified as the most cost-effective decarbonisation pathway, although the costs of the core decarbonisation pathways are relatively similar (the cost difference is within 10%). Though it is worth noting that given the uncertainties involved, the ranking may change when different assumptions apply.
- Systems with lower carbon emission targets will lead to higher costs. In all scenarios, further emission abatement, from 30Mt to 10Mt, is available at limited additional cost (the increased cost is between by 0.6 - 3.2 £bn/year). However, this changes when moving from 10Mt to 0 Mt, with the cost further increases by £31.5bn/year in the hydrogen scenario, compared to £2.7bn/year in the electric scenario.
- Electric and Hybrid pathways provide more optionality towards deep levels of decarbonisation compared to the H2 pathway, given the shift in hydrogen production from gas (ATRs) to electricity (electrolysers), which significantly increases the cost of hydrogen infrastructure.

- Regional scenarios for deploying hydrogen and district heating are more attractive than national deployment for these specific solutions. In some cases, regional heat decarbonisation choices – such as hydrogen in the North of GB, or district heating in heat dense areas - within a wider national system can reduce overall costs.
- Technologies such as micro-CHP can provide alternatives to electric heating and improve cross-energy flexibility between electricity and gas systems.

Considering the uncertainty across different heat decarbonisation pathways and emissions targets, "low/no regrets"[120] capacities of low-carbon generation technologies across different pathways and emissions targets have been derived from the modelling results. It indicates that there will be a minimum requirement of 5 GW of nuclear, 74 GW of wind, and 3 GW of H2 CCGT across all pathways. Additional electricity generation capacity will need to be built as the optimal generation portfolio will depend on many factors such as costs, system flexibility, selected decarbonisation pathway and the carbon target.

A range of sensitivity studies has also been carried out to assess the impact of different assumptions on each decarbonisation scenario and its associated costs. The sensitivity studies consider the influence of different discount rates, system flexibility, carbon emissions targets, capex of low-carbon generation, heating demands, etc. In most of the cases considered in the sensitivity analysis, the Hybrid scenario is identified as the least-cost decarbonisation pathway; although the volume of gas reduces significantly the value of existing gas infrastructure increases significantly by providing flexibility and reducing significantly investment in electricity infrastructure. The Hybrid pathway is generally more resilient to the sensitivities included in this analysis while the H2 and Electric pathways would cause higher levels of disruption to households (requiring both building upgrades, and disruption to streets with network upgrades).

In summary, the key findings of the modelling carried out are as follows:

- *Towards a zero-carbon energy system, the cost-effective decarbonisation of heat may require electrification*
  - Unless carbon capture rates involved in the production of hydrogen via gas reforming can reach close to 100%, then decarbonising via hydrogen would require significant investment in zero-carbon electricity generation in order to produce hydrogen via electrolysis, which the analysis has demonstrated appears to be expensive compared to other pathways
  - Technology improvement in both carbon capture rates and efficiencies of gas-based hydrogen production technologies would significantly reduce the cost of hydrogen pathways, particularly in a 0Mt scenario.

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[120] Low/no regrets capacity is defined as the capacity that will be needed irrespective of the decarbonisation pathway adopted in the future.

- *Energy efficiency is of key importance*
    - Reducing heat demand by improving energy efficiency of buildings can reduce system costs across all pathways.
- *Towards a zero-carbon energy system, overall system costs will be dominated by the capital expenditure, not operating costs*
    - Any measures that may reduce the capex (e.g. lower financing cost) will have a significant impact
    - Energy system pathways will be less sensitive than today's energy systems to fuel price variations, particularly in the Hybrid and Electric pathways.
- *System flexibility is of key importance for cost-effective energy system decarbonisation*

- The absence of flexibility would increase system costs in the Electric 0Mt scenario by more than £16 billion per year. The benefits of flexibility are highest in the Electric scenario and lowest in the H2 pathway, as both H2 and Hybrid scenario involve some inherent cross-vector flexibility, which reduces the benefits of other sources flexibility as defined in the study. The study demonstrates that having 50% of potential flexibility would already capture a significant proportion (70%-85%) of the benefits. As the benefits are non-linear, initial improvements in flexibility have the highest value; beyond 50% flexibility, the marginal value of additional flexibility diminishes.
    - It is important to note that IWES model co-optimises electricity, gas, hydrogen and heat systems, simultaneously considering both short-term operation and long-term investment decisions covering both local district and national/international level energy infrastructure, including carbon emissions and security of supply constraints. Absence of IWES cross-vector coordination would significantly increase costs of heat-decarbonisation. Hence the cross-vector flexibility and the link between local and national levels services across different time-scales are implicitly taken into account in all scenarios, and the benefits of flexibility quantified in the study are related to other sources of flexibility (e.g. pre-heating, smart-charging of EVs, etc).
    - Co-ordinating system flexibility across electricity and gas systems reduces system costs significantly, e.g. (i) the use of gas to supply heat during peak demand conditions significantly reduces investment in electricity system infrastructure (ii) hydrogen could be stored long-term and be used in the power system to reduce the need for firm low carbon generation (e.g. nuclear); (iii) household level flexibility around heat demand, facilitated by thermal energy storage and application of preheating, would enhance the utilisation of renewable energy resources and significantly reduce system capacity requirements.
    - Stronger planning coordination between electricity, gas and heating systems is needed to minimise whole-system costs.
    - When electrolysers are needed (e.g. to produce hydrogen), electrolysers can provide grid balancing services following the output of renewables. However, such

flexibility can also be provided by demand response and storage hence the decision to invest in electrolysers is not primarily driven by the need for grid balancing but by converting energy from low-carbon electricity generation to hydrogen which can then be stored more cost-effectively. Electrolysers have important role in H2 0Mt case but are less critical in other pathways.

- *Energy storage can reduce system capacity requirements and facilitate the cost-effective deployment of renewables.*
  - Storage can be used to improve load factors of baseload power generation and hydrogen production plants; the cost of storage is typically much lower than the capex of baseload plant, and therefore it can provide capacity at lower cost. The modelling results demonstrate that hydrogen storage is essential to maintain steady production in gas-reforming plants that produce hydrogen, reduce the need for hydrogen production capacity and its associated cost, provide cost-effective both short and long-term energy storage as a supplement or an alternative to other energy storage technologies (e.g. electricity storage and thermal storage). A hydrogen network provides significant 'linepack' storage of hydrogen.
  - Hydrogen storage can provide both short and long-term energy balancing services, which will facilitate more effective integration of RES.
  - The modelling results demonstrate that in the absence of thermal storage and other flexibility, there would be a need for more than 55 GW new electricity storage in the Electric scenario; however, if 58 GW_{th} of TES (1.7 kW_{th}/household) and preheating (more than 100 GW_{th}) are available, the need for new electricity storage reduces to below 10 GW, since the cost of preheating and thermal storage (e.g. hot water tanks, phase-change-material based thermal storage) is lower than the cost of electricity storage.
- *Importing low-cost hydrogen could potentially make the H2 pathway cost competitive against electrification pathways*; though producing hydrogen at the costs assumed in this analysis would require a significant reduction in the cost of electrolysis and shipping hydrogen. Imports of hydrogen could also reduce the need for UK based hydrogen storage.
- *Economies of scale of investment* are also important for achieving minimum overall cost. The modelling assumes that both electricity and hydrogen is produced on a centralised, rather than a distributed basis. More localised production would result in lower economies of scale, increasing system costs.
- *Gas network modelling suggests that additional network level storage of distributed hydrogen (131 – 333 GWh) is required to enable transport of hydrogen through high-pressure distribution gas networks.* This would increase the cost of the H2 pathway for approximately £0.35bn/year to £0.61bn/year. While the total volume required is relatively small, the distribution of these storages is important for consideration.

Therefore, this investment cost is in addition to significant investment in large-scale storage facilities in the H2 scenarios.

5.2 Policy implications and recommendations

A set of recommendations are outlined below, based on the modelling results and analysis carried out in this study.

5.2.1 Further analysis

In order to provide an in-depth understanding of the transition towards low carbon heat, a number of areas may warrant further investigation. These could include:

- Detailed analysis of different types of buildings considering typical heat requirements, levels of insulation, the role of thermal storage, etc. Following this, a further assessment of corresponding system performance and costs could be made.
- Further investigation of alternative decarbonisation pathways that involve diversified ("patchwork") heating solutions across different regions in the UK, and the impact these could have on national low-carbon heating choices. In the context of heat-sector decarbonisation it may be appropriate to investigate if the concept of levelized cost of end use heat technologies could be introduced to inform corresponding policy development.
- Development of robust least-worst heat decarbonisation pathways and corresponding policies, while considering explicitly a full range of technologies and system uncertainties.
- The resilience of the future energy systems considering high impact events such as extreme weather conditions, shortage of gas supply, etc.
- Role, value and business cases of emerging technologies such as Phase Change Material-based thermal energy storage, co-optimisation of energy for cooling and heating, research into long-term thermal energy storage technologies.
- Assessing the significance of the integration of transport and heat sectors through the vehicle-to-home / vehicle-to-grid concepts, and the impact on the need for thermal storage.
- Investigation into the operation and costs of managing the gas grid with reduced flows of gas (i.e. in the hybrid heat pump scenarios).
- Further research into the implications for further energy efficiency requirements – beyond what the CCC has assumed – across these heat decarbonisation pathways.
- Investigation in greater detail of the scope for H2 imports; this should include consideration of costs of solar PV, electrolysers, water productions, etc., marine transport, storage (ammonia versus liquid H2) and different locations (North Africa, Middle East, South Africa, Australia).

- Further research related to the provision of system inertia is needed to investigate the impact on the optimal portfolio of generation technologies, particularly in 0 Mt case, as the provision of synthetic inertia (e.g. by wind generation) could reduce the optimal volume of nuclear, while on the other hand, coordinated de-loading of nuclear generation during low demand and high renewable output conditions would reduce the size of the largest loss and hence enhance the value of nuclear generation.

5.2.2 Decarbonisation of electricity supply and enhancement of system flexibility

The studies demonstrate that the decarbonisation of electricity generation and improvement of system flexibility are essential, irrespective of the heat decarbonisation strategy. As the present renewable capacity, around 40 GW in total, is significantly lower than the no-regret capacity[121] (see discussions in section 2.5), this implies that the decarbonisation of electricity supply should be continued. In the short term, the development of low-carbon generation can focus on renewable power. In the medium and long-term, firm low-carbon capacity should be deployed to meet low emission carbon targets. Technologies such as nuclear, CCS and hydrogen-based CCGT/OCGT should be considered. Increased penetration of low-carbon generation capacity should be accompanied with increased flexibility in the system to minimise its system integration costs. Further knowledge and practical experience should be gained by trialling smart control systems in buildings in order to enhance the system flexibility.

5.2.3 Policy development for heat decarbonisation

At present, there is a large-scale programme underway for the decarbonisation of the electricity supply sector (i.e. a support mechanism for investment in low carbon generation). In order to facilitate investment in low-carbon heating appliances such as hydrogen boilers, heat pumps or hybrid heat pump, it would be important to review and develop further policy guidance and/or financial incentives - including the Renewable Heat Incentive (RHI)[122] - to individual end-users and/or energy communities in order to encourage and reward investment in low-carbon heating technologies. Furthermore, the price of electricity reflects the carbon content of the fuel mix, which is not the case for household currently on fossil fuel-based heating systems. A carbon price on heat should, therefore, be considered. In this context, it will be important to investigate the CO_2 reductions that could be achieved by demand-side focussed strategies, e.g. radical building energy efficiency programs.

[121] See discussions in section 2.5
[122] RHI provides financial incentive to promote the use of renewable heat including heat pumps.

5.2.4 New market design for flexibility

As demonstrated in this study, cross-energy system flexibility will be critical for facilitating a cost-effective transition to a low-carbon energy system (i.e. a reduction in investment in low carbon generation and energy conversion technologies, a reduction in system operating costs and investment in system capacity needed to meet the peak demand). In the electricity sector, there are several emerging markets focusing on new flexibility products (such as fast frequency response, demand-response reserve services, etc.). These initiatives should be extended through the development of cost-reflective flexibility markets[123] with appropriate spatial and temporal resolutions, that would link all energy vectors and facilitate competition between alternative solutions on a level playing field.

Furthermore, as demonstrated in the modelling, flexibility technologies and systems can reduce the amount of low-carbon generation needed to meet the carbon targets. However, suitable remuneration mechanisms for this value stream do not exist in the current market (and are not considered in the Electricity Market Reform). Such mechanisms should be developed to allow new flexible technologies to access revenues associated with a reduction in investment in low carbon generation through establishing the link between energy market and low-carbon agenda.

5.2.5 Pilot trials

One of the key conclusions from the studies carried out is that none of the heat decarbonisation pathways can be excluded as options for large-scale deployment, due to the proximity of overall system costs across the pathways within a significant level of uncertainty. Therefore, the focus of any action should be to address uncertainties. Knowledge and experience that will be gained from deployment at scale (i.e. 10,000s of households) will provide critical insights into the strengths and weaknesses of alternative approaches to heat decarbonisation and the technologies involved. Hence consideration should be given to a programme of technology deployment on a pilot trial basis. These initiatives should be designed to encompass all aspects of deployment - from production through to end-users - while including all types of representative buildings within the UK.

5.2.6 Carbon emission targets for energy

The studies illustrate the impact of reducing carbon emissions from energy from 30Mt to 0Mt – without decarbonisation of the heating system, residual emissions could be over 100 $MtCO_2$, which is incompatible with the UK's 2050 target. In the long-term, reducing energy system emissions to zero may be required to support other sectors that cannot

[123] This is coherent with the recommendation in the Pöyry and Imperial College's report to CCC: "Roadmap for Flexibility Services to 2030", May 2017.

achieve their share of the required greenhouse gas reductions. The consequence of this would be to substantially reduce natural gas-based technologies such as gas reforming and gas generation and would, therefore, require considerably more zero-carbon electricity generation technologies such as nuclear power and renewables, combined with energy storage. However, progress with importing hydrogen at low costs, or improving the efficiencies and carbon capture rates of gas reforming technologies could mitigate the need to build additional low-carbon electricity generation. This hydrogen production options warrant further investigation.

5.2.7 Hydrogen production demonstration plants

The two hydrogen production technologies for large-scale deployment are currently gas reforming and electrolysis. Although there is considerable experience of gas reforming it is limited to industrial applications. There is insufficient experience of electrolysis. In both cases, there is considerable uncertainty in terms of costs and performance, particularly for large-scale deployment. It would be informative to commit to build gas reforming and electrolysis demonstration plants within the UK to enable experience to be gained prior to making decisions on large-scale deployment.

Appendix A. Costs of alternative decarbonisation pathways

Figure A-1 shows the detailed cost comparison across a range of heat decarbonisation pathways discussed in section 2.4. Unless otherwise stated, all costs are expressed in terms of annual cost in real 2017 money. The capital costs are annuitized using the relevant discount factors, taking into consideration the economic life-time of the assets. The annual cost includes the fixed operating and maintenance cost.

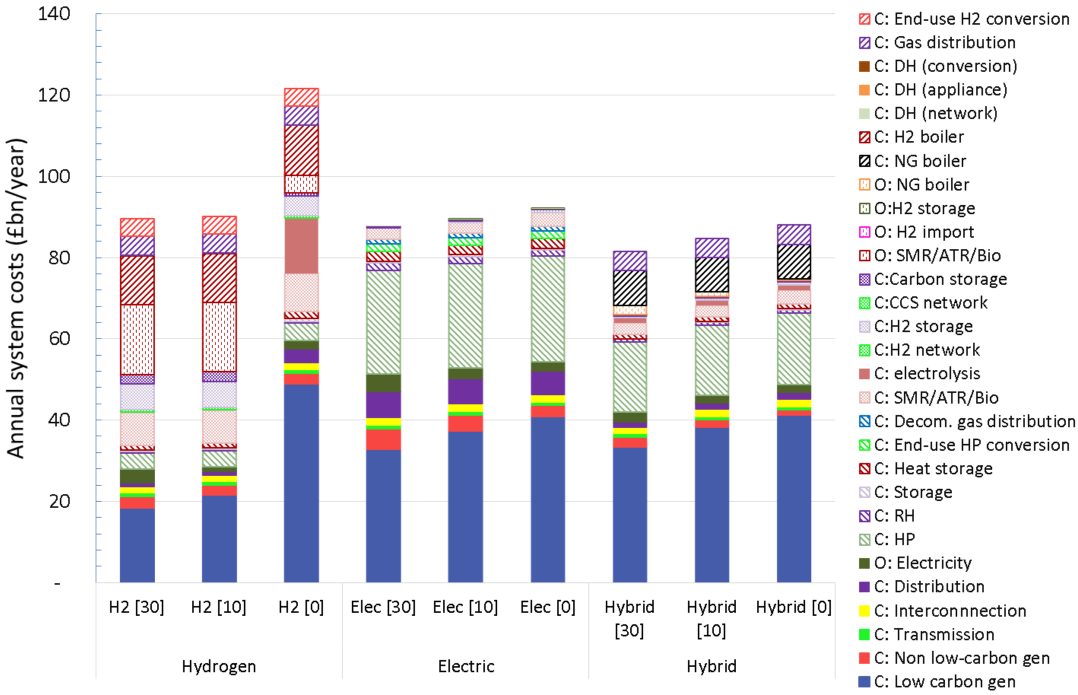


Figure A-1 Annual system cost components of hydrogen pathways in different cases

There are 29 cost components considered in the model, i.e.:

1. The capital cost of low-carbon generation [C: Low-carbon gen] which includes the capital cost of wind, PV, hydro, nuclear, CCS and H2-based generation.
2. The capital cost of non-low carbon generation [C: Non-low-carbon gen] which includes the capital cost of traditional fossil-fuel based generation such as CCGT, OCGT and CHP.

3. The capital cost of transmission [C: Transmission] which includes the cost of GB transmission network.
4. The capital cost of interconnection [C: Interconnection] which includes the cost of GB interconnectors.
5. The capital cost of distribution [C: Distribution] which includes the cost of reinforcing electricity distribution network.
6. Operating cost of electricity generation [O: Electricity] which includes the fuel cost, no-load cost and start-up cost of power generation.
7. The capital cost of heat pump [C: HP] – this includes the cost of heat pump devices, installation cost and the annual fixed operating and maintenance cost.
8. The capital cost of resistive heating [C:RH] - this includes the cost of resistive heating devices, installation cost and the annual fixed operating and maintenance cost.
9. The capital cost of electricity storage [C:Storage] which includes the cost of electricity storage in the system.
10. The capital cost of heat storage [C:Heat storage] which consists of the cost of domestic and district heating TES.
11. Conversion cost associated with replacing gas-based heating to electric heating [C: End-use HP conversion] which includes the cost of decommissioning gas-based heating systems and replacing the gas units (e.g. gas oven, gas hob) with the electrical appliances.
12. Cost of decommissioning gas distribution – this cost occurs only in the Electric scenario as the gas distribution network is no longer used and therefore, it should be decommissioned. The cost is estimated at £1bn/year.
13. The capital cost of H2 production technologies excluding electrolysis [C: SMR/ATR/Bio] which includes the capital cost of building SMR, ATR, and the biomass gasification with CCS.
14. The capital cost of electrolysers [C:Electrolysis] which includes the capital cost of various electrolysers.
15. The capital cost of H2 network [C:H2 network] which consists of the cost of building national H2 transmission network.
16. The capital cost of CCS network [C: CCS network] which includes the cost of building the CCS network.
17. The capital cost of H2 storage [C:H2 storage] which consists of the capital cost of both underground and overground storage.
18. The capital cost of carbon storage [C: Carbon storage] which includes the cost of storing carbon captured by CCS. It is assumed that the cost of carbon storage is £15/tCO_2.
19. Operating cost of SMR/ATR [O:SMR/ATR] which includes the fuel cost used by SMR/ATR to produce H2.
20. Cost of H2 import [O:H2 import]

21. Operating cost of H2 storage [O:H2 storage]
22. Operating cost of NG-based boilers [O:NG boiler] which includes the fuel cost, i.e. the cost of natural gas used by the boilers.
23. The capital cost of NG-based boilers [C:NG boiler] which includes the cost of natural-gas-based boilers, installation, and the operating and maintenance costs.
24. The capital cost of H2-based boilers [C:H2 boiler] which includes the cost of H2 based boilers, installation, and the operating and maintenance costs.
25. The capital cost of district heating network [C:DH (network)] which includes the operating and maintenance cost of the district heating network.
26. The capital cost of district heating household appliances [C:DH (appliance) which includes the cost of household heat infrastructure needed for the district heating system, e.g. metering, heat control, and connection to the main heat network.
27. The conversion cost needed to replace the existing house heating system with H2-based district heating [C: DH (conversion)] – this is associated with the cost of decommissioning natural-gas appliances and replacing it with electric appliances, e.g. replacing the gas hob and gas oven to an electric hob and oven and to add the hot-water storage system.
28. The capital cost of gas distribution [C: gas distribution] – this is the cost of retaining the present gas distribution network. This is applied to the H2 and Hybrid pathways.
29. Conversion cost needed to replace the existing house heating system with H2-based heating (H2 boiler) [C:End-use H2 conversion] – this is associated with the cost of decommissioning natural-gas appliances and replacing it either with H2-compliance or electric appliances.

The following tables provide more detailed information about the costs , optimal capacity and energy production in the core heat decarbonisation scenarios.

Cost (in million £/year)	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
C: Low carbon gen	18,505	21,650	48,896	32,911	37,281	40,858	33,452	38,357	41,294
C: Non low-carbon gen	2,835	2,465	2,655	4,963	4,076	2,784	2,455	1,726	1,223
C: Transmission	855	880	902	1,026	917	865	930	880	868
C: Interconnnection	1,515	1,515	1,786	1,786	1,786	1,786	1,515	1,786	1,786
C: Distribution	956	920	3,321	6,397	6,240	5,877	1,322	1,553	1,829
O: Electricity	3,351	1,163	2,172	4,365	2,670	2,164	2,437	1,842	1,780
C: HP	3,977	3,985	4,236	25,431	25,624	26,063	17,085	17,182	17,561
C: RH	347	342	283	1,800	1,674	1,478	854	900	886
C: Storage	243	269	800	510	495	521	64	96	196
C: Heat storage	1,288	1,235	1,730	2,393	2,266	2,342	1,089	1,187	1,233
C: End-use HP conversion	-	-	-	1,935	1,935	1,935	-	-	-
C: Decom. gas distribution	-	-	-	1,000	1,000	1,000	-	-	-
C: SMR	8,030	8,029	9,386	2,769	2,769	3,452	2,769	2,799	3,394
C: electrolysis	58	136	13,726	2	1	4	1,276	1,286	1,245
C:H2 network	592	582	509	-	-	-	-	-	-
C:H2 storage	6,441	6,415	4,823	155	403	699	455	523	835
C:CCS network	-	-	-	-	-	-	-	-	-
C:Carbon storage	2,307	2,303	815	311	311	311	311	311	311
O: SMR	17,123	17,092	4,334	-	-	-	-	-	-
O:H2 storage	3	3	6	0	0	0	1	1	1
O: NG boiler	-	-	-	-	-	-	2,329	1,194	458
C: NG boiler	-	-	-	-	-	-	8,452	8,410	8,366
C: H2 boiler	12,098	12,099	12,251	-	-	-	-	-	-
C: Gas distribution	4,733	4,733	4,733	-	-	-	4,733	4,733	4,733
C: End-use H2 conversion	4,325	4,325	4,325	-	-	-	-	-	-
C: DH (network)	41	41	41	41	41	41	41	41	41
Total	89,623	90,181	121,731	87,794	89,490	92,182	81,569	84,806	88,041

	H2 [30]	*H2 [10]*	*H2 [0]*	*Elec [30]*	*Elec [10]*	*Elec [0]*	*Hybrid [30]*	*Hybrid [10]*	*Hybrid [0]*
Electricity demand (TWh/year)									
Non-transport and non-heat demand	306	306	305	306	306	306	306	306	306
Electric heating	28	28	27	280	280	280	208	235	254
Electric transport	111	111	111	111	111	111	111	111	111
Smart domestic appliance	62	62	62	62	62	62	62	62	62
Electrolyser	1	4	441	0	0	0	48	48	48
Storage	6	9	0	8	8	8	4	4	6
Total	514	519	946	767	766	767	739	766	787
Electricity generation (GW)									
H2 CCGT	12	14	3	12	15	23	7	8	14
H2 OCGT	0	0	5	27	27	24	8	10	9
NG CCGT	30	19	11	41	28	13	26	11	0
NG OCGT	15	21	6	106	98	79	9	11	13
Post-combustion CCS	0	0	0	0	0	0	0	0	0
Nuclear	5	5	45	13	27	43	19	35	45
Wind	77	92	120	117	104	74	115	98	82
PV	63	76	150	146	128	129	110	99	103
Hydro	1	1	1	1	1	1	1	1	1
Storage	7	8	18	12	12	12	4	4	6
District CHP	8	9	18	0	0	0	8	8	8
Total	211	237	360	476	440	399	299	277	273

	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
Electricity generation (TWh/year)									
H2 CCGT	50	50	0	54	54	54	34	34	34
H2 OCGT	0	0	0	0	0	0	0	0	0
NG CCGT	74	19	10	80	30	5	41	11	0
NG OCGT	1	2	0	7	5	4	0	0	0
Post-combustion CCS	0	0	0	0	0	0	0	0	0
Nuclear	39	42	354	104	213	340	148	273	354
Wind	253	298	408	383	340	241	383	323	270
PV	56	65	139	124	109	108	95	86	89
Hydro	8	8	8	8	8	8	8	8	8
Storage	5	7	0	6	6	6	3	3	4
District CHP	28	28	26	-	-	-	28	28	28
Total	514	519	946	766	766	767	739	766	787
Heating (TWh of heat delivered)									
NG Boiler	-	-	-	-	-	-	92	48	18
H2 Boiler	532	532	532	-	-	-	-	-	-
RH	6	6	5	52	51	51	19	32	44
District CHP	40	40	38	-	-	-	39	39	39
HP	56	56	57	556	556	557	492	525	545
District HP	0	0	0	41	40	40	0	0	0
Total	634	634	632	648	648	648	644	645	646

	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
H2 production capacity (GW)									
ATR + CCS	90	90	90	-	-	-	-	-	-
Electrolyser	1	2	106	0	0	0	10	10	10
Biomass + CCS	12	12	18	12	12	15	12	12	14
H2 production (TWh)									
ATR + CCS	663	661	168	-	-	-	-	-	-
Electrolyser	1	3	406	0	0	0	44	44	44
Biomass + CCS	93	93	93	93	93	93	93	93	93
Biogas (TWh)									
Biogas	21	21	21	21	21	21	21	21	21
H2 storage (GWh)									
Underground	17,827	17,582	11,489	3	2	7	231	287	418
Overground (medium pressure)	1,733	1,756	1,501	128	334	578	335	382	616

Appendix B. Household conversion and heating appliance cost

The household conversion and heating appliance costs used in this study are presented in the following table.

Table B-1 Household conversion and heating appliance cost

Action required	H2 heating £3k including gas pipe upgrade	Electric - Heat pump (5kWth)and resistive heating (1 kWth), preheating (3.6 kWth), thermal storage (1.7 kWth)	Hybrid heat pump with natural gas (HP:4 kWth, gas boiler: 10kWth, thermal storage: 1.7kWth)	Small heat pump (£1k/kWth) with supplementary electric heating (£.2k/kWth) (Assume 5kWth for heat pump and 5kWth for electric heating) £6k	District heating £6.8k	Resistive heating £150/kWth (Assume 10kWth)	Hybrid resistive heating with natural gas (RH:4 kWth, gas boiler: 10kWth, thermal storage: 1.7kWth)
Decommission and/ or replace gas/oil boiler 24.9M (est.)	Yes – boiler will require replacing in order to operate on hydrogen	Yes – if a gas boiler is already installed it will require decommissioning - £0.5k	Not necessarily – gas boiler could be retained to operate as a bivalent system or for a unit HHP included in cost	Yes – if a gas boiler is installed it will require decommissioning - £0.5k	Yes – if a gas boiler is installed it will require decommissioning - £0.5k	Yes – if a gas boiler is installed it will require decommissioning - £0.5k	Not necessarily – gas boiler could be retained to operate as a bivalent system or for a unit HRH included in cost
Decommission and/or replace gas hob 14.8M2 or 59% See T3.12	Yes – no evidence that hydrogen can operate safely on open flame devices. Replace with electric hob - £0.5k	Yes – if a gas hob is installed it will require decommissioning and replacing with an electric hob - £0.5k	No – but this would add about 0.4MWhpapto consumer gas demand for gas hob	Yes – if a gas hob is installed it will require decommissioning and replacing with an electric hob - £0.5k	Yes – if a gas hob is installed it will require decommissioning and replacing with an electric hob - £0.5k	Yes – if a gas hob is installed it will require decommissioning and replacing with an electric hob - £0.5k	No – but this would add about 0.4MWhpapto consumer gas demand for gas hob
Decommission and/or replace gas oven 8.4M3 or 34% See T3.12	Yes – no evidence that hydrogen can operate safely on open flame devices. Replace with electric oven - £0.5k	Yes – if a gas oven is installed it will require decommissioning and replacing with an electric oven - £0.5k	No – see above 0.2MWhpa	Yes – if a gas oven is installed it will require decommissioning and replacing with an electric oven - £0.5k	Yes – if a gas oven is installed it will require decommissioning and replacing with an electric oven - £0.5k	Yes – if a gas oven is installed it will require decommissioning and replacing with an electric oven - £0.5k	No – see above 0.2MWhpa
Decommission and/or replace other gas appliances Assume 23.9M4 or 96% See T3.18	Yes – no evidence that hydrogen can operate safely on open flame devices. Replace with electric appliance - £0.5k	Yes – if other gas appliances are installed they will require decommissioning and replacing with an electric appliances (note 6)	No but this would add to consumer demand	Yes – if other gas appliances are installed they will require decommissioning and replacing with an electric appliances (note 6)	Yes – if other gas appliances are installed they will require decommissioning and replacing with an electric appliances (note 6)	Yes – if other gas appliances are installed they will require decommissioning and replacing with an electric appliances (note 6)	No but this would add to consumer demand
Replace/ upgrade / decommission (wet) heat emitters	No	Yes replacing/ upgrading required to compensate for lower flow temperatures (note 7)	No	Yes replacing/ upgrading required to compensate for lower flow temperatures - £0.5k	No	Yes – heat emitters will require decommissioning - £0.5k	No
Replace/ install hot water system with storage Assume 13.9M5 (est.) See T3.19	No	Yes – hot water storage will be required but assume it is included with heat pump. Domestic TES: 1.7kWth [£0.34k]	No but this would add 2MWhpa to consumer gas demand	Yes – hot water storage will be required but assume it is included with heat pump	Yes – hot water storage will be required - £1k	Yes – hot water storage will be required - £1k	No but this would add 2MWhpa to consumer gas demand

Action required	H2 heating £3k including gas pipe upgrade	Electric - Heat pump (5kWth)and resistive heating (1 kWth), preheating (3.6 kWth), thermal storage (1.7 kWth)	Hybrid heat pump with natural gas (HP:4 kWth, gas boiler: 10kWth, thermal storage: 1.7kWth)	Small heat pump (£1k/kWth) with supplementary electric heating (£.2k/kWth) (Assume 5kWth for heat pump and 5kWth for electric heating) £6k	District heating £6.8k	Resistive heating £150/kWth (Assume 10kWth)	Hybrid resistive heating with natural gas (RH:4 kWth, gas boiler: 10kWth, thermal storage: 1.7kWth)
Indicative building maximum space heating demand?	Not essential for heating performance	10MWhpa	10MWhpa	10MWhpa	Not essential for heating performance	7MWhpa	10MWhpa
Appliance cost (see note 7-11)	**£3.0k**	**£5.0k**	**£6.0k**	**£6.0k**	**£6.8k**	**£1.5k**	**£3.6k**
Conversion costs (see note 12)	**£1.0k**	**£1.0k**	**£0.0k**	**£1.5k**	**£1.0k**	**£2.5k**	**£0.0k**
Total costs	**£4.0k**	**£6.0k**	**£6.0k**	**£7.5k**	**£7.8k**	**£4.0k**	**£3.6k**

Notes:

1. 23.9M gas and 1.0M oil households with boilers - see T3.18 in ECUK_2017
2. There are 12.2M electric hobs and 3.1M households without gas and so must have electric hobs. Hence 9.1M gas households have electric already leaving 14.8M with gas hobs.
3. There are 18.6M electric ovens and 3.1M households without gas and so must have electric ovens. Hence 15.5M gas households have electric already leaving 8.4M with gas ovens.
4. There are 23.9M gas households so assume all have at least one other gas appliance.
5. There are 13.9M households with combination boilers and so assume there is no hot water storage.
6. Following discussion with CCC, the cost of decommission other gas applianced is included in the cost of decommissioning gas boiler.
7. The cost is included in the installation cost of heat pump.
8. Cost of H2 boiler is £3000/household.
9. Cost of Electric heating is around £5k/household. This includes the cost of 5kWth HP (£3000), 1kW$_{th}$ RH (£120), 1.7 kW$_{th}$ TES(£340), installation cost (£1500).
10. Cost of Hybrid Heat Pump is around £6k/household. This includes the cost of 4kWth HP(£2700), NG boiler (£750), TES(£340), installation cost (£2200)]. A conservative assumption is taken that the cost of 4 kW HP is 90% the cost of 5 kW HP. The cost does not decrease linearly.
11. Cost of Hybrid resistive heating is around £3.6k/household. This includes the cost of 4kW$_{th}$ RH(£480), NG boiler (£750), TES(£340), installation cost (£2000).
12. If both gas oven and gas hob need to be decommissioned and replaced with electric hob and oven, the cost remains £0.5k.
13. Another scenario that has been analysed in the Hybrid pathway, involves 10 GW of fuel cell based micro-CHP. In this scenario, the cost of micro-CHP is

assumed to be £2500/kW(e), with the installation cost of £1000/household with the operating and maintenance cost of £100/year. The capacity of micro-CHP per household is 3 kW; also hydrogen boiler is used. The household conversion cost for households with micro-CHP is the same as in the H2 pathway.

The cost of heat networks in the district heating study is based on the BEIS report in 2015[124].

[124] Department of Energy and Climate Change, "Assessment of the Costs, Performance, Characteristics of UK Heat networks," 2015. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/424254/heat_networks.pdf

Appendix C. Heat demand sensitivities

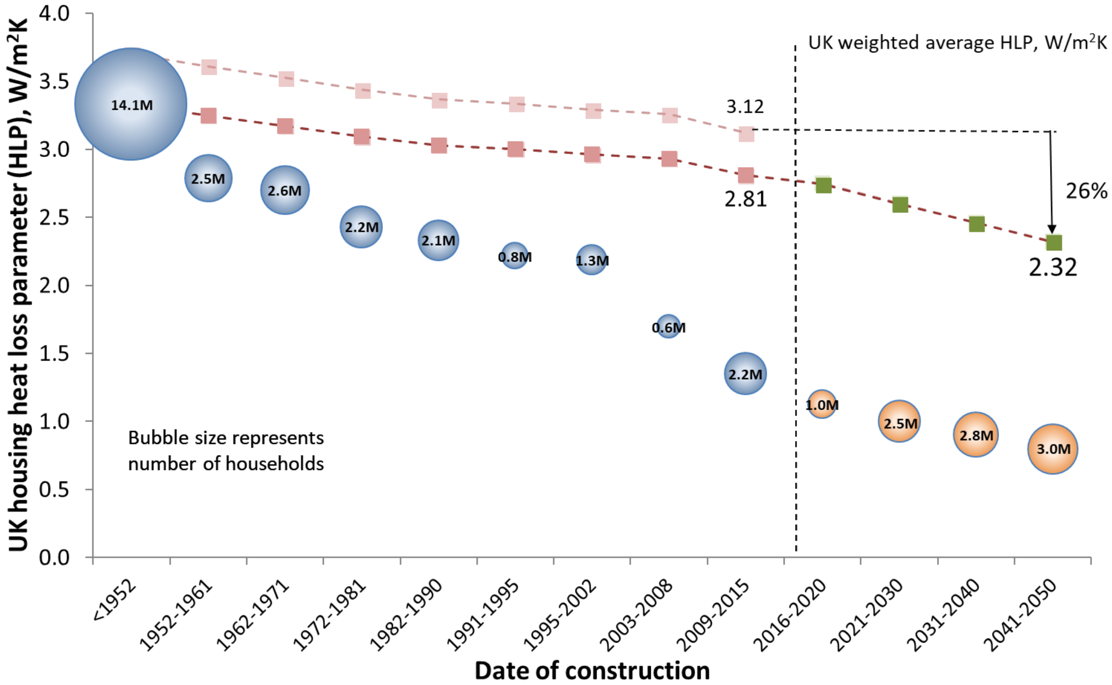


Figure C-2 Housing insulation pathway with 10% improvement in existing housing insulation

Figure C-1 shows an estimate of UK housing insulation pathway by date of construction and number of households against their heat loss parameter (W/m^2K) with a 10% improvement in existing (up to 2015) housing insulation by 2050. Added to the figure are projections of future housing stock with assumptions on insulation levels. It can be seen that based on these assumptions the weighted average housing insulation falls from the current level of 3.12 W/m^2K to 2.32W/ W/m^2K, ~26% by 2050. This improvement is more than the projected increase in households (from 27.1 M to 32.9 M[125] households) and so the overall impact is a small reduction in national annual household heat demand.

A "Low demand" sensitivity was constructed based on a 30% improvement in existing household insulation levels. This is shown in figure C-2 and results in a reduction in the weighted average housing insulation from the current level of 3.12 W/m^2K to 2.55

[125] This number was used in a different study to project the impact of increased future housing stock on the space heating demand. The number of households used in the main studies is 34.4M.

W/m^{2}K, ~40% by 2050. This more than offsets the increase in the number of households and results in a reduction in annual household heat demand from 349 TWh to 290 TWh by 2050.

Space heating demand is very much affected by external temperature. UK climate projections 2009 (UKCP09[126]) includes changes in winter mean temperatures of ~+2°C. Applying a Climate Change Adjustment (CCA) based on this increase and assuming no change to other influencing variables results in an estimated reduction in annual household heat demand from 290 TWh (Low demand) to 234 TWh (Low demand with CCA).

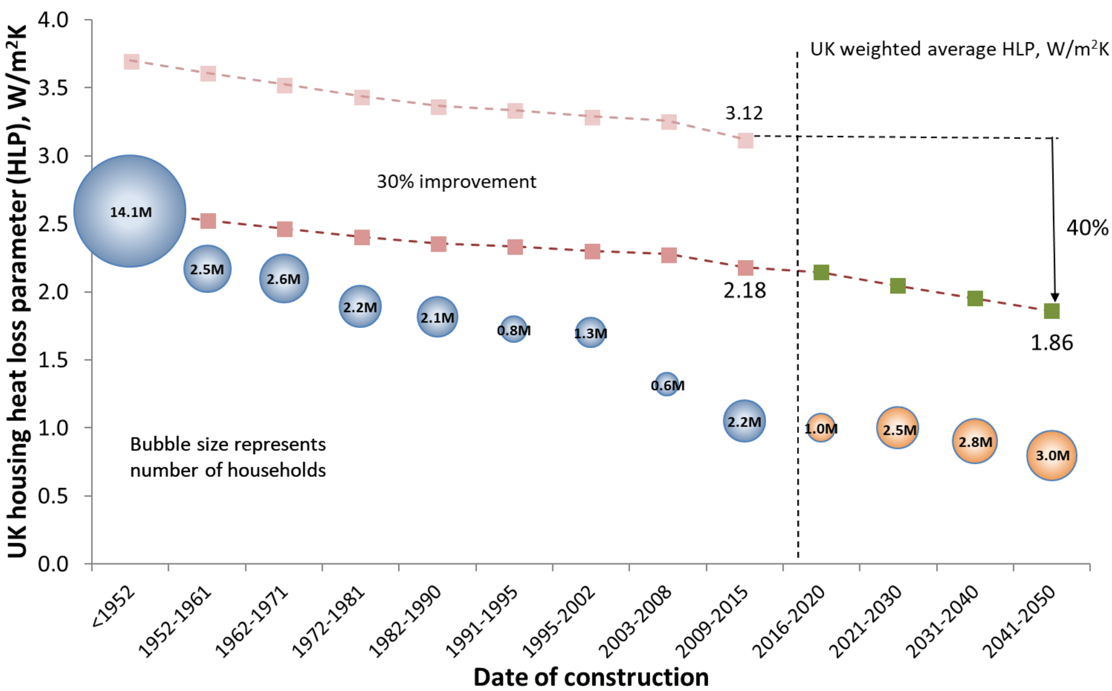


Figure C-2 Housing insulation pathway with 30% improvement in existing housing insulation

[126] Murphy, JM et al (2009) UK Climate Projections Science Report: Climate change projections

Appendix D. Feasibility of transporting hydrogen using existing gas distribution system

D.1 Objective

Hydrogen's volumetric energy density is only around 30% of the volumetric energy density of natural gas. This implies that more than three times volume of gas (hydrogen) has to be supplied to consumer premises via gas distribution networks to meet the same energy demand. This raises a question whether the existing capacity of gas distribution networks, if it is converted into hydrogen networks, can be used for hydrogen transport without significant reinforcement. The objective of this study is to investigate the technical capability of the existing gas distribution networks at various pressure tiers (i.e. high, medium and low pressure) to transport hydrogen instead of natural gas. In particular, this study (a) examines whether the existing gas distribution networks are capable of meeting peak energy demand via hydrogen and (b) quantifies the GB-wide hydrogen storage capacity required to meet heat demand. Safety issues, leakage rates related to the use and transporting hydrogen are important issues but not in the scope of this analysis.

A gas network-modelling tool was developed to analyse and compare transporting hydrogen and natural gas in a number of test networks. The capacity of hydrogen storage required to enable the distribution networks to meet peak energy demand using hydrogen was quantified for the test networks. The hydrogen storage capacity for the test networks was used to extrapolate required storage capacity for hydrogen across Great Britain's gas distribution systems. The modelling results suggest between 131 GWh to 333 GWh[127] distributed hydrogen storage capacity is required to enable the existing gas distribution networks across GB to meet the energy demand using hydrogen. While the total volume is relatively small (less than 5% of the overall gas storage capacity in the UK), the location of storage is also important to ensure sufficient local hydrogen supply capacity.

[127] It requires around 40-100 mcm of gas storage.

D.2 Methodology

To examine whether the existing gas distribution networks are capable of meeting energy demand using hydrogen, and investigate required expansion in terms of hydrogen storage, a methodology, shown in Figure D-1, was proposed. The proposed methodology consists of three main steps: (1) a modelling tool based on Combined Gas and Electricity Networks (CGEN) model[128] was developed for analysing hydrogen and natural gas transport via distribution pipelines, (2) a number of test networks representing low, medium and high pressure gas distribution networks were modelled and the hydrogen storage capacity required for these networks to meet peak energy demand was quantified, and (3) using regression models, hydrogen storage capacity for local distribution zones across GB was estimated.

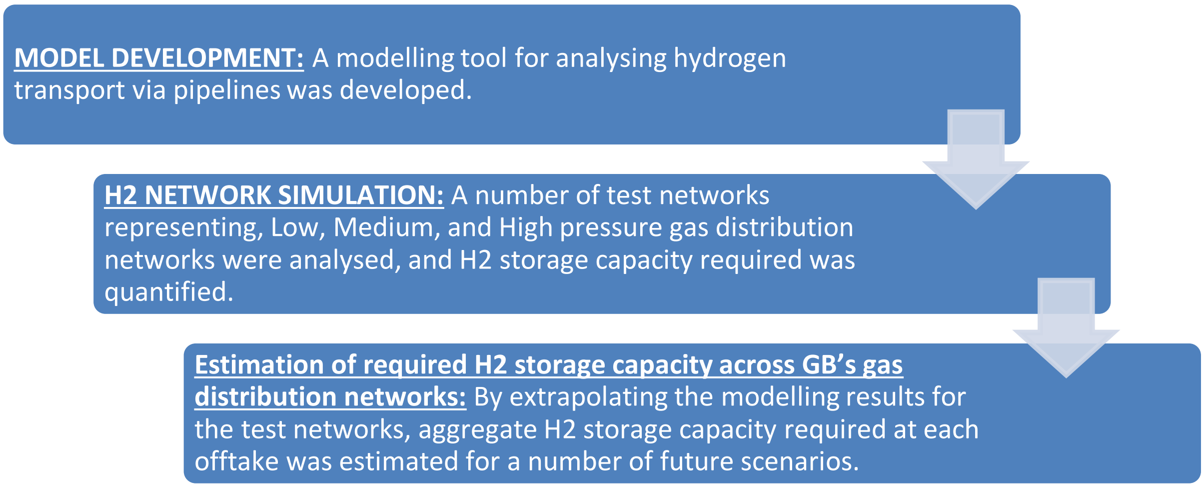


Figure D-1 Structure of the methodologies

Different steps of the methodology are described below.

D.1.1 Gas network modelling

Figure D-2 shows the structure of the model that was developed to analyse the operation of distribution networks for natural gas and hydrogen. The gas network model was developed based on the Combined Gas and Electricity Networks model (CGEN). The model is able to simulate gas networks at various pressure tiers for natural gas and hydrogen.

[128] M. Qadrdan, H. Ameli, G. Strbac, and N. Jenkins, "Efficacy of options to address balancing challenges: Integrated gas and electricity perspectives," Appl. Energy, vol. 190, 2017

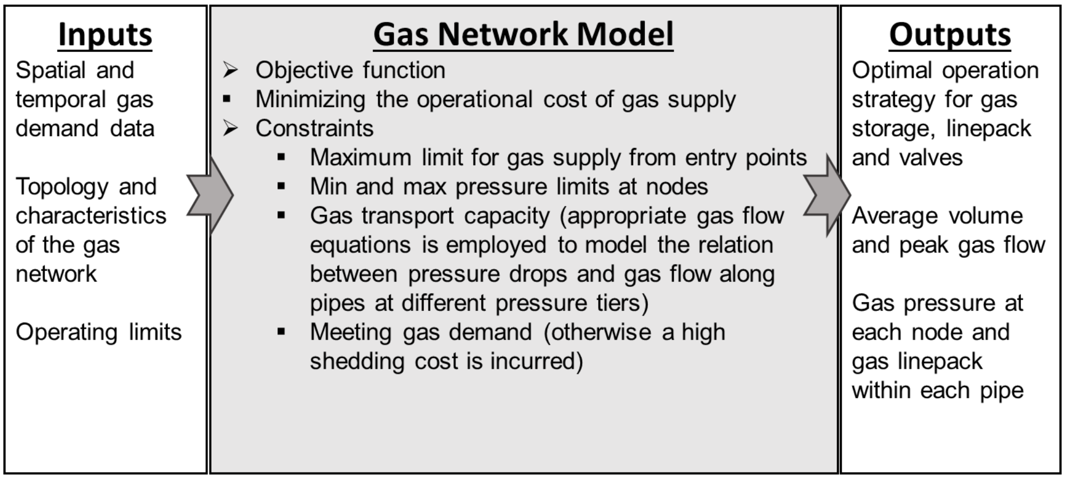


Figure D-2 Structure of the model for analysing gas networks operation

A sequential steady-state model was developed to analyse the detailed operation of natural gas and hydrogen distribution networks.

D.3 Case studies

A number of test networks representing various pressure tiers are modelled to analyse the impacts of transporting hydrogen and quantify the required hydrogen storage capacity. The test networks include three low-pressure networks (LP#1, LP#2 and LP#3), one medium pressure network (MP) and three high-pressure networks (HP#1, HP#2 and HP#3). Detailed information of the test networks including the network topology (pipes connection) and characteristics (pipes length and diameter), and energy demand is provided in Appendix E.

For each test network, two simulations were conducted: (1) *Natural Gas*: transporting 100% natural gas, and (2) *Hydrogen*: transporting 100% hydrogen. As the networks are primarily designed to meet the peak energy demand using natural gas, they have no unserved energy in NG cases. The network simulation results for hydrogen transport (H2 cases) inform if the networks are also capable of using hydrogen to meet peak energy demand. The additional hydrogen storage capacity needed to enable the distribution systems to meet energy demand using hydrogen were calculated based on the total amount of unserved hydrogen in H2 cases.

D.4 Key results

D.4.1 Impacts of hydrogen transport on low-pressure networks

The modelling results for LP#1 (Figure D-4) and LP#2 (Figure D-6) show that the transportation of larger volume of hydrogen has negligible impacts on the networks' pressure profiles (see Figure D-3 and Figure D-5) and consequently their capability to meet energy demand. This is mainly due to the lower specific gravity of hydrogen compared to natural gas which makes the hydrogen to travel faster along a pipe. Given the small size of the LP systems (short pipelines), almost the same pressure difference across a pipe establish three times larger volumetric flow for hydrogen compared to natural gas. Therefore, it can be concluded that transporting hydrogen using the existing low-pressure distribution networks (assuming the energy demand remain unchanged) is feasible from the supply capacity point of view. For example, at node 11, which is the farthest node from the supply point (node 1), the absolute pressure of hydrogen is insignificantly smaller than the pressure of natural gas. The same finding is also observed in the case of LP#2 system which has a more complex system topology.

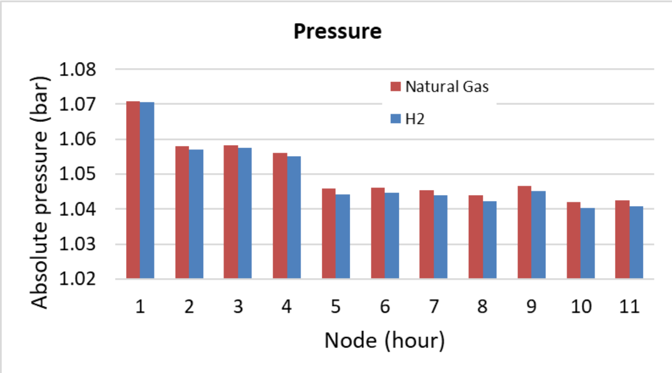


Figure D-3 Pressure profile for NG and H2 in LP#1

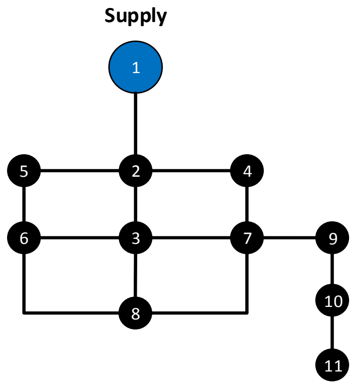


Figure D-4 Low-pressure network #1 (LP#1)

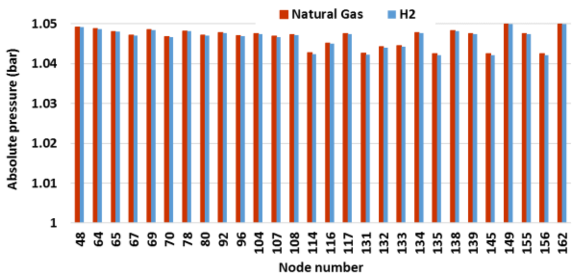


Figure D-5 Pressure profile for NG and H2 in LP#2

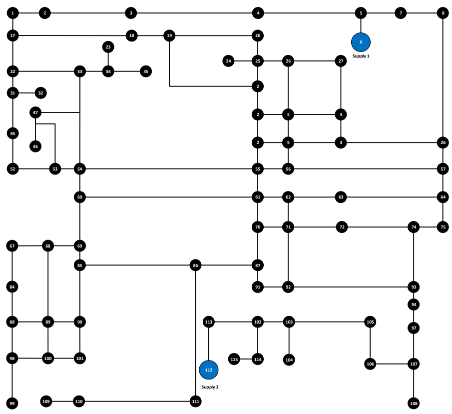


Figure D-6 Low-pressure network #2 (LP#2)

D.4.2 Impacts of hydrogen transport on medium pressure networks

Similar to the LP networks, our analysis shows in the MP network, there is no significant difference between pressure profiles of H2 and NG cases. Therefore, the transport capacity of the network is not affected. Figure D-7 shows the pressure profile across the MP network (Figure D-8).

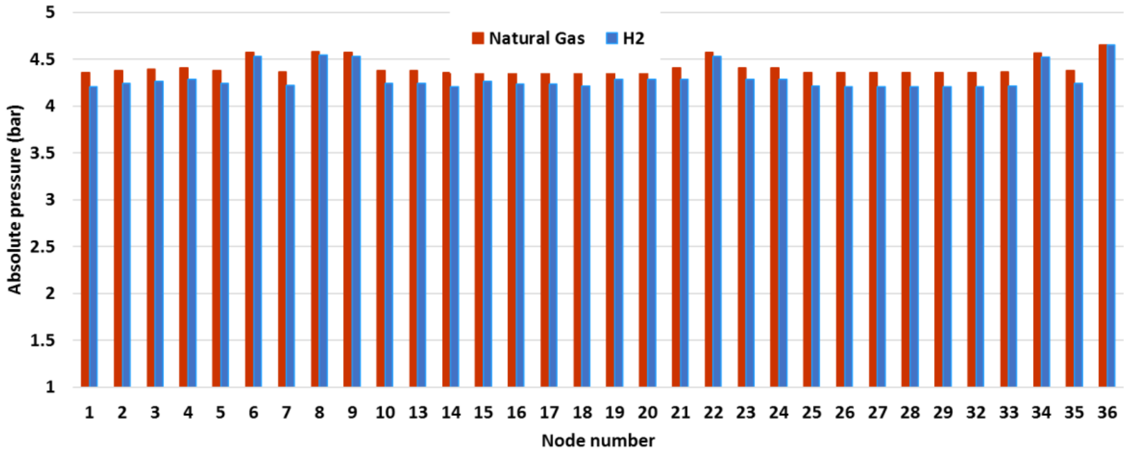


Figure D-7 Pressure profile for NG and H2 in MP

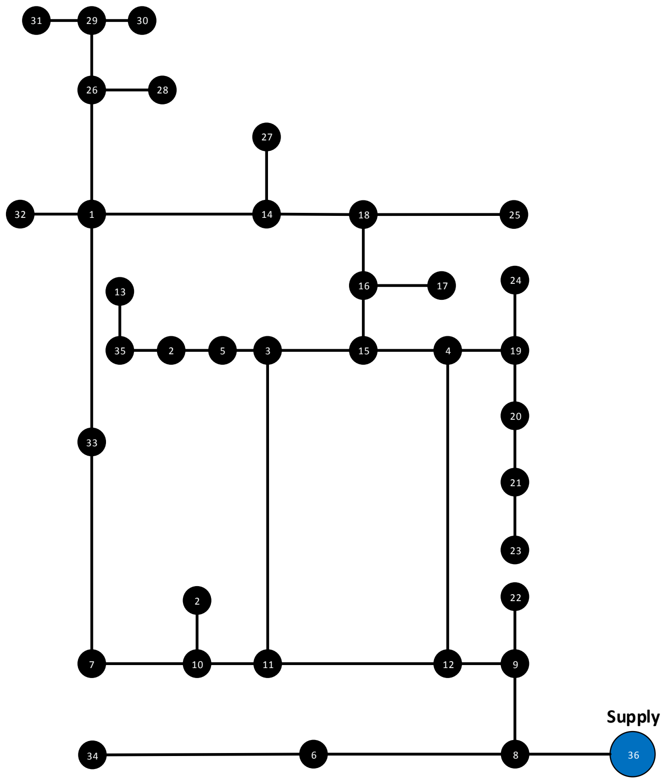


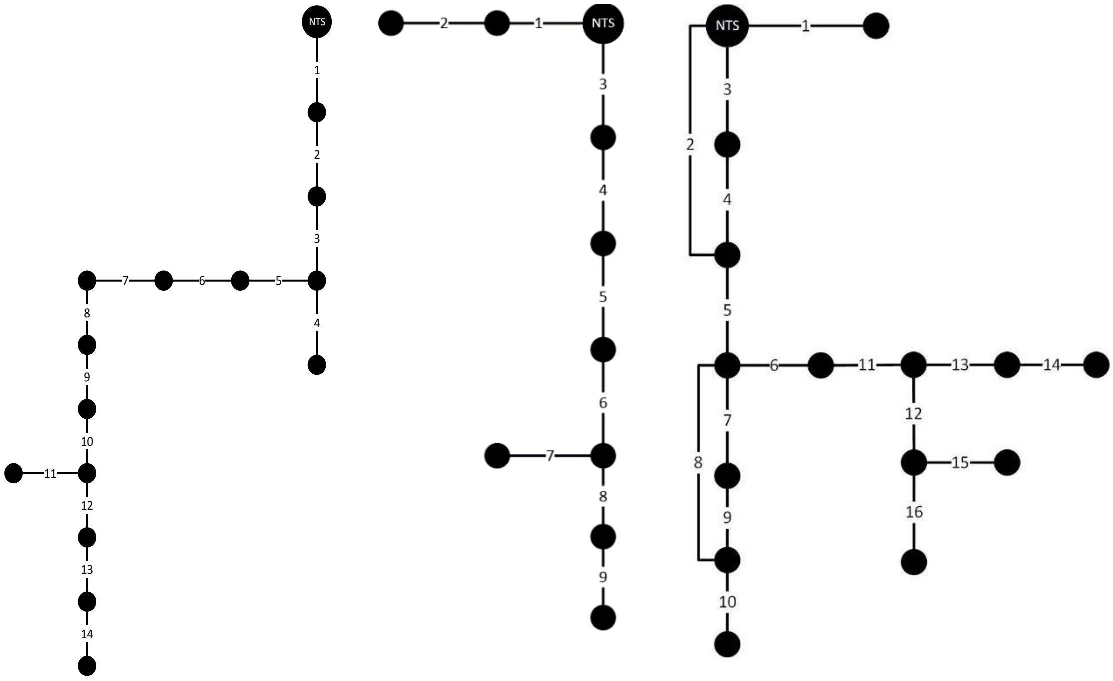
Figure D-8 Medium pressure network (MP)

D.4.3 Impacts of hydrogen transport on high-pressure networks

Three high-pressure test networks were simulated (Figure D-9). The simulation results show, for all the HP test networks, using hydrogen to meet the peak energy demand would result in unserved energy. Unlike, low and medium pressure networks in which the size of the networks are small, and therefore the within pipes storage is negligible, in the high-pressure networks the within pipes storage or ‘linepack’ plays a crucial role in meeting energy demand during peak hours. The lower density of hydrogen compared to natural gas reduced the available linepack in the HP networks and constrained their energy supply capacity.

Figure D-10 shows how linepack in the HP#1 changes in response to the varying energy demand (see Figure E-1 in Appendix E for the normalised hourly energy demand profile) in the case of natural gas and hydrogen. In particular, the linepack is used extensively during the evening peak (i.e. from 18:00 to 21:00). In the case of H2, considering the same supply pressure, the energy stored in the pipes are smaller than the case of NG, due to the lower density of hydrogen. Therefore, during the evening peak demand the stored hydrogen within the pipes is not sufficient to support meeting the energy demand, and consequently, almost 4 GWh of energy demand remain unserved.

The simulations conducted for HP#2 and HP#3 also suggest 0.5 GWh and 1.6 GWh unserved energy, respectively, when the networks transport hydrogen instead of natural gas. In order to avoid unserved energy in the high-pressure networks, new hydrogen storage with a capacity equal to the unserved energy are required. The hydrogen capacity requirements for the three test systems are summarised in Table D-1.



HP#1 HP#2 **HP#3**

Figure D-9 High-pressure test networks

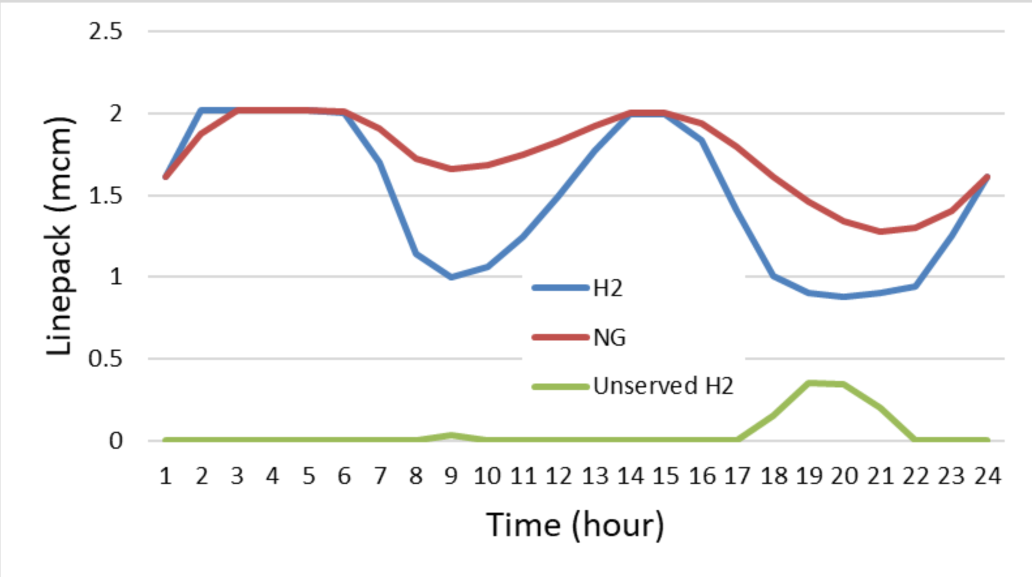


Figure D-10 Comparison of linepack and unserved energy in the case of natural gas and hydrogen transport for HP#1

Table D-1 Unserved energy demand for high-pressure networks transporting hydrogen

Network	Daily energy demand (GWh)	Unserved energy in H2 case (GWh) (i.e. hydrogen storage capacity required)
HP#1	104.5	4
HP#2	41.8	0.5
HP#3	79.2	1.6

D.4.4 Estimation of hydrogen storage capacity needed across GB gas distribution networks

From the modelling results for hydrogen transport in various pressure tiers, it was observed that there is no supply constraint for low and medium pressure networks, while in the high-pressure networks there is a need for hydrogen storage to avoid unserved energy demand. Therefore, to estimate required infrastructure expansion, in terms of hydrogen storage, to enable GB distribution networks to meet energy demand using hydrogen, the focus should be on high-pressure distribution networks.

Due to the challenges of accessing detailed networks data for all Local Distribution Zones (LDZ) in GB, it was not feasible to quantify the hydrogen storage capacity required for each individual LDZ via explicit network modelling. Therefore, the modelling results for the three high-pressure test networks were used along with a regression method to estimate the relationship between peak energy demand of a high-pressure gas distribution network and its required hydrogen storage capacity. Given the peak energy demand for various LDZ across GB, the regression model then was applied to estimate the required hydrogen storage capacity for each LDZ. A table of estimated hydrogen storage capacity in different GB regions can be found in Appendix E.

Figure D-11 shows the regression model based on the results of the three high-pressure test networks with peak gas demand of 104.5 GWh (9.5 mcm natural gas) for HP #1, 41.8 GWh (3.8 mcm natural gas) for HP #2, and 79.2 GWh (7.2 mcm natural gas) for HP #3. The estimated capacity of hydrogen storage required for each LDZ using this regression model is shown in Figure D-11 under “H2 storage - Low”. Using the regression model shown in Figure D-11, it is estimated that 131 GWh hydrogen storage capacity is required across the all LDZ to realise the conversion of the GB gas distribution networks to hydrogen networks.

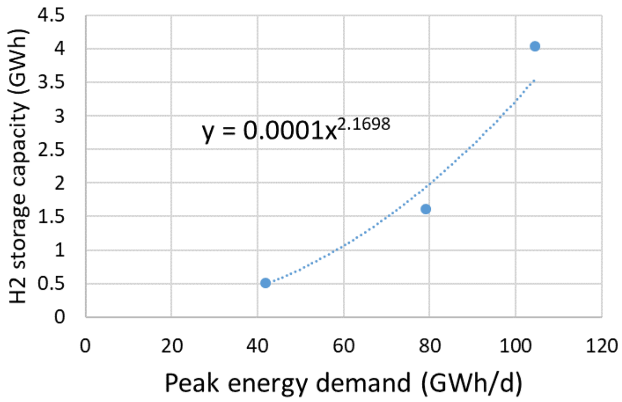


Figure D-11 Relationship between required hydrogen storage capacity and peak gas demand (regression 1)

The proposed regression model in Figure D-11, assumes different high-pressure distribution networks with the same peak energy demand require the same capacity of hydrogen storage. However, the capacity of hydrogen storage needed to enable a specific network to deliver the peak energy demand using 100% hydrogen, not only depends on peak energy demand but also is affected by the size of the network in terms of length and volume within pipelines. Therefore, to account of the impacts of different network characteristics, the peak energy demand of each high-pressure test networks, used for the other two networks and simulation was performed to quantify the hydrogen storage capacity required for each case to avoid unserved energy. A second regression model, shown in Figure D-12 resulted in a higher estimate of hydrogen storage capacity for LDZ totalling 333 GWh.

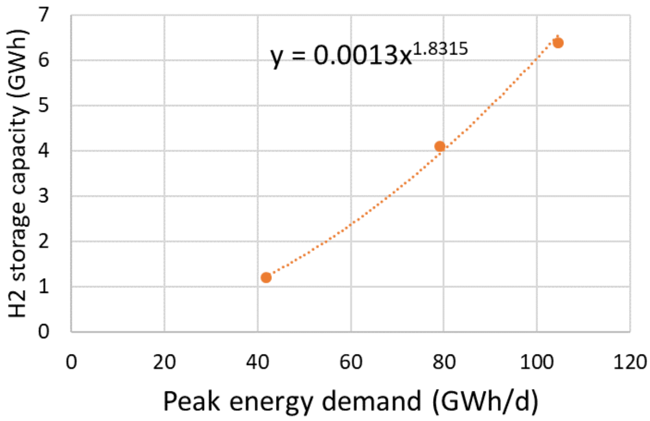


Figure D-12 Relationship between required hydrogen storage capacity and peak gas demand (regression 2)

Based on the modelling results which indicate the requirement for 131 – 333 GWh of hydrogen storage, the investment cost of the storage is estimated around £0.35bn/year to £0.61 bn/year. It is important to note that this cost is on top of the investment cost in hydrogen salt-cavern storage.

Appendix E. Gas network data

In this section, the characteristics of the studied gas distribution networks, including network topology, pipe data, and hourly demand are presented.

Normalised hourly energy demand

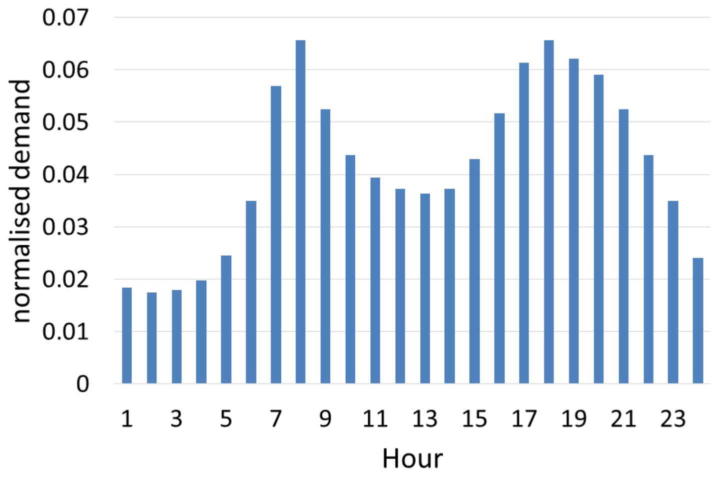
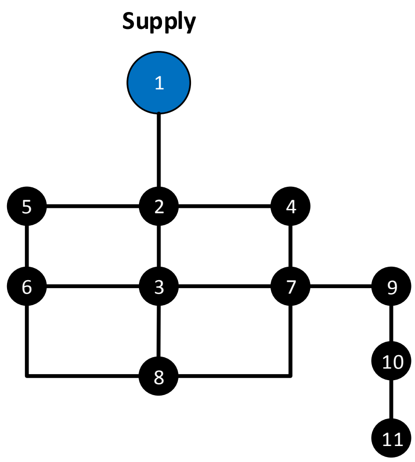


Figure E-1 Normalised demand for gas networks. The value of the bar chart at each hour shows the ratio of the energy demand at that specific time to the daily energy demand.

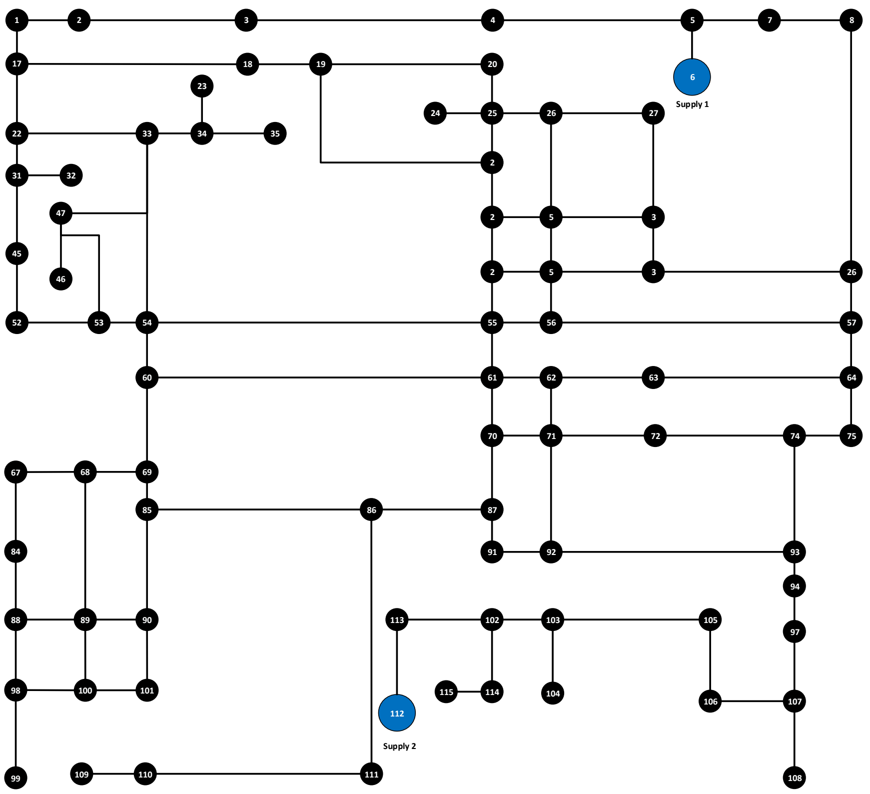
Low Pressure Network – LP#1



Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	1	2	50	0.16
2	2	3	500	0.16
3	2	4	500	0.11
4	2	5	500	0.11
5	3	6	600	0.11
6	3	7	600	0.11
7	3	8	500	0.11
8	5	6	600	0.08
9	4	7	600	0.08
10	6	8	780	0.08
11	7	8	780	0.08
12	7	9	200	0.08
13	9	10	200	0.08
14	10	11	200	0.08

Node No.	Gas peak demand (cm)
1	0
2	3462.0797
3	3046.6667
4	2769.5723
5	3600.5507
6	2492.6303
7	692.355
8	3254.297
9	761.66667
10	657.77533
11	484.57233

Low Pressure Network – LP#2



Network characteristic for LP#2:

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)	Pipe No.	From Node	To Node	Length (m)	Diameter (mm)

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)	Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	53	54	240	150	**55**	103	105	492	150
2	54	55	456	150	**56**	105	106	230	150
3	55	56	702	150	**57**	106	107	289	150
4	56	57	653	150	**58**	107	108	276	150
5	60	54	43	100	**59**	109	110	322	80
6	60	61	446	150	**60**	110	111	220	80
7	60	69	66	100	**61**	112	113	184	300
8	61	55	75	150	**62**	115	114	164	100
9	61	62	709	150	**63**	1	2	184	300
10	61	70	266	200	**64**	1	17	52	150
11	62	63	656	150	**65**	2	3	308	300
12	62	71	302	100	**66**	3	4	817	300
13	63	64	33	200	**67**	4	5	922	300
14	63	74	322	200	**68**	5	6	102	400
15	64	57	59	200	**69**	5	7	394	300
16	64	75	315	100	**70**	7	8	62	300
17	67	68	256	150	**71**	8	51	886	200
18	67	84	230	150	**72**	17	18	554	150
19	68	69	249	100	**73**	17	22	72	150
20	68	89	502	100	**74**	18	19	256	125
21	69	85	308	100	**75**	19	20	525	150
22	70	71	656	80	**76**	19	36	722	100
23	70	87	154	200	**77**	20	25	256	300
24	71	72	459	80	**78**	22	31	230	150
25	71	92	328	100	**79**	22	33	574	100
26	72	74	259	80	**80**	23	34	187	100
27	74	75	23	150	**81**	24	25	289	100
28	74	93	305	200	**82**	25	26	623	100
29	84	88	207	150	**83**	25	36	299	300
30	85	86	197	80	**84**	26	27	525	100
31	85	90	318	100	**85**	26	38	308	100
32	86	87	230	80	**86**	27	39	285	100
33	86	111	879	80	**87**	31	32	226	80
34	87	91	174	200	**88**	31	45	322	150

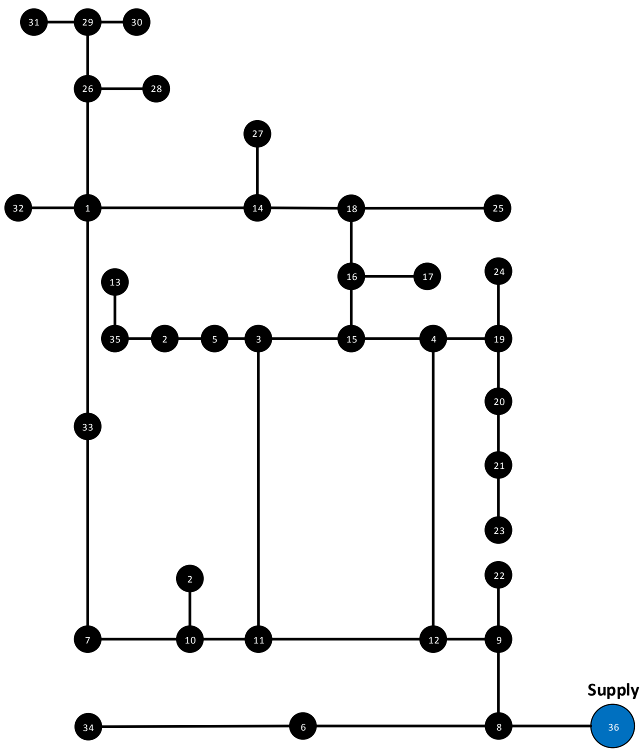
Pipe No.	From Node	To Node	Length (m)	Diameter (mm)	Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
35	88	89	361	80	**89**	33	54	531	100
36	88	98	331	100	**90**	33	34	256	100
37	89	90	197	80	**91**	34	35	594	100
38	89	100	315	100	**92**	36	37	66	300
39	90	101	302	100	**93**	37	38	614	100
40	91	92	732	100	**94**	37	48	269	300
41	91	102	390	200	**95**	38	39	535	80
42	92	93	728	100	**96**	38	49	295	100
43	92	103	341	100	**97**	39	50	285	100
44	93	94	52	150	**98**	45	52	302	150
45	94	97	367	150	**99**	46	47	200	100
46	97	107	118	150	**100**	47	53	361	100
47	98	99	295	80	**101**	47	33	256	100
48	98	100	240	100	**102**	48	55	276	300
49	100	101	220	100	**103**	48	49	689	80
50	101	110	312	100	**104**	49	56	269	100
51	102	103	827	150	**105**	49	50	551	80
52	102	113	499	300	**106**	50	51	46	80
53	102	114	400	150	**107**	51	57	230	200
54	103	104	295	100	**108**	52	53	295	150

Gas demand for LP#2:

Node No.	Gas peak demand (cm)	Node No.	Gas peak demand (cm)	Node No.	Gas peak demand (cm)
1	7.16415	**45**	8.041971	**85**	6.45623
2	4.927123	**46**	4.672272	**86**	38.14273
3	6.512864	**47**	12.88414	**87**	23.67284
4	2.803363	**48**	34.43323	**88**	12.54434
5	6.597814	**49**	35.70748	**89**	5.125341
7	6.597814	**50**	23.24809	**90**	4.417421
8	0.991088	**51**	0.991088	**91**	21.71899
17	3.5396	**52**	8.49504	**92**	21.94552
18	4.629797	**53**	8.183555	**93**	19.42532
19	20.18988	**54**	17.92453	**94**	30.63878
20	18.85899	**55**	26.22136	**97**	44.08926
22	7.362368	**56**	24.23918	**98**	52.86747

Node No.	Gas peak demand (cm)	Node No.	Gas peak demand (cm)	Node No.	Gas peak demand (cm)
23	4.87049	**57**	10.25068	**99**	25.00373
24	6.45623	**60**	7.16415	**100**	8.041971
25	38.14273	**61**	4.927123	**101**	4.672272
26	23.67284	**62**	6.512864	**102**	12.88414
27	12.54434	**63**	2.803363	**103**	34.43323
31	5.125341	**64**	6.597814	**104**	35.70748
32	4.417421	**67**	6.597814	**105**	23.24809
33	21.71899	**68**	0.991088	**106**	0.991088
34	21.94552	**69**	3.5396	**108**	8.49504
35	19.42532	**70**	4.629797	**109**	8.183555
36	30.63878	**71**	20.18988	**110**	17.92453
37	44.08926	**72**	18.85899	**111**	26.22136
38	52.86747	**74**	7.362368	**114**	24.23918
39	25.00373	**75**	4.87049	**115**	10.25068

Medium Pressure Network - MP



Network characteristic for MP:

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)	Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	1	26	1706	50	**21**	12	9	213	40
2	1	32	525	65	**22**	14	1	180	65
3	2	5	66	32	**23**	14	27	1378	50
4	2	35	66	32	**24**	15	4	148	40
5	3	5	197	32	**25**	15	16	197	32
6	3	15	131	40	**26**	16	17	197	40
7	4	19	213	40	**27**	16	18	197	32
8	5	14	295	32	**28**	18	14	197	65
9	6	34	492	200	**29**	18	25	394	65
10	7	10	197	32	**30**	19	20	164	40
11	7	33	482	50	**31**	19	24	180	25
12	8	6	1247	200	**32**	20	21	197	32
13	8	9	230	65	**33**	21	23	66	50
14	8	36	7546	200	**34**	26	28	427	40
15	9	22	148	40	**35**	26	29	295	40
16	10	2	591	32	**36**	29	30	164	40
17	10	11	197	32	**37**	29	31	98	40
18	11	3	541	32	**38**	33	1	469	50
19	11	12	279	32	**39**	35	13	164	32
20	12	4	525	40					

Gas demand for MP:

Node No.	Gas Peak Load (cm)	Node No.	Gas Peak Load (cm)
1	40.36985	**18**	22.2301
2	20.46993	**19**	16.80999
3	27.25011	**20**	14.87
4	25.61	**22**	5.499972
5	16.80999	**23**	5.499972
7	21.35002	**24**	5.499972
9	8.350058	**25**	39.65994
10	27.25011	**26**	23.06007
11	27.25011	**27**	26.03985
12	23.92005	**28**	5.499972
13	5.499972	**29**	14.87
14	42.70995	**30**	5.620035
15	8.350058	**31**	5.620035
16	8.350058	**32**	150
17	12.84988	**34**	5199.996

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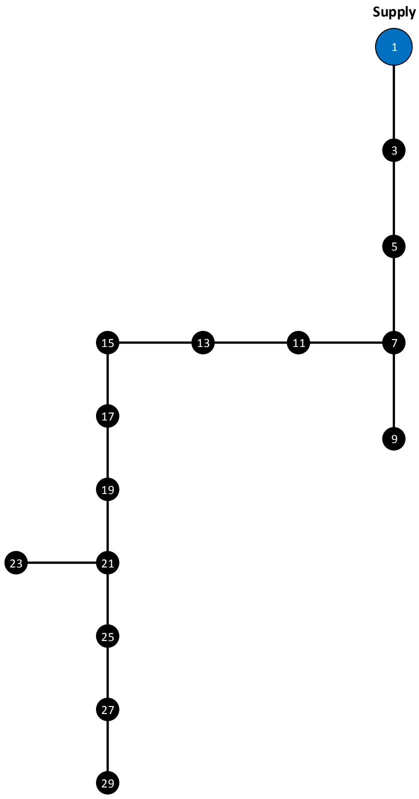
High Pressure Network – HP#1

A high-pressure gas distribution test network with supply pressure between 38 to 70 bar (NTS offtake) was simulated. The peak energy demand for this system is 104.5 GWh per day (equivalent to 9.5 million cubic meter of natural gas). The energy demand is distributed uniformly across the nodes.



Network characteristic for HP#1

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	1	3	8558	1193
2	3	5	9559	1193
3	5	7	12035	1038
4	7	9	50	590
5	7	11	7197	590
6	11	13	6726	590
7	13	15	4739	590
8	15	17	2495	590
9	17	19	4996	590
10	19	21	4844	590
11	21	23	50	590
12	21	25	4439	590
13	25	27	3774	590
14	27	29	2509	590

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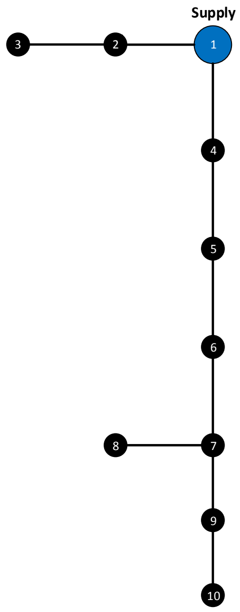
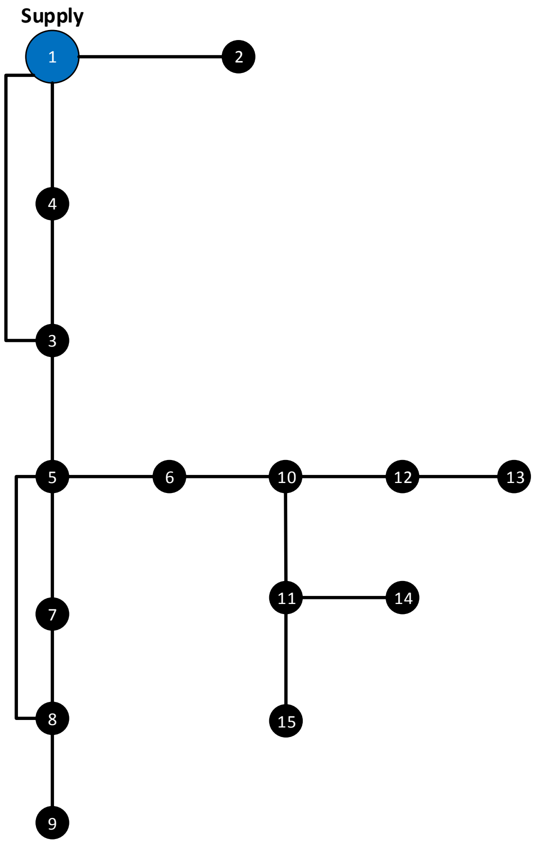
High Pressure Network – HP#2



Network characteristic for HP#2:

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	1	2	4742	584
2	2	3	3016	584
3	1	4	3860	438
4	4	5	11164	438
5	5	6	7550	438
6	6	7	7062	438
7	7	8	34135	438
8	7	9	3108	438
9	9	10	3000	157

High Pressure Network – HP#3



Network characteristic for HP#3:

Pipe No.	From Node	To Node	Length (m)	Diameter (mm)
1	1	2	22211	157
2	1	3	24035	590
3	1	4	5585	438
4	4	3	16322	438
5	3	5	6952	438
6	5	6	4287	309
7	5	7	4439	438
8	5	8	5032	304
9	7	8	81	438
10	8	9	6563	888
11	6	10	7636	309
12	10	11	3917	309
13	10	12	97	309
14	12	13	10123	590
15	11	14	5520	157
16	11	15	4298	309

Hydrogen storage capacity for balancing

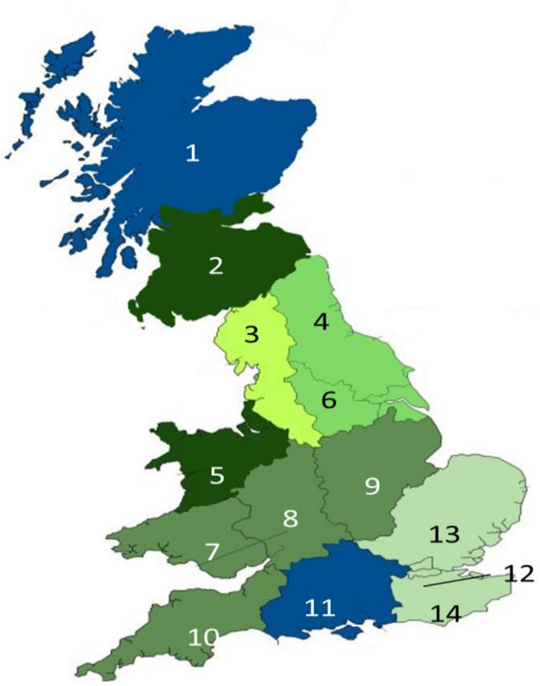
Table E-1 shows the hydrogen storage capacity requirement in different region.

Table E-1 Hydrogen storage capacity required in different region across GB

Region	H2 storage (GWh) - Low	H2 storage (GWh) - High
Eastern	9.9	25.8
East Midlands	12.2	32.2
North East	7.7	20.2
North	2.9	8.2
North Thames	22.0	47.9
North West	17.6	45.5
Scotland	10.1	26.1
South East	22.7	57.2
South	7.2	19.3
South West	1.7	4.8
West Midlands	11.7	30.6
North Wales	0.6	1.6
South Wales	5.2	13.7
Total	**131.4**	**333.1**

Appendix F. GB system model

The studies were carried out on a simplified 14-regions GB model resembling the GB distribution network operators' operating regions as shown in Figure F-1.



Region	Region name
1	North Scotland
2	South Scotland
3	North West England
4	North East England
5	North Wales, Merseyside and Cheshire
6	Yorkshire
7	South Wales
8	West Midlands
9	East Midlands
10	South West England
11	Southern England
12	London
13	East England
14	South East England

Figure F-1 A 14-regions GB model

The regions are interconnected by electricity and hydrogen transmission networks; the network capacities are optimised by the model. The interconnection capacities between GB and Ireland, and between GB and the continental Europe (Norway, France, Belgium, and Netherlands) are modelled and optimised.

In each region, the networks are grouped into two different types, (i) high demand density and (ii) low demand density systems. The annual heat demand (TWh_{th}) is given in Table F.1. The capacity of electrical distribution networks is optimised considering the local installed capacity of distributed generation and also the optimised electricity demand profiles depending on the level of demand flexibility used in the study.

Table F-1 Annual heat demand (TWh) across different regions

Region	**Districts with *high* demand density [urban] (TWh)**	**Districts with *low* demand density [non-urban] (TWh)**
North Scotland	3	19
South Scotland	11	33
North West England	17	32
North East England	16	19
North Wales, Merseyside and Cheshire	6	25
Yorkshire	24	21
South Wales	9	14
West Midlands	20	32
East Midlands	21	32
South West England	10	24
Southern England	28	38
London	55	0
East England	22	53
South East England	15	33