The implications of ambitious decarbonisation of heat and road transport for Britain's net zero carbon energy systems

Modassar Chaudry [a,*], Lahiru Jayasuriya [a,d], Simon Blainey [b], Milan Lovric [b], Jim W. Hall [c], Tom Russell [c], Nick Jenkins [a], Jianzhong Wu [a]

[a] School of Engineering, Cardiff University, Cardiff CF24 3AA, Wales, UK
[b] University of Southampton, Southampton SO17 1BJ, England, UK
[c] Environmental Change Institute, University of Oxford, South Parks Road, Oxford OX1 3QY, England, UK
[d] Department of Mechanical Engineering, Faculty of Engineering, University of Peradeniya, Sri Lanka

HIGHLIGHTS

- A novel integrated energy and transport system modelling approach is described.
- A combination of heat and transport decarbonisation options are assessed.
- Managed EV charging and vehicle to grid reduces energy system (opex + capex) costs.
- Hydrogen technologies for heating and transport are costly to implement.
- An integrated energy system enables increased utilisation of renewable energy.

ARTICLE INFO

ABSTRACT

Decarbonisation of heating and road transport are regarded as necessary but very challenging steps on the pathway to net zero carbon emissions. Assessing the most efficient routes to decarbonise these sectors requires an integrated view of energy and road transport systems. Here we describe how a national gas and electricity transmission network model was extended to represent multiple local energy systems and coupled with a national energy demand and road transport model. The integrated models were applied to assess a range of technologies and policies for heating and transport where the UK's 2050 net zero carbon emissions target is met. Overall, annual primary energy use is projected to reduce by between 25% and 50% by 2050 compared to 2015, due to ambitious efficiency improvements within homes and vehicles. However, both annual and peak electricity demands in 2050 are more than double compared with 2015. Managed electric vehicle charging could save 14TWh/year in gas-fired power generation at peak times, and associated emissions, whilst vehicle-to-grid services could provide 10GW of electricity supply during peak hours. Together, managed vehicle charging, and vehicle-to-grid supplies could result in a 16% reduction in total annual energy costs. The provision of fast public charging facilities could reduce peak electricity demand by 17GW and save an estimated £650 million annually. Although using hydrogen for heating and transport spreads the hydrogen network costs between homeowners and motorists, it is still estimated to be more costly overall compared to an all-electric scenario. Bio-energy electricity generation plants with carbon capture and storage are required to drive overall energy system emissions to net zero, utilisation of which is lowest when heating is electrified, and road transport consists of a mix of electric and hydrogen fuel-cell vehicles. The analysis demonstrates the need for an integrated systems approach to energy and transport policies and for coordination between national and local governments.

1. Introduction

The UK has legislated for a net zero carbon emissions target for the whole economy by 2050 [1]. Alongside the UK, countries such as Sweden, France, Denmark, New Zealand and Hungary have also established net-zero carbon objectives [2]. This will require energy systems that are

---

* Corresponding author.

decarbonised with heat related emissions from buildings substantially reduced alongside widespread adoption of electric, and possibly hydrogen, road vehicles.

Decarbonising heat is arguably the biggest challenge facing UK energy policy over the next few decades. In 2019 almost half of the UK's overall energy consumption was used for heating which was primarily fuelled by natural gas [3]. In Britain 85% of homes are heated with gas boilers, compared to ~54% in Germany and USA [4]. Countries like New Zealand have pursued heating policies that provide subsidies on heat pumps that run on renewable electricity, whereas Sweden and Norway have focussed on district heating infrastructure. In the UK, achieving the net zero carbon emissions target will require consumption of natural gas and other fossil fuels for heating to be replaced with low-carbon alternatives. The task of decarbonising heat is large in scale and diverse in the types of solutions that will be required.

The transport sector contributes the largest source of carbon emissions in the UK [5] accounting for 119MtCO$_2$ (27% of total CO$_2$ emissions) in 2019 where ~ 70% is due to road transport. To meet the overall net-zero emissions target, virtually all road vehicles would need to be zero emission by 2050, and to facilitate this the UK has introduced a ban on the sale of new petrol and diesel cars from 2030 [6].

The decarbonisation of heat and road transport by 2050 therefore requires the delivery of low carbon power generation, reinforcement of power networks, alternative heating systems, establishment of electric vehicle (EV) charging points and possible investment in hydrogen supply systems including re-fuelling infrastructure for hydrogen fuel-cell vehicles [7].

The UK power system is on a trajectory towards a low carbon future. The UK Committee on Climate Change (CCC) along with others such as the National Infrastructure Commission (NIC) and National Grid anticipate upwards of 150GW of wind (on and offshore) and Photovoltaic (PV) capacity by 2040s [7–9]. Nuclear generation capacity and the prospect of net negative emissions through bio-energy plants with carbon capture and storage (BECCS) are also projected to increase. To compensate for the variability of renewables and inflexible generation technologies, support from storage, interconnection to the continent of Europe and flexible plants (e.g. combine cycle gas turbines - CCGTs with CCS) alongside smart demand side management will be required.

Distributed low-carbon electricity generation in the UK is likely to consist of onshore wind, rooftop solar PV and some utility-scale solar farms [11]. Though there has been a moratorium on new onshore wind, construction at new sites may restart in the future, but the majority of wind potential is offshore. Distributed battery storage systems are gaining traction given the potential to improve utilisation of distributed renewable generation alongside the capability to provide flexibility services to the wider electricity system [10,11]. Distributed electricity generation from natural gas (dedicated gas turbines, and Combined Heat and Power - CHP) are going to have to decline in a net zero emissions future and could be replaced by technologies such as bio-fuelled CHP, hydrogen CHP (including fuel cells) and waste to energy systems. Studies [9,10,12] have explored how CHP units can be integrated within local energy systems and utilised to deliver flexibility services to the national electricity transmission system.

There has been a rapid growth in electric car and van sales in recent years in a number of countries, albeit from a low base, with such vehicles accounting for 54.3% of new cars sold in 2020 in Norway, a world leader [13]. While purchase costs remain higher than for conventional vehicles, the gap is rapidly closing, although 'range anxiety' is still regarded as a disincentive to uptake. In contrast, the development of hydrogen vehicles is still in its infancy, as relatively few vehicles are available with high purchase costs and very limited refuelling infrastructure. Hydrogen is however particularly suited to heavy goods vehicles which require more power, and many pilot applications have been on local bus networks. Hydrogen vehicles have a refuelling time advantage compared to EVs, and range anxiety can be addressed through larger fuel tank sizes. This is though currently negated by the availability of hydrogen

refuelling stations, with only 15 such stations in operation in the UK in 2019. However, if hydrogen is increasingly used for heating, the build-out of hydrogen distribution infrastructure could facilitate much wider uptake of hydrogen vehicles and refuelling infrastructure.

The transition to electric and hydrogen vehicles will pose challenges for the energy system. For example, there are growing concerns regarding the timing, location, and frequency of EV charging. The National Grid Future Energy Scenarios (FES) imply that unmanaged EV charging could potentially add an additional 24GW and 100GWh to future peak and annual electricity demand, respectively [14]. This is almost 40% of peak and a third of annual electricity demand in 2019. Management of EV charging through consumer participation mechanisms such as smart charging, vehicle to grid (V2G) and vehicle to home (V2H) can mitigate the increase in electricity peak demand.

The implications of EV charging behaviour on electricity systems have been studied extensively. These studies include EV charging impacts on power quality [15], thermal stress and voltage regulation [16,17] and reliability [18] of electricity distribution systems. In addition to the detailed technical analysis, recent studies have focussed on the impact of electric vehicle roll-out on climate policy [19,20] and assessment of vehicle to grid services [21]. However, most existing studies on decarbonisation of road transport are limited to electric vehicles and their impact on the electricity transmission and/or distribution systems. There are very few studies that examine a mix of alternative road transport decarbonisation options (e.g. hydrogen) on the energy system. This is in part due to the complexity of representing whole energy systems, as modelling spatially distinct local and national gas and electricity systems and their interactions remains difficult and computationally expensive [22].

In this paper we present a novel coupled multi-vector energy and transport model that simulates the complex interdependencies between these systems. The model is highly spatially resolved in its representation of energy supply, transmission/distribution and end-use, including in the transport network. A two-scale approach is adopted, which couples the national electricity and gas transmission systems, with 29 local 'energy hub' aggregations of energy demand and supply including technologies such as battery storage and CHP. Temporal resolution at an hourly scale enables representation of time-of-day as well as seasonal variations in demand, whilst variability in renewable energy supply is driven by hourly weather simulations. The interdependencies between energy systems and demand for road transportation are explicitly represented through integration of the energy supply and demand models with a comprehensive road transport model. Any residual emissions from electricity peak generation plants, heating, hydrogen production and industrial non-heating fossil fuel use are balanced by operating BECCS plants connected to the transmission system to meet UK net-zero carbon emissions target in 2050. A range of infrastructure strategies are simulated to explore the ability of the GB energy system to provide supplies for heating and road transport, given high penetration of electric/hydrogen fuel cell vehicles, variability of energy supplies, and different charging patterns (including residential slow and public fast charging, and the inclusion of smart charging and vehicle to grid services). The impact on energy system operation (electricity, natural gas, heat, and hydrogen supply), operating costs and emissions are explored.

2. Integrated energy – Transport systems modelling

2.1. Multi-scale modelling of integrated energy supply systems

The integrated energy supply systems model is based on the Combined Gas and Electricity Network (CGEN) model [23,24], which was significantly upgraded to represent local electricity, natural gas, hydrogen and heat supply systems and their interactions at high spatial resolutions [25].

At the transmission scale, natural gas and electricity networks interact through gas fired power generators. Energy resource supplies,
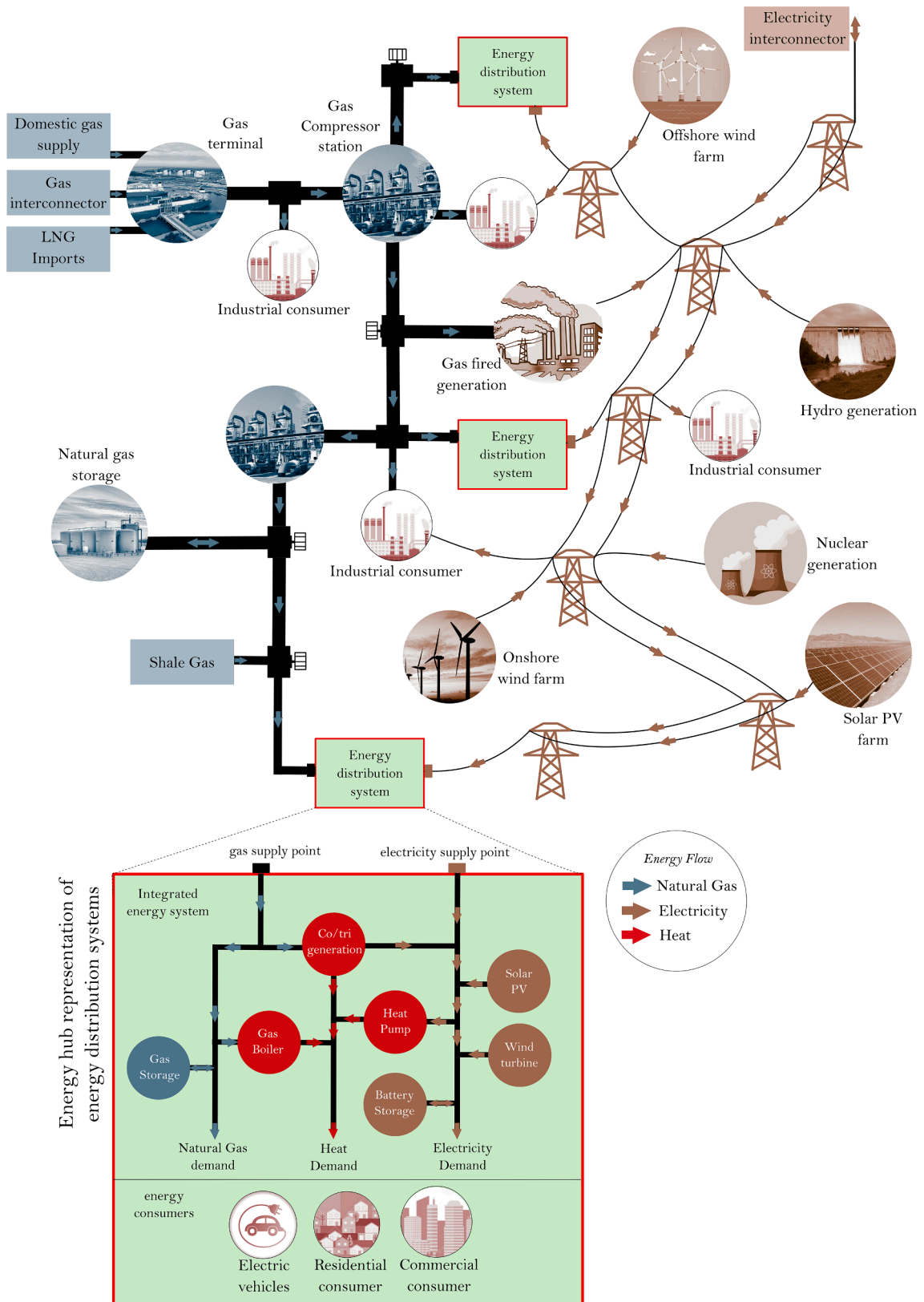
Fig. 1. Stylised representation of the national and local energy systems.
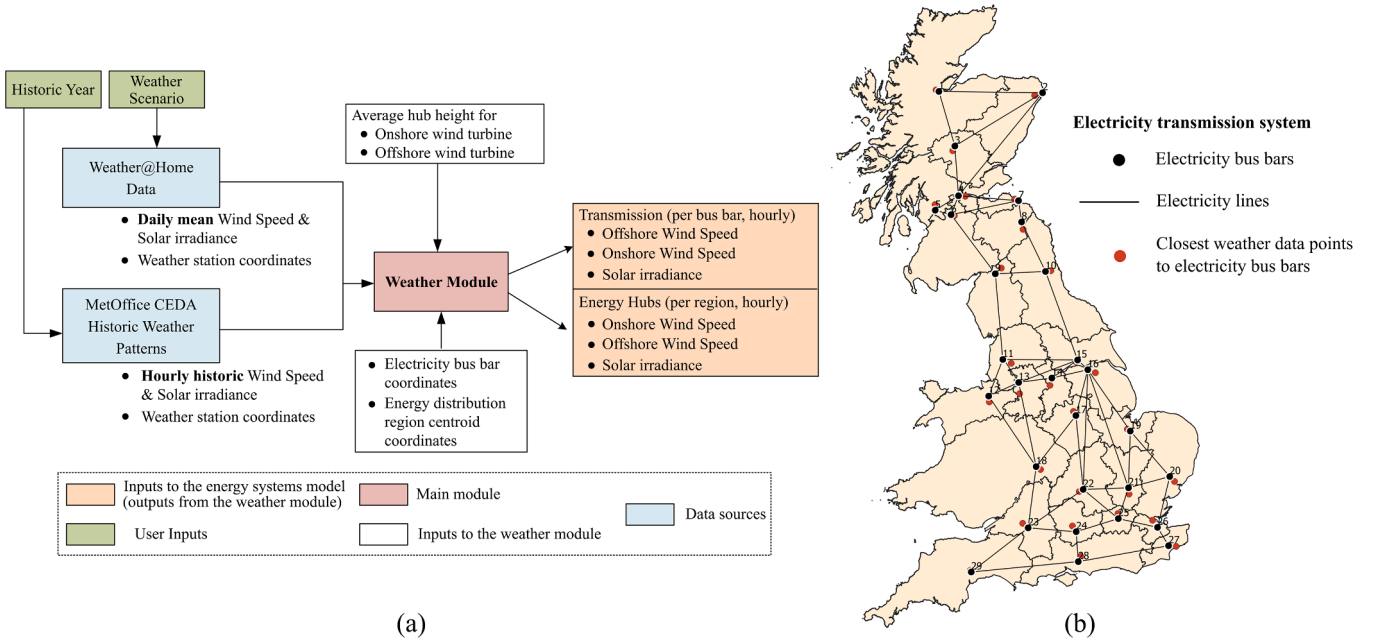
Fig. 2. (a) Weather module data and parameter inputs, and outputs, and (b) weather stations used to account for the spatial variability of weather parameters in the energy supply model.

$$Objective = min \sum_t^T \left\{ C_t^{ElecTran} + C_t^{GasTran} + \sum_{k=1}^N C_t^{EnergyHub_k} + C_t^{Carbon} + C_t^{unserved\_energy} \right\} \tag{1}$$

generation technologies and networks are explicitly modelled. Detailed modelling methods are used to represent seasonal gas storage operation, variable generation of renewables and operation of interconnectors. Energy supply at the transmission level meets demands from large industrial consumers and energy flows into distribution systems.

Within the energy distribution systems, electricity, natural gas, hydrogen and heat supply systems are modelled. To form the integrated framework of various energy carriers via energy conversion technologies an 'energy-hub' [26] concept is adopted. The energy hubs are connected with the gas and electricity transmission networks through grid supply points. Energy hubs utilise regionally distributed energy resources, storage (batteries, hydrogen, and gas) and transmission grid supplies to meet primarily residential and commercial energy demands. Constraints from each technology and network energy flow capacities were modelled.

A stylised illustration of the national and local energy systems, including a detailed representation of an energy hub is shown in Fig. 1. The spatial representation of the GB gas and electricity transmission networks, and local energy systems via energy hubs is provided in Appendix-A.

The combined national and local energy supply system model minimises total operational costs (Eq. (1)) to meet energy demands. The operational costs are derived from the natural gas ($C_t^{GasTran}$) and electricity ($C_t^{ElecTran}$) transmission networks, energy hubs $\left(C_t^{EnergyHub_k}\right)$, carbon costs ($C_t^{Carbon}$) and unserved energy ($C_t^{unserved\_energy}$) over the operational time horizon T.

The cost minimisation is subjected to constraints derived from the operational characteristics of assets in both national and energy hub systems while ensuring the balance between energy supply and demand.

where $C_t^{ElecTran}$ (Eq. (2)) includes, power generation costs C_j^{gen} such as fuel costs, operational and maintenance costs of power generator j (excluding interconnectors) for generating power $P_{j,t}$; costs of importing power $P_{i,t}^{imp}$ for a unit price C_i^{imp} and the revenues from exporting power $P_{i,t}^{exp}$ for a unit price C_i^{exp} via an interconnector link i.

$$C_t^{ElecTran} = \sum_j C_j^{gen} P_{j,t} + \sum_i \left(C_i^{imp} P_{i,t}^{imp} - C_i^{exp} P_{i,t}^{exp} \right) \tag{2}$$

$C_t^{GasTran}$ (Eq. (3)) includes, the cost of gas supply from terminal a at time t calculated by the volume of gas supplied $Q_{a,t}^{sup}$ and gas price $C_{a,t}^{gas}$; the cost of operating a gas storage facility u calculated by the gas volume injected $Q_{u,t}^I$ or withdrawn $Q_{u,t}^W$ at time t and the cost of gas injection C_u^I or withdrawal C_u^W.

$$C_t^{GasTran} = \sum_a C_{a,t}^{gas} Q_{a,t}^{sup} + \sum_u \left\{ C_u^W Q_{u,t}^W + C_u^I Q_{u,t}^I \right\} \tag{3}$$

The energy hub costs $\left(C_t^{EnergyHub_k}\right)$ of operating integrated electricity, natural gas, heat and hydrogen distribution systems (Eq. (4)), include operating costs of distributed technologies including fixed and variable costs $\left(C_i^{f\&v}\right)$ of operating technology (i) with respect to energy outputs $\left(E_{i,output,t}\right)$, and fuel costs for biomass $\left(C_{bio}^{fuel}\right)$ and solid waste (C_w^{fuel}).

$$C_t^{EnergyHub_k} = \left\{ \sum_i^{\{Tech\}} E_{i,output,t} \times C_i^{f\&v} \right\} + \left\{ \sum_j^{\{bio,w\}} E_{j,t} \times C_j^{fuel} \right\} \tag{4}$$

The carbon costs C_t^{Carbon} were applied across electricity generation, heat supply, hydrogen production and non-heating end-uses of fuels (natural gas, oil, solid fuel). Within both national and local energy
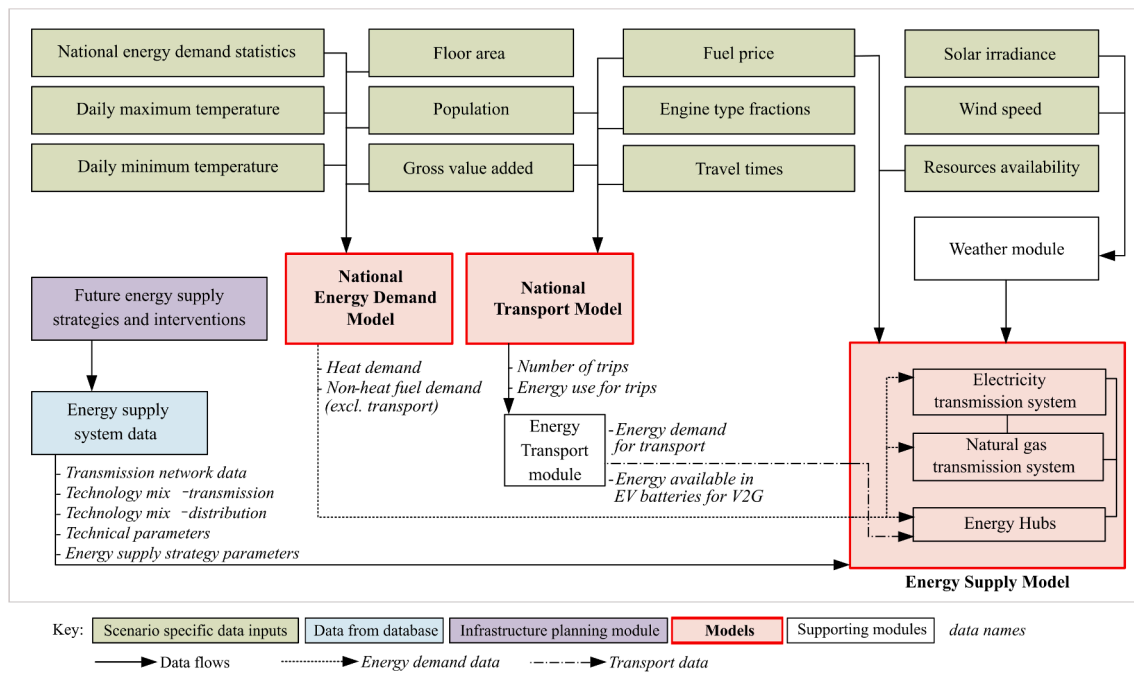
Fig. 3. Coupling of energy demand, supply – transport models: data inputs, outputs, and flows.

systems, penalty costs were applied for unserved energy $C_t^{unserved\_energy}$ demand.

Variable output from renewable energy supplies and curtailments[1] are modelled using time series of hourly wind speed and solar irradiance. Therefore, spatial and temporal variability of wind speed and solar irradiance are accounted for in the GB electricity transmission network and local energy hubs. A weather module was implemented and used to extract historic data from the Met Office [27] and time series simulations of future weather conditions from regional climate modelling of the UK (the "Weather@Home" dataset) [28]. Approximately ∼ 100 daily time series simulations of future wind speed and solar irradiance were downscaled to hourly time resolution using normalised patterns from historic hourly weather data from the Met Office [27]. The implemented weather module, data inputs and outputs are shown in Fig. 2a. In addition, the weather stations used to extract data according to each electricity busbar and energy hub region are shown in Fig. 2b.

The production of hydrogen using electrolysis and steam methane reformation (SMR) are modelled. Dedicated hydrogen transportation through distribution systems are considered in the Energy Hubs such that supply meets the heating, non-heating and transport hydrogen demands.

In the energy supply model, natural gas, grid-scale battery, and hydrogen storage facilities are modelled. Both short-term (intraday) and seasonal natural gas storage operations are represented. The operation of grid-scale battery storage systems is modelled including their operation to store excess renewable electricity generation during off-peak hours and withdraw during peak hours. In addition, the operation of hydrogen storage facilities is modelled, allowing storage of hydrogen which is produced via electrolysis using excess renewable electricity and through SMR during mainly off-peak hours. Seasonal gas storage facilities are connected to the natural gas transmission networks. Both grid-scale electric batteries and hydrogen storage facilities are connected locally within the Energy Hubs. Electric Vehicle (EV) charging, and hydrogen re-fuelling demands are modelled within energy hubs. In

addition, utilisation of EV batteries for electricity supply and demand balancing through Vehicle-to-Grid (V2G) services was modelled (a description of these processes and interactions with the transport model outputs is given in Section 2.4).

The spatial and temporal disaggregation provided within the model allows detailed analysis of future energy supply systems under various strategies such as integration of large capacity of renewables, expansion of community and distributed generation and benefits of storage including V2G services. Key outputs from the model include the energy supply mix, emissions and cost of operation at various scales (transmission, distribution etc.).

2.2. Energy demand model

Future energy demand is simulated using a national energy demand model produced by the Infrastructure Transitions Research Consortium (ITRC) [29]. Simulation is based on different socio-technical scenario assumptions such as population, Gross Value Added (GVA), technological efficiencies, changes in the technological mix per end-use consumption or behavioural change. Energy demands for each simulation year are projected relative to initial base year conditions (the year 2015 is chosen as the base year).

The energy demand model is based on a decomposition approach, distinguishing between residential, service and industry energy demands according to the Department for Business, Energy and Industrial Strategy (BEIS) for a total 28 end uses, 34 sectors and 7 fuel vectors [30]. For selected end uses such as heating, different technologies are configured. The model is a mixture of a top-down and bottom-up model, as end use demands are derived from national energy demand consumption statistics and specific load profile data per technology or end-use are provided at a disaggregate level [31].

A three-step process is utilised to obtain hourly and regional energy demand data. Firstly, national UK energy demand statistics are disaggregated to 391 local authority districts (LAD) based on different disaggregation factors. Secondly, future demand is projected relative to base year demands in a back-casting approach, where the uptake for each simulation year is based on scenario drivers according to changes in the dwelling stock, temperatures, technological efficiencies, the technology mix or behavioural change. Thirdly, regional annual demand

---

[1] Curtailments are the deliberate reduction in power output below what could have been produced, in order to balance energy supply and demand or due to technical - transmission/distribution or economic dispatch constraints.

data are disaggregated to hourly temporal resolution based on end-use and technology specific load profiles, which are collected from different measurement trial data. Specifically, for space and water heating, heating degree day[2] calculations are used for the disaggregation of annual to daily demand.

Sub-national non-residential gas and electricity demands [32] are used for calibration to improve the spatial disaggregation of non-residential energy demands of the simulation base year 2015.

2.3. Road transport model

The transport model used in this work is the second version of the strategic road transport model for Great Britain produced by the Infrastructure Transitions Research Consortium [33]. This is a road network model covering all major roads in Great Britain, with this network being superimposed on a zoning structure based on LADs. As part of the model development process a base year origin–destination (OD) road trip matrix was generated, allocated to the road network, and calibrated against traffic count data to provide a representation of initial traffic levels on all network links. The model can then be used to simulate changes in traffic levels in response to changes in population, economic activity, travel time and cost, using an elasticity-based framework. This involves calculating new traffic levels for each flow in the OD matrix using Eq. (5). These flows are then reassigned to the network using a probabilistic process based on the relative attractiveness of different route options in terms of time and cost.

$$F_{ijy} = F_{ijy-1} \left(\frac{P_{iy} + P_{jy}}{P_{iy-1} + P_{jy-1}} \right)^{\eta_P} \left(\frac{I_{iy} + I_{jy}}{I_{iy-1} + I_{jy-1}} \right)^{\eta_I} \left(\frac{T_{ijy}}{T_{ijy-1}} \right)^{\eta_T} \left(\frac{C_{ijy}}{C_{ijy-1}} \right)^{\eta_C} \quad (5)$$

where F_{ijy} is the flow between origin zone i and destination zone j in year y; P_{iy} is the population in zone i in year y; I_{iy} is the GVA per head in zone i in year y; T_{ijy} is average travel time between zone i and zone j; C_{ijy} is average travel cost between zone i and zone j; η is a demand elasticity.

The assignment of flows to the network leads to changes in travel time and cost on individual network links as a result of changing congestion levels. The relative costs of different route options for each flow are then recalculated based on these updated times and costs, and the new flow times and costs are fed back into Eq. (5) to further alter traffic levels. The model produces a range of outputs which include the amount of energy consumed for each trip, covering all road vehicle power sources (including electricity and hydrogen). EV charging and hydrogen re-fuelling is determined by an energy-transport module, which is described in Section 2.4.

Several 'scenario' variables can be prespecified at the start of the model run, including changes in the relative fuel efficiency of vehicles over time, and the proportion of vehicles powered by different fuels in each future year. This allows investigation of the impacts of changes in vehicle fuel efficiency and power source on outputs such as energy consumption and carbon emissions. The outputs can be disaggregated to various levels of spatial detail, with energy consumption reported at the LAD level.

2.4. Coupling of energy and road transport system models

The energy supply model is soft-linked with the national energy demand [29] and road transport models [33]. The data inputs, outputs and flows between each model are illustrated in in Fig. 3.

2.4.1. Energy demand – energy supply link (excluding energy demand for transport)

The energy demand model uses population, GVA, dwelling floor area, and temperature to calculate heating and non-heating (excluding transport) end-use energy demands for residential, commercial, and industrial consumers. These energy demands are calculated by LAD in hourly resolution throughout the year (8760 hours). These are aggregated spatially and temporally and are inputs into the energy supply model (see Section 2.2 for description of the energy demand model).

2.4.2. Transport – energy supply link via energy demand for transport and vehicle to grid (V2G)

The transport model requires population, GVA, fuel prices, engine type proportions (e.g. 50% battery electric, 30% hybrids and 20% internal combustion) and changes in vehicle fuel efficiency as inputs. Using these inputs, the transport model provides the number of vehicle trips (disaggregated by engine type) and energy consumed (electricity and hydrogen) for each trip within each LAD during each hour across weekday and weekends during a year.

An energy-transport module was used to translate outputs from the transport model to electricity and hydrogen demand for transport, and the availability of electrical energy in EV batteries for V2G services. The energy-transport module assumed a trip to vehicle ratio of one, a high probability that most trips are local, and an electric car battery capacity of 30kWh. EV charging is modelled within the energy hubs in two ways, unmanaged and managed charging.

The energy consumed by a vehicle is translated to a daily energy demand for transport by summing across 24 hours. The hourly unmanaged EV charging and hydrogen re-fuelling demands are modelled based on published hourly charging patterns by National Grid [34] which takes into account the differences between weekdays and weekends (See Appendix-B).

The performance of EV batteries under different conditions and scenarios such as heating/cooling needs, start/stop at traffic lights, climbing up and downhill and frictional forces from tyres can be modelled. Detailed characteristics such as these require individual modelling of the EV batteries with respect to road conditions (rough, soft, and wet), terrain details and weather conditions. A whole energy system modelling approach with high spatial resolution requires compromises, as inclusion of such details would impact modelling complexity and substantially increase time to solution. Therefore, the study uses average characteristics for EVs and battery performance.

The unmanaged EV charging profiles from National Grid [34] represent both residential and public charging and hydrogen refuelling station demands for fuel cell vehicles over a typical day utilising hourly resolution. These profiles are normalised by the daily total EV charging and hydrogen re-fuelling demands. The total daily energy demands for transport from the transport model are superimposed on the normalised hourly profiles to produce the hourly electricity and hydrogen demands for transport and are used as inputs to the energy supply model.

Modelling of managed EV charging does not use a fixed profile as described in the unmanaged charging case. Here, a decision variable is defined for the EV charging demand, which is summed over a 24-hour period and equals the daily EV charging demand from the transport model. Smart/managed charging assumes that EVs charge when there is plentiful renewable electricity available, for example during off-peak periods and when electricity generation costs are low.

With managed/smart charging applied, V2G services can be enabled. An average EV battery capacity of 30kWh was assumed and at a given time t, it was assumed that 20% of stationary vehicles provide the vehicle to grid services at a power output of 7 kW [20]. The electrical energy stored in EV batteries at time t $\left(E_{e,t}^{EV,store} \right)$ is described by Eq. (6). This includes electrical energy flows from vehicle to grid ($E_{e,t}^{V2G}$) and grid

---

[2] A rigorous method of mean degree 'hours' [41] was utilised to determine Heating Degree Day (HDD). HDD is a measurement designed to quantify the demand for energy required to heat a building. Heating degree days are defined relative to a base temperature; the outside temperature above which a building needs no heating (15°C in EU). The heating requirements for a given building at a specific location is directly proportional to the number of HDD at that location. Accuracy of modelling HDD was enhanced by using detailed end-use technology profiles [29].

Table 1

Local decarbonisation options for heat, electricity, and natural gas/hydrogen supply in 2050.

Energy sectors within Energy Hubs	Heat decarbonisation options	
	1). Electric	2.) Multi-vector
	E	E H₂ DH
Heat	• Heat is supplied completely by electricity using heat pumps, resistive heating, electric boilers, and hybrid heat pumps (combined electric heat pump and a gas boiler).	• Heat supplies are mostly from building level hydrogen boilers. • Homes without access to hydrogen supplies use heat pumps and hybrid heat pumps or are connected to a district heating network (supplied by biomass/biogas and fuel cell CHP units).
Electricity	• Distributed generation within the Energy Hubs is mainly from wind, solar photovoltaic (PV) with access to grid-scale battery storage systems. • Backup gas-fired generators are installed to compensate for the variability in wind and PV generation. • CHP units in district heating applications supply electricity as they produce heat (heat demand-driven CHP operation is assumed).	
Gas/Hydrogen	• Transmission grid supplies are available with limited gas storage facilities. • A large capacity of electrolysers is installed to produce hydrogen. • Hydrogen can also be produced via Steam Methane Reformation (SMR) with Carbon Capture and Storage (CCS). • Hydrogen production from SMR and electrolysers have access to hydrogen storage facilities. • Hydrogen is supplied via new hydrogen pipelines and re-purposed gas distribution pipes.	

Table 2

Assumptions used for vehicle engine type fractions (%) for transport decarbonisation options in 2050.

Engine type	1. Full electric option	2. Electric + hydrogen option
	E	E H₂
Car		
Battery Electric Vehicle	100	50
Fuel Cell electric vehicle	0	50
Van		
Battery Electric Vehicle	100	50
Fuel Cell electric vehicle	0	50
HGV		
Plug-in hybrid electric vehicle – diesel	25	25
Battery electric vehicle	75	25
Fuel cell electric vehicle	0	50

to vehicle ($E_{e,t}^{G2V}$), and the charging demand ($E_{e,t}^{transport}$).

$$E_{e,t}^{EV,store} = E_{e,t-1}^{EV,store} + \eta_e^{EV} \times \left(E_{e,t}^{G2V} - E_{e,t}^{V2G} + E_{e,t}^{transport} \right) \tag{6}$$

Here, η_e^{EV} is the efficiency of the EV battery. The charging demand $E_{e,t}^{transport}$ is the electrical energy required for trips. To ensure that this is not used to provide vehicle to grid $\left(E_{e,t}^{V2G} \right)$ power flows, an additional charging demand variable is introduced as grid to vehicle ($E_{e,t}^{G2V}$) which provides power flows back to the grid. The grid to vehicle and vehicle to grid electrical energy flows satisfy the following relationship (Eq. (7)) over 24 hours.

$$\sum_{t=1}^{24} E_{e,t}^{G2V} = \sum_{t=1}^{24} E_{e,t}^{V2G} \tag{7}$$

Using the assumption that only 20% of stationary EVs ($N_{stationary,t}^{EV}$)

provide vehicle to grid services at a power output for 7 kW per vehicle, Eq. (8) constrains the electrical energy flow between the vehicles and the electricity network at time *t*.

$$E_{e,t}^{V2G}, E_{e,t}^{G2V} \leq 7 \times N_{stationary}^{EV} \times 0.2 \tag{8}$$

The energy stored in the EV battery $\left(E_{e,t}^{EV,store} \right)$ at time *t* is constrained by the total EV battery capacity $E_e^{EV,store,max}$ as shown in Eq. (9).

$$E_{e,t}^{EV,store} \leq E_e^{EV,store,max} \tag{9}$$

3. Heat and transport decarbonisation options and strategies

The coupled energy-transport model was used to explore the impact of decarbonising heat and road transport on the GB energy system. Below we describe how heat and transport decarbonisation options for GB are defined and then combined to create cross-sectoral strategies.

3.1. Heat decarbonisation options

It is generally recognised that no single heat technology can provide the best solution for all consumers. A mix of technologies and options will need to be deployed to cater for diverse consumer requirements, numerous building types and conditions, and different local infrastructure provision and constraints [38].

Studies from the Committee on Climate Change [7], National Grid [9] and the National Infrastructure Commission [35] mainly focus on electric, hydrogen, and hybrid pathways to decarbonise the UK energy system. The pathways are polarised for the purposes of analysis and do not aim to capture the full complexity of systems. These pathways assist in the comparison of the strategic choice between a predominately hydrogen or electric energy system.

The local energy system decarbonisation options considered in this study were designed considering the use of low-carbon electricity and/or hydrogen to replace the consumption of fossil fuels. Two distinct decarbonisation options focusing mainly on heat were considered and are shown in Table 1. The two options are defined as: **1) Electric Option** that utilises low-carbon electricity through installation of heat pumps, hybrid heat pumps combining an electric heat pump with existing gas boilers, and resistive heating, and **2) Multi-Vector Option** that largely utilises hydrogen in boilers alongside bio-energy, hydrogen CHP units (fuel cells) and low-carbon electricity through heat pumps including hybrid heat pumps for heating.

3.2. Transport decarbonisation options

Decarbonisation of road transport was assumed through two contrasting technology/policy options: **1) Full Electric Option** where almost all vehicles are battery electric vehicles. **2) Electric + Hydrogen Option** where almost half of vehicles use hydrogen fuel cells and the rest are battery electric vehicles.

The narratives behind these transport technology/policy options are:

1. Full Electric Option: This describes a future where the efficiency of batteries increases at a rapid pace and their cost sees a similarly rapid reduction. This means that by 2030 electric vehicles comprise the vast majority of new passenger vehicle sales, by 2035 electricity is dominant for new vans, and by 2040 electric vehicles dominate the new HGV market as well. This alongside the continued imperative for substantial reductions in CO₂ emissions means that the government institutes a ban on the use of diesel and petrol cars and LGVs on public roads from 2050 and a similar ban for HGVs from 2053. A small residual fleet of diesel hybrid HGVs is assumed to remain on the road in the 2050s, now powered entirely by biodiesel, but these are rapidly withdrawn from service.

2. Electric + Hydrogen Option: This describes a future where hydrogen emerges as a viable and cost-effective vehicle fuel by around
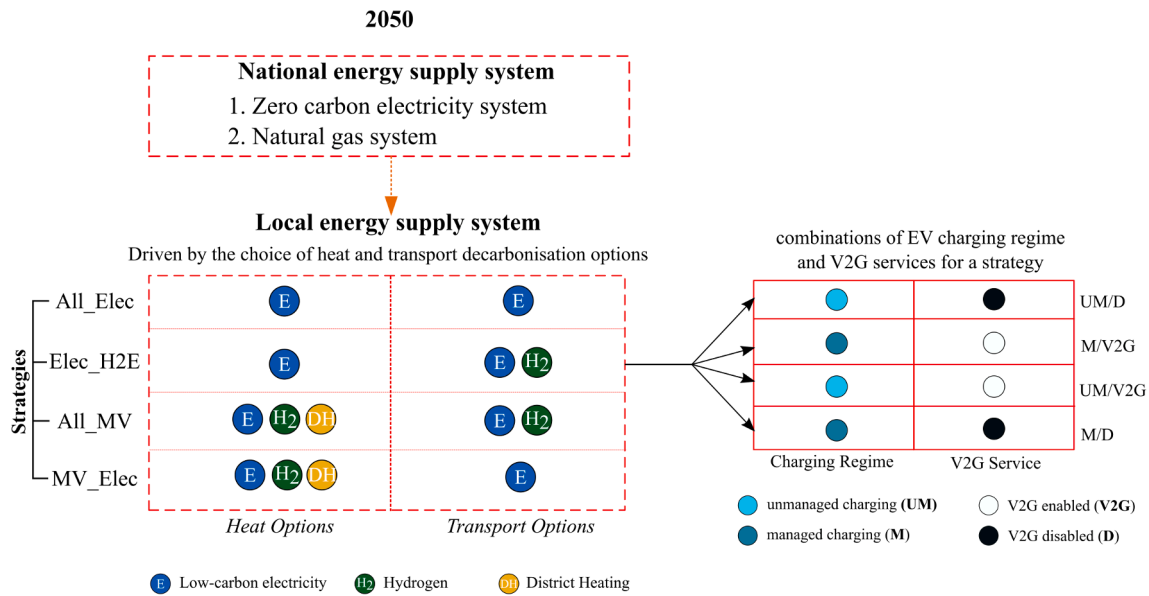
Fig. 4. (Left) Interaction between national (electricity and natural gas) transmission systems and local energy systems based on the heat and transport decarbonisation options, and (right) combinations of EV charging regime and V2G services for a strategy.

2035, meaning that by 2050 a significant proportion of the passenger and freight vehicle fleet is powered by hydrogen fuel cells. Battery development also continues to advance, meaning that electric vehicles also have an important role to play, but continuing cost and range-related challenges for both electric and hydrogen HGVs means that a residual fleet of plug-in hybrid HGVs remains in service in 2050.

The assumptions used for different vehicle engine type fractions under each transport decarbonisation option are shown in Table 2.

3.3. Definition of strategies

Strategies are defined by combining energy system (Table 1) and transport (Table 2) decarbonisation options as illustrated in Fig. 4 (left). Different combinations of unmanaged and managed (smart) EV charging and V2G services (enabled/disabled) were explored for each strategy and are illustrated in Fig. 4 (right).

The energy system and transport strategies are:

- **All Electric (All_Elec):** electrification of both heat and transport.
- **Electric heat + Multi-vector transport (Elec_H2E):** electrification of heating and electric and hydrogen transportation
- **All Multi-vector (All_MV):** multi-vector heating and transportation.
- **Multi-vector heat + Electric transport (MV_Elec):** multi-vector heating and electrification of transportation.

3.4. Energy supply capacities

The energy supply capacity data for the national electricity and natural gas transmission system was adapted from the Two Degrees National Grid Scenario [14] and the CCC's net-zero technical report [7]. The electricity transmission system includes generation technologies such as CCGTs, BECCS (Bio-energy with CCS), nuclear, offshore wind and electricity interconnectors. Negative emissions accrued through generation from BECCS [36] plants are able to ensure net zero emissions from the GB energy system in 2050.

The capacities in the energy hubs that represent local energy systems

were designed based on the strategy selected. The technology uptake across the Strategies were determined considering maturity and annual technology build rates [6,13,36,37]. In addition, the installed capacities were subjected to a capacity margin of 10% (de-rated) [39] in order to adhere to reliability concerns. Selected energy supply capacities are provided in Appendix-C.

4. Simulation of road transport and the energy supply system

4.1. Road transport

The transport model produced outputs for the base year of 2015 and the future year 2050 for the two transport decarbonisation options. With both options the model predicted substantial growth in road traffic, from just under 500 billion vehicle km per year in 2015 to 667 billion vehicle km in 2050 with the 'Electric + Hydrogen' option and 751 billion km with the 'Full Electric' option. This increase is driven mainly by population growth, with reduced fuel costs also meaning that there is additional use of vehicles in the 'Full Electric' option in particular. This means that transport demand management policies such as road user charging would be necessary in order to avoid substantial increases in congestion and journey times. In addition, with taxation revenues that are currently levied on petrol and diesel reducing to zero as these vehicles are phased out, there will likely be consideration of other means of taxing road users. Without such policies, the model estimates that link travel times could more than double at peak times with the 'Full Electric' option due to additional congestion, although in practice changes in travel behaviour (such as a shift towards more home and flexible working) and mode shift to public transport could mitigate these impacts. Unsurprisingly, given the scenarios tested, the model also predicts that there would be major changes in fuel consumption, with petrol and diesel consumption virtually eliminated by 2050, and growth in transport demand for electricity and hydrogen of up to 135TWh and 110TWh respectively, as shown in Fig. 5.

Fig. 5. (a) Annual heating and road transport energy demand by fuel prior to end use, (b) annual primary energy supply mix (c) annual electricity generation from the transmission and distributed generators (DG), (d) share of heat supplied by technology, (e) curtailed renewable electricity and discharged electricity from grid scale batteries across strategies in 2050.

4.2. Energy supply system

The coupled energy demand-supply-transport models were simulated for the year 2050. In the energy supply model, a simulation year comprised of four seasons, and each season was modelled by a representative week using hourly time series simulations.

The impact of heat and transport decarbonisation strategies on the operation of the energy system across EV charging methodologies with and without V2G services is analysed. Energy system operation, especially the impact on peak energy demand and flexibility, is assessed across these combinations.

4.2.1. Unmanaged electric vehicle charging

Electric vehicle smart charging and V2G services were disabled. The annual heat and road transport demand by fuel (prior to end use) for 2015 and across the strategies in 2050 is shown in Fig. 5a. It illustrates that energy demand for heating and transport is up to 50% lower in 2050

than in 2015. This is due to several factors such as efficiency improvements within homes (double glazing, cavity wall and loft insulation and smarter electronic devices) and in road transport vehicles, therefore a large reduction in overall heating and transport demand in 2050 is observed despite an increase in population.

Compared with other strategies, All_Elec has the lowest heat and transport demand (prior to end use), mainly due to the efficiencies expected from heat pumps. In strategies where hydrogen is required for heating (i.e. All_MV and MV_Elec), higher demands are observed as hydrogen boilers are not comparable with heat pumps from an efficiency perspective and with transport demand included the requirement for hydrogen can rise to as high as 400TWh in 2050. The simulations indicate nearly equal use of SMR and electrolysis to produce hydrogen. SMR produces hydrogen mainly during peak heating demand periods and when there is less availability of excess renewable electricity to produce hydrogen through electrolysis.

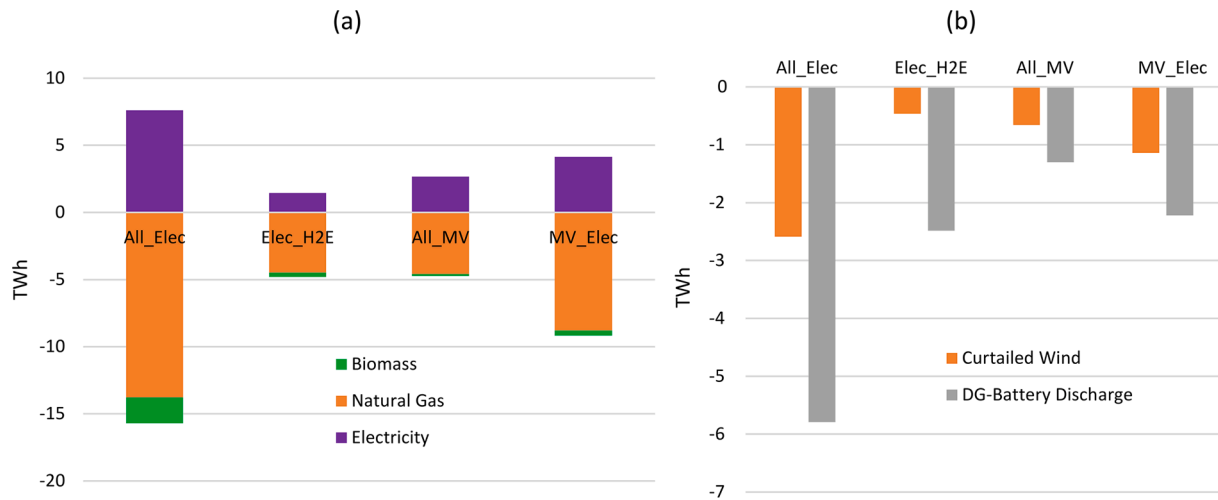Annual primary energy supply is projected to be between 25% and

Fig. 6. The changes due to the use of managed charging with respect to unmanaged charging for (a) annual primary energy supply and (b) annual renewable energy curtailed, and discharged energy from battery storage systems across all strategies in 2050 (no V2G utilised in all cases).
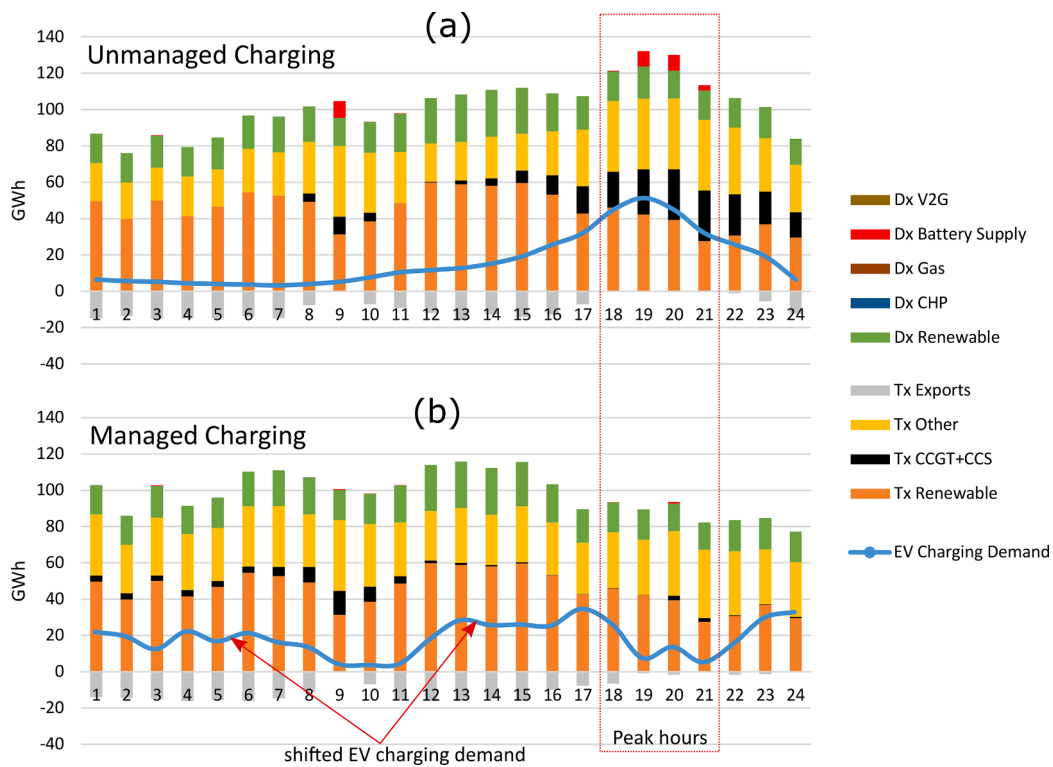

Fig. 7. Hourly electricity generation from the transmission system (Tx) and distributed generators (Dx) during a day in winter when a) EV charging is unmanaged, and b) EV charging is managed, for the All_Elec Strategy in 2050.

50% lower in all strategies in 2050 compared to 2015 as shown in Fig. 5b. Given the greater efficiency of electric vehicles and heat pumps compared to internal combustion engines and gas boilers, the All_Elec Strategy showed the lowest annual primary energy supply requirement of ∼ 800TWh. The multi-vector heating strategies (All_MV and MV_Elec) require greater annual primary energy supplies (>1000TWh) due to lower overall end use technology efficiencies (e.g. production of hydrogen for heating and transport).

Annual natural gas supply was approximately 793TWh in 2015. This is projected to reduce to less than 140TWh in strategies with the Electric heating option in 2050. It is highest in the All_MV Strategy reaching 270TWh mainly due to the significant use of natural gas in SMR to

produce hydrogen. Natural gas supplies are mainly imports (pipeline and LNG) given that by 2050 economically viable UKCS gas resources will have been largely depleted.

Electricity generation from the transmission and distribution system disaggregated by technology is shown in Fig. 5c. In 2015 annual electricity generation in GB was ∼ 300 TWh, which is projected to almost double across all the strategies in 2050 to over 600TWh. For the All_Elec Strategy, this is largely due to electricity demand from heating and transportation. Annual electricity generation is projected to be highest in strategies with the multi-vector heat option, mainly due to the requirement for production of hydrogen through electrolysis. In the All_Elec Strategy, the peak electricity demand (evening) is simulated at
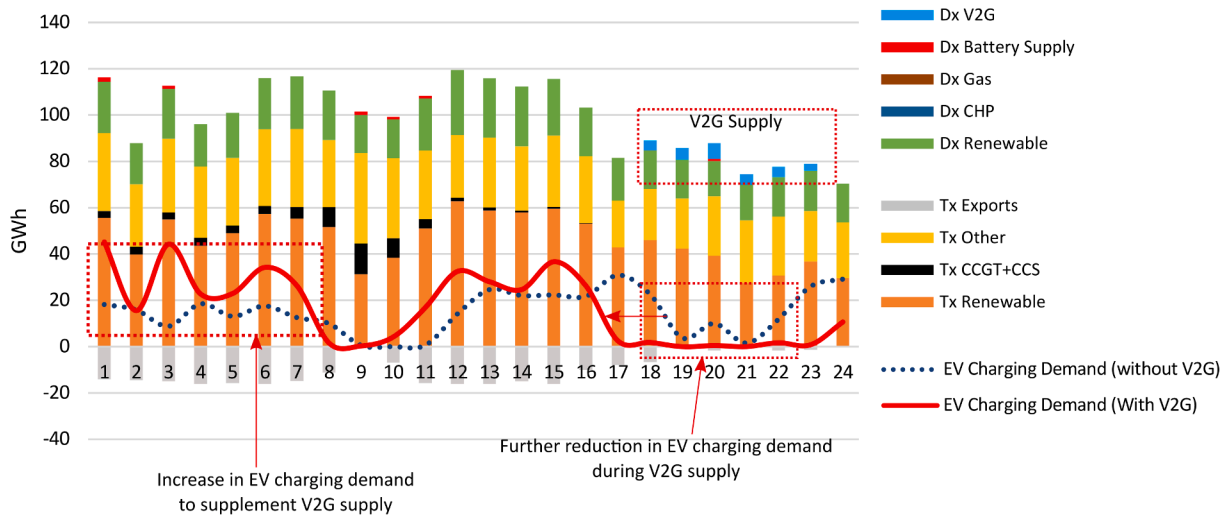
Fig. 8. Hourly electricity generation during a typical winter's day when managed EV charging with V2G services are enabled in the All_Elec Strategy in 2050.

around 120GW in 2050 compared with ∼ 55GW in 2015. The peak electricity demand in the other strategies is approximately 100GW.

In all strategies, annual electricity supplied through the transmission system is mainly from onshore and offshore wind, and nuclear, whilst gas fired generators with CCS are used to compensate for shortfalls in renewable generation in particular during peak heating and/or peak EV charging demand periods. Generation from BECCS plants is projected to average ∼ 23TWh in 2050 to offset residual CO_2 emissions across the strategies.

Annual nuclear generation is projected to be highest in the All_MV and MV_Elec strategies. This is due to large utilisation of renewables to produce hydrogen through electrolysis and therefore the requirement for increased nuclear generation to meet the electricity demand for other end-uses. Consequently, the curtailment of renewables in the system is lower compared to the All_Elec and Elec_H2E strategies. Annual interconnector imports are projected to average 70TWh across the strategies. Bi-directional interconnector flows are seen in all strategies where net flows are neutral over a year (i.e. exports equal imports).

The peak end-use heat demand is predicted to reduce from 230GW in 2015 to approximately 170GW during an average cold winter day in 2050 across the strategies. Heat supply by different technologies across the All_Elec and All_MV strategies is shown in Fig. 5d. The heat decarbonisation options illustrate the alternatives to meet the end-use heat demand using low-carbon electricity, hydrogen, bioenergy, and waste.

Grid-scale batteries were simulated to store excess renewable electricity during off-peak hours and discharge during peak hours. The renewable electricity curtailment and the total electricity discharged from grid scale batteries to balance the system is shown in Fig. 5e. The All_Elec and Elec_H2E strategies show the largest utilisation of grid-scale batteries to store mainly renewable electricity and where up-to 11TWh of electricity was discharged from batteries. Conversely, large renewable curtailments are observed in the All_Elec Strategy mainly due to lack of installed battery capacity which is fully utilised and network flow constraints. Renewable electricity curtailment is projected to be lowest in the All_MV and MV_Elec strategies. This is mainly due to the use of excess renewable electricity to produce hydrogen and utilisation of hydrogen storage facilities to store and meet large hydrogen demands in the system rather than using grid-scale batteries.

4.2.2. Impact of managed charging

The impact of managed charging (without utilising V2G services from EV batteries) on the operation of the energy system was investigated. The change in outputs compared to unmanaged charging (no

utilisation of V2G) across strategies are shown in Fig. 6 (+ve and −ve corresponds to either an increase or decrease in values).

Managed charging of EVs has the largest impact across the energy system when both heating and transportation is electrified as shown in the All_Elec strategy. In this case, EV charging occurs when there is plentiful renewable generation, and typically shifts away from peak electricity demand periods.

Primary gas supplies are projected to decrease across all strategies when managed charging is implemented (Fig. 6a.) In the strategies with Multi-vector heat decarbonisation option, managed EV charging results in increased use of renewable electricity for electrolysis, hence a reduction in natural gas supplies for hydrogen production.

Managed EV charging leads to a reduction in requirement for electricity generation from CCGT + CCS plants. In the All_Elec strategy, EV demand shifts to off-peak periods which enables a reduction in electricity generation from CCGT + CCS plants of up-to 6TWh mainly during the evening peak periods. This contributes to a 14TWh decrease in natural gas supplies and therefore associated CO_2 emissions. Compared to the unmanaged EV charging case the utilisation of renewable electricity increases across all strategies with managed charging. The All_Elec strategy shows the largest utilisation of additional generation from renewables at ∼ 15TWh annually.

Renewable curtailments are reduced as EV electricity demand is shifted to periods where excess renewable electricity is plentiful and therefore less is stored in grid-scale batteries across all strategies as shown in Fig. 6b. The largest reduction (5.5TWh) in electricity discharged from grid scale battery storage is seen in the All_Elec strategy.

Hourly electricity generation during an average day in winter for the All_Elec strategy is shown in Fig. 7. The unmanaged EV charging case is shown in Fig. 7a., and Fig. 7b. illustrates the managed EV charging case. V2G services are not utilised in both cases.

During the evening peak hour (7 pm) unmanaged EV charging adds approximately 50GW to the electricity demand. With low levels of renewable generation during the evening peak hour, CCGT + CCS plants ramp up to generate 25-30GWh electricity in addition to grid-scale batteries discharging up-to 10GWh of electricity. This is mainly because interconnectors are importing at maximum capacity and nuclear plants are not able to operate flexibly to ramp-up.

A managed charging scheme can shift EV charging demand from the evening peak hours to early morning and mid-day periods when there is plentiful electricity generation from renewables. However, to tackle variations in renewable electricity generation during these periods and the increase in demand from EVs, CCGT + CCS plants may be required to
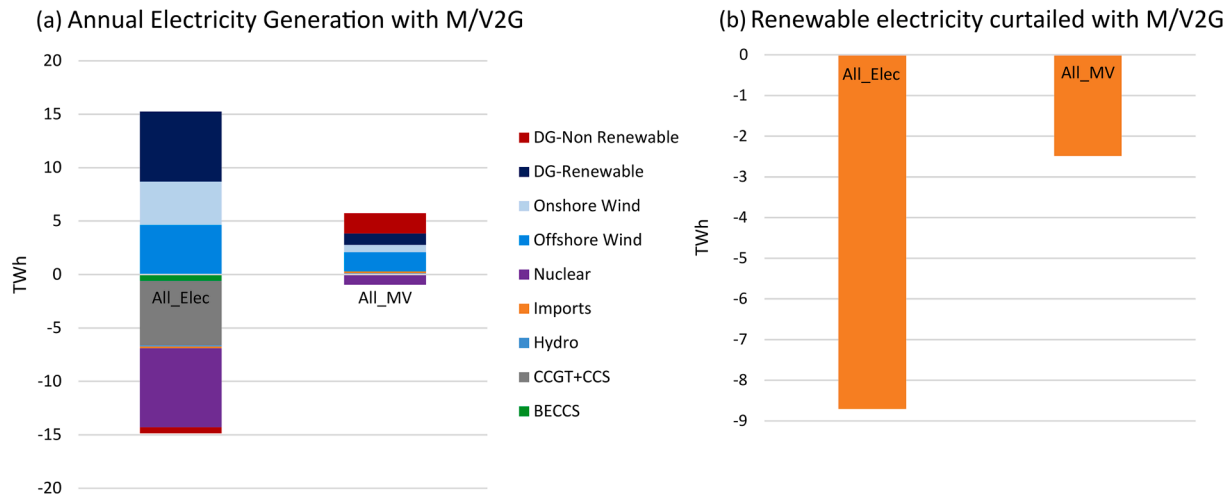
Fig. 9. The changes when V2G services are enabled in comparison with unmanaged charging without V2G for All_Elec and All_MV in 2050, for (a) annual electricity generation, and (b) renewable electricity curtailed.
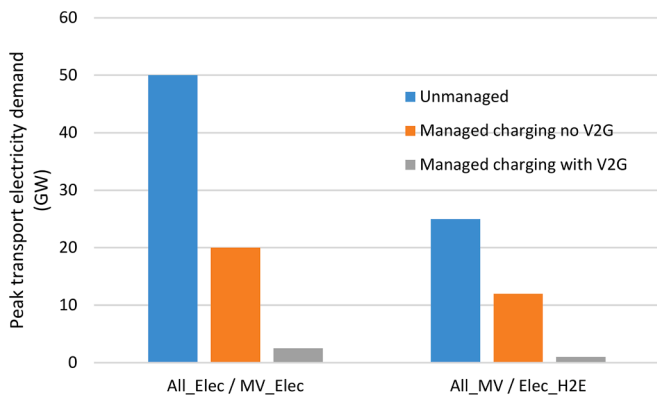

Fig. 10. Peak electricity demand for transport during the evening peak (7 pm) across (un)managed charging with/without V2G services in 2050.
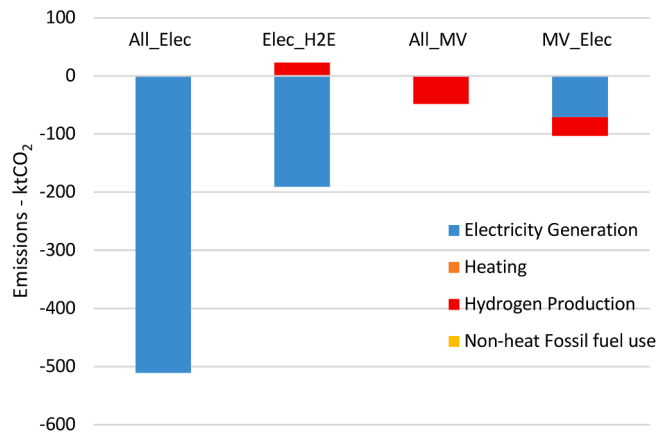

Fig. 11. Changes in annual CO_2 emissions due to managed charging with V2G compared to unmanaged charging without V2G across the strategies in 2050.

ramp up even though their overall utilisation is projected to decrease.

Reassignment of EV charging to match abundant renewable supplies is projected to result in a reduction in electricity exports of up to 12GW. Overall, in both managed and unmanaged cases interconnector flows are bi-directional throughout the day: i.e., exporting when there is plentiful renewables generation with low demand levels, and importing during peak hours.

The shift in EV charging demand and hourly electricity generation in MV_Elec is similar to the All_Elec strategy. One noticeable difference is that CHP units were ramped up instead of the CCGT + CCS plants to mitigate the variability of renewable electricity generation during EV charging demand periods. During these periods it is cheaper to ramp up already operating CHP units compared to starting up CCGT + CCS plants.

4.2.3. Vehicle to grid services enabled

The impact of managed charging on energy system operation whilst utilising V2G services through EV batteries was investigated. As expected, the potential of V2G electricity supply is higher in strategies with greater numbers of EVs. Utilisation of V2G services for All_Elec and MV_Elec strategies were upwards of 10GW of electricity supply during peak hours and 45TWh annually. Given the lower levels of transport electrification in the All_MV and Elec_H2E strategies, V2G supplies reduce to ~ 4GW during peak hours and 19TWh annually.

The hourly electricity supply during a typical winter-day in the All_Elec strategy with managed charging and V2G services enabled is shown in Fig. 8. It illustrates V2G electricity supply and reduction of EV charging demand during the evening peak hours. There is also an increase in EV charging demand during the late evening, mid-day and morning hours to supplement V2G supply at peak hours and to maintain sufficient state of charge in EV batteries for trips.

The impact on annual electricity generation due to managed charging with V2G (M/V2G) compared to unmanaged charging with no V2G in All_Elec and All_MV Strategies is shown in Fig. 9a. In addition, Fig. 9b. shows the change in renewable electricity curtailed due to the use of managed charging and V2G. Each figure shows the change (+ve and –ve) with respect to unmanaged charging without V2G.

In all strategies, when V2G is enabled the utilisation of renewable electricity increases. The increase in EV charging demand during mid-day, early mornings and late evenings is met by the excess renewable electricity available as overall electricity demand is low. In the All_-Electric Strategy the availability of excess renewable electricity is

Table 3
Total CO_2 emissions (MtCO$_2$) for all strategies under different EV charging and V2G options.

Charging mode and V2G option	All_Elec	Elec_H2E	All_MV	MV_Elec
Unmanaged charging without V2G	18.501	18.092	21.229	20.820
Managed charging without V2G	17.992	18.002	21.187	20.717
Managed charging with V2G	17.990	17.924	21.181	20.717

greater than in the All_MV Strategy where it is utilised to produce hydrogen. Consequently, in the All_MV strategy any remaining off-peak EV charging demand is met by ramping CHP technologies (non-renewable DGs in the figure) which are operating below full capacity.

The impact of V2G on the All_Elec Strategy results in a further reduction of transport charging demand during peak hours. In addition, V2G electricity supply also supports system balancing during peak hours. Consequently, this further reduces renewable electricity curtailed across all strategies beyond the levels observed with only managed charging. Therefore, the electricity generation from CCGT + CCS and nuclear plants at the transmission level, and non-renewable distributed generators (largely gas fired plants) are also reduced alongside electricity discharged from grid scale battery storage systems.

With unmanaged EV charging, transport electricity demand for Elec_H2E and All_MV strategies was approximately 25GW during peak (at 7 pm) and 57TWh annually, this compares with 50GW peak and 136TWh annually in All_Elec and MV_Elec strategies. The reduction in this evening peak transport electricity demand due to the use of managed charging and V2G services is shown in Fig. 10.

Implementation of V2G services encourages a large percentage of EVs that opted to continue charging during peak demand periods to shift to off-peak periods. Additionally, this makes available EV electricity supplies to the grid at peak periods.

4.2.4. Impact on CO_2 emissions
Annual CO_2 emissions[3] in 2050 when EV charging is unmanaged and without V2G services are projected to be lowest in the Elec_H2E strategy at 18 MtCO$_2$ and highest in the All_MV strategy at 21 MtCO$_2$. In the All_Elec strategy around 1MtCO$_2$ is due to the use of CCGT plants even though CCS is used (95% carbon capture rate). Similarly, large scale hydrogen production results in 2.2 MtCO$_2$ emissions annually in the

All_MV Strategy. The largest contributor of annual CO_2 emissions across all strategies was due to the remaining use of fossil fuels in industrial applications which averages around 17 MtCO$_2$.

The impact on CO_2 emissions due to managed charging of EVs with V2G was investigated across the strategies. The change in CO_2 emissions with respect to unmanaged charging without V2G is shown in Fig. 11.

Managed charging and the use of V2G directly impacts the CO_2 emissions from electricity generation (from CCGT + CCS and gas fired distributed generators) and from hydrogen production using natural gas. CCGT + CCS and gas fired distributed generators typically operate during peak hours as electricity from renewables fluctuates.

During periods of high electricity demand for heating (e.g. in All_Elec and Elec_H2E), electricity from renewables are mainly utilised through V2G to meet demand. This displaces the use of natural gas in peaking plants, hence the All_Elec strategy showed the largest reduction of emissions ~ 510 KtCO$_2$. In the Elec_H2E Strategy, renewable electricity is mainly used through V2G which results in a reduction of excess renewable electricity for production of hydrogen via electrolysis. Consequently, there is a minor shift towards SMR which leads to a ~ 23ktCO$_2$ increase in emissions. The cost of shifting hydrogen production to SMR (with CCS) is lower than operating gas fired generation at peak hours with the associated carbon emissions.

In contrast, when the overall electricity demand in the system for heating is lower (e.g. All_MV and MV_Elec strategies) renewable electricity is used and minor displacement of SMR with electrolysis is observed. This results in emissions reduction from hydrogen production of up to ~ 50ktCO$_2$.

A comparison of CO_2 emissions across all strategies with different charging and V2G options is presented in Table 3.The impact on CO_2 emissions is reflected in the use of BECCS plants to generate electricity and drive overall energy system emissions to net-zero, i.e. the larger the CO_2 emissions, the greater the requirement for electricity generated from BECCS plants. Therefore, the use of managed EV charging and V2G helps to reduce the electricity supplied from BECCS, particularly in the All_Elec strategy which leads to a ~ 110 million tonne reduction of biomass consumption annually.

4.2.5. Energy system strategy implementation costs
The annualised total costs of implementing energy supply solutions across energy strategies in 2050 are shown in Fig. 12. The operational
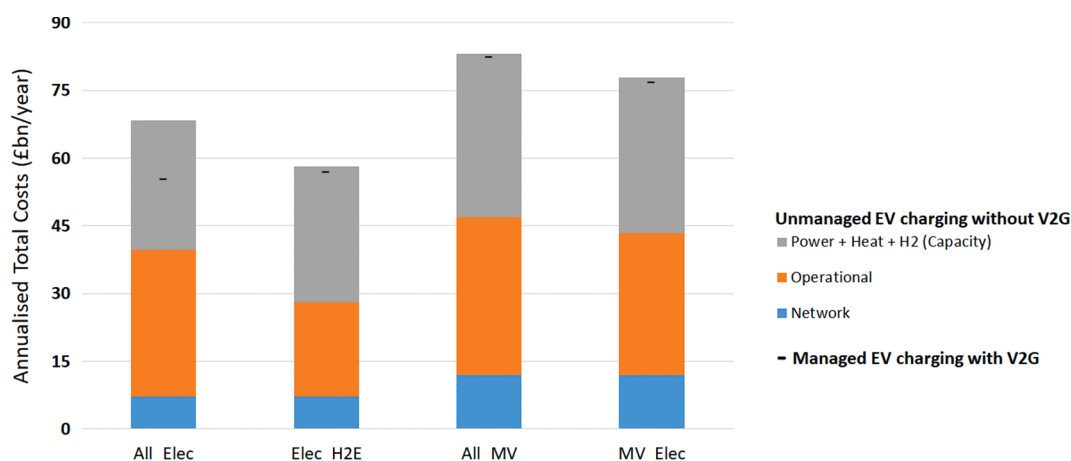

Fig. 12. Annualised (2050) total costs (Opex + Capex).

---

[3] All emissions reported in the manuscript are prior to balancing through negative emissions by electricity generated from BECCS plants to meet the net zero target.
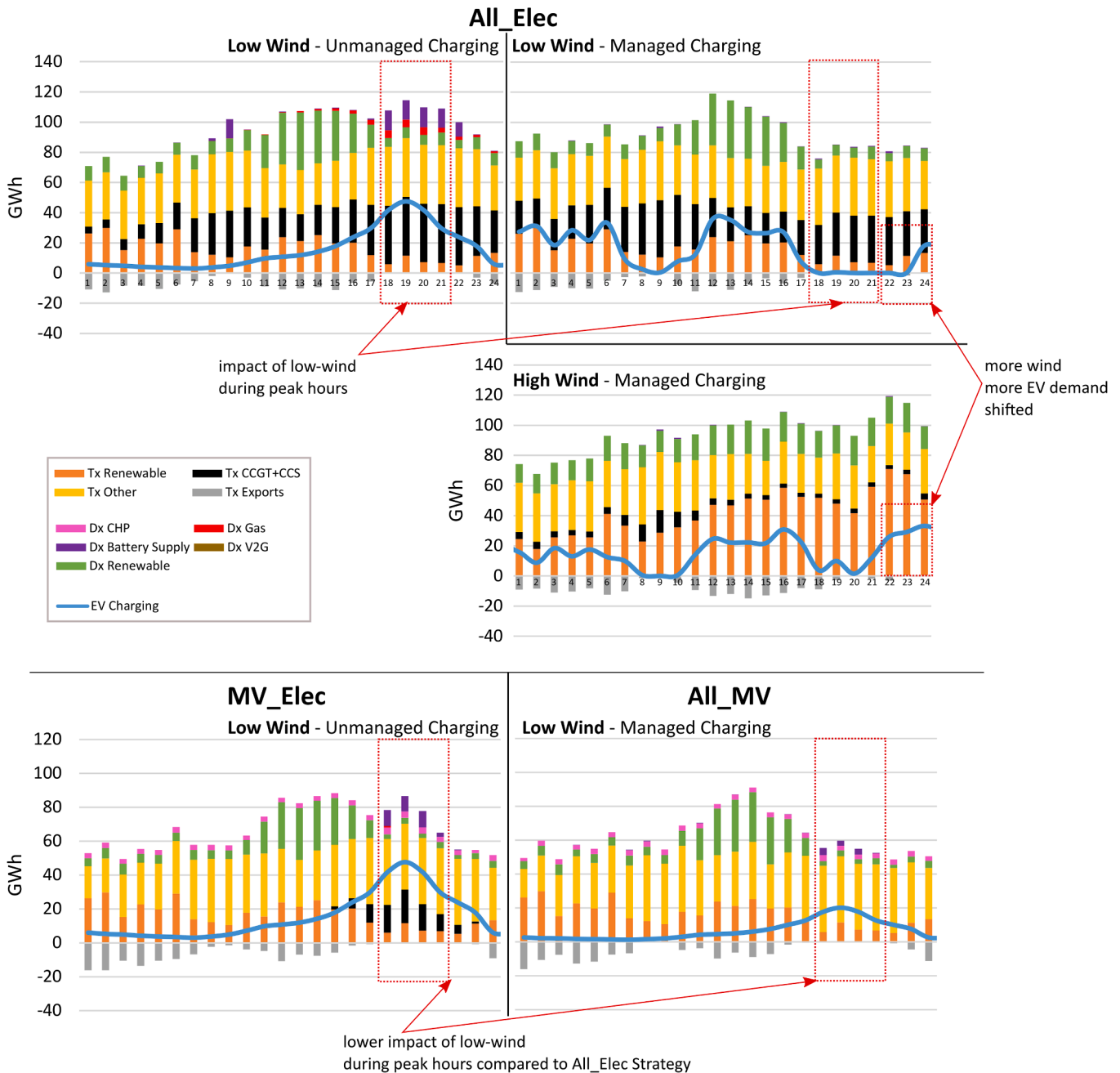
Fig. 13. Hourly electricity generation in All_Elec, MV_Elec and All_MV Strategies in 2050 across variable levels of wind generation and between managed and unmanaged EV charging regimes.

costs were determined by the model and include primary and secondary energy resources, generation of electricity and heat, variable and fixed operating costs, and carbon costs. Network costs such as for new power lines, pipes and investment in new power and heat generation capacities are included in the calculation of overall costs. Capital costs are annualised and take into consideration the economic lifetime of the assets. The bars in the diagram represent the system costs with un-managed charging and the hyphens illustrate the total costs with managed charging and V2G services.

a. Operational costs

The strategies with Multi-vector heat decarbonisation option, i.e. All_MV and MV_Elec are projected to incur similar annual operating costs to the All_Elec strategy. The operational costs of All_MV and MV_Elec strategies are mainly due to higher fuel resource costs

associated with producing hydrogen. In the All_Elec strategy high costs are due to greater requirement for gas supplies used in CCGT + CCS plants during peak periods which consequently attract carbon and gas supply costs whilst meeting the additional electricity demand from the transport sector.

Assuming unmanaged charging, operational costs are lowest in the Elec_H2E Strategy, where electric heating with a mix of electric and hydrogen transport decarbonisation options are applied. The system decarbonises mainly through the use of renewables, nuclear and biomass plants for the production of electricity supplying to highly efficient electrical heating systems and transport. The excess renewable electricity generation is used in the production of hydrogen through electrolysis to provide for the hydrogen vehicle fleet, and this reduces energy curtailments and therefore operational costs.
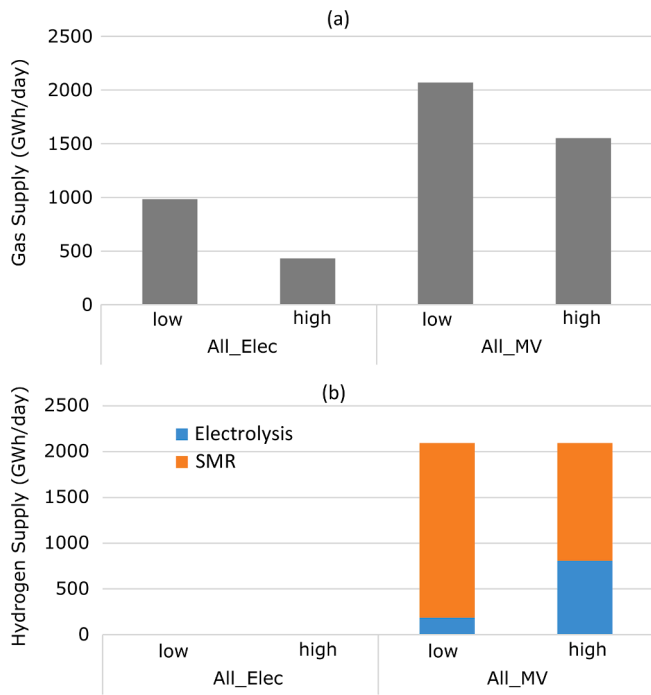
Fig. 14. (a) Daily gas supply, and (b) Daily hydrogen supply, subjected to low and high wind generation across Strategies for the unmanaged EV charging case in 2050.

connections (hydraulic interface units) within buildings are projected to remain high. Heat networks are deployed alongside biomass and waste CHP units and hydrogen fuel cells. It was also assumed that large sections of the gas distribution system would be repurposed for the use of hydrogen and therefore avoiding costs expected from laying new pipes.

c. Annualised total costs

The All_Elec and Elec_H2E strategies are projected to have the lowest annualised system implementation costs in 2050. This is mainly due to lower heat, power and hydrogen generation capacity and network expansion costs. Assuming unmanaged charging, the Elec_H2E strategy has the lowest annualised total costs at approximately £58 billion. Compared with the All_Elec strategy, the costs associated with the requirement for hydrogen capacity are more than compensated by lower operational costs as excess electricity generation from renewables is used to produce hydrogen. The multi-vector solutions (as in All_MV and MV_Elec Strategies) to meet net zero carbon emissions across heating and transport have the highest annualised total costs in 2050, approximately £24 billion greater than the least cost strategy, Elec_H2E. Given greater number of EVs in the All_Elec Strategy, the implementation of smart charging and V2G services maximises the utilisation of curtailed renewables and therefore reduces operational costs. This also lowers the capital outlay on generation and network capacity leading to approximately 16% reduction in annualised total costs.

5. Simulation of key sensitivities

5.1. Impact of wind variability

The impact of wind variability on electricity supply for heat and transport was analysed across a typical day in winter in 2050. The analysis explored the ability of the energy system to manage rapid changes in wind and during periods of high and low levels of wind generation.

The hourly electricity generation from transmission (Tx) and distributed (Dx) generation for unmanaged and managed EV charging (with no V2G services) for selected strategies are shown in Fig. 13.

In the All_Elec strategy, when low wind generation occurs during peak demand periods CCGT + CCS plants operate near their maximum capacity alongside distributed gas fired generators (small scale gas engines and turbines) and battery storage systems. In the All_MV and MV_Elec strategies, CHP units were ramped up instead of gas fired generators to compensate for low wind generation (as CHPs are already running and ramping them up would be cheaper compared to starting up CCGT/gas plants). However, the impacts of low-wind in the All_MV and
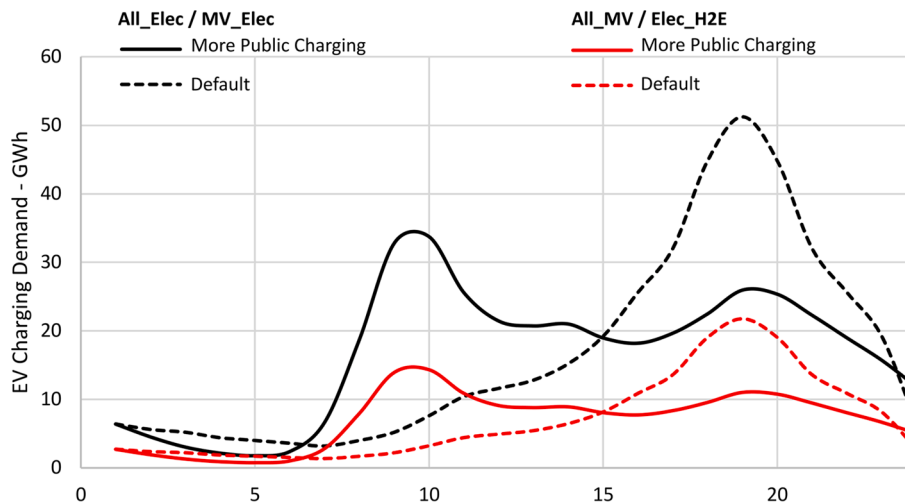
b. Network and supply technology capacity expansion costs

Costs associated with power, heat and hydrogen capacity are largest in the All_MV and MV_Elec strategies. This is mainly due to the use of expensive CHP (biomass, waste) systems and the requirement for large hydrogen production capacity to meet the demand for heating and transport.

The All_Elec strategy has the lowest power, heat, and hydrogen capacity costs. This is in part due to the reductions expected in heat pump capital costs from 2030s onwards and lack of requirement for hydrogen production capacity.

Network related costs in the All_MV and MV_Elec strategies are approximately 50% greater than the All_Elec and Elec_H2E strategies. This is mainly due to the implementation of heat networks where costs related to civil engineering works (digging trenches approximately three times deeper than electricity/gas lines and pipes), pipe deployments and

Fig. 15. Hourly EV charging demand with more public charging (solid lines) compared to the default residential charging (dashed lines) for the strategies in 2050.
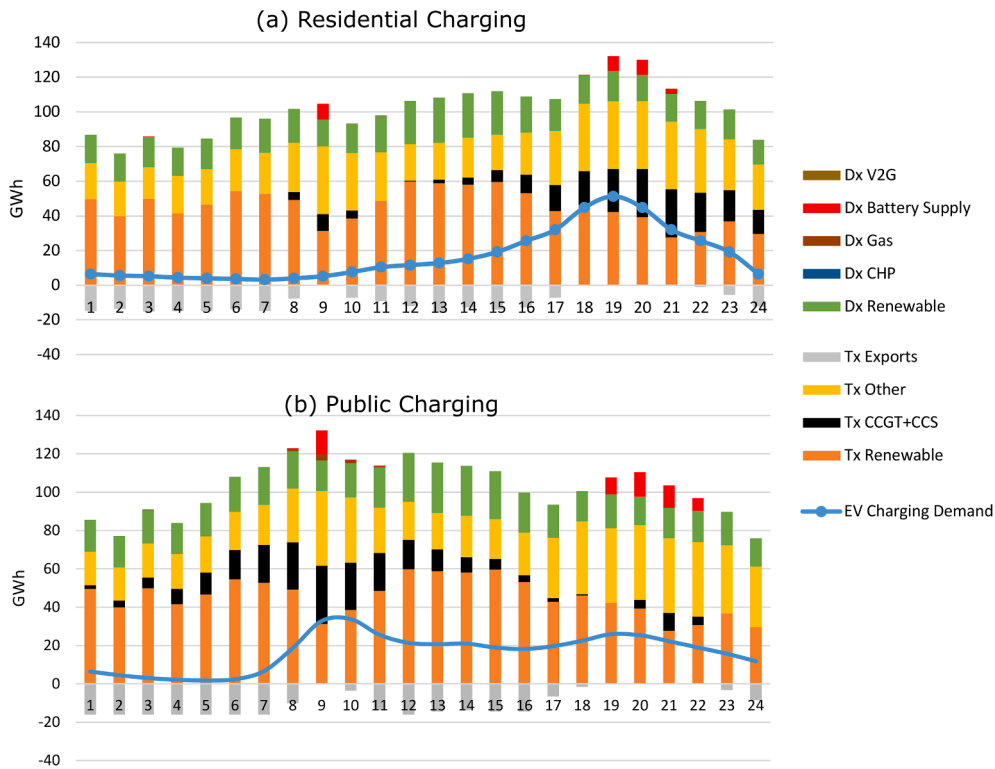
Fig. 16. Hourly electricity generation mix in the All_Elec Strategy in 2050 with a) default residential EV charging, and, b) increased public fast charging.
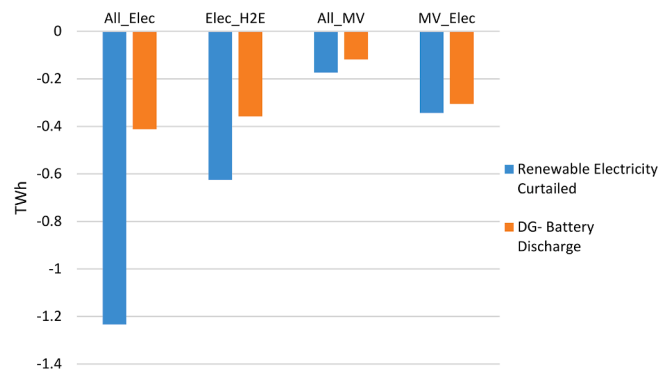

Fig. 17. Change in renewable electricity curtailed and electricity discharged from battery storage systems due to the use of V2G services with increased EV battery size compared to the default battery size assumption (M/V2G) in 2050.

MV_Elec strategies on electricity generation during peak hours were comparatively lower than in the All_Elec strategy regardless of EV charging regime. This is mainly due to the lower overall electricity demand (heating + transport) in All_MV and MV_Elec Strategies.

Implementation of managed charging was able to reduce the impact of low wind generation through the reduction of peak electricity demand (in the evening) by shifting EV charging to periods where excess wind generation was available. It was shown in the All_Elec strategy that whilst CCGT + CCS plants were still required to operate throughout the day given the large electricity demand from heating, the use of distributed gas fired generators and grid scale battery storage supply was reduced. In the All_MV and MV_Elec strategies, operation of CCGT + CSS plants was not necessary during peak demand hours. In all strategies, an increase in exports was shown when there is overall high wind

generation in the system and particularly during periods with low electricity demand from EVs.

In the All_Elec strategy, the daily natural gas supply was on average 430 GWh when there is plentiful wind generation and low use of gas fired plants. However, prolonged periods of low wind generation results in an increase in daily natural gas demand to 983GWh during a typical winters' day. The variations in daily gas and hydrogen supply across strategies and for low/high wind generation is shown in Fig. 14.

In All_MV and MV_Elec strategies, low wind generation causes an increased production of hydrogen using SMR and therefore a greater requirement for natural gas supplies. However, when there is plentiful wind generation, the gas supply for hydrogen production reduces as electrolysis is utilised. Additionally, the variability of wind generation increases the use of hydrogen storage systems to accommodate the
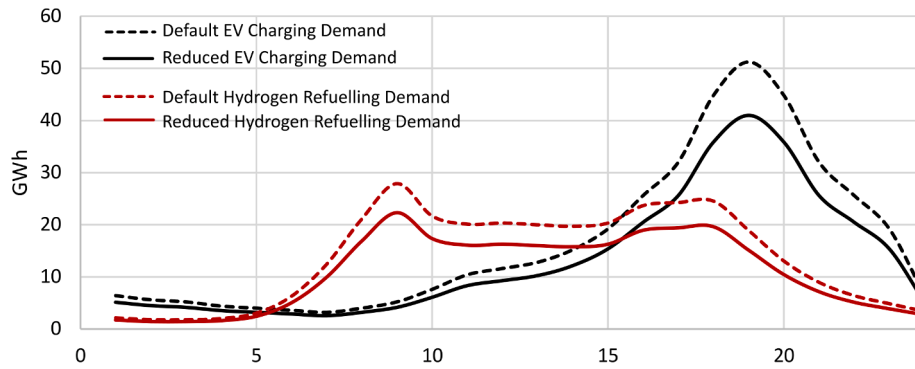
Fig. 18. Reduced (solid line) hourly EV charging demand for the electric transport decarbonisation option and hydrogen vehicle refuelling demand, in comparison to default (dashed lines) demand patterns in 2050.
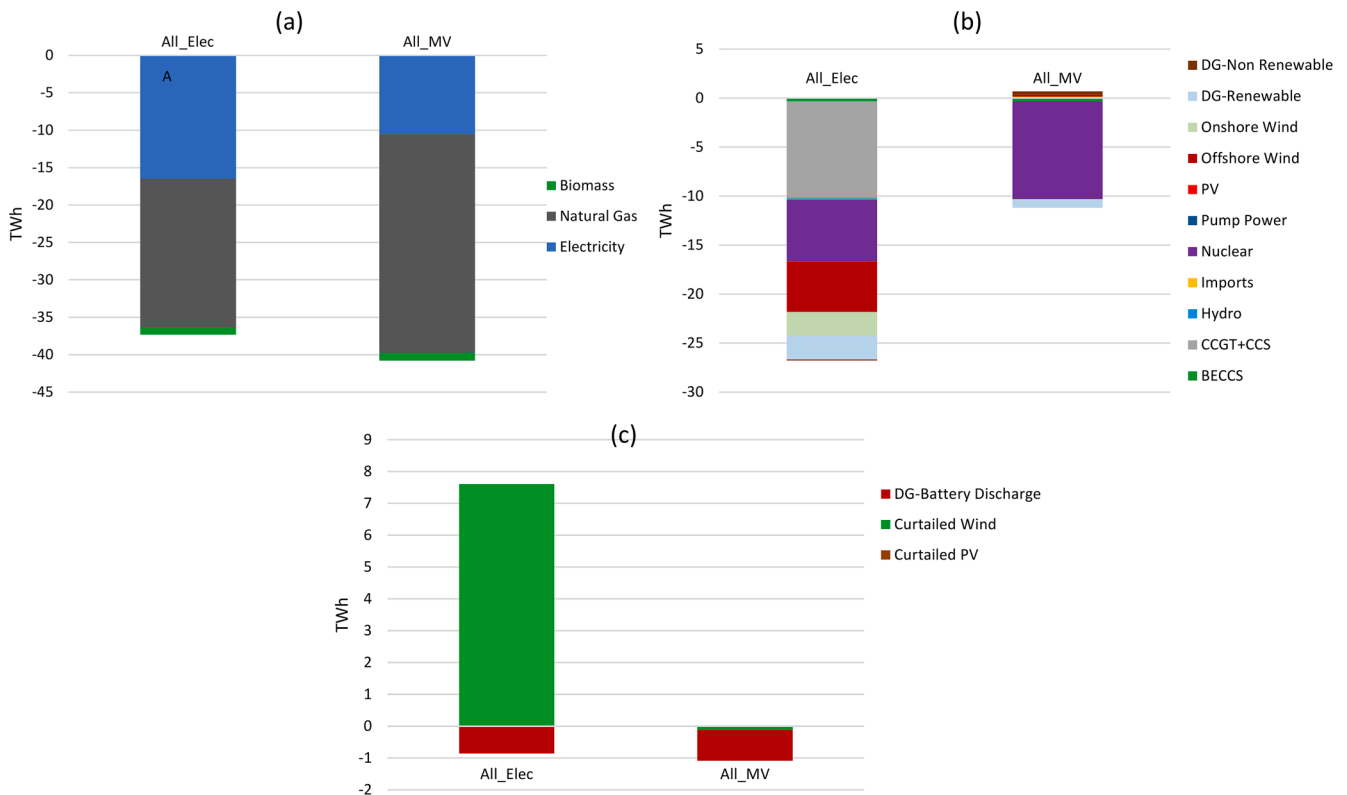

Fig. 19. Impact of transport energy demand reduction in 2050 on: (a) primary energy supply, b) annual electricity generation, and c) annual renewable electricity curtailments and electricity discharged from batteries.

change in hydrogen production (electrolysis to SMR and vice versa) and balance the system at lowest operational costs.

5.2. Impact of increased public (fast) EV charging

The default modelling assumption is that 90% of daily EV charging occurs at residences/workplaces with the remainder at public fast charging stations. The impact of an increase in EVs utilising public fast charging infrastructure was analysed. For this, approximately 30% of daily EV charging demand was assumed from public fast charging stations, and the remainder from slower charging at workplaces and residential settings. Additionally, the requirement for fast charging is sufficiently met by the power grid capacity which includes transmission network lines and bus bars, and total network capacity within Energy Hubs which were sized according to the peak demand in the system ~ 120–130 GW in 2050.

It was assumed that residential and workplace charging utilises a 7 kW connection, whereas public charging stations use a 22 kW connection [20]. The residential/workplace and public EV charging curves were based on the analysis by National Grid [34].

The change in hourly EV charging demands (unmanaged) due to more public charging across strategies is shown in Fig. 15. Greater public fast charging results in a 17GW reduction in peak electricity demand from EVs combined with a shift in the peak period from early evening to mid-day in the All-Elec and MV_Elec strategies. A similar charging pattern is observed in the All_MV and Elec_H2E strategies albeit with smaller peak charging demand.

The impact of increased public fast charging on hourly electricity generation in the All_Elec Strategy is shown in Fig. 16. Given the high electricity demand in the system for heating, the addition of more public fast charging requires backup CCGT + CCS plants and distributed generators to operate and grid-scale batteries to discharge up to 12GW when

generation from renewables is low. Overall, there is a 3TWh decrease in the use of CCGT + CCS plants leading to a reduction in annual gas supplies and associated CO_2 emissions.

The increase in public charging during the morning-midday period increases the utilisation of renewables. The largest reduction in curtailments of renewables (5TWh) occurs in the All_Elec strategy and leads to a 150 GWh decline in annual interconnector exports.

The largest impact on emissions and operational costs occurs in the All_Elec strategy, as increased public charging results in an annual reduction of 250ktCO$_2$ emissions and £ 650 million in operating costs.

5.3. Impact of increased battery size

The impact of changing average vehicle battery size from 30kWh to 80kWh in 2050 on V2G services was investigated. The increase in battery size leads to an increase in peak V2G supply from 10GW to 27GW in the All_Elec strategy. For the All_MV Strategy, there is an increase in V2G supply from 4GW to 11GW. The increase in battery size increases the potential annual V2G electricity supply to ~ 85TWh in the All_Elec strategy and 33TWh in the All_MV Strategy.

The change in renewable electricity curtailed and discharged electricity from grid scale batteries due to the increase in V2G supply across strategies compared with the default battery assumption with managed charging and V2G is shown in Fig. 17. The increase in battery size enables increased utilisation of electricity supply from renewables. The largest change is shown in the All_Elec strategy which utilises additional renewable electricity and reduces curtailments by ~ 1.2TWh. The large increase in V2G supply during peak hours reduces the need to operate nuclear and CCGT plants in all strategies. In addition, generation from BECCS plants is reduced and therefore lower annual biomass supplies are required. As EV batteries act as storage systems, the use of grid-scale batteries to supply electricity is largely reduced across all strategies. Electricity stored in EV batteries is also supplied to produce hydrogen in the All_MV and MV_Elec strategies leading to reciprocal reduction in hydrogen production using SMR. The All_Elec strategy showed the largest reduction of ~£10 million in operating costs due to the increased use of EV batteries as storage and to supply electricity during peak hours. Other strategies showed on average ~£5 million reduction in operational costs. The overall reduction in costs are low as the comparison assumes both battery sizes utilise an optimised (managed) charging regime. A bottleneck that potentially impedes further cost benefits from increased battery capacity is the 7 kW connection interface assumed in the modelling for residential properties. This constrains the instantaneous power exchange between the grid and the battery.

5.4. Lower demand for transportation

It was assumed that changes in travel behaviour and associated activities, such as an increase in home working, could result in a 20% reduction in road transport energy demand by 2050. This reduction was applied to both EV charging and hydrogen vehicle refuelling demands. The default and reduced electricity (unmanaged) and hydrogen demand patterns for road transport are shown in Fig. 18.

A 10GW reduction is shown in the peak EV charging demand in the strategies that use the Electric transport decarbonisation option. Annually this results in a 27TWh reduction in electricity demand. A 5.5GW and 22TWh reduction in peak and annual hydrogen refuelling demand is observed in strategies that use it as a transport decarbonisation option.

The impacts on the energy system due to a reduction in transport energy demands across strategies are shown in Fig. 19. The reduction in transport energy demand (electricity and hydrogen) results in decreased utilisation of CCGT + CCS plants and distributed gas fired generation across all strategies. Additionally, the utilisation of renewables

decreases leading to an increase in curtailments mainly in strategies with electrical heating systems.

The excess renewable electricity in the system is utilised in the strategies with Multi-vector heat decarbonising option to produce hydrogen using electrolysis. The reduction in hydrogen demand for transport in the All_MV strategy results in a large reduction of hydrogen produced through SMR. Decreased use of gas fired generators and SMR to produce hydrogen results in a reduction in annual gas supplies across all strategies.

The largest CO_2 emissions reduction averaging 260 ktCO$_2$ annually was observed in the All_Elec and All_MV Strategies. The operational cost savings are greatest at ~£8 billion in the All_Elec Strategy. This was due to the reduced use of gas fired peaking plants (including the distributed gas fired generators), associated gas supplies and carbon costs. Other strategies showed a reduction in operating costs averaging £1.5–2 billion/year.

6. Discussion and conclusions

In the UK heat accounts for approximately half of all energy demand and has often been described as the 'Cinderella' of energy policy. Interest in heat has grown and recently the UK government have made it a priority to decarbonise the sector to meet the net zero carbon emissions target by 2050. Alongside this the transport sector, which is now the largest carbon emitting sector of the economy, and in particular road travel will need to embrace low carbon alternatives such as electric and hydrogen vehicles. This paper explored the implications of ambitious decarbonisation strategies for heat and road transport that are required to meet net zero emissions in the UK. The performance of strategies focussed on electrification and multi-vector options to decarbonise heating and transport were analysed using an innovative coupled energy and transport simulation modelling approach.

The analysis illustrates that improvements within homes and superior 'tank/battery to wheel' efficiencies for road transport results in 24–50% lower annual energy demands in 2050 compared to 2015 across all strategies despite an increase in population. The electrification of both heating and road transport has the lowest overall primary input energy supplies in 2050, mainly due to the efficiencies that are expected from heat pumps. The strategies where hydrogen is utilised for heating purposes, requires additional primary energy supplies as hydrogen boilers have much lower energy efficiencies than heat pumps. When hydrogen vehicles are added the requirement for hydrogen supply increases to 400TWh annually. Natural gas supplies are projected to decline in all strategies to as low as 125 TWh in 2050, a greater than 80% decline from 2015. Where hydrogen plays a large role in heating the decline in gas is not as profound, as steam methane reformation (with CSS) is required to produce hydrogen.

Electricity maintains a prominent role in the energy supply mix regardless of strategy either due to large increase in demand or renewable electricity utilisation for electrolysis in the production of hydrogen. Annual and peak electricity demand are projected to more than double in 2050 compared with 2015 especially when both heat and transport are electrified.

Renewable capacity (including distributed renewables) is expected to grow dramatically in 2050, nearly a 10-fold increase from 2015 levels in a net-zero energy system where total renewable generation is projected to be over 400TWh regardless of the strategy. Given the variability of renewables, interconnector imports, BECCS and CCGT + CCS plants contribute to the balancing of supply and demand. Electricity generation from BECCS plants accounts for negative CO_2 emissions and therefore ensures net zero emissions are met nationally and is lowest in strategies with electrification of heat and road transportation is a mix of electric and hydrogen fuel-cell vehicles.

The use of excess renewable electricity to produce hydrogen during off-peak hours and storing it in hydrogen storage results in minimal renewable electricity curtailments. When both heating and transport is electrified a large capacity of grid-scale battery storage is required to reduce renewable energy curtailments. The implementation of a managed charging scheme reduces renewable energy curtailments by 16% and could be further reduced by an additional 10% through the utilisation of V2G services. Combining managed charging and V2G services also enables reduction in electricity peak demand. These actions result in decreased use of peak gas fired generators and therefore reduction in emissions, and operational and capital costs for infrastructure which is most noticeably seen with the electrification of both heat and road transport.

The impact on system operation during periods of low and high wind in 2050 could be greatly reduced through implementation of managed charging where EV charging is shifted to periods where there is plentiful wind generation. In strategies with Multi-vector heating systems, during low wind periods SMR is used to produce hydrogen, and the reverse in high wind periods where wind generation is used to produce hydrogen through electrolysis leading to a reduction in wind curtailments and costs.

Faster charging of EVs enabled more efficient utilisation of renewable energy supplies and a corresponding reduction in operating costs. It is often said the 'most sustainable energy is the energy you don't use' which is borne out by analysis of the impact of lower transportation demand on the energy system, which showed large reductions in annual and peak demands resulting in operational cost savings and consequently lower requirements for energy infrastructure especially for electricity generation and hydrogen production capacity. An increase in the assumed EV battery size was shown to more than double the available peak V2G supplies in 2050 across all strategies.

From a strategy implementation cost perspective, the electric heat and transport and (to a lesser extent) the strategy with electric heat and mix of electric and hydrogen transport are shown to be the lowest across a subset of sensitivities and EV charging methodologies. Operationally, multi-vector heat solutions are competitive and with learning over time there could be reductions in capital cost assumptions for CHPs, hydrogen production technologies and heat/hydrogen networks.

The analysis illustrates the importance of utilising an integrated systems approach which encompasses both energy and transport technologies and policies. A path to a hydrogen future faces many obstacles, as consumers will not purchase vehicles in large numbers until they are cost competitive, and the fuel is widely available. Meanwhile, fuel suppliers and producers will not provide fuel and the accompanying infrastructure if fuel cell vehicles are not widely available. This is a conundrum that is facing the industry and requires governments and industry to work in partnership to accelerate learning and therefore reduce costs and increase technology uptake.

Hydrogen could play a major role in the energy sector transformation and decarbonisation. Hydrogen was also shown to enable large scale renewable integration by providing a means of short and long-term energy storage and can serve as a buffer to increase overall energy-system resilience. If hydrogen is widely used for heating, with the existing gas network repurposed for hydrogen transport, it could provide a cost-effective means of distribution to vehicle fuelling stations.

Legacy energy supply infrastructure could play a crucial role in the availability and cost competitiveness of certain heating technologies. For example, retrofitting buildings with hydrogen boilers that are not connected to the gas grid might not be cost-effective as this would require laying of new hydrogen pipes. Additionally, the availability of low carbon and cheap sources of heat such as waste heat from industries could substitute for electricity or hydrogen heating.

Among the strategies analysed in this paper, the electrification of heating and road transport is the most cost-effective way to reduce emissions. Smart vehicle charging was shown to greatly reduce the impact on operating the electrical system and increase the utilisation of renewables. This, in turn, would reduce the requirement for electrical infrastructure. There are several policy questions that need to be addressed, including uncertainties regarding consumer behaviour and how companies could incentivise certain behaviours e.g., monetary inducements, tariff structure etc. Installation of hydrogen boilers, heat pumps and EV charging sockets will require change in infrastructure at the end user level and will be disruptive to householders to varying degrees. The heat and road transport strategies analysed have high upfront capital costs. This is a barrier for early deployment, but decision makers and governments would need to implement processes to absorb these costs so that technological learnings (costs and efficiencies) can be made.

7. Future work

Several areas for future modelling work and analysis have been identified:

- The technological 'learning' process can potentially result in large increase in efficiencies and reduction in costs. For instance, production of hydrogen at large scale is currently expensive. However, ongoing trials for hydrogen production and carbon capture and storage technologies are expected to lead to cost reductions. Frequent analysis of the energy system is essential to ensure latest trends with regards to future technology costs and efficiencies are examined.
- Analysis of cooling demand especially beyond year 2050 will be required. It is likely that households will install an AC system due to increasing temperatures during Summer. This will impact peak electricity demand and therefore it will be important to include cooling demands in energy system studies. The potential use and benefits of tri-generation CHP technologies and reversible heat pumps will also need investigation under scenarios beyond year 2050 with warmer and colder climates.
- Transport system analysis should go beyond road vehicles (cars, vans, lorries) to include trams and trains. These mass transport modes could offer potential alternative system design opportunities (as opposed to road construction) and their impact on energy systems will differ.
- The current transport model cannot explicitly model holidays and vacation periods. It is important from a resiliency perspective to explore variations in transport demand and therefore the impact on the energy system.
- Detail modelling of EV charging infrastructure and its interaction with the power system such as increase in three phase connections is essential.
- The focus of this paper is the analysis of the 'energy' system - First Law of Thermodynamics. There are beneficial aspects to expanding this to include exergy analysis (Second Law of Thermodynamics) which could aid better design and evaluation of systems especially with the introduction of large amounts renewable and heat pump capacity.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgement

Appendix

A. Representation of GB gas and electricity transmission networks and energy hub regions

The representation of the electricity and natural gas transmission networks, and energy hub regions (EH_Region_Boundaries) used in the energy supply model is shown in Fig. A.1.
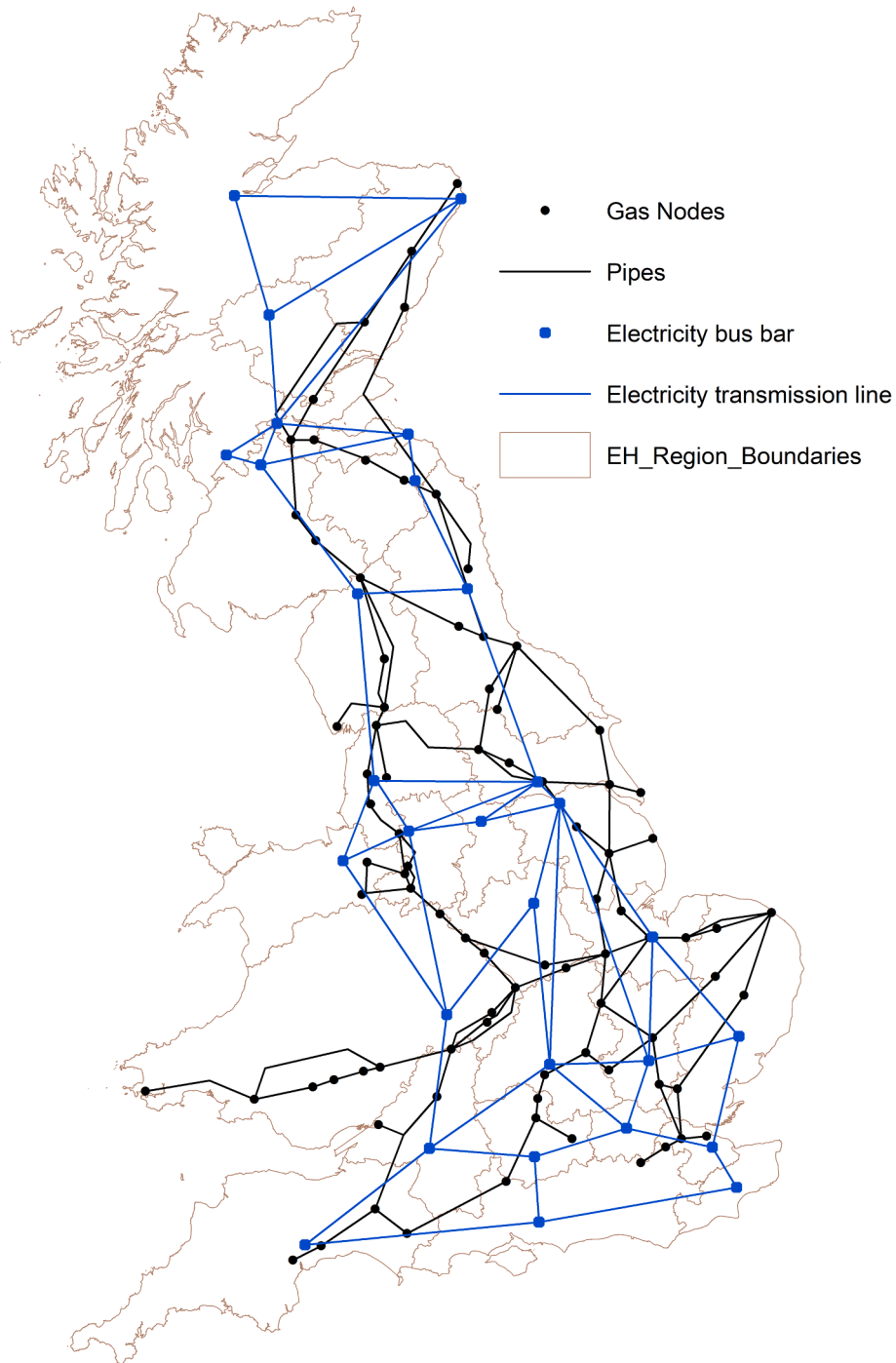

Fig. A1. Representation of the electricity and natural gas transmission networks and the energy hub region boundaries, used in the energy supply model.

B. EV and V2G modelling and assumptions

An energy transport module was implemented to assign EV charging profiles and hydrogen demand for transport and to determine the availability of electrical energy in EV batteries for vehicle to grid (V2G)

services. The number of EVs and trips at each hour and electricity consumed in the battery for each EV trip was used as inputs. The soft linked transport model [40] provides these inputs for the energy hub regions.
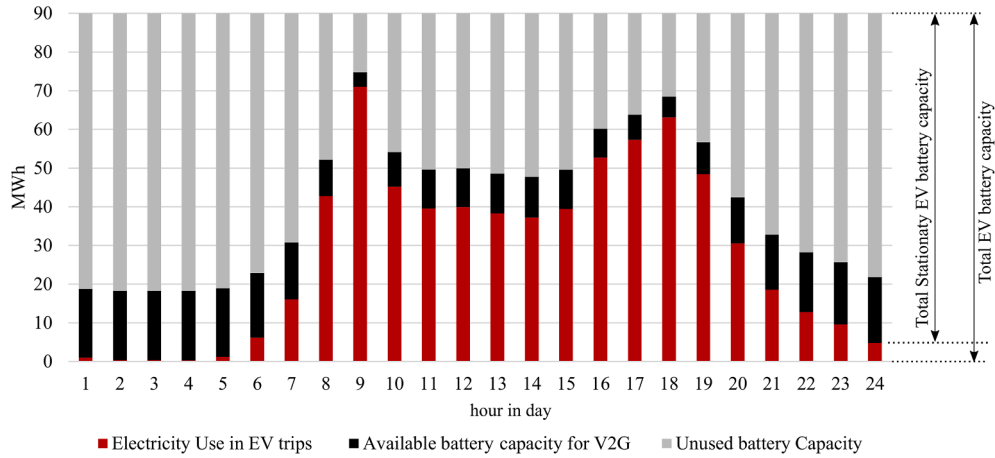

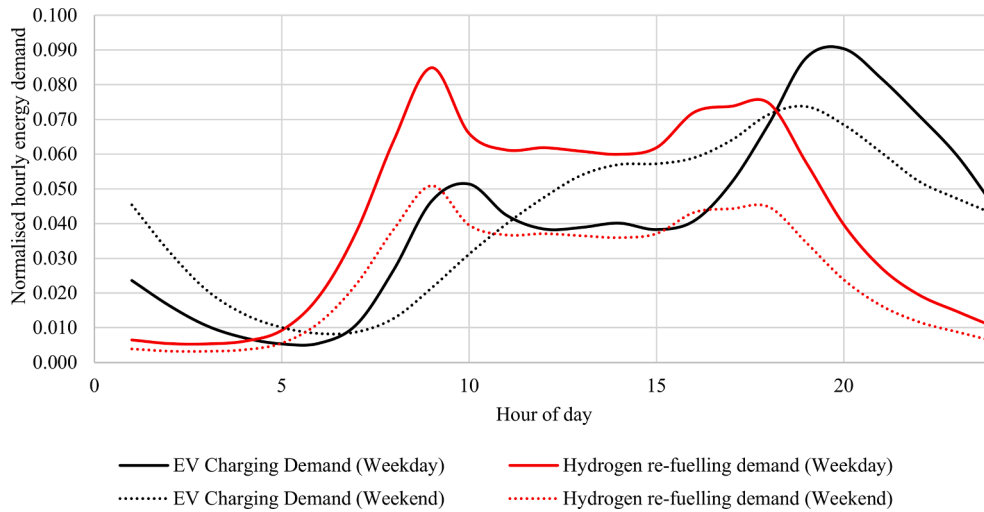**Fig. B1.** Illustration of electrical energy available in EV batteries for vehicle to grid.

Fig. B2. Normalised hourly EV charging, and hydrogen vehicle re-fuelling demand profiles for weekdays and weekends used in the study.

Table C1
Installed power generation capacities for the national electricity transmission system in 2015 and 2050.

Generation technology	Installed capacity – GW	
	2015	2050
Oil	0.8	0.0
CCGT with Carbon Capture and Storage (CCS)	0.0	42.9
Coal	17.3	0.0
Gas (CCGT + OCGT)	26.9	1.0
Hydro	1.1	1.3
Pumped hydro	2.7	5.8
Interconnectors	3.9	20.1
Other (tidal and marine)	0.0	3.9
Nuclear	8.9	18.6
Onshore wind	4.1	17.2
Offshore wind	4.3	62.0
Solar	0.3	0.9
Battery	0	5.3
Biomass with Carbon Capture and Storage (BECCS)	0	7.0
Total	*70.5*	*185.9*

Table C2
Aggregated electricity generation capacity for all Energy Hubs across All_Elec and All_MV Strategies.

Generation Type	Installed capacity - GW		
	2015	2050	
		All_Elec	All_MV
Gas (non-CHP)	1.3	1.5	
Onshore wind	3.7	22.2	
PV	6.7	41.1	
Gas CHP	2.3	0	
Oil (diesel etc.)	0.4	0	
Biomass CHP	0.4	0.9	3.1
Waste CHP	0.0	0.9	1.5
Fuel cells	0.0	1.2	3.1
Vehicle to grid	0.7	9.9	
Battery storage	0.0	15.9	11.9
Total (GW)	**16.3**	**94.5**	**94.4**

Table C3
Aggregated heat supply capacities for all Energy Hubs across All_Elec and All_MV Strategies.

Technology	Installation	2015 (GW$_{th}$)	Heat supply capacity (GW$_{th}$) in 2050	
			All_Elec	All_MV
Air source heat pumps	Building level	0.3	25.2	3.9
Gas boilers		44.0		
Electric boilers			4.1	
Resistive heaters		5.5	3.6	
Hydrogen boiler				20.3
Hybrid heat pump		0.1	4.1	6.1
Oil boilers		6.5		
Gas CHP	District heating network			
Biomass CHP		0.1		4.6
Waste CHP				2.3
Gas Boilers				
Heat Pumps				
Hydrogen fuel cell				4.6
Total (GW$_{th}$)		**56.5**	**37**	**41.8**

The energy-transport module calculates the availability of electrical energy in the EV batteries for V2G services, and its variability during the day with respect to daily travelling behaviour. The electrical energy battery use for EV trips (red bars) and the electrical energy available to provide V2G services (black bars) is shown in Fig. B.1.

The energy consumed in vehicles (electrical and hydrogen) were translated to hourly EV charging demands and hydrogen-refuelling demands using the following normalised profiles [34]. The profiles are normalised by the total daily energy demand and considers the difference between and weekdays and weekends. The profiles (Fig. B.2) are used as inputs to the energy-transport module.

C. Energy supply capacity

The power generation capacity for the national transmission system for the All_Elec strategy is shown in Table C1. The other strategies have similar capacities.

Energy supply capacity data for the Energy Hubs were calculated according to the strategy selected. The sizing of energy supply capacities ensures that supply is able to meet heating and non-heating energy demands across all energy supply strategies. The aggregated electricity generation capacities for all Energy Hubs for the All_Elec and All_MV

Strategies are shown in Table C2. The capacity values for the Elec_H2E is similar to All_Elec, and MV_Elec is similar to the All_MV Strategy.

The Energy hub heat supply capacities are determined according to the heat decarbonisation option selected and are shown in Table C3. The heat supply capacities are similar across strategies that use the same heat decarbonisation option.

References

[1] BEIS. Energy white paper: Powering our net zero future 2020. https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future (accessed February 26, 2021).

[2] Bazilian M, Gielen D. 5 years after Paris: How countries' climate policies match up to their promises, and who's aiming for net zero emissions 2020. https://theconversation.com/5-years-after-paris-how-countries-climate-policies-match-up-to-their-promises-and-whos-aiming-for-net-zero-emissions-151722 (accessed April 21, 2021).

[3] BEIS. UK ENERGY IN BRIEF 2020. 2020.

[4] Vivid Economics, Imperial College. International comparisons of heating, cooling and heat decarbonisation policies; 2017.

[5] BEIS. 2019 UK Greenhouse Gas Emissions, Final Figures. n.d.

[6] Dft. Consulting on ending the sale of new petrol, diesel and hybrid cars and vans 2020. https://www.gov.uk/government/consultations/consulting-on-ending-the-

sale-of-new-petrol-diesel-and-hybrid-cars-and-vans/consulting-on-ending-the-sale-of-new-petrol-diesel-and-hybrid-cars-and-vans (accessed December 12, 2020).

[7] CCC. Net Zero The UK's contribution to stopping global warming; 2019.

[8] NIC. National Infrastructure Assessment 2018; 2018.

[9] National Grid. Future Energy Scenarios; 2020.

[10] UKERC. Review of Energy Policy 2019 Summary of recommendations Securing our energy future. Brexit and net-zero 2019.

[11] Bell K, Gill S. Delivering a highly distributed electricity system: Technical, regulatory and policy challenges. Energy Policy 2018;113:765–77. https://doi.org/10.1016/j.enpol.2017.11.039.

[12] Mancarella P, Chicco G. 3.Real-time demand response from energy shifting in distributed multi-generation. IEEE Trans Smart Grid 2013;4:1928–38. https://doi.org/10.1109/TSG.2013.2258413.

[13] Wilson J. EVs Take Top Spot in Norwegian Car Sales; Wireless Charging Roads Explored. IET Eng Technol 2021. https://eandt.theiet.org/content/articles/2021/01/evs-take-top-spot-in-norweigan-car-sales-researchers-lay-out-future-of-wireless-charging-roads/ (accessed January 12, 2021).

[14] National Grid. Future Energy Scenarios; 2019.

[15] Khalid MR, Alam MS, Sarwar A, Jamil Asghar MS. A comprehensive review on electric vehicles charging infrastructures and their impacts on power-quality of the utility grid. ETransportation 2019;1:100006. https://doi.org/10.1016/j.etran.2019.100006.

[16] Hu Q, Li H, Bu S. The prediction of electric vehicles load profiles considering stochastic charging and discharging behavior and their impact assessment on a real UK distribution network. Energy Procedia, vol. 158, Elsevier Ltd; 2019, p. 6458–65. 10.1016/j.egypro.2019.01.134.

[17] Crozier C, Morstyn T, McCulloch M. The opportunity for smart charging to mitigate the impact of electric vehicles on transmission and distribution systems. Appl Energy 2020;268:114973. https://doi.org/10.1016/j.apenergy.2020.114973.

[18] Galiveeti HR, Goswami AK, Dev Choudhury NB. Impact of plug-in electric vehicles and distributed generation on reliability of distribution systems. Eng Sci Technol an Int J 2018;21:50–9. https://doi.org/10.1016/j.jestch.2018.01.005.

[19] Calvillo CF, Turner K. Analysing the impacts of a large-scale EV rollout in the UK – How can we better inform environmental and climate policy? Energy Strateg Rev 2020;30:100497. https://doi.org/10.1016/j.esr.2020.100497.

[20] Imperial College. Accelerated electrification and the GB electricity system; 2019.

[21] Energy Systems Catapult. Vehicle to Grid Britain; 2019.

[22] Pfenninger S, Hawkes A, Keirstead J. Energy systems modeling for twenty-first century energy challenges. Renew Sustain Energy Rev 2014;33:74–86. https://doi.org/10.1016/j.rser.2014.02.003.

[23] Chaudry M, Jenkins N, Strbac G. Multi-time period combined gas and electricity network optimisation. Electr Power Syst Res 2008;78:1265–79. https://doi.org/10.1016/j.epsr.2007.11.002.

[24] Chaudry M, Jenkins N, Qadrdan M, Wu J. Combined gas and electricity network expansion planning. Appl Energy 2014;113:1171–87. https://doi.org/10.1016/j.apenergy.2013.08.071.

[25] Jayasuriya L, Chaudry M, Qadrdan M, Wu J, Jenkins N. Energy hub modelling for multi-scale and multi-energy supply systems. 2019 IEEE Milan PowerTech, PowerTech 2019, 2019. 10.1109/PTC.2019.8810641.

[26] Geidl M. Integrated modeling and optimization of multi-carrier energy systems. ETH Zurich 2007.

[27] Met Office. MIDAS: UK Hourly Weather Observation Data 2016. http://data.ceda.ac.uk/badc/ukmo-midas-open/data/uk-hourly-weather-obs/dataset-version-201901/ (accessed June 30, 2018).

[28] Guilod BP, Jones RG, Kay AL, Massey NR, Sparrow SN, Wallom DCH. Managing the Risks, Impacts and Uncertainties of drought and water Scarcity(MaRIUS) project: Large set of potential past and future climate time series for the UK from the weather@home2 model 2017.

[29] Eggimann S, Hall JW, Eyre N. A high-resolution spatio-temporal energy demand simulation to explore the potential of heating demand side management with large-scale heat pump diffusion. Appl Energy 2019;236:997–1010. https://doi.org/10.1016/j.apenergy.2018.12.052.

[30] BEIS. Energy consumption in the UK 2018. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk (accessed August 3, 2019).

[31] Bhattacharyya Govinda SC, Timilsina R. Energy Demand Models for Policy Formulation A Comparative Study of Energy Demand Models. 2009.

[32] BEIS. SUB-NATIONAL ELECTRICITY AND GAS CONSUMPTION STATISTICS Regional, Local Authority, middle and lower layer super output area 2016.

[33] Lovrić M, Blainey S, Preston J. A conceptual model for a national transport model with cross-sectoral interdependencies. Transp Res Procedia 2018;27:720–7. https://doi.org/10.1016/j.trpro.2017.12.150.

[34] National Grid. Future Energy Scenarios 2019 Data WorkBook. Futur Energy Scenar 2019. https://www.nationalgrideso.com/documents/169951-fes-data-workbook-v30 (accessed December 12, 2019).

[35] NIC. National Infrastructure Assessment; 2018.

[36] ENA. Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain; 2019.

[37] ETI. Modelling the UK Energy System: Practical Insights for Technology Development and Policy Making; 2013. 10.2139/ssrn.2201993.

[38] Chaudry M, Abeysekera M, Hosseini SHR, Jenkins N, Wu J. 13.Uncertainties in decarbonising heat in the UK. Energy Policy 2015;87:623–40. https://doi.org/10.1016/j.enpol.2015.07.019.

[39] Royal Academy of Engineering. GB electricity capacity margin; 2013. 978-1-909327-02-3.

[40] Lovrić M, Blainey S, Preston J. A conceptual design for a national transport model with cross-sectoral interdependencies. Transp. Res. Procedia, vol. 27, Elsevier B.V.; 2017, p. 720–7. 10.1016/j.trpro.2017.12.150.

[41] The Chartered Institute of Building Services Engineers. Degree-days: theory and application; 2006.