Imperial College London

Analysis of Alternative UK Heat Decarbonisation Pathways

Extended Executive Summary

For the Committee on Climate Change

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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

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[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.

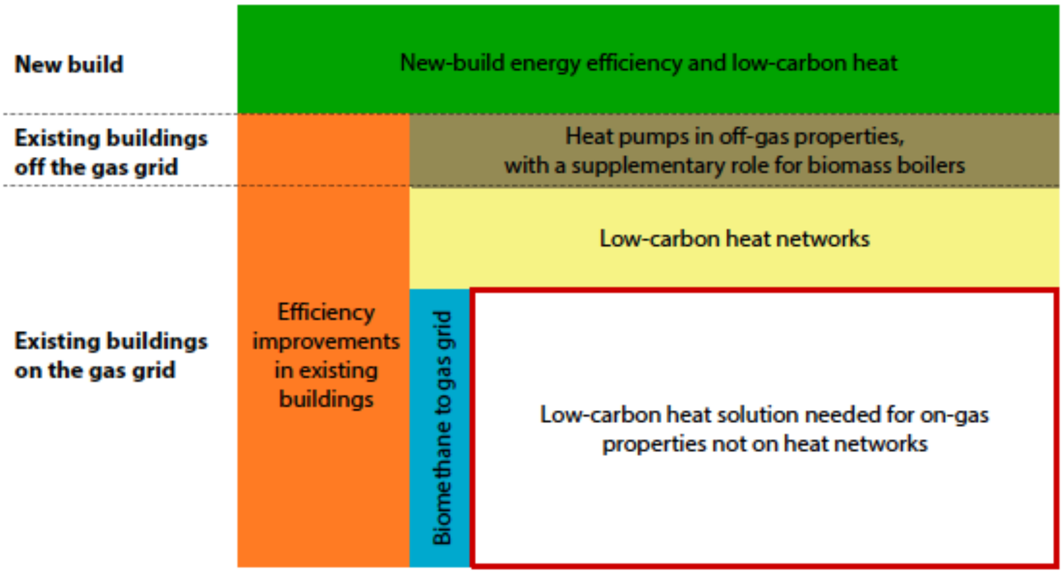

Figure E. 1 Low-regrets measures and the remaining challenge for existing buildings on the gas grid[6]

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.

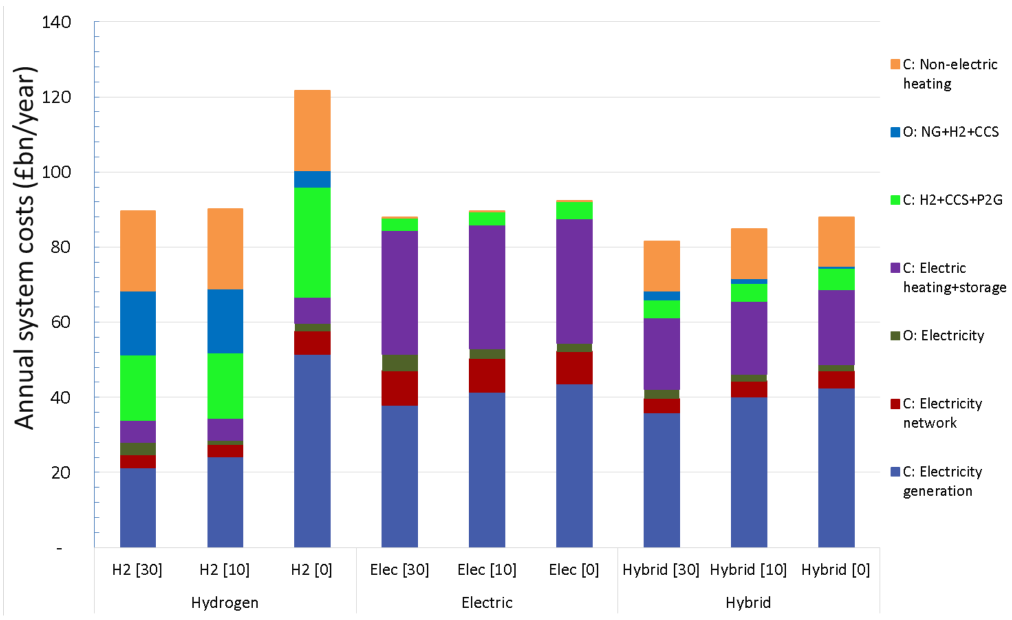

Figure E. 2 Annual system cost of core decarbonisation pathways

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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).

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[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 18).

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:

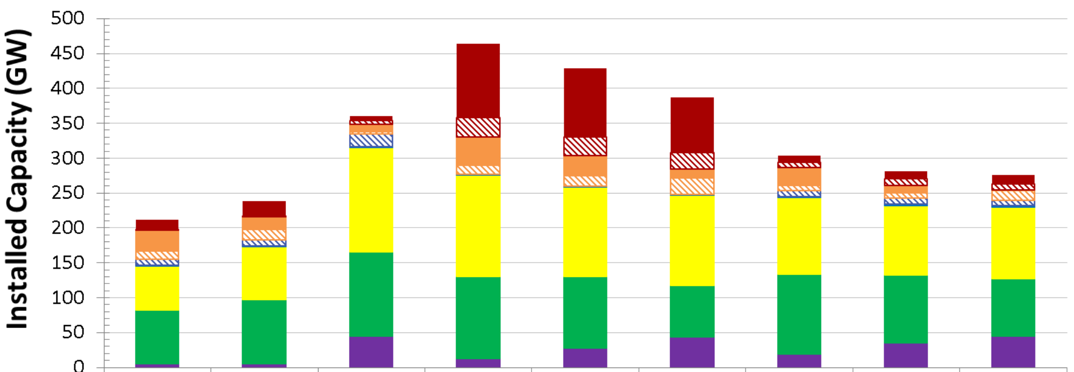
- Systems with more stringent carbon emission targets will lead to higher costs;
- Further decarbonisation beyond 30 Mt is possible at limited additional costs (few billions per year) in the hybrid and Electric pathways; this is also true for deep decarbonisation towards a zero-emissions energy system.
- 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.



	Hydrogen			Electric			Hybrid		
	H2 [30]	H2 [10]	H2 [0]	Elec [30]	Elec [10]	Elec [0]	Hybrid [30]	Hybrid [10]	Hybrid [0]
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

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[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

[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.

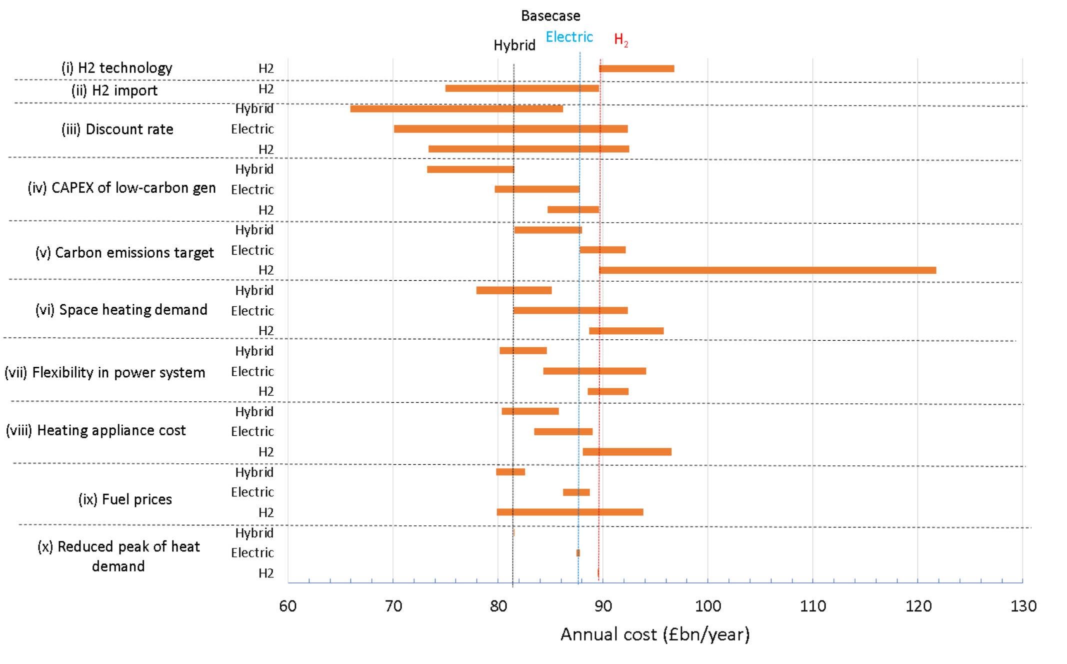


Figure E. 4 Cost changes in core decarbonisation pathways under different scenarios [30Mt]

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.

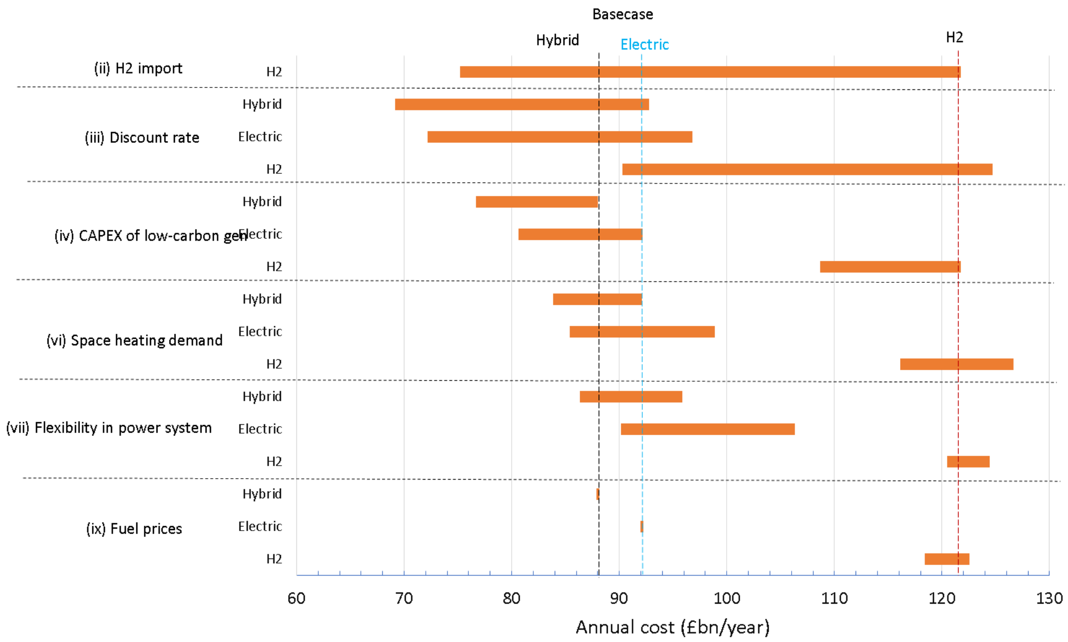


Figure E. 5 Comparison between the costs of different decarbonisation pathways under different scenarios [0Mt]

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.

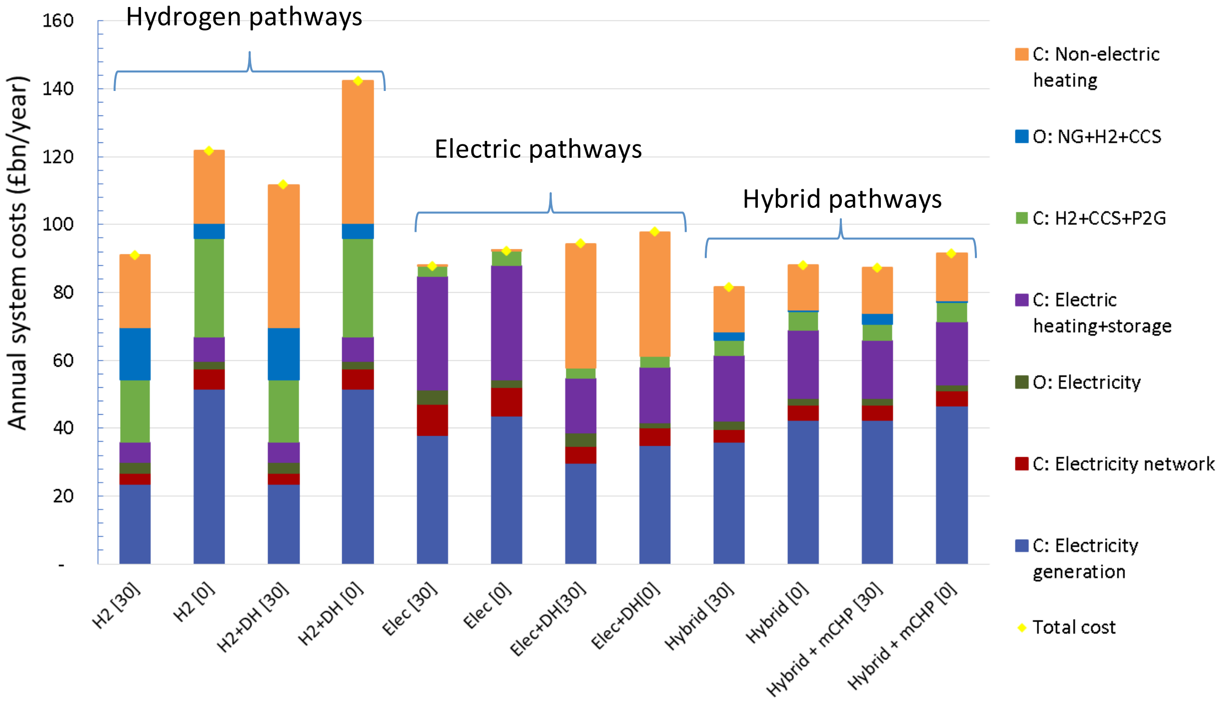


Figure E. 6 Annual system cost of different decarbonisation pathways

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

[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).

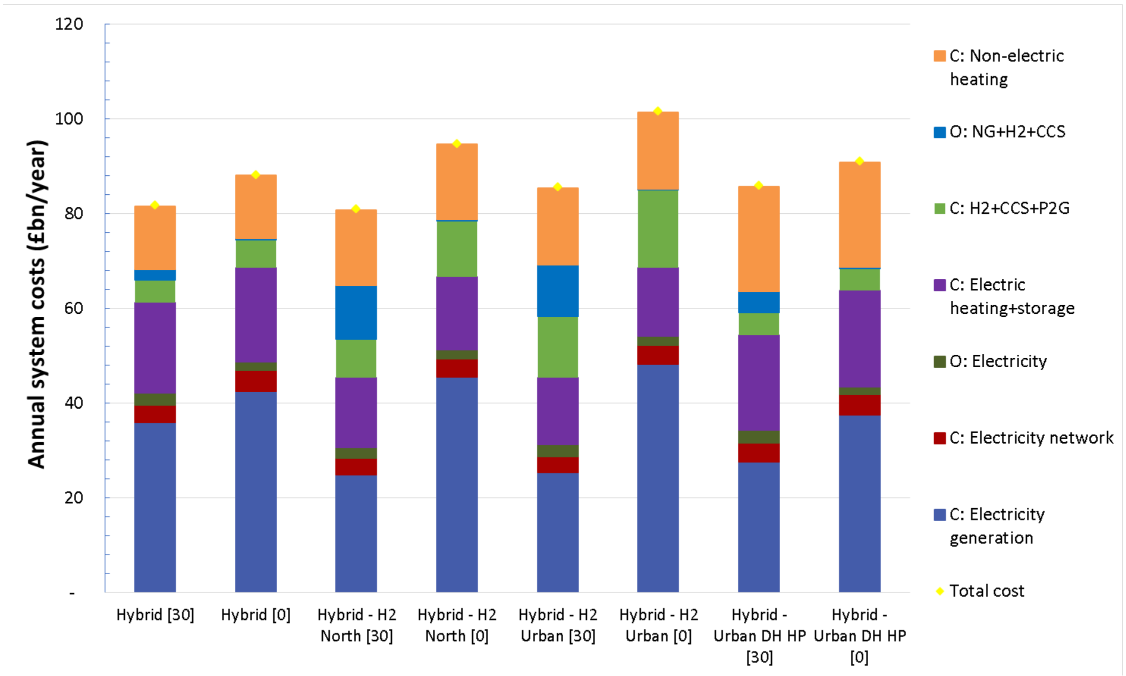


Figure E. 7 Costs of alternative Hybrid pathways

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

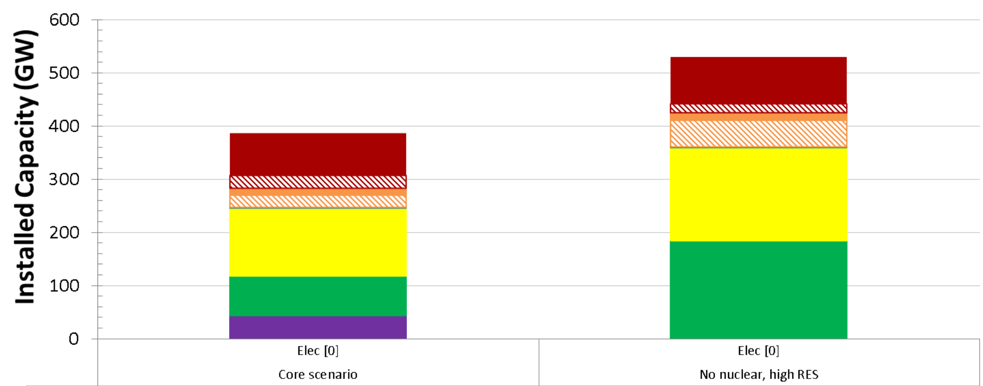
As discussed previously, improving energy system flexibility is necessary for enabling cost-effective integration of low-carbon electricity generation particularly renewables. Improving flexibility could save around 10 and 16 £bn/year in the 30Mt and 0Mt case respectively. The flexibility should be provided 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

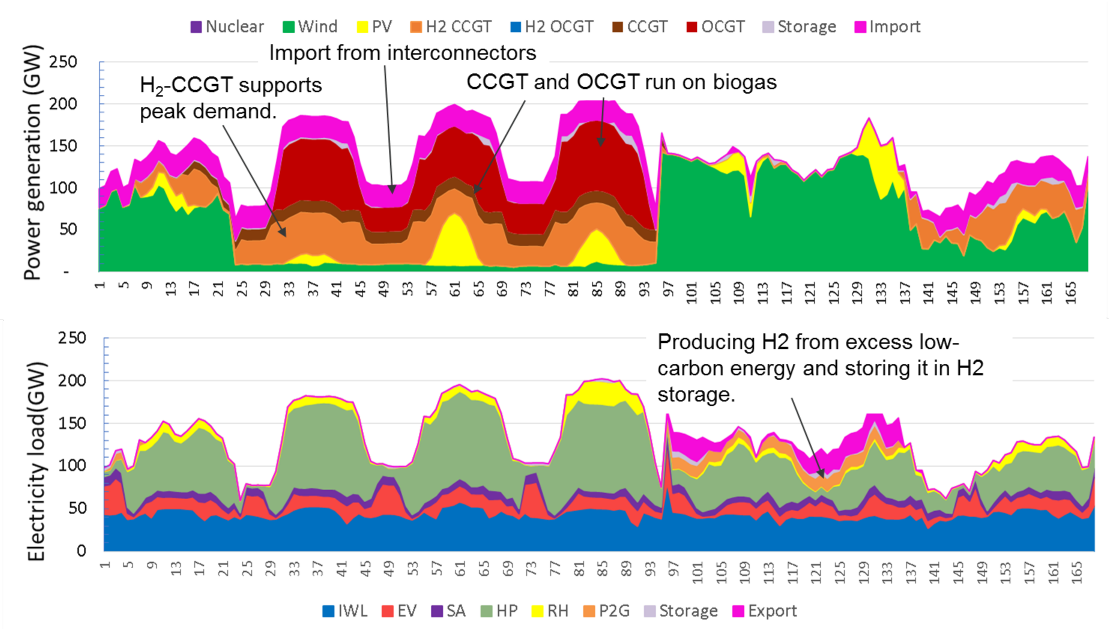
Figure E. 8 Comparison of the generation portfolio for Electric pathway with and without nuclear technology

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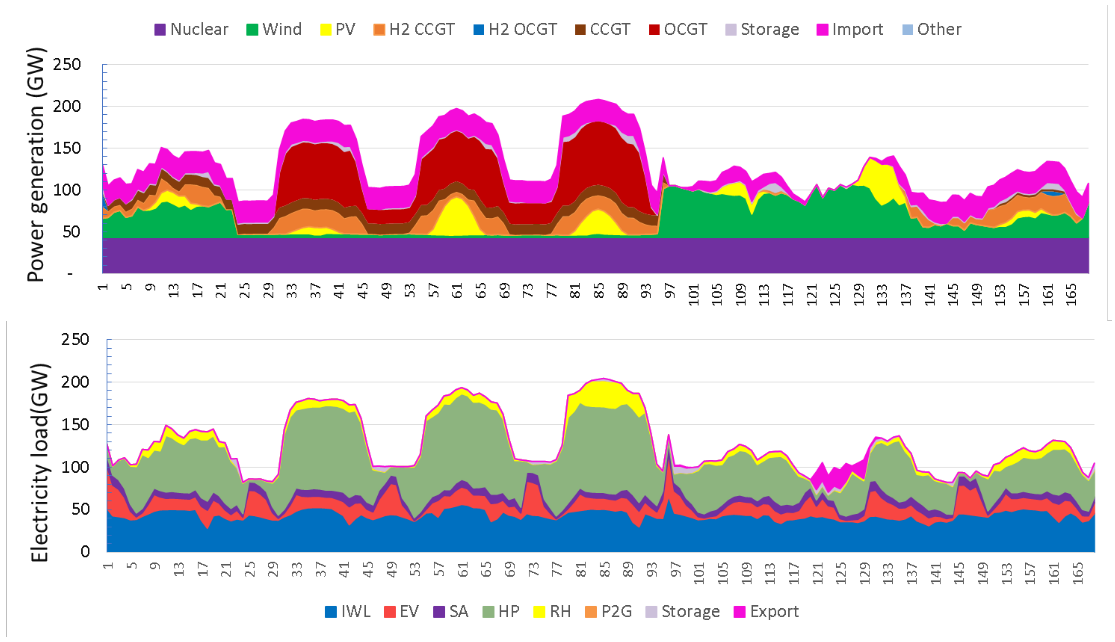
[33] Electrolysers also provide grid-balancing services particularly when the system is less flexible (e.g. in H2 0Mt case). In this case, electrolysers are used to save the excess of renewable energy in the form of hydrogen. Since there are losses associated with this process, it is carried out only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

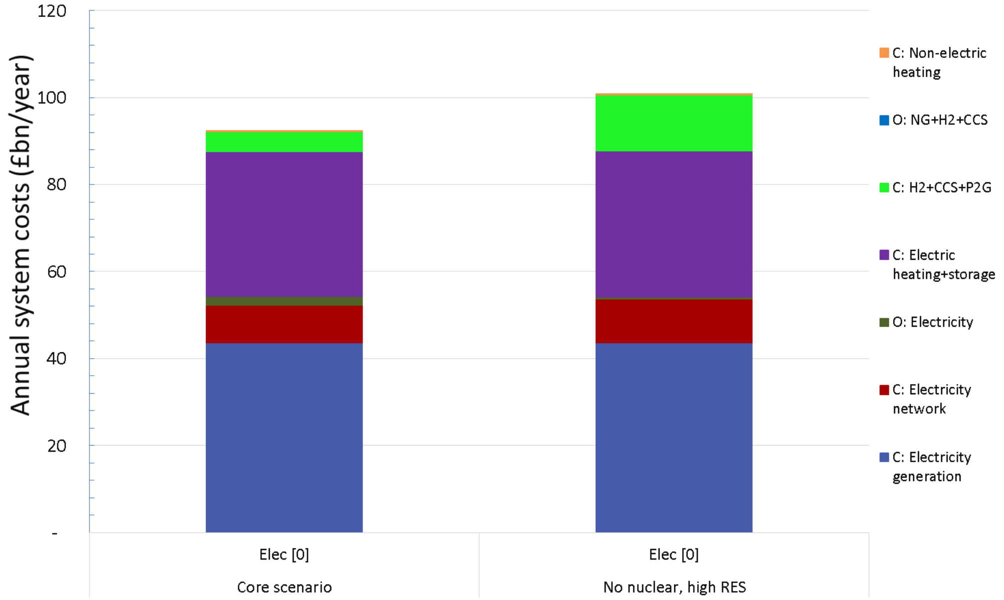


Figure E. 10 System costs of the Electric pathway with and without nuclear technology

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.

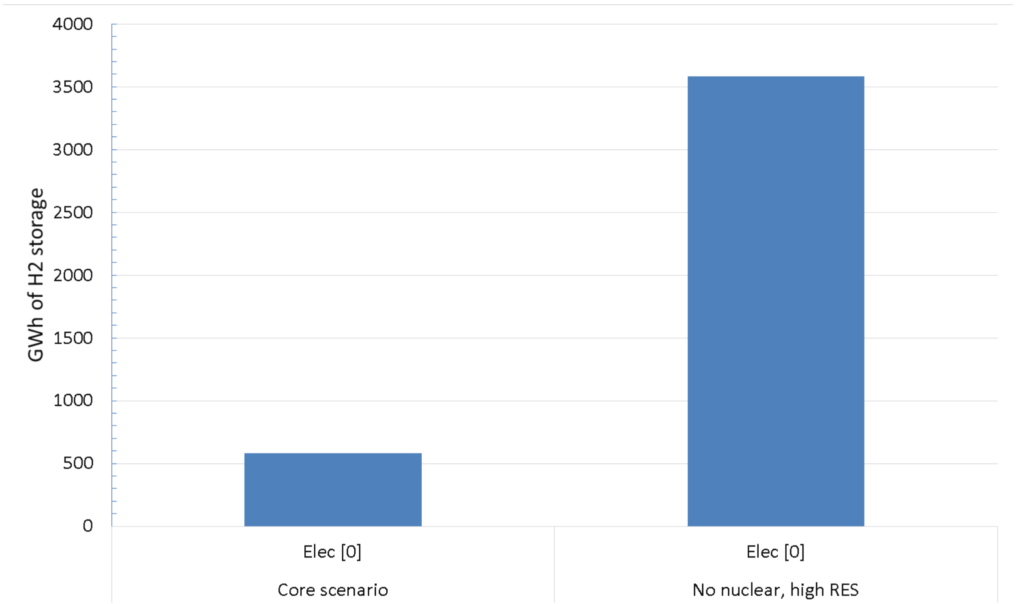


Figure E. 11 Comparison of the hydrogen storage requirement in Electric 0Mt cases

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.

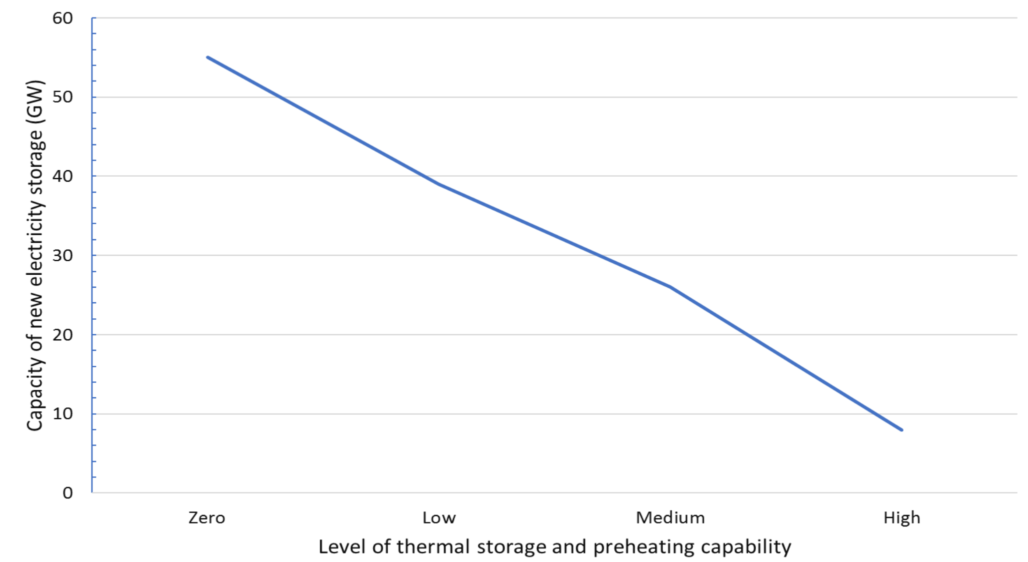


Figure E. 12 Correlation between TES and electricity storage

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%).

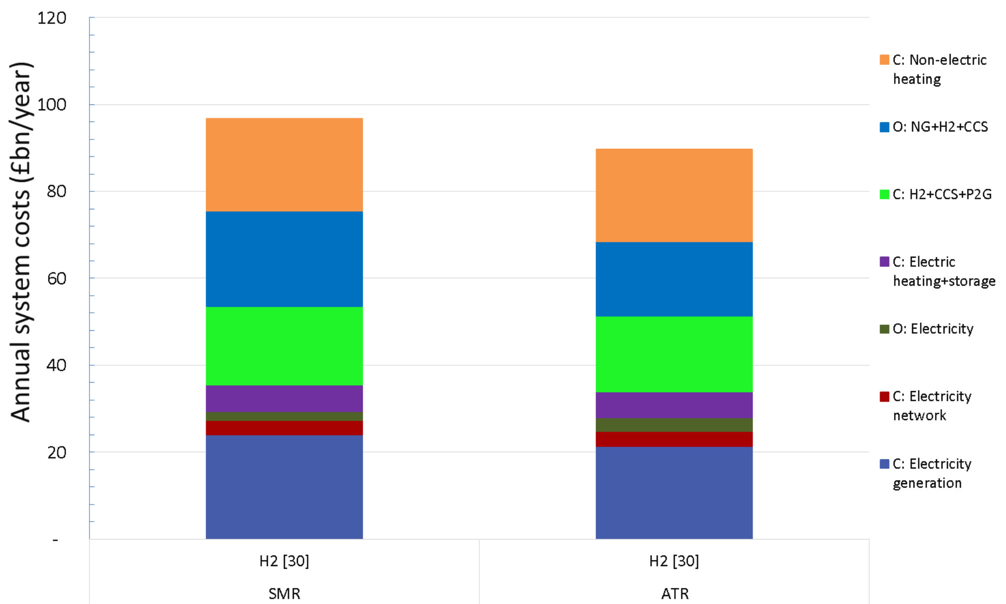


Figure E. 13 Cost performance of H2 pathways based on SMR and ATR

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.

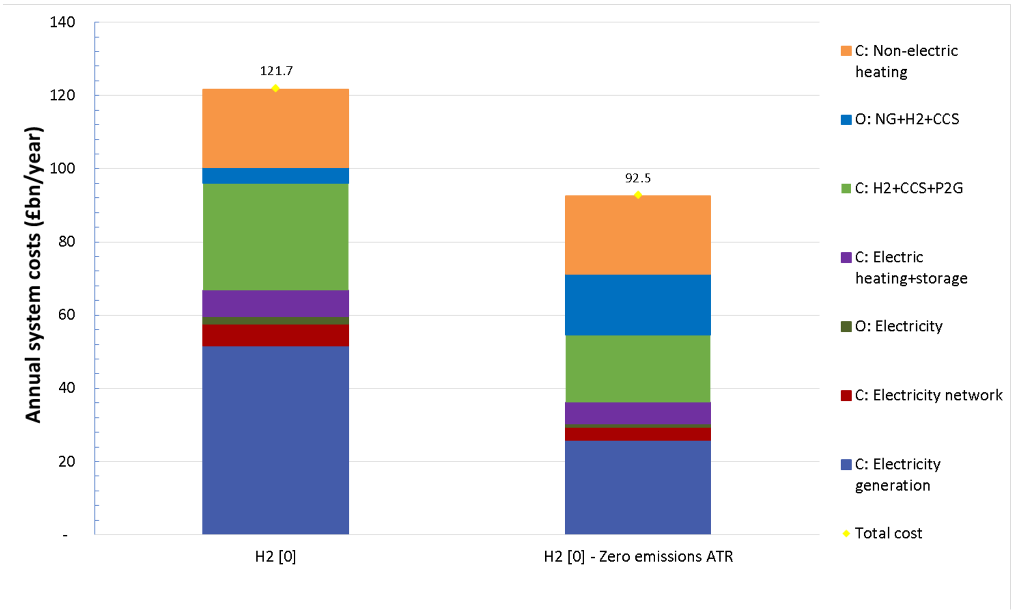


Figure E. 14 Value of enhancing the capture rate of ATR for a zero-carbon system

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.

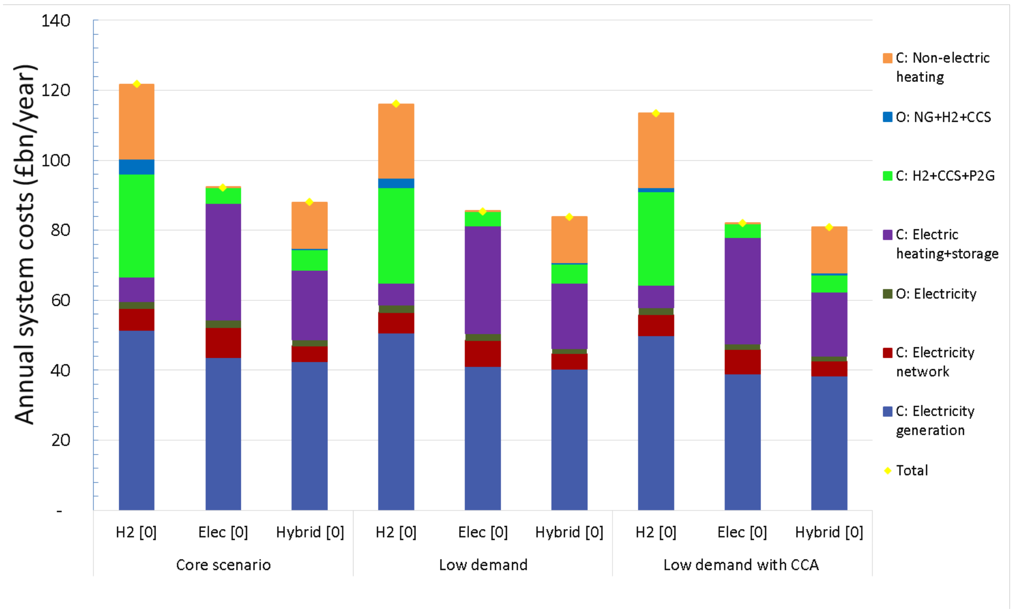
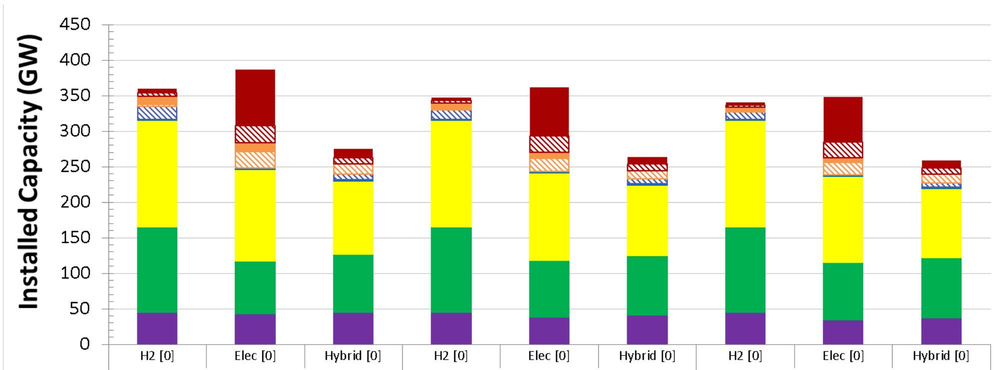


Figure E. 15 Impact of the reduction in heat demand on the system annual costs

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 **Error! Reference source not found.**).

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.