HyHy Project

Hybrid-Hydrogen

Report on behalf of Wales & West Utilities

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Approved by

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VERSION CONTROL TABLE

Version	Date	Author	Description
V0.1	25/05/2020	Tommy Isaac	First draft (internal)
V0.2	29/05/2020	Tommy Isaac	Second draft (sent to client)
V1.0	22/03/2021	Tommy Isaac	Final version (including client comments)

EXECUTIVE SUMMARY

The purpose of this project has been to assess the whole system implications of a Hybrid-Hydrogen (HyHy) regional net-zero energy system. This was assessed by considering the deployment of hybrid heating systems with domestic premises, and evaluating the resulting implications on the hydrogen supply requirements within a net-zero gas network.

Alongside investigating the relationship between domestic hybrid heating systems and hydrogen supply requirements and characteristics, a detailed assessment was developed of the whole system implication of domestic heat electrification. This assessment spanned the full range of potential domestic heat electrification scenarios within a net-zero energy system; from 0% electrification with hydrogen boilers providing all domestic heating requirements, to 100% electrification with heat pumps supplying all of domestic heating. Three supply sensitivities were undertaken for the 100% electrification scenario to understand the whole system implications of achieving 100% electrification by intermittent or flexible supply vectors.

The **key messages** from the project were:

1. Regional hydrogen production and CCUS (inc. shipping) is a low-cost supply option by scaling production with demand and only investing in critical storage.
2. Coupling hybrids and hydrogen has a material benefit for hydrogen supply, primarily due to CCUS logistics.
3. Overall cost to consumer is not materially different between 100% hydrogen up to 75% electrification via hybrids.
4. Meeting peak heat demand solely with electrification without supply flexibility is significantly more expensive due to low utilisation of assets.
5. Hydrogen hybrids are fairly cost-neutral compared to stand-alone hydrogen gas boilers; however, a ‘hybrids first’ approach would reduce overall cumulative emissions on the quickest path to reaching net-zero, helping to meet carbon budgets.
6. There is no standout optimum of decarbonised heat between 0-75% electrification in hybrids; therefore, deploy all technologies (hybrids, hydrogen, wind, storage, CCUS) at scale urgently and allow the market and customer choice to determine the final mix.

It was found that domestic hybrid heating systems could deliver up to 75% electrification of domestic heating and that acceptable abatement costs could be achieved across the full range of electrification – however only if gas-based flexibility was retained within the energy supply mixture to cater for peak heating, at a minimum.

All domestic heating scenarios which utilised a combination of hydrogen supply with hybrid heating produced net-zero abatement costs in the range of £100/tCO_2. Analysis of 100% domestic head electrification scenarios without gas-based flexibility (i.e. with the use of solar and wind capacity with batteries) produced net-zero system abatement costs of £1,000/tCO_2.

Post analysis research:

The hybrid heating systems modelled for the HyHy project are based on the Freedom hybrid heating project trials. Freedom hybrid systems utilise a hydrogen boiler with the addition of a small air source heat pump. During the HyHy project, a new hybrid heating appliance has been unveiled and is currently being trialled. The compact hybrid boiler combines the hydrogen boiler and heat pump in one unit. The benefits of this system are:

- Lower capital cost of the one unit compared to Freedom style
- Lower installation costs than an air source heat pump as Gas Safe Registered engineers can fit it
- No change needed to heating installation in the home, e.g. the fitting of a hot water cylinder or larger pipework/emitters
- Similar size unit to an existing boiler with better consumer acceptance

In summary, the compact hybrids will lower the household cost and abatement cost of the hybrid scenario.

CONTENTS

1.0 INTRODUCTION

1.1 Project Context

On the 27th June 2019 the UK parliament passed into law the decarbonisation target of net-zero emissions by 2050, becoming the first major economy to do so[1]. The path to net-zero is one which will involve significant change to the supply, distribution and use of energy across all demands (heat, power, industry and transport). The investment requirements of enabling a transition to net-zero have been estimated by the HM Treasury[2] to be £1 trillion, which spread over a population of 66.6 million people (UK population in 2019)[3] equates to £15,000 of investment per person, or £36,000 per household. Due to the scale of financial investment and potential disruption to consumers' lifestyles required to enable this legally binding transition, it is incumbent upon policy makers and transition stakeholders to ensure the least cost and least consumer disruption path is pursued.

Much analysis has been undertaken by a variety of organisations and energy system stakeholders to explore the engineering landscape of net-zero. The UK government's independent advisors and arbiters of carbon budgets, The UK Committee on Climate Change (CCC), published an analysis of net-zero in their May 2019 report 'Net Zero: The UK's contribution to stopping global warming'[4]. Within this report the basic architecture of a potential net-zero energy system is outlined, where hydrogen and hybrid heating systems are outlined as key enabling technologies. A separate, dedicated analysis, was undertaken by the CCC on the potential role of hydrogen within a decarbonised energy system[5], which drew out the following analysis "Hydrogen could play a valuable role as part of a heating solution for UK buildings, primarily in combination with heat pumps as part of 'hybrid heat pump' systems… Deployment of this combination of hydrogen and heat pumps could almost completely displace fossil fuel use in buildings".

Much work to date has investigated the technological and regulatory implications of transitioning to a hydrogen-based energy system, most notably projects such as H21[6], HyNet[7] and H100[8]. The purpose of this study is to investigate the techno-economic ramifications of the co-deployment of hydrogen supply technology alongside hybrid heating technology within domestic premises.

Utilising the CCC's Net-Zero report, alongside National Grid's 2019 Future Energy Scenarios[9] (FES) a base case 2050 regional net-zero energy system was established via the use of the Wales & West Utilities (WWU) Pathfinder Plus model. From this base scenario whole system analysis was undertaken to explore the techno-economic implications of incrementally electrifying the system via hybrid deployment coupled with hydrogen supply. To assess the relative implications of this assessment, optimised counterfactual analysis was undertaken to explore both a hydrogen-only and electrification-only energy system. This allowed a global domestic heat analysis to be explored, to understand the system effects of varying the degree of domestic heat electrification from 0 – 100%. The system benefits of hybrid heating technology coupled with hydrogen supply could then be assessed in their fullest context.

1.2 Objectives

The agreed objectives of the study were:

1. Develop a regional net-zero 2050 whole system model to act as an exemplar for the UK energy system
2. Incrementally deploy hybrid heating within domestic premises from the baseline value to 100%, assessing system implications at each increment
3. Undertake optimised counterfactual analysis of a 'hydrogen-only' and 'electrification-only' energy system for comparison
4. Explore the system implications of this analysis, most notably as they relate to system abatement costs

1.3 Pathfinder Plus Model

The Pathfinder Plus model is a whole-systems analysis tool which balances energy demands and supplies across an energy system on an hour-by-hour basis. The tool is highly configurable, with all inputs and profiles able to be amended as the scenario being analysed requires. The model was originally developed by WWU in collaboration with Delta-EE with economic functionality incorporated by Progressive Energy (NIA_WWU_055)[14]. The Pathfinder Plus model allows whole system techno-economic analysis to be undertaken, by assessing the technical structure of a given energy system (balance of energy flows between supply and demand as well as load factors of production sources) and then understand the economic implications of such a scenario to the average household. Overall household spend is calculated by the model based on the following categories:

1. Spend on delivered heating for all fuel types (electric, gas etc)
2. Spend on delivered power
3. Spend on transport for all fuel types
4. Household investment (including heating technology and home efficiency improvements)
5. Network investment (including both gas and electricity reinforcement)

Once the carbon and economic implications are quantified, the Pathfinder Plus model is then able to generate a system abatement cost for the scenario under consideration.

Typical outputs of the Pathfinder Plus model are shown in Figures 1-1 and 1-2.

Figure 1-1: Fortnightly Electricity Supply Mixture

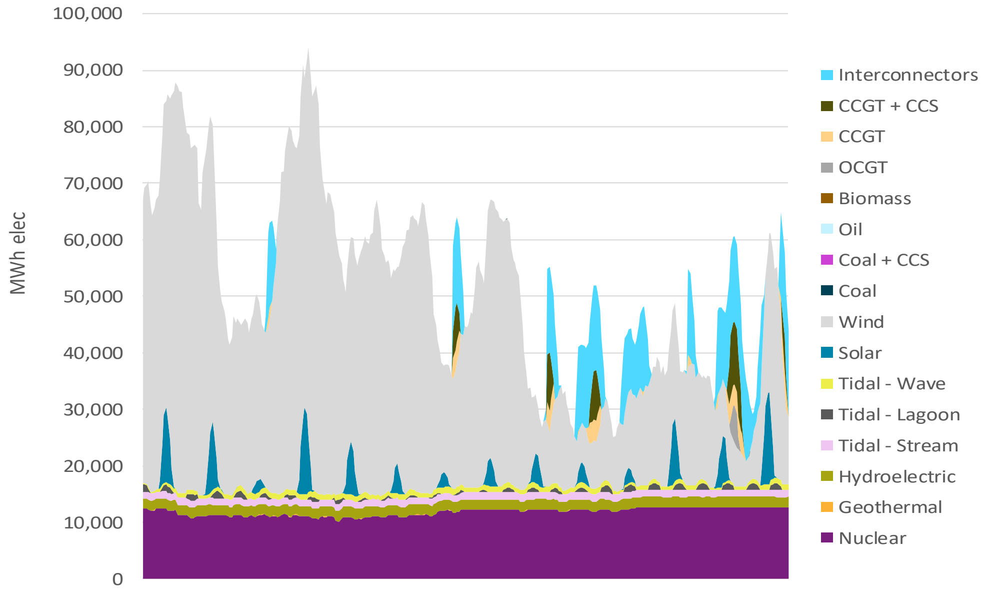
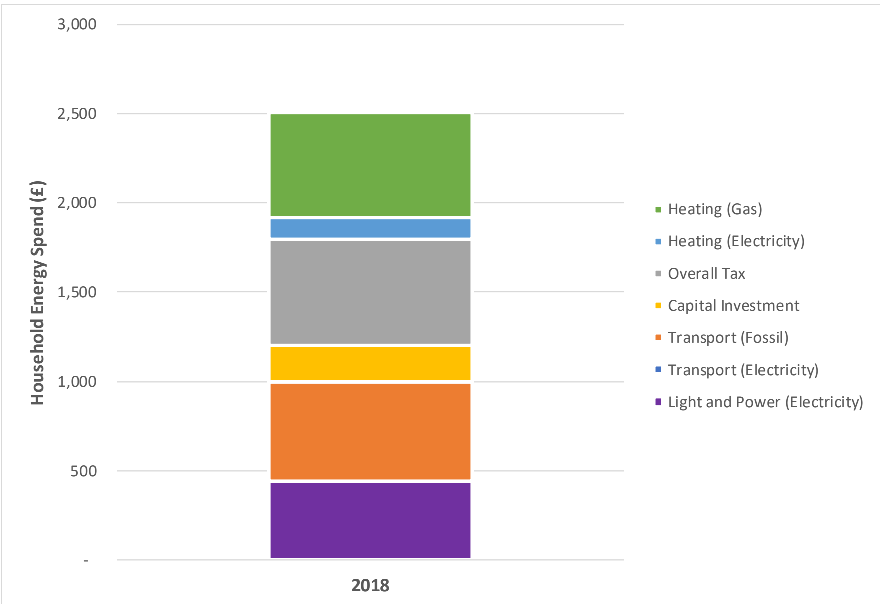


Figure 1-2: 2018 Typical Household Spend on Energy



By assessing both the technical and economic implications of an energy system, across heating, power and transport, the Pathfinder Plus model allows the full implications of any given energy system to be understood and allows a wide variety of potential scenarios to be compared to explore system dynamics and optimise decarbonisation pathways.

2.0 WHOLE SYSTEM MODELLING – 2050 BASELINE SCENARIO

2.1 2018 Cardiff Energy System

Cardiff was selected as the regional exemplar for the analysis of this study. The justification for Cardiff being selected was:

1. It represents a typically sized UK city (population of 360,000 in 2018)(10), therefore analysis results should be translatable to other cities across the UK
2. It was identified in the H21 report(6) as being one of the 21 cities within the UK suitable for hydrogen conversion and has since been subject to an outline conversion design
3. It has a suitability diverse energy demand mixture to allow generally representative results of the UK energy system to be drawn

The first stage of the assessment was to model the 2018 baseline Cardiff energy system, from which a 2050 net-zero energy system model could then be derived (detailed in Section 2.2). The primary inputs of the 2018 Cardiff model were derived from National Grid figures of energy use profiles, utilising the 2019 FES workbook. Table 2-1 outlines the profile of domestic heating by technology, where the national figures are given for comparison.

Table 2-1: 2018 Domestic Heating Profile

Technology	UK (%)	Cardiff (%)
Natural Gas Boiler	79.9	88.0
Storage Heater	10.2	11.3
Heat Pump	0.5	0.5
Hybrid Heat Pump	0.1	0.1
Oil	9.2	0.0
LPG	0.0	0.0
Biomass	0.1	0.1

Domestic heating in 2018 was dominated by gas boilers. To regionalise the national figures, the 9.2% of oil heated homes were converted into gas boiler or storage heater heated homes. This is because oil heating is an off-grid form of domestic heating typically used in rural areas. As Cardiff is an urban city, off-grid heating will not feature heavily in its heating profile, with any off-grid heating more likely to be storage heaters than oil.

The reference for electricity generation installed capacities was the 2019 FES Workbook. To determine the regional allocation of national assets, the national installed capacities were pro-rated to result in the average carbon intensity of the regional model being equal to the average carbon intensity of the national model. This process was selected because if extended across all regions within the UK, the sum of regional carbon emissions associated with electricity supply would be equal to the national figures – this is representative of a national system where all users receive the same average carbon intensity of supply, which was deemed the best approximation to the UK electricity system. Table 2-2 outlines the resultant national and regional installed capacities by technology and the average carbon intensity of supply from each model.

Table 2-2: 2018 Electricity Installed Capacities

Technology	UK	Cardiff
Solar (MW)	12,719	69
Wind (MW)	20,977	114
Nuclear (MW)	9,229	50
Coal (MW)	10,214	56
Natural Gas (MW)	36,521	198
Interconnector (MW)	3,585	19
Other (MW)	7,787	42
Carbon Intensity (gCO_2/kWh)	170	170

The pro-rata factor used to derive the regional figures from the national figures was 0.54%, which is equal to the ratio of populations between Cardiff and the UK. The Cardiff energy system was reviewed and it was determined that there was no reason not to take the national mix as there was no evidence of reginal abnormalities. The carbon intensity figure calculated for both the national and regional model was 170 gCO_2/kWh, this aligns well with the UK Government figures of 180 gCO_2/kWh for 2018(11).

The outputs of most relevance are the total and peak electricity and gas figures and the average household spend on energy. To validate that the national model used to generate the regional model was adequately representing the UK energy system, the calculated total gas and electricity demands were compared to UK Government figures(12, 13), the comparison is shown in Table 2-3.

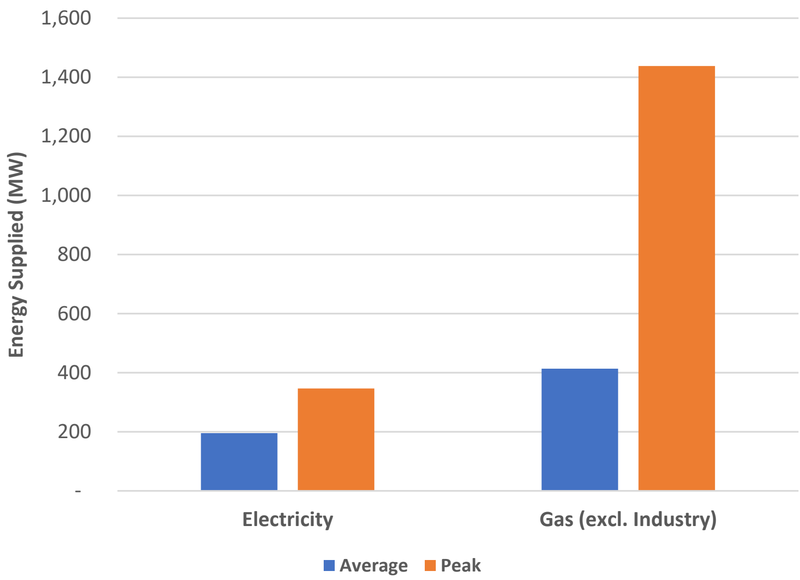
Table 2-3: National Model Validation

Energy Supplied	Model (TWh)	Actual (TWh)	Model Error (%)
Gas (excl. Industry)	666	677	-1.6
Electricity	314	317	-0.9

Given that the total supplied gas and electricity figures were calculated to be within 2% of the known values, the model was deemed to be sufficiently representative of the UK energy system to allow scenario analysis to be conducted.

Figure 2-1 provides the average and peak gas and electricity demands for the Cardiff 2018 model.

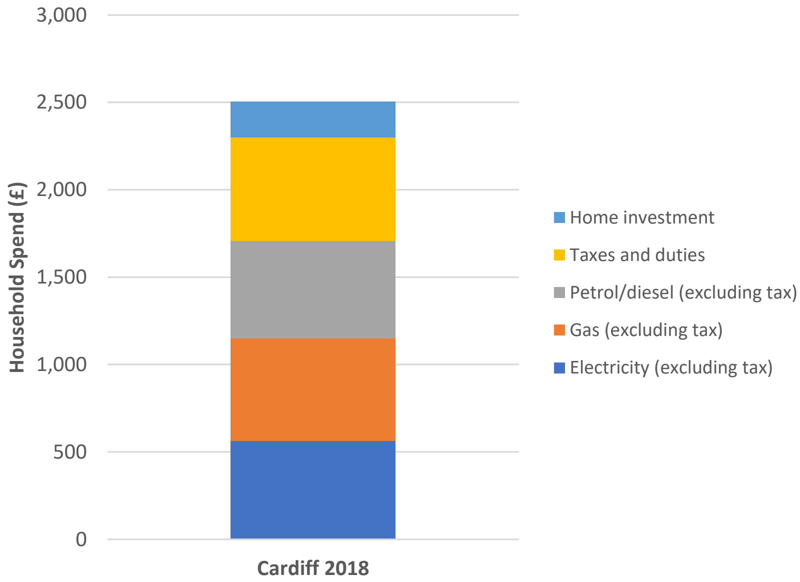
Figure 2-1: Cardiff 2018 Energy Demands



The Cardiff energy demand values are in line with the national assessment, the ratio of all respective values with their national counterpart being found to be the ratio of populations, which is consistent with Cardiff providing a good representation of the UK energy system. Figure 2-1 demonstrates the much greater variability of gas demand relative to electricity, as the ratio of peak-hour to average demand for gas was found to be 3.5 relative to a 1.8 factor for electricity.

The overall household spend on energy for Cardiff in 2018 was found to be similar to UK averages. The underlying economic logic of the Pathfinder Plus model is to utilise BEIS figures to determine the levelised cost of generation assets and then process those figures into an energy bill using the gas and electricity bill format issued by Ofgem. More detail can be found within the project documentation of the Pathfinder Plus project[14]. Figure 2-2 provides the breakdown of an average household's spend on energy from the 2018 Cardiff model.

Figure 2-2: Cardiff 2018 Household Spend on Energy



The total average household spend on energy was found to be £2,500 pa. The capital investment proportion of this figure is £200 pa, which essentially represents the annualised cost of a gas boiler. Of the consumption-based expenditure (ca. £2,300 pa) the total is shared relatively equally between the three underlying energy systems (gas, electricity and liquid transport fuels) and the collective taxes and duties applied to these systems. Once the taxes and duties are embodied within the energy bills themselves, petrol/diesel for transport becomes the primary energy-based expenditure as over 80% of energy-based household taxes and duties are accounted for by fuel duty. Taxes and duties have been separated within the economic calculations to ensure a consistent tax rate is applied to total energy expenditure across all scenarios modelled within Pathfinder Plus. Treating tax in this way avoids concluding a given scenario is lower cost simply because it results in paying less tax based on current tax regulations.

The values presented in Figure 2-2 constitute a baseline of expenditure to compare future scenarios to, to understand if total household spend on energy would need to change to accommodate a given scenario, as well as the characteristics of this expenditure as it relates to individual energy bills (i.e. capital vs consumption-based expenditure).

2.2 2050 Baseline Net-Zero Cardiff Energy System

A similar process that was undertaken to generate a current (2018) energy system model of Cardiff was used to generate a baseline net-zero system. The reference data for the net-zero scenario was both the 2019 FES workbook, as well as engagement with the CCC. The two most relevant input sets used to derive the net-zero model are the domestic heating profile (based on the proportion of homes heated by a given technology) and electricity installed capacities. As the purpose of the study was to investigate the relationship between hydrogen supply and hybrid heating technology, the net-zero model included a converted gas grid to 100% hydrogen. This would then allow the incremental impact of hybrid deployment to be understood, as it relates to hydrogen supply requirements and dynamics. Table 2-4 and 2-5 provide the domestic heating profile and installed capacities used to derive both the national and Cardiff net-zero models.

Table 2-4: Baseline Net-Zero Domestic Heating Profile

Technology	UK (%)	Cardiff (%)
Hydrogen Boiler	55.6	58.0
Storage Heater	0.0	0.0
Heat Pump	27.5	28.7
Hybrid Heat Pump	12.7	13.2
Oil	4.2	0.0
LPG	0.0	0.0
Biomass	0.0	0.0

The national domestic heating profile was taken from the 2019 FES Workbook, which shows a reduction in gas boiler usage and increase in electrification, particularly through the use of heat pumps and to a lesser extend hybrid heat pumps. The Cardiff profile spread the proportion of oil heated homes across the three other technologies in recognition of the lower-than-average proportion of homes off-grid in Cardiff.

Table 2-5: Baseline Net-Zero Electricity Installed Capacities

Technology	UK	Cardiff
Solar (MW)	25,000	136
Wind (MW)	140,000	761
Nuclear (MW)	15,000	82
Coal (MW)	0	0
Green Gas (MW)	50,000	272
Interconnector (MW)	25,000	136
Other (MW)	5,000	27
Carbon Intensity (gCO_2/kWh)	15	15

The installed capacities of electricity sources were derived through engagement with the CCC. Through bilateral discussions, the UK figures presented in Table 2-5 were agreed to be a reasonable 'net-zero' basis for electricity generation. The Cardiff figures were found by using the same pro-rating factor in the 2018 model, namely 0.54%, which results in an equal average carbon intensity of supplied electricity. The system emissions within the carbon intensity were found to be due to interconnector-supplied electricity. Given that the interconnectors to Europe will be using the marginal European generation source, it was assumed in 2050 that the final tranche of marginal generation across Europe would still be fossil fuel based (i.e. natural gas turbines).

The regional hydrogen supply requirements for Cardiff were assessed to understand the magnitude of production required to satisfy Cardiff's heating needs within a net-zero scenario. The split of hydrogen production technologies was set at 85% blue hydrogen (natural gas reforming plus CCUS) and 15% green hydrogen (electrolysis powered by dedicated wind farms). These are the same proportions outlined in the CCC's net-zero report as being the most credible capacity split for bulk hydrogen production. The resultant production capacity requirements for Cardiff are given in Table 2-6.

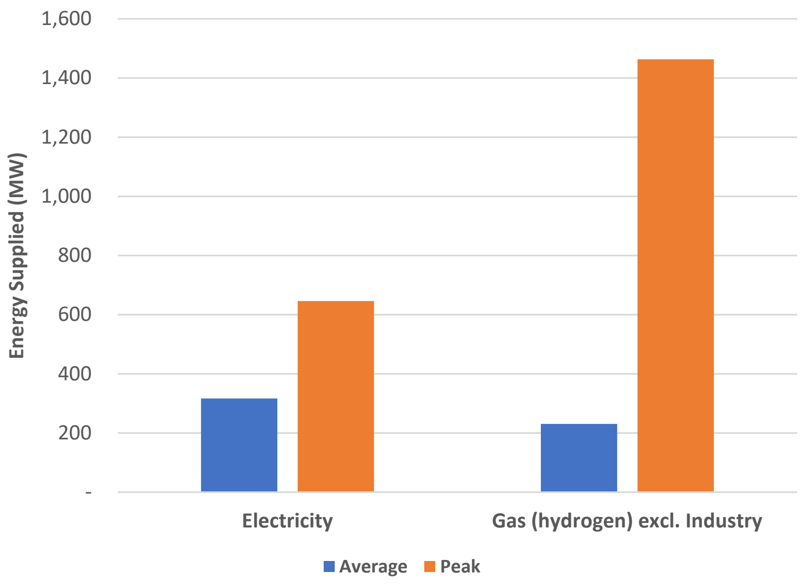
Table 2-6: Local Hydrogen Baseline Capacity Requirements

Production Technology	Cardiff Production Capacity Requirement (MW)
Reformation + CCUS	380
Electrolysis	70
Total	450

The required capacities of both blue and green hydrogen were found to be of a magnitude that could potentially be served by local investment, therefore providing optionality in any hydrogen deployment strategy between centralised national supply and transmission/distribution (mimicking the current natural gas network) or a 'gateway' strategy of local production within hydrogen hubs; city gateways, industrial gateways and power gateways, with transport accessing supplies in these areas.

The average and peak gas and electricity demands identified in the net-zero model are given in Figure 2-3

Figure 2-3: Cardiff Net-Zero Energy Demands



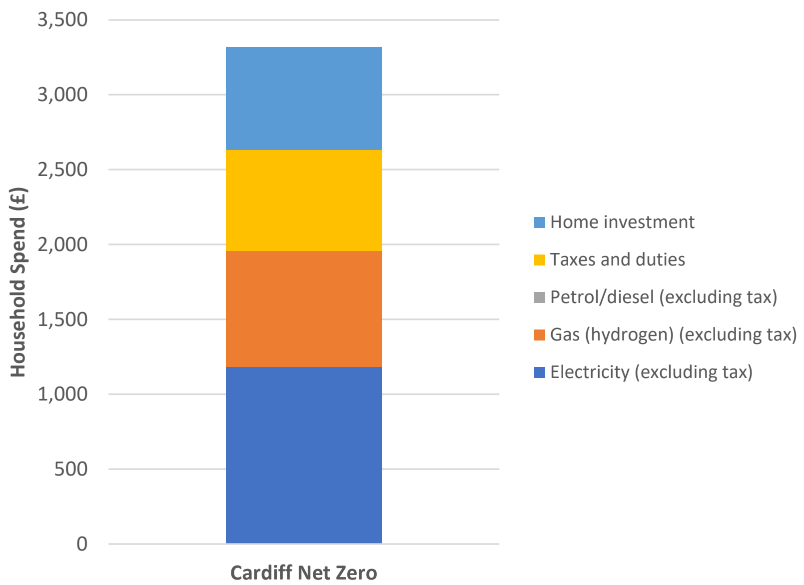
The transition from the current (2018) energy system to a net-zero energy system resulted in electricity becoming the largest demand of energy, instead of gas as it is currently (2018). Relative to the current system (Figure 2-1), both the average and peak-hour electricity demand for Cardiff were found to double. Relative to the current system (Figure 2-1) the average gas demand was found to halve, however the peak demand remained constant. This demonstrates the interesting dynamics within a net-zero scenario in that, although the electricity supply has become the dominant supply over gas, gas remains the critically needed supply for flexibility. Peak gas demand currently is driven by peak domestic heating requirements. The net-zero model found the same to be true, the only difference being delivery the mechanism:

1. Currently peak-hour gas demand has gas delivered directly to boilers to provide peak-heating needs,
2. In the net-zero model peak-hour gas demand has gas delivered both directly to boilers but also to flexible generation to provide electrical capacity for heat pumps.

Therefore, although the delivery mechanism has changed, the macro energy input during peak-heating remains gas-based.

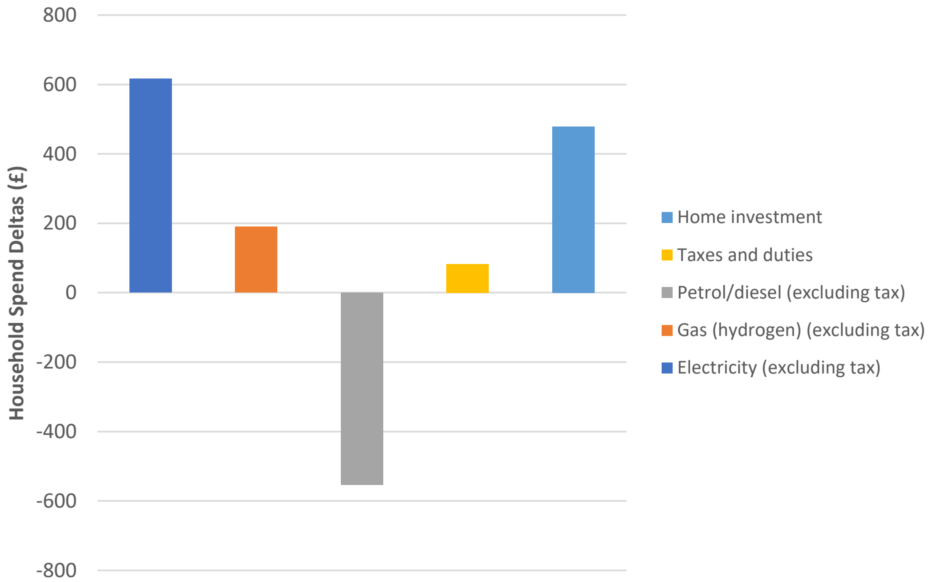
The resultant average household spend on energy within the net-zero model is given in Figure 2-4.

Figure 2-4: Baseline Cardiff Net Zero average Household Spend on Energy



The overall household spend on energy found by the Pathfinder Plus model for a Cardiff baseline net-zero scenario was ca. £3300 pa, which represents an increase in total expenditure of £800 pa; a factor of a third relative to current (2018) total expenditure. As well as the total spend changing, the nature of expenditure was found to change as well. The breakdown of the difference in spend across the categories given in the Figure 2-4 between the net-zero and current energy system for Cardiff is shown in Figure 2-5.

Figure 2-5: Household Spend on Energy Difference by Spend Categories



The dramatic reduction in petrol/diesel expenditure relates to the electrification of personal transport, as the net-zero scenario assumes a 100% conversion to electric vehicles for personal transport by 2050. This transition largely accounts for the rise in electricity bills (excluding tax), however within the electricity bill increase is a reinforcement cost found to be £210 pa to provide the additional capacity to meet the peak-hour demand. This reinforcement figure is based on reinforcement costs equating to £2.1 million/MW, which was derived using a study carried out by Imperial College London for the CCC(15). Gas bills (excluding tax) were found to have risen by £190 pa, which is a function of the nature and split of net-zero gas supplies. Reformation based hydrogen uses natural gas as a feed and therefore additional uplift will be required. However; the levelised cost of blue hydrogen was found to be £48/MWh, whereas the levelised cost of the green hydrogen was found to be £190/MWh. This factor difference is in line with other studies investigating the relative cost of green and blue hydrogen(16, 17, 31). There is likely to be a potential optimisation between green and blue hydrogen to ensure the lowest cost implications for gas users.

As total consumed energy bills were found to increase by £250 pa net (increased electricity and gas costs, minus petrol/diesel costs), an increase in taxes was equally found, namely £80 pa, which represents the current energy taxation rate across all household energy uses. Therefore, total consumption-based expenditure was found to increase by £330 pa.

Household capital expenditure was found to increase by £480 pa. This was caused by two factors; the 19% increase in home efficiency assumed within the FES 2019 net-zero scenario; and an increase in electrified domestic heating. The former was found to equate to a capital requirement of £7,700, which annualised over 30 years results in £260 pa. The latter was found to have increased annual spend on heating technologies by £220 pa, bringing total annual expenditure on heating technologies to £420 pa (£200 pa currently with a £220 pa increase). Additional capital expenditure was therefore found to be the primary cause of the increase in household energy spend.

The total household spend on energy is a convenient perspective to assess changes in costs as a result of decarbonisation, as it allows investigation to be undertaken of the way in which costs change between energy demands. However, undertaking scenario comparison solely in this manner can be misleading for two reasons:

1. Two scenarios being compared are likely to have different total emissions, therefore simply comparing total costs of the two scenarios does not account for the difference in carbon emissions of each
2. Embodying all decarbonisation costs within household energy bills makes the policy assumption that all incremental costs would be incorporated within household bills, instead of being paid for via alternative routes such as general taxation. Although embodiment within household bills is most likely, for example the Renewable Obligation Certificate Scheme (ROCS), not all low carbon support mechanisms are incorporated into bills, such as the Renewable Heat Incentive (RHI)

To overcome these two shortfalls, it is more appropriate to represent decarbonisation costs via the system abatement cost, which is measured in £/tCO_2, as this metric takes account of the total incremental cost of a scenario and the total carbon reductions of a scenario. This metric is also agnostic to policy and decarbonisation funding mechanisms. Table 2-7 outlines the system abatement cost of the net-zero scenario assessed.

Table 2-7: Net Zero Abatement Baseline Cost for Cardiff

Cardiff Scenario Parameter	Current System	Net-Zero System
Households (2050)	183,000	183,000
Household Spend (£/yr/household)	2,500	3,300
Total Spend (£m/yr)	460	610
Total Spend Change (£m/yr)	-	+150
Total Emissions (ktCO_2/yr)	1,380	60
Emissions Change (ktCO_2/yr)	-	-1,320
System Abatement Cost (£/tCO_2)	-	114

The system abatement cost of the Cardiff net-zero scenario was found to be £114/tCO_2, which is generally in line with previous analysis of the abatement cost of achieving deep carbon reductions(4). The current carbon pricing trajectory the UK is signed up to is the EU Emissions Trading Scheme (ETS)(26). Within the CCC's net-zero report(4) the average abatement cost of residential decarbonisation to achieve a net-zero energy system is stated as £155/tCO_2. Therefore, at a macro-economic level, investment that yields carbon abatement costs below this figure will have genuine economic benefits, through reduced energy taxation, alongside carbon benefits. The system abatement cost of £114/tCO_2 falls below the CCC's average abatement cost, demonstrating that a net-zero system could yield financial and carbon benefits to society.

3.0 HYDROGEN SUPPLY

3.1 Supply Cost & Optimisation

As stated in Section 2.2, the profile of hydrogen production capacity was constant between green and blue hydrogen. With green hydrogen from dedicated wind constituting 15% of the installed capacity and blue hydrogen with CCUS constituting 85% of installed capacities, this was taken to be Auto-Thermal Reformation technology (ATR). This split was selected to align with the hydrogen supply split within the CCC's net-zero report for bulk hydrogen supply.

The levelised cost of blue hydrogen was found to be £48/MWh, which was based on natural gas wholesale price of £20/MWh and includes the cost associated with CCUS at £37/tCO_2 of captured carbon dioxide, recognising the costs associated with regional transport to a CCUS hub. The capture process was taken to be 97% efficiency and the thermal efficiency of conversion being 84%(18). In this case, it was also assumed that low carbon hydrogen is used to provide power for the process, thereby ensuring the process does not import emissions to fuel itself.

The levelised cost of green hydrogen was found to be £190/MWh, which was based on the electricity supply being dedicated wind (i.e. wind farms that only produce hydrogen). A sensitivity was undertaken to assess the implications of utilising different sources and operating modes, the two were; curtailed renewable supply and dedicated nuclear supply. The resulting levelised cost of hydrogen did not materially change between these options due to the inverse relationship between fuel costs and asset utilisation e.g. curtailed supply uses 'free' electricity, but asset utilisation of <5%, compared to nuclear of ca. £90/MWh with an asset utilisation of ca. 90%. The conversion efficiency of electricity to hydrogen was taken to be an average of 75% based on market analysis(19). Further cost savings may be possible over time as electrolysis technology reaches technological maturity.

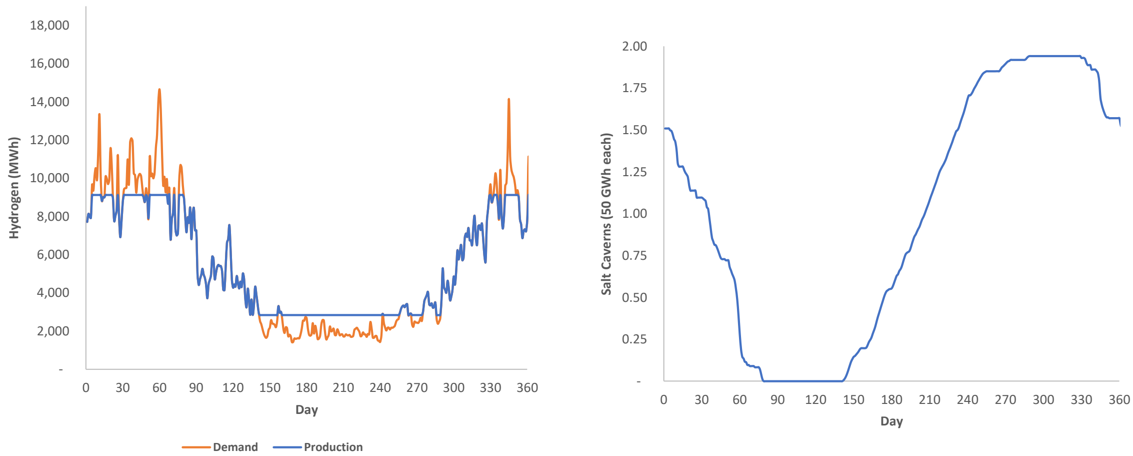
An assessment was made of the relationship between hydrogen storage and production costs. This is in recognition that, either:

1. Production capacity can be sized for average demand, with storage providing flexibility to satisfy seasonal variation, or
2. Production capacity can be sized for peak demand and load follow demand, resulting in no storage requirements.

These cases represent the two extremes of the balance between production capacity and storage capacity; therefore, an assessment was undertaken to explore the optimum balance of the two. To understand the relationship between production and storage capacity a simplified economic model was developed, which assessed total capital expenditure (capex). It is recognised that a more accurate determination would be through a levelised cost model, however total capex was used as the basis of comparison to simplify the assessment.

The ultimate hydrogen demand requirements were taken as the results from the net-zero model outlined in Section 2.2, namely 450 MW of hydrogen production capacity. A storage model was developed to allow a user-defined load factor of production to be specified, along with the seasonal demand curve (daily averages), which led to the calculation of the required storage and production capacity required. An example output of the storage model is given in Figure 3-1. The left-hand side figure is the balance of gas demand and production, in which periods where demand is greater than generation are supplemented by storage and vice versa. The right-hand side graph is the resulting storage requirement to satisfy the annual balance, where number of salt caverns has been used as the metric for storage capacity (with an equivalent capacity of 50 GWh per cavern).

Figure 3-1: Example Storage Model Output



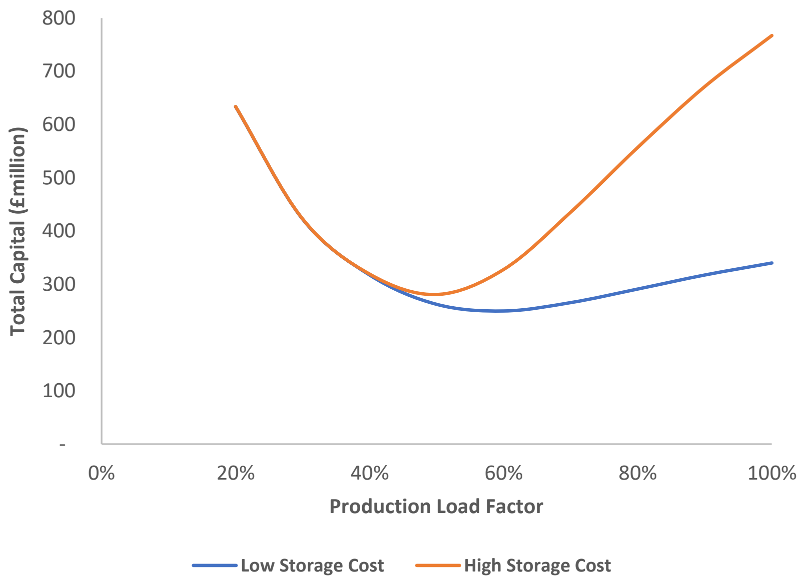
From the example analysis shown in Figure 3-1, a production load factor can be found and therefore a total capex vs load factor relationship can be explored. The capital cost values used for the production and storage are given in Table 3-1. Blue hydrogen was used as the production technology due to its dominance of supply and the load factor controllability. Bulk seasonal storage was taken to be salt cavern based. The capital figures for production[20] and storage[21] were identified from market assessments.

Table 3-1: Capital Cost Factors

Technology	Unit Capacity	Unit Cost (£million)	Capital Factor
Production	360 MW	200	£0.56 million/MW
Storage (low)	50 GWh	20	£0.40 million/GWh
Storage (high)	50 GWh	60	£1.20 million/GWh

The results of the total capex vs load factor analysis are shown in Figure 3-2.

Figure 3-2: Hydrogen Storage-Production Relationship



The two sensitivity curves are identical below 40% production load factor due to 40% load resulting in sufficient production capacity to provide peak demand and therefore require no storage. The optimisation curves in Figure 3-2 demonstrate the highly sensitive nature of the total capex requirements to storage costs. The minimum total capex requirements were found in the load factor range of 55-60%, based on the storage cost range, with total capex in the range of £250 million to provide the hydrogen production and storage requirements for Cardiff. If low-cost storage is available then there is a wide range of system design modes available for the supply of hydrogen, without incurring a material total capex penalty. However, if only high-cost storage is available then the system design for hydrogen supply is constrained to only supplying sufficient storage to provide flexibility for the top tranche of peak demand, and allow production assets to flexibly match demand for the majority of the year.

This analysis allowed a preliminary assessment of production and storage costs to be seen in aggregate as the total supply costs. A more detailed economic assessment based on total levelised cost of supply would yield a more accurate result, however capex was seen as a sufficiently suitable proxy for the purposes of a preliminary assessment.

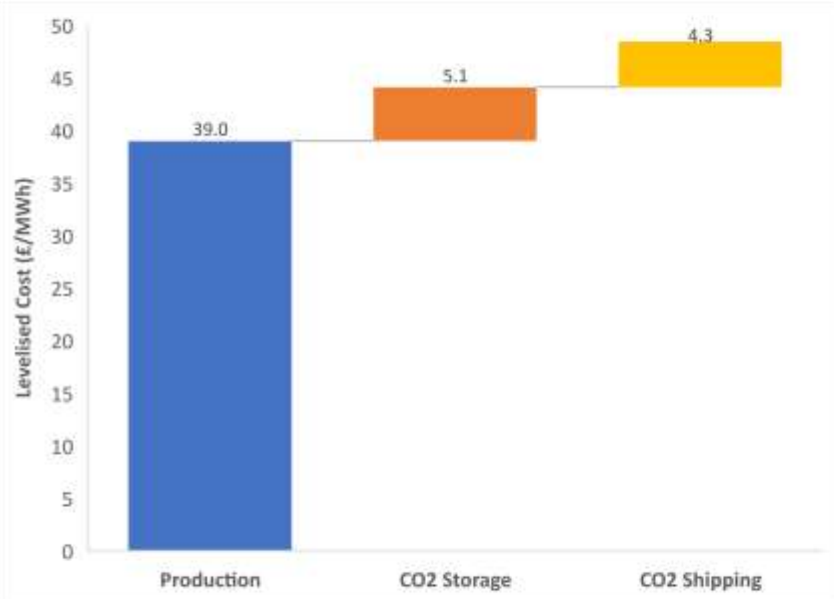
3.2 CCUS

The costs of CCUS were embodied within the costs of the blue hydrogen economics assessed. Previous research on CCS options for south Wales[22] determined that carbon dioxide shipping from the point source of the captured carbon dioxide to a CCS facility elsewhere in the UK would be the most economic local option. An example of a potential CCS facility suitable for south Wales would be depleted natural gas fields in the Irish Sea or Liverpool Bay.

The carbon dioxide shipping charge calculated for south Wales was found to be £17/tCO_2. Once shipped, the carbon dioxide would then need to be stored at a CCS facility. The BEIS CCUS Advisory Group has issued guidance on CCS costs in the UK[23], with a central figure of £20/tCO_2 as the 'gate fee' to store carbon dioxide. Therefore, the total CCS costs for any regional blue hydrogen production in the Cardiff area was taken to be £37/tCO_2.

These CCS costs were embodied within the levelised cost of blue hydrogen. The breakdown of the total levelised cost of £48/MWh is given in Figure 3-3.

Figure 3-3: Blue Hydrogen Levelised Cost Breakdown



Therefore, the CCS contribution within the levelised cost of blue hydrogen was found to constitute 20%. This regional assessment was undertaken to explore if local production was economically feasible. Although the resulting levelised cost of hydrogen is slightly greater due to the additional cost of carbon dioxide shipping, the total levelised cost of hydrogen was still found to be economically feasible in comparison[7, 18] to other hydrogen supply options elsewhere in GB.

To explore the logistics of local hydrogen production, the logistics of the carbon dioxide shipping was explored. The total annual shipping tonnage was found, with CCUS tanker capacity[24] taken as 10,000 tonnes. The annual tanker requirements for the net-zero scenario outlined in Section 2.2 were found to be 50 tankers per year. This annual tanker requirement was deemed to not present any material logistical constraint.

4.0 HYBRIDISED ENERGY SYSTEM

4.1 Hybrid-Hydrogen Relationship

To explore the relationship between the supply of hydrogen within a regional energy system and the deployment of hybrid heating technologies, a process of incremental hybrid deployment was carried out within the net-zero model outlined in Section 2.2. This process involved increasing the proportion of homes heated with hybrid technology in set increments, and proportionally reducing the allocations of other heating technologies. This process was repeated until the bounding case of 100% hybrid deployment was achieved (i.e. all homes heated with a hybrid system).

The modelling logic of Pathfinder Plus, with respect to hybrids, will preferentially utilise the heat pump over the gas boiler. Only if insufficient low carbon electricity is available to satisfy the heat load resulting from the heat pump will the system be switched to the gas boiler. Therefore; inherently, the hybridisation of gas boiler heated homes results in reduced gas demand. Within a net-zero scenario of a hydrogen converted gas grid, this manifested itself as:

1. Reducing the necessary hydrogen production capacity required to satisfy gas demands, as well as,
2. Reducing the logistical requirements of any CCUS system associated with the reduced blue hydrogen production.

These effects were quantified, along with other system effects of a hybridised energy system – which are detailed in Section 4.3. Table 4-1 outlines the domestic heating profiles used to assess the system characteristics of an incrementally hybridised energy system.

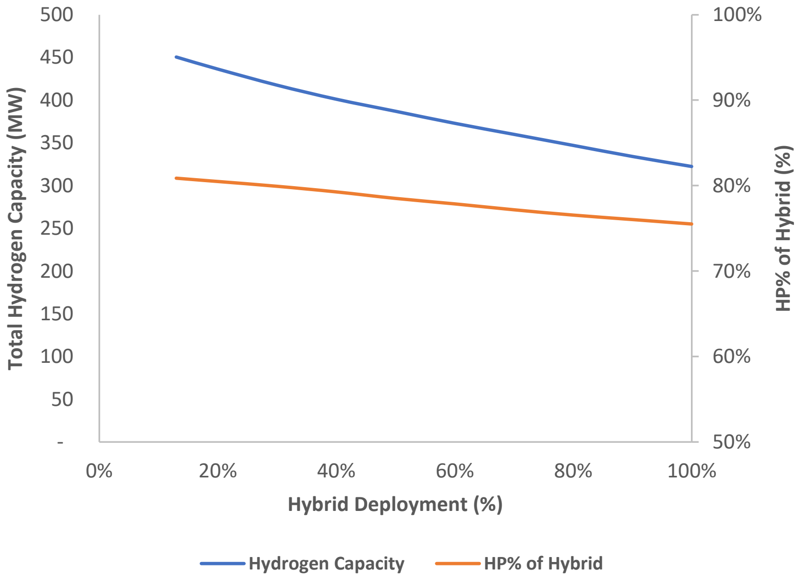
Table 4-1: Hybridisation Heating Profiles

Technology	Base Case	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7	Step 8	Step 9
H2 Boiler Only	58%	54%	47%	40%	33%	27%	20%	13%	7%	0%
Storage Heater	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Heat Pump	29%	26%	23%	20%	17%	13%	10%	7%	3%	0%
Hybrid (Heat Pump & H2 Boiler)	**13%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Biomass	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Note: Full hydrogen boiler and full heat pump counterfactuals are described in chapter 5

With each hybridisation step, the required hydrogen production capacity was recalculated, along with the proportion of heat being delivered by the heat pump element of the hybrid system. The results of this analysis are shown in Figure 4-1.

Figure 4-1: Hybrid-Hydrogen Relationship



The total hydrogen capacity requirements of Cardiff were found to reduce due to the deployment of domestic hybrid systems – at 100% hybrid deployment the hydrogen production capacity was found to be 320 MW, relative to 450 MW for the base case deployment of 13% hybrids. Even though hybrid deployment results in an incremental electrification of heating demands, the requirement for hydrogen never ceases all together. This is due to hydrogen capacity still being required to supplement heating when low carbon electricity generation was not available and to also continue the supply of gas to commercial users. Given the substantial installed capacity of wind generation assumed within the net-zero scenario (140 GW on a national scale), this demonstrates the vital role hydrogen capacity will play in a net-zero system to ensure the security of energy supplies within an intermittent-dominated electricity supply mix.

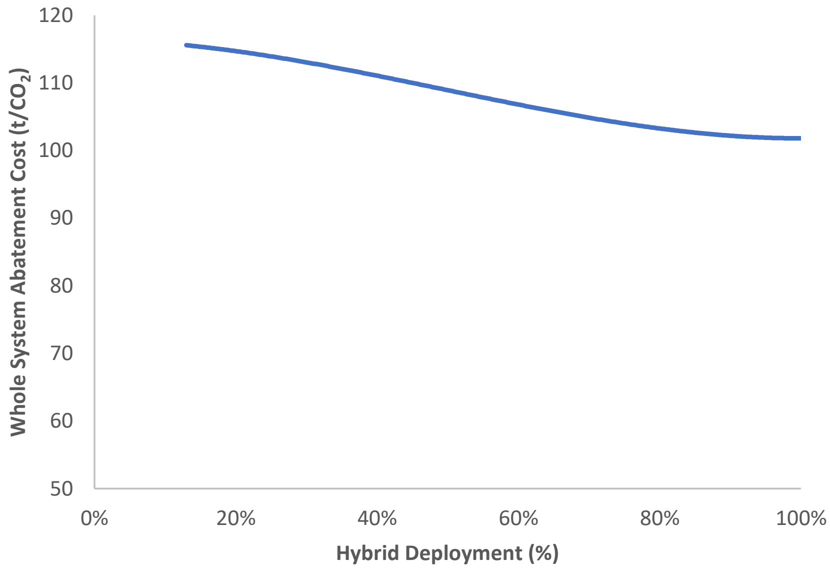
Although green hydrogen constituted 15% of the hydrogen capacity, it contributed a lower percentage of produced hydrogen. This was because the system conditions required to promote the need for hydrogen (i.e. low wind supply and high heat demand) also represented the conditions when green hydrogen production was at its minimum. Therefore, blue hydrogen represented the dominant actual supply as it is dispatchable by nature and therefore inherently flexible.

The proportion of heat delivered by the heat pump element of the hybrid systems varied relatively little across the full range of deployment steps assessed. The heat pump element delivered a reasonably consistent 75-80% of the heat, with the gas boiler element therefore delivering a remaining 20-25%. These results are in line with previous analysis of the potential split between the two elements of a hybrid system carried out by the Freedom Project[25]. The 20-25% of heat delivered by the gas boiler equated to the peak demand periods when heat demand outstripped low carbon electricity supply. The hybridisation analysis therefore found that at a boundary of 100% deployment of hybrid heating systems within a net-zero scenario with a hydrogen converted gas grid, domestic heating would be 75% electrified with peak demand remaining gas-based.

4.2 Abatement Costs

The economic implications of deploying hybrids within residential buildings for the purposes of decarbonisation has been assessed for each of the deployment 'steps' outlined in Table 4-1. The resultant whole system abatement costs were found for each step using the logic laid out in Table 2-7. Figure 4-2 outlines the resulting abatement cost implications of deploying hybrids within the Cardiff net-zero energy system scenario.

Figure 4-2: Abatement Cost Implications of Hybridisation



A steady reduction in the calculated whole system abatement cost was found as a result of hybrid deployment within the net-zero scenario. The economic implications of hybridisation manifest themselves in both capital and operating costs for consumers:

1. Hybrid heating systems have a greater capital cost than gas boilers, however have a lower capital cost than full heat pump systems. Therefore, the average incremental impact of hybridisation on household capital cost is a balance of these changes. Capital cost figures are given in Appendix 1.
2. Hybrid heating systems increase the degree of total domestic heat electrification. Therefore, for the same electricity supply capacities, the utilisation of the generation assets increases. This results in a reducing average levelised cost of electricity.

Regarding the carbon implications, there is a directional reduction in overall carbon emissions associated with hybridisation. This is due to the preferential operating mode of the hybrid, of being supplied with zero carbon electricity when available and then switching to the gas boiler when insufficient zero carbon electricity is available. The directional reduction is due to the following two impacts:

1. Converting a gas boiler to a hybrid reduces the total carbon emissions of the delivered heat, as a proportion of the gas supplied for heat is replaced with zero carbon electricity. The hydrogen has a very low carbon intensity due to the 97% capture rate of blue hydrogen and 15% of supply capacity being from green sources, however there is still a marginal reduction when hybridised, due to the use of zero carbon electricity.
2. Adopting a hybrid, compared with a heat pump, reduces the total carbon emissions of the delivered heat, as the peak heat requirements are satisfied via a more efficient supply chain. With a heat pump, peak heat is generally supplied with flexible dispatchable generation (open cycle turbines or the increasing fleet of gas engines) operating on gas, which are either in the UK or abroad and imported via an interconnector. With a hybrid, peak heat is still supplied by gas, but provided directly to a gas boiler. Gas network distribution to gas boiler heat conversion is a more efficient supply chain than open cycle electrical conversion, electricity grid distribution and then heat pump heat conversion (even accounting for a coefficient of performance).

It is the combination of both the economic and emissions implications of hybridisation that results in a reducing abatement cost as hybrids are deployed. Although the abatement analysis yielded a reduction in whole system abatement costs through hybridisation, these results should be treated with an appropriate degree of context given the inherent challenges involved in modelling an energy system 30 years into the future. Therefore, it would be prudent to think of hybridisation resulting in a directional reduction in abatement costs, of an order similar to that given in Figure 4-2, instead of applying absolute certainty with any individual results in the figure.

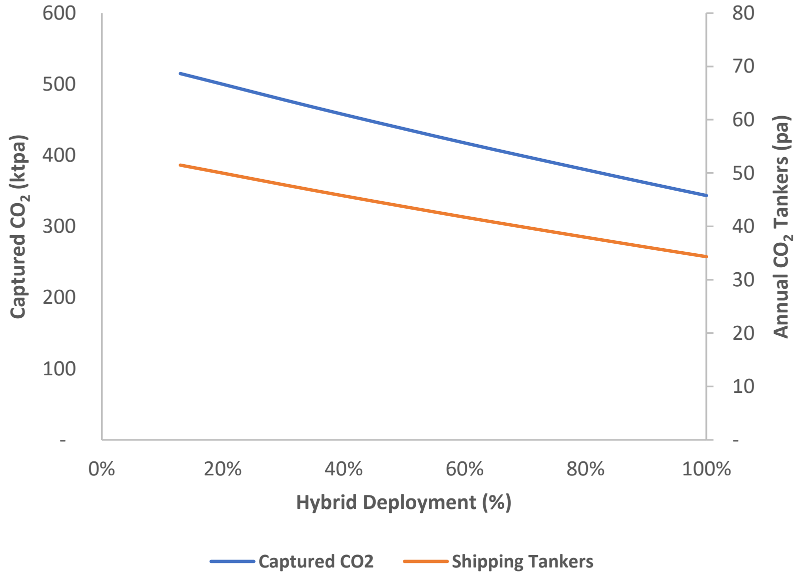
4.3 Whole System Effects

The whole system effects of hybridisation are far reaching, due to increased integration between the gas and electricity networks that results from the deployment of hybrid heating within residential homes.

4.3.1 Carbon Capture Utilisation and Storage

Hybridising residential heating results in a reduction of gas demand, as demonstrated by Figure 4-1. Within a net-zero energy system where gas supplies are 100% hydrogen, and blue hydrogen represents 85% of the production capacity, a reducing gas demand reduces the associated CCUS requirements. The outturn CCUS capture and shipping requirements are shown in Figure 4-3.

Figure 4-3: CCUS Implications of Hybridisation



Both the capture requirements of carbon dioxide and resultant shipping requirements of the captured carbon dioxide reduce by 35% as a result of full residential hybridisation. These system effects could be leveraged in the regional design of an energy system if constraints materialised regarding the capture or shipping of carbon dioxide. In practice, both the capture and shipping requirements across the full range of hybridisation assessed for Cardiff should be manageable. A capture rate of up to 0.5 $MtCO_2$pa is comfortably within the range of an industrial carbon dioxide capture plant, and tanker movements of up to 50 tankers pa is comfortably within the capacity of shipping jetties.

4.3.2 Hydrogen Storage

Gas network storage is classified into two categories; diurnal and seasonal. Typically, diurnal storage is managed through line pack (network pressure) and manages the intra-day variation in demand. Seasonal storage is managed through dedicated storage facilities and manages the inter-day variation in demand.

To determine the required diurnal storage capacity each gas-day (starting 05:00) a projection of the next gas-day's demand is made and the following 'flex' calculation is applied:

$$Flex = Gas\ Demand\ Between\ 05{:}00\ and\ 22{:}00 - \frac{2}{3} Total\ Forecast\ Gas\ Demand$$

Flex is required as, over a gas-day, the incoming rate of gas from the National Transmission System (NTS) into the Local Transmission System (LTS) is fixed. Therefore, all intra-day variability in demand must be managed through varying the pressure within the LTS.

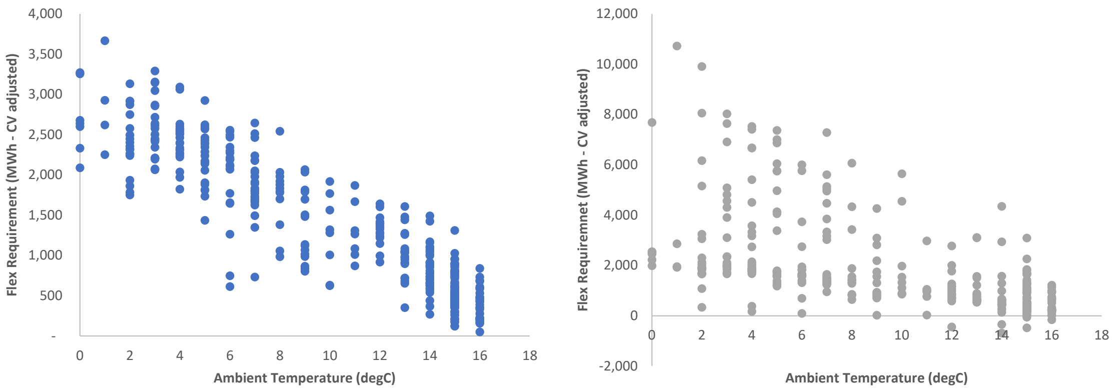
The flex requirement is an indication of the expected pattern of gas usage, given that:

- If flex > 0, then a higher demand rate is expected during the day than overnight. The magnitude of the flex gives the amount of energy needed to be stored overnight for the start of the next gas day,

- If flex = 0, then a constant demand rate is expected throughout the day and night, therefore no additional storage beyond linepack is required at the start of the gas-day,
- If flex < 0, then a higher demand rate is expected overnight than during the day, and the magnitude of the flex gives the amount of energy needed to be stored through the day for the night.

Historically, flex has always been positive and predictable, as gas demands have primarily been a function of a composite weather variable (ambient temperature plus wind chill) and the majority of domestic gas usage is during the day following a predictable pattern. A hybridised energy system results in a much greater variability in flex requirements. This is because, gas demand is no longer a function of just consumer heat demand but also of low carbon electricity availability. Given that, a hybrid will operate in heat pump mode until low carbon electricity supply reduces sufficiently that the gas boiler must then supply the required heat. Compounding this variability is electric vehicle charging. Given that the balance of charging behaviour and low carbon electricity availability will define the flexible generation operating behaviour, and hence gas supplies. Figure 4-4 demonstrates this; the left-hand side graph are the daily flex requirements of the 2018 model and the right-hand side graph are the daily flex requirements of the 2050 net-zero model with 100% deployment of hybrids. Both are shown against the average daily temperature for each day assumed by Pathfinder Plus. The flex requirements are calorific value (CV) adjusted to account for different gas qualities.

Figure 4-4: Flex Implications of Hybridisation



From the 2018 results there is a reasonably strong relationship between ambient temperature and flex requirements, with more flex required during colder days. This is consistent with a greater daytime gas demand during Winter. From the fully hybridised results, the relationship with ambient temperature is much weaker. This is indicative of other factors dominating gas demand patterns, such as low carbon electricity availability and electric vehicle charging patterns.

It should also be noted that the results shown are 'CV adjusted', this is to compare the two energy systems and take account of the fact that the 2050 system has a gas supply with a calorific value (CV) one third of that of the 2018 system (hydrogen vs natural gas). Therefore, pressure (or volume) variation will be much greater in the hydrogen gas grid as three times as much volume of gas would be required to satisfy the same energy demand.

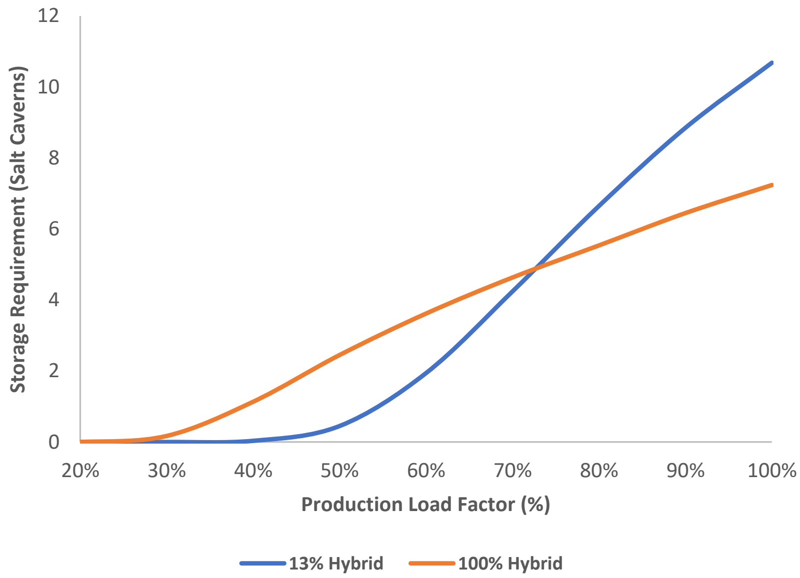
Another observation to note from the fully hybridised model results are the occurrences of negative flex. Flex requirements were found to be negative during some summer days with high wind availability during the day but low availability at night. During these days, when heat demand is naturally low, the requirement to charge electric vehicles that have been constrained from charging during the day results in a high overnight demand for flexible generation which in turn results in overnight gas demand being greater than daytime gas demand. This is not an operating mode the gas network has historically operated in, as this would require pressurising the network over the day to then let down overnight. This is the opposite to how the gas network operates today.

Overall, flex requirements were found to be much more variable as a result of decarbonisation and hybridisation, with flex requirements no longer a function of just ambient temperature but of the total system characteristics (heat, power and transport).

Seasonal storage has been assumed to take the form of salt caverns. It is recognised that local availability of salt caverns within the Cardiff area is low, however as the gas network is taken to be converted to hydrogen, storage does not necessarily have to be local to demand as long as a network is available connecting storage to both supplies and demands. South Wales does, however, have the potential to access storage opportunities in the salt deposits of Somerset or the use of hydrogen containing liquids. All diurnal storage needs have been assumed to be managed by line pack (or other storage mechanism); therefore, seasonal storage calculations were performed on daily average usage.

As outlined in Section 3.1, seasonal storage capacity requirements are a function the load factor of the hydrogen production. Given that production sized for peak demand requires no storage, whereas production sized for average demand requires more storage. To illustrate how hybridisation affects storage requirements, the two bounding hybridisation cases (13% and 100%) have been assessed. Figure 4-5 provides the output of this assessment.

Figure 4-5: Seasonal Storage Implication of Hybridisation

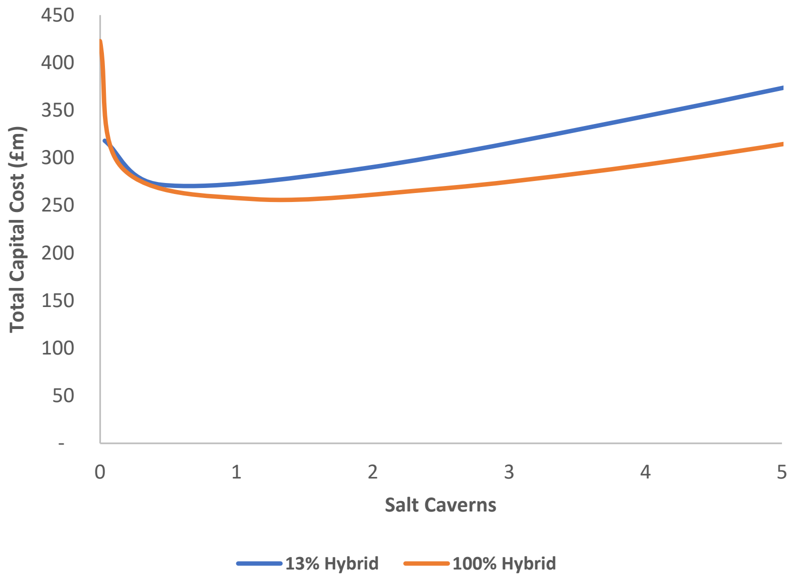


The overall hydrogen production requirement of the 100% hybrid case is lower than the 13% hybrid case, due to a greater proportion of domestic heat being supplied by low carbon electricity (primarily wind). Therefore, the maximum hydrogen storage requirement for the 100% hybrid case is lower than the 13% hybrid case.

As the pattern of hydrogen usage is much 'peakier' as a result of increasing hybridisation, more storage is required to satisfy demand at lower production load factors. This is because, within increasing hybridisation, the average demand reduces but the peak demand remains constant, therefore a greater proportion of gas demand is concentrated in the upper tier of peak heat demands.

Using an average storage price from Table 3-1, the below figure outlines the total capital cost profile for both the 13% and 100% hybrid cases as a function of storage capacity.

Figure 4-6: Total Capital Cost Implications of Hybridisation



It can be seen from Figure 4-6 that there is not a material difference between the two hybridisation cases when viewed from the perspective of total capital cost. As noted in Section 3.1, capital cost is a proxy measure employed for comparison, whereas the true measure of economic comparison should be the resultant levelised cost of energy. Nonetheless, the lowest capital cost requirements calculated for both cases are between £250 - 300 million with resulting salt cavern storage requirements of up to two caverns equivalent. Further analysis would be required, including local logistical constraints, to refine the analysis presented. However, this indicates that the overall capital requirements of hydrogen supply are not materially influenced by the degree of hybridisation.

The overall storage implications of hybridisation are therefore summarised as:

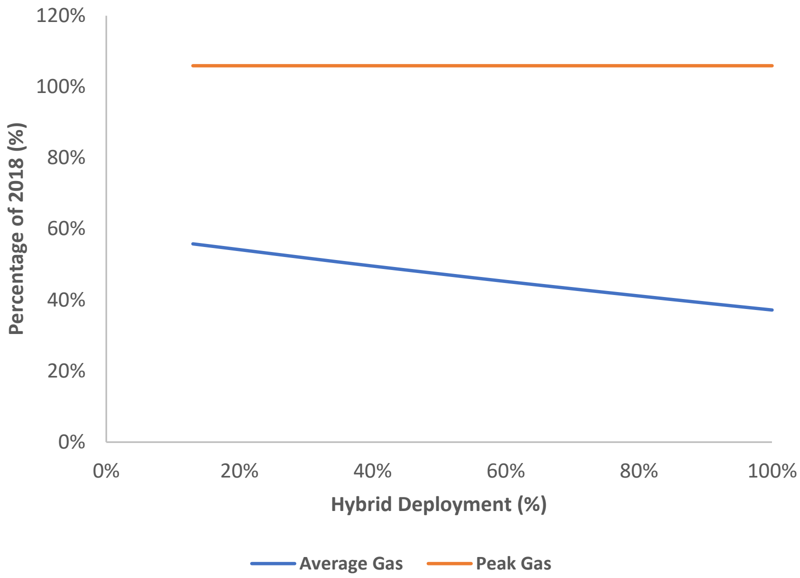
1. Diurnal storage requirements are materially influenced by hybridisation, as daily gas demand patterns become less dependent upon only ambient temperature

2. Seasonal storage requirements are not materially influenced by hybridisation, as seasonal storage is primarily influenced by peak requirements, which remain largely unaffected

4.3.3 Gas Network Operation

The introduction of hybrid heating within residential properties has been found to reduce overall gas usage, as a greater proportion of domestic heating is supplied via low carbon electricity generation with the heat pump. However, when heating demand outstrips low carbon electricity supply (either due to a dip in supply or increase in demand) the gas boiler element of the hybrid system becomes the primary heat source. This results in peak gas demand remaining unaffected by hybridisation. These two effects are shown in Figure 4-7, which shows both peak and average demand for Cardiff as a percentage of current (2018) peak and average demand.

Figure 4-7: Gas Network Operation Implications of Hybridisation



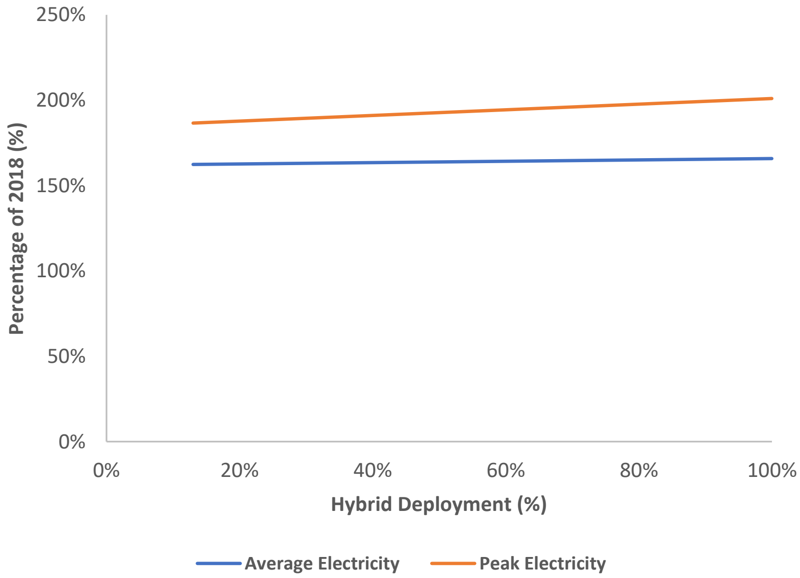
Peak demand is the defining characteristic of network capacity, as the expected 6 minute 1-in-20-year peak demand is used to inform gas network capacity requirements. Within the net-zero system assessed, peak requirements are marginally greater than current (2018) requirements. The average gas demand is materially affected by hybridisation. The average (which is simply the annual total divided by 8760 hours) demand factor reduces from 55% to 40% as a result of hybridisation, which is relative reduction of nearly 30%.

Overall, the current gas network supplying Cardiff is well sized to manage the requirements of hybridisation, with potential optimisation available of the exact delivery of gas based on the level of hybridisation.

4.3.4 Electricity Network Operation

The same analysis of assessing average and peak demands are presented in Figure 4-8 for the electricity network. Across all hybridisation cases there was found to be a material increase in both average and peak requirements of the electricity network.

Figure 4-8: Electricity Network Operation Implications of Hybridisation



Across the hybridisation cases assessed, peak electricity requirements rose from 190% to 200% of current (2018) peak demands. Therefore, across the range of hybridisation assessed within a net-zero energy system for Cardiff, the electricity network was found to require double the capacity of the current system. Average demand followed a less significant rise.

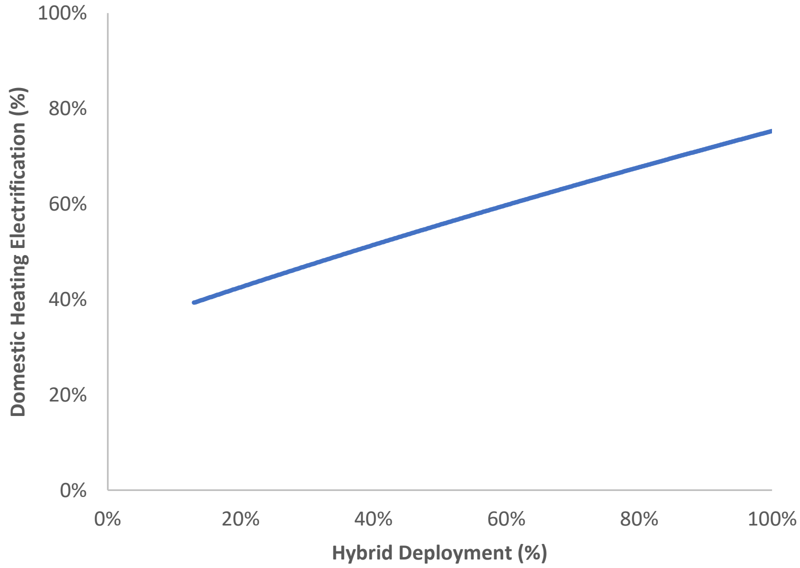
The baseload increases in both average and peak demands (corresponding to the hybridisation case of 13%) is largely due to the 29% of homes heated with heat pumps and a full electrification of personal transport. Around half of the baseload 90% increase in peak demand was found to be due to the electrification of personal transport, and the other half due to the partial electrification of residential heat. It should be noted that the split between constrained and unconstrained electric vehicle charging was optimised to minimise additional peak requirements, therefore the 50% increase due to electric vehicle charging should be seen as the minimum increase.

Overall, the electricity network was found to be undersized to satisfy the expected demand requirements of the net-zero scenario assessed. To ensure a reliable supply of electricity the network capacity was found to require doubling by 2050, relative to the current (2018) capacity.

4.3.5 Electricity Supplied for Domestic Heat

The hybridisation of the Cardiff net-zero scenario resulted in an increase in the overall electrification of domestic heat. This is because gas boilers remained the dominant form of heat delivery within the baseline scenario – 58% of homes. The overall proportion of domestic heat delivered via the electricity grid for each hybridisation step was evaluated, the results of which are given in Figure 4-9.

Figure 4-9: Domestic Heat Electrification via Hybridisation



The baseline level of domestic heat electrification was found to be 40% (corresponding to 58% gas boilers, 13% hybrids and 29% heat pumps), which rose to 75% domestic heat electrification when fully hybridised (100% hybrids). The remaining 25% of domestic heat was gas (hydrogen) based and represents the peak heat demand satisfied by the gas boiler element of the hybrid system.

5.0 COUNTERFACTUAL ANALYSIS

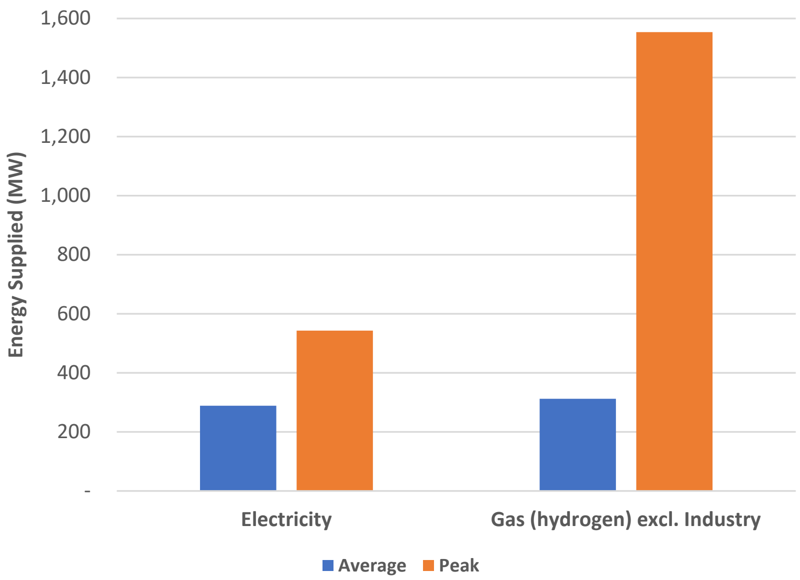
To allow accurate contextualisation of the hybridisation results outlined in Section 4, counterfactual analysis was undertaken for Cardiff. The two counterfactual cases assessed were; a full hydrogen scenario and a full electrification scenario. Three sensitivities were assessed for the full electrification scenario, which were; wind, solar and hydrogen-fuelled turbines. In each of these sensitivities, the selected electricity supply technology was scaled as needed to ensure sufficient supply was available to satisfy total demands. For each of the intermittent generation sensitivities (wind and solar power) a number of sub-sensitivities were assessed, varying the balance of additional generation with additional storage to identify the optimum cost case for both options.

The assessment of the counterfactual scenarios in combination with the hybridisation scenarios allowed the full range of residential heating options to be assessed (from 0% to 100% electrification). This overall comparison is undertaken in Section 6.

5.1 Full Hydrogen

The full hydrogen counterfactual was undertaken to assess the techno-economic implications resulting from no electrification of residential heating (i.e. all homes heated with a hydrogen gas boiler). To undertake this sensitivity analysis, the domestic heating profile was converted to 100% hydrogen boilers, along with a reduction of wind capacity from 140 GW to 100 GW (on a national scale). This was in recognition that in a 'no domestic heat electrification' scenario less wind capacity would be required. Overall, hydrogen production and storage capacity was then scaled as needed to ensure sufficient hydrogen supply was available to satisfy all heating requirements. The average and peak demands for gas and electricity that resulted from this analysis are given in Figure 5-1.

Figure 5-1: Full Hydrogen Counterfactual Energy Demands



The full hydrogen counterfactual resulted in the gas and electricity network delivering very similar total annual quantities of energy. Peak gas requirements remained largely unaffected, however peak electricity requirements reduced from a 90% increase for the baseline net-zero scenario relative to current (2018) requirements to a 50% increase in additional requirements. Therefore, relative to the baseline net-zero scenario, the additional capacity requirements of the electricity network were found to halve.

The hydrogen production requirements naturally increased, along with the shipping tanker requirements of the captured carbon dioxide associated with the reformation-based hydrogen production. The resulting supply and logistical requirements, along with the seasonal storage requirements (based on minimum overall capital cost) are given in Table 5-1.

Table 5-1: Hydrogen Production and Storage Capacity Requirements

Supply Parameter	Net-Zero Baseline	Full Hydrogen
Total Production Capacity (MW)	450	610
CO_2 Tankers (pa)	50	70
Seasonal Storage (No. of Salt Caverns)	1	1

The local hydrogen requirement was found to be 610 MW of generation and 1 salt cavern equivalent.

To understand the national implication, pro-rating to a national scale based on population ratios would yield a national hydrogen production capacity of 115 GW and 185 salt caverns. Table 5-2 outlines the resulting equivalent national installed capacity and storage profile of the full hydrogen sensitivity.

Table 5-2: Full Hydrogen Sensitivity Installed Capacities

Installed Capacity	Net-Zero Baseline	Hydrogen Sensitivity
Solar (GW_e)	25	25
Wind (GW_e)	140	100
Nuclear (GW_e)	15	15
Gas (GW_e)	50	50
Interconnector (GW_e)	25	25
Other (GW_e)	5	5
Battery Storage (GWh_e)	110	110
Hydrogen Production (GW_{th})	85	115
Hydrogen Storage (GWh_{th})	6,830	9,250

The overall abatement cost of the sensitivity was slightly lower but not materially different to the hybridised cases assessed, at a value of £90/tCO_2. Relative to the baseline net-zero scenario:

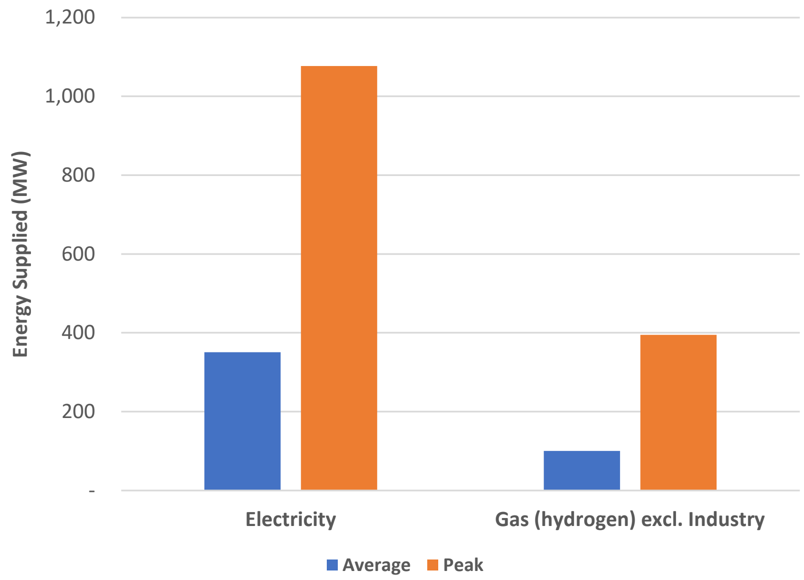
1. Overall domestic spend on heating technology reduced, as the annual cost of a gas boiler is lower than that of a hybrid systems or a heat pump
2. Capacity investment requirements in the electricity network reduces, due to a reduced peak demand
3. Diurnal gas storage requirements increased, due to greater daily demand,
4. Hydrogen supply investment increased to provide the required production capacity
5. CCUS logistics remained manageable

5.2 Full Electrification

5.2.1 Wind Sensitivity

The full electrification with wind sensitivity took the form of setting the domestic heating profile to 100% heat pumps, followed by increasing wind supply capacity (generation and storage) until the additional electricity demand was no longer met by gas-based flexible generation but being satisfied by wind-based electricity (either directly from the generation or from stored energy in batteries). The balance between additional generation capacity and additional storage capacity was optimised to identify the lowest overall abatement cost, this case was then taken as the output of the sensitivity. The average and peak demands for gas and electricity that resulted from this analysis are given in Figure 5-2.

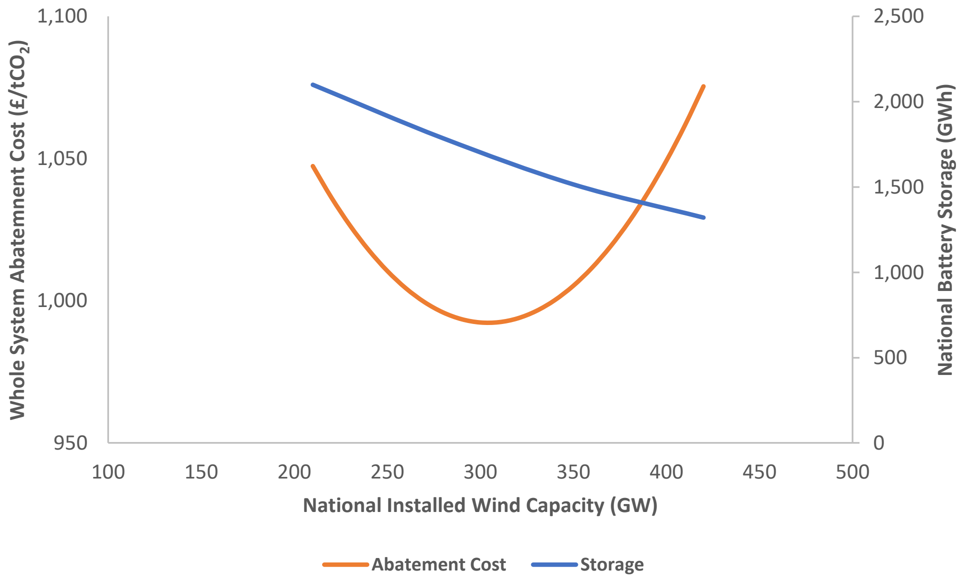
Figure 5-2: Wind Counterfactual Energy Demands



The resultant energy demand profile is an electricity-dominated system, as the electricity network is satisfying all domestic energy needs as well as commercial power requirements and transport. The gas network is providing heat for commercial buildings and a minority of gas vehicles. The resulting peak capacity requirements of the electricity network was found to be three times the current (2018) capacity requirements, which is a function of the electricity network having to supply domestic peak heating.

Figure 5-3 outlines the analysis of balancing generation and storage capacities to identify the lowest abatement cost for a full electrification via wind scenario. The cost of battery storage was taken from an IRENA report on projected installed costs of industrial Li-ion batteries(29).

Figure 5-3: Wind Capacity Abatement Optimisation



Across all of the full electrification via wind cases the resulting whole system abatement cost remained nearly or above £1,000/tCO_2. The lowest system abatement cost was found to be £990/tCO_2 which corresponded to a national installed wind capacity of 300 GW. The resulting battery storage capacity for Cardiff was found to be 9.2 GWh. If scaled to a national level with would be equal to 1,700 GWh of industrial battery storage, which is equivalent to 13,200 Tesla Mega batteries[32]. The final national installed capacity mixture is given in Table 5-3.

Table 5-3: Full Electrification – Wind Sensitivity Installed Capacities

Installed Capacity	Net-Zero Baseline	Wind Sensitivity
Solar (GW_e)	25	25
Wind (GW_e)	140	300
Nuclear (GW_e)	15	15
Gas (GW_e)	50	0
Interconnector (GW_e)	25	25
Other (GW_e)	5	5
Battery Storage (GWh_e)	110	1,700

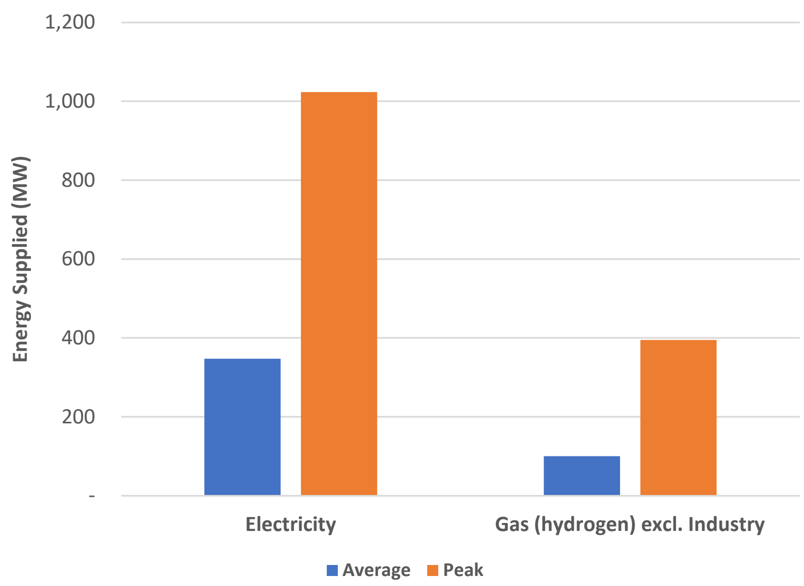
Installed Capacity	Net-Zero Baseline	Wind Sensitivity
Hydrogen Production (GW_{th})	85	0
Hydrogen Storage (GWh_{th})	6,830	0

The lowest abatement cost for a full electrification scenario, with wind supplying additional generation requirements, was found to be nearly 10 times the abatement cost for a full hydrogen or hybridised scenario. The reason for this is due to the requirements of peak heating. Peak domestic heating requirements are such that to satisfy them on an annual basis with intermittent generation requires a vast overcapacity to be invested alongside significant storage. This results in a diminishing returns relationship, where each incremental proportion of peak heating requires a greater incremental quantity of generation and storage capacity. The result of this relationship, once extended to satisfy the full peak heating requirement, is that the average load factor of electricity infrastructure reduces substantially. This reduction in utilisation manifests itself as a material increase in the levelised cost of electricity.

5.2.2 Solar Sensitivity

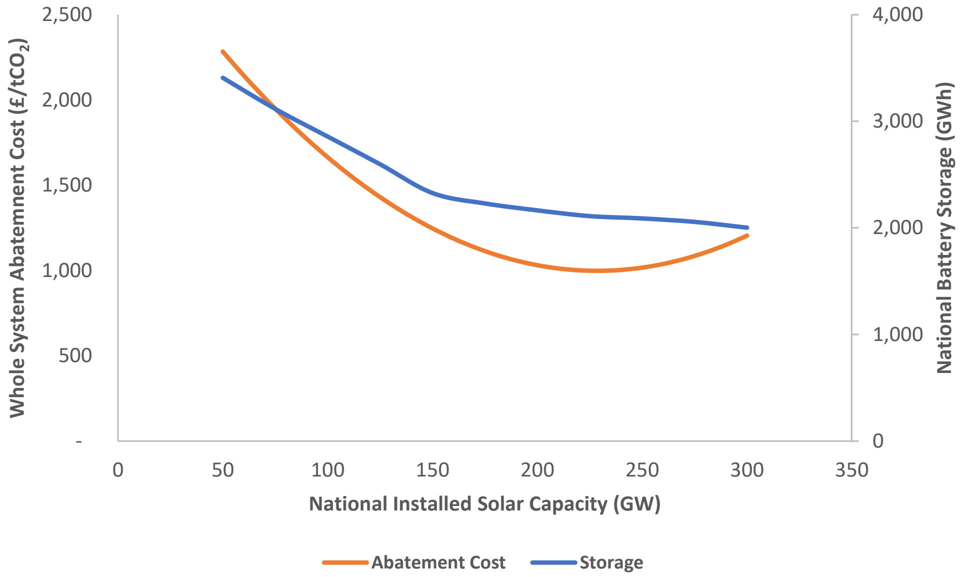
A similar process to the full electrification via additional wind was undertaken to explore a full electrification via additional solar sensitivity. All homes were set to be heated with a heat pump and additional solar generation and storage capacity was increased to satisfy all additional demands, with an abatement cost optimisation performed on the balance of generation and storage. The average and peak demands for gas and electricity that resulted from this analysis are given in Figure 5-4.

Figure 5-4: Solar Counterfactual Energy Demands



The overall energy profiles of electricity and gas were found to be almost identical to the wind counterfactual, with small differences in peak electricity requirements based on the charging profile of the additional battery storage. Figure 5-5 outlines the analysis of balancing generation and storage capacities to identify the lowest abatement cost for a full electrification via solar scenario.

Figure 5-5: Solar Capacity Abatement Optimisation



The optimum abatement cost for the solar sensitivity was found to be almost identical to the optimum abatement cost for the wind sensitivity, namely £1000/tCO_2. This whole system abatement cost corresponded to a total of 230 GW of solar capacity, at a national level. The national battery storage requirement was 2,100 GWh, which is equivalent to 16,300 Tesla Mega batteries. 11.3 GWh of storage would be required for Cardiff. It is observed that the abatement cost implications of installing less than the optimum capacity of solar are much greater than the implications of installing less than the optimum wind (Figure 5-3). This is because the resulting battery storage requirements for a sub-optimal solar capacity are much greater, due to solar availability being almost inversely proportional to heat requirements – heat demand increases with colder weather conditions, which normally corresponds to low solar output from a lower sun angle and fewer daylight hours. The final national installed capacity mixture is given in Table 5-4.

Table 5-4: Full Electrification – Solar Sensitivity Installed Capacities

Installed Capacity	Net-Zero Baseline	Solar Sensitivity
Solar (GW_e)	25	230
Wind (GW_e)	140	140
Nuclear (GW_e)	15	15
Gas (GW_e)	50	0
Interconnector (GW_e)	25	25
Other (GW_e)	5	5
Battery Storage (GWh_e)	110	2,100

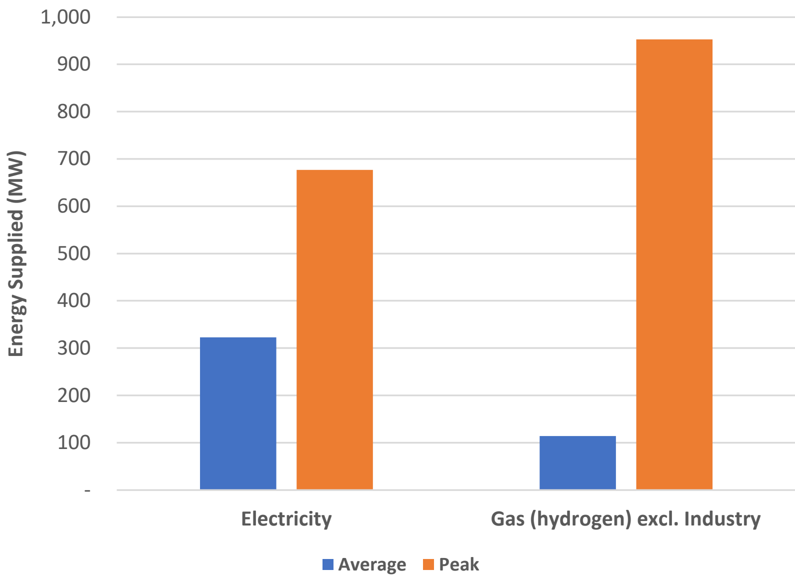
Installed Capacity	Net-Zero Baseline	Solar Sensitivity
Hydrogen Production (GW_{th})	85	0
Hydrogen Storage (GWh_{th})	6,830	0

The underlying technical justification for the substantial battery storage requirements and generation capacity is the same as the explanation provided for the wind sensitivity in Section 5.2.1. The requirement to satisfy peak heating needs with intermittent electricity generation results in vast over-capacity requirements (both generation and storage), which in turn results in a significant reduction in overall electricity infrastructure utilisation and ultimately manifests itself as a substantially higher levelised cost of electricity.

5.2.3 Hydrogen Power Sensitivity

A third and final full electrification sensitivity was explored, concerning the use of flexible generation to provide the additional electricity requirements to satisfy a fully electrified domestic heating profile. All domestic heating remained as heat pumps; however, hydrogen production and storage capacity was increased relative to the other full electrification sensitivities to allow sufficient hydrogen-based flexible generation to take place to satisfy the additional domestic heating electricity demand. The average and peak demands for gas and electricity that resulted from this analysis are given in Figure 5-5.

Figure 5-5: Hydrogen Power Counterfactual Energy Demands



The peak requirement of the gas network is substantially greater than the peak requirement for both the wind and solar electricity full electrification sensitivities. This is due to the gas network providing the energy source to satisfy peak heating requirements. The peak requirement of the electricity network was also found to be lower than the wind and solar sensitivities. The technical justification for this is that, in both the solar and wind sensitivities, the supply of electricity to heat pumps during peak heating periods was not the peak capacity requirement of the electricity network. The peak capacity period of the electricity network was in charging the industrial batteries required to then be held in reserve to supplement generation in providing power for peak heating needs. This is because the periods of surplus electricity generation were found to be less frequent that the periods of peak heating, therefore the significant quantity of industrial batteries required for the wind and solar sensitivities must be charged over a relatively short period of time whilst they can take advantage of the surplus supplies. Therefore, ultimately, the peak electricity network requirements are driven by peak heating requirements, however satisfying this requirement with flexible generation results in less additional network capacity to charge industrial batteries in preparation for supplying peak heat.

The resulting hydrogen production and storage requirements for Cardiff, along with the annual shipping tanker needs to cater for the captured carbon dioxide associated with the reformation-based production, are given in Table 5-5.

Table 5-5: Hydrogen Production and Storage Capacity Requirements

Supply Parameter	Net-Zero Baseline	Full-Electrification Hydrogen Power Sensitivity
Total Production Capacity (MW)	450	60
CO_2 Tankers (pa)	50	7
Seasonal Storage (No. of Salt Caverns)	1	<1

The 60 MW of hydrogen production, in combination with storage, to provide the peak electricity supply for peak residential heat is the equivalent of 10 GW of hydrogen fuelled electricity generation at a national scale. This generation capacity was found solely to satisfy domestic peak requirements, to provide a robust comparison with the other full-electrification sensitivities, therefore it does not include any hydrogen production requirements to provide peak supplies for commercial users. The overall installed capacity energy mix for the hydrogen power sensitivity, pro-rated to a national level, is given in Table 5-6.

Table 5-6: Full Electrification – Hydrogen Power Sensitivity Installed Capacities

Installed Capacity	Net-Zero Baseline	Hydrogen Power Sensitivity
Solar (GW_e)	25	25
Wind (GW_e)	140	140
Nuclear (GW_e)	15	15
Gas (GW_e)	50	50
Interconnector (GW_e)	25	25
Other (GW_e)	5	5
Battery Storage (GWh_e)	110	110

Installed Capacity	Net-Zero Baseline	Hydrogen Power Sensitivity
Hydrogen Production (GW_{th})	85	10
Hydrogen Storage (GWh_{th})	6,830	800

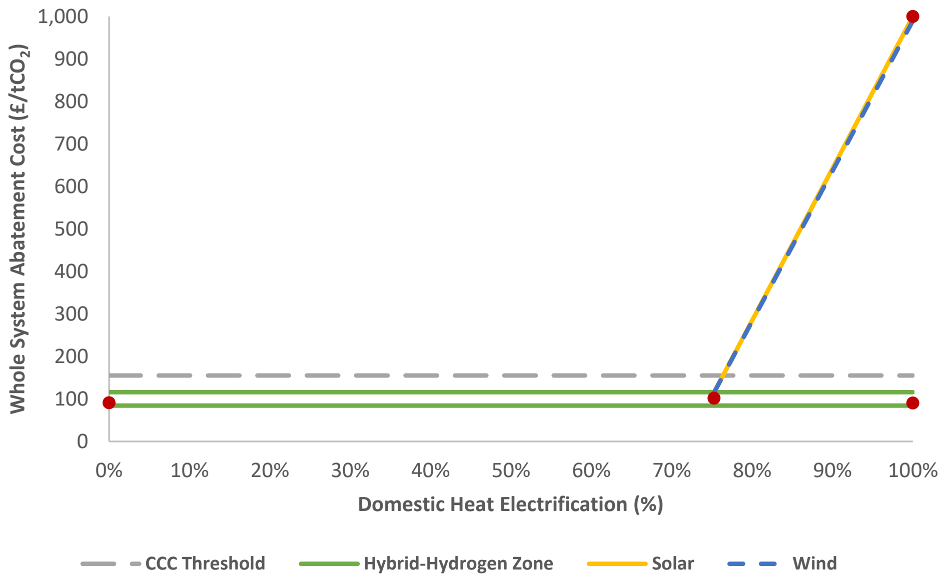
The overall hydrogen power sensitivity abatement cost for full electrification was found to be within the hydrogen-hybridisation range at £90/tCO_2. This is because the two scenarios of 100% hybrid deployment and heat pumps with hydrogen-supplied flexible generation are very similar from a macro system perspective. The two scenarios only differ in the delivery mechanism of peak heat – either supplying hydrogen to a gas boiler or to a gas turbine, which in turn supplies electricity to a heat pump. The order of magnitude difference between the abatement costs of the hydrogen power sensitivity relative to the solar and wind sensitivities demonstrates the system value of flexibility when catering for highly variable demands.

6.0 OVERALL DOMESTIC HEAT ANALYSIS

6.1 Abatement Cost

The core hybridisation scenarios, as well as the counterfactuals, can be compared using their abatement costs. The abatement cost of each scenario is shown against their degree of domestic heat electrification in Figure 6-1 below. The degree of residential heat electrification takes account of hybrids and full heat pumps. Within the CCC's net-zero report[4] the average abatement cost of residential decarbonisation to achieve a net-zero energy system is stated as £155/tCO_2. This reference point is also displayed in Figure 6-1 for the purpose of comparison. A select number of key scenarios have been plotted on Figure 6-1 as well.

Figure 6-1: Overall Domestic Heat Abatement Cost Curve



The green zone contains the scenarios which are based on a combination of hydrogen and hybrid technologies, inclusive of:

1. The full hydrogen counterfactual (0% electrification)
2. The 13-100% hybrid cases (40 – 75% electrification range)
3. The hydrogen-power full electrification counterfactual (100% electrification)

The yellow and blue lines correspond to the solar and wind full electrification sensitivities respectively.

The overall analysis of domestic heating demonstrates that material electrification can be achieved via the use of hybrid heating systems, without resulting in unacceptable carbon abatement costs. This is shown by the 75% domestic heat electrification that is achieved through the full deployment of hybrid heating systems, and the resulting abatement cost remaining within the CCC's threshold for net-zero residential abatement. Electrification beyond the 75% boundary with acceptable abatement costs can only be achieved through the deployment of full heat pumps married with hydrogen-supplied flexible generation.

The requirement to satisfy peak heating needs solely through intermittent renewable generation and storage was found to result in abatement costs an order of magnitude above the acceptability threshold. This is because intermittent generation is inherently unsuited to cater for peak heating demands. Therefore, substantial over-capacity is required in both generation and storage to store sufficient energy during period of surplus supplies in preparation for peak heating periods. The net result of this over-capacity is to substantially reduce the utilisation of the electricity supply chain, as well as to introduce vast quantities of industrial batteries, which results in a significant rise in the levelised cost of electricity.

The full hydrogen counterfactual (0% electrification) resulted in an acceptable abatement cost relative to the net-zero threshold and aligned with the other scenarios containing hydrogen in some form.

Figure 6-1 demonstrates the inherent suitability of flexible energy supplies to cater for highly variable demands, such as peak heating. The overall abatement cost was found to not be materially affected by the degree of domestic heat electrification, as long as the supplies of energy retained flexibility. This flexibility could manifest itself as supplying gas boilers during times of peak demand or supplying flexible generation to then supply heat pumps. It was only when the supplies of energy were no longer inherently flexible and dispatchability had to be produced by means of additional capital investment (i.e. industrial batteries) that the resulting net-zero system costs were found to be unacceptability high. Within all acceptable scenarios the availability and use of hydrogen was integral to the delivery of an acceptable abatement cost.

6.2 Scenario Discussion

Analysis by abatement cost allows a reasonable comparison of energy system scenarios. However, it does not take account of other important factors such as consumer acceptance, deliverability, and the cumulative emissions pathway.

Given that there is no clear abatement cost optimum with regard to the degree of domestic heat electrification (assuming flexibility in energy supplies) the other factors outlined above should be used to contrast and compare the different scenarios.

Consumer Acceptance is a challenging metric to quantify, however it is broadly understood to account for the level of disruption consumers would need to accept to achieve a certain outcome. In lieu of politically mandated initiatives, consumer acceptance will ultimately define the degree of deployment of any heating technology. Consumer acceptance can be increased by means of incentives to compensate for disruption, however the degree of compensation (incentives) would need to increase with increasing disruption, ultimately resulting in higher overall costs.

Therefore, as a general principle, net-zero strategies should rely upon minimising consumer changes (disruption) as otherwise a strategy is inherently dependent upon aggregated decision making by consumers to elect to disrupt their lifestyle more than they have to. Therefore, domestic heating strategies that result in minimising the degree of fabric changes to homes (invasive insulation, upgraded heat delivery such as larger radiators, bulky heating system installation etc) should be favoured over others that result in a greater degree of fabric changes. The application of this principle would result in favouring a strategy that balances gas boilers and hybrids over full heat pumps, given that the installation and use of gas boilers requires significantly less fabric changes to a household than full heat pump systems. The 'fabric-first' principle is no longer appropriate, since whole system solutions across technology, fabric and supplies should take an optimised retrofit approach to a least cost pathway for the same net-zero outcome. Fuel poor homes, however, still warrant a funded fabric efficiency approach to minimise their ongoing bills.

Deliverability accounts for the overall 'ease' of a strategy to be delivered. Deliverability takes account of consumer acceptance, but also involves the assessment of other factors. Any form of change is easier to deliver if the number of stakeholders requiring to take action is reduced; therefore, strategies that rely upon small groups of stakeholders taking action to achieve a given objective should be favoured over strategies that rely upon larger groups of stakeholders to be active participants.

Alongside this principle, strategies that can be mandated in a politically acceptable framework are also inherently more deliverable than those that cannot. This is part of the justification why carbon targets are prescribed by law, as otherwise achieving them would be contingent upon aggregated free will, which is inherently fickle. Combining these two principles results in favouring decarbonisation strategies that are politically more acceptable and can be achieved with fewer stakeholders having to make changes.

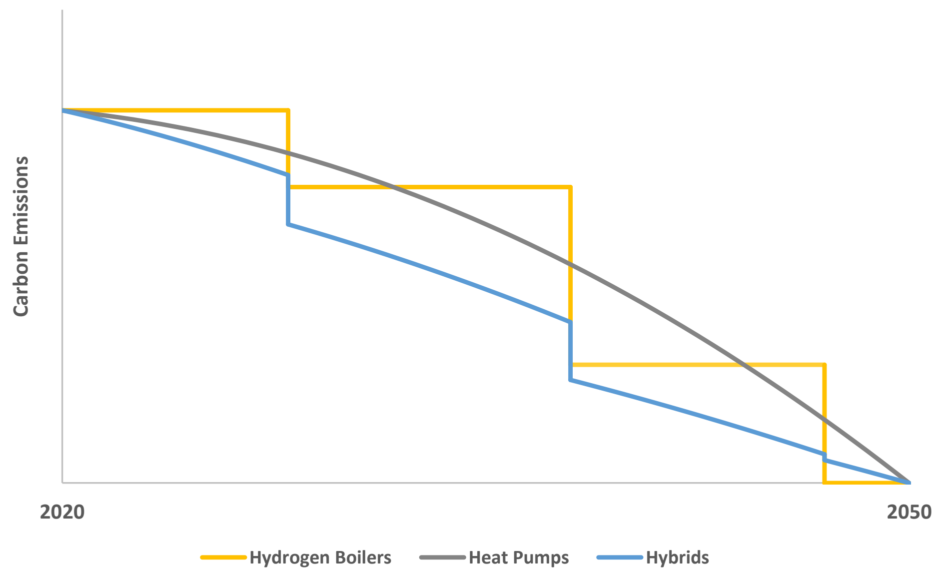
The application of these deliverability principles shows the benefits of decarbonisation strategies which are driven by supply decisions instead of demand decision (i.e. reducing the carbon intensity of supplied energy instead of removing demand for carbon-based energy). This is because demand decisions are consumer led and, to make any material difference, have to be taken en masse, whereas supply decisions are more centrally determined and therefore fewer stakeholders are involved who can be incentivised or legally compelled with greater ease.

Therefore, strategies that require minimal decision making by consumers and put the onus on a small group of entities that can be incentivised or compelling to act are inherently more deliverable. Within the context of domestic heat decarbonisation this would favour hydrogen boilers, then hybrids, and finally heat pumps. Primarily because this perpetuates the status quo of residential infrastructure and allows decarbonisation to be fully supply-led, instead of being reliant upon material change to residential infrastructure.

Cumulative Emissions Pathways are a quantifiable comparative metric which takes account of the emissions trajectory from the current energy system to a net-zero energy system. Setting a trajectory of pathway emissions is undertaken by the carbon budgets, which outline the carbon reduction steps required in 5 yearly increments to ultimately achieve the UK's carbon targets. Strategies which reduce cumulative emissions along the pathway should be favoured over strategies with higher cumulative emissions.

The application of this principle to domestic heat decarbonisation would favour hybrids over gas boilers and heat pumps. This is because a hybrid is able to absorb all of the genuinely available low carbon electricity available, and then utilise a decarbonising gas supply when the low carbon electricity availability reduces. Therefore, in comparison to a gas boiler, hybrids result in lower emissions due to the proportion of heat delivered by low carbon electricity. In comparison with a heat pump, hybrids result in lower emissions as a proportion of heat delivered by the heat pump element of the hybrid must be supplied by flexible generation or imported via an interconnector – both of which almost always have greater marginal emissions factors across the energy system than a gas boiler. The comparative analysis is illustrated in Figure 6-2.

Figure 6-2: Illustrative Cumulative Emissions Pathway Curve

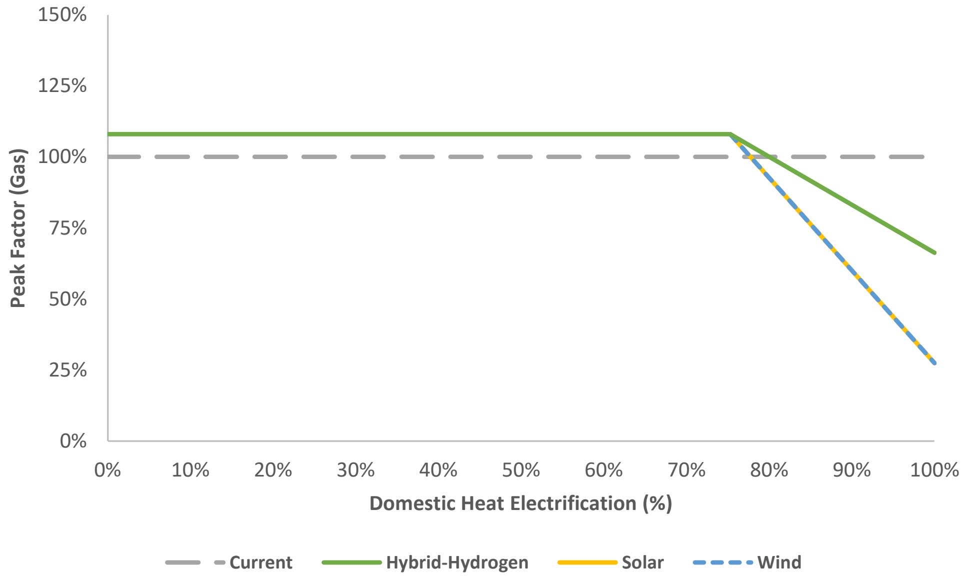


In this illustrative example, the total cumulative emissions are given by the area underneath each pathway curve. This example shows increasing supplies of renewable electricity, hydrogen blending in the late 2020s and then two example phases of local conversion to 100% hydrogen supply. The Hybrid First pathway benefits from the incremental deployment of low carbon electricity capacity as well as the hydrogen steps. The relative impact of the hydrogen steps on the Hybrid First pathway decreases with time, this is illustrative of the increasing proportion of heat being delivered by the heat pump part of the hybrid.

6.3 Gas Network

The function of the gas network varies substantially across the residential heat scenarios assessed, from supplying all domestic heating via hydrogen boilers (0% electrification) to supplying no domestic heating due to 100% electrification with renewable electricity generation. Commercial heating was not assessed at part of the scenarios, to allow isolation of residential premises and their implications on the energy system. Therefore, the gas network retains an energy delivery function, even within the 100% electrification sensitivities (for commercial gas demand and distributed power generation). Network investment is largely driven by peak capacity requirements. The peak capacity requirements of the gas network over the range of domestic heat electrification scenarios assessed is given in Figure 6-3. The peak capacity is shown as a ‘peak factor’, which is the ratio of each scenario’s peak capacity requirement to the current (2018) peak capacity requirement. This allows an assessment of the future investment scale required to deliver each scenario.

Figure 6-3: Gas Network Peak Factor



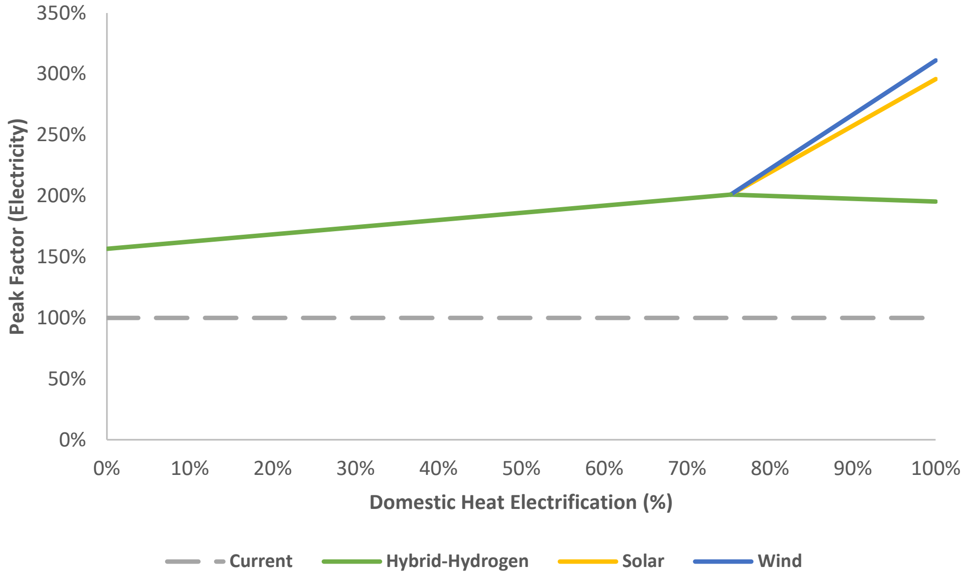
Up to an electrification proportion of 75%, the peak capacity requirements of the gas network remain unaffected. This is because within a gas boiler-only or hybrid scenario the gas network retains the function of supplying peak heat via domestic gas boilers. Across most scenarios the peak capacity of the gas network rises by ca. 10% relative to current system requirements (2018). It is only when electrification surpasses 75% that the peak capacity of the gas network drops below the current requirement, which is in line with the change in peak heat energy supplies. Both the solar and wind full electrification sensitivities result in the same reduction in peak capacity requirements, as both wholly replace the requirement for gas to service peak heat. The hydrogen-power full electrification sensitivity retains a greater peak capacity requirement as gas demand is retained to allow flexible generation to load-match peak heat requirements.

Overall, the current network capacity of the gas network is well-suited and flexible to the future requirements. Gas network investment is therefore more likely to be a function of storage requirements than capacity requirements, which are discussed in Section 4.3.2.

6.4 Electricity Network

The function of the electricity network also substantially varies throughout the range of domestic heat electrification scenarios assessed. The function of the two networks are largely inversely related across the range of electrification scenarios assessed. Much like the gas network, the electricity network is largely governed by the expected change in peak capacity requirements. To undertake a similar assessment of the peak capacity requirements of the electricity network, the peak factor for each scenario was assessed as a function of each domestic heat scenario, the results of which are shown in Figure 6-4.

Figure 6-4: Electricity Network Peak Factor



The minimum peak capacity increase of the electricity network was found to be 50%, which is largely due to the requirement to fulfil electric vehicle charging. Electrifying domestic heat up to 75% was found to require a further 50% increase in network capacity (100% increase in total). The electrification of the remaining 25% of heat was found to require a further 100% increase (200% increase in total) if undertaken via intermittent generation. There was no further capacity requirement found to electrify the last 25% of heat if undertaken via flexible generation.

As outlined in Section 5.2.3, the additional capacity requirement to electrify peak heat via intermittent generation is a function of the need to store energy in batteries in preparation for the supply of peak heat. This is because a material quantity of battery storage is required to balance the system (1,700 GWh and 2,100 GWh for wind and solar respectively, on a national scale) and the batteries can only be charged during periods of surplus supply. Therefore, a significant increase in network capacity is required to facilitate the necessary charging rate to enable the battery storage to be sufficiently charged to subsequently satisfy peak heating needs. This requirement is removed if the peak heat supply is catered for by flexible generation. This is a good demonstration of the system value of flexibility.

Overall, the electricity network was found to be significantly undersized currently to cater for the future demands it could potentially need to satisfy. At a minimum, an additional 50% in peak capacity was identified, with a further 50% required to facilitate any material electrification of domestic heating. Therefore, it would seem reasonable to conclude that a doubling of the electricity network capacity would be required to enable any meaningful domestic heat electrification, alongside the battery storage requirements to ensure the grid is appropriately balanced.

7.0 CONCLUSIONS

7.1 Regional Hydrogen Supply

The hydrogen production capacity required for the baseline net-zero energy system was found to be 450 MW, which was sourced from 380 MW of reformation-based hydrogen production with CCUS in combination with 70 MW of electrolytic hydrogen production from dedicated wind. These proportions were in accordance with the production split outlined within the CCC's net-zero report(4). The total hydrogen production requirement was a function of the degree of domestic heat electrification. Table 7-1 outlines the four key scenarios, as they relate to hydrogen production requirements, and the resulting supply requirements for Cardiff.

Table 7-1: Cardiff Hydrogen Supply with Domestic Heat Electrification

Supply Parameter	100% Hydrogen	Net-Zero Baseline	100% Hybrid Hydrogen	100% Electrification (Hydrogen Power)
Total Production Capacity (MW)	610	450	320	60
CO_2 Tankers (pa)	70	50	35	7
Seasonal Storage (No. of Salt Caverns)	1 - 2	1	1	<1

It can be observed that the production capacity across the full range of hydrogen-containing scenarios spans a factor ten in the range if 60-610 MW. Therefore, a broad range of potential hydrogen supply capacity is presented based on the degree of domestic heat electrification.

The resulting carbon dioxide tanker requirements to ship the captured carbon dioxide associated with the reformation-based hydrogen also spans a factor of ten in the range of 7 - 70 tankers pa. The logistical implications of transporting up to 70 tankers per year is not seen to be a constraint, therefore it is unlikely the carbon capture and storage processes needed for hydrogen production for Cardiff would prevent local supply. This provides degrees of freedom when planning the hydrogen supply infrastructure for Cardiff, as production (with associated CCUS) could either be cited elsewhere in the UK with the hydrogen transported to Cardiff, or could be located locally to the demand.

The supply optimisation found that the lowest total capital investment in hydrogen production and storage was typically associated with production load factors of approximately 60%. This result was fundamentally due to levelised cost of hydrogen being dominated by operating costs instead of capital costs, therefore investing in further production capacity was found to be incentivised relative to a counterfactual of minimum production capacity which results in maximum storage needed. As stated previously, this assessment would benefit from total levelised cost assessment, but is considered sufficient for these purposes. The storage requirements to cater for the seasonal fluctuations in demand were found to be up to 2 salt caverns (each cavern with a storage capacity of 50 GWh). Even though there is minimal salt cavern storage within the Cardiff area, this storage could be provided by other regions within the UK as long as a hydrogen transportation network provided the generation-storage-demand connections. South Wales does, however, have the potential to access storage opportunities in the salt deposits of Somerset.

The levelised cost of hydrogen was found to be variable based on the production technology. The levelised cost of reformation-based hydrogen produced locally (i.e. inclusive of a £17/tCO_2 shipping charge for the carbon dioxide) was nearly £50/MWh, with the base production asset accounting for 80% of this cost and the CCUS (shipping and storage) accounting for the remaining 20%. The levelised cost of the electrolytic hydrogen was on average £190/MWh, which was largely due to higher £/kW capital cost of the generation technology as well as fuel costs, although may reduce over time. The regional average hydrogen levelised cost was typically found to be £55/MWh, which is price competitive with other forms of low carbon gases such as biomethane, which has a value of £60/MWh based on the non-domestic Renewable Heat Incentive(30) (RHI).

The inherent variability of domestic heat demand results in flexible energy sources being far more suitable to satisfying demands. Within all of the acceptable abatement cost scenarios (below the £155/tCO_2 threshold taken from the CCC's net-zero report), hydrogen was the key energy source ensuring an acceptable abatement cost. Therefore, the availability and use of hydrogen, either directly in gas boilers, or supplied to flexible electricity generation, is critical to achieving a net-zero energy system at an acceptable abatement cost.

7.2 Hybridisation Effects

Overall abatement cost was found to be broadly similar with increasing deployment of hybrids, as described in Section 4.2. Although overall spend on heating technologies was found to increase with hybridisation (due to the higher capital costs of a hybrid system compared to a gas boiler) the better utilisation of the electricity network combined with reduced emissions resulted in overall lower abatement costs.

The impact of hybridising the Cardiff energy system was found to be extensive and offer tangible benefits to the energy system as a whole, a brief summary of the key metrics evaluated as part of this study, and how they are affected by hybrid deployment, is given in Table 7-2.

Table 7-2: Hybridisation Effects

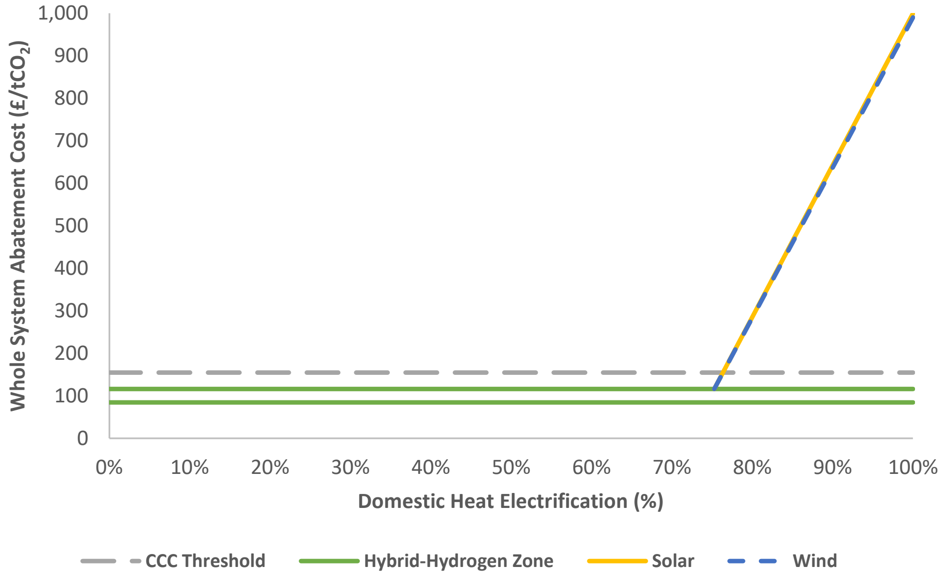
Supply Parameter	Net-Zero Baseline (13% Hybrids)	Full Hybridisation (100% Hybrids)
System Abatement Cost (t/CO_2)	115	100
Gas Network Peak Factor (% of 2018 peak)	110%	110%
Electricity Network Peak Factor (% of 2018 peak)	190%	200%
Total Hydrogen Production Capacity (MW)	450	320
Domestic Heat Electrification (%)	40%	75%

The effect of hybridising domestic heating is to reduce the reliance upon the gas network to provide the majority of heating, and instead only rely upon the gas network to provide peak heating. This leads to an overall reduction in the gas volumes consumed, but the network maintains the same capacity requirements to provide storage and flexibility. Concurrently, both average and peak demand for the electricity network increase as a result of hybridisation. There were found to be economic benefits of hybridisation, in the form of a lower system abatement cost, as well as emissions benefits as the total cumulative emissions along the pathway of achieving a net-zero energy system are lower with the deployment of the Hybrids First principle within domestic premises, as described in Section 6.2.

7.3 Electrification Limits

The degree of domestic heat electrification that could be delivered with the full domestic hybridisation was found to be 75%, with the remaining 25% supplied via a decarbonised gas network to satisfy peak heating needs. The overall cost effectiveness of electrification is given by Figure 7-1 below.

Figure 7-1: Overall Domestic Heat Abatement Cost Curve



The hybrid-hydrogen zone given above demonstrates that a high degree of cost-effective electrification could be possible, however only if energy sources retain a degree of inherent flexibility. Within a net-zero energy system this flexibility primarily comes in the form of hydrogen usage, either directly within domestic gas boilers or supplied to flexible gas turbines which in turn provide electricity to heat pumps. Removing gas-based supply to provide the required flexibility for domestic heating was found to result in system abatement costs increasing by an order of magnitude. This is due to the inherent unsuitability of intermittent generation to satisfy a highly variable demand such as domestic heating.

The intermittency of both wind and solar generation requires additional capital investment in the form of industrial batteries to enable generation to be dispatchable. The magnitude of necessary storage to enable this transition results in significant inefficiencies within the electricity supply chain, most principally reducing the utilisation of generation, storage and transportation infrastructure. This leads to far greater abatement costs when compared to providing that same degree of flexibility via a gas-based solution.

The impacts of electrification on the electricity network were found to be profound. With a potential doubling of network capacity required to facilitate a 75% electrification via hybrids, and tripling if 100% electrification is required without gas-based flexibility.

7.4 Technology Deployment

The analysis of how domestic heating electrification affects system abatement cost did not yield a standout optimum of domestic heating technologies. Therefore, it naturally follows that, in lieu of a theoretically derived optimum, it is incumbent to promote all decarbonisation technologies (hybrids, hydrogen-ready boilers, wind, solar, hydrogen production, CCUS etc) and allow the market and consumer choice to determine the ultimate mixture of technologies to achieve a net-zero energy system. This would require technology neutral support policies to enable all relevant technologies to compete, as this will drive improvements and innovation to then provide a broader range of options to consumers and businesses to consider. Some technologies are likely to require initial market stimulus.

The principles discussed in Section 6.2 outline the rationale for favouring strategies which rely on minimising consumer disruption, are deliverable and result in lower cumulative pathway emissions. The application of these principles within the context domestic heat decarbonisation, when no clear economic optimum has been identified regarding a degree of electrification, results in:

1. Decarbonisation strategies that rely upon supply-led decision making over demand-led decision making (for example, favours wind and hydrogen over retrofit home insulation to enable heat pumps), as well as,
2. Strategies that ultimately result in a net-zero domestic heating profile which is a balance of hydrogen gas boilers and hybrid heating systems. The exact balance of which would be determined by consumer choice and preference.

Technology deployment, along with network investment, will be crucial to achieving a net-zero energy system (both for Cardiff and the UK). Therefore, due care should be taken to ensure the market dynamics and consumer choice/preference are the ultimate deciders of a net-zero domestic heating profile, and not due to externally imposed or mandated adoption of any certain technology.

7.5 Cardiff Scenario Summary

Scenario	Abatement Cost/tCO2	Methane Boiler %	Hydrogen Boiler %	Hydrogen Hybrid %	Heat Pump/Direct Electric %
2018	-	88	0	0	12
2050 Baseline	114	0	58	12	27
100% Hydrogen	100	0	100	0	0
Hybrid First	100	0	0	88	12
Wind or Solar	1000	0	0	0	100

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A.1.0 CAPITAL COST OF HEATING TECHNOLOGIES

The capital costs of each heating technology used within the hybridisation analysis is given in Table A1-1. The CCC net-zero report was used as the base reference, providing capital costs of an installed hybrid system as well as an installed heat pump (excluding heat distribution upgrades and heat storage, which were assessed using other sources[27, 28]), the installed costs of a hydrogen gas boiler was taken to be 10% greater than the installed costs of a current natural gas boiler.

Table A1-1: Domestic Heating Technology Capital Costs

Technology	Installed Cost (£)	Notes
Hydrogen Gas Boiler	1,800	Natural gas boiler + 10%
Hybrid System	7,000*	Average between 2035 and 2050 cost projections
Heat Pump	10,300	Inclusive of heat distribution upgrades and hot water cylinder

*single unit hybrid systems may offer a reduced capital cost of hybrid installations in both immature and mature markets. These are currently being explored in the HyCompact[33] project and are expected to be around £4,500.