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Green light: Net zero emission energy system designs for the UK

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Contents

Glossary

AC	Air Conditioning
AGR	Advanced Gas cooled Reactor
BECCS	Bioenergy Carbon Capture and Storage
BEIS	Business Enterprise and Industrial Strategy (now DESNZ)
BEV	Battery Electric Vehicle
C, CO, CO_2	Carbon, carbon monoxide, carbon dioxide
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CO_2e	Carbon dioxide warming equivalent
COP	Coefficient of Performance
ΔH_0	Enthalpy
DAC, DACCS	Direct Air Capture, DAC with Carbon Sequestration
DH	District Heat
DHW	Domestic Hot Water
DV	Decision Variable
ESTIMO	Energy Space Time Integrated Model and Optimiser
ETSimpleMo	Energy Time Simple Model
FT	Fischer Tropsch
GDF	Geological Disposal Facility
GHG	Greenhouse Gas
H, H_2	Hydrogen
HC	Hydrocarbon

HP, ASHP, RAAHP	Heat Pump, AS air source, RAA reversible air to air
LCOE	Levelised Cost of Energy
NDA	Nuclear Decommissioning Authority
NE	Negative Emission
NH_3	Ammonia
NO_x	Nitrogen Oxides
OBR	Office for Budget Responsibility
PV	Photovoltaic (solar)
PWR	Pressurised Water Reactor
RAB	Regulated Asset Base
RF	Radiative Forcing
RWGS	Reverse Water Gas Shift
SHL	Specific Heat Loss (W/K)
Units	
SI Prefixes	k kilo (thousand), M Mega million, G Giga (billion), T Tera (trillion)
kW, MW, GW	Power W Watts
kWh, MWh, TWh	Energy Wh Watt-hours
MJ, GJ	Energy J Joules
Energy form suffix	e-electricity, th-thermal, c-chemical, f-fuel, g-gas e.g., kWe, GWhth, MWc, GWf, TWhg
kg, t	Mass metric: k kilogramme, t tonne
ha	Area: hectare (1/100 of a km2)
km2	Square kilometre
odt	Oven dried tonne (biomass)

Unconventionally, a 'scientific 'expression of physical and monetary units is used: number, space " ", prefix, unit. Quantities, including money, are expressed using SI prefixes – e.g., £billion is G£, £million is M£, £thousand is k£. /a is used for p.a. or /yr.

Acknowledgements

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Of particular importance is the use of meteorology and wind generation modelling by Dr Ed Sharp.

Thanks go to Bob Lowe and Catherine Lippold for their useful comments.

Headlines

- Use variable renewable solar and wind power.
- Use waste biomass; biocrops use much land and imported biomass is insecure.
- Nuclear power is too expensive and unreliable.
- Use energy storage to ensure demands are met every hour of the year.
- Provide heat and cool with heat pumps at consumers 'premises and via district heating.
- Replace fossil fuels in industry with electricity and hydrogen.
- Power road and rail transport with electricity.
- Fuel ships with renewable ammonia (or hydrogen).
- Aviation is the hardest problem because its high altitude emissions cause global warming and fossil kerosene emits CO_2 and replacing this with zero emission kerosene synthesised from limited biomass or atmospheric carbon and renewable hydrogen is costly. Most negative emission with direct air capture and storage (DACCS) is to balance aviation. Altogether aviation costs about 20% of the total energy system cost.
- DACCS using surplus renewable electricity primarily provides negative emissions to balance aviation and other minor emissions.
- Net zero designs are technically and economically secure as they require no substantial imports except perhaps kerosene, and exposure to international fuel prices is limited.
- At current oil and gas prices, net zero systems will cost about the same as now.

Summary

This report describes least cost designs for net zero carbon emission energy systems for the UK that might be developed over three decades. A central aim is to show that the systems designed will work in engineering terms hour by hour across the year. Not all possible technologies and system configurations can be assessed.

The most difficult problems of system design are aviation fuelling and high altitude warming, negative emissions and heating and cooling. Considerable space is given to a comparative analysis of nuclear and renewable generation as two leading options for zero carbon primary supply. Most primary energy in the scenarios is renewable electricity. Nuclear power is not cost competitive even assuming it is baseload, and is slow to build. Biomass is assumed to be restricted to waste biomass because of competition with food, the environmental impacts of biocrops, and the insecurity of UK production and import availability given climate change and population growth.

Most major energy demands are met with electricity, including most equipment and heating and cooling in the stationary sectors, and road and rail transport. Oil for ships is replaced with ammonia made from electricity, air and water. Heating with heat pumps in consumer systems or district heating is lower cost than hydrogen.

Reversible heat pumps can heat and cool and provide resilience to climate change, but like all consumer heat pumps will cause some disruption. These systems will require large scale energy network development and there is uncertainty as to the technicalities and costs of this. Some industrial processes require temperatures and chemicals that cannot be met with electricity, and renewable hydrogen or hydrocarbons are needed there.

Zero carbon electricity can be produced by renewables and nuclear power. The least cost generation mix found in this study is mainly offshore wind but with some onshore, and a substantial solar capacity. Nuclear generation does not appear in the least cost mix, beyond Hinkley C which is presumed committed and operational in 2050. Historically, nuclear capacity has suffered large unplanned outages which require back-up supply. System dynamic surpluses and deficits are managed with the storage of electricity in vehicle batteries and grid stores, heat in district heat stores, and chemical energy in hydrogen, biomass and fossil fuel stores. Hydrogen electrolysis and direct air capture and carbon sequestration (DACCS) use electricity surplus to other demands. It is found that spilling 20% or more of renewable generation is lower cost than investing in extra storage or usage process capacity such as of electrolysers or DACCS, but a major modelling limitation here is that interconnector trade with other countries, which can reduce both spillage and storage, is not included.

Aviation is a hard problem. Aviation demand management, shifting to modes such as electric rail, and more efficient aircraft have limited potential. For the foreseeable future, long range aircraft need kerosene which has carbon in it, and engine emissions of water and nitrogen oxides from any fuel at high altitude cause global warming. Beyond limited waste biomass, it is hypothesised that it is cheaper to use electrically driven direct air capture (DAC) to capture and sequester atmospheric CO_2 (DACCS) to balance fossil kerosene emissions from aviation, rather than using DAC carbon with renewable hydrogen to synthesise renewable kerosene in Fischer Tropsch plant. A preliminary analysis of synthesising renewable kerosene this way indicates this would increase total system cost but more research on this complex issue is needed. Plainly the assumed continued use of fossil kerosene has the political implications attached to allowing one major sector to continue emitting CO_2 at scale. Accounting for the costs of the required negative emission, aviation incurs about 20% of the total net zero system cost.

DACCS is an option for negative emissions to balance aviation and other greenhouse gas emissions such as from cement production. DACCS is a relatively simple process for which energy consumption and costs can be approximately estimated, but it is not implemented at commercial scale and its environmental impacts are uncertain. Other negative emissions options such as afforestation or bioenergy carbon capture and storage (BECCS) are not modelled here because of uncertainty and impacts but may play a role. Negative emission options are the least proven elements of system design.

At the 2023 fossil prices, net zero 2050 designs cost about the same as the current system, using the same costing model. Apart from fossil kerosene, zero designs are not subject to unpredictable international fuel prices and events affecting imports, and therefore provide security both economically and technically.

1. Introduction

The overarching objective is to produce cost minimised UK energy system designs having net zero carbon dioxide emission, which do not rely on net imports, and that utilise energy sources and technologies with acceptable environmental impacts. Prime aims are to show that the systems will function hour by hour across the year even with severe meteorological conditions and to calculate system costs. There is no attempt here to detail the wider economic or political aspects of the scenarios, or policies for implementation. The systems are optimised for 2050 and transitions over the years 2020 to 2050 are simulated, but at the time of writing it is nearly 2024 so these dates are more to illustrate a possible three-decade transition to net zero.

The modelling and report cover the whole system and are inevitably broad brush. Energy related greenhouse gas emissions such as methane and nitrous oxide are not modelled, but these will generally fall in line with carbon emission. Greenhouse gas emissions from sources other than energy, such as agriculture or cement, are not included in this work. Fossil fuels, even with carbon capture, are excluded except for aviation kerosene and some flexible generation. Renewable electricity driven direct air capture and carbon sequestration (DACCS) is the only negative emission option modelled and this is mainly to balance aviation emissions.

Net zero emission energy system designs are created using ETSimpleMo, a model which simulates hourly flows and costs in a dynamic energy system. It is called E for Energy and T for time, and Simple because it does not include Space (interconnector trading) and many other details; this is unlike ESTIMO (Energy Space Time Integrated Model and Optimiser) which includes interconnector trading across Europe and its effect on reducing storage need - see Gallo Cassarino and Barrett (Gallo Cassarino and Barrett, 2021). The aim is to include the most important demands and supply options in the system modelled, and to include hydrogen electrolysis and negative emissions using otherwise surplus electricity. Optimisation is applied to find the least cost net zero system designs within constraints. The focus here is on renewable systems with predominantly electric heating. Variant scenarios with hydrogen heating and high nuclear capacity are analysed and reported in less detail because they increase costs. The costs for building efficiency and heat and cooling are included in the model, but other end use costs such as for industrial process equipment or electric vehicles are not.

The system is outlined in section 2 and demands are described in 3. Technologies are set out in 4. In 5, the economic methodology and the design and optimisation procedures are described. In 6, scenarios are described and 20% DH heat share system (DH20) results are given including summer sample hourly simulations, technical and cost results for the transition from 2020 to 2050, and 2050 results for all the scenarios. An analysis of aviation kerosene made with fossil oil, biomass, and electricity and atmospheric carbon is given in 7.

A discussion follows in 8 with conclusions and further work in 9. Appendix 10 compares Green Light with other scenarios, gives heat demand data, and hourly simulation detail for summer periods.

2. System outline

2.1. Meteorology data

The meteorology data used are built on MERRA hourly reanalysis data for the 31 year period 1980 to 2010 which is available for the world at a spatial resolution of ½° latitude by ⅝° longitude (Rienecker, Suarez *et al.*, 2011). Ambient temperature, and wind and solar data were collated for the UK and surrounding waters and renewable generation is calculated with a complex suite of algorithms written in python by Ed Sharp (Gallo Cassarino, Sharp *et al.*, 2018). In this modelling the data years 2009 and 2010 were used.

The MERRA data used are for ambient temperature which drives space heat and air conditioning demand and heat pump efficiency. Solar radiation drives solar photovoltaic generation and building heating and cooling loads. It is assumed that solar collectors will be near population, and so solar radiation and the demand driving ambient temperature are all weighted by the UK population spatial distribution by km^2; this processing is by Ed Sharp.

Hourly MERRA wind speeds are collated for UK onshore and offshore wind farm locations. These are processed accounting for wind turbine height and wind speed power curves to produce normalised hourly output, GW output per GW installed for each wind farm location. These farm outputs are then weighted to produce total hourly percentage of installed capacity factors for the set of onshore and offshore farms; this processing is again by Ed Sharp.

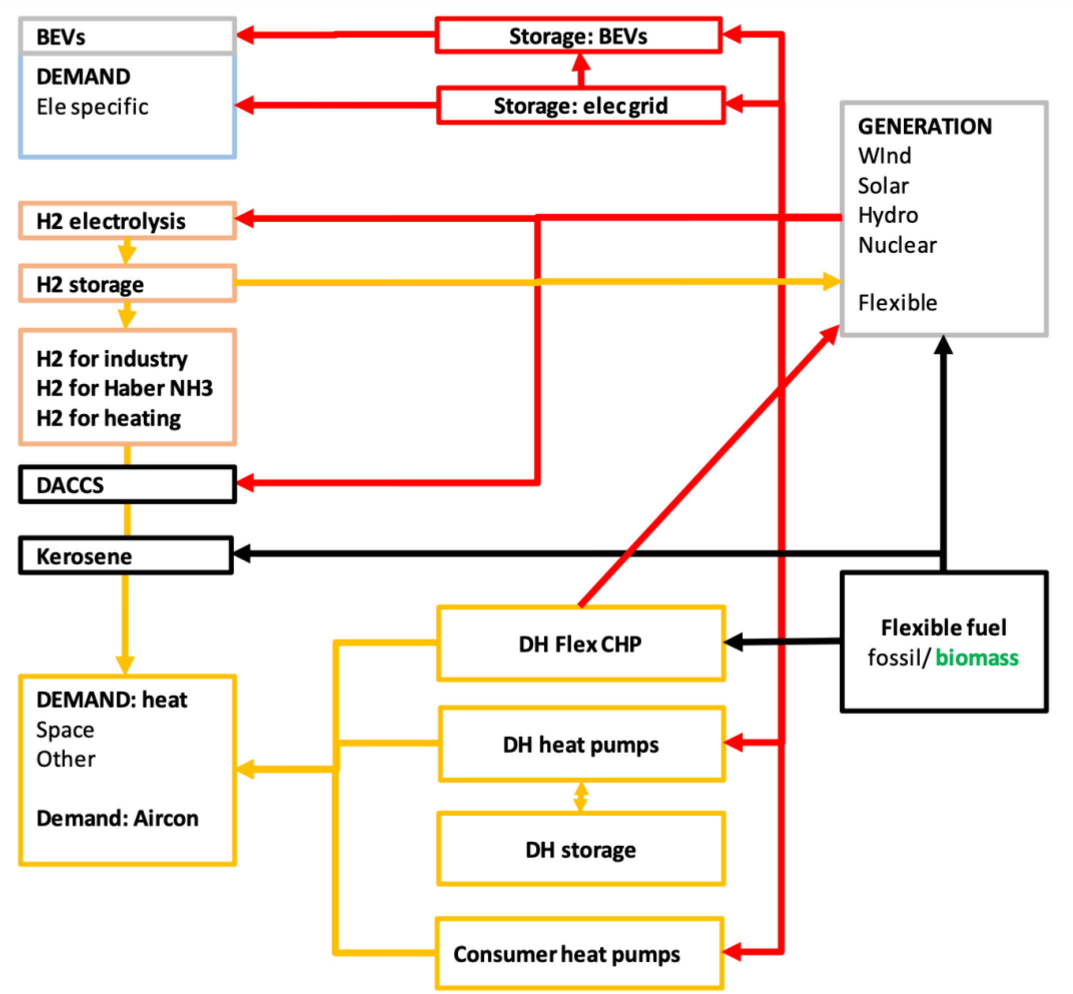
Climate change will generally increase ambient temperatures, and consequently decrease building and vehicle space heat demand, increase air conditioning demand, and increase heat pump heating efficiency and decrease cooling efficiency. The Met Office (Met Office, 2022) makes probabilistic projections of climate change for the UK in 2070, with a range 1.3 °C to 5.1 °C in summer, and 0.6 °C to 3.8 °C in winter in the high emission scenario with different probabilities. The scenarios explored here assume transitions to net zero by 2050, however, the system developed by that date will operate for decades after 2050 and so the Met Office 2070 projections are used as conditions for optimum system design. To simply reflect climate change, in 2050, an addition of 2 ^{o}C, approximately the middle of the Met Office range, is made to ambient temperature to the MERRA 2009/2010 data for each hour of the year, winter and summer: this is applied in all scenarios except one where, to explore the effect on the energy system's resilience, optimum design and operation, the scenario has an assumed temperature rise of 5 ^{o}C. Increases are linearly interpolated from 0 ^{o}C to 2 ^{o}C (or 5 ^{o}C) between 2020 and 2050.

Whilst the sea temperature around the UK has been warming over the past 40 years (Cornes, Tinker *et al.*, 2023), there is some uncertainty (Mccarthy, Jackson *et al.*, 2020) about the stability of the Atlantic Meridional Overturning Circulation (AMOC) current that might reduce marine heat transport to the UK and thereby lower UK temperatures significantly. A variant scenario with a temperature <u>decrease</u> might be developed in further work.

2.2. Energy system

Figure 1 outlines the energy system modelled. It is a great simplification of the real system and covers just the UK system; there is no modelling of other regions and international trading between them. Four large system stores are modelled: grid storage, EV batteries, DH thermal storage, and hydrogen storage for ensuring a continuous hydrogen supply to industry. These are modelled as single aggregate stores and costed assuming they are large with economies of scale. EVs and their batteries are not costed as they are assumed in all systems and not optimised. There will be a multitude of small stores such as domestic hot water tanks; these are outside the model detail but would add to storage.

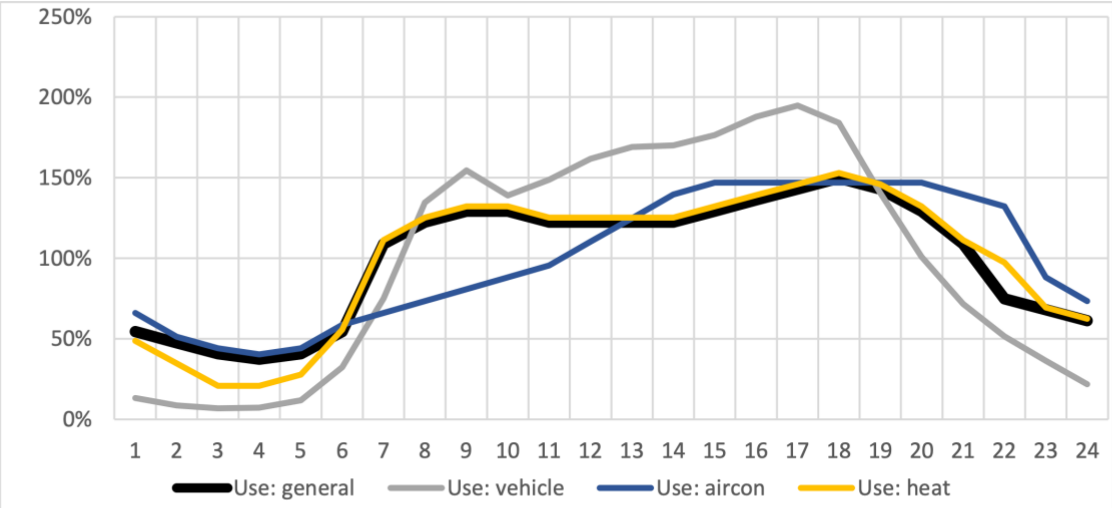
Figure 1 : System schematic



The system is simulated at hourly time steps. Least cost optimisation of system capacities for 2050 demands is carried out. Then the system demands and capacities are interpolated across the transition 2020-2045 at 5 year intervals and the system simulated for each of these intervals.

Useful energy demands are assumed to follow four normalised use patterns from Gallo Cassarino and Barrett (Gallo Cassarino and Barrett, 2021): one a general pattern, one for transport, one for building heating and one for building cooling. For buildings and vehicles, heating and cooling demands are further modified by weather. Useful energy is converted to delivered energy using delivered-to-useful energy using conversion efficiencies for each technology.

Figure 2 : Demand use patterns



Meteorology and renewable data

Two years (2009 and 2010) of hourly ambient temperature data and hourly solar, onshore and offshore generation data are used. Other work has shown that 2010 is a particularly difficult year in terms of renewable deficit so it is used for optimising the system.

2.3. System control algorithm

ETSimpleMo simulates the system hourly energy flows over one year with the algorithm set out in Table 1. Note that it is modelled as if there is just one of each major component – stores, generators, electrolysers and so on – when in fact there will be many of each type with different technical characteristics such as efficiency, ramp rate and so on. The assumption of single stores implicitly assumes all stores of a kind will reach empty or full at the same time, and that input and output power capacities will remain maximum until that time. In reality, there will be a distribution of storage levels and input/output power will gradually reduce as they fill or empty.

A major limitation of the algorithm is that it does not use forecasts of meteorology affecting future demands and couple these with storage levels to optimise operation over some future period; the algorithm only uses states for the current hour. This is discussed further in 8.1.

Table 1 : Basic ETSimpleMo model simulation logic

Demands	Weather independent	(Use pattern) x (average demand)
	Weather dependent	(Use pattern) x (Tint_oC - Tamb_oC) (Specific heat loss) - (IncGain)
	Elec: general	(Use pattern) x (average demand)
	Elec: BEVs	(vehicle use pattern) x (average demand) x (weather sensitivity)
	Hydrogen demand	Variable demand for heat + average demand for industry/NH3
	Ammonia demand	Average demand
Generation	Hydro	follows general use pattern
	Sol PV	hourly varying resources
	Win_on	hourly varying resources
	Win_off	hourly varying resources
	Nuclear	base load
	Flexible	dispatched if shortage
BEV	Charge	if battery nearly empty
Heat supply	**Consumer HP**	(Heat demand) (HP heat share)
	Elec use - cons HP	Consumer HP / COP(Tdemand, Tamb)
	District heating	(Heat demand) (DH heat share)
		1 Heat from store
		2 Heat from heat pumps to demand if store empty
		3 Heat and elec from CHP if more heat needed
Surplus	If surplus electricity and store not full	1 To EV battery
		2 To electricity store
		3 Put heat into DH store using DH heat pumps
		4 To H2 electrolyser
		5 To DACCS
Deficit	If deficit electricity	1 From electricity store
		2 From flexible generator

2.4. EV flows

EV batteries output to the current EV demand which varies with use pattern and weather. The assumption is made that the electricity flows one way from the grid to EVs and EV charging occurs when there is a surplus of renewable generation, within the maximum battery capacity (GWh) and charge rate (GW), except when the battery level reaches the minimum and charging is forced.

There is the possibility of using EV batteries to output to the grid, vehicle-to-grid (V2G), or vehicle-to-demand (V2D) to local demand such as in the home. There are many uncertainties about such operation, including:

- The impact on EV battery life of more cycling
- The overall efficiency and cost as compared to grid battery or other storage

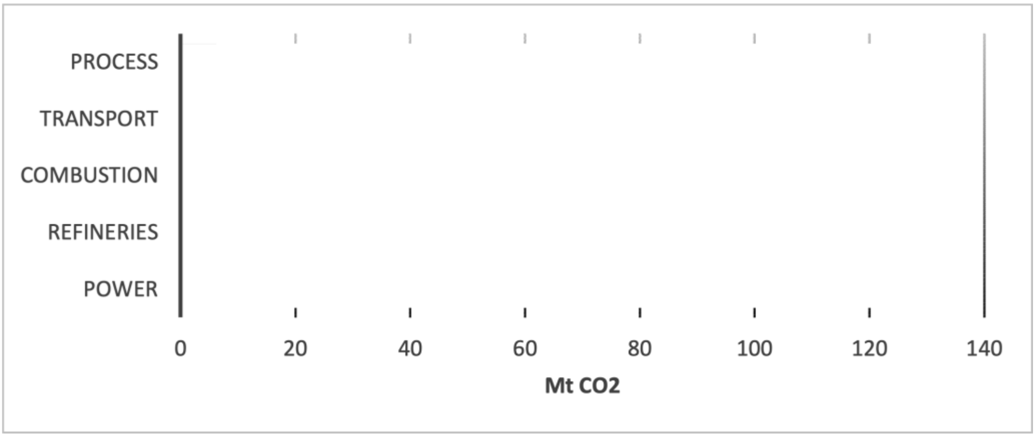
- The fraction of EVs that can be connected to chargers and demands when stationary
- The cost of infrastructure of charging points in individual off-road or street parking spaces as compared to fewer, high power charging points in public garages or car parks

Because of these uncertainties, bidirectional EV flows are not modelled here.

3. Demands

Demands are restricted to services using energy, and GHG emissions are restricted to CO_2 apart from aviation where high-altitude warming due to gases other than CO_2 is included. Fossil fuel related GHG such as methane and nitrous oxide will generally fall in line with CO_2. Figure 3 shows aggregated CO_2 emission. Chemical process CO_2 emissions such as from cement production are not included in the modelling here, but are minor, about 2% of total. Negative emissions with direct air capture and carbon storage (DACCS) could be increased to balance such 'non-energy 'emissions.

Figure 3 : UK CO_2 emission aggregate sources - 2020



Source: Table 1.3 Final UK greenhouse gas emissions national statistics: 1990 to 2020

There are these major demands considered in this work:

- Electricity specific uses (lighting, refrigeration, computing, motors, etc.)
- Transport – road, rail, shipping, aviation
- Building space heat and air conditioning, and non-space heat
- Industrial processes using hydrogen and electricity

Overall, the policy is to electrify all demands directly or indirectly. Hydrogen is assumed to be 'green 'electrolytic hydrogen, and not made from natural gas with steam methane reforming (SMR) because of its greenhouse gas emissions and implications for technical and economic security; SMR hydrogen is analysed by Barrett (Barrett and Gallo Cassarino, 2021). Hydrogen for heating is included as an option but as optimisation later shows it is uneconomic.

Electric vehicles are the dominant new technology and hydrogen vehicles are not included. Otherwise, hydrogen is reserved for certain industrial demands and fuel production, most notably for ammonia for ships.

Heat and cool

The bulk of heat and cool demand occurs in buildings and vehicles. An assessment of non-transport heat demand is given in 10.2. Most heat is low temperature, less than 100 ^{o}C, but about 6% of heat is high temperature mainly in industry. Heat pumps can supply heat up to around 150 ^{o}C so they can meet a proportion of higher temperature demand, but it is assumed some direct electric heating and hydrogen meets some of the industrial demand as described below. It is assumed that low temperature heat can be supplied with some mix of heat pumps, district heating (with heat pumps), and hydrogen boilers. Consumer heat pumps are assumed to be reversible air-to-air (RAAHP) providing heat and cooling is no extra cost. District heating and hydrogen heating with boilers would require additional heat pumps for air conditioning. District cooling is not included in the model. Consumer heat pumps are assumed to have little heat storage. District heat has heat storage and two possible heat sources – heat pumps and CHP using biomass or gas. DH schemes can range in scale from communal serving a few consumers to city wide systems, but DH is modelled as a single 'national 'system.

Transport

All land transport is electrified with battery electric vehicles (BEV) and electric rail. The useful energy for transport is assumed to be reduced by 20% by 2050 due to improved vehicle body efficiency; in addition, delivered energy is reduced because electric vehicle motors are two or three times as efficient as internal combustion motors.

Shipping energy consumption is assumed constant from 2020 – essentially assuming efficiency gains offset demand growth. Fossil oil is assumed to be replaced with ammonia (NH3) produced with the exothermic Haber process, with the energy and feedstock provided by electrolytic hydrogen and atmospheric nitrogen.

Aviation energy demand is assumed constant with efficiency offsetting demand growth, approximating scenario 1 of Jet Zero (UK Department for Transport, 2021). Waste biomass is insufficient to produce all aviation kerosene and it is assumed that no supplementary biocrops or imported biomass are used because of environmental impact, competition with food production and climate related productivity risks. Aviation fuel in the scenarios is assumed to be mainly fossil kerosene with a small fraction of synthetic kerosene made from biomass. Fossil kerosene CO_2 and aviation high altitude CO_2e emissions are balanced by DACCS (Direct Air Capture and Carbon Sequestration). It is hypothesised that this is a lower cost solution than making kerosene with DAC CO_2 and electrolytic H_2 input to the

Fischer Tropsch process: aviation fuelling is analysed and discussed further in section 7, but alternative aviation fuels have not yet been modelled in ETSimpleMo.

Industry

Industrial processes are highly variegated with some processes, such as cement, emitting CO_2 because of chemical change; some requiring high temperature heat (>400 °C) or direct heating, which cannot practically be met with electric heating and requiring combustion; and some using fossil fuels to produce organic (including carbon) products such as plastics. It is beyond the scope of this modelling to detail how these emissions can be reduced through means including efficiency, product use reduction, recycling, material substitution, carbon capture, and the use of renewable electricity and hydrogen. Industrial CO_2, such as from cement or iron production, might be captured and sequestered or combined with hydrogen to make hydrocarbons such as kerosene but this would not be net zero. A good summary of issues is provided by Gross (Gross, 2020). Here it is simply assumed that 40 TWh of fossil fuels providing high temperature heat based on BEIS data (BEIS, 2020b) is replaced by hydrogen, and an additional 20 TWh of hydrogen is used to replace fossil fuels used for other purposes such as iron production. 5 TWh of hydrogen is assumed used for ammonia production for fertilisers in addition to that for ships. Total industrial hydrogen demand (excluding ship ammonia) is then 65 TWh. This may be regarded as a 'placeholder' - plainly a deeper analysis is required of industry.

3.1. Weather sensitivity

Building and vehicle heating and cooling loads vary with weather, and alongside social activity patterns this is the principal cause of demand variation which impacts on renewables' correlations with demands and thence storage needs.

3.1.1. Building stock, modelling and efficiency

The building stock is modelled in ETSimpleMo as a single building. There is uncertainty about building heat losses, particularly of non-domestic buildings, and temperatures and occupancies. The numbers and losses of domestic and non-domestic buildings and their specific heat losses (SHL GW/K) are estimated in Table 2, with two estimates for non-domestic (a) and (b). A total 2020 building stock SHL of 9 GW/K is estimated comprising 7 GW/K for domestic and 2 GW/K for non-domestic buildings.

Table 2 : Domestic and non-domestic buildings stock

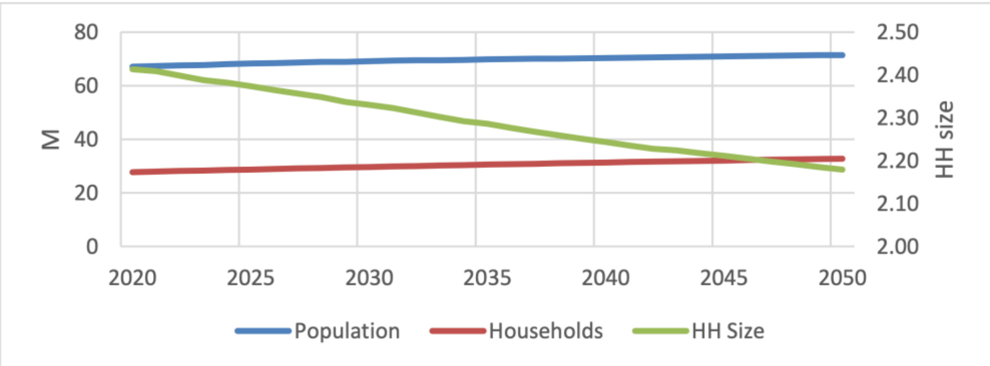
	Number M	GFA Mm2	Average m2/bldg	SHL/bld W/K	SHL tot(a) GW/K	SHL tot(b)
Dom	27.8	2363	85	250	7.0	7.0
Nondom	2.5	646	261	768	1.9	3.4
Total	**30.3**	**3009**			**8.9**	**10.4**

Changes in the SHL will be a balance between an increase because of a greater number or size of buildings driven by demographic and economic change; and a decrease because of the improved efficiency of new and retrofitted buildings. It is assumed that non-domestic buildings follow the same trend as the dwelling projections made below. With this, and incidental gains and the building specific heat loss (SHL in GW/K), the model approximately follows the 2020 space heat load calculated from ECUK statistics.

3.1.1.1. Domestic stock

Over 2020 to 2050 the UK population is projected (UK Government, 2021) to increase by 7% from 67 to 72 M, and households by a greater 18% from 27.8 to 32.8 M because of population growth and smaller households. Therefore about 5 M more dwellings (DLUHC, 2020) will be required, and given demolition perhaps 6 M new dwellings or 20% of the current stock. Given a reducing household size, average dwelling floor area may decrease and there may be an increasing proportion of flats with less external wall area; these trends coupled with energy efficiency will lead to a lower SHL per dwelling. These projections are charted in Figure 4.

Figure 4 : Population and households projection



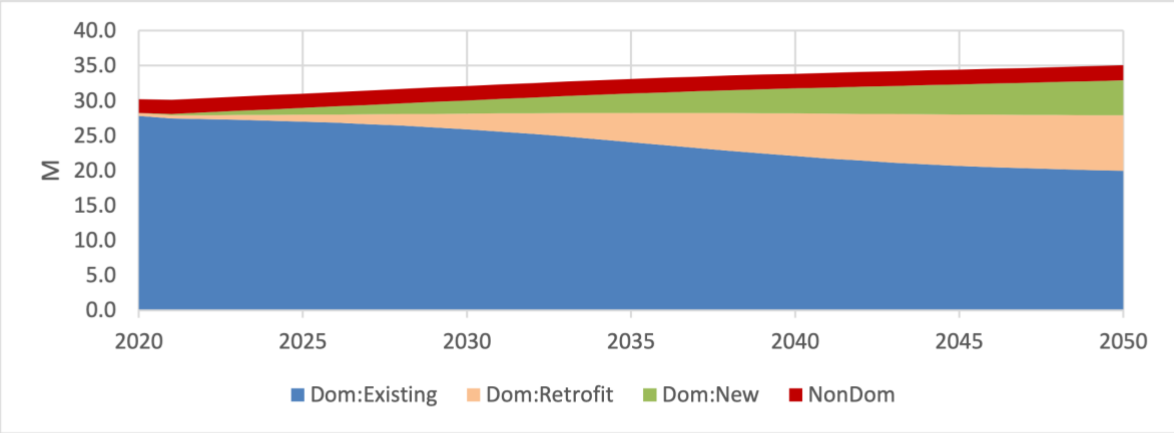
Retrofit encompasses many individual measures including wall, loft, and floor insulation and double glazing and many houses already have some of these measures. It is complex to account for this and there is a lack of data. A simple assumption is made of a 20% reduction through retrofit and 40% in new dwellings as in Table 3.

Table 3 : Specific heat loss of building stock segments

	Existing	Retrofit	New
Index	100%	80%	60%
SHL W/K	250	200	150

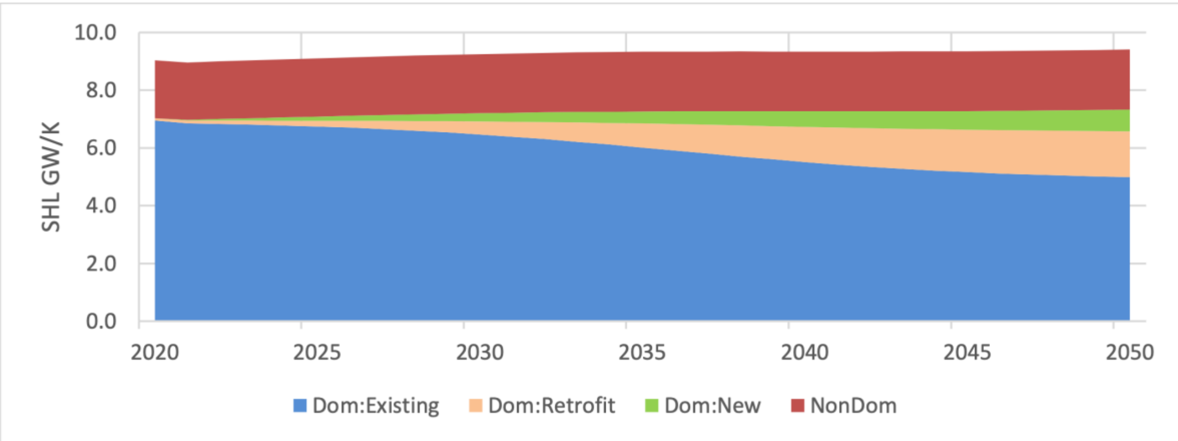
Assuming 30% of dwellings, about the same percentage as the pre-war stock, is retrofitted by 2050 and 5 M new houses are built, then the dwelling stock projection is as follows; with non-domestic building numbers assumed to increase with population. The stock projection is shown in Figure 5.

Figure 5 : Building stock numbers projection



These stock numbers may be multiplied by the SHLs to give the dwelling stock SHL increasing from 7 to 7.3 GW/K, and the non-domestic SHL increasing proportionately to 2.1 GW/K. With these assumptions the overall the stock SHL changes little as shown in Figure 6.

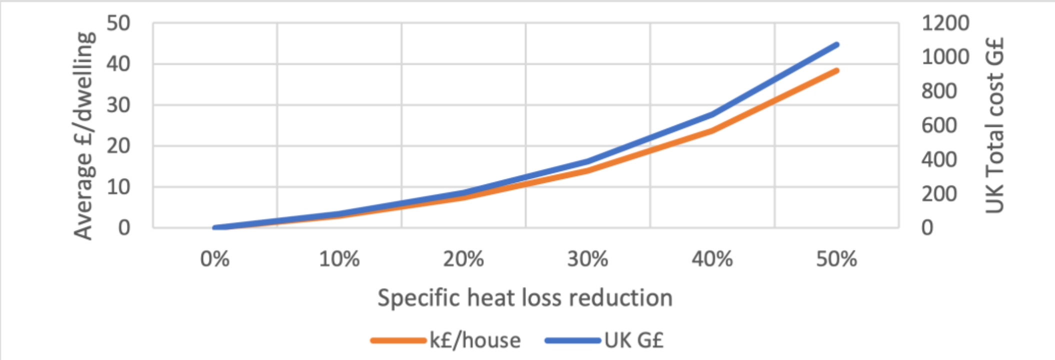
Figure 6 : Stock specific heat loss projection



3.1.1.2. Retrofit

It is assumed that efficiency in new build is not optional so its cost is therefore excluded from system economics and optimisation. Given the heterogeneity of the building stock and the differing current (2020) percentage applications of measures such as adequate loft insulation (~50%), wall insulation (~40%), and double glazing (~85%), it is difficult to estimate the demand reduction and costs of retrofitting buildings. Using data from sources including the *Household Energy Efficiency detailed release* (Department for Business, 2020), a cost curve for specific heat loss reduction has been generated, as shown in Figure 7.

Figure 7 : Building retrofit cost



If it is assumed that retrofit reduces the stock SHL by 10% at an average cost across all dwellings of 3 k£ per retrofitted dwelling equivalent, 100 G£ is invested in retrofitted dwellings in the period 2020-2050.

Efficiency is not included in the optimisation. Preliminary analysis suggests that deep retrofit measures, such as external wall insulation, are not cost-effective because of the cost reductions in wind and solar and the resultant lowered cost of heat from consumer or DH heat pumps. A further question is the impact of extra insulation, depending on design details, either exacerbating or reducing overheating following climate change. History has shown how hard it is to implement deep retrofit programmes because of capital cost, disruption to consumers, and constrained supply chain capacity in terms of skills and so on. Such modest effort on retrofit may appear paradoxical. But since energy costs rise modestly, if at all, under the least cost Green Light scenarios, it is hard to justify more ambitious retrofit.

3.1.1.3. Building thermal model

An average internal building temperature Tint of 19 °C is assumed as the set point minimum temperature for heating during occupied periods, and 25 °C the maximum set point temperature for building cooling where installed. The building modelled heat or cool load in GW in any hour is:

NetHeat = Use [SHL (Tint–Tamb) – SolarGain – EquipmentGain – PeopleGain] GW

Where:

- Use is the occupancy pattern,
- SHL is the stock specific heat loss (GW/K)
- Tint is the internal temperature (oC); 19 oC for heating and 25 oC for cooling
- Tamb is the ambient temperature (oC)
- SolarGain, EquipmentGain, and PeopleGain are incidental gains in GW.

When NetHeat is negative then there is a cooling load (GW).

With climate change, it was found that very high maximum cooling loads occur, so an automatic SolarControl, representing a blind or shutter, is applied that decreases from 1 to 0.5 when ambient temperature and insolation are high.

SolarGain = Insolation EffectiveAperture SolarControl GW

where insolation is solar radiation (W/m2) and EffectiveAperture (Gm2) is the effective UK area through which solar radiation is transmitted into the building.

3.1.1.4. Cooling

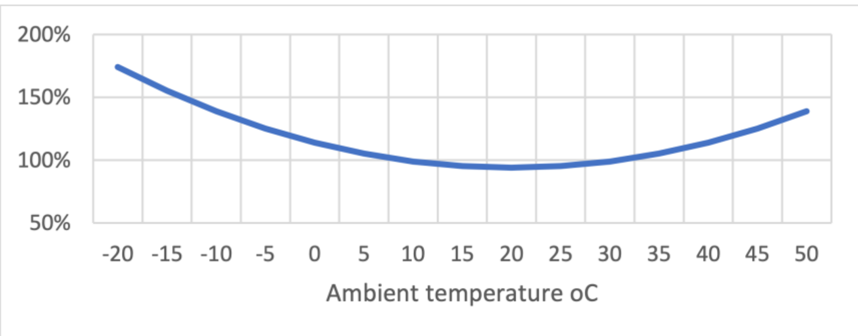
Space air conditioning (AC) is currently mainly confined to non-domestic buildings. However, climate change will increase cooling requirements and this may stimulate rapid growth in AC in the domestic sector. It is assumed that 10% of the total potential cooling load is currently met across all sectors – about half of the non-domestic load. For 2050, it is assumed that 80% of the total AC load is met in non-domestic and domestic buildings combined, except in the +5 oC climate change scenario when it is 90%. The assumptions about cooling greatly affect the seasonality of demand and can make peak summer electricity demand of a similar magnitude to that in winter. AC load is well correlated with solar radiation and this affects the optimal mix of wind and solar as explored in the +5 oC climate change scenario.

The cooling load is assumed to be met with reversible air-to-air heat pumps (RAAHP) systems which can both heat and cool – see 4.1. District cooling is an option which has not been included here, but is quite widespread in some European cities so is something for further research.

3.1.2. Electric vehicle (EV) weather sensitivity

Road and rail EVs can be considered as buildings on wheels and their energy demands increase at low temperatures because of cabin heat load, and at high temperatures because of cooling. Additionally, batteries and other EV systems are less efficient at temperature extremes. The change in EV energy demand with ambient temperature is shown in Figure 8; this is based on a separate EV model.

Figure 8 : EV demand weather sensitivity



4. Technologies

4.1. Heating and cooling systems

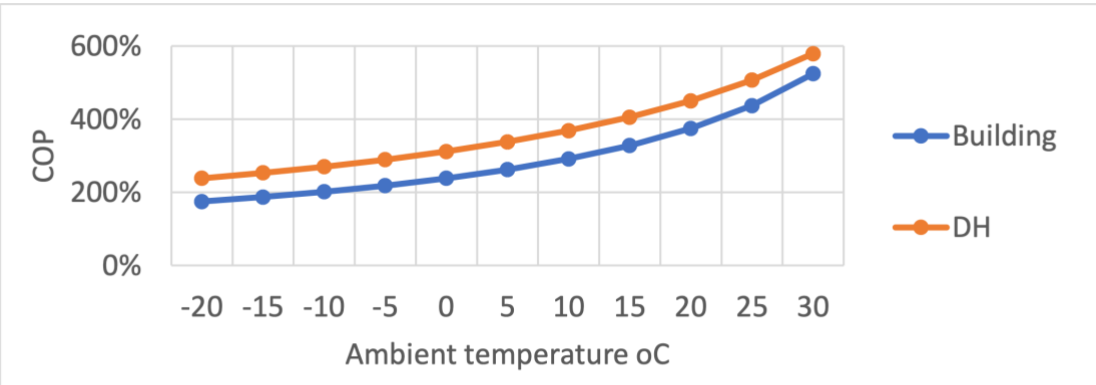
Heat demand is a major consumer of delivered energy; see appendix 10.2 for a breakdown of heat demand. About 60% of heat demand is in the domestic sector with 20% in the services and 20% in industry industrial sectors. About 70% of heat is space heat for providing thermal comfort.

Personal comfort systems (PCS) such as heated/cooled furniture can improve comfort and reduce the useful heat and cool supply from conventional heating and cooling systems by relaxing set point heating on or cooling on temperatures; see for example the review by Rawal et al (Rawal, Schweiker et al., 2020). PCS may contribute to energy and cost savings but are not modelled here except in the low demand scenarios via changes to setpoint temperatures. An advantage of PCS is that they can be implemented rapidly compared to building modification.

About 85% of heat demand is at temperatures below 60 oC, with about 10% of demand in industry for temperatures above 120 oC. Heat up to 150 oC can be supplied with electric heat pumps so these are assumed to be the main heat source with high temperature industrial heat using hydrogen. Heat pumps can use low temperature heat sources including the air, ground, water or process waste; the higher the temperature of these the higher the heat pump coefficient of performance or COP. Heat pumps can also cool. Heat pump systems may be implemented at all scales, from individual consumer systems to small DH systems serving a few dwellings, often called communal, to the largest city DH schemes. DH modelled here has the same components as a consumer HP except that the heat pump, heat distribution and primary heat store are outside the consumers 'premises.

The COP of heat pumps is assumed to be a fraction of the ideal Carnot efficiency using hourly air temperatures as a heat source: 40% of Carnot for buildings HPs outputting at 55 $^{\circ}$C with a weighted annual average COP of 2.9; and 60% of Carnot for DH HPs outputting at 65 $^{\circ}$C with an average 3.6. COP curves are shown in Figure 9.

Figure 9 : Heat pump COP curves



The costs and practicalities of HPs and DH will vary greatly with building type and size and heat load density. DH applied to large city blocks will be relatively low cost, whereas HPs may be difficult to install for practical or aesthetic reasons – for example fitting individual heat pumps in flats may be problematic for reasons of noise and space – but such detail is beyond scope here. As heat density reduces, DH and HP costs may generally increase because of network costs. A significant fraction of city blocks will have air conditioning and district heating and cooling (DHC) supplying chilled water can sometimes plug into these systems.

The advantages of DH include low consumer disruption, low noise, small internal space requirement, applicability to most building types, economies of scale, multiple heat sourcing and access to low temperature heat sources such as the ground or water bodies, and space for large heat stores. The disadvantage is the requirement for a heat network, but this is balanced by lower loads on the electricity distribution network compared to consumer HPs, and the ability to accommodate heat storage at much larger scales than is possible in individual buildings.

Consumer heating and cooling systems modelled are:

- reversible air-to-air heat pumps (RAAHP) which can heat and cool with fan convector emitters, and a separate domestic hot water (DHW) tank possibly with a separate HP
- district heat with standard radiators and heat interface unit (HIU)
- hydrogen boiler with standard radiators, the costs of which are assumed to be the same as for natural gas, though hydrogen boilers are not yet available.

Air source heat pumps (ASHP) with radiators are commonly assumed in the UK but are not modelled here because they do not provide air conditioning unlike RAAHP. RAAHP may offer lower costs and more rapid installation and less disruption because they can use small fan convector heat/cool emitters rather than radiators. A study of cooling in the UK (BEIS, 2021a) provides some support for RAAHP. It notes '*adopting reversible heat pumps for cooling could benefit greater penetration of low carbon space heating into the existing building stock.* 'And RAAHPs are '*capable of providing both space heating and cooling at a higher efficiency (with higher COPs) than hydronic air-water systems.* 'BEIS (BEIS, 2021a) give an estimate of fixed cooling costs of 1234 £/room is given which would sum to about 8 k£ for a six-room house. Eunomia (Eunomia, 2014) estimated there were 2.8 M RAAHPs, mainly non-domestic, operational in the UK in 2014 so the RAAHP installation base and installer capacity is much greater than that for ASHPs - Delta estimated perhaps 10 times the size (Delta, 2017). Unlike ASHP, RAAHPs are not currently (2023) eligible for grants despite offering lower cost and equal or better efficiency. Given this and that cooling will likely become more common with climate change, grants should be extended to RAAHP.

The DH and H_2 systems are assumed to have separate split air conditioning systems which serve part of the cooling load. District heating and cooling (DHC) has a hot and a cold network; it is not included in the systems modelled here though it can provide heat and cool at the same time and include cool as well as heat storage for load shifting. DHC would avoid the need for separate RAAHP and thereby possibly reduce costs.

Table 4 gives estimates of 'typical 'costs for new dwelling installations including new heat and cool fan convectors or radiators but excluding upstream costs.

Table 4 : Consumer heating system costs

	Life Yrs	Capital Cost k£	CapAnn Cost k£/a	Components included RAAHP	ASHP	DH	H2
Radiators standard	20	2.5	0.18			1	1
Radiators large LT	20	3.5	0.25		1		
Boiler	13	2.5	0.24				1
ASHP	15	8.0	0.69		1		
Reversible split HP + emitters	15	8.0	0.69	1			
Aircon split	15	4.0	0.35		1	1	1
DHW tank+HP integrated	15	4.0	0.35	1			
DHW tank	20	1.5	0.11		1		
DHW HP	15	3.0	0.26				
Heat interface unit	15	2.5	0.22			1	
		k£	Capital	12.00	17.00	9.00	9.00
		k£/a	CapAnn	1.04	1.39	0.74	0.77
		k£/a	O&M	0.24	0.34	0.18	0.18

4.2. Networks

Of technologies widely used today, it is perhaps most difficult to estimate the requirements and costs of future networks for electricity (EleN), district heat (DHN), and hydrogen (HydN). Note that it is assumed that transporting natural gas in networks ceases except for supplying peaking generators with existing transmission so its costs are not calculated.

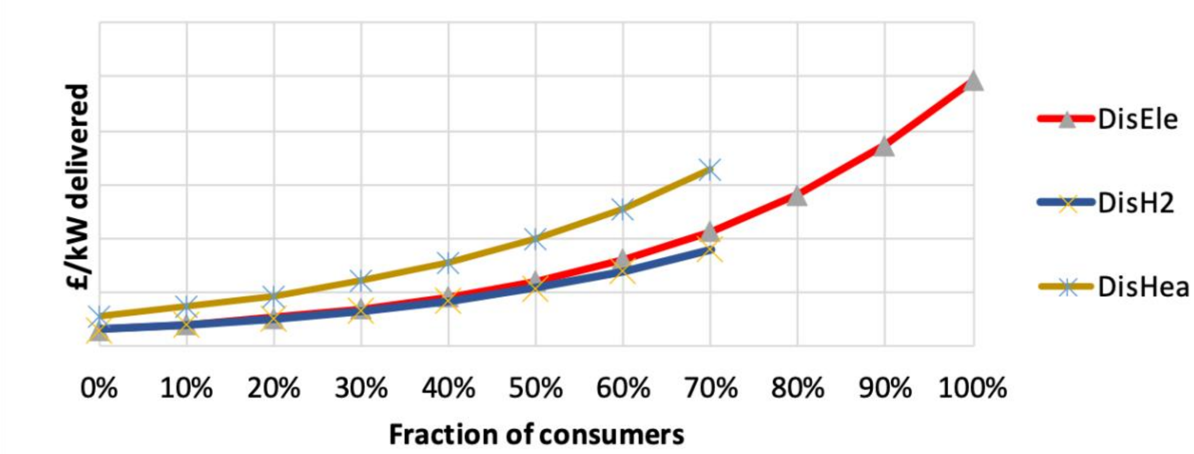
The sheer scale and complexity of the networks in urban environments, and patchy data and monitoring of current systems make it hard to detail future network requirements and costs. Networks utilise cables or pipes located above or underground, or undersea, connecting supplies input to the network to consumer interface equipment (CIE) comprising meters and other gear. Public stores of electricity, heat or hydrogen are modelled separately from networks. Networks are usually divided into major supply inputs into transmission which is high voltage electricity or high pressure gas, and the voltage is reduced with transformers and the pressure reduced for input to low voltage or low pressure distribution which is connected to consumers. The lengths of high pressure gas and high voltage electricity transmission are about 2% of the total network length with 98% being distribution which makes up most of the cost, though transmission costs more per unit length.

Networks have a range of other components apart from cables and pipes: notably, for EleN, there are transformers; for DHN, pumps; and for gas/hydrogen compressors and pressure reducers/regulators.

In city centres buildings are mostly multi-storey with little spacing along the road and the external network length per load is small. The total length of cables and pipes inside buildings is of similar magnitude to the external length but the cost per length is lower. A large fraction of network cost is laying pipes or cables underground and this cost per metre is generally more in high density areas than low density. The costs of CIE are more or less fixed per consumer whether in high or low density areas.

Unlike DHN and HydN, all consumers will be connected to EleN. In general, the length of distribution network per consumer increases as the load area density (MWh/km^2) or linear density (MWh/km) decreases, going from city centres to suburban areas and villages in rural areas. Distribution networks are mostly underground in high density areas, but some electricity distribution is above ground in rural areas. The cost of distribution is driven by cost per length, and length which increases with decreasing density and thus the network cost per kW or per consumer will in general increase with load share whether EleN, DHN or HydN. Figure 10 illustrates qualitatively how the peak power network costs might vary with fraction of consumers served.

Figure 10 : illustrative network cost change with demand fraction



Electricity

The length of the electricity network currently comprises about 20,000 km of high voltage (400/275 kV) transmission, mostly overground, and 800,000 km, or 40 times as much, of lower voltage distribution, mostly underground (BEIS, 2022b). To reduce the transmission voltage to lower voltages there are about 590,000 transformers[1].

[1] https://www.emfs.info/sources/substations/

The electricity distribution and transmission networks will have to increase capacity to accommodate a two or threefold growth in demand and generation peak flows, and also be spatially extended to connect diffuse renewable generators to demands.

The electricity distribution capacity, apart from general demands for equipment and lighting, will need to accommodate increased consumer loads due to EVs and generation with urban PV; and for consumer HPs if installed rather than DH. PV generation will generally occur at different times from maximum HP and EV loads. HP loads will peak when weather is cold, and this will affect all HPs at the same time; and consumer storage of heat or electricity will not be adequate to avoid such a peak after a day or so; therefore EleN will have to meet such a peak. Further, the power capacity of EleN will have to be adequate to absorb a reasonable fraction of renewable electricity. Thus, unlike DHN, EleN serves several purposes.

Currently the peak on EleN distribution is about 55 GW or 2 kW average per consumer and this is projected to increase to about 150 GW or 5 kW per consumer. A substantial fraction of additional demand will be for electrolysis and DACCS which may be sited near renewable generators and connected at high voltage. BEIS (BEIS, 2022b) assume there is currently an average distribution excess thermal (power) capacity of 60%, therefore there is not enough power capacity for the future demand peak on average, though there may be some areas that have sufficient slack to meet higher demands. In addition, there will be extensions to distribution to new dwellings and other consumers, and to generators. Alexander (Alexander, 2010) gives estimates of the average technical life of 54 years for EleN transmission and 73 years for EleN distribution, the life being when a component falls below acceptable performance levels. Given this, about half of the existing EleN will need replacing by 2050. The extra cost beyond that for installation of replacing existing components with a higher power capacity (kW) will be smaller than for entirely new network sections.

BEIS (BEIS, 2022b) estimate that net zero will add 40-110 G£ to network costs for a total 270-350 G£ which, assuming a 150 GW peak, is about 2000 £/kW. A value of 2000 £/kW is applied to the distribution peak and 300 £/kW to the peak consumption which accounts for transmission. These values are input as constants to ETSimpleMo and multiplied by peak flows to calculate the undiscounted capital cost of EleN, which is then annuitised.

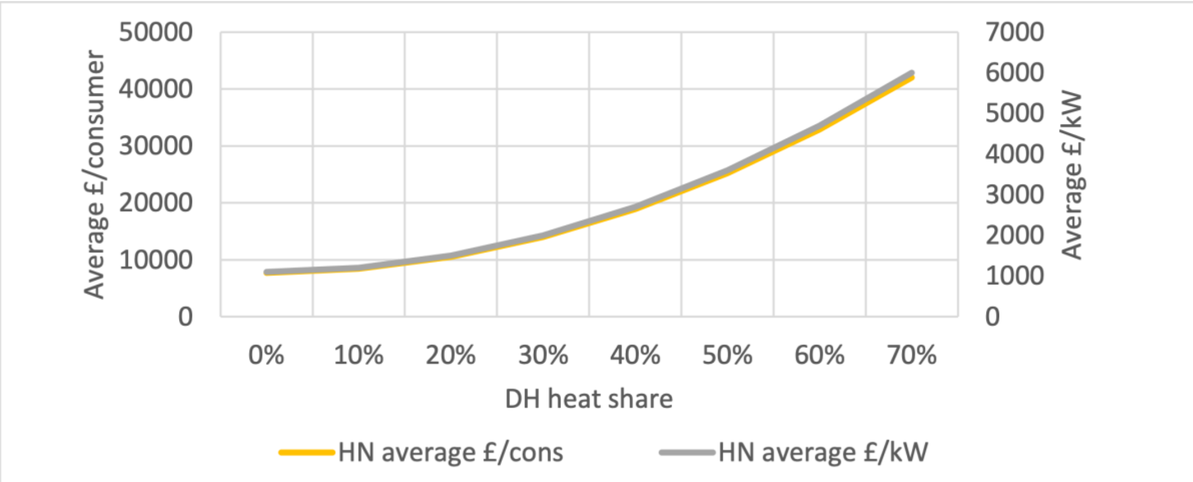
District heat

DH is more efficient overall than consumer HPs in terms of heat supplied per unit of electricity because DH HPs are more efficient and because large DH HPs will often be connected at higher voltage which is more efficient. The peak flow to DH HPs will be proportionately less per heat delivered because DH thermal storage allows avoidance of peak demands. DH will reduce the peak electricity flows on EleN in areas where DH is installed in place of HPs.

As the DH share increases, load density decreases and the fraction of large consumers such as offices decreases, and DHN costs per kW and per consumer will increase. At the same time, the average lower residual heat load density served by HPs will mean an increasing average EleN distribution cost per consumer, but this is not accounted for, though network savings through reducing peak electricity flows are.

District heating is limited in the UK and so most networks will be new, but DH is widely implemented in other countries. DHN costs per unit of heat delivered increase with decreasing density. Data from Poyry (Poyry, 2009), DECC (DECC, 2015) and AECOM (AECOM, 2017) were used to develop the average cost curve shown in Figure 11, ranging from a minimum of 8000 £/consumer or 1100 £/kWth.

Figure 11 : DH network capital costs



Hydrogen

The costs of hydrogen transmission and distribution are poorly known as there is little experience with new or repurposed gas systems at any scale. The existing natural gas network has a total length of 284,000 km of which 7600 km or about 3% is transmission (Ofgem, 2018). ACER (ACER, 2021) review issues concerning hydrogen networks. Existing gas pipelines converted to H_2 will have energy flows about 80% of the natural gas flow and require three times the compressor power. There is uncertainty as to the resilience to hydrogen of existing components including pipes, compressors and valves, including those within buildings. ACER report that new hydrogen pipelines are 110-150% of the cost of a new natural gas pipeline but repurposed just 10-35% of the cost of a new hydrogen pipeline. Walker et al (Walker, Madden *et al.*, 2018) assume hydrogen transmission will be new, not repurposed gas transmission. They estimate 413 GW of hydrogen transmission would cost 25.9 G£ which is 116 £/kW. It may be assumed the costs of hydrogen networks (HN) per consumer will increase with reducing load density and also the limited extent to which existing gas components can be used. Hydrogen meters are under development and yet to be fully commercialised but might cost about £1000 installed or about 100 £/kW. Most difficult to estimate is the cost of hydrogen distribution.

A placeholder distribution cost of 1800 £/kW is assumed, to give a total cost of hydrogen delivery and metering of 2000 £/kW; this is assumed constant but will increase similarly to EleN or DHN as the hydrogen share is increased. The costs of the natural gas network, and the savings as it becomes redundant, are not calculated.

4.3. Primary energy

Primary energy sources used in 2050 are renewable electricity (hydro, wind, solar), nuclear, biowastes, fossil oil for aviation, and a small amount of gas for flexible generation in some scenario variants. Other renewables such as solar heating and geothermal energy (beyond heat pumps) are excluded as presumed minor. As noted, bioenergy is assumed constrained to current biowaste resources because of the environmental impacts of biocrops and the competition with food production. Fuel for dispatchable generation in power only and CHP plant is a scenario dependent mix of constrained biowastes and fossil gas, or hydrogen.

The main primary generation sources included are wind, solar, hydro and nuclear and they are assumed to be zero emission though some greenhouse gas emission is incurred in their production and, particularly for hydro, in their operation. Embedded construction emissions will reduce as industry decarbonises.

Renewable generation varies because of environmental resources – wind speeds and solar radiation over shorter periods, and hydro over longer. Nuclear generation varies because of scheduled maintenance and refuelling, and because of faults. The historic UK maximum loss of annual generation as compared to average annual output is over 30% for nuclear and around 15% for wind and solar combined, so in this sense renewables are more reliable.

There are thousands of mass produced wind and solar generators, many built in reasonably transparent and competitive markets which exposes their generation costs and some details of construction and operation cost elements. The numbers also give certainty to construction time and operation. In contrast, nuclear power stations are few and their costs and construction times are highly uncertain. The nature of nuclear power is such that it will not be developed by the private sector without public support and the costs are not transparently exposed. The costs of decommissioning are particularly uncertain because there is little experience with this process for nuclear, solar and wind. A sensitivity analysis of renewables and nuclear costs is presented in 4.3.3.

In addition to wind, solar and nuclear, optimisation results in about 50 GW of flexible capacity operating at a capacity factor of around 1%. This capacity may be fuelled by a mix of biofuels, hydrogen and natural gas, with the emissions of the latter balanced with DACCS. This is discussed further in section 8.5 on resilience.

4.3.1. Renewables

Renewable generation is calculated by multiplying installed onshore and offshore wind and solar capacities by hourly capacity factors for different years, see Cassarino et al (Gallo Cassarino, Sharp et al., 2018). These reflect the statistical nature of these sources. Of particular importance is the wind capacity factor, around 55% for newer offshore.

Wind and solar have inevitable variations which are large over periods of weeks or months, but less annually where outputs historically have varied by about ±20% for onshore wind, ±9% offshore wind and ±11% solar PV. Hydropower can suffer large, long term variations because of precipitation patterns; UK annual hydro output has varied ±27% but is small. For the mix of wind and solar generation in these scenarios, the maximum reduction in annual generation below the average is less than 15%.

BEIS, (BEIS, 2020a) and (BEIS, 2023), and the Danish Energy Agency (Danish Energy Agency, 2020) make projections to 2040 of wind and solar costs, operational lives and performance. 2040 is taken as an average year of introduction of generators operating in 2050. These data, and the data assumed are set out in Table 5. The largest wind turbine sizes[2] produced in 2023 are 14-16 MW, with 18 MW at a concept stage. Sizes of 30 MW by 2030 are now being discussed[3].

In the non-hydrogen heating scenarios, offshore wind capacity is around 200 GW; and with hydrogen heating, up to double this. It may be expected that unit capacity costs will increase with total installed capacity because of factors such as going from fixed to floating wind turbines and increasing transmission length; but this has not been modelled. At the same time capacity factors may increase with distance from shore.

It is interesting to note that the BEIS capacity factors projected for 2040 have increased from 63% (BEIS, 2020a) to 69% (BEIS, 2023) for offshore wind, a 10% increase in output per MW, and from 34% to 41% for onshore, a 21% increase.

Wind turbine performance degrades with age with estimates by Hamilton et al (Hamilton, Millstein et al., 2020) and Astolfi and Pandit (Astolfi and Pandit, 2022) of output reducing by 0.17 %/a to 0.53%/a, which would amount to 3 to 8% over 15 years, half the assumed wind turbine life. Thus if the capacity factor of turbines were 63% when new, this might be expected to fall to a fleet average of 58-61% which is in line with ETSimpleMo modelling. However, the most recent BEIS capacity factors are 10-20% greater than modelled here with ETSimpleMo for offshore and 0-20% more for onshore; if this were realised then proportionate decreases in installed capacity would be required and costs would be lower by roughly the same proportions.

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[2] List of most powerful wind turbines - Wikipedia

[3] 30 MW Offshore Wind Turbines Being Considered for New Project in Sweden | Offshore Wind

Furthermore, the higher capacity factors would probably reduce storage needs and spillage. Plainly wind modelling needs further work, but it seems the assumptions made here are robust in terms of performance and cost.

Solar costs vary according to the size and ease of installation, with large solar farms about half the cost of small domestic installations. Retrofit rooftop systems cost more than on new build.

Table 5 : Wind and solar technology data

			CAPITAL £/kW		O&M %cap/a	LIFE Yrs	CapFac 2040
WIND		**2030**	**2040**	**2050**			
Assumed	**Offshore**		**1730**		**1.8%**	**30**	**Modelled**
Assumed	**Onshore**		**1170**		**2.4%**	**25**	**Modelled**
BEIS 2020	Offshore	1230	1230			30	63%
BEIS 2020	Onshore	1120	1020			30	34%
DNK	Offshore	1636	1527	1491		30	56%
DNK	Onshore	945	891	873		30	42%
SOLAR		**2030**	**2040**	**2050**			
Assumed	**Average**		**400**		**1.6%**	**30**	
BEIS 2020	Utility	450	350			35	11%
DNK	Domestic	764	636	582		40	14%
DNK	Comm	518	418	373		40	14%
DNK	Utility	345	291	264		40	14%

Capacity factors			
BEIS		**BEIS/Modelled**	
2023	**Modelled**	**2020**	**2023**
69%	58%	109%	119%
41%	34%	100%	121%

Sources: BEIS (BEIS, 2020a), (BEIS, 2023), DNK The Danish Energy Agency (Danish Energy Agency, 2020), ETSimpleMo results

The costs of decommissioning renewables are discussed by BEIS (BEIS, 2020a), however, there is no specific cost per kW given, rather the decommissioning cost is expressed as a LCOE of less than 1 £/MWh or 0.1 p/kWh. There is not much evidence of costs as little decommissioning has been done, and costs are dependent on the mechanics of decommissioning and the positive and negative values of waste streams. A range of references, e.g. Arup (Arup, 2018) and Invernizzi et al (Invernizzi, Locatelli *et al.*, 2020) lead to decommissioning cost estimates here of 50 £/kW (solar), 200 £/kW (onshore wind) and 300 £/kW (offshore wind). This assumes complete removal and recycling and disposal but no doubt many systems will effectively have indefinite lives with elements such as faulty solar PV panels or inverters being replaced and others reused, such as wind turbine foundations, thereby reducing net decommissioning or new build costs. For renewables it is assumed that decommissioning takes one year. Construction times are also given by BEIS (BEIS, 2020a) and these are assumed here for LCOE calculations.

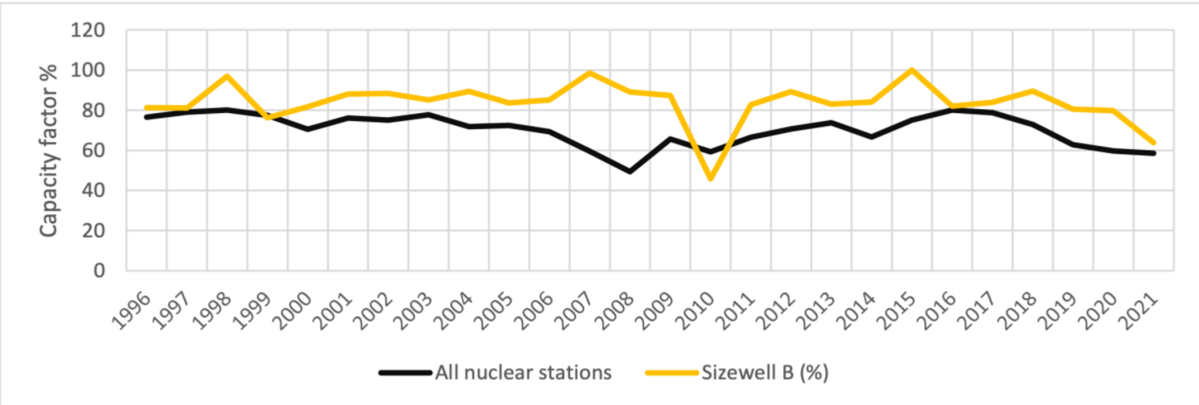
4.3.2. Nuclear

Nuclear stations are designed to have capacity factors of around 90%, with about 10% of the time zero generation because of scheduled reactor refuelling and maintenance which occurs for a few weeks every 18 months or so. If possible, this downtime will be scheduled for months having expected low demand net of renewables.

However, technical problems mean that the average annual capacity factor realised globally and in the UK is less than 90% and can fall far below this in some years. Some UK nuclear generation history is depicted in Figure 12.

The capacity factor of the Sizewell B 1250 MWe station, the UK's most modern, has averaged 83% across all operating years, but suffered with its capacity factor falling to 45.9% in 2010 and 64% in 2021 because of safety concerns[4]. Compared to the average, 45% of annual output or about 4 TWh of electricity was lost in 2010. To cover this loss, about 10 TWh of stored fuel input to 1.25 GW of thermal generation capacity would be needed. Alternatively, or 4 TWh electricity storage.

Figure 12 : UK nuclear and Sizewell B capacity factor history



Sources:
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1094465/DUKES_5.10.xlsx; https://www.world-nuclear.org/reactor/default.aspx/SIZEWELL%20B

The UK nuclear fleet capacity factor has averaged 70% and ranged between 50% (2008) and 80% since 1996. There seems to be a slight ageing effect: capacity factors were 6% higher during 1996-2000 than 2017-2021. In 2008, the nuclear fleet had a capacity of 10 GW output and its output fell by about 17 TWh below the average. The maximum loss of nuclear generation compared to the average has been 32% over this period. Hinkley C, due to start generating around 2028, will have been operating for 20 years by 2050. There is a review of extending Sizewell B's life by 20 years from 2035 to 20555 so this may also be operating in 2050. As the number of nuclear stations contracts the percentage variation in fleet output can be expected to increase.

[4] https://www.newcivilengineer.com/latest/safety-concerns-delay-sizewell-b-nuclear-reactor-reopening-by-three-months-18-05-2021/

[5] https://www.edfenergy.com/media-centre/news-releases/sizewell-b-starts-review-extend-operation-20-years

For simplicity in modelling, nuclear output is assumed to be a constant 85% of maximum net output in GW across the year but as shown above, this is optimistic since replacement generation will be required when it is not operating and 85% is higher than historic values. It would be possible to model refuelling downtime, and the effect of nuclear faults assuming some random capacity loss and duration derived from historic hourly or monthly output data for nuclear stations; for example, a 30% loss of fleet output for 3 months. But then the simulation and optimisation would be destabilised. A makeshift approach would be to estimate the extra cost of back-up generation and allocate some proportion of this to nuclear costs.

Since BEIS did not update nuclear costs in its most recent generation cost reviews by BEIS (BEIS, 2020a), (BEIS, 2023), approximate Hinkley C costs are used as far as they can be ascertained. In February 2023, EdF reported [6] a Hinkley C cost of 32 G£, which is about 9700 £/kW; if in 2023 prices then this is about 8700 £/kW in 2020 prices. Also '*The plant was scheduled to begin operation in June 2027, but an additional delay of around 15 months is now possible, EDF warned.*' This would suggest a start of operation in late 2028 and as initial site work for Hinkley C began in 2014[7], this means a construction time of 14 years. BEIS (BEIS, 2021c) explored policy options including regulated asset base (RAB) to reduce risks to companies and therefore the financing cost of nuclear power; the modelling there looked at construction costs (2021 prices) of 7700 £/kW and 13000 £/kW (a mid-point is 10350 £/kW), a construction period of 13 or 17 years, and hurdle rates of 9% if CfD funded, and 5% if RAB. The RAB option effectively means consumers sharing the nuclear project risk and is effectively a subsidy.

Nuclear station costs are assumed to include decommissioning costs incurred at the power station sites, and they should include the costs of fuel and waste handling at facilities such as at Sellafield. These costs are even more uncertain than the costs of construction and are greatly influenced by the choice of discount factor applied. The following surveys some information about decommissioning.

- 13.1 GW of nuclear capacity have been built. The House of Commons Public Accounts Committee reviewed decommissioning costs (House of Commons Public Accounts Committee, 2020) saying: '*According to the NDA's most recent estimates it will cost the UK taxpayer £132 billion to decommission the UK's civil nuclear sites and the NDA estimates that the work will not be completed for another 120 years.*' 132 G£ over 13.1 GW is 10,000 £/kW.

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[6] https://www.neimagazine.com/news/newsedf-increases-cost-estimates-for-hinkley-point-c-10612738

[7] https://en.wikipedia.org/wiki/Hinkley_Point_C_nuclear_power_station

- In Appendix A of the NDA Annual Report and Accounts 2017/18 (NDA, 2018), the undiscounted costs for Sellafield are 91.4 G£, and for nuclear power stations and geological sites, 29.6 G£: the NDA give a total 121 G£. If this is all allocated to 13.1 GW of built nuclear stations, the undiscounted cost is 9,300 £/kW. *'Until 2011/2012, the discount rate for provisions was 2.2% per annum. […] The discounting effect has now effectively been reversed,.[…] The rates are currently: […] Long-term (over 10 years) -1.56%.[…] The application of these rates produces the overall discounted total […] of £234.1 billion.'* Thus, the negative discount rate seemingly increases the undiscounted cost from 91.5 G£ to 234.1 G£, a factor increase of 2.57. If all this cost allocated to civil nuclear, 234.1 G£ to decommission 13.1 GW is a 17,900 £/kW discounted cost.
- The cost of a geological disposal facility (GDF) is estimated by the Committee on Radioactive Waste Management (CoRWM, 2022) with a 100% contingency to be 10.8 G£ and an operational cost of 96 M£/a for 100 years (9.6 G£ total), though it is not clear how much longer the GDF will incur costs. This undiscounted total of 20.2 G£ would, if all allocated to 13.1 GW of power stations, be 1,540 £/kW.
- 4.4 GW of Magnox stations were built. The House of Commons (House of Commons Public Accounts Commttee, 2020) reported *'The NDA now estimates that it will cost between £6.9 billion and £8.7 billion'.* This is 1,600-2,000 £/kW.
- 7 AGR nuclear stations with a capacity of 7.5 GW were built. The Public Accounts Committee (Public accounts committee, 2022) report *'The Fund, set up to meet the decommissioning costs of the seven Advanced Gas-cooled Reactor nuclear power stations now owned by EDF, has failed to meet its investment targets or keep up with increased estimates of decommissioning costs, which have almost doubled since March 2004 to £23.5 billion in March 2021.'* This is 3,100 £/kW.
- The Office for Budget Responsibility (OBR) reviewed nuclear decommissioning costs (Office Budget Responsibility, 2017). Said, concerning Hinkley C, '*The company [EdF] that will build and operate it expects decommissioning and waste management to cost £7.3 billion (in 2016 prices)'.* This is about 8.2 G£ in 2020 prices, or 2,500 £/kW. The OBR also notes: '*If the plant was forced to shut down for technical reasons, the company is liable for any outstanding liabilities, but if they were unable to do so the Government would ultimately be responsible.'* And *'that other projects using the type of reactor planned at Hinkley Point C are experiencing problems, creating a risk that the company could require government support, notwithstanding the agreed terms of the project.'*

Thus, the estimated specific power station site decommissioning undiscounted costs vary from 1,600-2,000 £/kW (Magnox), 3.100 £/kW (AGR), and 2.500 £/kW (PWR). If Sellafield costs are included the cost is around 10,000 £/kW. If discounted at -1.6%/a, the total present value cost is estimated as 234.1 G£ or 17,900 £/kW. These costs are very uncertain because no power station or related Sellafield facility has been fully decommissioned, and the construction of the GDF has not started - a location has yet to be decided.

In general, no estimate of a significant nuclear power cost element has seen a reduction compared to prior estimates. Plainly there is huge uncertainty in the overnight costs of decommissioning and this uncertainty is magnified by the application of arbitrary discount rates that have varied from positive to negative.

The operating lives of UK nuclear stations that ceased generation by 2023 averaged 38 years. The average age of French nuclear stations is 37 years and in 2022, 32 reactors, about half of the fleet, were shut down because of corrosion and cracks. Few stations of modern PWR design have operated for more than 45 years so little is known about the problems attendant to longer lives and the risks and costs of extending them. Lives of 60 years are proposed for new stations[8], but history so far does not support this.

As input to the scenarios model, a nuclear cost of 9,000 £/kW is assumed, comprising construction 6,500 £/kW and decommissioning 2,500 £/kW, with a 10 year construction time, a 50 year operating life and 100 years for decommissioning. A capacity factor of 85% is assumed for every year of operation. These assumptions may be viewed as optimistic given the historic performance, construction time and cost data set out above, particularly for decommissioning. In 2020 EdF said[9]' *The current cost estimate for the Sizewell C Project is circa £20 billion.* 'This is about 30% less than the Hinkley C cost estimate made here and as there is no published substantiation of this, it is not considered further. The assumptions made about nuclear operation and maintenance and fuel costs are loosely based on past BEIS estimates. It is noted that the insurance liability of operators is to increase to €1.2 billion [10], less than 1% of the cost of a nuclear accident such as Fukushima, possibly in the range 200-660 G$[11], so government underwriting of insurance is required – effectively a public subsidy.

4.3.3. Comparative costs

Here a more detailed analysis of renewable and nuclear generation costs is undertaken to ensure that the simpler economic methodology applied equally to all technologies and utilised for optimisation does not lead to a different cost ranking of these technologies.

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[8] https://www.edfenergy.com/energy/nuclear-new-build-projects/hinkley-point-c

[9] https://infrastructure.planninginspectorate.gov.uk/wp-content/ipc/uploads/projects/EN010012/EN010012-001678-SZC_Bk4_4.2_Funding_Statement.pdf

[10] https://www.gov.uk/government/publications/enhancing-the-uks-nuclear-third-party-liability-regime/ratification-of-the-uks-nuclear-third-party-liability-regime

[11] https://www.scientificamerican.com/article/clearing-the-radioactive-rubble-heap-that-was-fukushima-daiichi-7-years-on/

The approach is to calculate the levelised cost of energy (LCOE). The overnight costs for each of the years y of construction (Cy), operation (Oy) and decommissioning (Dy), are subject to discount rates (d) to be applied to these phases for the different technologies and summed to give a present value. The annual generation is similarly discounted. The LCOE is calculated thus where costs are expressed to produce p/kWh:

$$LCOE = \frac{\sum [(C_y + O_y + D_y) / (1+d)^y]}{\sum [(G_y) / (1+d)^y]}$$

Table 6 summarises the central overnight cost assumptions. No estimates are made here of transmission or system balancing costs as these depend on whole system optimisation: because nuclear is assumed to generate a constant 85% of installed capacity, the optimisation is to nuclear power's advantage in this respect.

Table 6 : Central generator cost assumptions

Generator	Solar	Wind On	Wind Off	Nuclear
Capacity MW	30	8	12	3300
Construction Yrs	4	4	5	12
Operate Yrs	30	25	30	50
Decommission Yrs	1	1	1	100
CapFac	11%	34%	57%	85%
Generation kWh/kW	964	2978	4993	7446
Const Capital £/kW	350	1020	1430	6500
Decom £/kW	50	150	300	2500
O&M £/kW/a	2.5%	2.5%	2.2%	2.0%
O&M £/MWh	1.0	6.0	3.0	2.0
Fuel p/kWh				0.5
Tech. specific rate	6.5%	6.5%	7.5%	8.9%

Source: *Author's* collation

4.3.3.1. Discount rates

To calculate the LCOE it is necessary to calculate the overnight costs incurred and electricity generated in each year and discount these to the first year using applicable discount rates. Different discount rates may be applied to different technologies and phases to reflect the associated risks and attendant cost of capital.

The construction time and cost risks of nuclear attract high interest rates so mechanisms to reduce the risk such as the regulated asset base (RAB) are proposed. The National Infrastructure Commission (National Infrastructure Commission, 2019) said: '*New nuclear power plants will not be built by the private sector without some form of government support.*' and '*By using a RAB* [regulated asset base] *model, a company's investors share some of a project's risks with consumers. This can lower the cost of finance for funding new nuclear plants, which is the main driver of project cost.*' Such a mechanism is effectively a public subsidy and it is hard to find a rationale for supporting one technology in this way and not others.

In its 2016 report (BEIS, 2016) based on 2014 data, BEIS proposed hurdle rates of 6.50%/a for solar, 6.70%/a for onshore wind, 8.90%/a for offshore wind and 8.90%/a for nuclear. Given the great expansion of solar and wind and the reduction in costs since 2014/16, the renewable rates should now be lower as risks have been reduced, so 5.5%/a for solar, 5.5%/a for onshore wind 7.5%/a for offshore wind are assumed for specific rates.

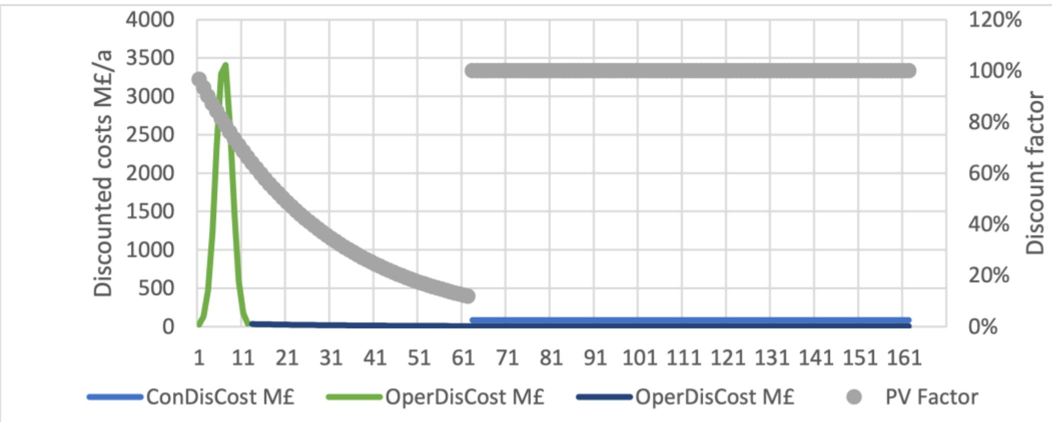
The Green Book (HM Treasury, 2020) p119, suggests a rate of 3%/a for costs 31-75 years ahead, but no particular rate was found for decommissioning renewables so a more conservative 1%/a is assumed. The rate for nuclear decommissioning has varied widely over the years, with the NDA (Nuclear Decommissioning Authority, 2022) most recently applying -1.34%/a for a term greater than 40 years; such a negative rate causes a huge increase in the present value of discounted decommissioning costs.

4.3.3.2. Levelised cost of energy for renewables and nuclear

The overnight costs for construction, operation and decommissioning are allocated across the project's years. Different discount rates for these phases are applied and the total discounted present value of costs and generation calculated, and a LCOE produced.

Figure 13 shows an example of the year by year overnight costs for nuclear construction, operation and decommissioning. The present value (PV) factor is the effect of discount rates of 3.5 %/a for construction and operation and 0 %/a decommissioning rate. It illustrates the heavy annual construction expenditure followed by much lower annual costs for operation and decommissioning but extended over longer periods such that the long term discount rates assumed become critical, especially for nuclear decommissioning.

Figure 13 : Annual nuclear costs example



Sensitivity cases are explored. The construction, operation and decommissioning rates are set at technology indifferent and technology specific values.

Figure 14 shows the unit generation costs calculated for different assumptions as in Table 6 and variants. The coding is:

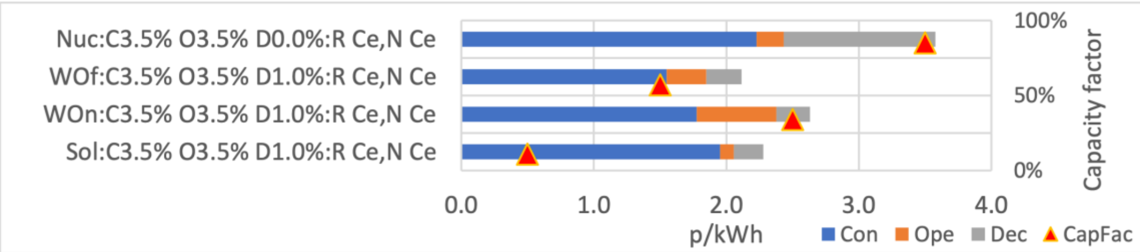
- Generators: Sol Solar; WOn, onshore wind; WOf offshore wind; Nuc nuclear
- Discount rates: C Construction; O Operation; D Decommissioning
- Construction cost: R Ce Renewable Central; N Ce Nuclear Central; N +20% nuclear cost over Central.

The ranking produced is the same as that produced by the optimisation using a single global discount rate of 3.5%/a for all technologies whereby solar and wind are lower cost than nuclear. System back-up and balancing costs are not included for any technology.

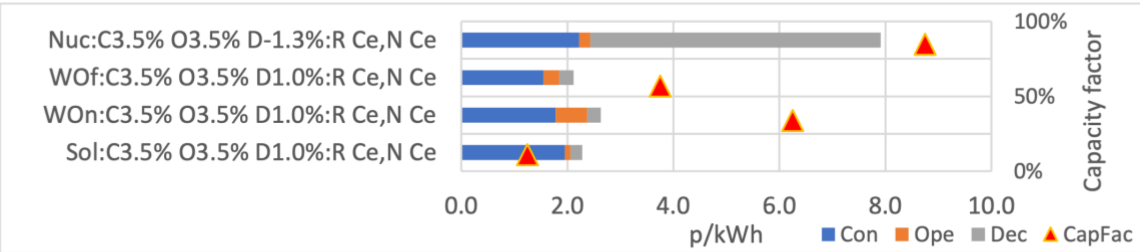
For possibly conceivable assumptions most favourable to nuclear, the LCOE of nuclear is about 1.7 times the cost of offshore wind, but in most cases it is a multiple of four, five or more. For the nuclear LCOE to converge on renewable costs it is necessary to reduce nuclear costs by 20%, increase renewables costs by 20%, apply the lowest discount rates for construction, operation and decommissioning, reduce the nuclear construction time by 2 years, increase the operating life to 60 years and increase the capacity factor to 90%.

Figure 14 : LCOE generation cost sensitivities

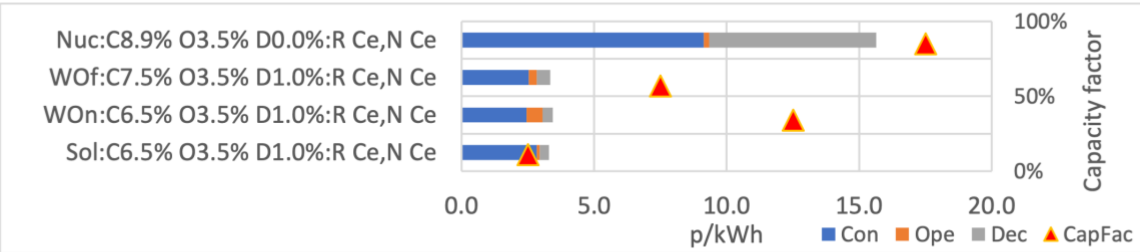
Indifferent discount rates: nuclear decommissioning rate 0%/a



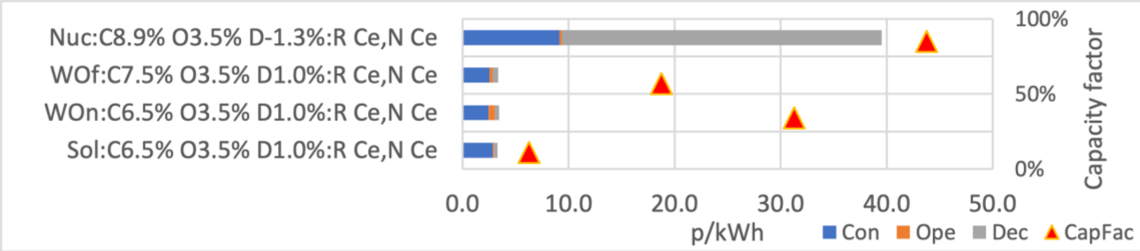
Indifferent discount rates: nuclear decommissioning rate -1.3 %/a



Technology specific discount rates 0%/a nuclear decommissioning rate



Technology specific discount rates -1.3 %/a nuclear decommissioning rate



It has been shown that the overnight costs of nuclear construction and decommissioning are particularly uncertain and it is argued that the assumptions made here are favourable to nuclear power. It is also clear that the discount rates applied have a profound effect on LCOE generation costs, again particularly for nuclear power where the complete phases of construction (10 years), operation (60 years), decommissioning and waste (100 years and more) extend over 170 years, and a further century or more in the geological disposal facility. In contrast, the complete solar and wind life span is about 40 years and thousands are installed each year.

4.4. Negative emission and carbon capture

Negative emission (NE) is required to balance residual greenhouse gas emissions or other global warming processes that cannot be easily prevented technically or economically. In this analysis the main energy related emissions not eliminated with renewables are due to aviation. There are many other sources of GHG and global warming. such as cement production and agriculture and CCS can reduce some of these, but these are not primarily energy processes, though DACCS could balance their emissions. The assumption is made here that the NE would be located in the UK, but NE can be located wherever costs and impacts are lowest.

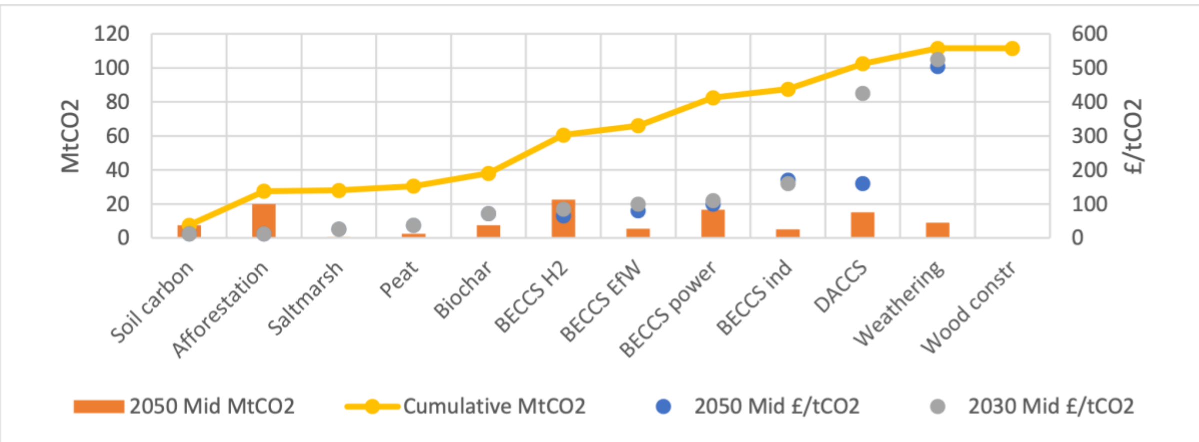
In the scenarios, aviation is mostly fuelled with fossil kerosene, but alternatives are explored in section 7, including the use of renewable kerosene synthesised from direct air capture (DAC) atmospheric CO_2 and electrolytic hydrogen. Aviation is modelled in 2050 to result in 43 Mt fuel CO_2 (12 MtC) and a high altitude radiative forcing of 21 $MtCO_2e$, a total 64 $MtCO_2e$. If 8 $MtCO_2e$ is offset by biowaste substituting for fossil fuels a net 56 $MtCO_2e$ remains. This is the main residual energy related global warming emission in the scenarios that negative emission is to balance.

Negative emission involves the separation of carbon dioxide from the atmosphere or sea and its transport and permanent or long term storage underground in reservoirs or aquifers, or in plants, or the soil, or in rocks, or in products such as wood or concrete. These storage options have different ultimate capacities and necessarily must have negligible leakage rates over long periods. The absorption, pipeline transport and sequestration phases of NE have a range of environmental impacts including land use, chemical and water consumption, and risk of CO_2 release. The negative emission considered involves separating 56 Mt CO_2 with a concentration of 0.04% from the air. Assuming all the CO_2 is absorbed in the air processed by a DACCS, a minimum of 140,000 Mt of air would have to be processed, which is a huge amount of physical and chemical processing, however it is done.

There are two basic categories of NE – biological (NEb) where plants absorb CO_2, and engineered (NEe) where chemical and mechanical processes absorb CO_2. Also, non-BECCS NEb has limits when no more carbon can be stored in forests etc. The common conclusions are that there are major uncertainties as to technical potential, environmental impacts and costs and competition for land. The Royal Society (The Royal Society, 2018) reviews four classes of NE: engineered, biological, mineral, and nutrient based processes.

BEIS, elementenergy *et al* (BEIS, elementenergy *et al.*, 2021) review NE including DACCS, various biomass energy and carbon capture and sequestration (BECCS) routes, storage in wood products, afforestation and habitat restoration, enhanced weathering, soil carbon and biochar. The potential mid-range 2050 emission reduction and 2030 and 2050 costs from this study are shown in Figure 15, ordered by increasing cost, along with the cumulative potential reduction. NEb requires a large land area per carbon captured and there are significant uncertainties as to potential carbon absorption and retention, particularly with climate change. The natural processes – soil, forest, saltmarsh, peat - are lower cost than the other options considered and can have ecological benefits. The largest single ‘natural ’contribution is afforestation which alone might contribute about half the required NE to balance aviation and other energy emissions, but afforestation is ultimately limited by available area. The BECCS mid-potential is 57 Mt CO_2 and this would require about 24,000 km^2 or about 20% of UK agricultural land area if UK sourced biocrops were used. DACCS is the highest cost along with weathering, but note, in Figure 15, that large DACCS cost reductions are projected for 2050.

Figure 15 : Negative emission potentials and cost estimates



Source: (BEIS, elementenergy et al., 2021), but author’s collation using mid ranges

Biowastes are small, geographically diffuse and physically and chemically varied –sewage, wood waste, animal manure, straw, etc. It is assumed in the scenarios that no biomass is imported. Biocrops require inputs such as water and fertilisers and the scope is limited because of land take, biodiversity loss and competition with food production. Increased temperature and drought or flood caused by climate change may reduce productivity. Furthermore, biocarbon may be needed to produce fuels such as kerosene, or materials. For example, The Royal Society (The Royal Society, 2023) estimate that 68% of the total agricultural land in the UK would be required to produce 12.3 Mt of aviation fuel from biomass. Biomass is diffuse and substantial transport is needed take biomass to BECCS or other plant. The sustainable scope for NEb beyond biowastes to balance energy emissions is judged to be uncertain and is not considered further here.

4.4.1. Direct air capture and sequestration DACCS

A leading NEe option is direct air capture (DAC) which may be coupled with carbon sequestration (DACCS). Air is blown across an alkali which absorbs CO_2 and then the alkali is made to release the CO_2 using heat and the alkali then recycled. The CO_2 is concentrated, compressed, transported and sequestered or used for purposes such as fuel synthesis. DACCS engineering is proven to work at small scale, but there are uncertainties concerning commercial scale performance and costs, and environmental impacts. The process can be driven purely by renewable electricity and requires substantial inputs including water and chemicals. DACCS requires relatively little, low quality land but needs to be located so as to use renewable electricity and allow low cost CO_2 transport to a storage site, such as a depleted gas field. DACCS has a low land use requirement reported to be less than 1 $km^2/MtCO_2/a$; see for example Viebahn *et al* (Viebahn, Scholz *et al.*, 2019). DACCS might even be located offshore as considered by the Offshore Wind and CCUS Co-location Forum (Crown Estate, 2023).

CO_2 from DACCS or BECCS will have to be transported to a sequestration site, with pipeline being a likely choice. An advantage of DACCS is it can be sited flexibly as it needs little land, whereas biomass is necessarily diffuse requiring more transport of biomass or CO_2. BEIS (BEIS, 2022a) express a need for 15 G£ investment in the early phases of CO_2 transport and storage. Element Energy (Element Energy, 2013) identify 70 Gt CO_2 of potential storage, mainly near the UK east coast, with an undiscounted cost for pipelines and sequestration of about 6 to 20 $£_{2013}/tCO_2$ depending on scale and a marginal cost curve for cumulative lifetime sequestration ranging up to 45 Gt CO_2 for cost ranging from about 5 to 100 $£_{2013}/tCO_2$. Using Danish Energy Agency data (Danish Energy Agency, 2021) the author estimates a cost of about 5 $£/tCO_2$ for a 300 km pipeline and 12 kWh/tCO_2 electricity consumption. These data indicate that the energy, capital and operating costs of CO_2 transport and sequestration are lower than for the DAC part of the system.

DACCS cost estimates approximately ranging 50-1000 $£/tCO_2$ can be found in the literature. Erans *et al* (Erans, Sanz-Pérez *et al.*, 2022) carry out a comprehensive and recent review, remarking *'It needs to be stressed that there is a large discrepancy in the reported economic viability of DAC, and the cost of CDR up to 400–800 € per tCO2 that has been reported.'* Fuhrman *et al* (Fuhrman, Clarens *et al.*, 2021) project 2030 non energy costs between 78 and 384 \$/tCO_2. The IEA (International Energy Agency, 2022) provide a useful review of solid and liquid solvent DACCS including of land and water use; the energy (heat and electricity) consumption GJ/t data are converted to electricity assuming heat is provided with electricity and the data shown in Table 7.

Table 7 : IEA DACCS data

	Solid-DAC	Liquid-DAC
Net water requirement (tH20/tC02)	-2 to none	0-50
Land requirement (km2/MtC02)	1.2-1.7	0.4
Author estimates		
Electricity anciliary kWh/tCO2	519	200
Electricity for heat kWh/tCO2	1624	1636
Electricity total kWh/tCO2	2143	1836

Source: IEA (International Energy Agency, 2022) and author's post analysis

Here it is assumed that an electrical input of 2000 kWh/tCO_2 provides both power and heat to drive the DACCS processes including transport and storage. DACCS capital cost is taken to be 7000 £/kWe, O&M costs 2% of capital cost per annum, and a lifetime of 20 years. The electricity cost will be low as DACCS uses electricity surplus to all other demands. These data are assumed to cover CO_2 transport and sequestration. In the central scenario, DACCS has a maximum capacity of 83 MtCO_2/a with an electrical capacity of 20 GWe. It consumes 110 TWh of otherwise surplus electricity at a capacity factor of 60-70% sequestering 56 MtCO_2/a thereby balancing aviation emissions. The total DACCS cost is then about 300 £/tCO_2.

DACCS is assumed here to be the only NE option for balancing energy emissions, partly, it is admitted, because it is methodologically simpler to quantify CO_2 capture and costs than NEb. If other lower cost options prove to be practical and timely, then they would reduce the need for DACCS; for example, afforestation might provide about half the required total NE. A comprehensive analysis of negative emission requirements would need to include residual non-energy related greenhouse gas emissions and, for NEb, incorporate modelling of land use, agriculture and ecosystems, climate change on productivity and of the environmental impacts.

It is further noted that DACCS does not have to be located in the UK – there may be lower cost, lower impact places elsewhere in the world.

4.4.2. Energy and industrial processes with carbon capture

CO_2 can be captured from energy production and other processes with carbon capture and sequestration (CCS) and this is usually lower cost than DACCS because CO_2 concentrations are higher than in the atmosphere, but not all CO_2 is captured at the plant. Furthermore, the CCS does not reduce upstream emissions incurred in the production and transport of fossil fuels. CCS can be applied to fossil fuelled plant such as a power stations or a steam methane reformer producing hydrogen. CCS can also be applied to industrial processes such as cement production which involve chemical changes releasing CO_2, but this is excluded from the analysis in this report.

CO_2 is captured from the exhaust gases. Typically, 80-90% of the CO_2 is captured. The CO_2 capture process requires more energy as the percentage of CO_2 capture increases. Budinis et al (Budinis, Krevor *et al.*, 2018) estimate that CCS on a CCGT reduces output by 15-16% and efficiency by 6-11.3%. Here a brief appraisal of a CCGT plant with CCS is made. If 90% of the flue gas CO_2 is captured, then with 10% efficiency loss the emission per kWh generated is reduced by less than 90%. Upstream gas supply emissions of greenhouse gases including CO_2 and methane are not reduced. BEIS (BEIS, 2020a) give CCGT/CCS data as 1300 £/kW, an operating life of 25 years, and an efficiency of 47%; a CO_2 removal rate is not given so 90% is assumed. An arbitrary capacity factor of 50% is posited for calculating unit costs.

Natural gas is mostly methane and its GHG content is about 184 gCO2e/kWh[12] with most of the GHG being $CO_{2;}$ then with 90% CCS removal the emission is 39 gCO_2/kWhe. UK gas supply may increasingly be imported via LNG and long distance pipelines with larger energy, CO_2 and methane leakage overheads than UK sourced gas. Barrett and Gallo Cassarino (Barrett and Gallo Cassarino, 2021) estimate that upstream gas production, processing and transport by pipe or LNG add substantially to GHG emission, depending on assumptions about energy use and leakage, and the application of different global warming potentials and from that report a range 29-180 gCO_{2e}/kWh of gas is used, which, dividing by the generator efficiency, results in 62-383 gCO_{2e}/kWhe. This additional upstream emission is not controlled by the CCGT/CCS and if added to the 39 gCO_2/kWhe results in total emissions of 101- 422 gCO_{2e}/kWhe.

The unit costs of generation may be calculated from the capital and O&M costs, the capacity factor, the plant life, the efficiency, and the wholesale gas price which is about 5 p/kWh in February 2023. The economic method is not a full cash flow analysis as in 4.3.3.2. The capital cost is annuitized at 3.5 %/a but BEIS (BEIS, 2020a) gives a hurdle rate of 7.3%/a for CCGT/CCS. The base electricity cost is 13 p/kWh, of which 10.6 p/kWh is the gas cost. A carbon tax may be applied – in a net zero system this should be the cost of negative emissions which for DACCS might range 100-500 £/tCO_2; a placeholder tax of 200 £/tCO_2 is

12 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1049333/conversion-factors-2021-full-set-advanced-users.xlsm

applied. Table 8 shows the calculation. There are uncertainties in all the assumptions, particularly in the future gas price, upstream emissions and negative emission cost.

Table 8 : CCGT/CCS calculations

	Efficiency		47%
	Capital	£/kW	1300
	Life	yrs	25
	Annuitised capital	£/kW/a	79
	O&M	%cap/a	2%
		£/kW/a	26
	Annual fixed cost	£/kW/a	105
	Capacity factor		50%
	Fixed cost	p/kWh	2.4
	Gas price	p/kWh	5
	Base generation cost	p/kWh	13.0
	CCS removal		90%
Gas	Base GHG	gCO2e/kWh	184
	Upstream low	gCO2e/kWh	29
	Upstream higher	gCO2e/kWh	180
Electricity	Base	gCO2/kWhe	39
	Upstream low	gCO2e/kWhe	62
	Upstream higher	gCO2e/kWhe	383
	Base+Upstream low	gCO2e/kWhe	101
	Base+Upstream higher	gCO2e/kWhe	422
CO2e tax	Base	p/kWh	0.8
	Base+Upstream low	p/kWh	2.0
	Base+Upstream higher	p/kWh	8.4
Generation + GHG tax	Base	p/kWh	13.8
	Base+Upstream low	p/kWh	15.0
	Base+Upstream higher	p/kWh	21.5

The potential for CCGT/CCS as a flexible plant was tested in the optimisation using the input data as in Table 8, but excluding the upstream GHG emission so the emission is 39 gCO_{2e}/kWhe. The optimisation results in 40 GW of CCGT/CCS operating at a capacity factor of 1%. This is similar to the optimum capacity of unabated flexible peaking plant but overall the CCGT/CCS adds about 2 G£/a to total system costs, so it is not optimal. If the upstream emissions were included then extra DACCS negative emissions would be required adding to system costs.

4.5. Summary technology performance and cost assumptions

Table 9 summarises key technology data assumed to apply in 2040 and to represent averages for 2050. Most data are taken from the Danish Energy Agency database (Danish

Energy Agency, 2020) which is comprehensive, coherent and includes projections of costs. The costs are not discounted in Table 9 but they are for system costing and optimisation. DH network costs in red vary with heat share. Renewables and nuclear details are set out in 4.3.

Knowledge about negative emission is poor. Direct air capture and carbon sequestration (DACCS) is the sole negative emission option exercised here. This is because of the environmental complexity and uncertainty of biomass and other negative options. DACCS itself is uncertain, but the indications are that it has lower environmental impacts than biocrops supplying BECCS, for example, and its costs and impacts are more easily quantified and modelled. This is discussed in 4.4.

Table 9 : Technology data

Tech	Efficiency	Unit	Capital £/unit	Life Yrs	O&M %Cap/a
Bld eff		Dwelling	2877	50	
Gas boilers	85%	Dwelling	9000	15	2.0%
Heat pump	276%	Dwelling	12000	20	2.0%
AirCon	400%	Dwelling	4000	15	2.0%
Ele distrib	95%	kWe	2000	50	2.0%
StEle_In	93%	kWe	25	25	2.0%
StEle_Sto	86%	kWhe	100	25	2.0%
StEle_Out	93%	kWe	25	25	2.0%
DH network	90%	kWth	*1500*	50	2.0%
DH HeaSto		kWhth	5	40	1.0%
DH HP	354%	kWe	2000	25	2.0%
DH FlexCH	35%	kWe	900	30	2.0%
H2 network		kWH2	2000	50	2.0%
H2 electro	75%	kWe	500	20	1.0%
H2 store	97%	kWhH2	5	30	1.0%
Haber	85%	kWch	500	25	2.0%
Fischer Trop	80%	kWch	1240	30	2.0%
DAC		kWe	7000	20	2.0%
Hydro		kWe	3400	80	2.0%
Sol PV	20%	kWe	400	30	2.5%
Win_on		kWe	1170	25	2.5%
Win_off		kWe	1730	30	2.2%
Nuclear	40%	kWe	9000	50	2.0%
Flexible	40%	kWe	350	35	2.0%

5. System economics and optimisation

5.1. Economic methodology

Since the constraint of zero net emission is applied, the problem addressed here is to find a combination of technologies that will deliver net zero at least total technology and fuel cost. There is no attempt to estimate health, environmental or other costs and include them in a cost benefit analysis. The economic methodology applied is simple so as to minimise model size and maximise optimisation speed.

The only system capital costs calculated relate to net zero investments - the system savings arising from discontinuing fossil fuel systems such as for gas and oil production and distribution systems are not accounted for. All ‘overnight ’capital costs are annuitized at a global discount rate over the lifetime of the technology to derive unit annuitized capital costs of £/kW/a for energy converters and £/kWh/a for storage. In the optimisation a single discount rate is applied across the board. The global discount rate is set to 3.5%/a as set out by the Treasury Green Book (HM Treasury, 2020). These unit annuitized capital costs are applied to the total installed capacity (GW or GWh) of the technology in any year. The operation and maintenance (O&M) costs are either a percentage per annum of the overnight capital or a variable £/MWh, depending on the technology.

In reality there will be millions of technologies installed at different times over the 30 years or so to 2050, some with lives such that there will be replacements during that period, such as electric vehicles with a life of 10-15 years. It is beyond scope to model in detail the addition to and retirements from these stocks.

Technology projects are better assessed by assembling annual cash flows over the construction, operation and decommissioning phases and applying discount rates to arrive at a present value of costs and revenues. In practice, there will be a variation in discount rates depending on the risks and impacts of technologies and processes. These variations may be because of financing availability or because of ethical considerations. Varying cost assumptions and discount rates are explored in 4.3.3 with respect to the key primary nuclear and renewable generation technologies, with the use of a negative discount rate for nuclear waste being especially of note.

The costs for fossil fuels are assumed constant across the scenario. In general, these are relatively unimportant for the net zero systems designed here as fossil fuel use is mostly eliminated. However, one critical assumption is the fossil kerosene price as this will affect whether it is lower cost to make aviation fuel net zero with negative emissions or renewable kerosene synthesis; however, this fuel synthesis is not included in the optimisation and is something for further work. A discussion of aviation fuel is provided in section 7.2.

5.2. Optimisation process

The challenge then is to find a least cost net zero design by altering the capacities of key system components, represented by decision variables (DV), and simulating designs in the ETSimpleMo model to prove operability and calculate costs. The meteorology year used is 2010 as it is a stress year with meteorology driving high demand and low renewable generation. The target for total net carbon emission (CO_2) plus high altitude aviation warming (CO_2e) is set to zero. The DVs can be constrained to minimum and maximum values. The optimiser sets the heating shares of consumer heat pumps (HP) and district heating (DH) within the total limit set for electric heating so as to minimise cost. HP and DH shares can be constrained to minima and maxima. The hydrogen (H_2) share is set manually such that the (HP+DH)+ H_2 shares sum to 100%. The H_2 share is not optimised because it costs more than either DH or HP, so the H_2 share is set as an external constraint and then the rest of the system optimised.

The user can explore system designs by manually inputting DV values, which gives a 'feel ' for the system. The model simulates hourly across the year in about 2 seconds. However, manual design is slow compared to using optimisation software. Here a hybrid optimiser OptimEx (by Barrett) using steepest descent, genetic and particle swarm algorithms is applied to ETSimpleMo to find the least cost system design as specified by the decision variables. The Excel inbuilt Solver can be used but its results are not so good.

Currently ETSimpleMo has 14 decision variables (DVs), from DH (district heat) share to DAC, as in Table 10, with the first row of numbers the optimised current values and, for optimisation bounds, the second and third rows give the maxima and minima. Table 10 shows the values for the decision variables for the optimised 2050 system which has a DH share set to 20%, with the remaining heat met by HPs. The optimised nuclear capacity is the minimum 3.3 GW of committed Hinkley C capacity because it is not cost-effective.

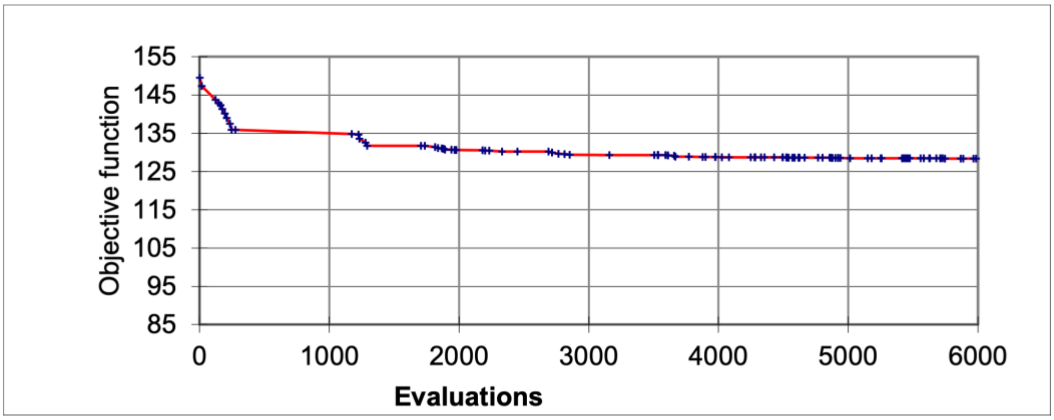
The rows labelled MaxGW, MinGW, TWh and CapFac are results from the simulation. The rows labelled £/kW to p/kWh are cost input assumptions (yellow cells) and calculated costs.

Table 10 : Decision variables and optimum values for 2050

Heat Share	SUPPLY Renewables			Other		INTERMEDIATE Electricity storage			CONSUMPTION District heat		Hydrogen		DAC
DH share	Sol PV	Win_on	Win_off	Nuclear	Flexible	StEle_In	StEle_Sto	StEle_Out	DH HP	DH HeaSto	H2 electro	H2 store	DAC
%	GWe	GWe	GWe	GWe	GWe	GWe	GWh	14	GWe	GWh	GWe	GWh	GWe
20%	**102**	**15**	**182**	**3.3**	**57**	**8**	**58**	**8**	**11**	**1105**	**27**	**4250**	**21**
20%	200	200	400	3.3	100	100	300	100	50	10000	150	20000	40
20%	15	15	15	3.3	0	8	50	8	0	0	0	0	0
MaxGW	85	15	182	3	57	8	58	7.4	11	1103	27	4235	21
MinGW	0.0	0.1	5.0	2.8	0.0	0.0	0	0.0	0.0	0	0.0	507	0.0
Eff	20%			40%	40%	93%	86%	93%			75%	97%	
TWh	**115**	**40**	**891**	**24**	**5.6**	**3**	**58**	**2**	**23**	**1105**	**171**		**115**
CapFac	13%	**30%**	**56%**	85%	1.1%	4.0%	11%	3.5%	7%	11%	72%		63%
£/kW	400	1170	1730	9000	350	25	100	25	2000	5	500	5	*7000*
Yrs	30	25	30	50	35	25	25	25	25	40	20	30	*20*
G£	41	18	314	29	20	0	6	0	23	6	14	21	*146*
G£/a	2.2	1.1	17.1	1.3	1.0	0.0	0.4	0.0	1.4	0.3	1.0	1.2	*10.2*
OM%cap	2.5%	2.5%	2.2%	2.0%	1.0%	2.0%	2.0%	2.0%	2.0%	1.0%	1.0%	1.0%	*2.0%*
G£/a	1.0	0.4	6.9	0.6	0.2	0.0	0.1	0.0	0.5	0.1	0.1	0.2	*2.9*
G£/a				0.1	0.7								
G£/a	3.2	1.5	24.0	2.0	1.9	0.0	0.5	0.0	1.8	0.3	1.1	1.4	*13.2*
p/kWh	**2.8**	**3.8**	**2.7**	**8.1**	**33.8**	**0.6**	**0.8**	**0.7**	**7.9**				

The optimisation software OptimEx automatically adjusts the DV values representing component capacities, simulates the annual performance at hourly steps, and evaluates the objective function (total system cost) as it searches for a least cost system design. An example using the OptimEx optimiser is depicted in Figure 16. As is typical with optimisation, large reductions in the objective function are found in the first evaluations, and then the marginal improvement gradually decreases.

Figure 16 : Optimisation – least cost found vs evaluations

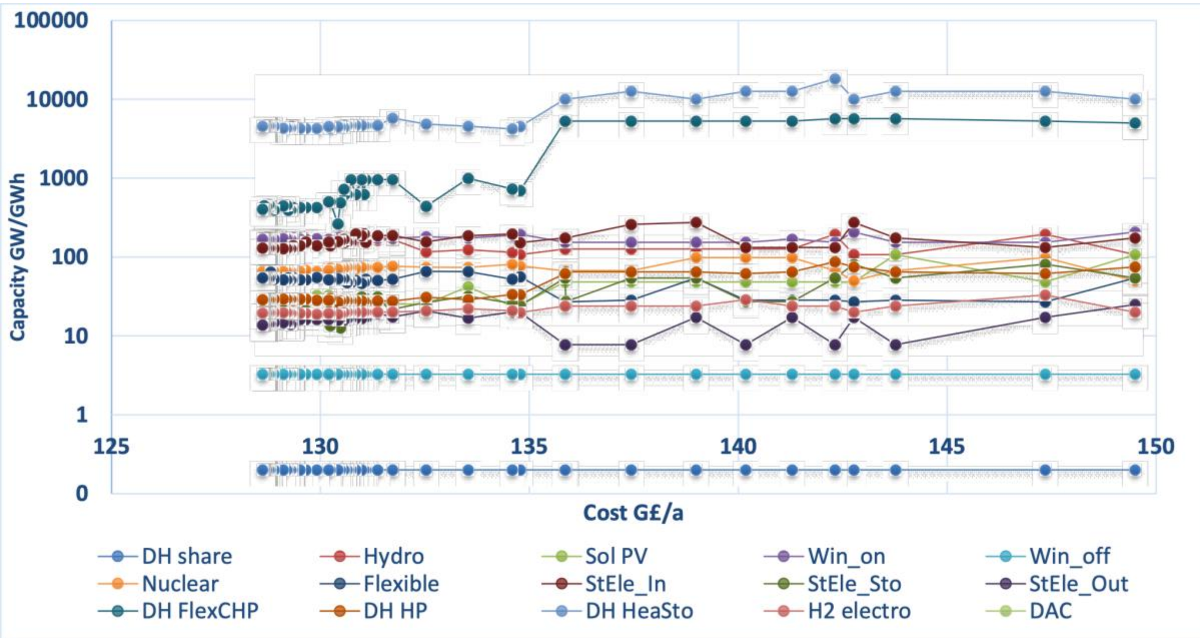


Source: OptimEx operating on ETSimpleMo

Figure 17 shows the movements of the decision variable (DV) values (note logarithmic y-axis) as the optimiser searches for lower cost solutions, proceeding right to left on the x-axis which shows the objective function (total cost). What is noticeable is that even when near the least cost found, the movements of some of the DVs are still significant. This means that other criteria can be considered for changing the design without increasing costs too much. These other criteria might include factors such as the feasible maximum implementation of a technology such as district heating, the availability of biomass or environmental impacts.

It is not certain that the optimum found is the global optimum; however, running the optimisation multiple times with different starting points does not substantially change the minimum cost found, and the fact that the DVs are continuous (not discrete) gives confidence there is not some much better undiscovered solution. It is emphasised that there are great uncertainties about future climate, demands and technology characteristics, which might lead to significantly different optima.

Figure 17 : Optimisation - DV value trends



6. Scenarios

The system is specified for the base year of 2020. Demands are projected for 2050 with logistic and linear quinquennial interpolations for the intervening years 2025 to 2045 inclusive. The system is optimised to produce a set of decision variable values defining the least cost system in 2050. It is noted that the years 2020 and 2050 are really indicative labels - it is already 2023 - for a development of about 30 years. Then these decision variables are interpolated between 2020 and 2050 with logistic curves. The interpolations are assumed and determine the rate of implementation of technologies; there is no explicit modelling of feasible implementation rates such as of consumer heat pump installation. The model is then run for each five year interval 2020 to 2050 to ensure the system functions in that supply and demand are nearly in balance in transition and the results in terms of system capacities, energy flows, emissions and costs are recorded and charted.

6.1. Scenarios summary

Eleven scenarios, set out below, were evaluated with variations being in heat pump, district heat and hydrogen heat shares, in demand levels, climate change and nuclear capacity. DH heat shares are constrained to 0%, 10%, 20%, 30%, 40% and 50% with the remaining share being HP. Two scenarios had hydrogen heat shares constrained to 30% and 70%. A low demand scenario was set in which demand use efficiencies in buildings and transport are set higher; this is somewhat arbitrary as it is not based on thorough analysis and is to keep low demand in the picture. A high climate change scenario was set with a 5 °C addition to ambient temperature. Hydrogen heating and extra nuclear power do not appear in the optimisation, so these were forced in by applying constraints. As explained, it is possible to change decision variables near the optimum without changing total costs much, so the optima found are not 'perfect' and the trends across the scenarios are not all smooth.

Eleven systems were optimised with different constraints using 2010 meteorology data and the systems simulated at 5 year intervals between 2020 and 2050 and transitional scenarios produced. Detailed results are given for the core DH share of 20% (DH20) scenario in 6.3 and summaries for all scenarios in 6.4. The trends of decision variables across scenarios are not smooth because of the inexact optimisation process.

District heat / heat pump share variants

This analysis is of a series of fixed levels varying 0% to 50% for the decision variables (DV) which define the mix of DH (large HPs and thermal storage) and HPs, and letting the model optimise all the other DVs. One aim of this is to quantify how much low cost DH thermal storage can reduce costly electricity storage.

Low demand

Lowering demands increases the possible rate of CO_2 emission reduction and can reduce costs. Demands can be reduced through behavioural measures such as changing building temperatures, choosing smaller cars, driving more slowly on motorways, and flying less, and behavioural changes can act faster than technological change thereby more rapidly reducing emission and therefore the cumulative emission to 2050.

These reductions 2020-2050 compared to the base demand scenario are assumed:

- 20% reduction in useful energy for land transport
- 20% reduction in aviation and shipping fuel demands
- 20% reduction in electrical equipment demand
- 20% reduction in building SHL

- Personal comfort systems (PCS) leading to a 1 °C reduction in building heating-on set temperature and a 2 °C increase in cooling-on set temperature

These changes are judged to be of reasonable magnitude though the assumption for aviation is at best speculative, but no justification of or detailed costing for them is offered. Energy efficiency measures are more varied and harder to cost than supply technologies.

A recent study of low energy demand (LED) by CREDS authors (Barrett, Pye *et al.*, 2021) detailed behavioural and technical measures which would maintain services but decrease energy demand in a set of scenarios. The electricity generation in these scenarios ranges 500 TWh to 800 TWh and it is assumed that 5% of electricity is imported. The LED scenario assumes 150 TWh of bioenergy imports, 50 TWh of UK biomass production, and substantial production of hydrogen from natural gas with CCS, whereas the Green Light scenarios have none of these, which at least partly explains the higher primary electricity consumption in Green Light. ETSimpleMo has inadequate demand detail to simulate the LED scenarios, and this is a possible area for future development.

Greater climate change

The greater climate change scenario has an increase of 5 °C and an assumption that 90% of the cooling load is met, rather than 80% in the other scenarios. This is compared to the default setting for climate change, which is an increase of 2 °C in ambient temperature across the year, with 80% of the cooling load being met.

Nuclear

Because of high nuclear costs, optimisation results in nuclear capacity set to the constrained minimum assumed for 2050, which for the current retirement and committed build programme is just the 3.3 GW of Hinkley C. In its *British Energy Security Strategy*[13] the UK government has announced plans for deployment of civil nuclear to up to 24GW by 2050. Therefore an optimisation has been carried out with the minimum 2050 nuclear capacity set at 24 GW.

Hydrogen heating

The heating shares of consumer HPs and DH are included explicitly in the optimisation. The hydrogen (H_2) heating share is constrained to 30% or 70%, and then the system is optimised as before.

The key settings for the eleven scenarios are set out in Table 11. DH20 is emboldened because this is the lowest cost system out of the first six, but only by a percent or two.

[13] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

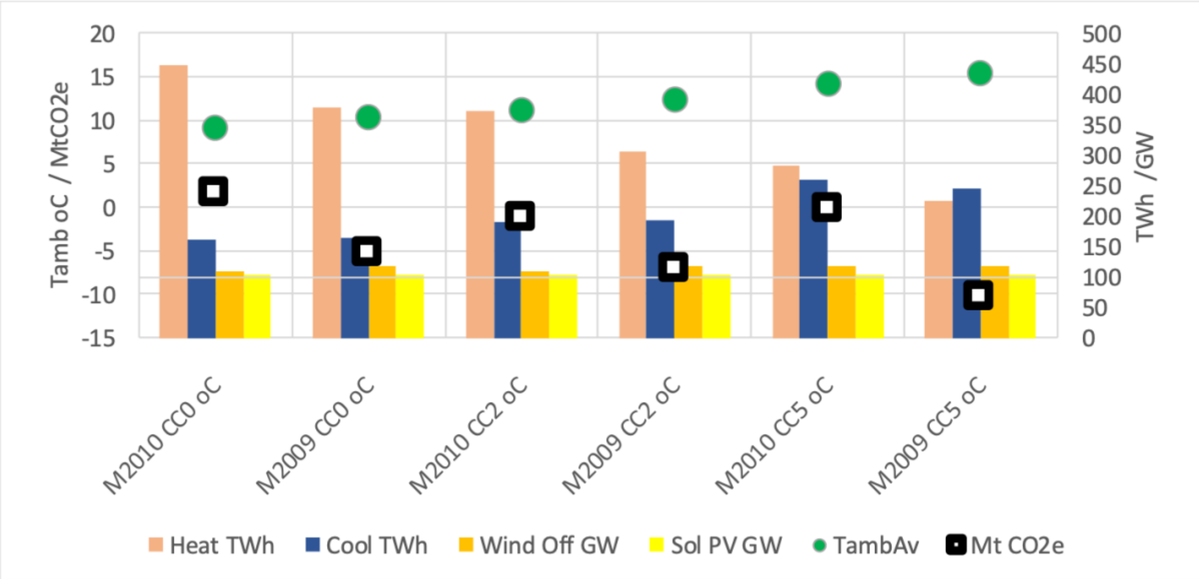
Table 11 : Scenario key parameters

	Acronym	Climate +oC	Heat share HP	DH	H2	Nuc GW
1	DH0	2	100%	0%	0%	3.3
2	DH10	2	90%	10%	0%	3.3
3	**DH20**	**2**	**80%**	**20%**	**0%**	**3.3**
4	DH30	2	70%	30%	0%	3.3
5	DH40	2	60%	40%	0%	3.3
6	DH50	2	50%	50%	0%	3.3
7	LowDH20	2	80%	20%	0%	3.3
8	Hot +5 oC	5	75%	25%	0%	3.3
9	Nuc	2	70%	30%	0%	24.0
10	H30	2	63%	7%	30%	3.3
11	H70	2	27%	3%	70%	3.3

6.2. Meteorology sensitivity

The meteorology year 2010 is chosen as a stress year because it is colder than average and has low offshore wind output, but note that it is not just the average but also the variation across the year that is important – for example it might be colder than average because of a colder summer but with a warmer winter, so both less heating and less cooling. For the DH20 system optimised to 2010 meteorology, Figure 18 shows the effect of the meteorology year (M: 2009, 2010) and climate change adjustment (CC: 0, 2, 5 ^{o}C) on average ambient temperature and the reduction in heat demand, and increase in cool demand, though not all this latter is serviced as the average ambient temperature is increased. Temperature also drives heat pump efficiencies: the consumer HP COP is 17% higher in the +5 ^{o}C climate than the +0 ^{o}C climate. Also shown is offshore wind generation, it being about 7% less in 2010 than 2009. The combined effect of these factors on net CO_2e emission is also shown and this ranges from +1.6 Mt CO_2e for 2010 without climate change, to -7.1 Mt CO_2e for 2009 with +2 ^{o}C climate change, and to -10.3 Mt CO_2e for 2009 with +5 ^{o}C climate change. This analysis indicates that the net zero system designs will on average meet the net zero target, but that in some years net emissions may be more than zero, and in some years less - net zero is statistical.

Figure 18 : Meteorology sensitivity of demands and emissions



6.3. Least cost scenario - DH 20% share

This section first sets out samples of the simulated energy flows for the DH20 system which is, narrowly, the least cost design for base demands, but costs are lower in the low demand scenario though they are not comprehensively calculated. This is followed by a description of the transitional energy flows and costs during the period from 2020 to net zero in 2050.

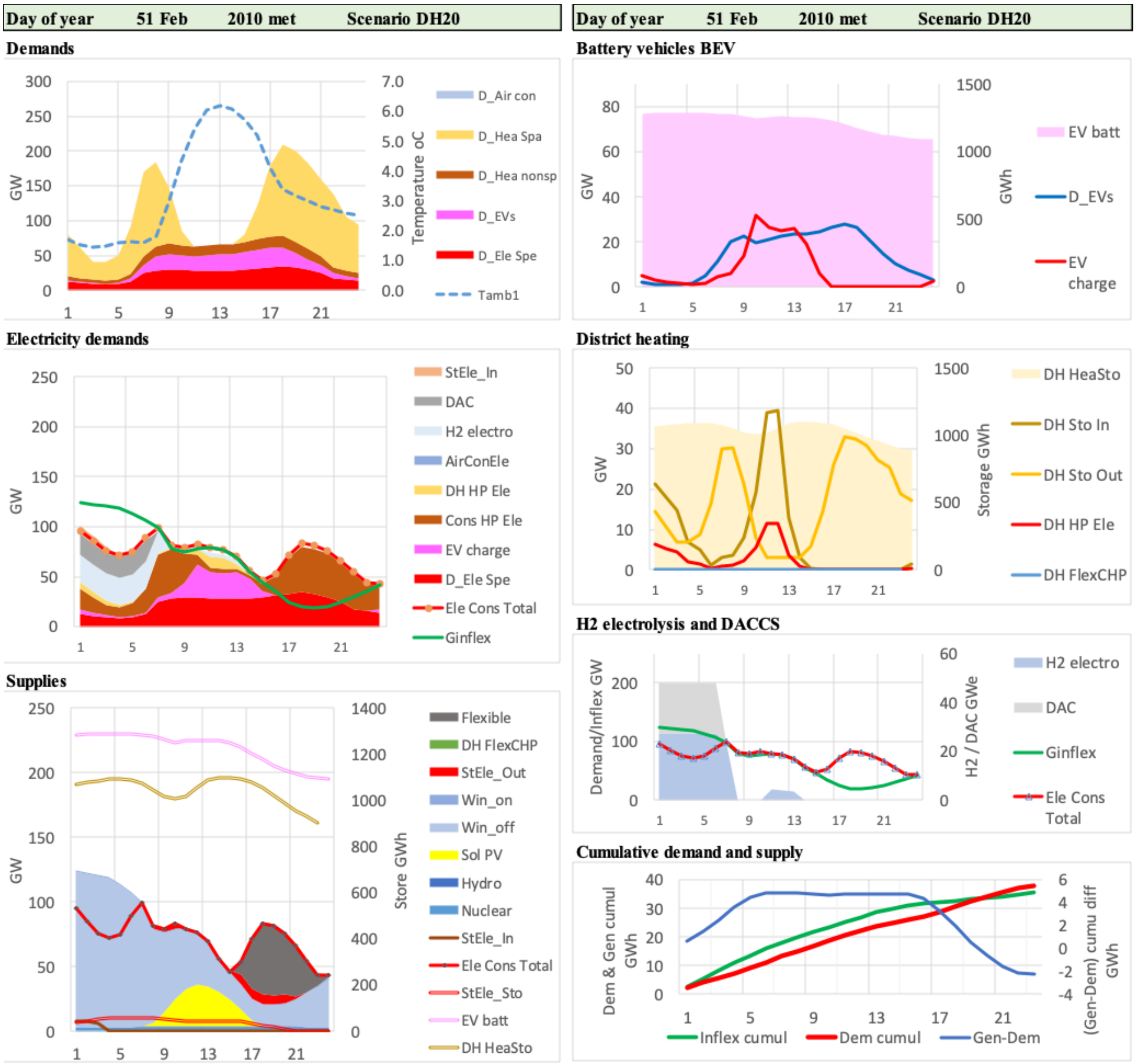
6.3.1. Simulation samples for the DH20 system in 2050

Central to this research is to demonstrate that the designs will work in engineering terms hour by hour under different meteorological and renewable resource conditions. The charts in this section illustrate the winter operation of the 2050 DH20 system with 2010 meteorology with charts of hourly energy flows. Periods of surplus and deficit of wind and solar are shown; when there is surplus the potential generation is spilled. The simulation shown in this section is for diurnal and fortnightly operation in a winter stress period when there is a renewable deficit and electricity storage and flexible generation are needed.

In the diurnal chart, we see an excess of inflexible generation over demand up to 6am, then demand is constrained to inflexible generation up to about 3 pm, when battery and flexible fuelled generators come meet the remaining deficit.

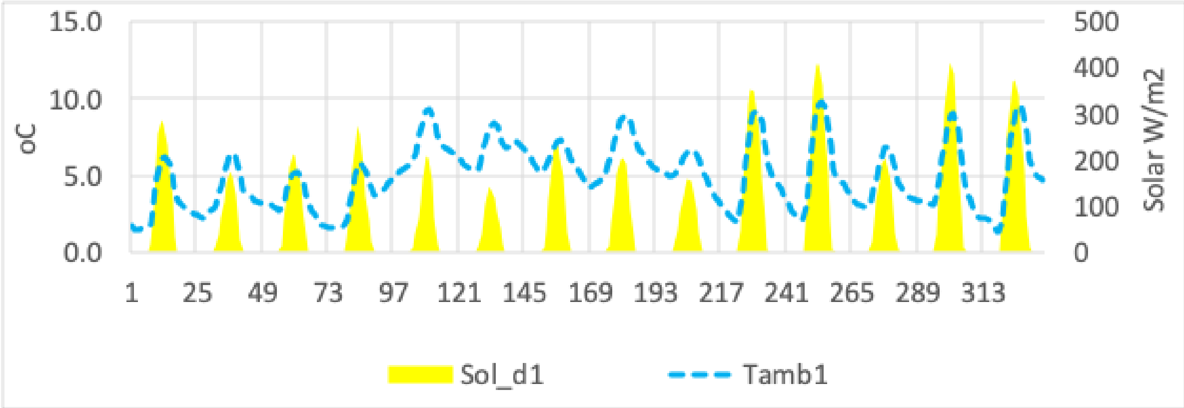
Then the annual operation is shown for the stress meteorology year of 2010. Results for a summer period are shown in section 10.3.

6.3.2. DH20 sample day and fortnight simulation: winter

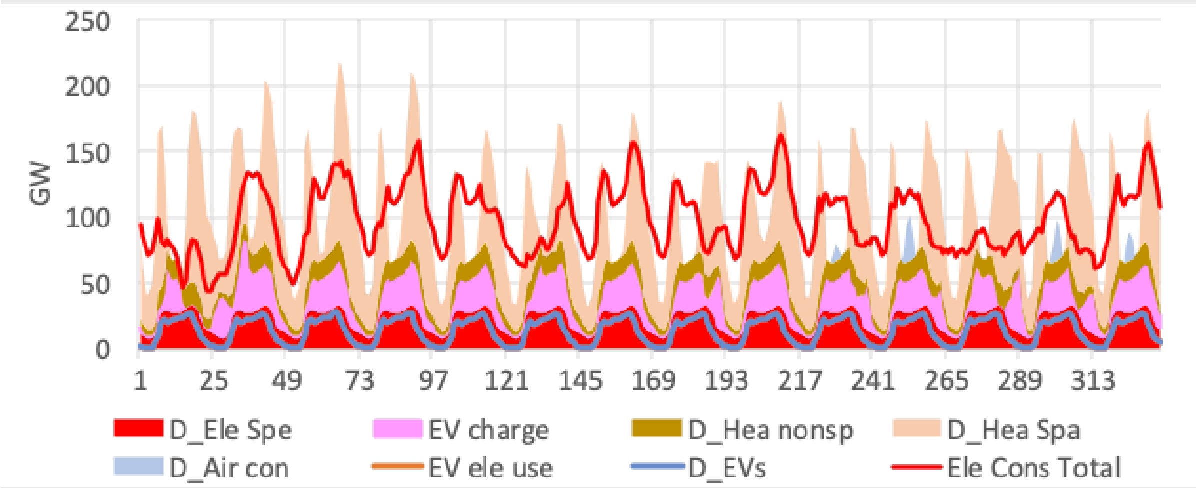


Fortnight from day	51 Feb	2010 met	Scenario DH20

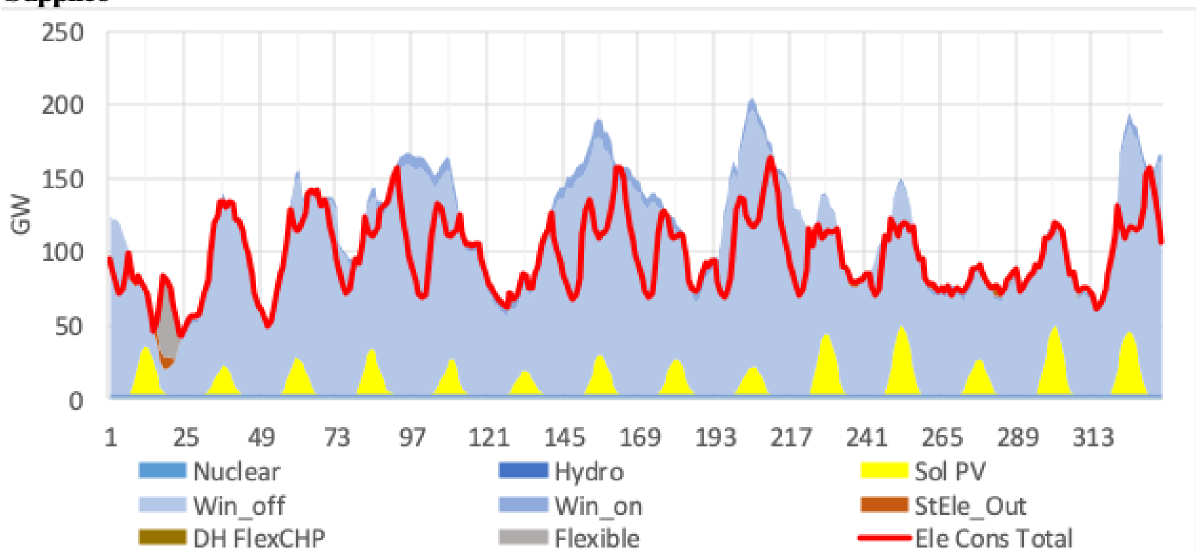
Meteorology



Demands

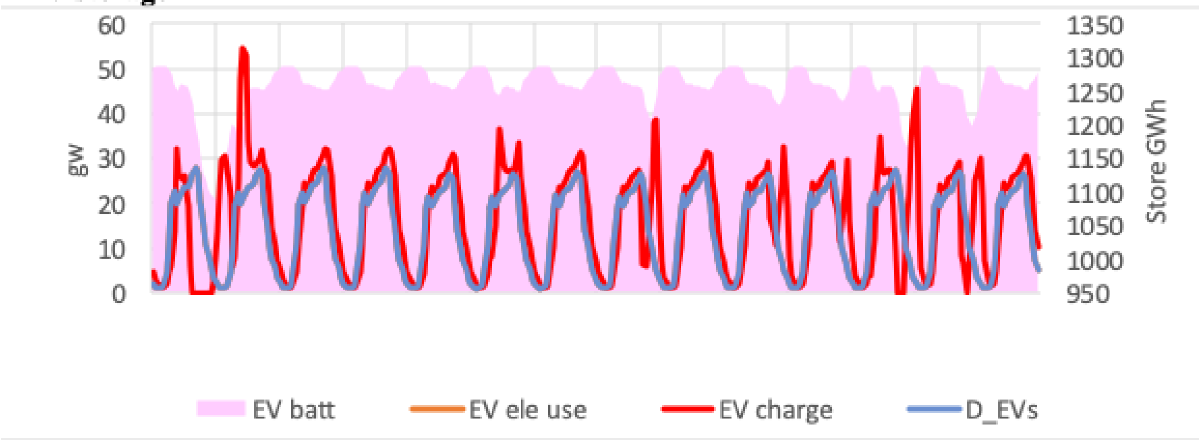


Supplies

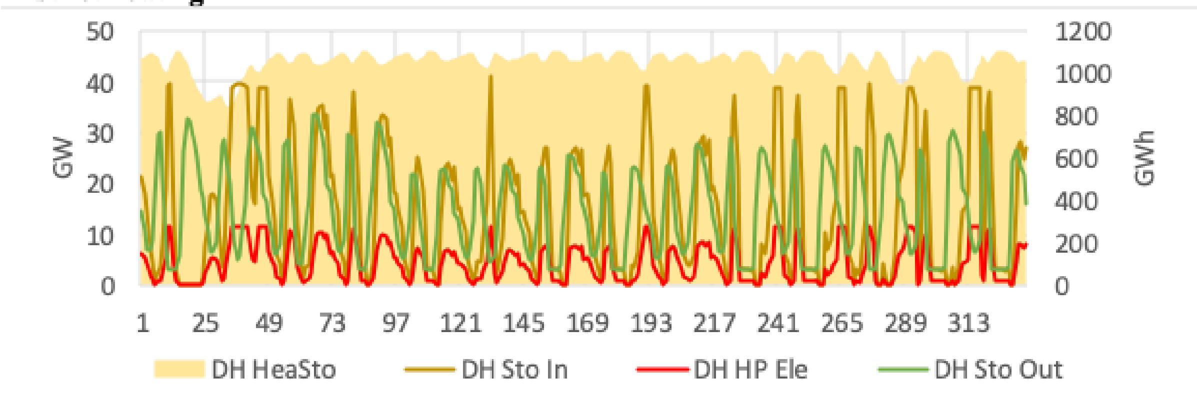


Fortnight from day	51 Feb	2010 met	Scenario DH20

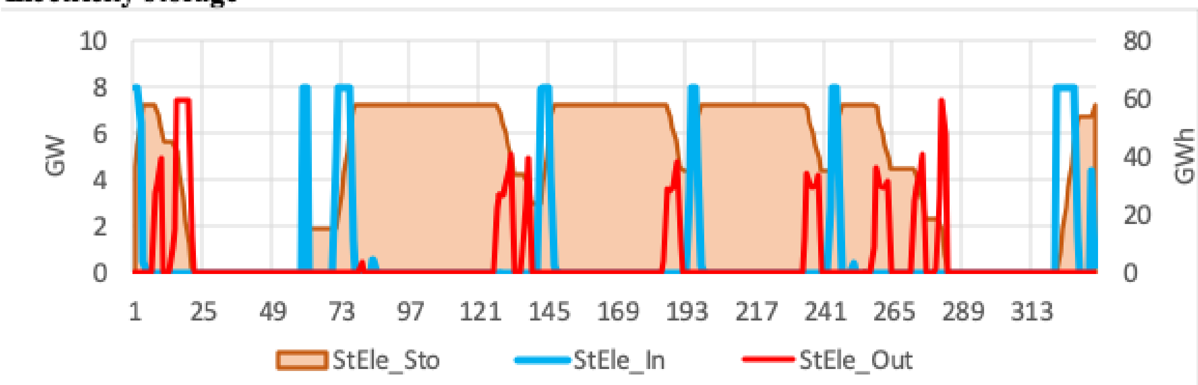
BEV storage



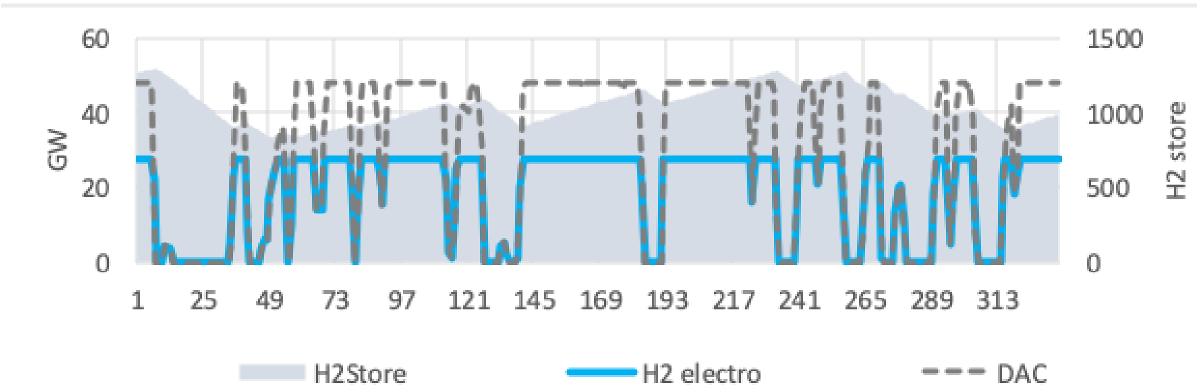
District heating



Electricity storage



H2 electrolysis and DACCS

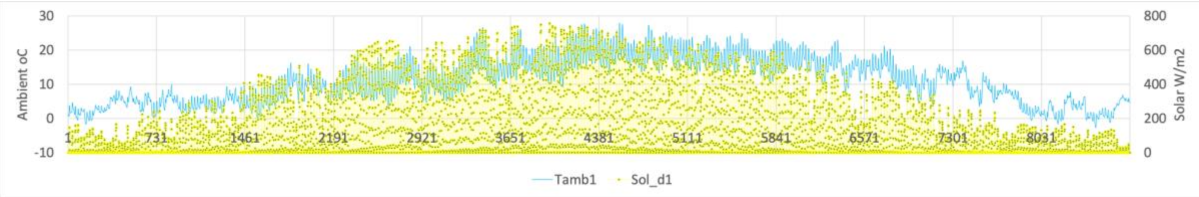


6.3.3. DH20 hourly simulation for one year

Hourly simulation results for one year (2010) for the scenario DH20 are shown in the following charts.

Figure 19 shows the 2010 meteorology. The ambient temperature and solar radiation are spatially weighted by population and used to drive space heating and cooling demands, and solar PV generation.

Figure 19 : DH20 – Year 2010 ambient temperature and solar radiation



The heat demands shown in Figure 20 are for heat and cool, not the electricity used to supply heat or cool using heat pumps. The winter heating and summer cooling peaks are similar in magnitude because of climate change and insulation, but heat demand is greater than cooling demand.

Figure 20 : DH20 – Year demands, ambient temperature, renewable and nuclear generation

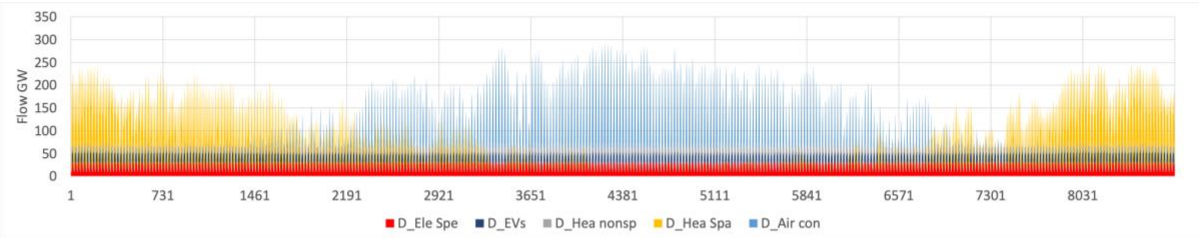


Figure 21 shows how the consumer and DH heat pumps COPs vary with hourly ambient temperature using the COP functions set out in Figure 9 (p13). Consumer HPs are assumed to absorb heat from air at ambient air temperature. The DH HP absorbs from ambient air temperature or 5 °C whichever is highest – this is to crudely emulate DH's ability to utilise higher temperature winter heat sources such as the ground or the sea.

Figure 21 : DH20 – Year heat pump COPs

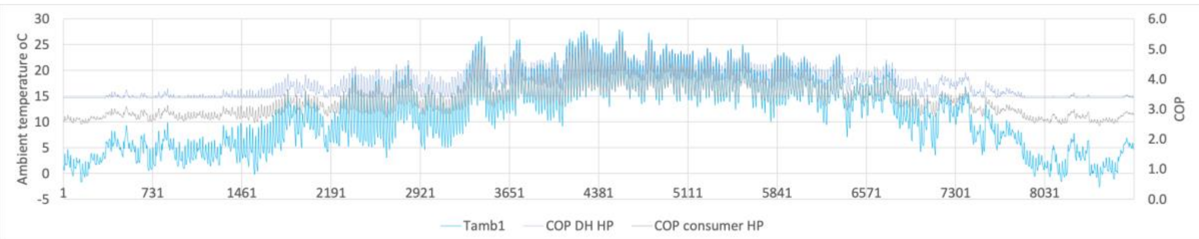


Figure 22 shows generation from the six categories of generator. Generation is dominated by offshore wind across the year but with a big contribution in summer from solar PV.

Figure 22 : DH20 – Year generation

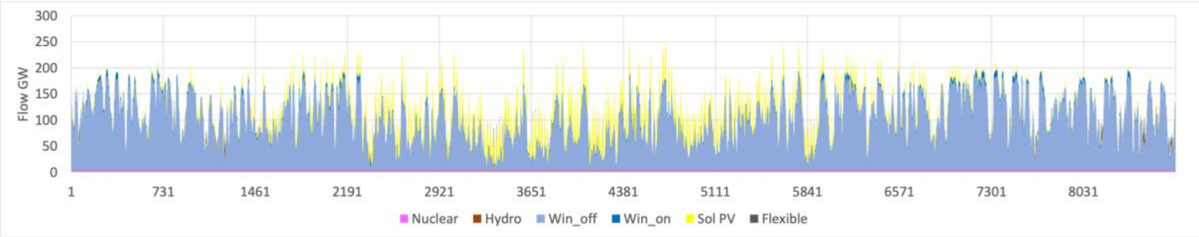


Figure 23 shows the surplus potential generation ("Gv surplus before H2 DAC") which is variable renewable and nuclear generation minus all demands except for H_2 electrolysis and DACCS. Any surplus after all other demands have been met is first used for hydrogen electrolysis up to the capacity (GWe) of the electrolyser, and then the remaining surplus is used by DACCS up to its capacity (GWe). The model assumes H_2 electrolysis and DACCS can load follow as required, but it may be that in practice some storage might be used to smooth operation. The annual capacity factors of the electrolyser and DACCS range 65-75%. The avoidable cost of the surplus electricity used will be low as it does not require much additional capital investment in generation or transmission, and so electrolysis and DACCS costs may be dominated by plant capital and O&M costs. Research on the marginal costing of electricity is required, but it is complex. A hydrogen store is used to ensure that hydrogen supply to industry and ammonia production is continuous.

Figure 23 : DH20 – Year residual demand and surplus used for H2 electrolysis and DACCS

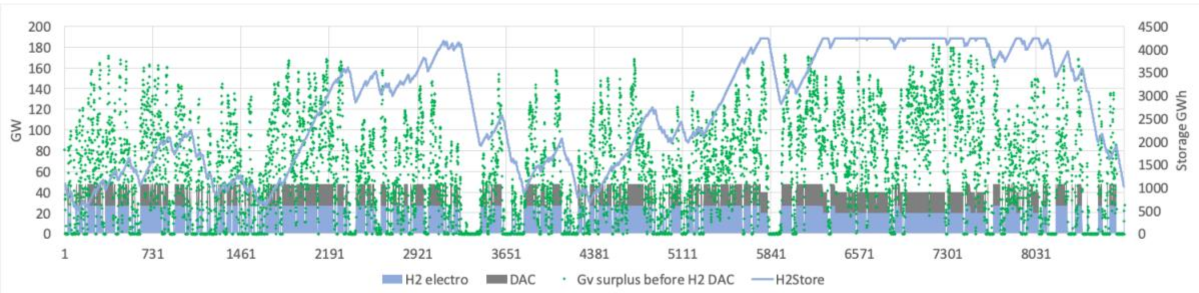


Figure 24 shows the levels of the four system stores modelled: grid, BEV, DH heat and hydrogen, the inflexible renewable and nuclear generation, and the flexible fuelled generation. When there is a surplus of renewables after all other demands are met, hydrogen electrolysers are first run, and only if there still remains a surplus after this, the DACCS is run. H_2 storage ensures that an adequate supply of hydrogen to industry or gas boilers is maintained in any hour. Storage levels are lowest when cumulative renewable deficits are highest, and this is restricted to a small proportion of the year for stores apart from H_2. Note that the initial assumed level is important, and ideally the simulation would be continued over longer periods. The issue of resilience to extremes is discussed in 8.5.

Figure 24 : DH20 – Year stores and inflexible and flexible generation

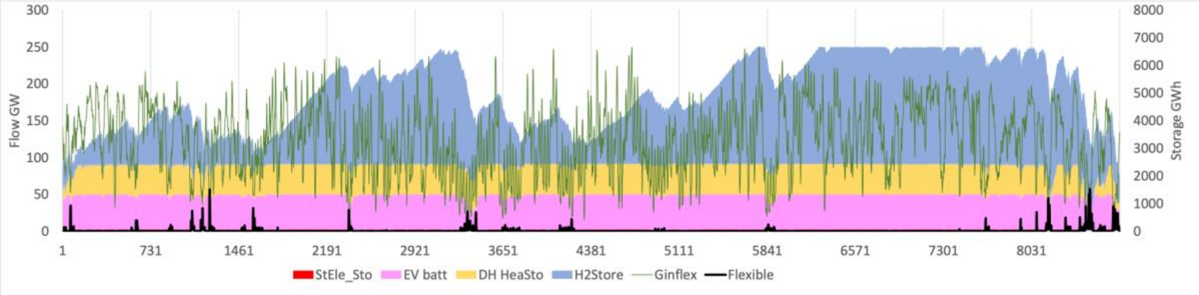
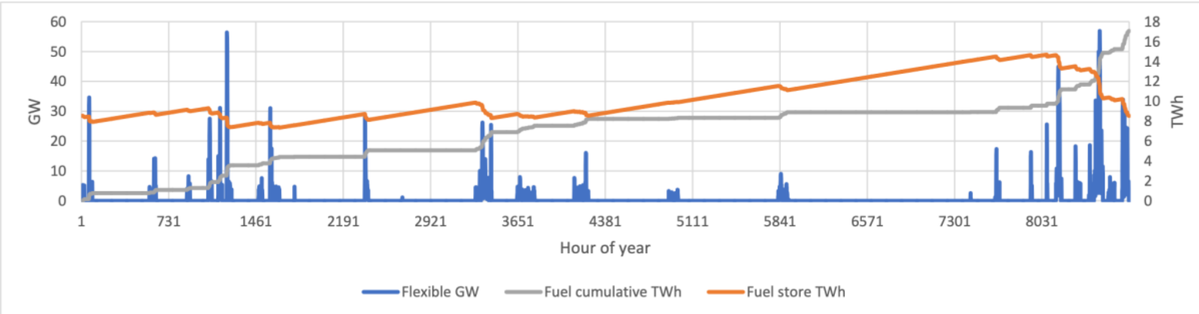


Figure 25 shows flexible generation using stored fuel, cumulative fuel consumed and implications for storage given a constant fuel supply. The maximum generation is 57 GW and the capacity factor is 1%. 6 TWh are generated and 17 TWh of fuel used. If a continuous fuel supply of 2 GW is provided then the store level is the same at the end of the year as the beginning, 8 TWh. The minimum store level is 7 TWh and the maximum 15 TWh so 8 TWh of storage are used.

Figure 25 : DH20 – Flexible generation, fuel use and storage



In the least cost system design found, apart from the low demand scenario, the DH share is 20%.

Table 12 gives data for buildings, temperature controls for turning on heating and cooling, and meteorology data and the assumed climate change ambient adjustment. The cells coloured yellow are input assumptions to ETSimpleMo.

Table 12 : Heating and cooling drivers

METEOROLOGY				
	Met data year	**2010**	2009 or 2010	
	Climate change	2	oC	
HEAT AND COOL DEMAND				
	Base spec heat loss	9.0	GW/oC	
	Insulation index	90%		
	Heat on temp	19	oC	
COOL	Cool on temp	25	oC	
	AirCon pc	80%		
	SolarControl	80%		
	AirCon effic	400%		
		Cool		**Ele**
	GWp	225		56
	TWh	189		47

Table 13 gives a breakdown of heat demand and supply, and electricity consumption and supply. Energy flows units are annual TWh, peak GWp and average GWav. The heat supply mix (gas, hydrogen, heat pumps, district heating) is specified. Of note is the dominance of renewable generation and that 22% of potential generation is spilled.

Table 13 : DH20 optimised heat and electricity flows in 2050

HEAT		TWh			CapFac
Heat non space		100	11	GWav	22%
Total useful heat		**372**	**190**	GWp	
		Share	TWhth	Eff	TWh
	Gas heat	0%	0	85%	0
	H2 heat	**0%**	0		0
	Ele heat	**100%**	372		
	HP of ele	**80%**	HP share	80%	
			Heat	**Ele**	**COP**
DH	Total	TWh	83		
		GWp	42		
	HP	TWh	83	23	3.54
		GWp	41	11	
	CHP	TWh	0	0	
		GWp	0	0	
Cons HP		TWh	298	108	2.76
		GWp	152	64	
TOTAL		**TWh**	**380**	**131**	

ELECTRICITY				**Loss**
Consumption		**TWh**	**GWp**	**TWh**
	Electricity specific	200	34	14
	EV charge	138	55	9
	Consumer HP	108	64	7
	DH HP	23	11	0
	Cooling	47	56	3
	Hydrogen	171	27	3
	Direct Air Capture	115	21	2
	Grid store			0
	Total	**802**	**132**	**41**
Supply	Renewable	1046	247	97%
	Nuclear	24	3	2%
	DH FlexCHP	0	0	0%
	Flexible	6	57	1%
	Ele storage increase	0		
	Country supply	**1076**		
	Spilled eletricity	234	22%	

6.3.4. Base demand scenario

The future demands for useful energy will change according to the contending forces of climate, cultural, demographic and economic trends, increases in efficiency and physical resource (such as ores) availability. The base demand scenario is applied to all scenarios except the low demand scenario (all demands lower) and the high climate change scenario (less heat more cooling).

Compared to 2020, in the base scenario 2050 demand changes are as follows:

- Electricity specific, non-space heat demands are 90% of 2020.
- Useful surface transport energy is 80% of 2020 through improved vehicle body efficiency. Delivered energy is further reduced as the transition from internal combustion engines to electric vehicles is made because the efficiency of an electric drive train is about three times the efficiency of an internal combustion engine and gearbox train in converting energy delivered to the vehicle into motive power.
- Shipping and aviation energy inputs are unchanged, i.e., demand growth is assumed to be balanced by efficiency gains to 2050. This is a strong assumption for aviation.

Space heat demand falls by 45% because of climate change (+2 °C in 2050) and improved building efficiency reducing the building stock specific heat loss from 9 GW/ K to 8 GW/K. Air conditioning demand increases because of climate change and increased ownership.

There are additional demands for electrofuels and DAC operation.

Figure 26 : Demands scenario

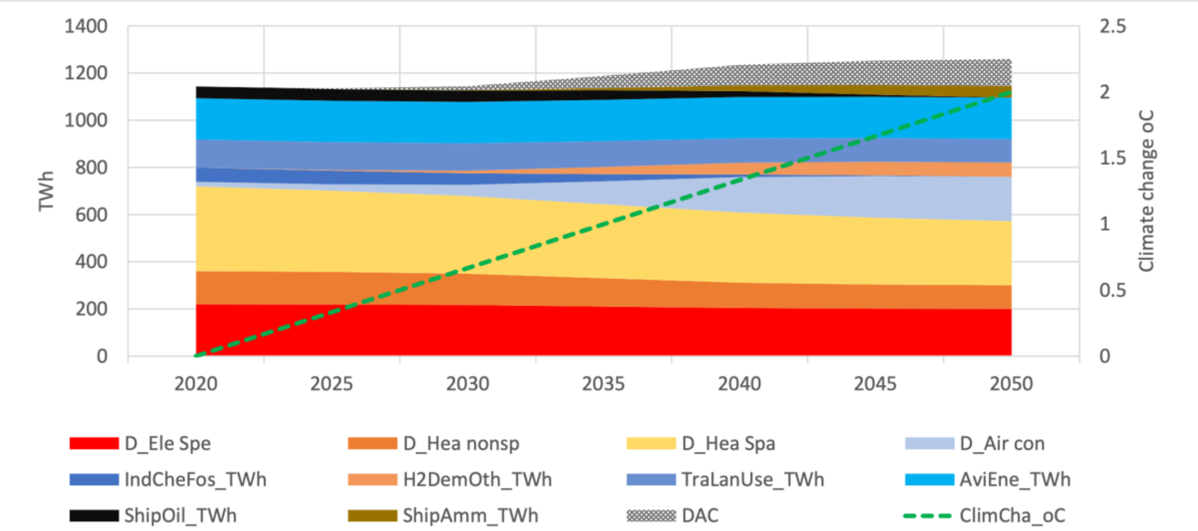
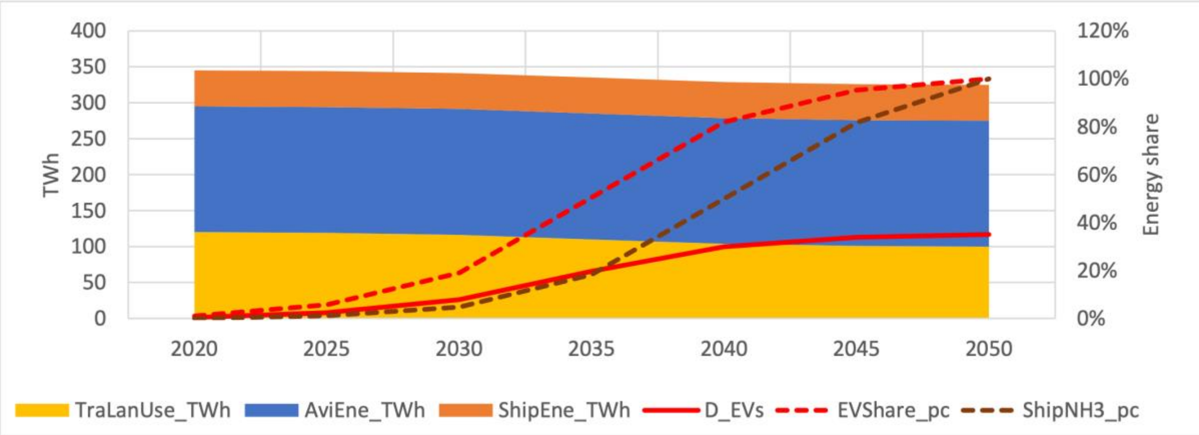


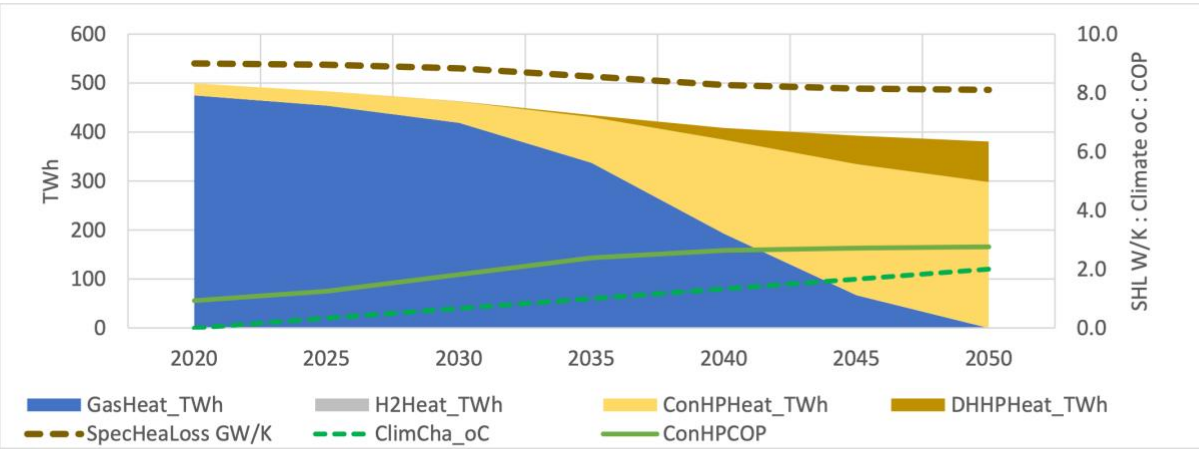
Figure 27 shows the assumed <u>useful</u> energy demand for land (road, rail) transport, and the total energy/fuel inputs to aircraft and ship engines, and the changing delivered energy shares for road/rail as they are electrified and ship transport as it converts to ammonia.

Figure 27 : Demand scenario – transport



Total heat demand falls from 500 TWh to 380 TWh because of climate change (+2 °C) and improved building efficiency in new build and retrofit reducing the building stock specific heat loss from 9 GW/ K to 8 GW/K, thereby reducing space heat demand. Heat supply is progressively switched from gas and electricity (resistance heating) to electrical consumer HP and DH heat pumps, with the latter's share expanding more slowly. Minor heating fuels such as oil, coal and wood are not modelled as they will be small. The change from electric resistance to consumer heat pump heating is reflected by changing the heat pump COP, The COP is calculated hourly using the ambient temperature in the Carnot equation and assuming the COP is a fraction of the Carnot maximum. Climate change increases the heating COP. These trends are depicted in Figure 28.

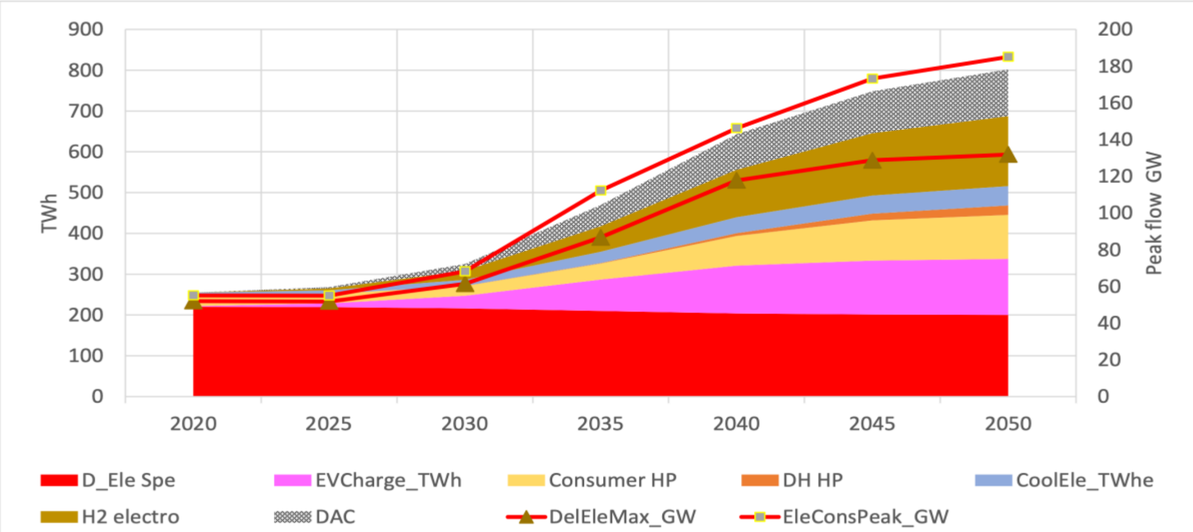
Figure 28 : DH20 heat supply scenario



6.3.5. DH20 electricity demand and supply scenario

Electricity demand grows as heat is electrified and cooling increases, as transport is electrified directly or indirectly via electrofuels, and as there are additional demands for electrolytic hydrogen and DACCS. The annual electrical energy demand (TWh) grows threefold to 800 TWh. The peak delivered demand (GW) on the lower voltage distribution network increases from 55 GW to 130 GW, whereas the peak consumption which also includes losses and electrolysis and DACCS demands connected at higher voltage, grows to 190 GW. This shown in Figure 29.

Figure 29 : DH20 demand – electricity



Generation capacity comprises variable renewables (hydro, wind, solar), nuclear and flexible plant using biowastes, fossil gas or hydrogen. Figure 30 shows the generation trends. By 2050, offshore wind has grown to 180 GW, onshore wind to 15 GW, and solar to 100 GW. The nuclear capacity declines from 8 GW (2020) as existing plant retire, down to the committed minimum capacity of 3.3 GW (Hinkley C). Flexible generation capacity reaches 57 GW fuelled with gas and biowaste. Grid storage input capacity is 8 GW, 60 GWh storage and output capacity is 8 GW. So flexible plus storage output capacity is 65 GW.

Figure 30 : DH20 generation – capacities

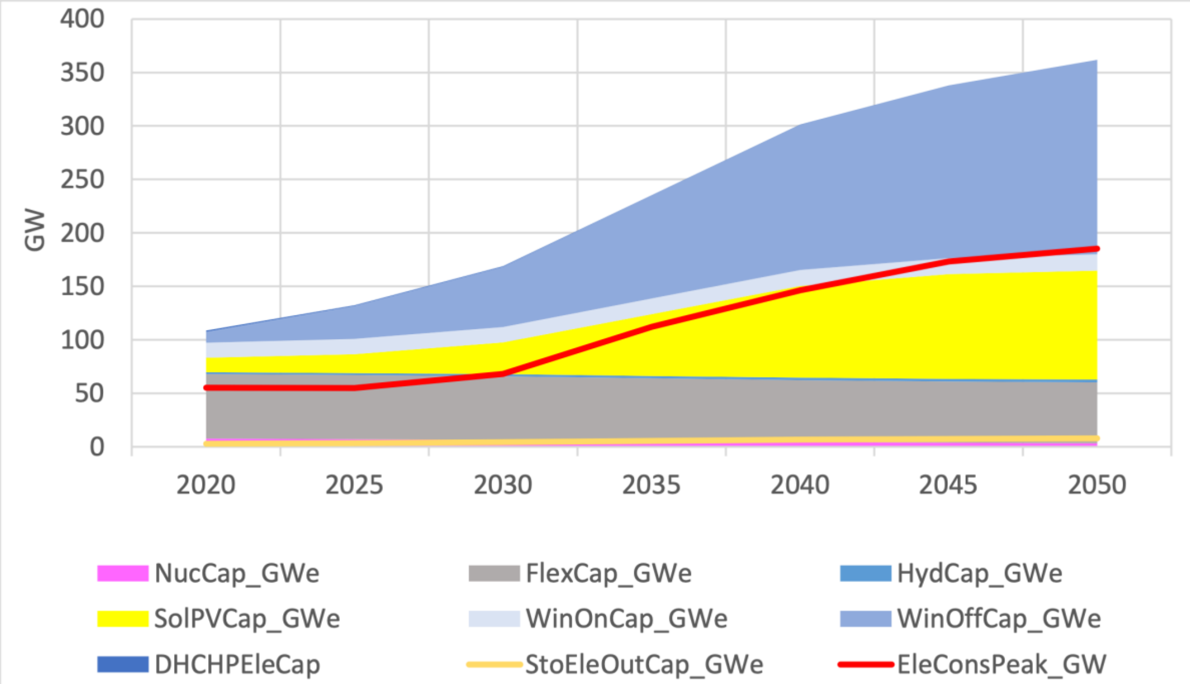


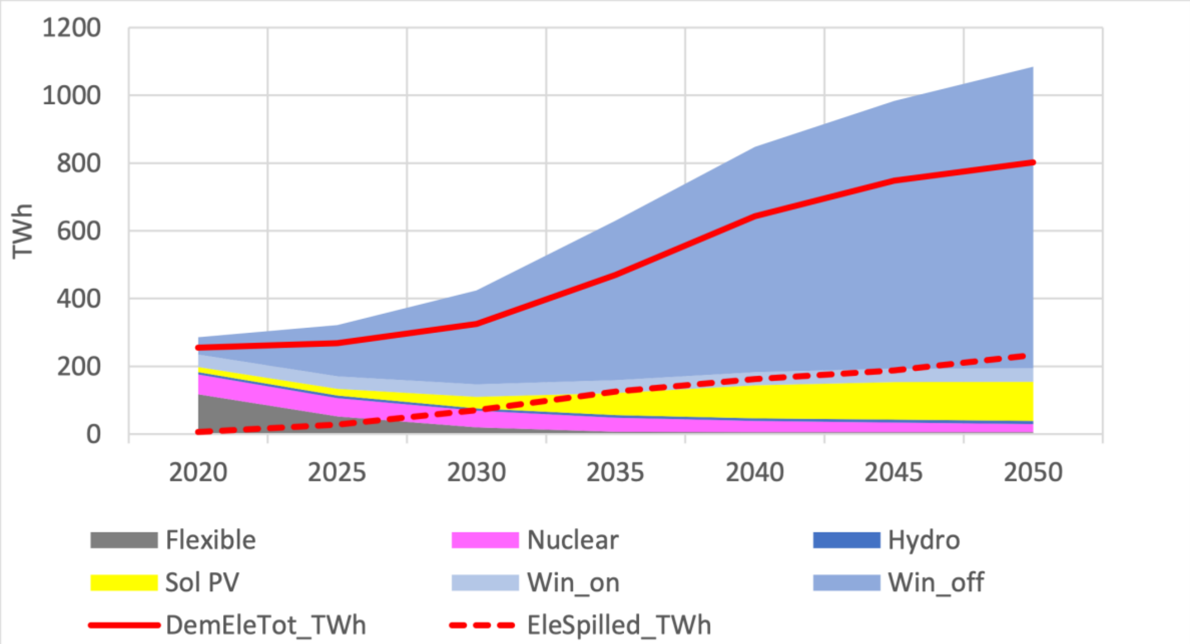
Figure 31 shows potential generation from renewable, nuclear and flexible sources – generation data given are potential output some 20-30% of which will be spilled – generation for renewables should be read as shorthand for potential generation. In 2050, offshore wind (potentially) generates 890 TWh which is 83% of total generation. Solar generates 115 TWh and onshore wind 40 TWh. Nuclear generates 25 TWh or 2% of total and 57 GW of flexible plant outputs 6 TWh operating at a capacity factor of around 1%.

In the least cost 2050 systems 20-30% of potential generation is spilled, and this is one of the most surprising optimisation results. Essentially, this is because it's cheaper to build 'excess 'renewables than more absorption capacity with storage or demand – e.g., grid storage, DH heat pumps or electrolysers – which would be operating at increasingly low capacity factors and therefore higher unit capital costs. However, this spillage is in a system with no interconnector trade which other analysis by Gallo Cassarino and Barrett (Gallo Cassarino and Barrett, 2021) has shown can reduce storage needs or spillage. This is a major limitation of the modelling here. In fact, spillage of potential generation is a feature of the current system; for example, gas generator capacity factors have fallen over the past 20 years from around 60% to 40% because of increasing renewables, and could generate much more than they do, so they also spill potential generation but unlike solar and wind, this has the substantial avoidable cost and emissions of gas.

Even in 2022, spillage can occur: renewable capacity is 40 GW (2 GW hydro; 13 GW solar; 24 GW wind), and nuclear 8 GW, a total 47 GW of zero carbon. The minimum UK night demand is about 20 GW so wind alone can exceed this. During a summer Sunday, nuclear, wind and solar can exceed demand during the day.

An alternative assumption that flexible generation uses stored hydrogen is also modelled but optimisation shows this to increase costs.

Figure 31 : DH20 potential electricity generation and spillage



6.3.6. DH20 storage scenario

Storage can be divided into:

- **one-way** primary stores where stored primary energy (fossil, nuclear, biomass) is put into a conversion device to output secondary energy (electricity, heat, chemical)
- **two-way** stores where primary or secondary energy is put into a store, and energy in the same or other form is output. In the system modelled here, two-way stores are grid, BEV, DH heat and hydrogen

In general the efficiencies of store charge and discharge, and standing losses, are variable, but this is a refinement that is currently beyond the capabilities of ETSimpleMo.

Grid storage input and output powers (GW) and energy capacity (GWh) are separate decision variables. In 2050, grid storage is about 60 GWh, about twice the 30 GWh in 2020, and the input and output capacities rise from 3 GW in 2020 to 8 GW in 2050 so the ratio of energy to power is lower, falling from about 10 hours in 2020 to 4 hours in 2050.

Grid storage cost and efficiency data are approximately based on lithium batteries, with the assumption that future replacements such as sodium sulphur batteries will have similar cost and performance.

The electricity storage option of combined electrolytic hydrogen, hydrogen storage and hydrogen generation was tested in the optimisation but was found uneconomic because of its high capital cost and low throughput efficiency: Table 14 shows an approximate comparison of grid storage using battery and hydrogen storage.. A sensitivity would be to use data for alternatives such as compressed air or liquid storage. In general, the cost per kWh stored of these is less than lithium, but the power cost is higher and the throughput efficiency is lower. Batteries have lower power costs and higher efficiency; hydrogen has lower energy storage costs.

Table 14 : Battery/hydrogen grid storage comparison

	Battery	Hydrogen	Battery/H2
Input	Battery	Electrolyser	
Eff	93%	75%	
£/kWe	25	350	0.1
Storage	Battery	Tank	
Eff	99%	97%	
£/kWh	100	10	10.0
Output	Battery	Generator	
Eff	93%	55%	
£/kW	25	500	0.1
Throughput			
Elec eff	86%	40%	2.1
Heat	14%	60%	0.2

The main electricity store is BEV batteries. The capacity and availability of these will be determined by factors including required vehicle range, EV consumption per distance, battery costs, fast charging infrastructure, and the availability and impacts of materials for batteries. As land transport is electrified in all scenarios, EV costs are not included in system costs and so EV battery capacity is not optimised and yet the days of average demand that EV batteries store has an impact on the required capacities of generation and storage in the rest of the system, and sensitivity analysis is required here. In these scenarios, the batteries are assumed to store 4 days demand which is about 1300 GWh, equivalent to an average 40 kWh per vehicle for 32 M vehicles. The stock has a maximum charge rate of 130 GW which can fully charge batteries in 10 hours with a throughput efficiency of 85%, It is assumed there is no vehicle to grid or demand facility.

DH storage is assumed to be sensible heat through temperature change in water, but it is simply modelled as a given capacity with no account of the effect of temperature on DH HP

COP and losses. In practice DH store temperature might be adjusted according to time of year and renewable surplus.

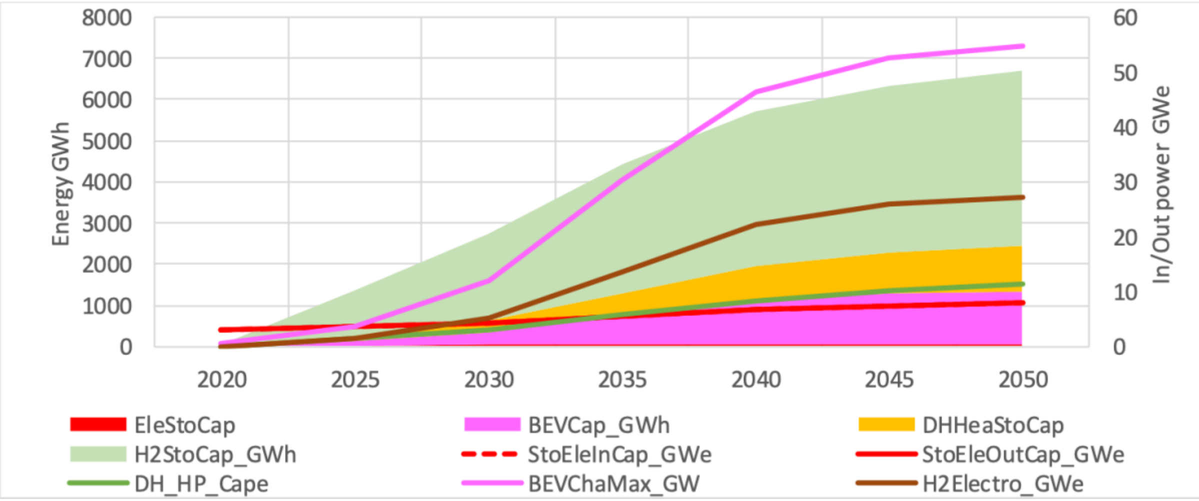
Optimal DH thermal storage of 1100 GWh stores about 26 hours of peak DH demand of 40 GWth. DH has an electrical heat pump capacity of 11 GWe (about 40 GWth) which can fill the store from empty in about 30 hours.

The largest store is hydrogen which is sized to deliver baseload hydrogen to industry and ammonia production in Haber plants which can then run at their maximum capacity factor; but it may be that reducing hydrogen storage and having a lower industrial capacity factor gives a lower cost solution and further analysis is required here. Optimisation sets H_2 storage to 4200 GWh for scenarios without hydrogen heating, about 300 hours average industrial demand.

The system includes flexible generation which has access to gas storage of unspecified size. Optimisation sets flexible generation to generate about 6 TWh, using 20 TWh of fuel. During 2022/2023 the peak UK two-way gas storage was about 29 TWh (8/11/23) with 13 TWh LNG (23/11/22)[14].

There will be many other stores such as small heat stores and batteries in buildings and ammonia stores for ships and industry, but these are beyond the model scope and resolution. and may be relatively minor in terms of overall system behaviour and cost apart from at short timescales. Storage trends are show in Figure 32.

Figure 32 : DH20 storage

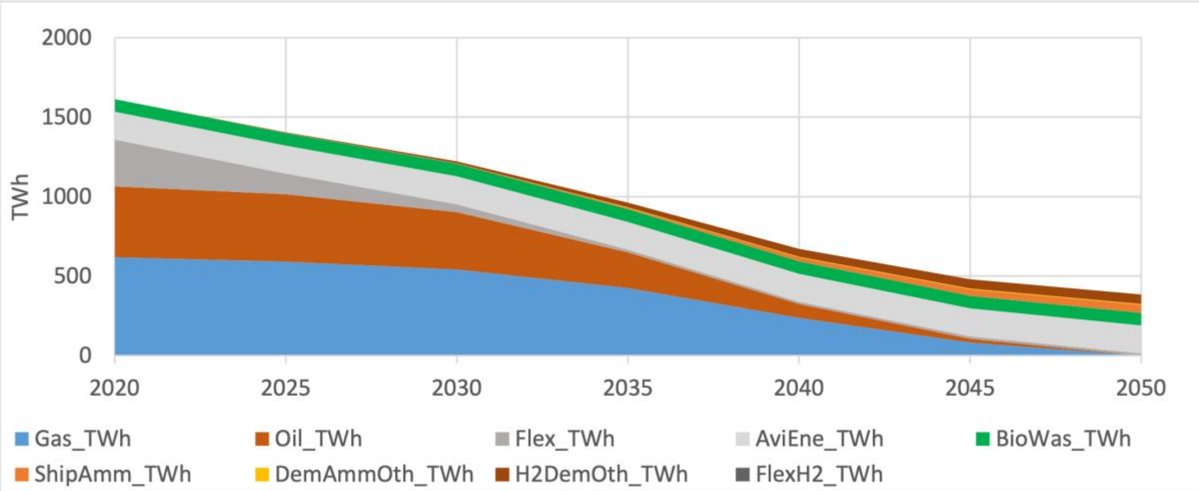


[14] https://data.nationalgas.com/find-gas-data

6.3.7. DH20 fuel deliveries scenario

Fuel deliveries are shown in Figure 33: fossil fuel consumption falls to near zero in all sectors except aviation where it is assumed that fossil kerosene continues to be used. In shipping, fossil oil is replaced with electro ammonia, and some industrial demand uses hydrogen. Biowaste energy is assumed constant across the years.

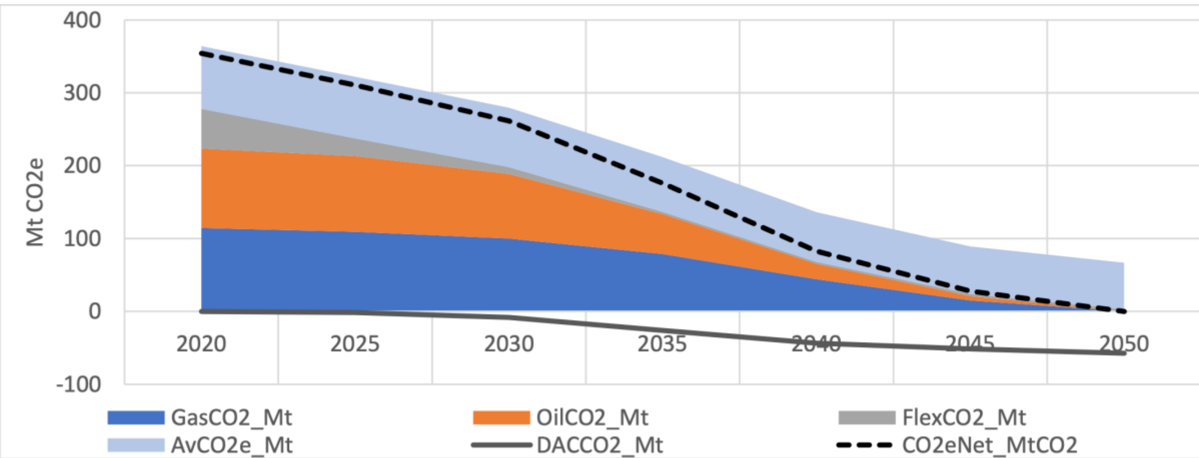
Figure 33 : DH20 fuel deliveries



6.3.8. DH20 emission scenario

Renewable electricity replaces almost all land-based stationary and transport fossil demands directly with electricity, and marine oil with electro ammonia. Aviation is assumed to be fuelled with kerosene, a fraction of which is made from biomass, but the bulk of which is fossil kerosene with its associated CO_2 emission. High altitude global warming is assumed to reduce to 1.5 times the CO_2 warming by 2050 – see section 7.1. As seen in Figure 34, aviation emissions are increasingly dominant and are assumed to be balanced with negative emission from DACCS. Other energy related greenhouse emissions such as methane emissions from gas or biofuels are not calculated but will be small in 2050 and could be balanced with more DACCS, if required.

Figure 34 : DH20 emissions scenario

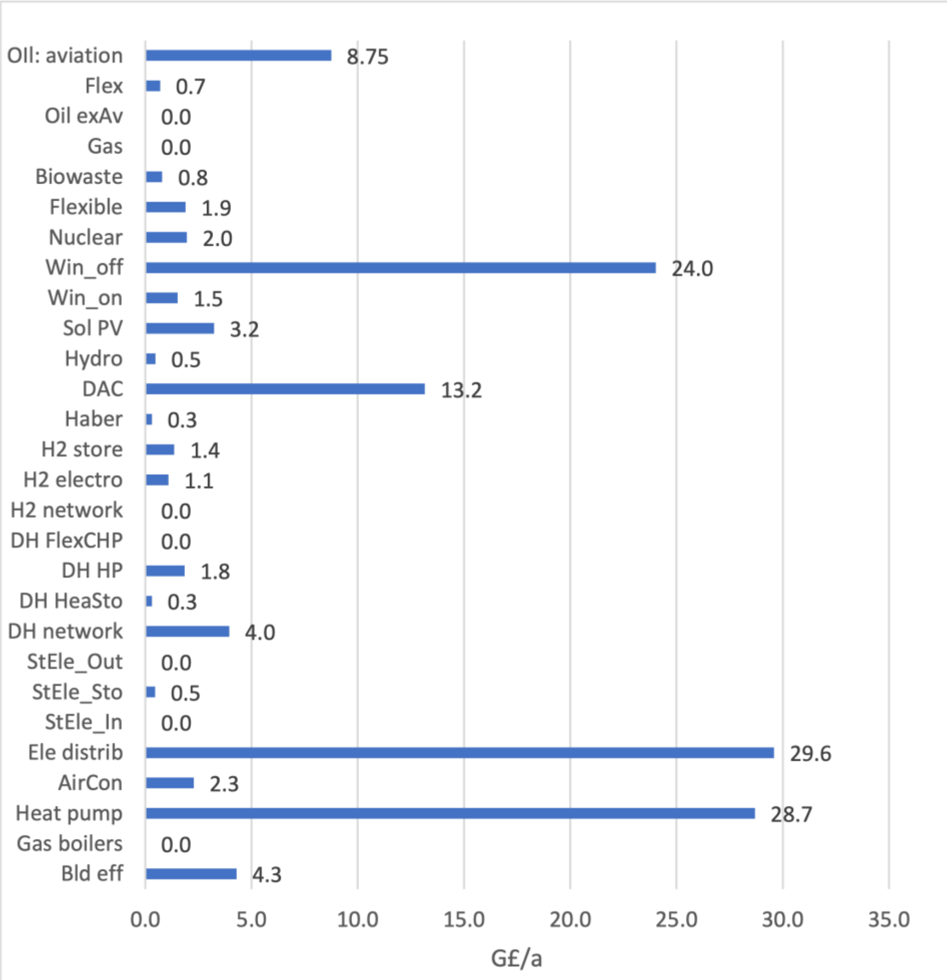


6.3.9. DH20 scenario costs

As set out in 5, all capital costs are annuitized at a single discount rate of 3.5%/a over technology operational lifetimes. Annuitized capital and operational costs in 2050 are shown in Figure 35.

The largest component costs are for the electricity network (23%), consumer heat pumps (22%), offshore wind (19%), DACCS (10%), and aviation fuel (7%), together accounting for 81% of the total annual cost. Notable is that the electricity grid costs are about the same as the generation cost. Apart from fossil kerosene, DACCS cost is the most uncertain significant cost as there are no operating commercial scale plants. As most DACCS is for negative emissions to balance aviation emissions, DACCS cost should mostly be allocated to aviation, such that aviation becomes a large fraction of total system cost. The assumed fossil prices critically affect the costs. During 2021-2022, wholesale oil and gas prices increased greatly, fluctuating between 2 and 18 p/kWh. It is assumed that oil and gas prices are steady at 5 p/kWh across the scenarios. As oil and gas consumption reduces the unit production costs will increase, particularly for oil products where refinery costs are significant, and there will be refinery fractions which will not be used.

Figure 35 : DH20 2050 annual costs in G£/a



Annual fuel and aggregated annuitized capital and O&M costs are shown in Figure 36 and disaggregated in Figure 37. Note that the cost of the natural gas network is not calculated as it is largely redundant in 2050.

Given the current fossil pricing assumption, energy system costs make a transition from the current system where fuel costs are about half of total cost to one where capital and O&M costs dominate, with aviation fuel being the main remaining fuel cost. With the assumed fuel prices and technology costs, the total annual cost of the energy system ranges from about 140 G£/a to 125 G£/a across the scenario. The fuel cost reduces from 40% of total cost in 2020 to 10% in 2050. The fixed annuitised capital plus O&M costs increase from about 50% of total cost to about 90% in 2050. The undiscounted capital value of the system increases from 550 to 1500 G£ in 2050 but note that the value of the existing gas system is excluded. The cumulative capital investment will be greater than this as shorter lived technologies such as heat pumps will be replaced by 2050.

One advantage of net zero is clear: fuel costs are a smaller fraction of total costs than currently, so the system is less vulnerable to political events and markets driving fluctuating prices. But there would likely be increased vulnerability to variations in interest rates and, depending on the extent of offshoring of critical industries, of exchange rates. Aviation oil is the main remaining fuel cost, and this is generally priced in international markets. Given applied treasury discount rate of 3.5 %/a and the gas and oil price assumptions, the annual cost of the net zero system is about the same as the current system cost.

Figure 36 : DH20 scenario annual and capital costs

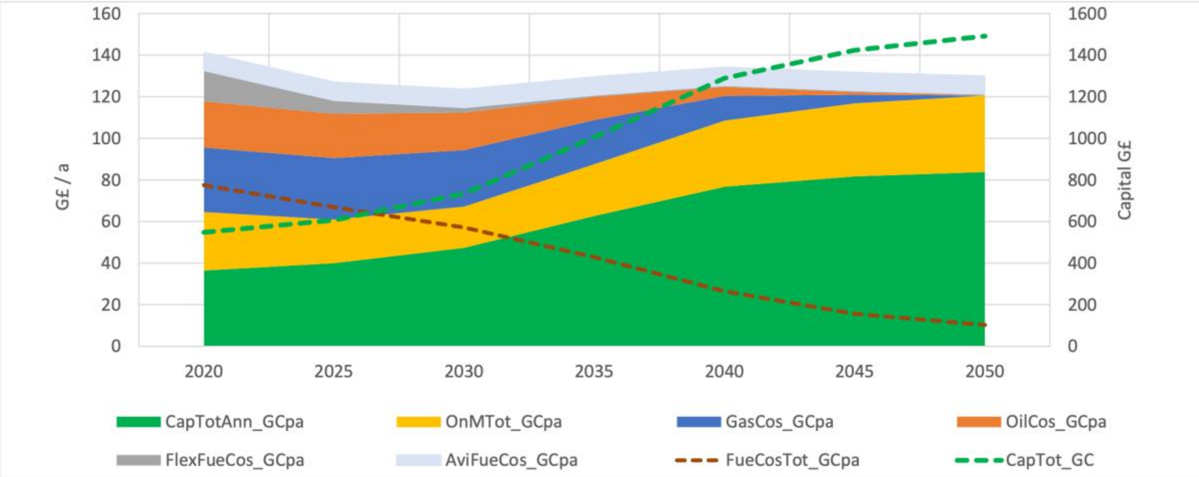
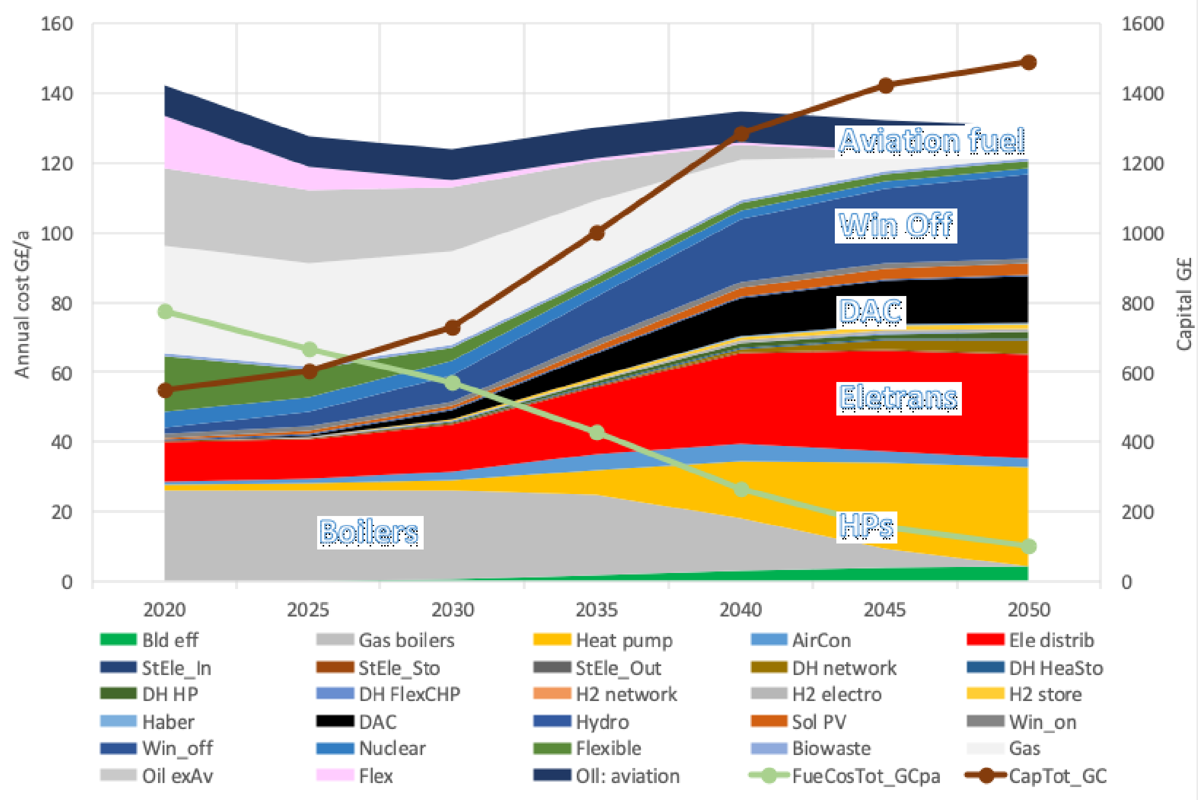


Figure 37 gives a detailed breakdown of annual costs across the scenario.

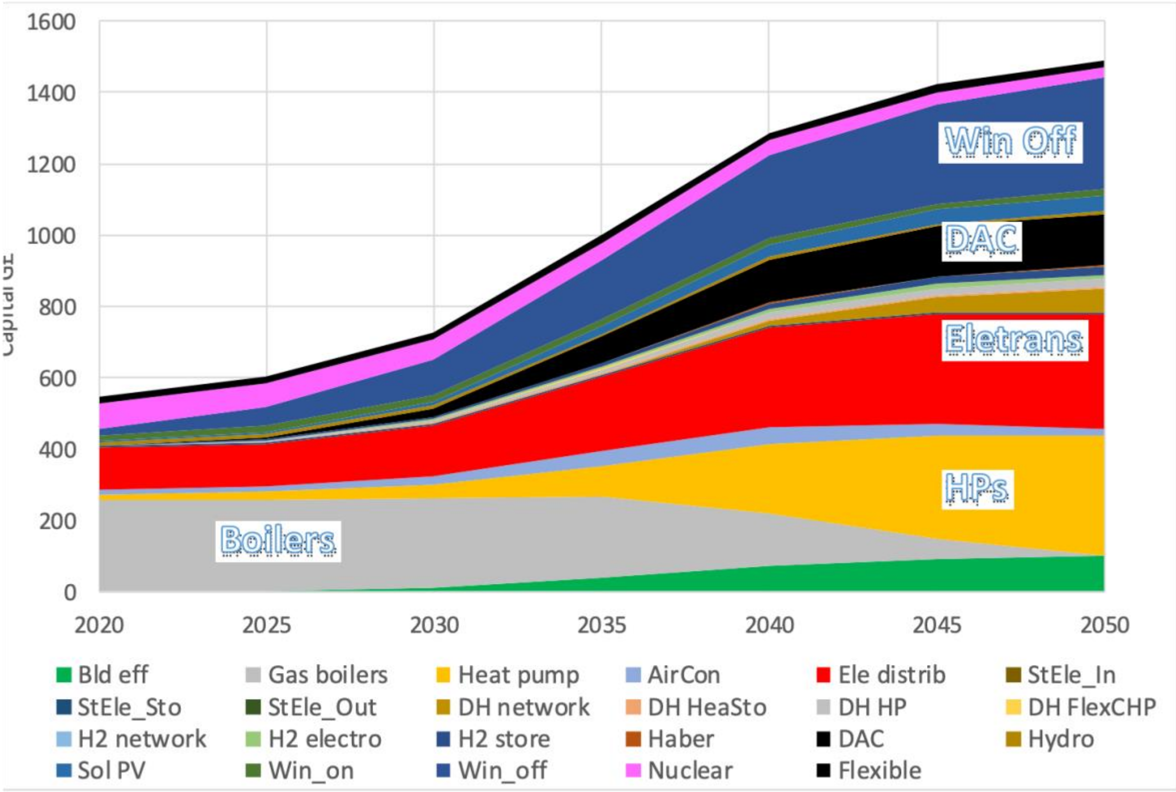
Figure 37 : DH20 scenario annual costs detailed



The capital value of the system, excluding the natural gas network, increases from about 550 G£ to 1500 G£ as shown in Figure 38. The capital value of the system is dominated by electricity transmission, offshore wind, heat pumps and DACCS which together comprise about 60% of total. The energy system capital of 1500 G£ in 2050 spread over 30 years is an average annual investment of 50 G£/a, though with much higher investment in the middle years 2030-2040 because of the implementation profile. This is a coarse estimate because as noted some technologies have lives less than 30 years, notably heat pumps, and some will be replaced before 2050. 50 G£/a capital investment is 2% of current annual UK GDP which in 2022 was 2490 G£/a[15]. Capital investment is required whichever energy system is built, so 50 G£/a is not the additional capital above some other scenario such as a continued fossil based system, but the net zero system will be more capital intensive.

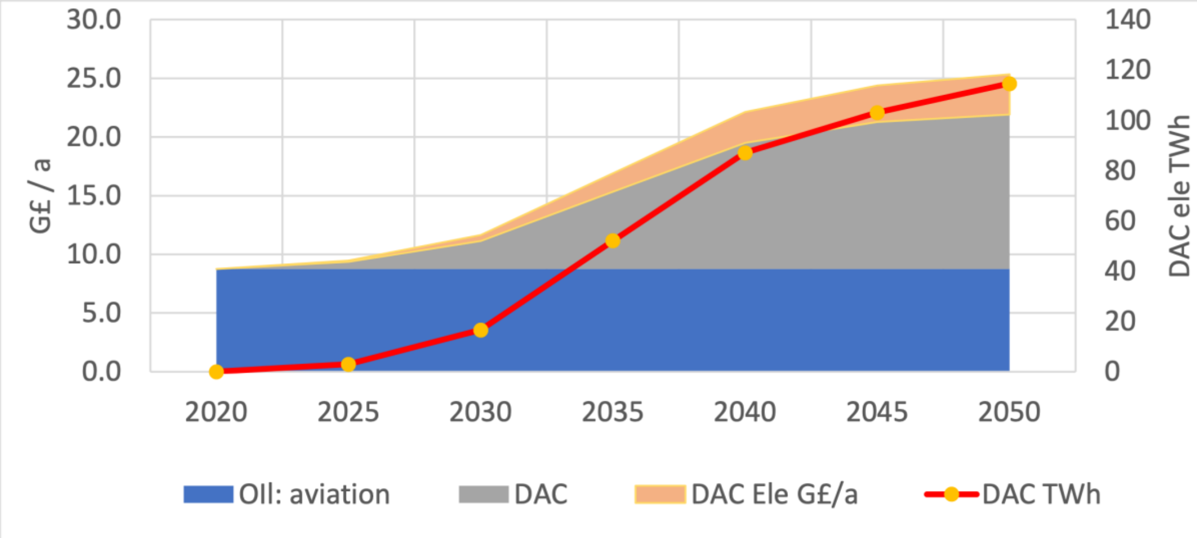
[15] https://researchbriefings.files.parliament.uk/documents/SN02783/SN02783.pdf

Figure 38 : DH20 scenario capital value evolution



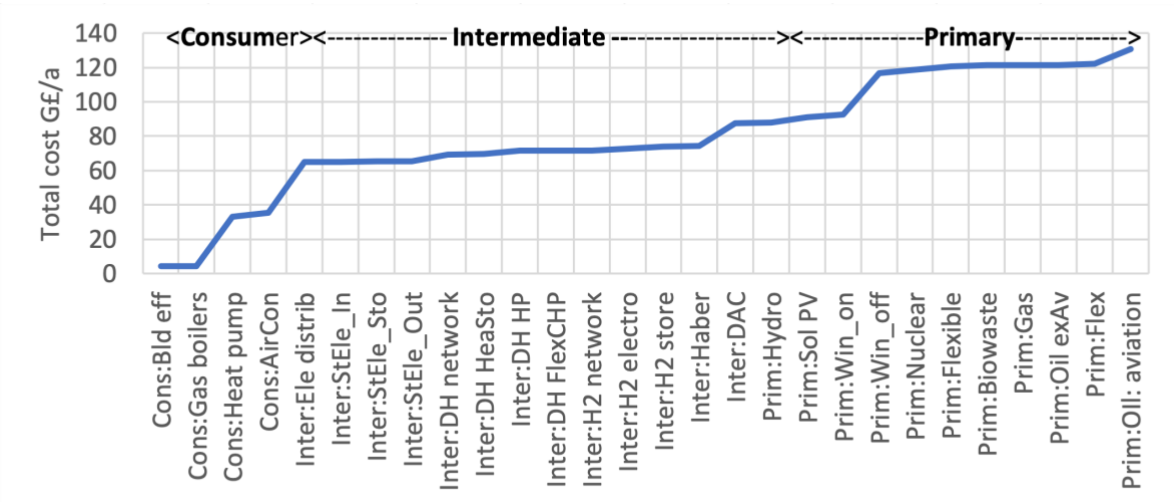
If all negative emission costs are allocated to aviation, then DACCS annuitised capital and O&M cost plus aviation fossil kerosene costs a total 21 G£/a. In 2050 the average electricity generation cost is about 4 p/kWh, and since DAC uses electricity surplus to all other demands and is connected at high voltage, a nominal electricity cost of 3 p/kWh is assumed and applied to the 115 TWh of electricity consumed by DACCS which then costs 3.5 G£/a. The total aviation cost is then about 25 G£/a, which is about 20% of the total net zero energy system cost. Figure 39 shows the evolution of aviation and related DACCS costs.

Figure 39 : DH20 aviation costs



The 2050 cost may be accumulated from consumer costs, across the intermediate system and then to primary energy as in Figure 40. About 25% of the total annual cost is incurred at consumers 'premises for building and heating and cooling systems. This highlights a major problem of net zero implementation – financing consumer systems.

Figure 40 : DH20 2050 annual costs accumulated across the system



6.4. All scenarios

The preceding DH20 scenario is with a 20% DH share. This section summarises the 2050 results for all the scenarios set out in Table 11 on page 38. The trends in some design variables are not smooth because the optimisation is not perfect as discussed in 5.2.

6.4.1. Demands

Demands, depicted in Figure 41, are constant across all HP:DH: H_2 heat shares. Demands are lower in the low demand scenario. Heat demand is lower and cool demand higher in the Hot +5 °C scenario. Hydrogen demand is higher in the hydrogen heating scenarios.

Figure 41 : Scenarios – demands.

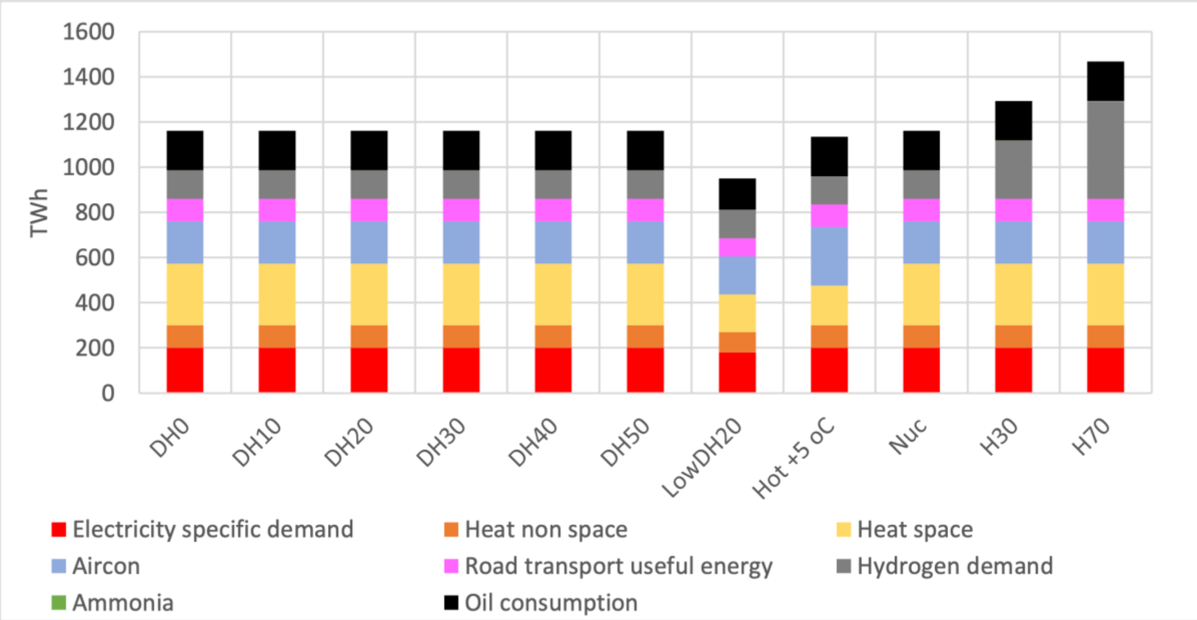


Figure 42 shows the heat supply mix and cooling demand across the scenarios. Of note is that in the Hot +5°C scenario cooling demand is about the same as heating.

Figure 42 : Scenarios heat and cool demand and supply

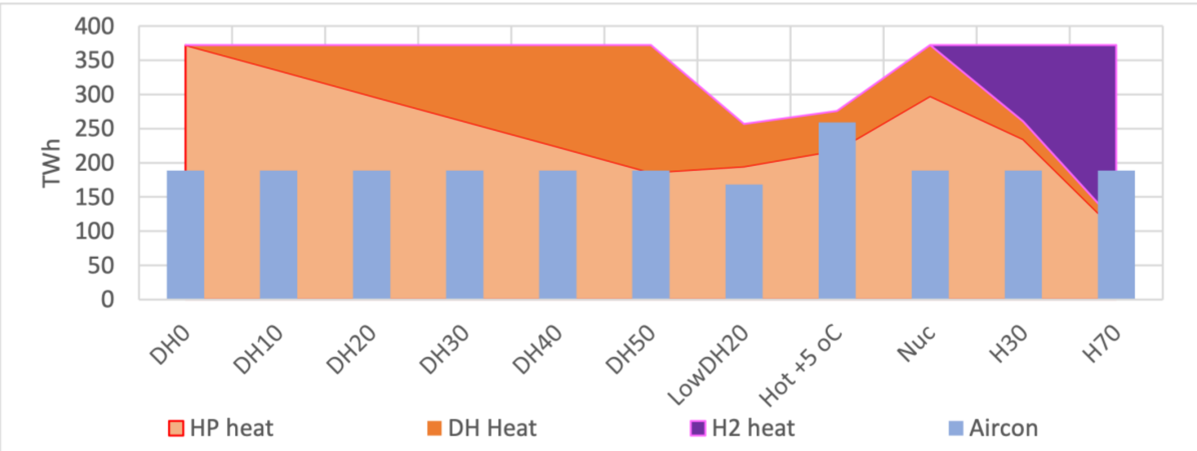
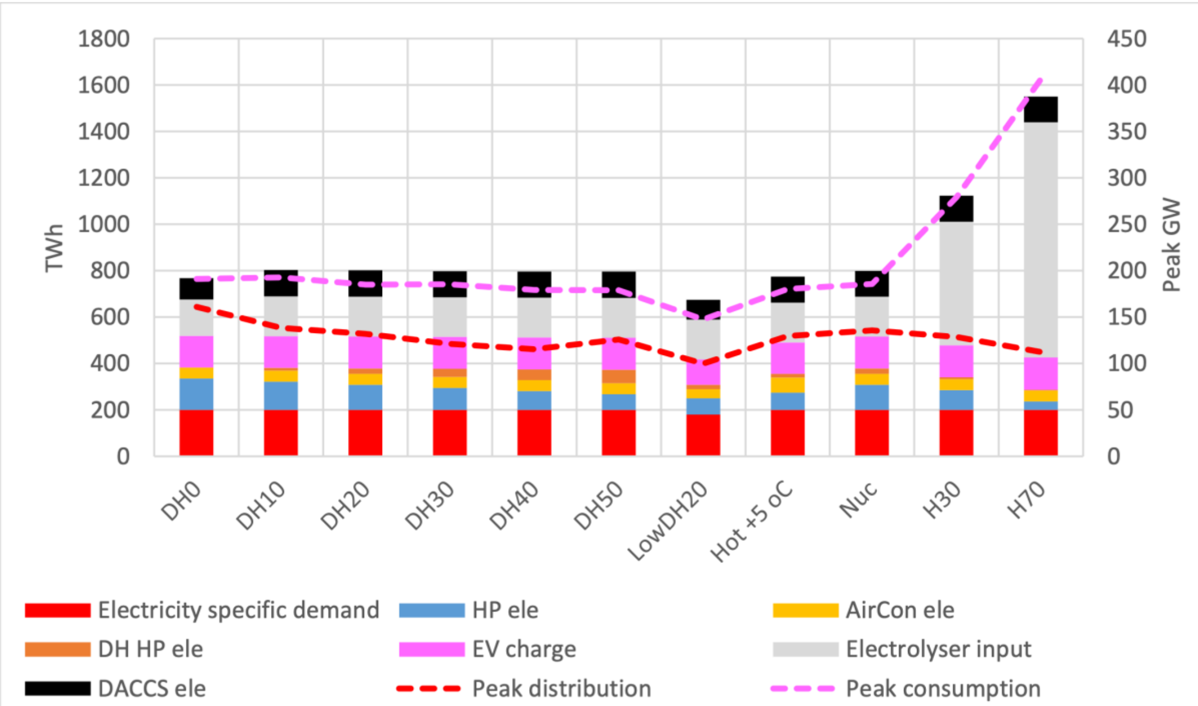


Figure 43 shows the annual electricity demands in the scenarios. The consumption generally is about 800 TWh in scenarios without hydrogen heating but reduces to 700 TWh in the low demand scenario.

Hydrogen consumes about four times as much electricity per unit of heat because the combined efficiency of electrolysis and boiler is about 65% as compared to HP's 300%, so total electricity demand increases to 1100 TWh with 30% hydrogen heating and to 1500 TWh with 70%. DH uses less electricity than consumer HPs per unit of heat delivered because DH's higher COP and lower electricity transmission losses are only partly balanced by DH network losses.

District heating reduces the peak flow on electricity networks as its storage allows reduced heat pump demands at peak times. The peak consumption greatly increases in the hydrogen heating scenarios as the electrolyser capacity is increased from around 30 GWe with no hydrogen heating to 130 GWe with 30% hydrogen heating and 290 GWe with 70%.

Figure 43 : Scenarios – electricity demands



6.4.2. Electricity

A large fraction of system costs is for technologies that use electricity. The smaller devices such as computers, refrigerators, lights, televisions, industrial equipment and so on that consume about 200 TWh of electricity are not modelled separately and costed; nor are EVs which consume 115 TWh. The consuming devices costed explicitly in ETSImpleMo and optimised are consumer and DH heat pumps, electrolysers and DACCS. The capacity of these along with maximum flows on the distribution system and consumption are shown in Figure 44. There is about 150 GW of these devices in most scenarios, but a much greater capacity of 100 and 260 GW of electrolysers in the 30% and 70% hydrogen heating share scenarios.

Figure 44 : Scenarios – electricity consuming capacities

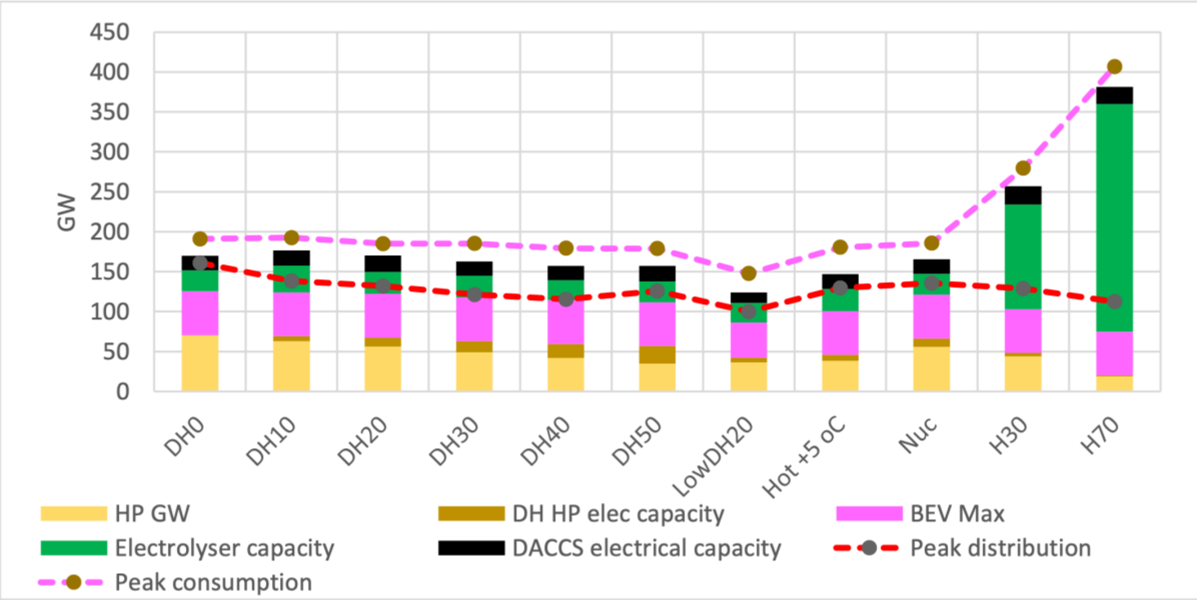


Figure 45 shows generating capacities (GW). The high nuclear scenario (Nuc) requires less total generation capacity because nuclear stations have, on average, a higher capacity factor than renewables, but note that nuclear is assumed to be baseload whereas it is shown in 4.3.2 that it can suffer large reductions, so back-up capacity is underestimated for nuclear, particularly in the 24 GW scenario. The H2 scenarios require greater capacity because of the higher electricity consumption. The higher the DH fraction and storage up to about 20% DH share, the lower the grid storage and flexible capacity needed as DH thermal storage helps manage the system.

Of note is that in the Hot+50C scenario, PV capacity is about 200 GW, double the capacity in the +2 °C scenarios, because there is much greater demand in the summer when PV peaks, and lower in the winter when heating peaks and so less wind generation capacity is optimal.

Figure 45 : Scenarios – electricity capacities

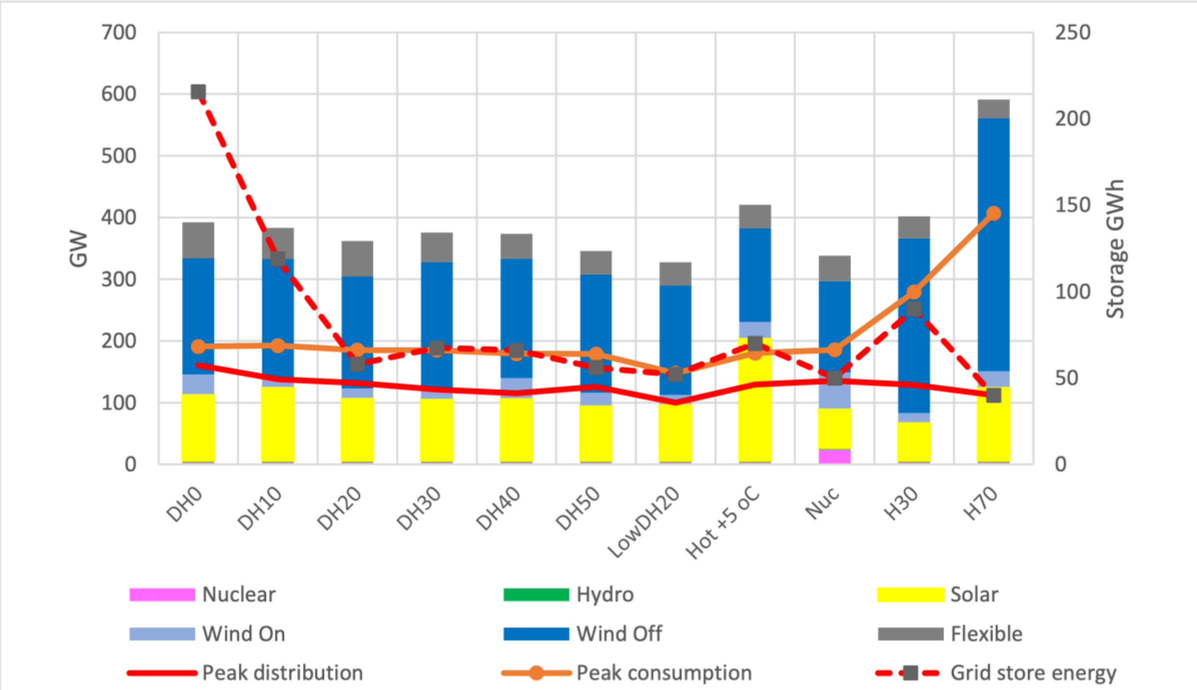
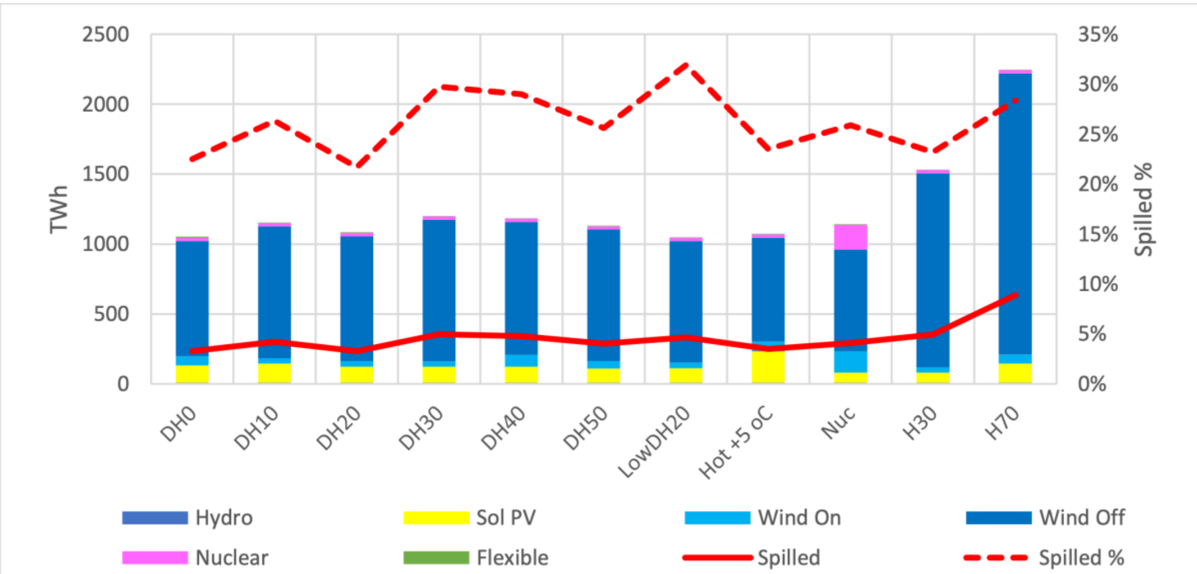


Figure 46 shows the potential generation by source and spilled energy. Generation is broadly similar across scenarios except for H30 and H70. For the hydrogen heating scenarios, electricity demand and generation are much higher.

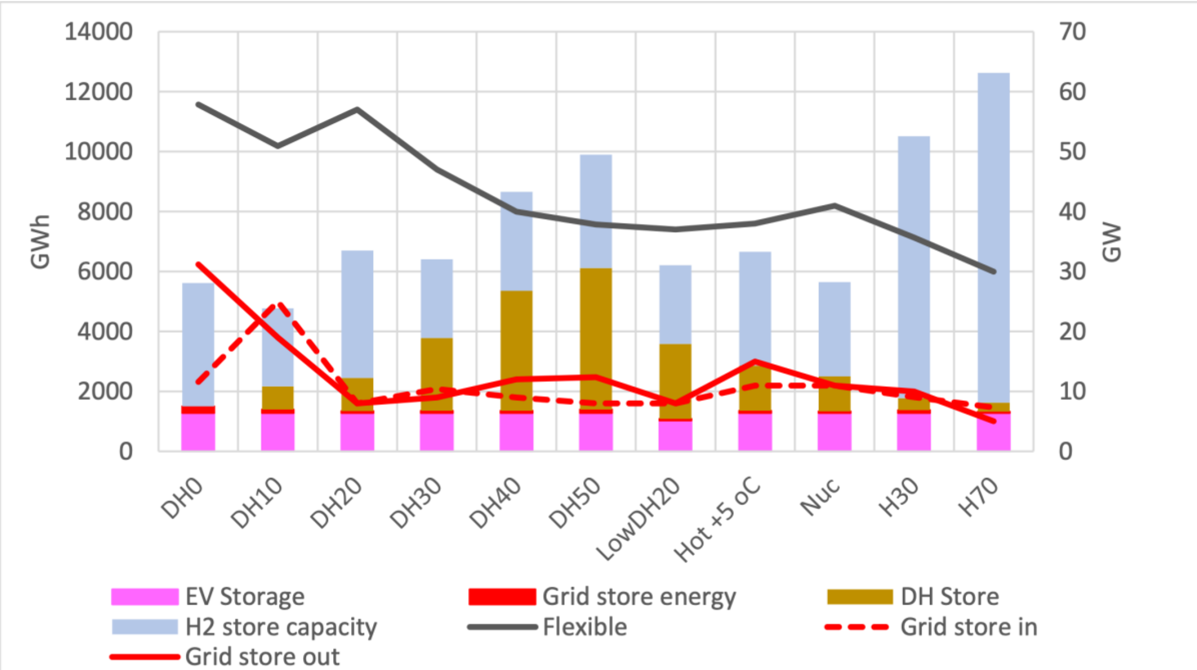
Figure 46 : Scenarios – potential generation



6.4.3. Storage

Figure 47 shows storage capacities. The trends are not very smooth because the optimisation is imperfect, but district heat storage increases with DH share and hydrogen storage increases with hydrogen heating share.

Figure 47 : Scenarios – storage



6.4.4. Costs

Figure 48 shows the trends in costs across the scenario. The low demand scenario is the least cost but note that efficiency costs apart from buildings are not included in the costing. The high climate change scenario is also lower cost.

Apart from these, the least cost systems are those without hydrogen heating and higher nuclear, with different HP and DH fractions. The total system cost is lowest for the DH20 scenario, but DH shares across the range 10-40% show small cost differences. The costs with different shares will be very dependent on the details of applying heating and cooling options to different building and consumer types, and the network costs at different load densities; such detail is beyond scope here.

The 24 GW nuclear (Nuc) scenario costs than DH0-DH40 even though nuclear is only providing 15% of electricity. The H30 and H70 scenarios cost most because of the greater electricity consumption, and the capacities of generators, electrolysers and storage needed.

Figure 48 : Scenarios – capital, O&M and fuel costs

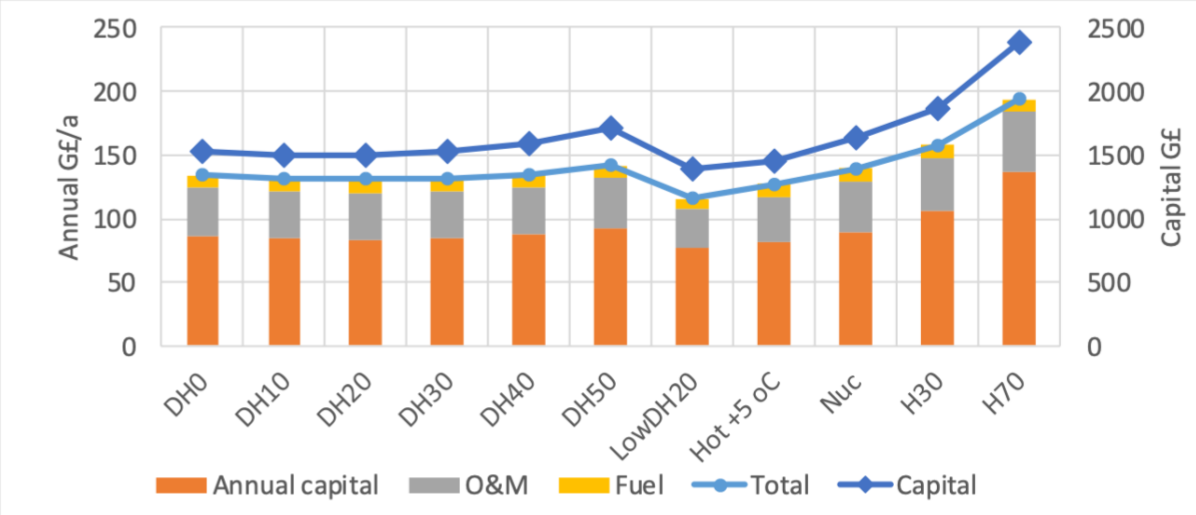
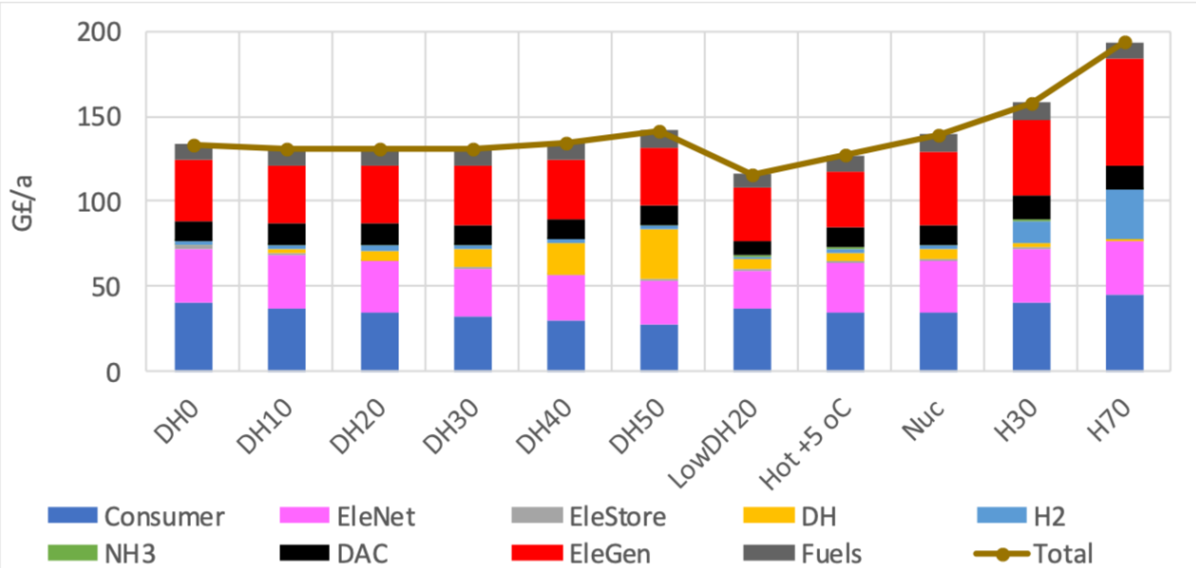


Figure 49 shows the costs for aggregated components. The large costs for consumers, the electricity network and generation are of note.

Figure 49 : Scenarios – costs for aggregate components



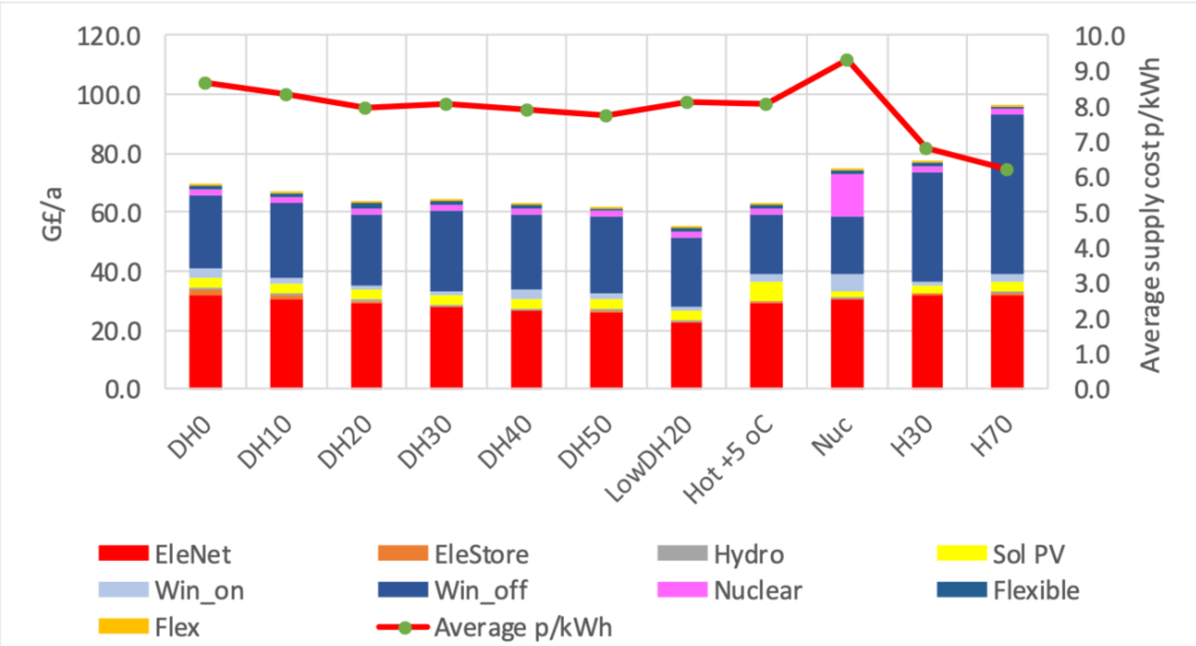
6.4.4.1. Electricity costs

The energy system integrates many devices that consume, transmit, store and generate electricity. In general, changing one device will alter the optimum configuration of other devices. For example, increasing the DH heat share, storage and heat pump capacities can reduce total and peak electricity consumption and the consequent capacities and costs of networks and generation. It is therefore not possible to easily allocate the cost of 'back-up ' or 'balancing 'for renewable or nuclear generation, or to generally isolate the 'electricity cost'. Figure 50 shows the annual costs of the principal components of devices solely concerned with electricity supply. About half the cost is network and half generation.

About 60% of the total cost is annuitised capital at 3.5%/a discount rate, with a more commercial rate of 7%/a the annuitised capital costs would increase by about 30%. The total cost may be divided by the total electricity consumption, including losses, to give an average unit cost p/kWh of consumption.

Electricity network costs reduce with DH share and unit costs are consequently lower. Unit costs increase in the high nuclear scenario because of nuclear's high cost. Total costs increase in the hydrogen scenarios, but unit costs reduce because the network costs per consumed kWh are much lower as it is assumed that electrolysers, consuming 300-700 TWh to produce hydrogen for heating, are connected at high voltage with lower costs as compared to distribution, and hydrogen heating reduces the electricity distribution costs as the distribution peak is lower than with heat pumps.

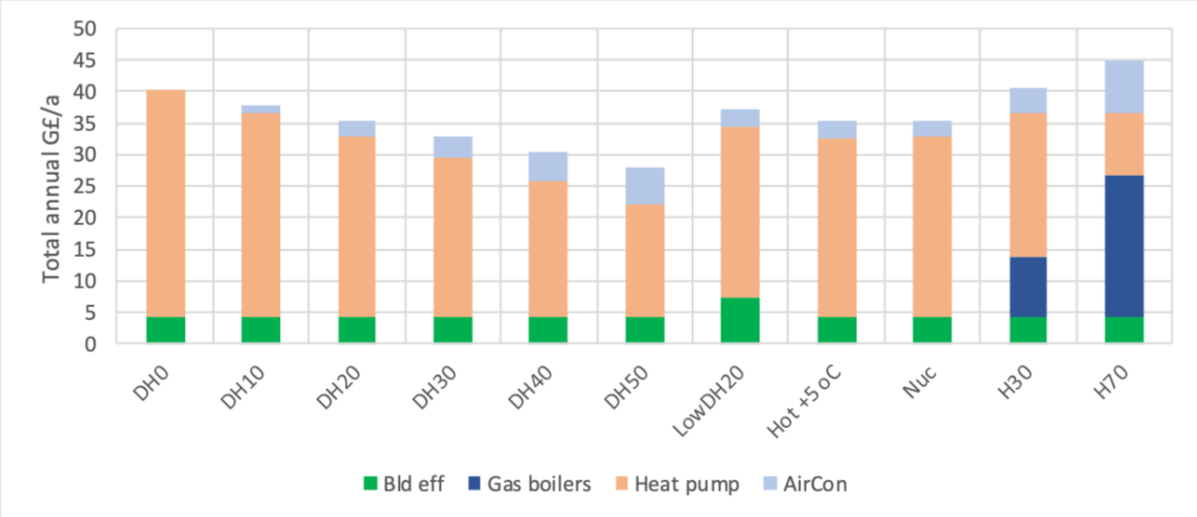
Figure 50 : Scenarios – electricity supply costs



6.4.4.2. Consumer costs incurred at premises

Costs incurred at consumers 'premises for building efficiency, boilers, heat pumps and air conditioning, shown in Figure 51, comprise 20-30% of the total annual system cost. These costs are important because of the problem of consumers affording the capital costs of measures in their buildings. It is assumed that heat pumps are reversible so as to provide cooling, whereas DH and H_2 boilers require additional heat pumps for cooling. The capital costs of DH incurred by consumers may be zero (apart from radiators), if the heat interface unit is owned by the DH company such that all DH costs including the interface are met through heat bills.

Figure 51 : Scenarios – consumer costs



6.4.5. Scenario heating share comparisons

The heating and cooling options adopted are described in 4.1. Detailed costing of DH, HP and cooling installations in different buildings and the requisite networks in different geographical areas is beyond the scope of this work so there is much uncertainty here.

The higher efficiency of DH heat pumps and the load shifting with DH heat storage leads to a small reduction in annual demand (TWh) but a significant reduction in peak electricity consumption, particularly on the distribution network, and thence network and electricity generation capacity requirements.

As laid out in 4.1, RAAHP cost less than ASHP and provide air conditioning at no extra cost. The extra costs of ASHP+AC compared to RAAHP may then be estimated, assuming no extra O&M costs for the double system of ASHP+AC as compared to RAAHP, which may be optimistic for ASHP. These costs are set out in Table 15.

Table 15 : Extra costs of ASHP+AC compared to RAAHP

ASHP	Extra capital k£	5.0
	Annuitised capital k£/a	0.4
Aircon	Extra capital k£	4.0
	Annuitised capital k£/a	0.3
Total	Extra capital k£	9.0
	Annuitised capital k£/a	0.6

Table 16 gives a summary of some scenario data relating to heat share. The change in total system cost with different HP and DH heat shares may be divided by the number of consumers changing heating mode to estimate cost differences of heating mode.

The central case is reversible air-to-air heat pumps (RAAHP), but the costs of ASHP are also explored. For example, compared to RAAHP, increasing the DH share from 0% to 10% reduces the system cost from 133.7 to 131.2 G£/a, meaning by shifting from 0 M to 3.5 M DH consumers, the cost to each of these 3.5 M consumers is reduced by 0.71 k£/a. Moving from 10% to 20% DH, incrementally saves each consumer shifting 0.06 k£/a. The difference may also be calculated as an average from the base DH 0% to higher shares: for example, changing from the base to 20% DH saves 0.42 k£/a/consumer and to 30%, 0.24 k£/a/consumer.

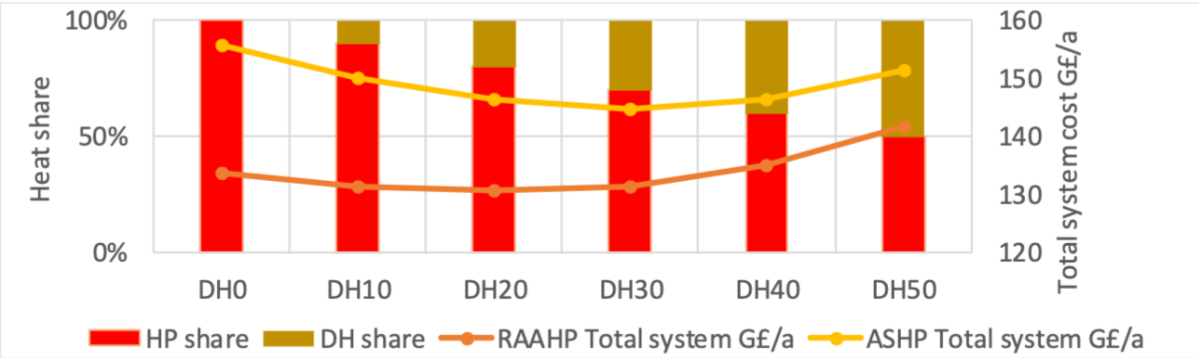
Table 16 : Scenario heating share and heat pump comparisons

	DH0	DH10	DH20	DH30	DH40	DH50	LowDH20	Hot +5 oC	Nuc	H30	H70
HP share	100%	90%	**80%**	70%	60%	50%	76%	79%	80%	63%	27%
DH share	0%	10%	**20%**	30%	40%	50%	24%	21%	20%	7%	3%
H2 share										30%	70%
HP consumers M	35.0	31.5	**28.0**	24.5	21.0	17.5	26.5	27.7	28.0	22.1	9.5
DH consumers M	0.0	3.5	**7.0**	10.5	14.0	17.5	8.5	7.3	7.0	2.5	1.1
H2 consumers M										10.5	24.5
Consumption TWh	802	802	**802**	798	796	793	675	774	799	1123	1550
Peak distribution GW	144	138	132	121	115	113	100	130	135	129	112
Peak consumption GW	192	192	**185**	185	179	176	148	180	186	279	407
Generation capacity GW	584	574	**547**	561	553	545	475	601	524	681	998
Flexible GW	58	51	**57**	47	40	38	37	38	41	36	30
Average ele cost p/kWh	8.7	8.3	**8.0**	8.1	7.9	7.8	8.1	8.1	9.3	6.8	6.2
RAAHP Total system G£/a	133.7	131.2	**130.8**	131.2	134.8	141.5	115.7	127.2	139.3	157.7	193.7
Average cost per consumer k£/a	3.8	3.7	**3.7**	3.7	3.9	4.0	3.3	3.6	4.0	4.5	5.5
Incremental change G£/a		-2.50	**-0.42**	0.43	3.63	6.70					
Incremental saving k£/a/consumer		-0.71	**-0.06**	0.04	0.26	0.38					
Change from base G£/a		-2.50	**-2.92**	-2.49	1.13	7.84					
Saving from base k£/a/consumer		-0.71	**-0.42**	-0.24	0.08	0.45					
ASHP Total system G£/a	155.9	150.0	146.2	**144.7**	146.4	151.2	130.4	143.6	154.7	169.9	198.9
Average cost per consumer k£/a	4.5	4.3	**4.2**	**4.1**	4.2	4.3	3.7	4.1	4.4	4.9	5.7
Incremental change G£/a		-5.86	**-3.77**	-1.51	1.70	4.77					
Incremental saving k£/consumer		-1.67	**-0.54**	-0.14	0.12	0.27					
Change from base G£/a		-5.86	**-9.63**	-11.14	-9.44	-4.67					
Saving from base k£/a/consumer		-1.67	**-1.38**	-1.06	-0.67	-0.27					

The trends of these costs are shown in Figure 52. It may be seen that the higher costs of ASHP+AC compared to RAAHP increase total system costs and move the minimum cost towards a higher share of DH.

These cost comparisons rest on simple analysis without details of building types or of network costs, or of installation practicalities. Particularly important is the assumed change in DH and electricity network cost per consumer with heat share as explored in 4.2.

Figure 52 : Heat shares, heat pump types, system costs



7. Aviation

This section discusses options for controlling global warming caused by aviation. Aviation poses two hard problems: first, it requires a high gravimetric (kWh/kg) and volumetric density (kWh/m^3) fuel, currently fossil kerosene; and second, high altitude emissions from any fuel cause global warming which requires balancing with negative emission. Aviation fuel use can be controlled to a degree with demand management, seat spacing and load factor, technology and logistics. However, demand growth has historically been strong because of reducing flight costs and increasing wealth across much of the world, with UK aviation growing at about 4%/a since 1990 excluding covid years[16]. 4%/a growth compounded over 30 years would increase aviation demand to 3.2 times the current level.

Some aviation demand might be switched to electric rail but this is limited to shorter overland routes with high speed rail links, and extensive modal change would require substantial rail development. A report to Transport and Environment (Transport & Environment, 2020) estimated that rail might reduce aviation emissions by 2-4% in Europe.

The potential of efficiency gains through technology and logistics is already widely exploited to reduce aviation costs and increase aircraft range. Technology change is slow because of safety standards and because aircraft have operational lives of 20-30 years. A number of small technological changes such as winglets and weight reduction are reviewed by Schäfer et al (Schäfer, Evans *et al.*, 2016) and might together reduce aviation fuel consumption by perhaps 15%.

[16] https://www.gov.uk/government/statistical-data-sets/aviation-statistics-data-tables-avi

Passengers constitute about 10% of the weight of a fully laden Boeing 747 and therefore the energy consumption of an aircraft changes little if 90% of seats are occupied rather the current 80%[17], so if occupancy could be increased to 90% without other countervailing effects, an energy reduction of about 10% would be made. The '*Boeing 747-400 can accommodate up to 524 passengers in a two-class configuration. For a three-class configuration, the capacity is around 416 passengers.*'[18] . The passengers carried by an aircraft can be increased by reducing business and first class seat spacing[19] areas to that of economy thereby increasing number of seats by perhaps 20%, depending on aircraft type and route. Increasing occupancy and seat spacing together might save 25%. For the same mix of aircraft sizes, these measures would reduce aircraft needed and movements by about 25% with further emission reductions because fewer of the least efficient aircraft would be needed and there would be less congestion on the ground and in the air. An advantage of these measures is that they are low cost, require no technology change and could be implemented much faster than new technologies and fuels. However, these measures would impact on the flight availability in terms of frequency and routeing.

To reduce aviation fuel consumption and high altitude global warming further requires more radical technological and operational changes.

Most jet planes have turbofan engines where the jet engine and a fan are enclosed in a cowl. A proven technology is turboprops with open propellers which are 20-30% more efficient than turbofan jet, e.g. see Buchholz *et a*l (Buchholz, Fehrm *et al.*, 2023). A type of modern turboprop called a propfan is also more efficient than a turbofan and can fly at similar speeds but is as yet under development. Turboprops can have similar ranges as jets. Turboprops cruise at around 8 km altitude, compared to jets at about 10 km, so the high altitude radiative forcing of turboprop engine emissions will generally be less than jets. Turboprops are slower than jets for longer flights thereby increasing flight time but they can be faster for shorter flights as they reach cruise altitude faster. Also note that the time taken to travel to and from airports and at airports is a large fraction of total travel time – perhaps 50% of an 8 hour UK-USA flight. Noise and turbulence may be greater in turboprops than jets. Switching to turboprops might reduce fuel consumption by about 25% and high altitude warming by a greater fraction because of less fuel use and emission, and lower altitude flying. Schäfer *et al* (Schäfer, Barrett *et al.*, 2019) use their Aviation

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[17] https://www.iata.org/en/iata-repository/publications/economic-reports/air-passenger-market-analysis---december-2022/

[18] https://measuringly.com/how-much-does-boeing-747-weigh/

[19] https://theluxurytravelexpert.com/2022/01/19/review-british-airways-777-first-class/

Integrated Model AIM2015 to estimate that about 60% of global aviation fuel use is for flight distances of 3000 nautical miles and less, and 80% for 4000 nautical miles or less.

If turboprops served these fractions with 25% less fuel, then the overall fuel use would be reduced by around 15-20%, though turboprops can have ranges similar to jets so the fraction could be higher.

Electric aircraft with batteries driving propellers, reviewed by Gyamfi *et al* (Adu-Gyamfi and Good, 2022), have some potential to replace kerosene fuelled aircraft, but the low gravimetric energy density (kWh/kg) of batteries and other factors means their range is currently very limited. Like turboprops, electric aircraft have propellers and will fly slower and lower than jets. Hydrogen has a high gravimetric energy density (kWh/kg) but a low volumetric density (kWh/m^3) which means radical aircraft redesign is needed for long range. Jayant and Rutherford (Jayant Mukhopadhaya and Rutherford, 2022) reckon hydrogen aircraft entering service in 2035 might service 31-38% of passenger traffic. Clean Sky 2 and FCH (CleanSky2 and FCH, 2020) estimate that hydrogen aircraft could constitute 40% of all aircraft by 2050. These new technologies are at an early stage of development and cannot be expected to contribute much by 2050.

Combining the reductions through seating, small technical improvements and turboprops, emissions per passenger kilometre might be reduced by around 50%. UK aviation demand has grown at 3-4% since 1990. A much lower future 2%/a growth rate is assumed, as this compounded over 30 years leads to a 50% increase in demand, which just balances the emission reduction measures and results in constant fuel use. **A** 2%/a growth rate implies major lifestyle change.

The assumption is made that kerosene is the only fuel, and that efficiency improvements would balance demand growth so aviation energy demand is constant to 2050; this approximates to the Department for Transport Jet Zero scenario 1 (UK Department for Transport, 2021). It is further assumed that most kerosene is made from fossil oil because it is probably lower cost, though obviously this is politically problematic when other sectors are radically decarbonising; this assumption is explored further below.

It is beyond the scope of this work to properly assess these options with sensitivities, so it was assumed that no significant switch to electricity, hydrogen or other fuel such as ammonia is made, though these fuels are already included in ETSimpleMo so it would be relatively easy to do. Kerosene synthesis is complex to model as shown in 7.2.3.

7.1. High altitude global warming.

Aircraft cause global warming through radiative forcing (RF) because of CO_2 emissions (RF_{CO_2}), and also the high altitude emissions of water, NO_x and other wastes from engines cause forcing (RF_{alt}) through cloud formation and other processes. In contrast to RF_{CO_2}, the magnitude and persistence of RF_{alt} depends on many complex factors so it is not possible to provide a single value for RF_{alt} for all time horizons and routes. In particular, the atmospheric residence time of high altitude water and NO_x is much shorter than CO_2. However, RF_{alt} should be included in climate mitigation policy development. Lee *et al* (Lee, Fahey *et al.*, 2021) estimate these major RF components *'contrail cirrus (57.4 mW m−2), CO2 (34.3 mW m−2), and NOx (17.5 mW m−2)'*, or in other words that the RF due to contrail plus NO_x is about twice the RF_{CO_2} for aircraft; thus the total forcing RF_{tot} is three times RF_{CO_2}. Teoj *et al* (Teoh, Schumann *et al.*, 2020) explore how the high altitude RF_{alt} can be lowered by reducing contrail formation through altering flight altitude and path, and fuel characteristics, whilst not incurring a significant fuel consumption (and therefore CO_2) penalty. Hydrogen fuelled aircraft would also cause high altitude warming, see Svensson *et al* (Svensson, Hasselrot *et al.*, 2004), but hydrogen fuelling is not modelled here.

The simple approach taken here is to assume RF_{alt} equals RF_{CO_2} in the base year, and that RF_{alt} falls by 50% due to lower flying turboprops and flight planning and fuel measures by 2050; therefore RF_{alt} equals 50% of RF_{CO_2} in 2050; or the total RF in CO_2e in the base year is 2 times the CO_2 emission currently, falling to 1.5 times the CO_2 emission in 2050. This may be optimistic. It may also be inadequate to account for the longer residence time of CO_2 than high altitude effects.

For aviation, negative emissions are needed to balance high altitude global warming emission from kerosene, whatever the source of kerosene.

7.2. Kerosene

Liquid hydrocarbon (HC) fuels have high volumetric and gravimetric energy densities and are readily used in engines, which makes them suitable for transport generally and for aviation in particular. Liquid hydrocarbon fuels are mostly composed of carbon chains with hydrogen attached, with about 85% of the mass being carbon. Alkanes comprise the major component and have the formula C_nH_{2n+2}. In general, the longer the carbon chain, the higher the temperature at which the HC melts and boils. HC fuels must remain liquid in their safe operating temperature ranges which are approximately -47 °C and above for aviation kerosene, and -15 °C and above for gasoline and diesel. HC for transport are generally in the chain length range C7-C16, often called middle distillates, which provide this performance. Aircraft engines and associated fuel storage and supply systems are designed to use tightly specified kerosene.

Kerosene can be produced variously:

i. from refined fossil oil
ii. synthesised from biomass possibly supplemented with hydrogen using Fischer Tropsch and other processes
iii. synthesised from atmospheric carbon captured with DAC and renewable electrolytic hydrogen using the Fischer Tropsch process

Options ii and iii are renewable. These processes produce by-products to kerosene such as naptha and diesel fuel and these may be used for other purposes such as fuelling ships or standby generators. Some analysis of these processes is given in the next sections, but there are many uncertainties about the resources, efficiencies, environmental impacts and costs of these production pathways.

Kerosene from any source produces high altitude warming which has to be balanced by atmospheric carbon capture and storage.

7.2.1. Fossil kerosene

Crude oil is refined and processed. Fractional distillation first separates crude oil into different hydrocarbon (HC) chain lengths according to their boiling points, and kerosene is collected at 150 °C to 250 °C and then further refined. Higher boiling point fractions with longer chain lengths can be processed to produce shorter chain kerosene with a process called hydrocracking. Currently around 8% of global refinery output is kerosene[20]. The cost of refining with a new refinery may be around 10 $/barrel which is about 0.5 p/kWh averaged across all products[21], but some products will cost more than others to produce. In a net zero system there will be low demands for petroleum products other than kerosene as sectors such as road transport are electrified directly or switched to non-carbon electrofuels such as ships using ammonia. This poses difficult questions: how much would fossil oil processing convert non-kerosene fractions to kerosene, what would be the energy overhead, what would be the associated emissions, what would be the cost of aviation kerosene production, and what would be done with the unwanted fractions of crude oil? These questions are not answered here.

7.2.2. Kerosene synthesis from waste biomass

Kerosene can be synthesised from biomass supplemented with renewable hydrogen and renewable electricity as necessary, using the Fischer-Tropsch and other processes. The general scenario assumption in this report is made that no biocrops or bioenergy imports are used.

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[20] https://www.iea.org/data-and-statistics/charts/world-refinery-output-by-product-1971-2019

[21] https://link.springer.com/chapter/10.1007/978-3-030-86884-0_3

As an indication of the impact of using biomass, The Royal Society (The Royal Society, 2023) estimated that 68% of the total agricultural land in the UK would be required to produce 12.3 Mt of aviation fuel, near the current kerosene demand, from biomass.

If all the UK biowaste carbon and energy (~260 PJ) were used for aviation, perhaps 20% of current aviation fuel could be produced, using the simple estimation shown in Table 17. Not all biowastes would be used for kerosene production because of biowaste's varied physical and chemical characteristics, and its diffuse geographical distribution, meaning its collection, transport and processing would be costly and inefficient. Biowastes not used for transport fuels could be used for heat or electricity production, perhaps with BECCS.

Table 17 : Simple estimation of kerosene production from biowastes

	Energy			Mass	Carbon		Max Ker	Suitable		Bio	Ker	
	PJ	TWh	GJ/t	Mt	%	MtC	Mt	%	MtC	PJ	FT prod	Mt
W:Animal biomass	10	3	13	0.8	30%	0.2	0.3	30%	0.1	3	50%	**0.0**
W:Sewage gas	16	4	50	0.3	75%	0.2	0.3	70%	0.2	11	50%	**0.1**
W:Landfill gas	34	9	50	0.7	75%	0.5	0.6	50%	0.3	17	50%	**0.1**
W:Renewable waste	74	21	10	7.4	50%	3.7	4.4	70%	2.6	52	50%	**1.5**
W:Anaerobic digestion	58	16	14	4.2	75%	3.1	3.7	50%	1.6	29	50%	**0.9**
W:Waste wood	10	3	13	0.8	50%	0.4	0.4	50%	0.2	5	50%	**0.1**
Wood	37	10	13	2.9	50%	1.4	1.7	50%	0.7	19	50%	**0.4**
Plant biomass	143	40	12	11.9	50%	6.0	7.0	50%	3.0	72	50%	**1.8**
Non-renewable waste	78	22	10	7.8	30%	2.3	2.7	30%	0.7	23	50%	**0.4**
UK Waste	**263**	**73**	**150**	**21**	**3**	**10**	**11**	**3**	**5**	**132**	**3**	**3**
					Mt CO2	**36**						
UK Total	**461**	**128**		**37**		**18**	**21.1**		**9.3**	**231**		**5.4**
					Mt CO2	**66**						
UK Waste: % UK aviation fuel							**76%**		**34%**			**20%**
UK Total: % UK aviation fuel							**141%**		**62%**			**36%**

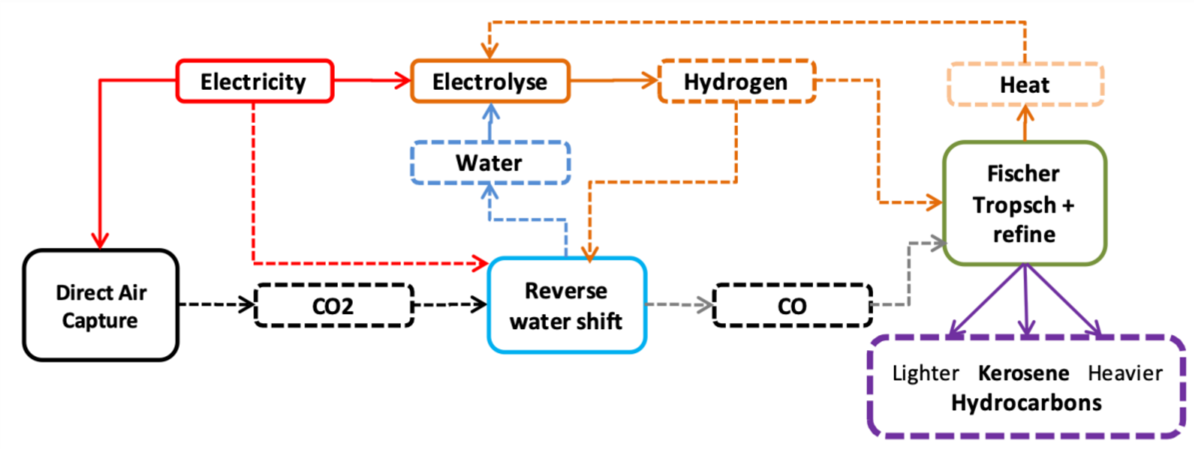
Source: Biomass resource DUKES Table 6.1, author's estimates

7.2.3. Kerosene synthesis from atmospheric carbon and hydrogen

As shown above, only a fraction of kerosene could be made from waste biomass, so if fossil kerosene use is to be minimised, an alternative renewable 'electrokerosene', a so-called 'power-to-liquid fuel', would be needed. One possibility is the synthesis of electrokerosene from renewable electrolytic hydrogen (H) and carbon (C) produced from renewable electricity powering Direct Air Capture (DAC) machines. The aim here is to explore some issues concerning this synthesis with some quantitative estimates, but there is great uncertainty throughout, as data on component costs and performance data are wide ranging. There are many possible variant designs and combinations of processes and complex chemical engineering is involved. A superficial summary can only be given here of a commonly proposed method in which syngas (H and carbon monoxide CO) are input to the Fischer Tropsch (FT) process.

Figure 53 outlines the main processes and chemical flows involved. Electricity and electrolytic hydrogen provide the energy to drive the synthesis processes. Useful overviews of electrokerosene are given by the Danish Energy Agency (Danish Energy Agency, 2017) and the German Environment Agency/Umwelt Bundesamt (Umwelt Bundesamt, 2016). Much of the process description and performance data here are from Meurer and Kern (Meurer and Kern, 2021) and Zang *et al* (Zang, Sun *et al.*, 2021).

Figure 53 : Electro hydrocarbon synthesis system



Enthalpy (H) is defined as the change in energy of a process for specified identical initial and final temperatures and pressures: H is defined as the internal energy (U) plus the product of pressure (p) and volume (V); $H = U + pV$. Enthalpy for chemical processes is expressed in kJ/mol of input or product where mol is the molecular weight of the chemical in grams. Enthalpy in kJ/mol can be converted into energy per kg of desired product by applying atomic weights. An exothermic reaction (such as burning oil) is one in which energy is released and the enthalpy is less than zero ($H < 0$), and an endothermic reaction (such as electrolysis) is one requiring energy input to drive it and the enthalpy is greater than zero ($H > 0$). The enthalpy is the minimum energy requirement for chemical reactions assuming initial and final temperatures and pressure change and does not account for energy requirements for ancillary processes such as separation and compression. For many of the reactions described here, only fractions of inputs react to form the desired products, so some of the reaction inputs will be recycled, and some by-products used or discarded as waste.

In this section, to clarify suffixes are sometimes used to denote the type of energy: electricity - TWhe and GWe; chemical TWhc and GWc.

Hydrogen. Hydrogen (H) production with electrolysis is an endothermic process with an enthalpy of 39.5 kWh/kgH, requiring 53 kWhe/kgH of electricity with an assumed electrolysis efficiency of 75%.

$2H_2O \Rightarrow 2H_2 + O_2$

Direct air capture (DAC). Carbon dioxide (CO_2) is captured from the atmosphere at about 400 ppm and output as a high purity CO_2 stream. DAC is an immature technology and a wide range of estimates of electricity consumption per kilogramme of CO_2 may be found: 2 kWh/kgCO_2 is assumed here. It is assumed that DAC with carbon sequestration (DACCS) uses the same amount of electricity per kgCO_2 as DAC, i.e. that the carbon sequestration phase uses negligible electricity compared to separation and compression.

Reverse water gas shift (RWGS) reaction. H_2 and CO_2 are input to the RWGS running at a temperature of 900 °C or more, and water (H_2O) and carbon monoxide (CO) are formed. The RWGS reaction is endothermic having an enthalpy of -41 kJ/mol.

$H_2 + CO_2 \Rightarrow H_2O + CO$

[An alternative integrated process for producing syngas inputs water (H_2O) and CO_2 to a high temperature *solid oxide electrolysis cell (SOEC) which, with co-electrolysis, produces H_2 + CO (syngas) and oxygen. This process is relatively undeveloped but offers potential efficiency and cost* advantages.

$H_2O + CO_2 \Rightarrow H_2 + CO + O_2$]

Fischer Tropsch (FT). CO mixed with H_2 is called syngas and is input to the FT process which assembles H and C into hydrocarbon (HC) chains of different lengths. For example, a $C_{12}H_{26}$ chain, which can be representative of the kerosene mixture, has this chemistry:

$12CO + 25H_2 \Rightarrow C_{12}H_{26} + 12H_2O$

The FT process is exothermic with a standard reaction enthalpy of −165 kJ/mol of CO combined. This heat must be removed and can be used for other purposes. FT produces a mixture of HC with different formulae that depend on FT inputs, operating conditions, catalysts and so on. The FT process operates at 150-300 °C, with lower temperatures being conducive for chains in the kerosene range. The FT output mass percentage of HC with chains suitable for kerosene typically ranges 30-60%.

Refining and hydrocracking. The FT output is refined into fractions with different chain lengths. To increase the fraction of HC suitable for kerosene, mostly HC with chain lengths 5 to 16, some of the longer chain HC can be split into shorter chains by hydrocracking; a process in which FT output and hydrogen are reacted in the presence of a catalyst at about 360 °C.

Zang *et al* (Zang, Sun *et al.*, 2021) give a final FT product mix of 47% kerosene (assumed here), 27% diesel, and 26% naptha which is a low boiling point liquid. The residual mixed HC (RMHC) other than kerosene can be used variously. The RMHC diesel can replace fossil oil, renewable hydrogen or ammonia in internal combustion engines. Other RMHC might be used for electricity or heat production, or industrial processes, or materials such as plastics. One possible use of RMHC is for stored energy for flexible back-up generation. Here it is simply assumed that the RMHC replace electrolytic hydrogen and its attendant electricity demand.

Several important simplifying assumptions and restrictions have been made in this analysis. Material inputs such as water and sundry chemicals are not accounted for. No mass loss occurs, assuming any unreacted chemicals are recycled. Apart from chemical process energy, energy is required to make up heat losses and for miscellaneous processes such as heating, cooling, purification, pumping, compression, separation, hydrocracking, refining and so forth. The endothermic RWGS process energy input and the exothermic FT heat output are not integrated in this analysis. Excluding these other energy flows results in an overall efficiency of electricity to HC of 59%, whereas figures around 50% are usually quoted; e.g. Zang *et al* (Zang, Sun *et al.*, 2021) estimate 53-57%. Therefore an arbitrary 4 kWhe/kgHC is added for these miscellaneous processes resulting in an overall process efficiency, defined as total HC energy out divided by electrical energy in of about 50%.

The Danish Energy Agency (Danish Energy Agency, 2017) make an energy balance of electrofuel production in which, excluding DAC, 25% of the electrical energy input for electrolysis and the FT plant results in about 155 TWh of low temperature heat. If this could be used to meet industrial or DH heat demands then it would reduce electricity demand in heat pumps by about 50 TWh assuming a COP of 3. In the case of process heat at significantly higher temperatures, COPs of heat pumps in counterfactual systems would be lower, and more electricity would be displaced.

Table 18 summarises the chemistry and the main mass and energy flows where electricity units are TWhe and GWe, and chemical energy units are TWhc and GWc.

Assuming kerosene is an average $C_{12}H_{26}$ and that the atomic weights are exactly C(12), H(1) and oxygen O(16), we can calculate the masses required of C, H, CO_2 and CO to synthesise a unit mass of kerosene. Kerosene is assumed to have a gross calorific value of 46 GJ/t or 13 kWh/kg.

i. The aviation kerosene demand is assumed to be 15 Mt. This contains 12.7 Mt of C and 2.3 Mt of H.
ii. Fischer Tropsch followed by hydrocracking is assumed to output 47% kerosene by mass, with the remaining output being residual mixed hydrocarbons (RMHC). Therefore a minimum 27.0 Mt of C and 4.9 Mt of H are needed as input to FT to produce 15.0 Mt of kerosene, and 16.9 Mt of RMHC which includes 8.7 Mt (112 TWh) of diesel. This diesel could replace all of UK marine fossil diesel oil consumption, which is about 4 Mt or 50 TWh, and which is assumed to be replaced with electro ammonia in the scenarios.
iii. 27.0 Mt of FT C input is contained in 99.1 Mt of CO_2. Supplying this CO_2 requires 198 TWhe of electricity assuming a DAC consumption of 2 kWh/kgCO_2.
iv. 4.9 Mt of H input to the FT requires 256 TWhe assuming 53 kWhe/kgH of electricity used in 75% efficient electrolysis.
v. To reduce 99.1 Mt of CO_2 to produce 63.1 Mt CO in the reverse water shift gas (RWGS) reaction requires 4.5 Mt H using 237 TWhe in electrolysis.
vi. A further 128 TWhe (assuming 4 kWhe/kgHC) is assumed for miscellaneous purposes such as pumping and compression.
vii. Then the total electricity required is 819 TWhe to produce 15 Mt of kerosene and 16.9 Mt of residual mixed hydrocarbons (RMHC).

For comparison, The Royal Society (The Royal Society, 2023) estimate 468 – 660 TWh of electricity is required to make 12 Mt of ‘power-to-liquid e-jet fuel’. The estimates made here are of similar magnitude.

Table 18 : Hydrocarbon synthesis mass and energy flows

	Formula	Wt	%Ker Wt	Kerosene Mt	HC Total Mt	Elec TWhe	Source	Energy per mass
Kerosene	**C12H26**	**170**		**15.0**	**31.9**			13 kWhc/kgKer
	C	144	85%	12.7	27.0			
FT input	H	26	15%	2.3	4.9	256	Electrolysis	53 kWhe/kgH
RWSG input	CO2	528	311%	46.6	99.1	198	DAC	2 kWhe/kgCO2
RWSG input	H	24	14%	2.1	4.5	237	Electrolysis	53 kWhe/kgH
FT input	CO	336	198%	29.6	63.1			
Miscell: heat, compress, crack…					**31.9**	128	Refine	4 kWhe/kgHC
						819	**Total**	
				Total HC out	**31.9**	**410**	TWhc	13 kWhc/kgHC
				Kerosene out	15.0	193	TWhc	13 kWhc/kgKer
DAC not required for fossil kerosene emission						-93	TWhe	
Residual mixed HC RMHC					16.9	-217	TWhc	(Diesel:112 TWh)
H2 electrolysis displaced by RMHC						-289	TWhe	
Aviation fuel net additional electricity						**436**	**TWhe**	
Waste heat for district heating etc?						*155*	*TWhth*	
						kWhe/kWhcHC		**Efficiency**
					Total HC	26		50%
					Kerosene	29		44%

Source: assumptions in text and author's calculations

The zero emission HC production calculated here can be used to offset DACCS negative emissions and other fuels, and the energy they require:

i. No negative emissions are needed to balance 15 Mt of aviation fossil kerosene producing 46.6 Mt of CO2, a saving of 93 TWhe of DACCS input. But negative emission is still required to balance high altitude warming of 23.3 MtCO2e in 2050, as supplied by 47 TWhe feeding DACCS.
ii. The 16.9 Mt of zero emission residual hydrocarbon RMHC has a chemical energy content of 217 TWhc which may be used to replace hydrogen, ammonia, or other fuel or carbon-based chemicals. If we assume the RMHC replaces 217 TWhc of electrolytic hydrogen, then this will save 289 TWhe needed for electrolysis; if the RMHC displaced a more electricity intensive fuel such as ammonia, the displaced electricity would be more.
iii. Overall, 26 kWhe of electricity are required per kg of HC (kerosene and RMHC) which has an energy content of 13 kWh/kg, so the overall efficiency of producing HC is 50%.
iv. The gross electricity consumed for HC (kerosene and RMHC) is 819 TWhe, but a DACCS saving of 93 TWhe is made and RMHC saves 289 TWhe, leaving a net system electricity demand for HC of 436 TWhe.

v. 436 TWhe would be about a 50% addition to the 2050 total 800 TWhe UK consumption in most scenarios modelled in this report.

The preceding is an estimate of the annual mass and energy flows engendered by electrokerosene production. A cost comparison may be made with the counterfactual of aviation fossil fuel CO_2 being balanced with negative DAC emissions, the base assumption in the scenarios. The comparison is coarse because of uncertainties in the energy and mass analysis above, in the capital and operational costs of the technologies, and in the future price of fossil kerosene. Many technologies are not included such as storage and transmission. No attempt is made to differentiate the costs of different FT products such as kerosene, diesel, naptha, etc.

Zang *et al* (Zang, Sun *et al.*, 2021) analyse the performance and costs of a synthetic fuel plant producing 351 t/day which equates to a chemical power output of about 170 MW. The plant comprises H and CO2 compressors, syngas producer, Fischer Tropsch, hydrocracking and power – these are referred together as Fischer Tropsch or FT for brevity here, although this component is just 20% of the total capital cost. Zang *et al* estimate the cost to be 258 M$ or 212 M£, which with a 10% addition for ancillary equipment such as CO_2 transport, equates to 1240 £/kWc, which is assumed. An 80% capacity factor is assumed for FT and 55% for all other plant - DAC, electrolyser, and renewable generator (offshore wind). The technology assumptions are set out in Table 19. In general, the costs are projected for 2030-2050.

Table 19 : Electrokerosene production component cost assumptions

Technology	Life yrs	Unit cost	Capacity factor	Reference
DAC	25	7000 £/kWe	55%	
Electrolysis	25	350 £/kWe	55%	(IRENA, 2020)
Fischer Tropsch	25	1240 £/kWC	80%	(Zang et al., 2021)
Offshore wind	25	1400 £/kWe	55%	(BEIS, 2020a)

In March 2023, the cost of fossil aviation fuel was 900 $/t: this is 750 £/t, 16 £/GJ or 5.8 p/kWh. The cost has varied by a factor of 10 over the period 2016 to 2022[22] because of factors including covid19 and the Ukraine war. A question is what the cost in 2050 might be. First, the future refining carbon emission and costs per unit for kerosene will likely be higher, given that most other oil demands will have all but disappeared - kerosene is a small fraction of refined oil, globally about 8% currently[23].

[22] https://www.iata.org/en/publications/economics/fuel-monitor/

[23] https://www.iea.org/data-and-statistics/charts/world-refinery-output-by-product-1971-2019

Second, crude oil prices might fall because of reduced demand, or rise because of higher extraction costs due to declining low cost reserves. Third is the question of what the carbon and other environmental taxes on oil will be. The cost of fossil kerosene will have to be greater than renewable kerosene if market forces alone are to press aviation to net zero, otherwise regulation will be needed. However, for the purposes of comparison here the March 2023 price of 5.8 p/kWh is used.

Capital is annuitized at 3.5% (as assumed in general in this report) over 25 years for the technologies in Table 19 and O&M is assumed to be 2 %/a of capital cost.

Gross costs

The gross costs of HC production are first calculated without allowing cost savings for displacing fossil kerosene and other fuels such as hydrogen with RMHC. The electricity generation requirement includes 20% spillage above demand as found to be broadly optimal in the scenarios, though including interconnector trade would likely reduce this. The capital and operating costs of the principal components are calculated as shown in Table 20. It is estimated that the costs of extra hydrogen and CO_2 storage, and transmission capacity would add about 10% to the total of these costs. The gross costs of production are 682 G£ capital and an annual 55 G£/a assuming 3.5%/a over 25 years, with the main costs being 42% for DAC and 42% for electricity. The DAC CO_2 cost including electricity is 281 £/tCO2. This results in an average HC cost of 13.4 p/kWh at the 3.5 %/a interest. 13.4 p/kWh is the average cost of HC: not of kerosene in particular. The interest rate has a large effect on capital intensive renewable systems 'costs; at 8%/a interest, used by Zang *et al* (Zang, Sun *et al.*, 2021), the HC cost calculated here would be 40% higher than 13.4 p/kWh at 18.9 p/kWh.

The literature gives a wide range of electrokerosene production costs from 10 to 40 p/kWh but it is not easy to compare these costs with the costs estimated here because 13.4 p/kWh represents the cost of all HC, not just kerosene, and because of the wide range of system designs, projection years, renewable resources, currencies, and so on. range of system designs, projection years, renewable resources, currencies, and so on. But rough comparisons can be made with other estimates in the literature. Using the author's own cost conversions, Breyer *et al* (Breyer, Fasihi *et al.*, 2022) estimate 6-14 p/kWh, Transport & Environment (Transport&Environment, 2021) 12-20 p/kWh, Grahn *et al* (Grahn, Malmgren *et al.*, 2022) 12-17 p/kWh and Umwelt Bundesamt 14 p/kWh (Umwelt Bundesamt, 2016).

Table 20 : Hydrocarbon synthesis gross cost

		Capital £/kW	G£	Life Yrs	Ann.Cap G£/a	Per energy p/kWh	Per HC p/kWhHC	%
DAC TWhe	198							
GWe	*41*	7000	288	25	23.2	11.7	5.7	42%
Electrolysis TWhe	493							
GWe	*102*	350	36	25	2.9	0.6	0.7	5%
Fischer Tropsch TWhc	410							
GWc	*58*	1240	72	25	5.8	1.4	1.4	11%
Generation TWhe	983							
Offshore wind GWe	*204*	1400	286	25	23.0	2.3	5.6	42%
		Total	**682**		**55**		**13.4**	**100%**

Source: Author's calculations

Net costs

As shown in Table 20, electrokerosene displaces fossil kerosene and DACCS to balance fossil kerosene, and RMHC can displace hydrogen or other fuel such as ammonia, and the associated costs of these fuels. These bring system cost savings which need to be accounted for to arrive at the net cost of synthetic HC. The comparative cases are called *'Negative emissions'* (the base scenario) and '*Synfuel*', and the energy, capacity and costs of these case and their differences are shown in Table 21.

Synfuel replaces with electrokerosene 15 Mt or 193 TWhc of fossil kerosene priced at 5.8 p/kWh and thereby saving 11 G£/a. If a 300 £/tCO_2 tax were applied to fossil kerosene this would add 1.6 p/kWh to the unit cost making the saving 14 G£/a and reducing the net cost to 3.6 p/kWh.

Synfuel also replaces 217 TWhc residual HC (RMHC), comprising 112 TWhc diesel and 106 TWhc other HC, are assumed to replace hydrogen as a fuel which would be electrolysed using 289 TWhe of renewable energy, but as noted the diesel could replace electro ammonia for ships or other transport.

Synfuel requires:

i. An extra 105 TWhe of DAC electricity and 22 GW capacity costing 153 G£ capital and 12 G£/a annuitized.
ii. 493 TWhe of electrolytic electricity, but RMHC displaces 217 TWhc of other net zero fuels which would need 289 TWhe, so a net 204 TWhe of electricity is needed for 42 GWe of electrolyser costing 15 G£ capital and 1 G£/a.
iii. 410 TWhc total FT HC output. This costs 72 G£ and 6 G£/a.
iv. An extra 337 TWhe generation supplied by an extra 84 GW of offshore wind. This costs 118 G£ capital and 9 G£/a.

Table 21 : Hydrocarbon synthesis net cost

		Negative emissions	Synfuel	Syn-Neg Difference	£/kW	Cost extra Capital G£	Annual G£/a
Fossil kerosene	TWhc	193	0	**-193**			-11
DAC	TWhe	140	245	**105**			
	GWe	29	51	**22**	7000	153	12
Electrolysis	TWhe		204	**204**			
	GWe		42	**42**	350	15	1
Fischer Tropsch	TWhc		410	**410**			
	GWc		58	**58**	1240	72	6
Generation	TWhe	119	524	**405**		44	
Offshore wind	GWe	25	109	**84**	1400	118	9
					Total net	**401**	**18**
					Net cost	**4.3 p/kWh**	

Source: author's calculations

Altogether *Synfuel* costs an extra 401 G£ capital and 29 G£/a, but it saves 11 G£/a in avoided fossil kerosene costs; so *Synfuel* incurs an extra 401 G£ and net 18 G£/a. Assuming this extra cost is spread over the total HC output, the unit cost is 4.3 p/kWh, which is to be compared to the March 2023 kerosene cost of 5.8 p/kWh. It is noted that the fossil kerosene price implicitly includes both the crude oil price and the capital and operating costs of the necessary oil extraction, refining, and other infrastructure and these may change radically. Also noted is that aviation kerosene is currently exempt from general or environmental taxes.

Previously it was shown (p 59) that the capital cost of the net zero system is about 1500 G£ and the annual cost about 125 G£/a (Figure 48, p67). This coarse comparison has shown that using electrokerosene rather than fossil kerosene might add about 30% to the total system capital cost and 15% to the annual cost.

The wider integration of fuel production is discussed in 8.1 below

7.2.4. Aviation ticket and carbon pricing

The possible effects of fossil and electrokerosene costs and carbon taxes on air travel costs are illustrated here. Adapting data from Carbon Independent [24], an aircraft is assumed to travel at 900 kph and consume 30 g of fuel per passenger kilometre (p.km), using a load factor of 80%. An assumption is made of a 300 £/tCO_2 tax, similar to that in Jet Zero (UK Department for Transport, 2021), and similar also to the cost of CO_2 removal by DACCS. These assumptions and calculations may be made and are set out in Table 22:

[24] https://www.carbonindependent.org/22.html

i. If it is assumed that the altitude radiative forcing is half the fossil CO2 emission and is the same for fossil and electrokerosene CO_2, then the fuel CO_2 plus altitude CO_2e emission is 140 $gCO_2e/p.km$ for fossil kerosene and 47 $gCO_2e/p.km$ (passenger.km) for electrokerosene.

ii. Applying a 300 £/tCO_2 tax gives costs of 4.2 p/p.km (pence per p.km) or 38 £/hr for fossil kerosene and 1.4 p/p.km or 13 £/hr for electrokerosene.

iii. A fossil kerosene (F-kerosene) price of 5.8 p/kWh gives 2.3 p/p.km. Electrokerosene (E-kerosene) costs of net 4.3 p/kWh and gross 13.4 p/kWh (from the cost analysis in 7.2.3) gives 1.7 and 5.2 p/p.km respectively. The combined CO_2 tax and fuel cost gives a F-kerosene cost of 6.5 p/p.km or 58 £/hr, and an E-kerosene net-gross cost of 3.1-6.6 p/p.km or 28-60 £/hr.

With these assumptions, the E-kerosene gross cost per p.km is about the same as fossil kerosene, whereas the E-kerosene net cost per p.km is about 60% of the fossil kerosene cost.

Table 22 : Aviation passenger fuel and environmental costs

		F-kerosene	E-kerosene	
			Net	Gross
Altitude CO2e	gCO2e/p.km	47	47	47
Fuel CO2	gCO2/p.km	94	0	0
Alt + fuel CO2e	gCO2e/p.km	140	47	47
CO2e tax cost	p/p.km	4.2	1.4	1.4
	£/hr	38	13	13
Fuel cost	p/kWh	**5.8**	**4.3**	**13.4**
	p/p.km	2.3	1.7	5.2
	£/hr	20	15	47
Fuel+CO2e cost	p/.p.km	6.5	3.1	6.6
Fuel+CO2e cost	£/hr	58	28	60

Source: authors' calculations

Table 23 illustrates the impact of fuel and environmental costs on return flights from the UK to Spain, the USA and Australia with 2023 ticket prices respectively £200, £700, and £1400, being arbitrarily selected from online quotes which are very wide ranging with class (economy, business, first) and time of year. The flight times are return distances divided by a cruise speed of 900 kph. The non-fuel cost and F- and E-gross and net kerosene and carbon taxes are calculated to arrive at a total ticket cost. Compared to current ticket cost, the total cost for F-kerosene is increased by 63-78-105% for the three flights; for Enet kerosene - 12-15-20%; and E-gross kerosene by 150-162-184%.

The flight CO_{2e} emissions are compared to the 2020 average emission of an African of about 1 tCO_2/capita, showing the impact of a few hours flying. This underlines the climate change magnitude and equity problem of aviation.

Table 23 : Aviation global warming and costs of return flights

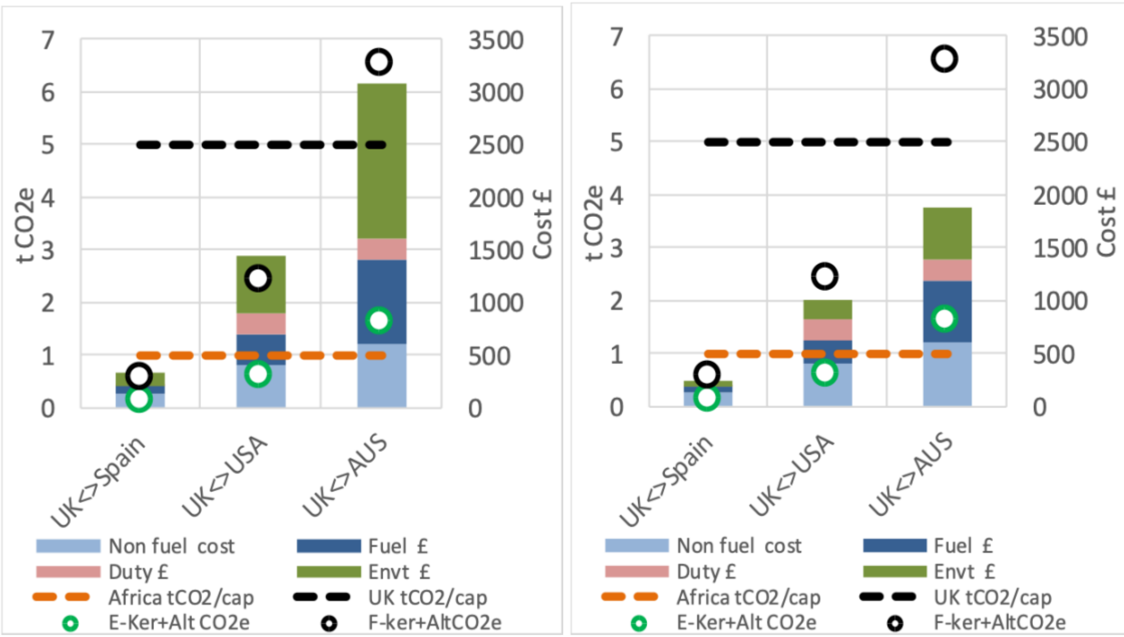
		UK<>Spain	UK<>USA	UK<>AUS
Distance	km	3000	13000	35000
Time	hrs	3.3	14.4	38.9
Airline ticket	£	**200**	**700**	**1400**
Current fuel cost	£	68	294	792
Non fuel cost	£	132	406	608
F-kerosene cost	£	68	294	792
E-kerosene fuel net cost	£	50	218	587
E-kerosene fuel gross cost	£	157	679	1829
Altitude CO2e	t	0.14	0.61	1.64
F-kerosene CO2e	t	0.42	1.82	4.91
E-kerosene CO2e	t	0.14	0.61	1.64
F-kerosene CO2e tax	£	126	547	1473
E-kerosene CO2e tax	£	42	182	491
Total F-kerosene cost	£	326	1247	2873
Total E-kerosene net cost	£	225	806	1686
Total E-kerosene gross cost	£	500	1835	3972
		Increase from current ticket cost		
F-kerosene		63%	78%	105%
E-kerosene net cost		12%	15%	20%
E-kerosene gross cost		150%	162%	184%
		Multiple average African CO2 emission		
F-kerosene		0.42	1.82	4.91
E-kerosene		0.14	0.61	1.64

Source: author's calculations

These costs, with the addition of UK air passenger duty (2023) are charted in Figure 54. It shows that using electrokerosene reduces emissions and therefore environmental costs, and the total cost (using net costs) of E-kerosene is less than that of F-kerosene.

Figure 54 : Aviation journey emissions and costs – fossil kerosene

Fossil kerosene **E-kerosene (net cost)**



7.3. Summary

The challenge of decarbonising aviation has been explored in this section and previously where it was shown that fossil kerosene supply and balancing high altitude warming would engender about 20% of total energy system costs. There is no alternative to aviation for fast long distance travel over water. Aviation will cause significant high altitude warming which has to be balanced with negative emissions, whichever fuel Is used. There is no near term alternative to kerosene. Fossil kerosene costs and impacts may be problematic when there is little demand for other petroleum fractions. Zero emission kerosene can be made but it has high costs. The production of renewable aviation fuels results in hydrocarbon by-products which may be used for other purposes, and this reduced the net cost of electrokerosene. Ideally, system models such as ETSimpleMo should be extended to integrate aviation fuel production fully into the energy system. Reducing aviation emissions to net zero will add significantly to air travel costs and help manage demand growth.

In the scenarios, it is assumed that aviation growth rate is reduced from 3-4 %/a to 2 %/a. It would be possible to make a higher growth rate net zero but at greatly increased costs.

8. Discussion

What follows is a general discussion of economics, operational algorithms, chemical process integration, implementation, resilience, and environment.

8.1. Economics

A Treasury rate of 3.5 %/a has been used to annuitise the capital costs of all technologies, but this is different from the rates applied by the explicit or implicit rates used by consumers or companies for different technologies. As noted in the assessment in 4.3.3 of wind, solar, and nuclear generation costs, project financing rates, interest during construction and project risk may vary widely with technology. In that assessment of LCOEs for wind, solar and nuclear, there was little change in the cost ranking with different assumptions..

The Ukraine war has caused higher gas prices which have directly increased gas heating and gas generation costs, and as gas is the major marginal generator, this has in turn caused increases in electricity prices. Altogether these have fed inflation and interest rates which increase the costs of capital and labour and thence of building and operating energy technologies. For some technologies, such as offshore wind, there is also increasing competition across a constrained supply chain, further increasing costs.

To an extent, these increasing prices will affect zero emission energy technologies similarly as they are all capital intensive with mostly fixed O&M costs. It may therefore be that the relative costs and resultant optimum mix of demand and supply capacities would not change significantly with rate changes.

It is interesting that the Fukushima nuclear disaster also increased international (and UK) gas prices because of Japan's increased import of LNG. This highlights interactions between fossil and nuclear energy, and the energy and economic security benefits of the high renewable, low import scenarios advanced here.'

8.2. Dynamic system operational algorithm and pricing

Dynamically controlling the system is a most difficult problem. Model algorithms have been developed here that operate the system hour by hour in different demand and supply conditions. The model ETSimpleMo has a Global Optimal Dispatcher (GOD) which has complete knowledge and control of the system; but this algorithm uses current and not forecast meteorology and demands. GOD serves as a proof of concept design for an actual operating system but at a national level only. The ESTIMO model (Gallo Cassarino and Barrett, 2021) has a more complex algorithm as it includes international trading across five European regions simultaneously modelled. Whether an algorithm is optimal is hard to determine.

Properly, we should optimise the selection of components and their connectivity and their sizes and the operational algorithm all at the same time, but this is beyond the capability of current models.

Currently (2023) gas generators mostly determine the marginal cost and determine the wholesale market price much of the time, but the annual operating hours of such gas fuelled flexible plant will decline as renewables and storage replace fossil generation, as Figure 60 shows. This will vary year to year: for example, in one scenario, renewable plus nuclear spillage is 22% of total generation potential in 2010 and 27% in 2009; and flexible generation is 40% higher in 2010 than 2009. About 50% of electricity costs are for transmission and 50% for generation. Flexible generation fuel cost represents about 2% of total electricity supply cost.

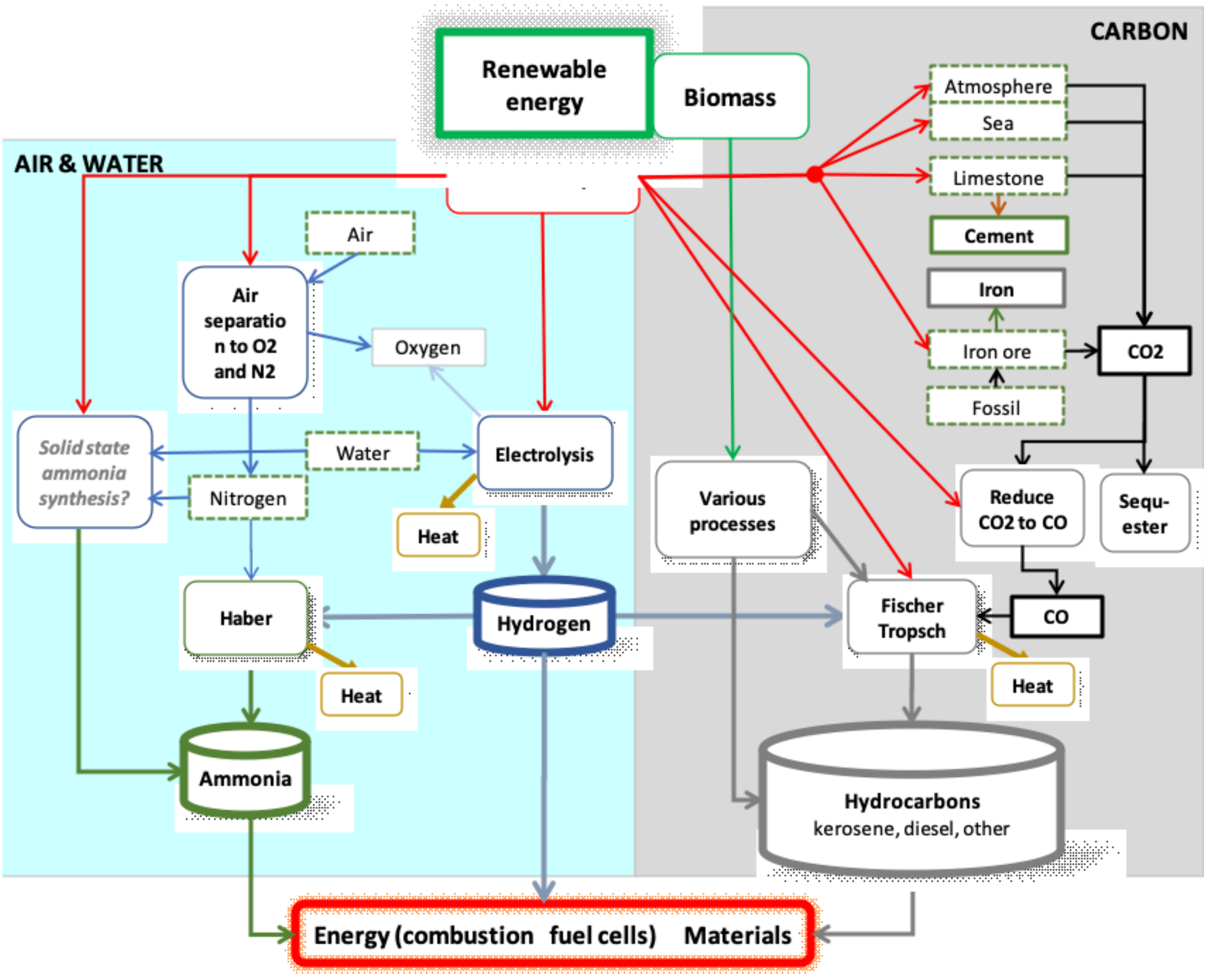
A question is: how will hourly electricity pricing be determined in a system where fixed capital and O&M costs comprising some 98% of total electricity system costs are incurred whether or not a component such as a generator or store operates? On the one hand, fixed costs need to be recovered else capital investments will not be made; on the other, the components need to be operated efficiently dynamically to make the best use of available resources. Additionally, markets and pricing need to be developed to ensure investment in new assets. An example of marginal costing theory and modelling has been developed by Siddiqui *et al* (Siddiqui, Macadam *et al.*, 2020) for such a system. This shows long periods with low costs but with short periods of extreme cost spikes when gas or other flexible generation plant or storage is operating. The operationalisation of such a cost theory might be difficult in practice.

Further questions follow. To what extent will prices reflect marginal costs given the need to protect consumers? How can a system control algorithm be implemented in a social market through regulation, pricing or contracts? Is it possible to have a stable dynamic system with 30 M competitors, or does much control need to be done centrally?

8.3. Chemical process integration

The analysis of aviation fuel in 7 introduced some of the possible interdependencies between kerosene production and other processes. Wider interdependencies such as illustrated in Figure 55 give rise to the potential for industrial clusters integrating chemical processing to extract resources (CO_2, nitrogen, water, etc.) and produce fuels (hydrogen, ammonia, hydrocarbons, etc.). These processes can produce useful by-products such as oxygen and many produce low temperature waste heat which might be used for meeting heat demands. Industrial clusters might be located near facilities such as offshore wind, ports, salt caverns, sequestering sites and energy transmission.

Figure 55 : Chemical and fuel production integration



As shown for kerosene production, integration can decrease the net costs of electrokerosene. The HC and heat by-products of kerosene synthesis could meet significant fractions of chemical energy and heat demand. In 2050 aviation fuel demand is projected as 175 TWh (13.6 Mt). If this is produced with Fischer Tropsch outputting 47% as kerosene then 370 TWh total hydrocarbons (HC) are produced, 220 TWh of which are non-kerosene remaining mixed hydrocarbons (RMHC) comprising roughly 110 TWh of diesel and 110 TWh of naptha and other HC. The shipping fuel demand is 50 TWh, so if this were fuelled with RMHC diesel, 60 TWh of diesel remain. Industrial chemical demand is 60 TWh and some of this could be met with diesel or other FT fractions such as lighter naptha. Shipping and industry might thus use about 110 TWh of RMHC leaving 110 TWh of a mix of naptha and other RMHC. If all this were used for back-up generation, it would generate about 40 TWhe at 35% efficiency, as compared to 6 TWh in the optimised DH20 system. Some RMHC might be used for producing plastics or other carbon based products.

Using Danish data (Danish Energy Agency, 2017), an estimate is that the FT HC process produces about 140 TWh of low temperature heat. Industrial low temperature heat demand is about 50 TWh (see Table 26, p 105) and FT waste heat could potentially provide a significant fraction of this assuming demand and FT operation were both baseload and collocated. In DH20, DH provides 83 TWh of heat. Some of this might also be provided by FT waste heat, but DH demand is highly seasonal and much will be based in cities where FT is unlikely to be located, and this would limit the contribution.

8.4. Implementation

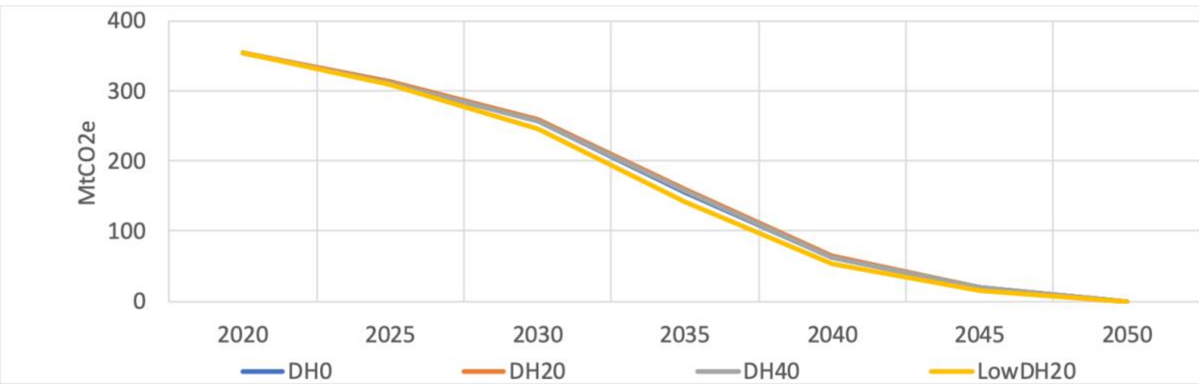
The scenarios developed here require a substantial new build of the energy system over a 30 year period including switching some 30 M consumers from gas to zero carbon heat and from oil powered vehicles to EVs, building 200 GW of offshore wind and 100 GW of solar, and building networks to connect them.

Logistic curves are used to emulate system development between the base year and the optimised (2050) system. Logistic curves reflect the general changing rates often found with the introduction of 'new 'technologies, slow at first, then fast, then slow as saturation is approached. There is no modelling here of processes such as consumer uptake or supply chain expansion and somewhat arbitrary parameters are used in the logistic curves.

Of central importance is the cumulative GHG emission over the scenario, particularly of CO2 with its long residence time: this places emphasis on fast early demand reduction and increase in zero emission supply. Behavioural change can be more rapid than technology stock change as is briefly discussed in 6.1. Figure 56 shows the emission profiles for selected scenarios.

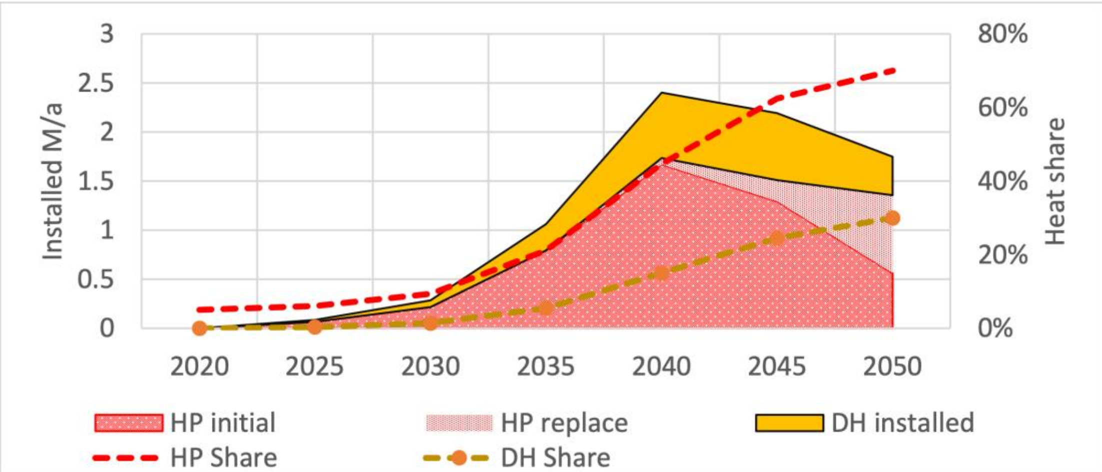
The low demand (LowDH20) scenario reduces emissions more rapidly, mainly because the assumed rate of change in heating and cooling set temperatures is faster than the technology stock replacements: in consequence the total scenario emission over the period 2020 to 2050 of LowDH20 is 5% less than the other scenarios.

Figure 56 : Scenario emission reduction profile 2020-2050



Arguably the most difficult technologies to implement are building efficiency and consumer heating and cooling heat pump systems because of their disruption, high capital costs and labour inputs, incurred at consumers 'premises. For scenario DH20, Figure 57 shows the heat shares and annual installation rates for the initial consumer HPs replacing gas boilers and assuming a 20 year life, the replacement HPs, and DH, following from the logistic curves assumed. To achieve full decarbonisation by 2050, about 1 M consumers per year on average will need new heat and cool supply systems, but the peak installation rate would be about double this (2 M/a) given the time taken to expand the supply chain. It was noted in 4.1 that reversible heat pumps might be lower cost and faster to install than ASHP for heating and provide cooling at no extra cost.

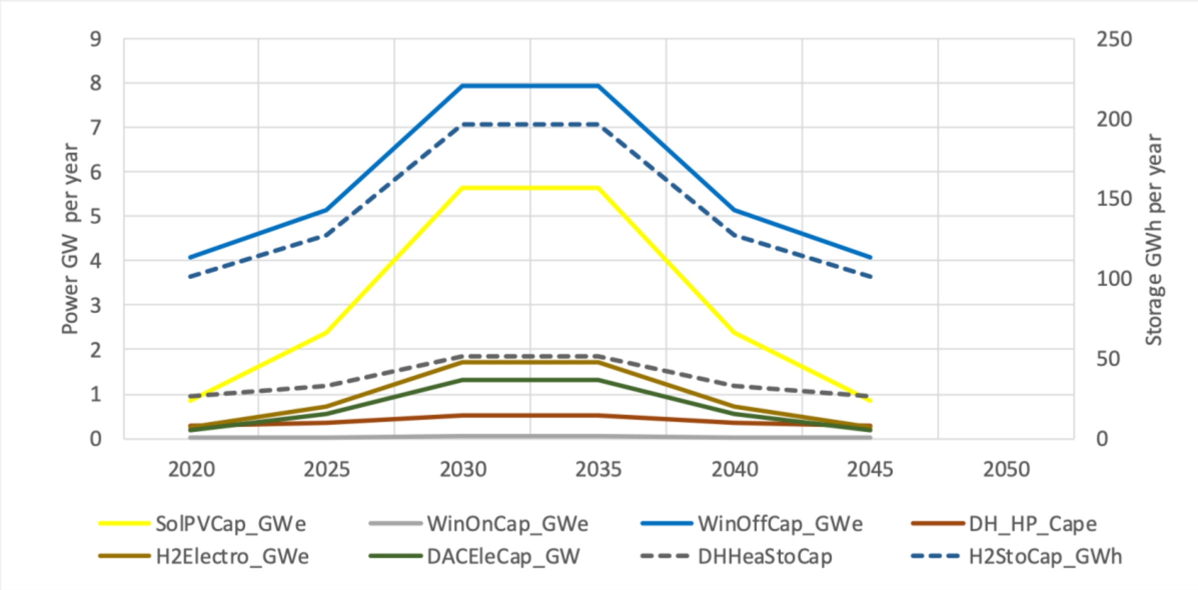
Figure 57 : DH20 consumer heat pump and DH shares and implementation rates



In general, public energy systems and system components (networks, generators, stores, etc.) have a smaller direct impact on consumers and public policy can, in principle, bring about rapid change. However, the social capacity for manufacture, installation and financing take time to develop. District heating can be applied to most buildings with less disruption than heat pumps, and its capital costs can be paid through energy bills; however, DH requires implementation on an area basis.

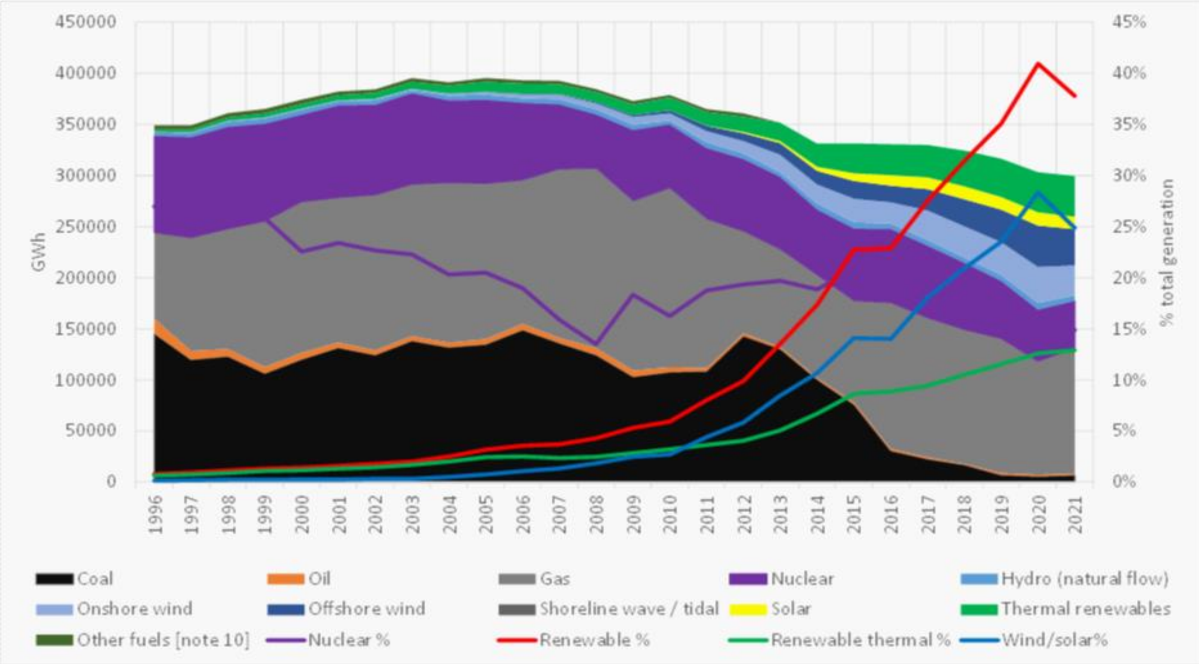
On the primary supply side, a wind capacity of 200 GW and solar PV of 100 GW represent a huge challenge to implement. This capacity will have to be coordinated with electricity demand growth and network development. Figure 58 shows the assumed profile of annual capacity build of some major components in the DH20 scenario.

Figure 58 : DH20 rate of capacity build of major components



The recent rate of change of the UK electricity generation mix has been rapid as shown in Figure 59. Renewable generation has grown from 2% of generation in 2001 to 122 TWh or 38% in 2021; it exceeded nuclear in 2015. About half renewable generation is biomass thermal generation with storage, but much of this uses imported biomass, mainly for Drax power station, with questionable greenhouse gas emissions, wider environmental impact, and security implications. One reason for this fast growing fraction is that total generation has fallen by 23% since a peak in 2005 because of declining demand, partially driven by efficiency. This shows the importance of the demand side of the equation in accelerating emission reduction.

Figure 59 : UK historic generation development



Source: Table 5.6 DUKES

8.5. Resilience

The energy system operation can be degraded for various reasons including extreme meteorology affecting demand or renewables, technical failure or political events which may endure for days, months or years. The system must be reasonably resilient to these. The systems designed do not rely on fossil fuel except aviation kerosene and a small use of gas for flexible back-up generation. Most of the simulations use 2010 meteorology and renewable data; other work has shown this is a stress year in terms of weather, renewables and storage. However this is historic meteorology.

Climate change can bring weather conditions very different from those historically encountered; these include extreme high and low temperatures, wind speeds, fire, rain, hail, snow, flooding, and sea level surge. These can impact on most demand and supply technologies including buildings, heat pumps, transmission and renewable and nuclear supply. Analysis of such impacts is beyond the scope of this work: the reader is referred to analysis such as that by the World Meteorological Organization (World Meteorological Organization, 2022) which explores energy resilience to climate change through case studies in countries which already face problems which the UK has yet to deal with.

Table 24 summarises the main demand side and grid level flexible balancing options for modelled in ETSimpleMo except consumer heat/cool storage. For demand side, each option is grid connected with a certain electrical capacity and has a converter, with an efficiency, that outputs electricity, hydrogen or heat to a store.

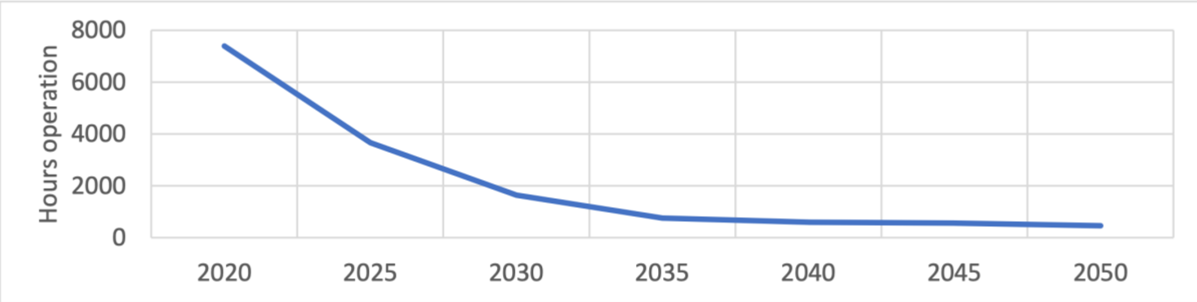
Energy is taken out from the demand connected stores to meet demand hour by hour, so the input to the store can be controlled, but not the output. The approximate time to fill each store from empty and discharge it from full can be estimated. The heat side flexibility is mainly in winter when demand is high while the cool side flexibility is in summer. Heat (or cool) storage for consumer heat pumps generally will be limited for active heat (or cool) stores for reasons of space and cost, and passive heat (or cool) storage in the fabric is constrained; these are set nominally to an hour here. The total storage attached to demand is 6950 GWh and the total connected input power 188 GW. These demand side options can replace some of the frequency control and inertia functions of rotating turbines in conventional generators through rapid electronic load adjustments in EV chargers, electrolysers and heat pumps. This is discussed by Ullmark *et al* (Ullmark, Göransson *et al.*, 2023). Grid storage inputs and outputs, and flexible generation, are not directly connected to demands and so are not constrained by them.

Table 24 : Flexibility summary for DH20 scenario

		Storage		Power	Fill	Store output to demand		Empty
				In	Store	Power		Store
		Form	GWh	GWe	Hrs	GW		Hrs
EV charging		Electricity	1300	64	20	13	Average	97
Electrolyser		Hydrogen	4300	27	213	14	Average H2 demand	302
DAC			no limit	21	no limit			
District heat HP	Seasonal	Heat	1200	11	37	42	Peak heat	28
Consumer HP	Seasonal	Heat (pass)	*150*	64	1	161	Peak heat	1
Total demand			***6950***	***188***				
Grid store		Electricity	50	15	3	32		1.6
Generator NG/H2/Bio		Fuel		50		large		

In the systems designed, apart from kerosene and waste biomass, primary energy is in the form of electricity from variable renewables and a small fraction from nuclear, so resilience across most of the system can be achieved with flexible 'back-up 'generators using stored electricity, biofuels, electrofuels or fossil fuels. Optimisation results in about 50 GW of flexible fuelled capacity operating at a capacity factor of around 1%. Dispatchable generation might include retained existing gas CCGT of which there is about 30 GW in 2023 and retaining or building as necessary a mix of plant such as biomass, open cycle gas turbines (OGT) or diesel engines, or even old coal or oil. The annual operating hours of such flexible plant will decline as renewables and storage replace fuelled generation as shown in Figure 60. Figure 25 (p 46) shows the operation of dispatchable plant for 2050 and the fuel supply and storage needed; this is for 2010 meteorology, a difficult year.

Figure 60 : DH20 scenario flexible generation operating hours



CO_2 emission from flexible generation is small and balanced by DACCS, as it is found to be cheaper than applying CCS directly to plant that operate at low capacity factors. The option of generators using electrolytic hydrogen has been modelled and would eliminate the use of fossil fuel for flexible generation; this adds to the system costs but reduces the required negative emissions. Another option to consider is DH CHP using renewable fuels or gas as this would produce electricity and heat which would reduce the DH HP electricity demand. However, DH CHP costs more per kWe and would be operated at a very low capacity factor and optimisation indicates it is not cost effective. Figure 25 (p 46) shows the usage of flexible fuelled generation in the DH20 scenario with 2010 weather: a continuous fuel supply of 2 GW and an 8 TWh store are sufficient.

But resilience should plan for exceptional circumstances, and this is explored. If an extreme ambient temperature of -15 °C or 40 °C is applied in the model, the peak electricity demand is about 150 GW and this might endure such that the stores in Table 24 were exhausted. If, at the same time, renewable and nuclear generation and interconnector import are all zero and the stores all empty, then 150 GW of replacement generation plant would be needed. In reality, it is probable that contracted or enforced load reduction would be exercised *in extremis* to reduce demand but a minimum demand will remain for essential services.

The largest renewable energy store in 2023 is in the wood pellet supply system to Drax power station which includes 320 kt (1.6 TWh) of pellet storage at the power station (DraxBiomass, 2020b) and 200 kt (1.0 TWh) at the Immingham dock (DraxBiomass, 2020a), to give a total 2.5 TWh of storage. 2.5 TWh input to the 4 GW Drax station could provide about 1 TWhe of electricity over 250 hours. It has already been noted that Drax biomass import is of questionable carbon content, environmental impact and long term security, but this might be partially replaced with domestic biomass. Drax flexibility is limited, in that its ramp rate is low.

As an example, operating constantly for a week, 150 GWe of 33% efficient open cycle gas turbine (OGT) would use 450 GWf of fuel (gas or oil) to produce 25 TWhe of electricity whilst consuming 55 TWhf of fuel. The fuel could be a gaseous or liquid fuel, and it is possible there may be substantial by-products from fossil or synthetic kerosene production which might be used.

The UK system currently has a maximum gas supply rate of 200-250 GW (National Grid, 2021) from indigenous production, imports and storage, so considerable expansion would be required if this were to fuel 150 GWe of OGT. During 2022/2023[25] the maximum UK two-way total gas storage was about 29 TWhg (8/11/23) with LNG peaking at 13 TWhg (23/11/22). The Rough field, originally with a capacity of 40 TWhg, was closed but is currently being recommissioned though no reference was found for its future capacity. Thus existing input/output gas storage is perhaps of the order of 50 TWhg. In addition, UK output only gas reserves can be deployed. Currently the UK produces about 350 TWhg/a of gas (an average 40 GWg).

As noted in 8.1, it may be that there will be liquid and gaseous hydrocarbon byproducts from kerosene synthesis which may be used for generation.

The annuitized capital cost of 150 GW of OGTs would be about 3 G£/a, or 3% of the total system cost. This excludes the fuel storage cost. The operating and fuel costs, and emissions of flexible plant would be small or zero in most years.

This discussion is to illustrate issues concerning resilience in exceptional circumstances, not to suggest any measures outlined above are optimal.

8.6. Environment and materials

It is beyond the scope of this analysis to detail environmental impacts and materials. ETSimpleMo could be extended to quantify some impacts and materials needs of system designs, at least in a simple manner, but this must be left for further work.

All technologies cause environmental impacts during their fabrication, installation, operation and decommissioning. There is extensive implementation of most of the main technologies assumed in the scenarios in the UK or elsewhere, including consumer heat pumps, electricity and heat networks, and wind and solar generators, which indicates that impacts are not unacceptable. Processes such as electrolysis, Haber-Bosch ammonia and Fischer-Tropsch have a range of impacts such as water and land use, but these technologies are already commercialised and relatively common. Most of the technologies, nuclear and DACCS excepted, do not leave problematic, long lived wastes.

[25] https://data.nationalgas.com/find-gas-data

There is little experience with DACCS: it will not require much land, but it requires significant quantities of water and chemicals. Biocrops are excluded because of concerns about their environmental impacts, as well as their implications for energy and food security.

Analysis by Barrett and Scamman (Barrett and Scamman, 2023) showed that over 100 GW of solar PV can be accommodated within the built environment, that onshore wind takes little physical area, but that biomass requires large areas per energy produced. As the scenarios here use no biocrops and a small increase in onshore wind, and most electricity comes from solar PV and offshore wind, the necessary rural land use for primary supply is low. However transmission and other facilities will have visual impacts.

8.6.1. Other greenhouse gases

The focus here has been on CO_2, but other greenhouse gases such as methane, nitrous oxide, hydrogen, and some refrigerant fluids used in heat pumps are important. The radiative forcing of GHGs is commonly expressed as a global warming potential (GWP) over 100 years (GWP100) with methane having a GWP100 of 27.9 [26]. Methane and combustion gases such as nitrous oxide from combustion will generally fall as fossil fuels are reduced, as indeed will air pollutants.

However, the emissions of hydrogen and refrigerant fluids can be expected to increase as they are used more in the scenarios than currently. The current leakage of natural gas, mostly methane, from the distribution system is poorly known – a figure of 0.3% may be used[27] for now, but future leakage is for speculation. The effusion of a gas through a given hole is proportional to the square root of the gas 'molecular weight: therefore hydrogen (weight 2) will leak from a hole in the ratio $(16/2)^{0.5} = 2.8$ times faster than (mass/time) than methane (weight 16). Hydrogen has a GWP100 of 11.6 ±2.8 according to Sand *et al* (Sand, Skeie *et al.*, 2023). Given the GWP100 of methane of 25[28] the global; warming of hydrogen distribution may be of similar order to methane. A range of refrigerant fluids are available[29] including some with lower GWP100 than those commonly used, such as ammonia and CO_2.

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26 https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter_07_Supplementary_Material.pdf

27 https://www.gov.uk/government/statistics/natural-gas-chapter-4-digest-of-united-kingdom-energy-statistics-dukes

28 https://archive.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

29 https://ggbec.co.uk/a-small-leak-can-sink-a-great-ship-a-comparison-of-selected-refrigerants-used-in-domestic-heat-pumps/

8.6.2. Materials

Net zero technologies can use scarce metals with issues about mining impacts, availability and costs. They are used in permanent magnets in EV motors and wind generators where they improve efficiency and reduce weight, although a significant fraction of these use more common metals for magnets or do not use magnets at all. Marmier *et al* (Marmier and Pavel, 2016) discuss substitutes for wind turbines and Widmer *et al* (Widmer, Martin *et al.*, 2015) in EV motors. Scarce metals are also used in some batteries but substitutes for these are available as discussed by Amory Lovins (Lovins, 2022). Replacements for scarce metals may in some cases have slightly inferior performance but improvements are being made, and most importantly some current generators, motors and batteries already avoid using scarce materials.

Some researchers advance bleak prospects but these may be pessimistic. Groves *et al* (Groves, Santosh *et al.*, 2023) conclude that *'many metals, particularly Co, Ni, Cu, Se, Ag, Cd, In, Te, and Pt, may be severely to terminally depleted by 2060, making further low carbon technology production impossible.'* Wei *et al* (Wei, Ge *et al.*, 2022) conclude '*the total minerals* supply *will not meet the total minerals demand (74260 kt) in 2060.'*

9. Conclusions and further work

9.1. Conclusions

It was noted in section 2.4 that significantly changing some decision variable values near the optimum found can have a small effect on total system cost, and therefore there is some flexibility in certain aspects of design. It was also noted that the optimisation will not find the exact global minimum but should get quite close to it. Additionally, technology costs and performance will not be single values but ranges; for example the costs of offshore wind will vary with turbine size and location. Scenario development and system design is a never-ending process, but the following significant results have emerged so far:

- All major demands except aviation can be directly or indirectly decarbonised with renewable electricity. However, industry requires further analysis.
- Aviation is the hardest sector. The assumption is made that future annual demand growth is about half of historic growth; this is tough to realise. If aviation uses fossil kerosene and if all DACCS costs are allocated to aviation as the only significant fossil fuel user and CO_{2e} emitter, then aviation costs are about 20% of total energy system costs. The assumption that aviation continues fossil fuel use is obviously politically problematic, but it has been shown that biowastes cannot provide enough feedstocks, and that electrokerosene is costly. However, electrokerosene production results in hydrocarbon by-products which can displace other fuels.

- For heating, consumer heat pumps and district heating are similar in cost. Reversible heat pumps look to be a cost-effective option, providing resilience to climate change. Hydrogen for heating is more costly because of its electricity requirement.
- With climate change, the cooling electricity demand peak is the same order of magnitude as for heating. Its summer, the peak is well correlated with solar PV generation. In the +5 ^{o}C climate scenarios the heating and cooling loads are about the same, and the optimal PV capacity is double that at +2 ^{o}C.
- One important finding is that if hydrogen electrolysers and DACCS run on electricity that is surplus to all other demands, their capacity factors range 60-70%. In practice, this would mean that their electricity costs would be relatively low.
- Optimisation results in 20-30% of renewable electricity being spilled or curtailed. This is perhaps one of the most surprising results. Spillage would be reduced if interconnector trade were included, or if demand side technologies and storage became cheaper relative to generation.
- Offshore wind supplies about 80% of primary energy.
- Nuclear power does not appear in least cost system designs, apart from Hinkley Point C, which is assumed to be committed and operational in 2050.
- The optimisation results in high, dispatchable (using stored energy) power capacities operating at low capacity factors to meet rare shortfalls. Grid storage has an optimised output capacity of about 10 GWe operating at around a 2% capacity factor. The fuelled dispatchable generation has an optimised capacity of about 50 GW and operates at a capacity factor of around 1%. These dispatchable sources constitute about 3% of total system costs.

9.2. Further work

In terms of energy system design perhaps the hardest decisions are how to fuel aviation, how to provide heating and cooling to consumers with heat pumps or district heating, and how to provide negative emissions.

System scope

- **Interconnector trading.** One critical missing component in the energy system modelled with ETSimpleMo is interconnector trading. This can potentially reduce spillage and/or storage by averaging demands and renewables over large geographical areas. Analysis by Gallo Cassarino *et al* (Gallo Cassarino, Sharp *et al.*, 2018) showed that European interconnection could reduce European storage needs by up to 30%. The UK currently (2023) has about 6 GW of operational interconnectors with a further 8.5 GW with regulatory approval and due to operate by 2030, to give a total 14.5 GW by that date[30]. This excludes further interconnectors under consideration but which have not been assessed. To accurately model interconnector trade, simultaneous modelling of demand, renewables and storage in each European region is required: one example of this is by Gallo Cassarino and Barrett (Gallo Cassarino and Barrett, 2021) using the ESTIMO model. Plainly to design systems for the whole of Europe is a large task, and European system evolution cannot be determined by UK policy alone.
- The scope of this work is generally limited to predominantly energy processes and related emissions or other radiative forcing aviation). Some processes emit GHG from the chemical changes incurred, notably cement production. Land use, agriculture and waste handling.

Spillage and capacity factors. Particularly important is to explore how the 20-30% generation spillage could be reduced to lower the required capacity build and environmental impacts of renewables, and storage requirements.

- **Interconnectors** could substantially reduce spillage.
- **Higher offshore wind capacity factors.** The offshore wind capacity factors modelled with ETSimpleMo range 55-60% in the 2009/2010 meteorology years. BEIS (BEIS, 2020a) projected 63% and then 69% (BEIS, 2023) for 20 MW turbines installed in 2040 which if averaged across the 2050 fleet would increase generation per GW and reduce storage needs compared to the scenarios modelled here.
- **Nuclear** is currently assumed to constantly operate at a baseload 85% of maximum capacity. Supplementary analysis might estimate the generation capacity and energy storage required to back-up nuclear when it is not generating because of scheduled outage or faults and the costs thereof.

Demands. A fundamental uncertainty is the evolution of demands to 2050. If the proportional mix of demands changes little, then the optimal mix of renewables and storage will also change little.

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[30] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

- **Fast measures.** It is the total emission over the coming decades that causes climate change, not just the emissions in 2050. Fast measures such as reducing aviation growth, downsizing cars, reducing speeding and reducing building overheating can have a rapid effect and thereby reduce total scenario emissions significantly. Fast measures generally require behaviour and lifestyle change; this could be modelled.
- **Detailing** demand projections could be improved, particularly of industry with its varied processes.
- **Building efficiency.** One uncertainty here is the heating and cooling loads which depend on climate change and heating and cooling systems implemented, and this will affect the seasonal distribution of demand, and thence the optimal renewable mix. Currently the efficiency level of buildings is an assumption. This might be included in the optimisation.

District heating and cooling (DHC). With climate change, the potential cooling load will increase. DHC systems are used even in colder countries like Finland. DHC is analogous to district heating except chilled water is distributed and stored, as well as hot water. As for consumer heat pumps, DHC could use reversible heat pumps and provide cool as well as heat and some cooling can use sea water.

EV batteries. The capacity of EV batteries has an impact on the required capacities of generation and storage in the rest of the system, and sensitivity analysis is required here, for example increasing the EV battery capacity from 1.3 TWh to 2.2 TWh.

System stress. Long durations of extreme high and low temperatures and low renewables could be simulated to stress the system and test resilience.

Costs. The greatest cost uncertainties which could be narrowed are:

- Aviation fossil or synthetic fuels
- DACCS capital and O&M costs
- The costs of (mostly new) district heating networks, upgrading electricity distribution and transmission networks, and converting gas networks to hydrogen, and how these network costs vary with heating share and consequent load density.

Further optimisation would increase confidence in the least cost designs. A sensitivity analysis of designs to technology performance and cost input changes, would inform design. If technologies such as batteries, electrolysers and DACCS were cheaper relative to renewables, the optimum would shift, and spillage would probably be reduced. Constraints could be put on technology capacities e.g. of renewables and the change in system cost calculated.

Chemical process integration. As explored in 7.2.3 and 8.1 process and overall system integration could bring benefits, and the ETSimpleMo modelled system could be extended to include this.

Negative emissions. A deeper assessment of the alternative processes and technologies for negative emissions and further analysis of DACCS would be useful. This could include both natural and engineered options.

Modelling operational markets and prices. The ESTIMO model includes an operational algorithm to control energy flows within and between European regions and ETSimpleMo has an algorithm for the UK. The application of an hourly electricity pricing methodology might provide one input to market modelling.

Environmental and material impact assessment. It would be possible to apply impacts per unit of capacity or production to simply estimate such things as the land areas required by the scenarios.

Implementation. The social capacity required in terms of skilled workers and the time required to implement the rates of change in the capacities in the scenarios could be estimated.

10. Appendix

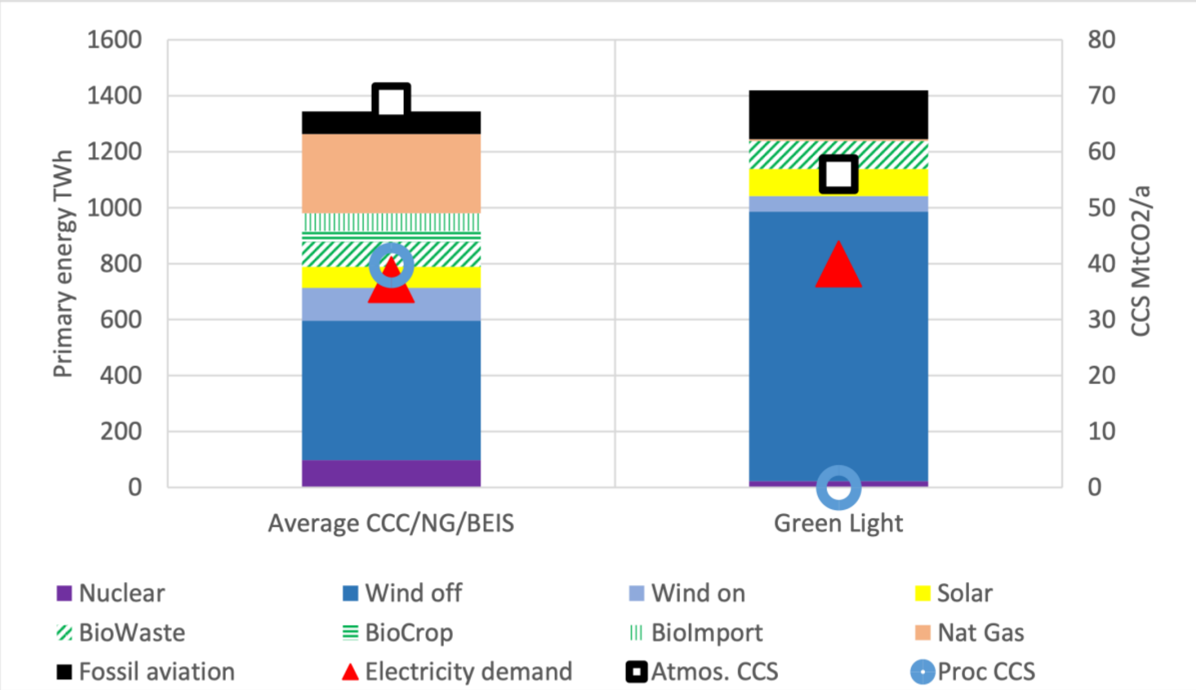
10.1. Comparison with other scenarios

A summary and simple comparison of some features of Green Light (GL) with other scenarios is made below. The Climate Change Committee produced five scenarios for the Sixth Carbon Budget (Climate Change Committee, 2020); National Grid, three scenarios (National Grid, 2022); and BEIS, three scenarios (BEIS, 2021b). Altogether these comprise 11 CCC/NG/BEIS scenarios with a range of component sizes. Simple averages of the ranges of annual electricity demand, renewable and nuclear generation, biomass and carbon sequestration across all scenarios have been made and then compared with the GL scenarios. A simple average of CCC/NG/BEIS conceals wide ranges. It is understood that primary renewable and nuclear electricity are functionally different from primary chemical energy in biomass or fossil fuels.

The main primary energy differences are that compared to GL, CCC/NG/BEIS have more nuclear, natural gas, and biocrops and imported biomass. In GL, 20-30% of renewable generation is spilled whereas in CCC/NG/BEIS it seems little is spilled; one reason may be because GL has less stored fossil, nuclear and biomass primary energy for flexible generation.

Despite GL spilling so much primary renewable electricity, the primary energy demand of CCC/NG/BEIS is similar in total and this will be in part because fossil and biomass fuels have lower efficiencies, typically ranging 30%-50% for motive power to 85% for heat with additional CCS inefficiency, as compared to electricity with conversion efficiency of 85% to motive power, and 300% to heat or cool. Because of the greater use of fossil fuels in CCC/NG/BEIS there is more need for process and atmospheric carbon capture and storage. Altogether CCCNGBEIS deploy about twice the total carbon capture of GL. Figure 61 depicts a summary comparison of CCC/NG/BEIS and GL, where generation in GL is potential generation including spillage.

Figure 61 : Comparison of Green Light with other scenarios



Some points of comparison are set out in Table 25. The renewable generation mix is similar but more weighted to offshore wind in GL.

Table 25 : Comparison of Green Light with other scenarios

	CCC/NG/BEIS average	Green Light
Scope	Land use, agriculture, etc. included	Energy only
Electricity demand	About 800 TWh	About 800 TWh
Electricity generation	About 800 TWh	About 1100 TWh
Renewable generation	Wind offshore 65-140 GW, onshore 25-69 GW, solar 35-91 GW	Wind 190 GW, onshore 20 GW, solar 100 GW
Nuclear	13 GW (5-44 GW range)	3 GW Hinkley
Spillage	Little or no spillage, but some scenarios have interconnectors	20-30%. No interconnectors.
Biomass	Waste, biocrops and imports	Waste only
Aviation	Mix of fossil and renewable fuels	Mostly fossil kerosene
Process CCS	40 MtCO2	0 MtCO2
Atmospheric CCS	69 MtCO2e	55 tCO2e

10.2. UK heat demand

The UK heat demand may be estimated from delivered fuel data in DUKES table 1.04 and is shown in Table 26. About 60% is domestic and the reminder non-domestic heat. The supply of heat causes about 50% of total CO_2 emission and this fraction is currently increasing as electricity generation decarbonises faster than gas heating.

Table 26 : UK heat demand estimate (2019)

	Emitted heat/cool TWh	Gas	Oil	Solid fuel	Electricity	Heat	Bio&waste	Total	% UK heat	% UK Del Energy	CO2 Mt	% UK CO2
Domestic	Space heating	175	17	3	18	3	18	**233**	47%	20%	44	22%
	Water heating	52	4	0	5	0	1	**62**	13%	5%	12	6%
	Cooking/catering	4	0	0	4	0	0	**8**	2%	1%	1	1%
	Clothes/dishwasher							**0**	0%	0%	0	0%
	Space + water	**227**	**20**	**4**	**22**	**3**	**19**	**295**	**60%**	**25%**	**56**	**28%**
Services	Space heating	53	13	0	9	3	7	**85**	17%	7%	17	8%
	Water heating	7	2	0	2	0	1	**12**	2%	1%	2	1%
	Cooking/catering	3	5	0	7	0	0	**15**	3%	1%	3	2%
	Space + water	**60**	**15**	**0**	**11**	**3**	**8**	**97**	**20%**	**8%**	**19**	**10%**
Industry	Space heating	9	1	1	7	0	0	**18**	4%	2%	3	2%
	High temperature process	16	1	5	9	0	0	**31**	6%	3%	7	3%
	Low temperature process	31	2	2	16	0	0	**51**	10%	4%	10	5%
	Drying/separation	9	1	1	6	0	0	**16**	3%	1%	3	2%
	Unknown (heat)	0	0	0	0	8	11	**19**	4%	2%	4	2%
	Space + LT process	**48**	**4**	**4**	**29**	**8**	**11**	**104**	**21%**	**9%**	**13**	**7%**
STATIONARY	Space heating	237	31	4	34	6	24	**336**	68%	28%	65	33%
	Water heating	59	6	0	6	0	2	**74**	15%	6%	14	7%
	Low temperature process	31	2	2	16	0	0	**51**	10%	4%	10	5%
	High temperature process	16	1	5	9	0	0	**31**	6%	3%	7	3%
	Heat	**343**	**41**	**11**	**65**	**6**	**26**	**492**	**100%**	**41%**	**95**	**48%**

Source: Digest UK Energy Statistics Table 1.04, author's estimation

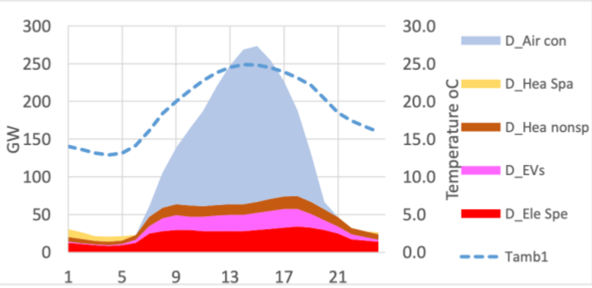
10.3. Further sample simulation results for DH20 - summer

Generally, the system is less stressed in the summer because there is less variation in renewable generation, as solar is then a larger and more reliable source, though wind is lower than in winter. Demand is generally lower, but much depends on climate change and the assumed implementation of air conditioning. With the assumptions here, the maximum cooling demand (GW) is a similar magnitude to the maximum winter heat demand, but it is well correlated with solar generation as solar radiation drives both ambient temperatures and solar gain to buildings through windows.

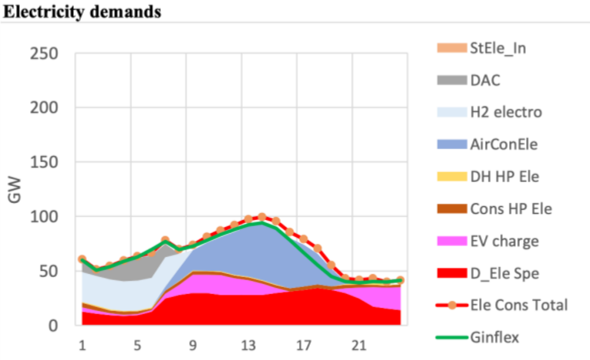
10.3.1. Sample day and fortnight simulation: summer

Day of year 172 Jun 2010 met Scenario DH20

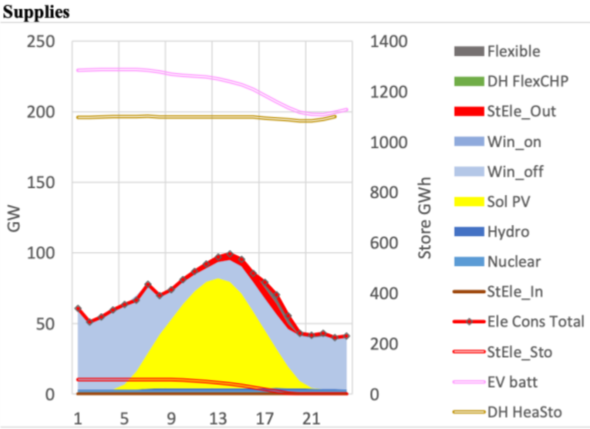
Demands



Electricity demands

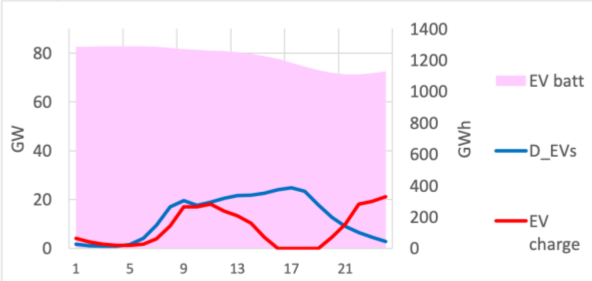


Supplies

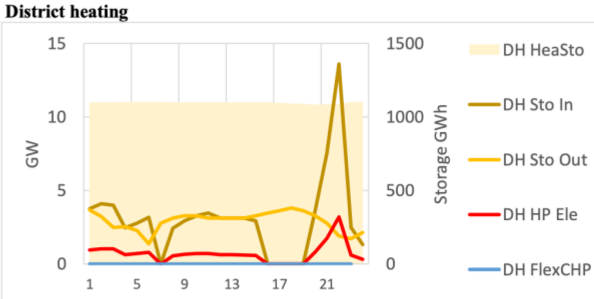


Day of year 172 Jun 2010 met Scenario DH20

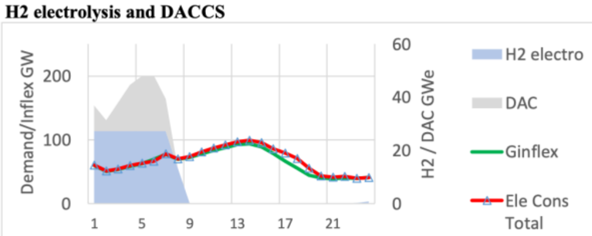
Battery vehicles BEV



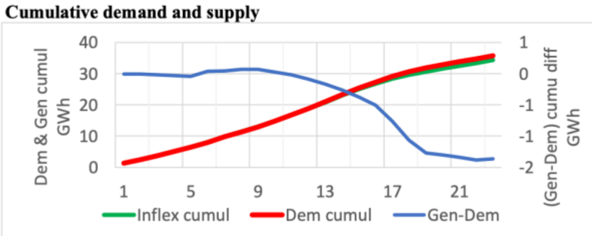
District heating



H2 electrolysis and DACCS

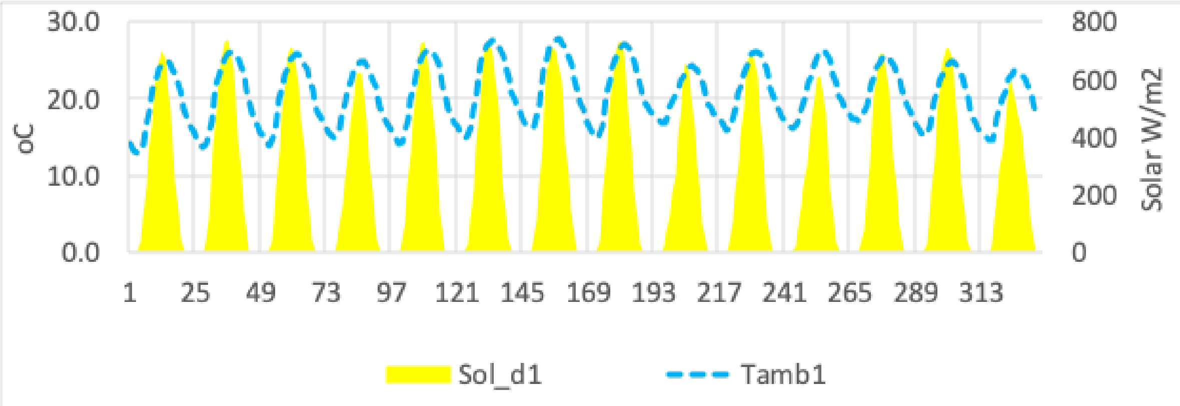


Cumulative demand and supply

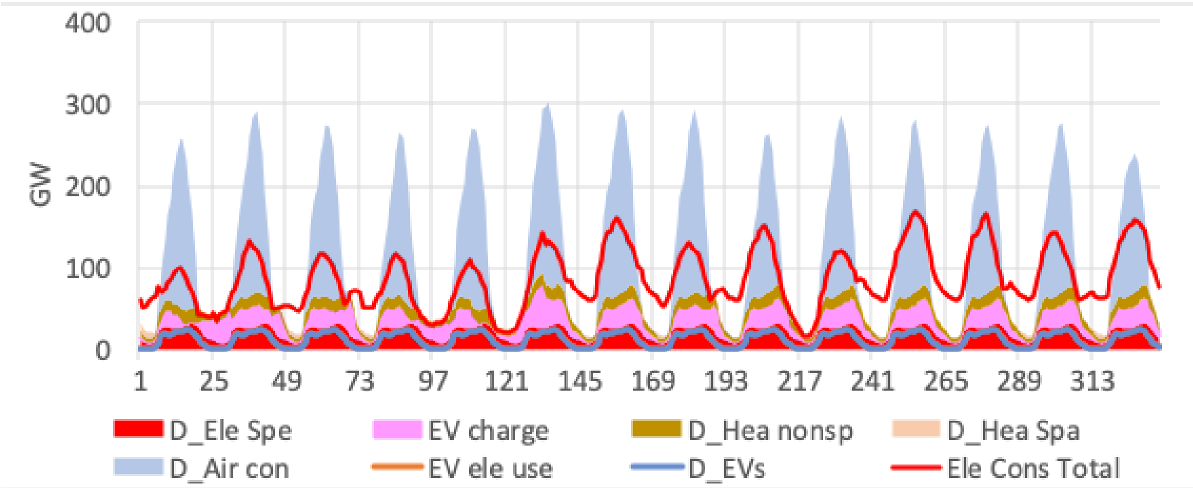


Fortnight from day	172 Jun	2010 met	Scenario DH20

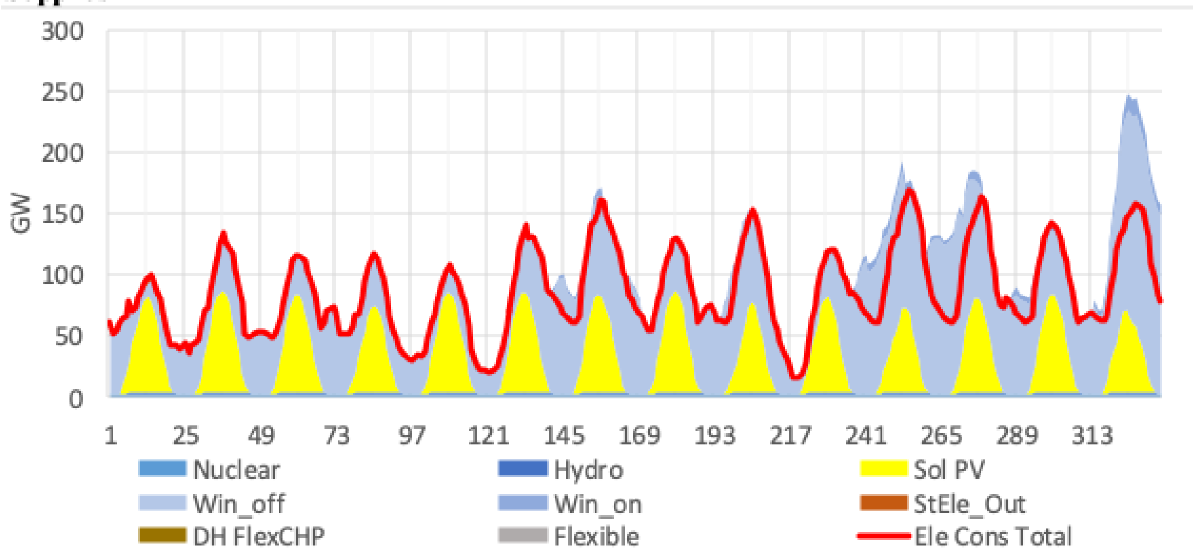
Meteorology



Demands

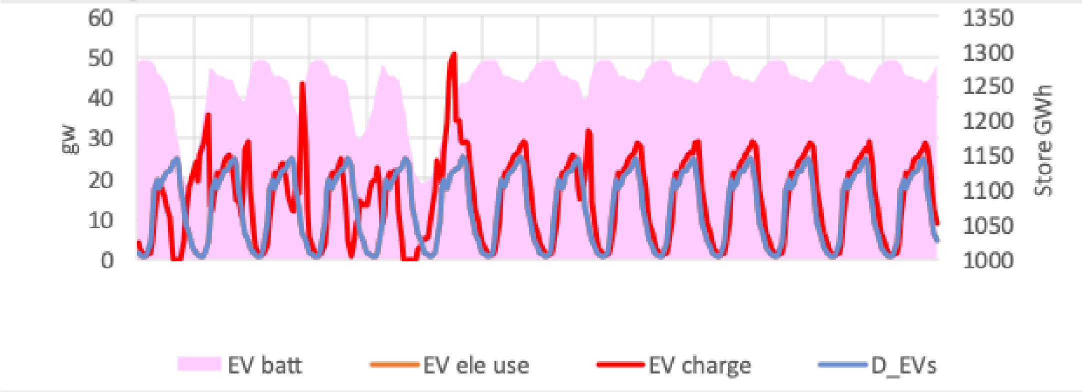


Supplies

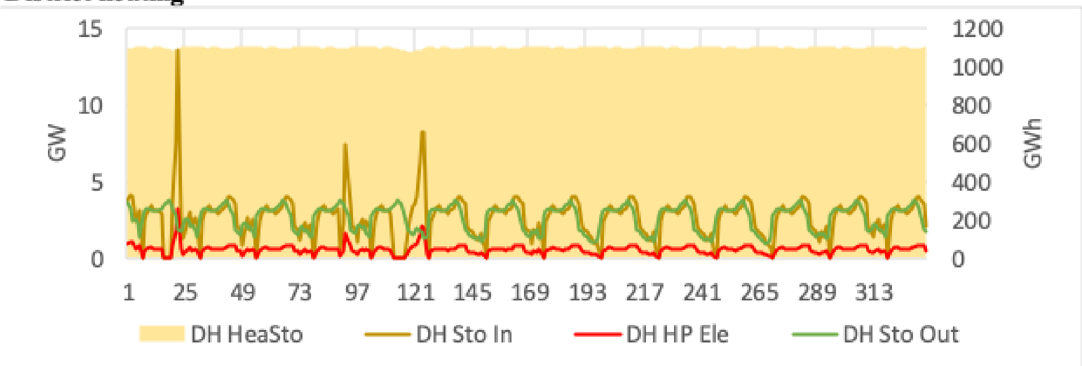


Fortnight from day 172 Jun 2010 met Scenario DH20

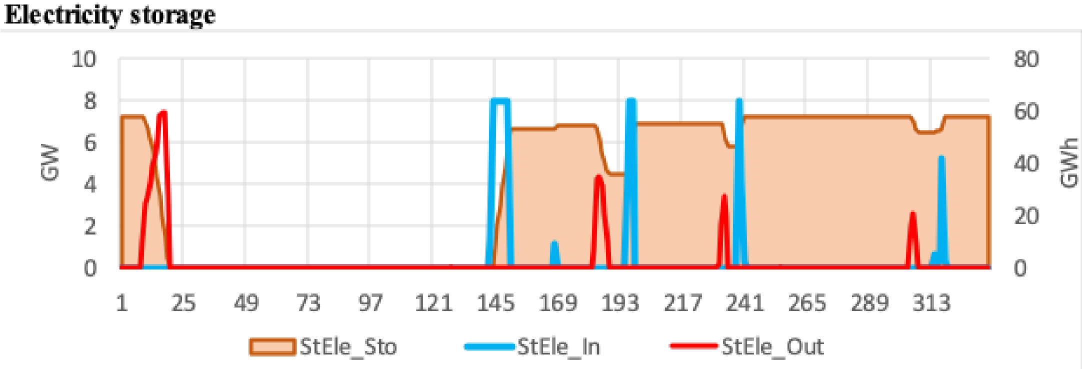
BEV storage



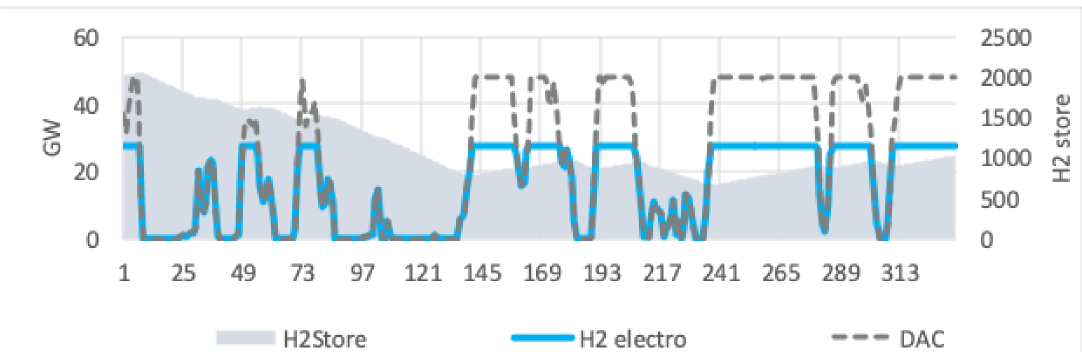
District heating



Electricity storage



H2 electrolysis and DACCS



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