Accelerated electrification and the GB electricity system

Report prepared for Committee on Climate Change

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Imperial College London

Executive Summary

The Committee on Climate Change has been asked to prepare advice to Government on a net zero target for the UK.

A net zero emissions target may require accelerated electrification of heat and transport. Meeting the existing Climate Change Act target for an 80% reduction in greenhouse gas emissions by 2050 is likely to require deployment of electric vehicles and heating technologies, and a net zero target could require faster deployment. Accelerated electrification could involve:

- Up to 9 million electric and plug-in hybrid cars and vans by 2025, rising to 37 million by 2035; and
- Up to 2 million heat pumps by 2025, rising to 15 million by 2035[1].

The Committee on Climate Change has commissioned Vivid Economics to investigate the impacts of accelerated electrification of transport and heat. Accelerated electrification will have impacts on the electricity system. In this context, the CCC requested advice to assess the feasibility of accelerated electrification. Specifically, we investigate the feasibility of:

- Accommodating accelerated electrification at manageable cost;
- Carrying out the necessary reinforcements to distribution networks;
- Deploying the necessary generation capacity; and
- Delivering the level of demand response needed to accommodate accelerated electrification.

We find that achieving accelerated electrification is feasible with immediate and sustained effort. However, current policy is not adequate to drive the necessary change. Key findings from this study are:

- While rapid deployment of electric vehicles and hybrid heat pumps and new renewable generation capacity will require new investments, together they could reduce the cost per kWh of electricity.
- While new distribution network investment will be needed, it will represent no more than 4% of the cost per kWh of electricity.
- The UK has adequate onshore wind, offshore wind and solar PV resource, and past build rates are sufficient to deliver an expanded and decarbonised electricity system.
- The demand response and smart charging of electric vehicles necessary to support accelerated electrification are technically feasible.
- To minimise the cost and disruptiveness of distribution network reinforcement, investments need to be future-proof. The current price control framework does not cover the required multi-decade time horizon.
- To deliver the necessary low-carbon generation at current build rates, sustained build of new onshore wind, offshore wind and solar PV are needed. If constraints on onshore wind and solar PV continue, a major ramp up in new offshore wind build is needed.
- Large-scale policy reform and market design are needed to deliver a flexible electricity system.

[1] Figures are for Great Britain; figures for the UK, including deployment in Northern Ireland, are slightly higher.

Achieving accelerated electrification is feasible, with immediate and sustained effort.

While rapid deployment of electric vehicles and hybrid heat pumps and new renewable generation capacity will require new investments, together they could reduce the cost per kWh of electricity.

- Accelerated deployment of electric vehicles and heating technologies is unlikely to increase the cost per kWh of electricity. If renewables are used to meet the new demand, the cost of electricity could decrease.
- Electric vehicles and hybrid heat pumps are inherently flexible. Electric vehicles can shift their charging needs, while hybrid heat pumps can switch to gas mode during periods of high electricity demand. As a result, these technologies contribute little to the peakiness of electricity demand.
- A flexible electricity system is needed to reduce curtailment of wind and solar to very low levels and minimise the cost of electricity. Further deployment of flexible resources would not significantly reduce costs.
- Provided they are used efficiently, hybrid heat pumps could deliver carbon savings almost as large as electric heat pumps, but with significantly lower impact on the cost of electricity.
- Clustering (faster uptake of electric vehicles and hybrid heat pumps in some areas) will have important implications for distribution networks, but overall impacts on electricity costs will be small.

While new distribution network investment will be needed, it will represent no more than 4% of the cost per kWh of electricity.

- Utilisation of the existing distribution network is poorly understood. If network is close to fully utilised (there is no 'headroom' in network capacity), an increase in electricity demand could significantly increase the quantity and cost of reinforcements. Accurate information on network utilisation is needed before the right distribution network investments can be made.
- Significant distribution network reinforcements could be needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps.
- Overall, rapid uptake of electric vehicles and hybrid heat pumps could increase total expenditure on distribution networks by up to £50 billion by 2035, or £1.8 billion per year. However, this investment represents only 4% of the total cost of the electricity system.
- The high cost of reinforcing underground network lines accounts for around two thirds of the cost of reinforcing distribution networks. Costs of overhead lines and transformers make up the remainder.
- Flexible resources can substantially reduce the cost of the necessary network reinforcements. Around 20 GW of battery storage and 9 GW of demand response can reduce the cost of reinforcing distribution networks by almost 10% by 2035. In principle, electric vehicles providing vehicle-to-grid services could provide some or all of the necessary battery storage.
- Further cost reductions could be achieved by relaxing the current 'P2/6' network security standard. This standard requires a degree of redundancy in network assets to minimise the risk of supply interruptions for all network users; however, the cost of this redundancy could be greater than the value of the enhanced security that it confers.
- A range of additional measures, including changing voltage levels, splitting network lines and smart voltage control, could further reduce the need for network reinforcements.
- Clustering of electric vehicles and heat pumps could increase network reinforcement costs in the near term, but will would not materially increase costs over the long term.

- The majority of network reinforcements will occur in semi-rural networks, where disruption will be low. However, reinforcements to urban networks could create disruption. With accelerated electrification, the majority of urban networks could need upgrading, and much of the upgrades will be to underground lines.

The UK has adequate onshore wind, offshore wind and solar PV resource, and past build rates are sufficient to deliver an expanded and decarbonised electricity system.

- Significant new renewable generation capacity is needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps. Over the period to 2035, up to 35 GW onshore wind, 45 GW offshore wind and 54 GW solar PV could be needed. Further deployment is likely to be needed over the period to 2050.
- The UK onshore wind, offshore wind and solar PV resource are likely to be more than adequate to deliver an expanded and decarbonised electricity system to 2050. However, the onshore wind resource is highly sensitive to public acceptability and further work is needed to develop a realistic and accurate estimate of the offshore wind resource.
- Past build rates are sufficient to deliver an expanded and decarbonised electricity system.
- While large levels of backup capacity would have a minimal impact on the cost of electricity, they may be challenging to deliver. Flexible resources are cost-effective solutions to moderate backup capacity requirements.

The demand response and smart charging of electric vehicles necessary to support accelerated electrification are technically feasible.

- The long-term potential for demand response is significant. Analysis shows that up to 53% of residential electricity demand, 32% of commercial electricity demand and 22% of industrial electricity demand are potentially movable.
- Smart charging could significantly reduce peak electricity demand. Analysis of driving patterns shows that overnight charging could meet the majority of charging needs, minimising the need to charge during the evening peak.

However, current policy is not adequate to drive the necessary change.

To minimise the cost and disruptiveness of distribution network reinforcement, investments need to be future-proof. The current price control framework does not cover the required multi-decade time horizon.

- With electrification of heat and transport, electricity demand is likely to grow over the period to 2035, and potentially beyond. Investments that are adequate to accommodate near-term demand growth may not adequate to accommodate electrification over the longer term.
- Network reinforcements are a major investment, and are disruptive. Further, the costs of over-sizing network infrastructure are very low. As a result, future-proofing investments by over-sizing network infrastructure is a very low-regrets option.
- Uncertainty over electric vehicle and heat pump uptake is a major challenge to accurately projecting network investment needs. Great Britain's regulatory framework for distribution networks (the 'RIIO' framework) should be flexible enough to allow distribution network operators to respond to emerging evidence on future uptake, even during a single price control period.
- Batteries and demand response can reduce the need for distribution network reinforcement. The RIIO price control framework should continue to incentivise distribution network operators to reduce total expenditure (TOTEX) and make use of these solutions where possible.

To deliver the necessary low-carbon generation at current build rates, sustained build of new onshore wind, offshore wind and solar PV are needed. If constraints on onshore wind and solar PV continue, a major ramp up in new offshore wind build is needed.

- While policy is delivering new offshore wind, planning constraints on onshore wind are limiting the potential for new deployment, while the lack of CfD auctions creates risks for both onshore wind and solar PV. New solar capacity in 2017 was under 1 GW, around 80% below its 2015 peak.
- To support delivery of onshore wind and solar, planning restrictions on new onshore wind would need to be relaxed, and a route to market provided for onshore wind and solar PV.
- To deliver the necessary investment, Government needs to anchor expectations around the volume of capacity needed, and address remaining market failures to deploying renewables. It is not clear that new capacity on this scale could be delivered by merchant investment, and a sustained programme of CfD auctions may be needed.
- If constraints on onshore wind and solar PV continue, new offshore wind would need to rapidly increase to around 5 GW per year, nearly three times its 2017 peak. A significant scale up in the supply chain would be needed to deliver these volumes.

Large-scale policy reform and market design are needed to deliver a flexible electricity system.

- Current market arrangements are not adequate to deliver large-scale battery storage and demand response. Ofgem, BEIS and National Grid are working to ensure storage and demand response providers can be rewarded for the value they deliver, and to remove barriers to their participation in the electricity system. These objectives will need to be achieved by the by the early 2020s to support the necessary investment.
- In parallel, a shift in consumer and attitudes will be needed to support demand response. Consumers will need to accept to move from fixed to time of use electricity pricing, and to engage with new technologies and business models to vary their electricity demand in line with the value they place on it.

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1 Introduction

1.1 Background

The Committee on Climate Change has been asked to prepare advice to Government on a net zero target for the UK. On 15 October the Energy and Clean Growth Minister Claire Perry asked the Committee on Climate Change for advice on setting a date for achieving net zero greenhouse gas emissions from across the economy; whether to review the 2050 target of cutting emissions by at least 80% relative to 1990 levels to meet international climate targets set out in Paris Agreement; how emissions reductions might be achieved; and the expected costs and benefits in comparison to current targets.

A net zero emissions target may require accelerated electrification of heat and transport. The Committee on Climate Change's Central scenario, which underpins its advice on the Fifth Carbon Budget, involves extensive electrification of surface transport, industry and buildings. For example, the scenario involves electric cars and vans achieving a 60% share of new vehicles by 2040, and heat pumps rolled out to properties on the gas grid at scale from the 2030s. In this scenario, 22 million electric cars and vans and 6 million electric heat pumps could be connected to the GB electricity system by 2035. However, more rapid electrification could be needed to meet a net zero target. Earlier deployment of electric vehicles and heat pumps could bring forward deep decarbonisation of the heat and transport sectors. Hybrid heat pumps, which are able to use electricity to meet the majority of heat demand, but also to use gas at peak times to reduce impacts on the electricity system, could play a role in this transition. In such a scenario, 37 million electric cars and vans and 15 million electric and hybrid heat pumps could be connected to the GB electricity system by 2035.

However, accelerated electrification needs further investigation. Specific issues include:

- the impact of accelerated electrification on the cost of electricity, including the cost of the necessary distribution network reinforcement, and any costs associated with addressing challenges to the operation of the electricity system;
- the scale of the distribution network reinforcements needed to accommodate the increased demand from electric vehicles and hybrid heat pumps and whether these reinforcements can be delivered when they are needed;
- the renewable and backup generation capacity that could be needed to meet the growth in electricity demand, whether the UK renewable resource is adequate and whether it can be developed in time to deliver an expanded and decarbonised electricity system; and
- whether the levels of demand response needed to accommodate accelerated electrification can be achieved.

1.2 Objectives

The Committee on Climate Change has commissioned Vivid Economics and Imperial College to investigate the feasibility of accelerated electrification. Specifically, the Committee on Climate Change are seeking to understand the feasibility of:

- accommodating accelerated electrification at manageable cost;
- carrying out the necessary reinforcements to distribution networks;
- deploying the necessary generation capacity; and
- delivering the level of demand response needed to accommodate accelerated electrification.

1.3 Approach

First, we carry out detailed electricity system modelling to characterise the electricity system under accelerated electrification. To assesses the feasibility of accommodating accelerated electrification at manageable cost we develop a set of whole electricity system scenarios under accelerated electrification. To develop these scenarios, we use two sophisticated modelling tools:

- **Imperial College's Whole-energy system Investment Model (WeSIM).** WeSIM is an electricity system optimisation model that characterises the investment in and operation of the electricity system resources needed to minimise the overall cost of the electricity system, while maintaining security of electricity supply.
- **Imperial College's Load Related Expenditure model of electricity distribution networks (LRE).** The LRE model is a fractal network model that estimates the quantity and cost of the distribution network assets needed to meet demand for electricity across all GB distribution networks. The LRE model uses fractals to reproduce realistic network topologies and lengths and therefore allow for the characterisation of distribution networks of different types.

Using these scenarios, we estimate the cost of the electricity system resources needed to meet electricity demand under accelerated electrification while maintaining security of electricity supply. Further details of the WeSIM and LRE models are set out in Annex 1.

We then assess the nature and pace of required distribution network investments. Network lines and transformers will need to be upgraded to accommodate the increase in electricity demand under accelerated electrification. To assesses the feasibility of carrying out the necessary distribution network reinforcements, we consider the disruptiveness of the upgrades, in terms of the scale of necessary reinforcements, their nature (the split between replacement of underground and overhead network lines) and the number of customers affected.

We examine the evidence on the deployment potential of renewables. To assess the feasibility of deploying the necessary generation capacity, we examine the evidence on the UK onshore wind, offshore wind and solar PV resource. First, we carry out a literature review on the factors that determine the size of each resource, and identify previous estimates of the total resource. We then critically assess the literature and indicate whether previous estimates are likely to be accurate, or to under- or overestimate the total resource. Finally, we investigate historical build rates of onshore wind, offshore wind and solar PV and consider whether these are sufficient to deliver the accelerated electrification scenarios.

We then review the evidence on the potential for demand-side response. To assess the feasibility of delivering the level of demand response needed to accommodate accelerated electrification, we examine the evidence on UK demand response potential. We carry out a literature review on demand response potential in the residential, commercial and industrial sectors. We then carry out analysis of passenger car travel trends using the National Travel Survey to estimate the extent to which smart charging in the overnight period could reduce the need to charge electric vehicles during the day.

1.4 Structure of this report

This report sets out the findings of this analysis:

- **Section 2: Accelerated electrification scenarios** describes the three accelerated electrification scenarios modelled in this study, in terms of the extent of electric vehicle and heat pump deployment, and the flexibility of the electricity system.
- **Section 3: Overall electricity system impacts** characterises the electricity system in the accelerated electrification scenarios, showing the additional generation capacity and network infrastructure needed to meet demand from electric vehicles and heat pumps, and sets out the implications of the additional capacity and infrastructure for the cost of electricity system.
- **Section 4: Impacts on the distribution network** focuses on distribution networks in the accelerated electrification scenarios, characterising and costing the distribution network reinforcements and assessing their disruptiveness.
- **Section 5: Deployment potential of UK renewables** sets out the evidence on the UK onshore wind, offshore and solar PV resource and assesses the adequacy of historical build rates of these technologies to deliver the accelerated electrification scenarios.
- **Section 6. Demand response potential** reviews the evidence on the potential for demand-side response in the residential, commercial and industrial sectors and discusses the potential for smart charging of electric vehicles to shift charging demand away from peak times.
- **Section 7: Policy implications** assesses the current market arrangements relating to distribution networks, deployment of renewables and demand response, and identifies barriers to delivery of the necessary investments. It then makes recommendations for market and policy reform to deliver the accelerated electrification scenarios.
- **Section 8: Conclusions** summarises the key findings of this study.

2 Scenarios and assumptions

To assess the feasibility of accelerated electrification we develop a set of electricity system scenarios. These scenarios are set out in Table 1.

Table 1 Characteristics of the Central and Accelerated scenarios

Scenario	Technology		Million units		
			2025	2030	2035
Central	Electric vehicles	EV	1.2	3.9	7.9
		PHEV	3.2	8.3	14.1
	Heat pumps	Electric heat pump	0.8	2.2	5.7
		Hybrid heat pump	0	0	0
Rapid EV	Electric vehicles	EV	2.6	7.8	13.2
		PHEV	6.7	16.2	23.8
	Heat pumps	Electric heat pump	0.8	2.2	5.7
		Hybrid heat pump	0	0	0
Rapid HHP	Electric vehicles	EV	1.2	3.9	7.9
		PHEV	3.2	8.3	14.1
	Heat pumps	Electric heat pump	0.8	2.2	5.7
		Hybrid heat pump	1.0	3.9	9.5
Rapid EV+HHP	Electric vehicles	EV	2.6	7.8	13.2
		PHEV	6.7	16.2	23.8
	Heat pumps	Electric heat pump	0.8	2.2	5.7
		Hybrid heat pump	1.0	3.9	9.5

Source: Committee on Climate Change

For each of the scenarios we develop a high flexibility variant, with higher uptake of demand response, battery storage, interconnection and heat storage. Table 2 shows assumptions on the level of demand response in the Core and High Flex variants of each scenario in 2025, 2030 and 2035. Table 3 shows the maximum level of battery storage and interconnection capacity in the same scenarios. Finally, Table 4 shows the share of electric heat pumps that have heat storage.

Table 2 Maximum potential and uptake of demand response in the modelled scenarios

Segment	Maximum potential (shift in peak demand)	Share of maximum potential					
		Core			High Flex		
		2025	2030	2035	2025	2030	2035
Residential appliances	41%	25%	50%	50%	50%	100%	100%
Industrial and commercial	10%						
Electric vehicles	80%						

Source: Vivid Economics, Imperial College

Table 3 Battery storage and interconnection capacity in the modelled scenarios

Resource	Capacity (GW)					
	Core			High Flex		
	2025	2030	2035	2025	2030	2035
Storage	8.7	17.1	19.5	13.0	25.7	29.2
Interconnection	13.3	17.5	18.9	20.0	26.3	28.3

Note: Battery capacity expressed based on 1.5 hour duration batteries (1 GW = 1.5 GWh)
Source: Vivid Economics, Imperial College

Table 4 Heat storage in the modelled scenarios

	2025	2030	2035
Share of electric heat pumps with storage	28%	35%	40%

Source: Vivid Economics, Imperial College

3 Impacts of accelerated electrification

Box 1 Key messages

While rapid deployment of electric vehicles and hybrid heat pumps and new renewable generation capacity will require new investments, together they could reduce the cost per kWh of electricity.

- Accelerated deployment of electric vehicles and heating technologies is unlikely to increase the cost per kWh of electricity. If renewables are used to meet the new demand, the cost of electricity could decrease.
- Electric vehicles and hybrid heat pumps are inherently flexible. Electric vehicles can shift their charging needs, while hybrid heat pumps can switch to gas mode during periods of high electricity demand. As a result, these technologies contribute little to the peakiness of electricity demand.
- A flexible electricity system is needed to reduce curtailment of wind and solar to very low levels and minimise the cost of electricity. Further deployment of flexible resources would not significantly reduce costs.
- Provided they are used efficiently, hybrid heat pumps could deliver carbon savings almost as large as electric heat pumps, but with significantly lower impact on the cost of electricity.
- Clustering (faster uptake of electric vehicles and hybrid heat pumps in some areas) will have important implications for distribution networks, but overall impacts on electricity costs will be small.

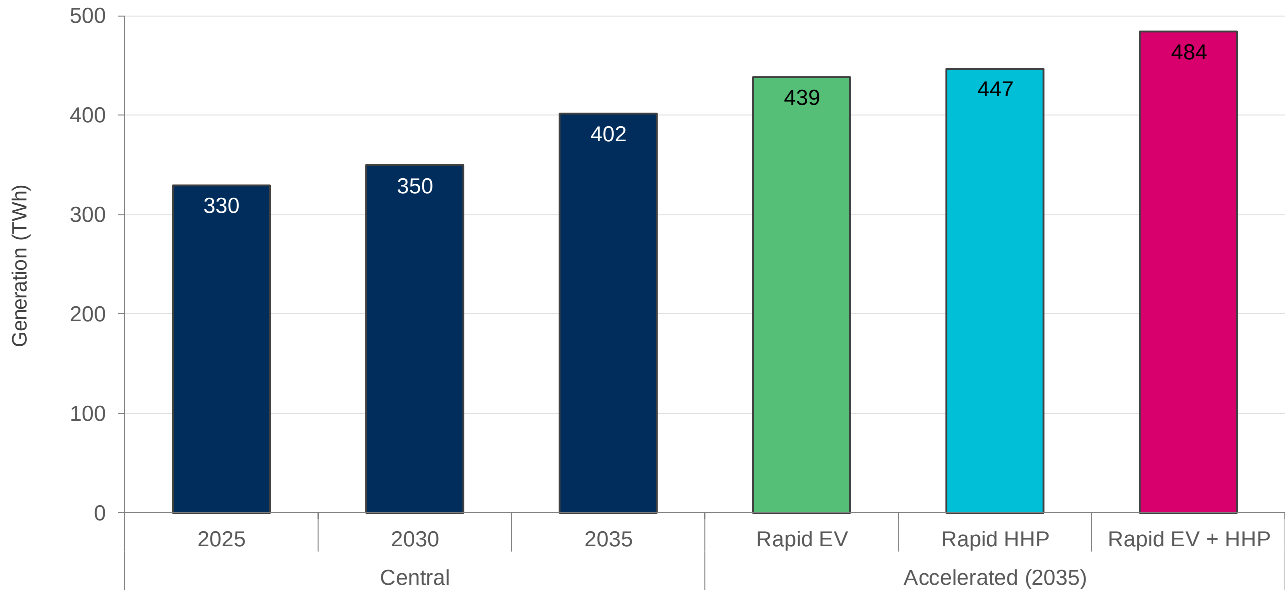
3.1 Overall impacts

In the Central Scenario, the electricity system must expand substantially to 2035. To accommodate 37 million electric cars and vans and 15 million electric and hybrid heat pumps over the period to 2035, electricity generation and capacity need to increase substantially. Figure 1 and Figure 2 show the level of electricity generation and capacity needed to meet electricity demand between 2025 and 2035 in the Central Scenario, and in 2035 in the Rapid EV, Rapid HHP and Rapid EV+HHP scenarios. In the Central Scenario, electricity generation increases from 330 TWh in 2025 to 402 in 2035. To provide this generation, substantial new renewable generation capacity is needed. In 2025, renewable generation capacity consists of 20 GW onshore wind, 12 GW offshore wind and 22 GW solar PV. By 2035, onshore wind increases 9 GW to 30 GW; offshore wind increases 17 GW to 29 GW and solar PV increase 28 GW to 50 GW.

Further expansion is needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps. In the Rapid EV scenario, electricity generation increases by a further 37 TWh in 2035 to meet higher demand from electric vehicles, while in the Rapid HHP scenario, electricity demand increases by 45 TWh to meet demand from hybrid heat pumps. In the Rapid EV+HHP scenario, electricity demand increases by 82 TWh to meet both additional demands. To provide this generation, renewable generation capacity consists of 35 GW onshore wind, 45 GW offshore wind and 54 GW solar in the Rapid EV+HHP scenario.

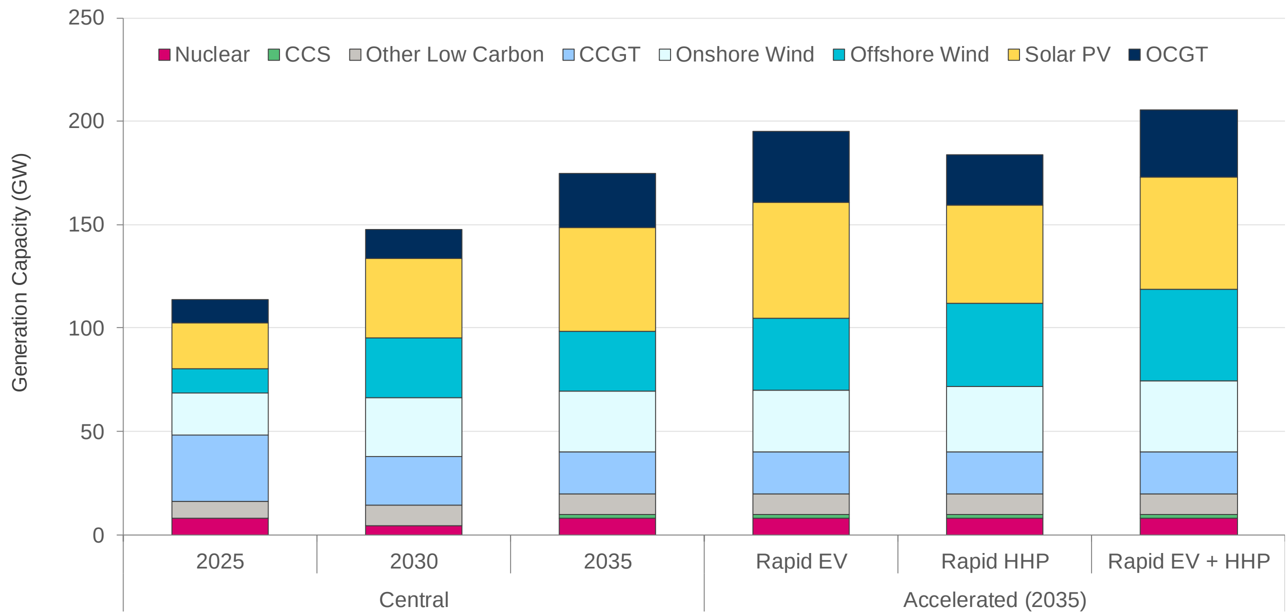
The most cost--effective capacity mix could depend on the type of additional demand. In the Rapid EV scenario, wind and solar PV capacity are higher than in the Central scenario, by 6.3 GW and 5.6 GW respectively, to meet the higher demand from electric vehicles. In the Rapid HHP scenario, solar PV capacity is 2.9 GW lower than in the Central scenario and wind capacity is 13.4 GW higher to meet the higher demand from hybrid heat pumps. The shift from solar to wind reflects the limited solar output during at times of high levels of heat demand (which peak in winter evenings). In the Rapid EV+HHP scenario, solar PV capacity is 3.8 GW higher than in the Central scenario and wind capacity is 20.4 GW higher.

Figure 1 Accelerated electrification of heat and transport substantially adds to electricity demand



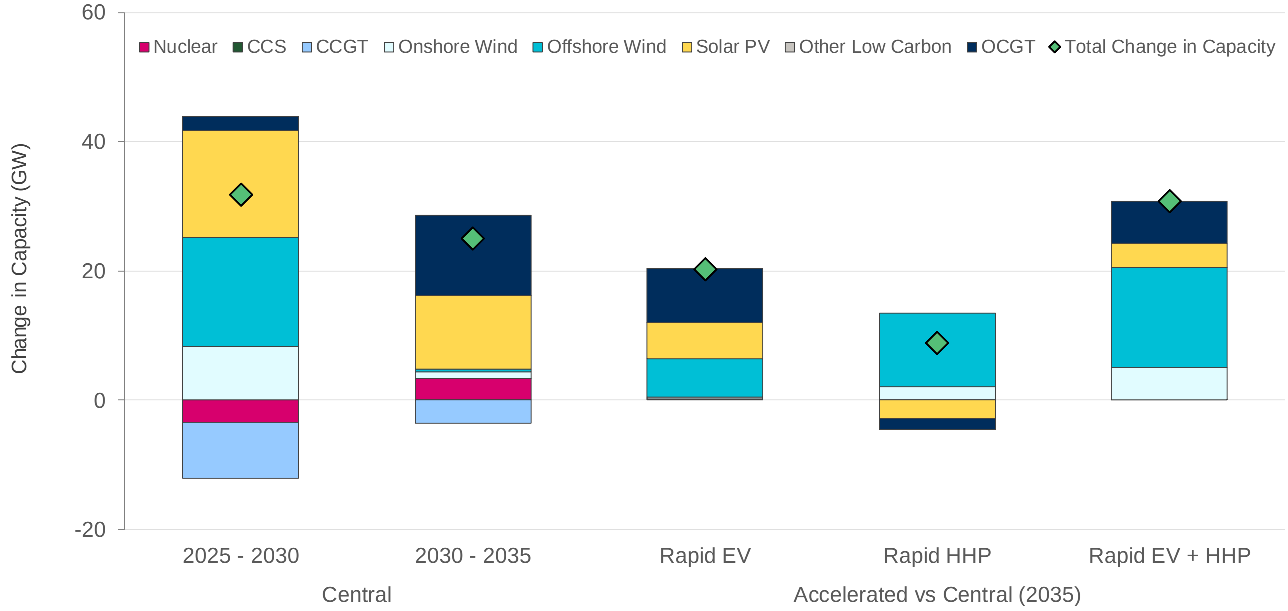
Source: Vivid Economics, Imperial College

Figure 2 New capacity will be needed to meet the new demand



Source: Vivid Economics, Imperial College

Figure 3 The capacity mix differs across scenarios

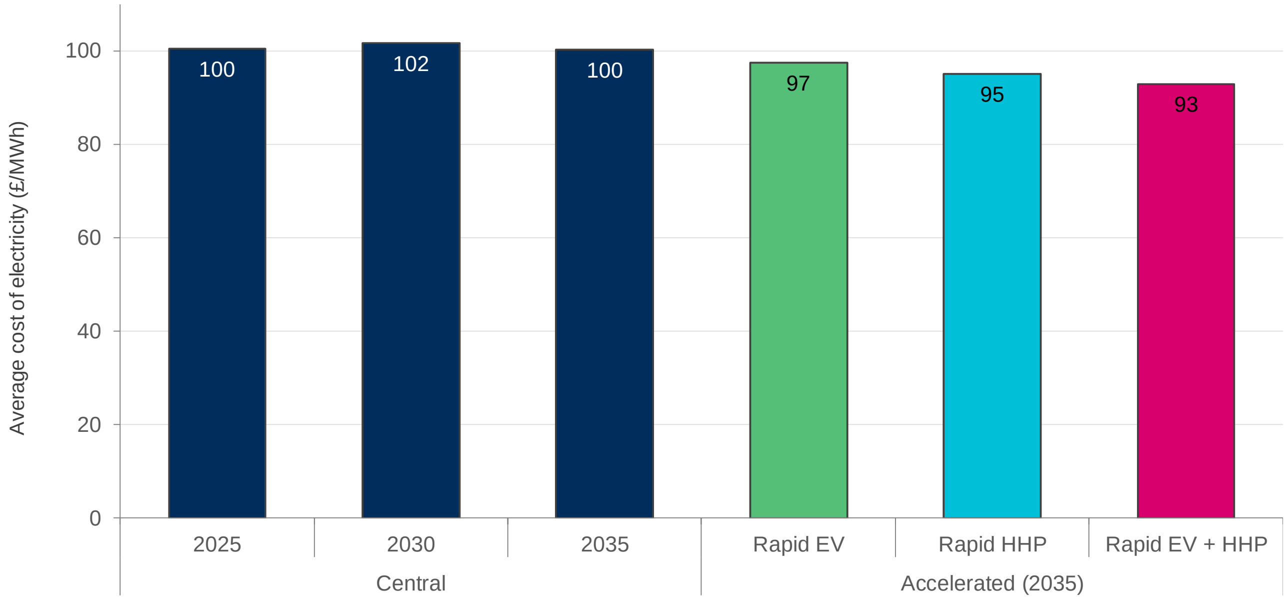


Source: Vivid Economics, Imperial College

In the Central Scenario, reducing CO_2 emissions to 2035 has minimal impacts on the cost of electricity. Average electricity costs in the Central scenario increase by around 1% between 2025 and 2030. The limited increase is due to the low cost of renewables in the scenario assumptions. Average costs then decrease by around 1% between 2030 and 2035. The slight reduction is due to the costs of routine transmission and distribution maintenance being spread over a higher level of demand.

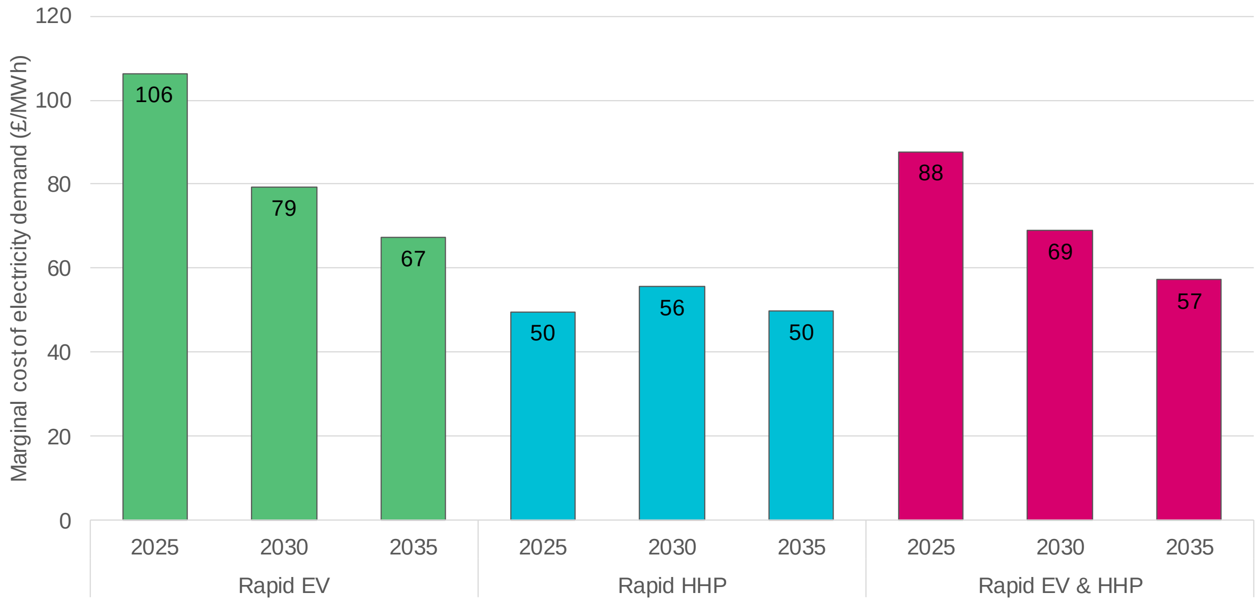
Rapid uptake of electric vehicles and hybrid heat pumps in 2035 could decrease the cost of electricity. Figure 4 shows the average cost of electricity in the Central scenario to 2035, and the Accelerated scenarios in 2035. In the Rapid EV scenario, the average cost of electricity is £98/MWh, around or 3% lower than in the Central scenario cost of £101/MWh; the marginal cost of the additional generation is only £67/MWh. In the Rapid HHP scenario, the cost of electricity is lower, at £95/MWh, a 6% reduction; the marginal cost of the additional generation is only £50/MWh. In the Rapid EV+HHP scenario the cost of electricity is lower still, at £93/MWh, a 7% reduction; the marginal cost of the additional generation is £57/MWh. Figure 5 shows the marginal cost of meeting the additional electricity demand in the Accelerated scenarios in 2035, relative to the Central scenario. Between 2025 and 2035, the marginal cost of the additional generation decreases from £106/MWh to £67/MWh in the Rapid EV scenario, and ranges between £50/MWh to £56/MWh in the Rapid HHP scenario. In the Rapid EV+HHP scenario the marginal cost of meeting the additional electricity demand decreases from £88/MWh to £57/MWh over the same period.

Figure 4 Rapid uptake of electric vehicles and hybrid heat pumps could decrease the cost of electricity



Source: Vivid Economics, Imperial College

Figure 5 Rapid uptake of electric vehicles and hybrid heat pumps could decrease the cost of electricity



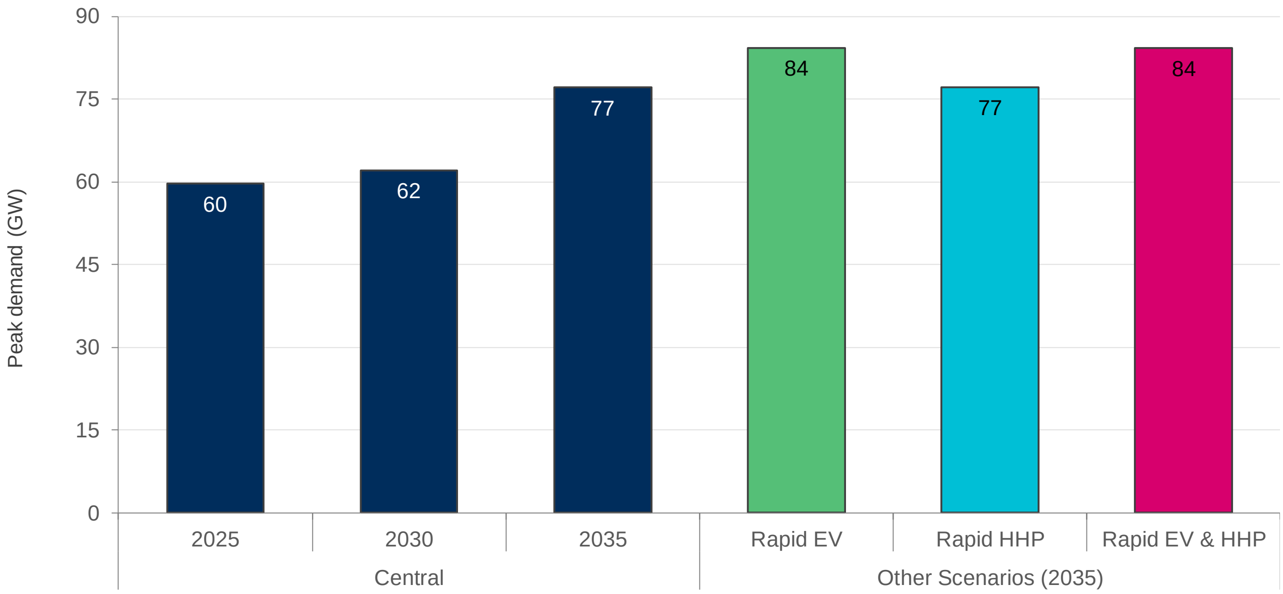
Source: Vivid Economics, Imperial College

The reduction in the cost of electricity is driven by the low cost of renewables, and the limited impact of electric vehicles and hybrid heat pumps on peak demand.

- Low cost of renewables. Renewables are projected to be cheaper than other forms of low-carbon generation. If the additional electricity demand is met with renewables, the additional generation would be cheaper than the average cost of electricity in the Central Scenario, which includes nuclear and CCS in the generation mix.

- **Limited impact on peak demand.** Electric vehicles would not reduce utilisation of the capacity mix, while hybrid heat pumps could improve it. The impact of a new loads on the electricity system depends on its demand profile. A new load that increases peak demand by more than it increases overall demand will be costly to accommodate, as it will need new capacity that must run at lower load factors. However, a new load that increases peak demand by less than it increases overall demand could reduce costs, as it could make better use of existing capacity and need less new capacity. Figure 6 shows peak demand in the Central and Accelerated scenarios over the period to 2035. In the Rapid EV scenario, electric vehicles increase peak demand and overall demand in roughly the same proportion. As a result, electric vehicles do not reduce utilisation of the capacity mix. In the Rapid HHP scenario, hybrid heat pumps have minimal impact on peak demand, despite increasing overall demand. As a result, hybrid heat pumps improve utilisation of the capacity mix.

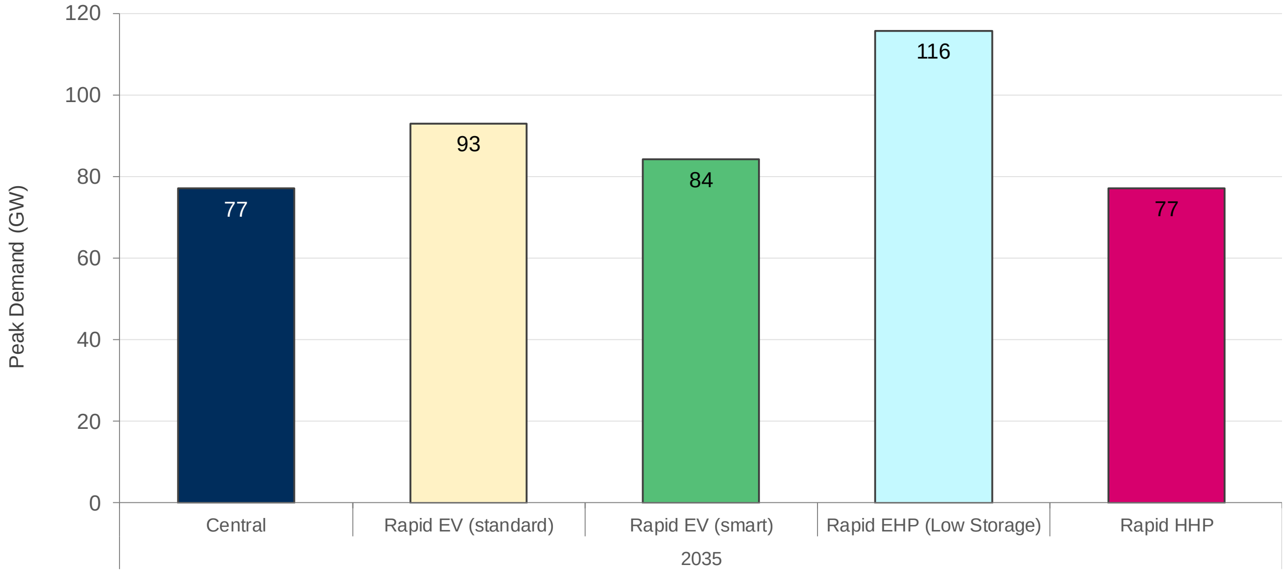
Figure 6 Electric vehicles could materially increase peak demand, but hybrid heat pumps could have limited impact



Source: Vivid Economics, Imperial College

The inherent flexibility of electric vehicles and hybrid heat pumps contributes to their limited impact on peak demand. Figure 7 shows peak demand in 2035 under a range of assumptions. With standard charging, accelerated deployment of electric vehicles could increase peak demand by 16 GW (assuming charging at an average of 6 kW). However, with smart charging, the increase in peak demand could be only 7 GW, as large numbers of electric vehicles charge overnight or during the day in periods of high renewable generation. Similarly, with electric-only heat pumps, and low levels of heat storage, accelerated deployment of heat pumps could increase peak demand by 32 GW. However, with hybrid heat pumps, the increase in peak demand could be minimal. This is because hybrid heat pumps can switch from electric mode to gas mode to avoid consuming electricity at peak times, while still meeting 93% of heat demand in electric mode.

Figure 7 EV smart charging and hybrid heat pumps limit the impact of these loads on peak demand



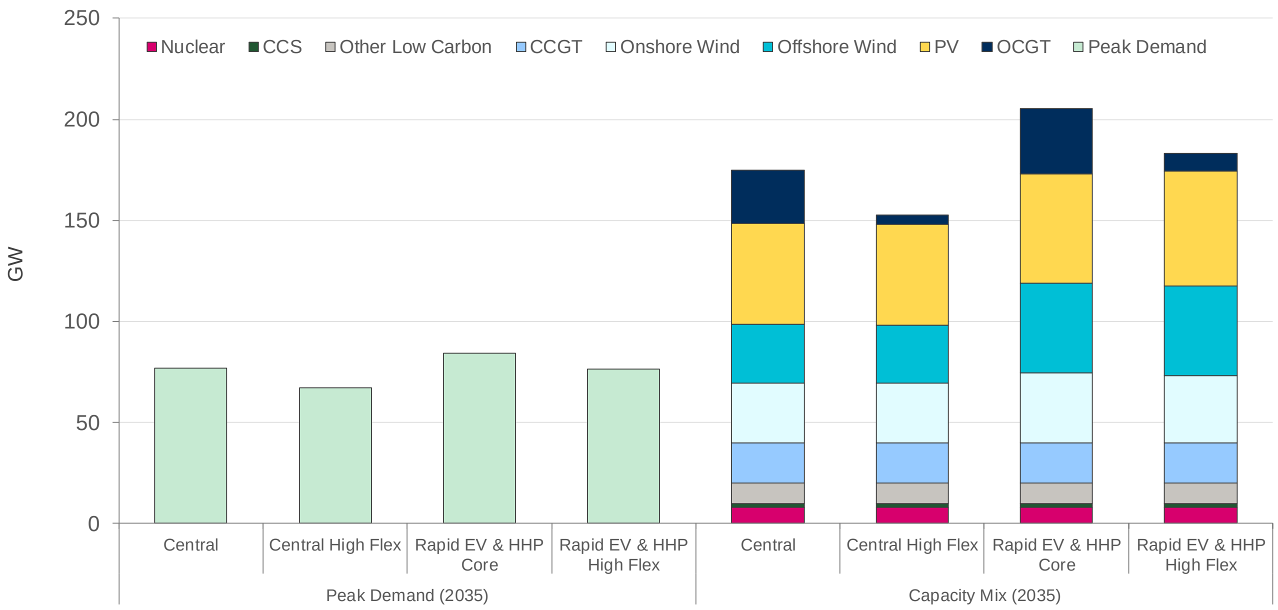
Source: Vivid Economics, Imperial College

Battery storage and demand response help to mitigate the costs of meeting demand. In the Central Scenario, 20 GW Battery storage, 9 GW demand response and 19 GW interconnection in 2035 reduce peak demand and the need for backup capacity, and help reduce the cost of electricity. In a scenario with lower levels of storage and demand response (The Low Flex variant discussed in Section 4, with only 2 GW of battery storage and 1 GW of demand response), the cost of electricity could be 8% higher in 2035.

In principle, electric vehicles providing vehicle-to-grid services could provide some or all of the necessary battery storage. Assuming an average battery pack size of 30 kWh for battery electric vehicles and 15 kWh for plug in hybrid vehicles, the fleet of electric cars and vans in the Rapid EV+HHP scenario could reach around 400 GWh in the Central scenario and over 600 GWh in the Rapid EV+HHP scenario, by 2035. As average daily car travel distances are far smaller than the expected range of an electric vehicle, much of this battery capacity would remain unused and in principle available to provide vehicle-to-grid if stationary. If only 20% of this unused battery capacity were available to provide vehicle-to-grid at a power output of 7 kW per vehicle, it would represent around 22 GW of battery storage in the Central scenario, and 35 GW in the Rapid EV+HHP scenario, and could in principle provide all the battery storage needs in those scenarios.

Additional increases in flexibility of the electricity system could further reduce peak demand and the need for backup capacity, though the impact on cost could be small. Demand response and storage can avoid the need for additional capacity by shifting demand for electricity from peak to off peak periods, and by improving the utilisation of variable renewables. To illustrate the impact of increasing the flexibility of the electricity system, we develop variants of the Central and Rapid EV+HHP scenarios with higher levels of battery storage and demand response (the High Flex variants). Figure 8 shows the impact of different levels of electricity system flexibility on peak demand and on the capacity mix. In the Central scenario, the High Flex variant reduces peak demand from 77 to 67 GW, a 13% reduction. The reduction in peak demand allows a reduction in the level of backup capacity needed: the level of OCGT decreases from 26 to 5 GW. The impact of the High Flex variant in the Rapid EV+HHP scenario is similar. The additional flexibility reduces peak demand by 9%, and reduces the level of OCGT needed from 33 to 9 GW. However, the additional flexibility does not significantly reduce the average cost of electricity, due to the high utilisation of variable renewables achieved in the Central and Rapid EV+HHP scenarios. Figure 8 shows the impact of different levels of electricity system flexibility on the average cost of electricity. In the Central and Rapid EV+HHP scenarios, the High Flex variant reduces generation costs by 1-2%.

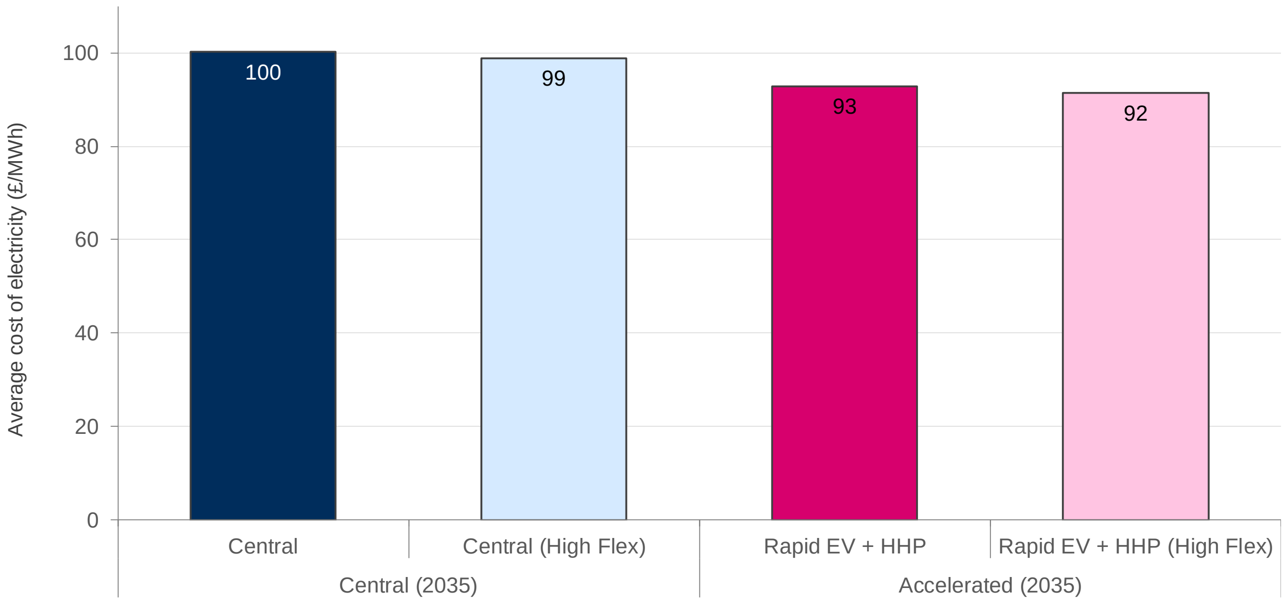
Figure 8 By reducing peak demand, flexible resources reduce the need to build additional generation capacity



Note: Peak demand was around 59 GW over winter 2017/18. Central scenario includes 50% of maximum demand response potential and 19.5 GW storage; High Flex scenario includes 100% of maximum demand response potential and 29 GW storage.

Source: Vivid Economics, Imperial College

Figure 9 Flexible resources reduce the costs of electricity generation



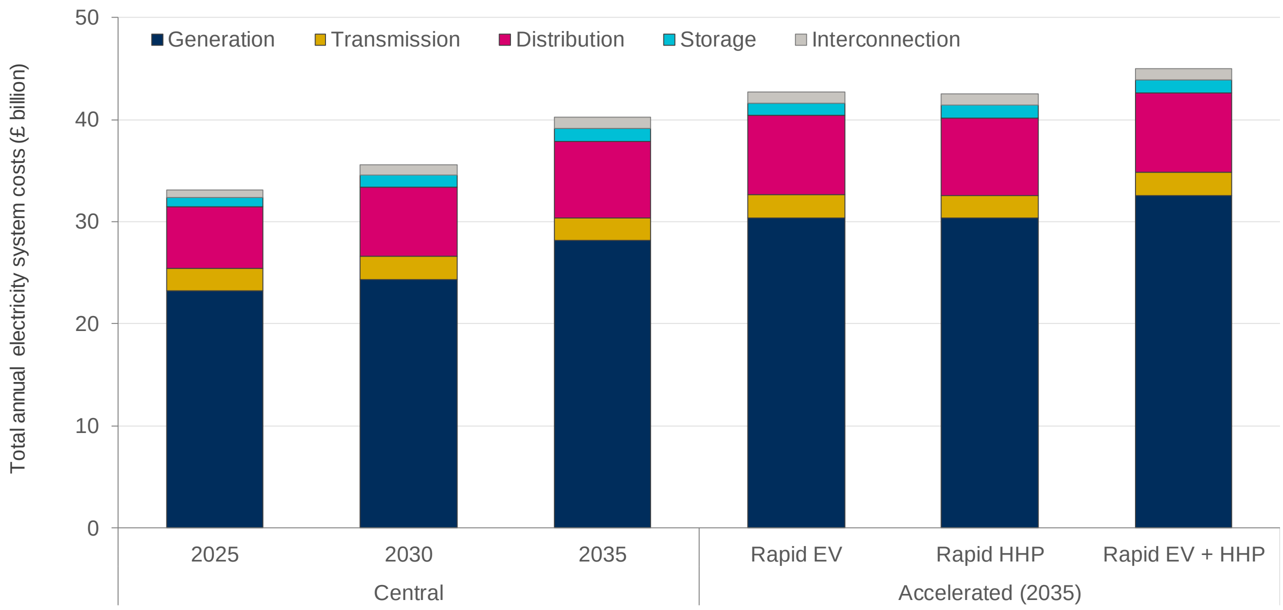
Source: Vivid Economics, Imperial College

Transmission network costs account for 5-7% of electricity system costs, and up to 6% of the additional cost of accelerated electrification. Figure 22 shows the total cost of the electricity system between 2025 and 2035 in the Central Scenario, and in 2035 in the Rapid EV, Rapid HHP and Rapid EV+HHP scenarios.

Transmission costs, comprising both the cost of routine asset replacement and network reinforcement, account for 5-7% of total electricity system costs in all scenarios.

Distribution network costs could account for 17-18% of electricity system costs, and up to 6% of the additional cost of accelerated electrification. Figure 22 also shows that distribution costs, comprising both the cost of routine asset replacement and network reinforcement, account for 17-18% of total electricity system costs in all scenarios. However, distribution costs account for a significantly lower share of the additional costs of electrifying heat and transport. While total electricity system costs in the Rapid EV+HHP scenario are around 16% higher than in the Central scenario, generation costs account for 94% of this increase, with distribution costs accounting for the remaining 6%.

Figure 10 Distribution network costs account for 17-18% of electricity system costs



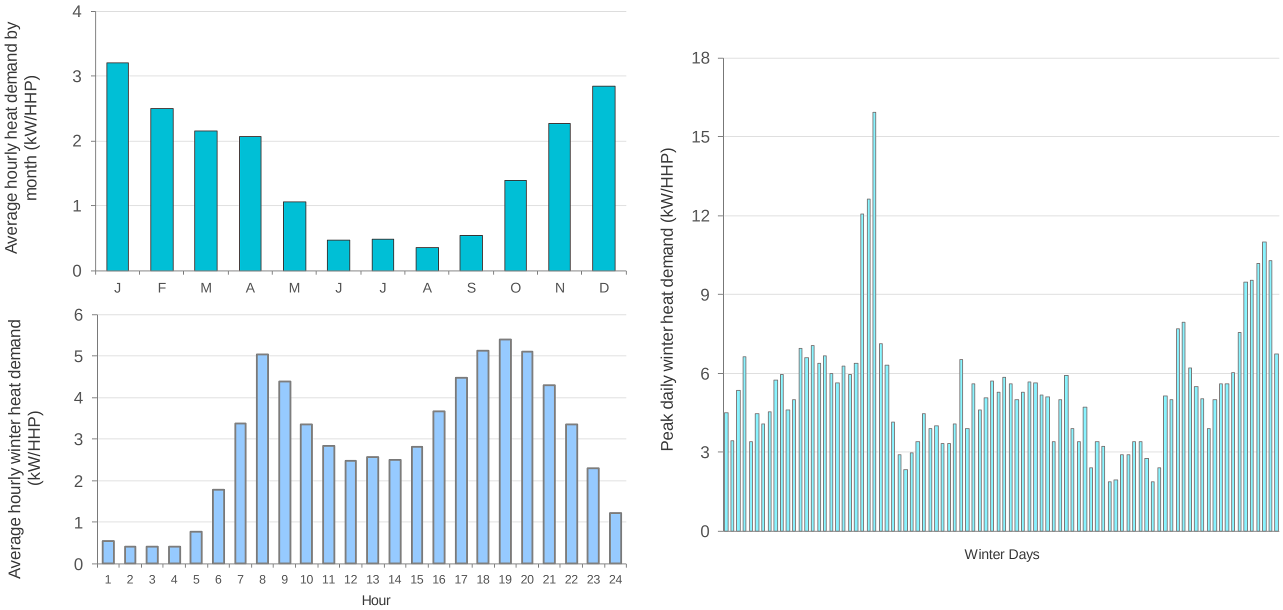
Note: In line with current practice, transmission and distribution investment costs are annuitized to produce an annual cost. Annuitisation is over a 40 year period, at a discount rate of 3.5%.

Source: Vivid Economics, Imperial College

3.2 Value of hybrid heat pumps

Heat demand is highly uneven. Figure 11 shows variation in overall heat demand (comprising both space heating and hot water demand) for an average household across different time periods. Heat demand is highly seasonal, with average demand in winter around nine times higher than demand in summer. Variation within a single winter day is even larger, with average demand at the evening peak (between 5 and 8pm) around thirteen times higher than overnight (between 1 and 4am). Finally, there is considerable variation even within winter peaks. Over a single winter, the highest peak could be around nine times greater than the lowest peak, driven by the impact of variation in temperatures on demand for heat across the winter.

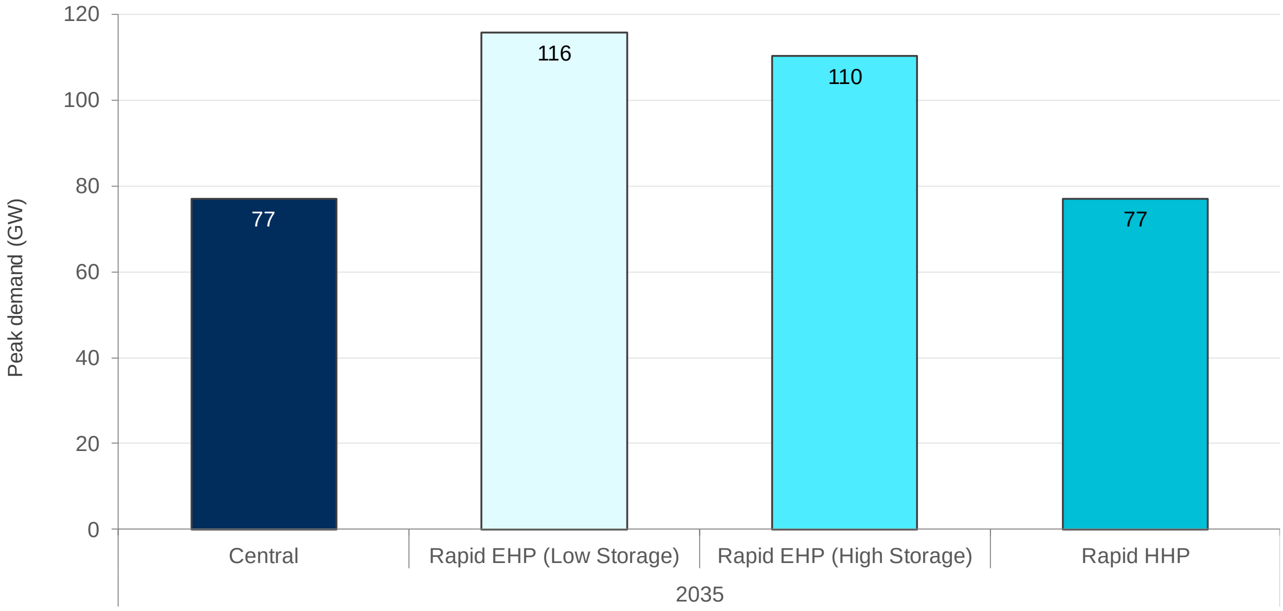
Figure 11 Heat demand varies significantly throughout the year, the day, and across winter peaks



Source: Vivid Economics, Imperial College

Hybrid heat pumps would significantly reduce demand peaks for electrified heat. To illustrate the impact of fully electrifying heat production, we develop a scenario for electric-only heat pumps (the Rapid EHP scenario). Overall deployment of heat pumps in the Rapid EHP scenario is the same as in the Rapid HHP scenario. The Rapid EHP scenario comprises a Low Storage and High Storage variant. In the Low Storage variant, around 15% of electric heat pumps are fitted with storage by 2035, while in the High Storage variant, 40% are fitted with storage. Figure 12 shows the level of peak electricity demand under different scenarios for the electrification of heat. In the Low Storage variant of the Rapid EHP scenario, peak electricity demand increases from 77 to 116 GW, as very high levels of heat demand on a limited number of days is provided by electric-only heat pumps, and ability to shift this demand through storage is limited. In the High Storage variant, peak electricity demand is slightly lower at 110 GW, as storage provides greater ability to shift demand away from the peaks. In the Rapid HHP scenario, peak electricity demand is no higher than in the Central scenario, as hybrid heat pumps switch hybrid heat pumps from electric mode to gas mode at peak times.

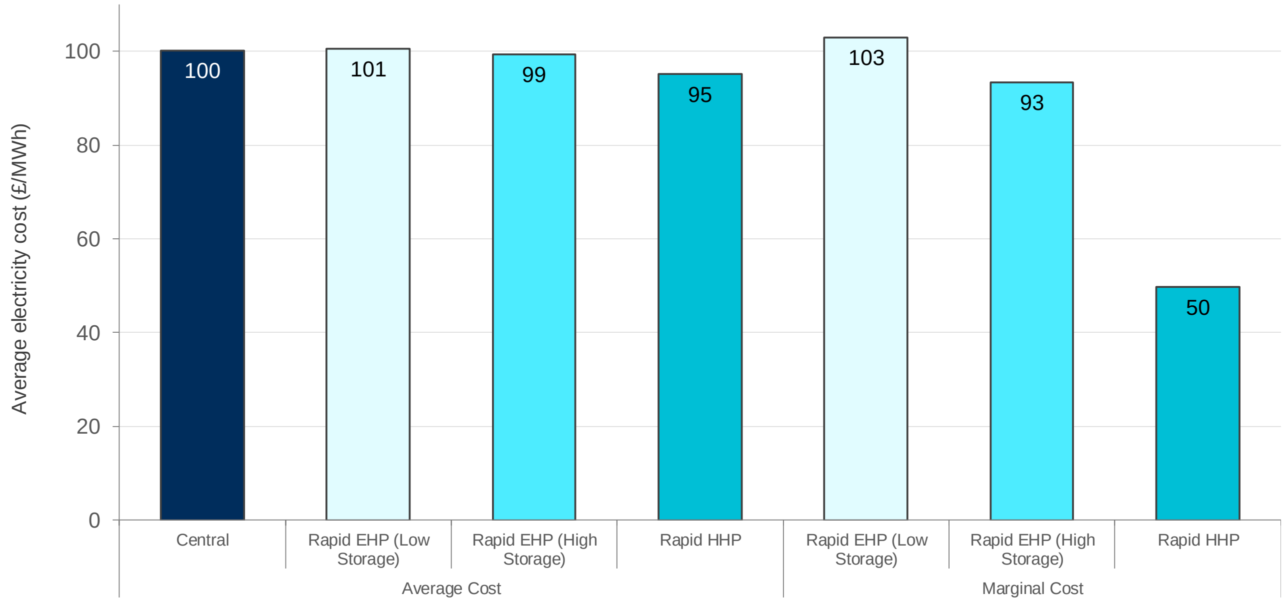
Figure 12 Unlike conventional heat pumps, hybrid heat pumps may have no impact on peak demand



Source: Vivid Economics, Imperial College

As a result, hybrid heat pumps could deliver large cost reductions. Given that heat demand reaches very high levels on a limited number of days, capacity built to meet that level of heat demand would be costly. Figure 13 shows the average and marginal cost of meeting electricity demand under different scenarios for the electrification of heat. The average cost of electricity does not differ significantly across scenarios, as electrified heat makes up only a small proportion of total electricity demand. However, the marginal cost of meeting additional demand for electrified heat varies significantly. In the low and high storage variants of the Rapid EHP scenario, the cost of meeting additional demand for electrified heat are around £103/MWh, while in the Rapid HHP scenario the cost of meeting additional demand for electrified heat is £50/MWh, or the projected cost of new renewables in 2035. This indicates that in a flexible electricity system, hybrid heat pumps are able to make highly efficient use of new renewable generation capacity.

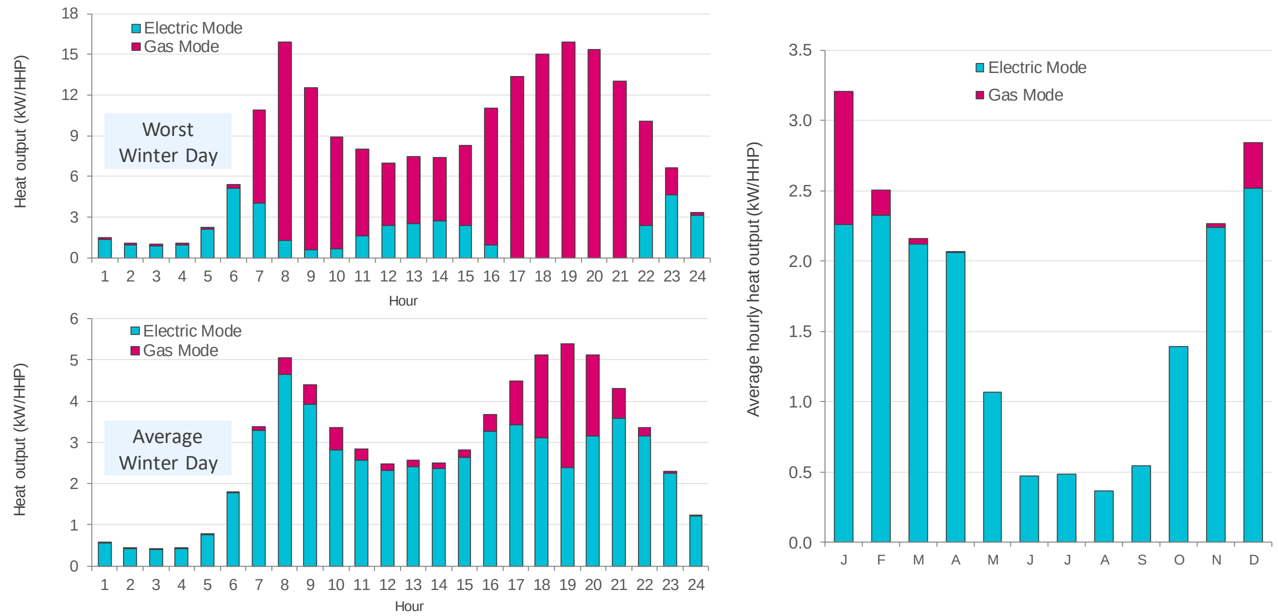
Figure 13 The cost of meeting demand for conventional heat pumps is much higher than for hybrid heat pumps



Source: Vivid Economics, Imperial College

Provided they are used efficiently, hybrid heat pumps could still deliver large carbon savings. If used efficiently, hybrid heat pumps could meet 93% of heat demand in electric mode, reducing CO2 emissions relative to a gas boiler by the same amount. Figure 11 shows heat demand met by hybrid heat pumps in electric and gas modes across different time periods. As there is considerable variation within winter peaks, on some days the majority of heat demand is met in gas mode. For example, on the worst modelled winter day, when peak heat demand from a household equipped with a hybrid heat pump reaches almost 15 GW, only 20% of heat demand is met in electric mode. However, on an average modelled winter day, when peak heat demand reaches around 5 GW, 83% of heat demand is met in electric mode. And outside of winter, around 99% of heat demand is met in electric mode, as heat demand is significantly lower and less peaky.

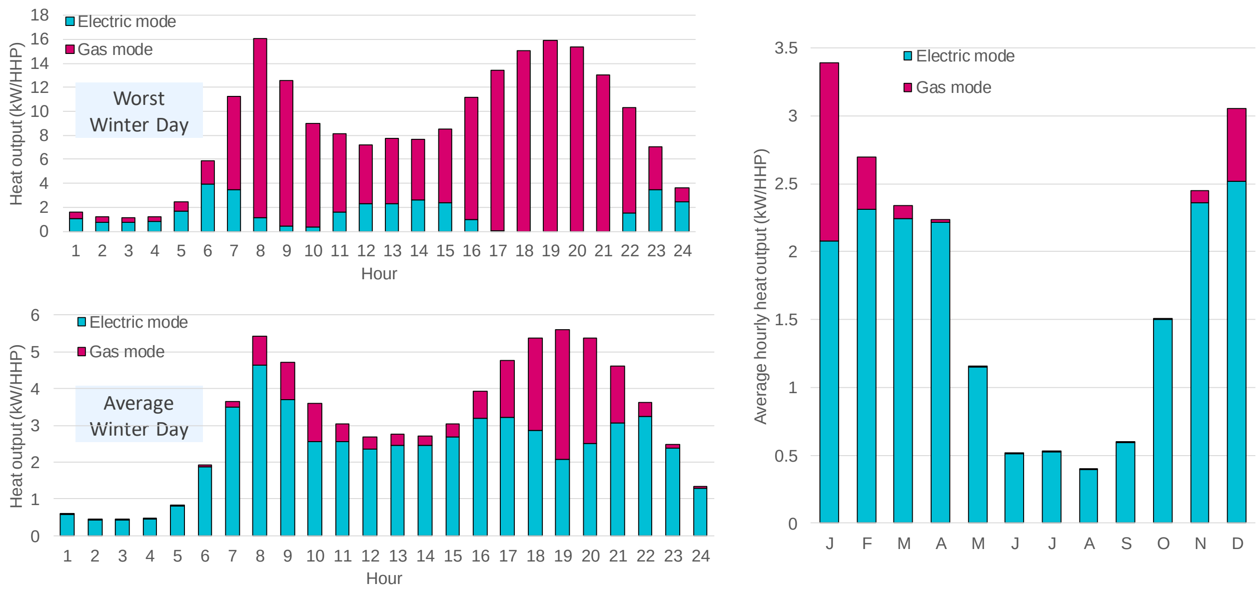
Figure 14 If used efficiently, hybrid heat pumps could meet over 90% of heat demand in electric mode



Source: Vivid Economics, Imperial College

If used inefficiently, hybrid heat pumps could meet a greater share of demand in gas mode. To ensure that consumers use hybrid heat pumps in electric mode when it is cost-effective to do so, they will need to face appropriate price signals, and respond to those price signals. If consumers have an innate preference to use their hybrid heat pump in gas mode, and disregard price signals in selecting their mode of operation, they could meet a greater share of demand in gas mode than is cost-effective. Figure 15 shows heat demand met by hybrid heat pumps in electric and gas modes across different time periods if consumers do not face (or do not respond to) a carbon price on their gas consumption. In this case, the overall the share of heat demand met in electric mode decreases from 93% to 75%, eroding the environmental benefits of hybrid heat pumps.

Figure 15 If used inefficiently, hybrid heat pumps could meet only 75% of heat demand in electric mode



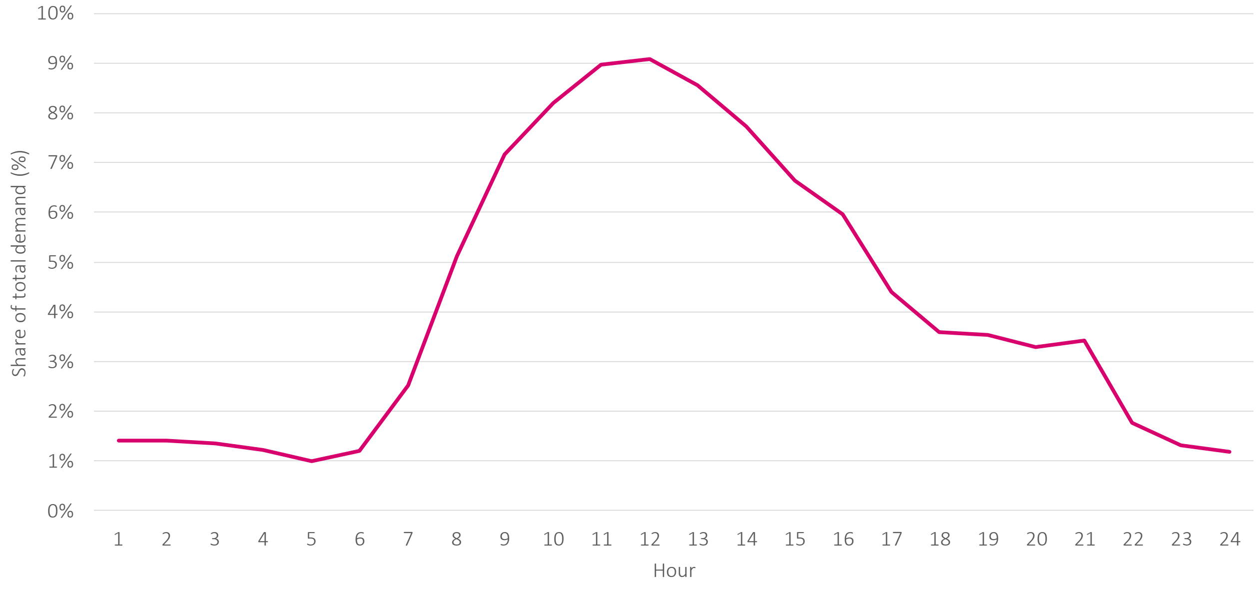
Source: Vivid Economics, Imperial College

3.3 Risks associated with accelerated electrification

3.3.1 Fast charging of electric vehicles

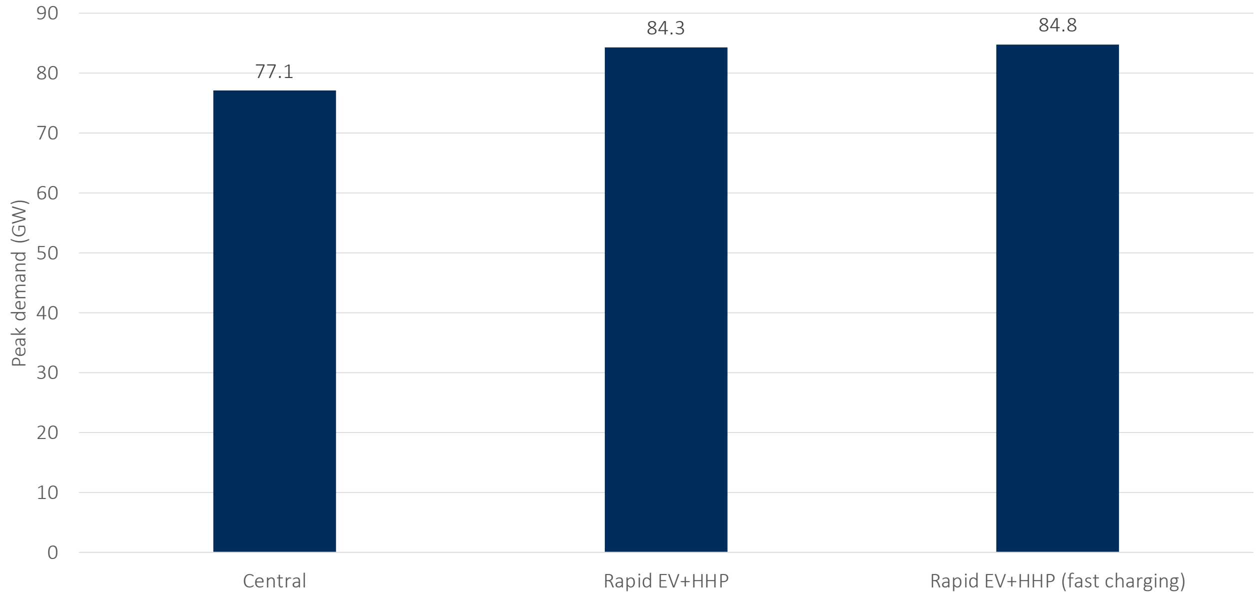
If fast chargers are predominantly used when vehicles are stationary, they would be unlikely to increase peak electricity demand. The Fast Charging scenario identifies the potential impact on the electricity system of widespread use of public fast chargers. In the Fast Charging scenario, 30% of charging demand is supplied through public fast (22 kW) charging stations. As shown in Figure 16 , public chargers are predominantly used during the day, while vehicles are stationary. Figure 17 shows peak electricity demand in the Rapid EV+HHP and Fast Charging scenarios. Peak electricity demand in the Fast Charging scenario is only slightly higher than in the Rapid EV+HHP. This is because the majority of fast charging occurs during the day, and only 3-4% of fast charging occurs during each hour of the evening peak.

Figure 16 Public chargers are predominantly used during the day



Source: Vivid Economics, Plugged-in places Chargepoint Usage Data

Figure 17 Widespread use of fast public chargers would not necessarily increase peak electricity demand

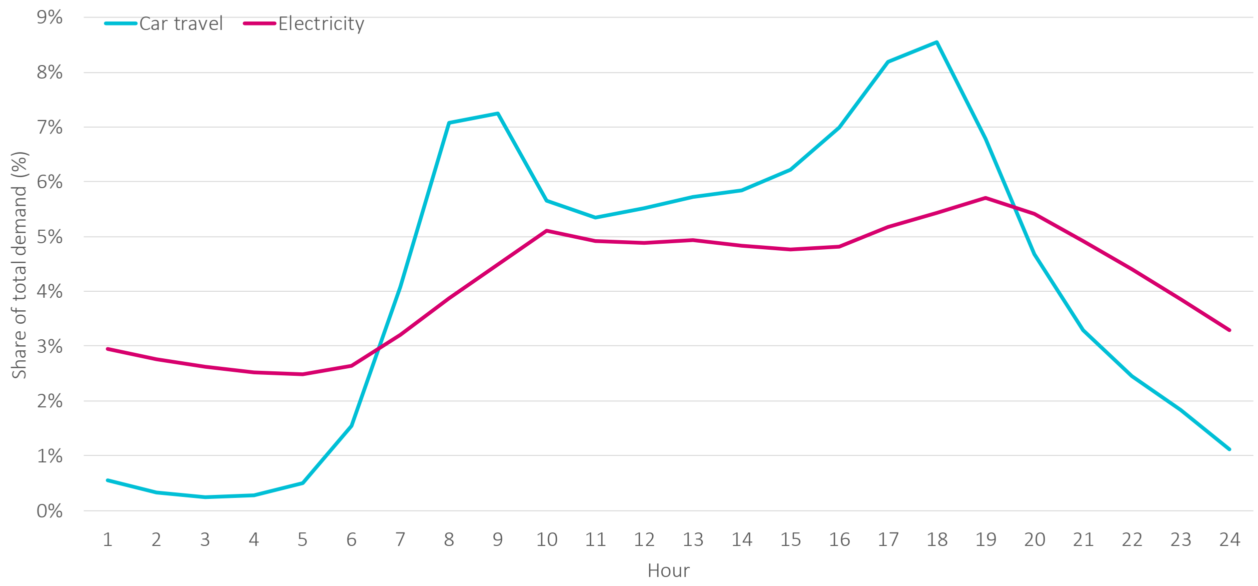


Note: The Fast Charging scenario charging profile is based on Low Carbon London project data on usage of public charging stations

Source: Vivid Economics

However, if fast chargers are predominantly used during journeys, they could substantially increase peak electricity demand. The peak in car travel is closely related to the peak in electricity demand. Figure 18 shows the time profile of car travel, and the time profile of electricity demand. The peak in car travel occurs between 6pm and 7pm, very close to the peak in electricity demand between 7pm and 8pm. The Central and Accelerated scenarios are based on an EV charging profile in which all vehicles are recharged in full immediately after a return trip. Under this charging profile, peak EV charging demand would be 16 GW in the absence of any smart charging. If one in five cars were to charge during the evening commute, electricity demand between 6pm and 7pm could increase by around 3 GW (one fifth of the 16 GW peak), potentially triggering additional investment in generating capacity and distribution network reinforcements, and increasing the cost of electricity.

Figure 18 The peak in car travel occurs very close to the peak in electricity demand



Source: Vivid Economics, Imperial College

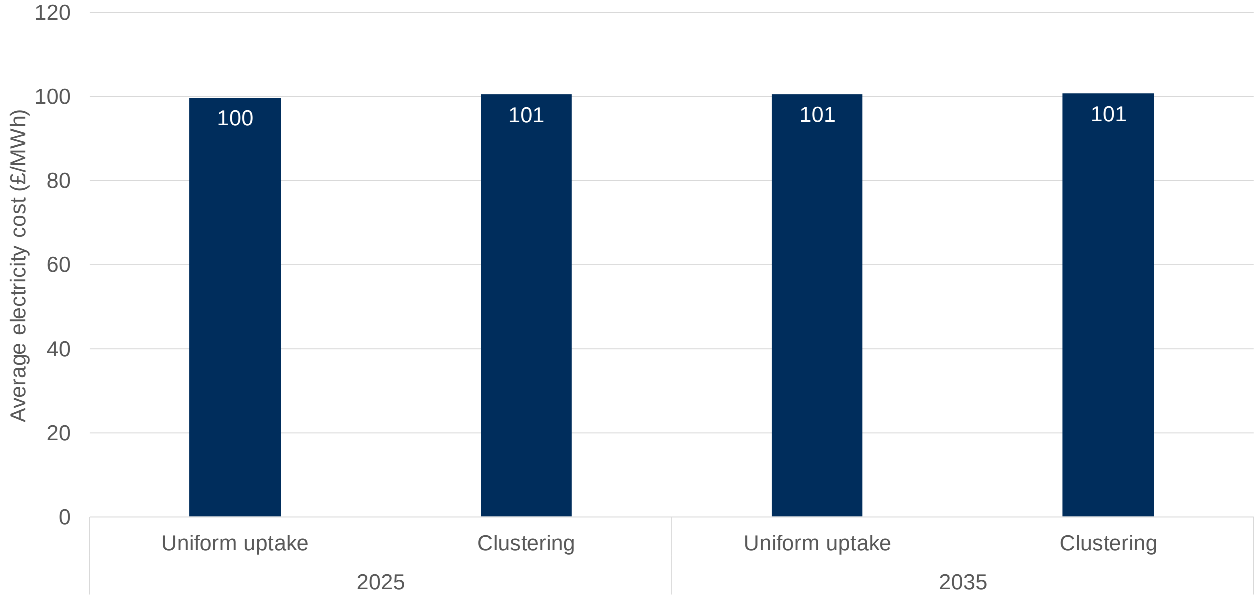
Nevertheless, impacts of widespread fast charging on the wider electricity system could be contained through cost-reflective pricing. Cost-reflective pricing would ensure that the costs of fast charging are borne by the motorists who impose them; encourage motorists to shift their charging patterns to off-peak times; and incentivise operators of charging facilities to install battery storage to minimise the volume of additional investments needed.

3.3.2 Clustering of electric vehicle and hybrid heat pumps

Some areas might see faster uptake of electric vehicles and hybrid heat pumps than others. So-called ‘clustering’ of electric vehicle and hybrid heat pump uptake could occur for a number of reasons. Early adopters of electric vehicles and hybrid heat pumps might influence other consumers in their communities to switch to these technologies. Alternatively, some areas might be better suited to electric vehicles and hybrid heat pumps than others due to differences in travel patterns, availability of charging infrastructure, or variation in the size and thermal efficiency of the building stock.

Clustering will have important implications for distribution networks, but overall impacts on electricity costs will be small. Section 4 describes the impact of clustering on distribution networks, and demonstrates that clustering could increase the cost of distribution network reinforcements by around 29% in 2025, falling to 2% by 2035. However, distribution network reinforcement costs account for only a small share of total electricity system costs in the Rapid EV+HHP scenario (around 3% of total in 2025, rising to 5% by 2035). Figure 19 shows the average cost of electricity in 2025 and 2035 under uniform uptake and clustering. Clustering is defined as highly uneven uptake, ranging from zero in some areas, to three times average levels in others. Overall, clustering of electric vehicles and hybrid heat pumps could increase the average cost of electricity by around 1% in 2025, and by only around 0.1% by 2035.

Figure 19 Clustering of electric vehicles and hybrid heat pumps would have little impact on average electricity costs



Source: Vivid Economics, Imperial College

4 Impacts on distribution networks

Box 2 Key messages

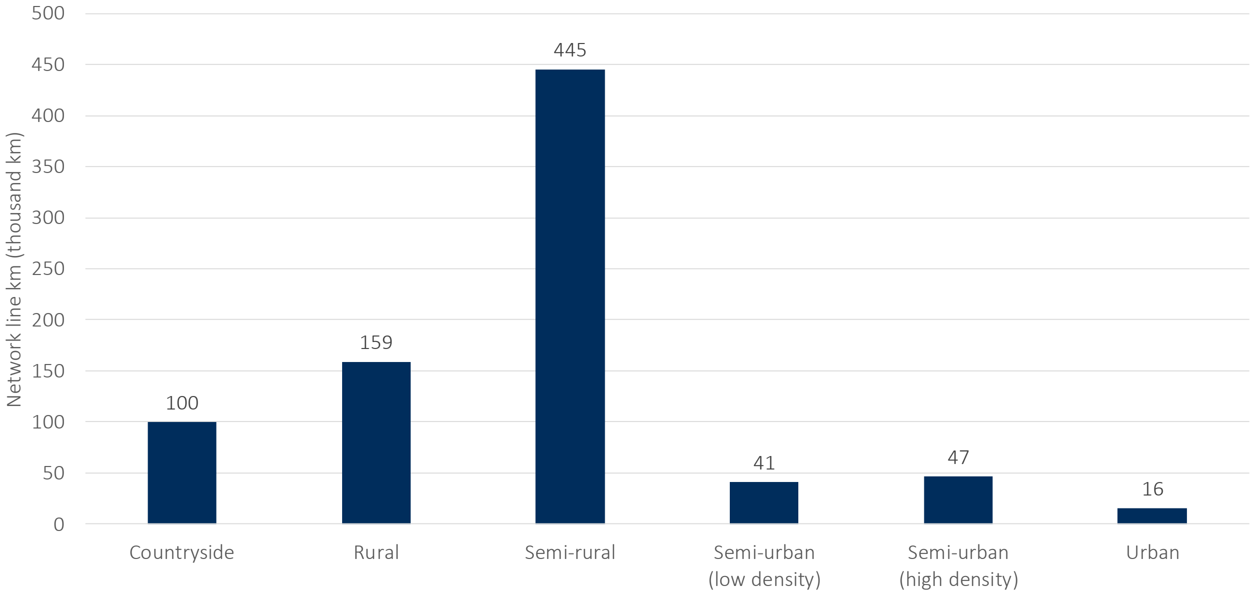
While new distribution network investment will be needed, it will represent no more than 4% of the cost per kWh of electricity.

- Utilisation of the existing distribution network is poorly understood. If network is close to fully utilised (there is no 'headroom' in network capacity), an increase in electricity demand could significantly increase the quantity and cost of reinforcements. Accurate information on network utilisation is needed before the right distribution network investments can be made.
- Significant distribution network reinforcements could be needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps.
- Overall, rapid uptake of electric vehicles and hybrid heat pumps could increase total expenditure on distribution networks by up to £50 billion by 2035, or £1.8 billion per year. However, this investment represents only 4% of the total cost of the electricity system.
- The high cost of reinforcing underground network lines accounts for around two thirds of the cost of reinforcing distribution networks. Costs of overhead lines and transformers make up the remainder.
- Flexible resources can substantially reduce the cost of the necessary network reinforcements. Around 20 GW of battery storage and 9 GW of demand response can reduce the cost of reinforcing distribution networks by almost 10% by 2035. In principle, electric vehicles providing vehicle-to-grid services could provide some or all of the necessary battery storage.
- Further cost reductions could be achieved by relaxing the current 'P2/6' network security standard. This standard requires a degree of redundancy in network assets to minimise the risk of supply interruptions for all network users; however, the cost of this redundancy could be greater than the value of the enhanced security that it confers.
- A range of additional measures, including changing voltage levels, splitting network lines and smart voltage control, could further reduce the need for network reinforcements.
- Clustering of electric vehicles and heat pumps could increase network reinforcement costs in the near term, but will would not materially increase costs over the long term.
- The majority of network reinforcements will occur in semi-rural networks, where disruption will be low. However, reinforcements to urban networks could create disruption. With accelerated electrification, the majority of urban networks could need upgrading, and much of the upgrades will be to underground lines.

4.1 Introduction

The GB distribution networks consist of hundreds of thousands of kilometres of network lines and transformers. Lines and transformers are distributed across a range of network topologies, and at several voltage levels. Figure 20 shows total network length by topology across the low- and high- voltage network. Analysis by Imperial College indicates that the total replacement cost of the distribution network could be around £100 billion.

Figure 20 The distribution network includes of over 800,000 km of lines across different network topologies



Source: Vivid Economics, Imperial College

Utilisation of the GB distribution network is poorly understood. A network line or transformer needs reinforcing if its capacity is lower than the demand it faces. In order to accurately estimate the quantity and cost of network reinforcements needed to meet growing electricity demand, accurate information on the capacity and demand on the 800,000 km of distribution network lines would be needed. However, this information is not currently available.

The quantity and cost of network reinforcements needed to meet growing electricity demand will depend on the degree of utilisation of the existing network. If the network is close to fully utilised (there is no 'headroom' in network capacity), an increase in electricity demand could significantly increase the quantity and cost of reinforcements. If the network is less than fully utilised (there is significant headroom in network capacity), an increase in demand could have a more moderate impact on the quantity and cost of reinforcements. This section first considers in detail the impacts of accelerated electrification on the assumption that there is very limited headroom in distribution network capacity; it then considers the implications for these results in the event that there is significant headroom.

4.2 Overall impacts

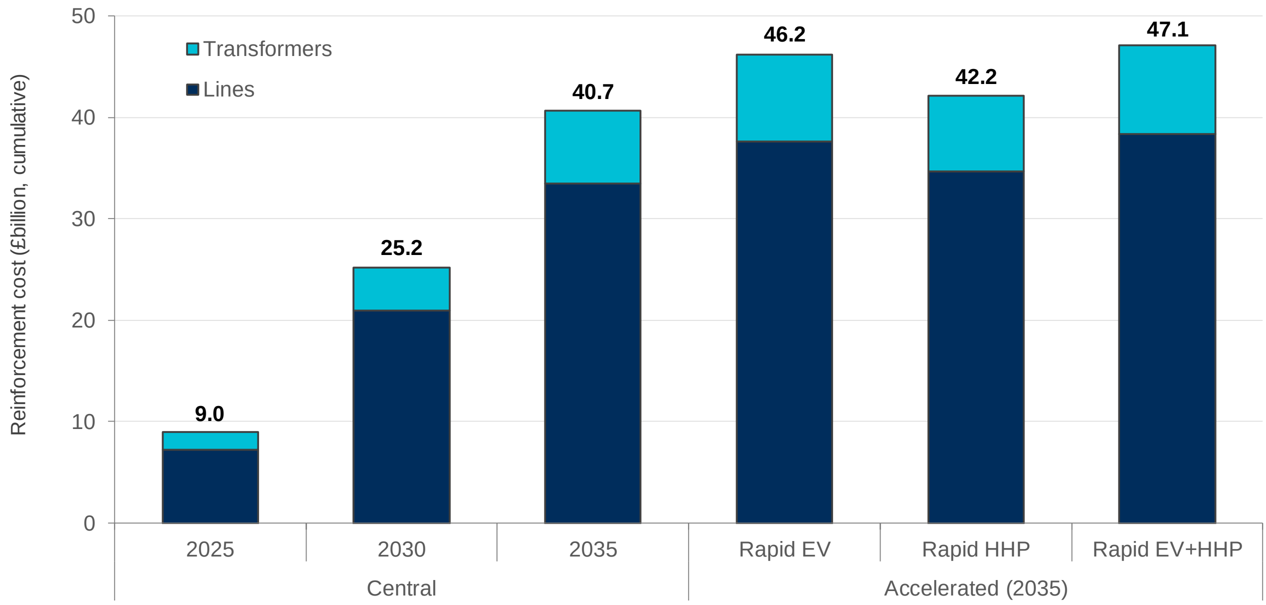
In the Central scenario, significant distribution network reinforcements are needed to 2035. Figure 21 shows the investment in distribution network reinforcements needed in the Central and Accelerated scenarios over the period to 2035. In the Central scenario, around £9 billion of total cumulative investment is needed by 2025, rising to around £41 billion in 2035.

Further distribution network reinforcement is needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps. As shown in Figure 21:

- In the Rapid EV scenario, total cumulative investment ton 2035 could be around £46 billion, 14% higher than in the Central scenario;
- In the Rapid HHP scenario, total cumulative investment could be around £42 billion, only 3% higher than in the Central scenario; and

- In the Rapid EV+HHP scenario, total cumulative investment could be £47 billion, 16% higher than in the Central scenario.

Figure 21 Distribution network reinforcement costs increase with electrification, and particularly with electric vehicles



Source: Vivid Economics, Imperial College

These costs could represent a doubling of network investments relative to today's levels, and an overall 35-40% increase in distribution charges. DNOs collect their revenues from customers through Distribution Use of System charges (DUoS). The DuOS charges reflect the DNOs' approved expenditure levels, and the impacts of other incentive mechanisms such as the IIS, and other adjustments to allow for the cost of capital and taxation. The cost of the distribution network reinforcements needed to 2035 in the Central and Accelerated Scenarios can be compared with the historical revenues DNOs have collected from consumers:

- In 2017/18, DNOs were allowed to collect £5.5 billion through customer bills. In the same year, expenditure on network investment amounted to around £1.2 billion, of which network reinforcement accounted for £345 million, and routine maintenance ('replacing and refurbishing equipment') accounted for £897 million (Ofgem, 2017). The remaining revenues are accounted for by the cost of operating the DNOs, repairing network faults, and a set of financial adjustments accounting for the difference between expenditure and allowed revenues.
- The cost of network reinforcement needed to 2035 in the Central and Accelerated Scenarios ranges from £1.9-2.2 billion per year, a £1.6-1.9 billion increase on current levels. Increasing the capacity of network lines is not expected to increase costs of routine maintenance; however, it is possible that an increase in reinforcement costs could also increase other costs of operating the DNOs.
- This comparison indicates that the additional reinforcement costs to 2035 could represent a doubling of expenditure on network investments from current levels, but only a 34-39% increase in DuOS charges to consumers.

Upgrades to network lines make up the majority of new network reinforcement. Figure 21 also shows the split of investment in network reinforcement between network lines and transformers. The cost of lines account for 81%-83% of investment to 2035, and across scenarios. Figure 22 shows the length of network line reinforcement in each scenario. In the Central scenario around 75,000 km of line reinforcement is needed to 2025 (9% of the total network), rising to around 340,000 in 2035 (42% of the total network).

Relative to the increase in reinforcement needed in the Central scenario, the impact of accelerated electrification is relatively limited. The Rapid EV scenario increases the amount of network line reinforcement needed by 2035 by only 12%, while the Rapid HHP and Rapid EV+HHP scenarios increases the amount of reinforcement needed by 3% and 13%, respectively.

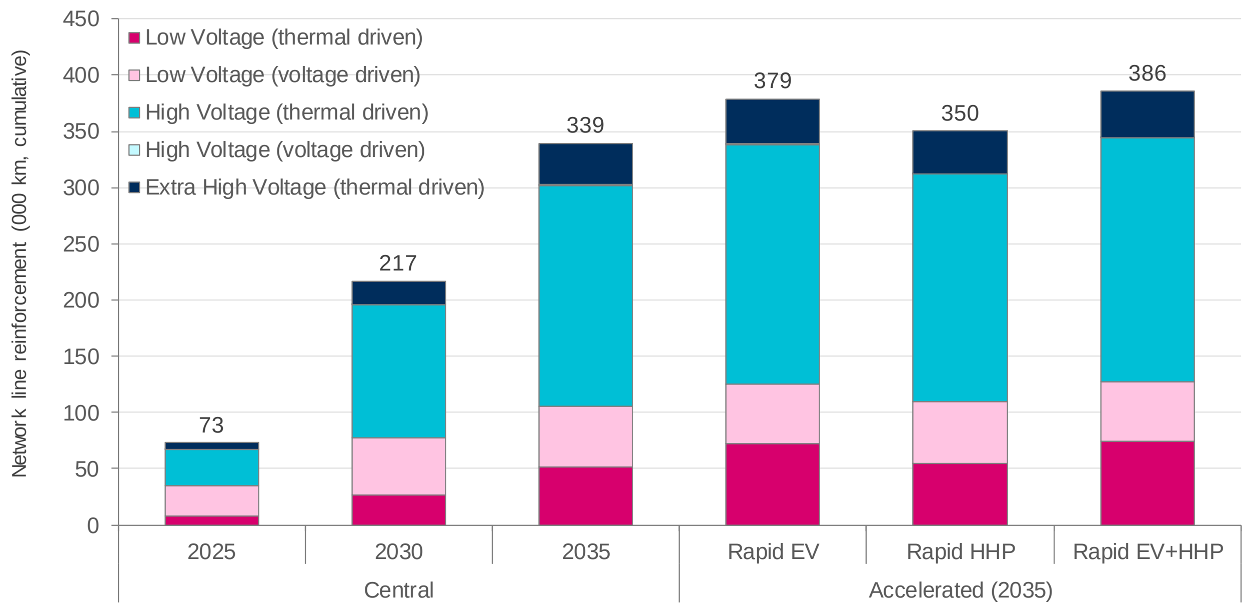
The majority of upgrades occur at the low and high voltage levels. Figure 22 also shows the length of network line reinforcement at each voltage level. By 2035, extra high voltage lines account for around 10% of network line reinforcement, high voltage lines for around 60% and low voltage lines for around 30%, in all scenarios.

Voltage constraints drive network reinforcements in the early years, but thermal constraints increasingly drive reinforcements in later years, and with accelerated electrification. Network reinforcements can be triggered by thermal constraints, or voltage constraints:

- **Thermally driven constraints.** An increase in electricity demand may raise the power flow above a network cable or transformer's capacity (strictly, its apparent power, measured in volt-amperes).
- **Voltage-driven constraints.** Longer network lines suffer from voltage drop, where the voltage decreases the further the electricity travels. Distribution network operators are required to limit voltage drop and maintain voltage within -6%/+10% of the nominal connection voltage. Voltage drop is higher with high resistance (low capacity) cables, and with higher levels of power flow. An increase in demand (and therefore power flow) on a network line could cause the voltage to drop below 6% of its nominal level. In that case, a lower resistance (higher capacity) cable would be needed to limit the voltage drop, even if the rated capacity of the line is adequate for the increase in demand.

Figure 22 shows the length of network line reinforcement at each voltage level. At the high and extra high voltage levels, 99-100% of reinforcements are triggered by thermal constraints. At the low voltage level, the role of thermal and voltage constraints changes over time and across scenarios. In the Central scenario, voltage constraints account for the majority of upgrades in 2025, but thermal constraints account for around half of upgrades by 2035. In the Rapid EV and Rapid HHP scenarios, the impact of electric vehicles on peak demand places greater strain on network capacity, and thermal constraints account for 57-58% of upgrades. Across all voltage levels, thermal constraints account for 84-86% of upgrades in 2035.

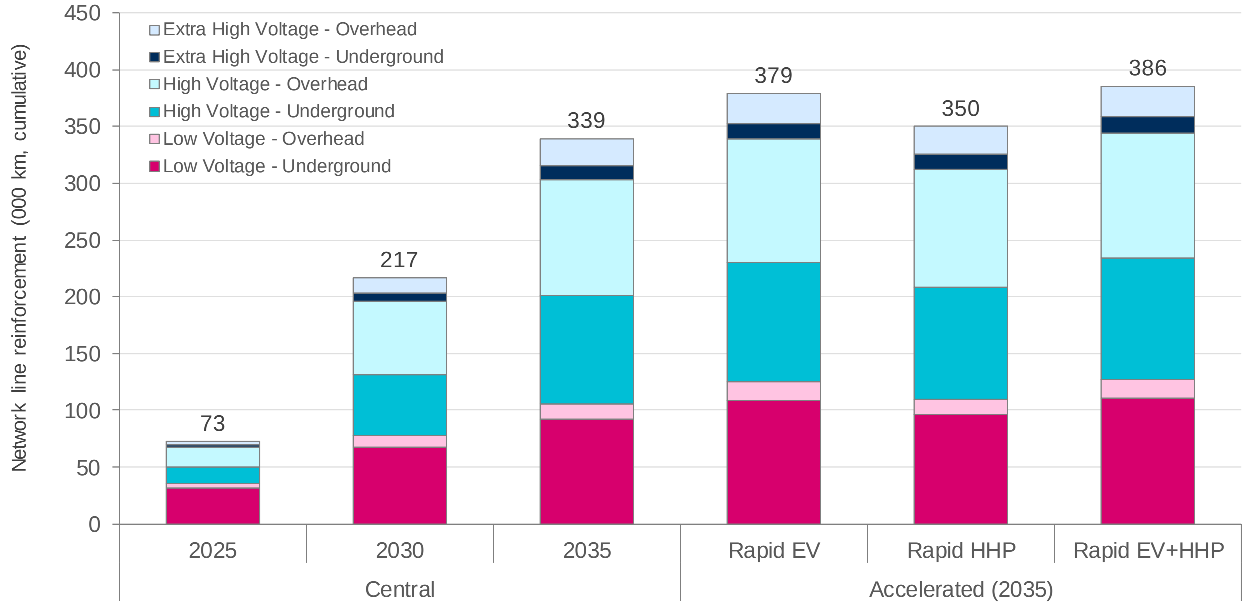
Figure 22 Electrification of heat and transport will require significant reinforcement of network lines



Source: Vivid Economics, Imperial College

The majority of upgrades and reinforcement costs are to underground network lines. Figure 23shows the length of network reinforcement, split between underground and overhead lines. The share of underground lines is highest at low voltages. At the extra high voltage level, underground lines account for only a third of reinforcements; however, underground lines account for just under half of all reinforcement at the high voltage level, and 87-88% of reinforcement at the low voltage level. Across all voltage levels, underground lines account for 59-66% of upgrades. The cost of upgrading underground lines is significantly higher than overground, due to the works that need to be carried out to access underground cables. Therefore, while 59-66% of upgrades are to underground network lines, these upgrades make up a significantly larger share of total reinforcement costs. Figure 24 shows the total network reinforcement cost, split between underground and overhead lines. Underground lines account for around 72% of reinforcement costs at the extra high voltage level, 74-75% at the high voltage level, and around 96% at the low voltage level. Across all voltage levels, underground lines account for around 81% of reinforcement costs in all scenarios in 2035.

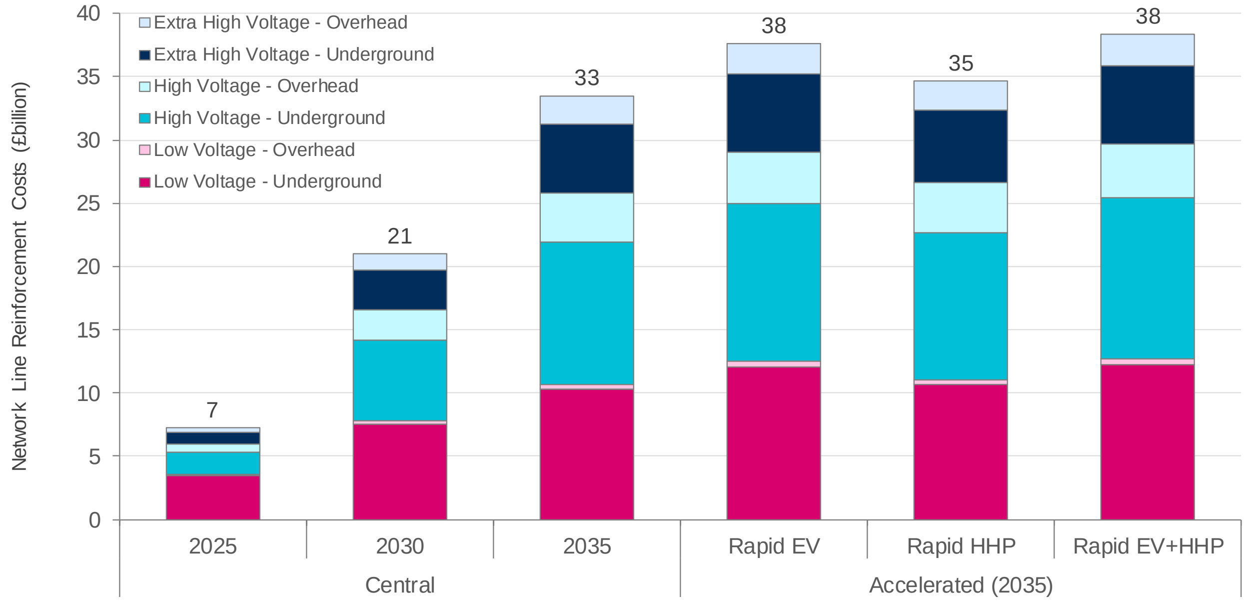
Figure 23 The majority of upgrades are to underground network lines



Note: The LRE model represents upgrades to the current distribution network, and does not make assumptions on the extent to which overhead lines may be undergrounded in future

Source: Vivid Economics, Imperial College

Figure 24 The majority of network reinforcement costs are to underground lines

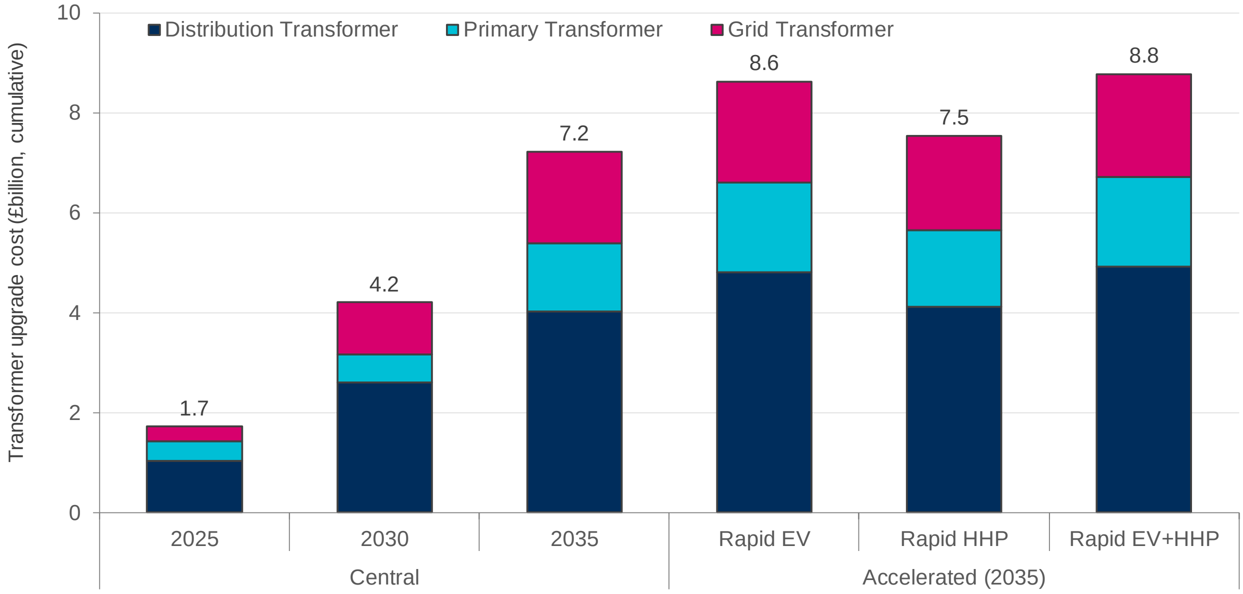


Source: Vivid Economics, Imperial College

Upgrades to transformers make up a small share of new network reinforcement. Figure 21 above shows the split of investment in network reinforcement between network lines and transformers. The cost of transformers accounts for 17-19% of investment to 2035, and across scenarios.

Figure 25 shows the total cost of transformer upgrades in each scenario, by type of transformer. The majority of reinforcement costs are accounted for by upgrades of Distribution Transformers. Distribution Transformers are used at both low (0.4 kV) and high (11 kV) voltage levels, and can be either Pole- or Ground-mounted. Pole-mounted transformers are usually installed with overhead lines in rural networks and have relatively lower ratings (up to 200-315 kVA), while Ground-mounted transformers are more common in urban areas and have ratings from 200 kVA and above. The remainder of reinforcement costs are accounted for by upgrades of Primary and Grid Transformers. Primary Transformers at used at high (11 kV) and extra-high (33 kV and above) voltage levels, while Grid Transformers are used at the 66 kV or 132 kV voltage levels.

Figure 25 Upgrades to transformers make up a small share of new network reinforcement.

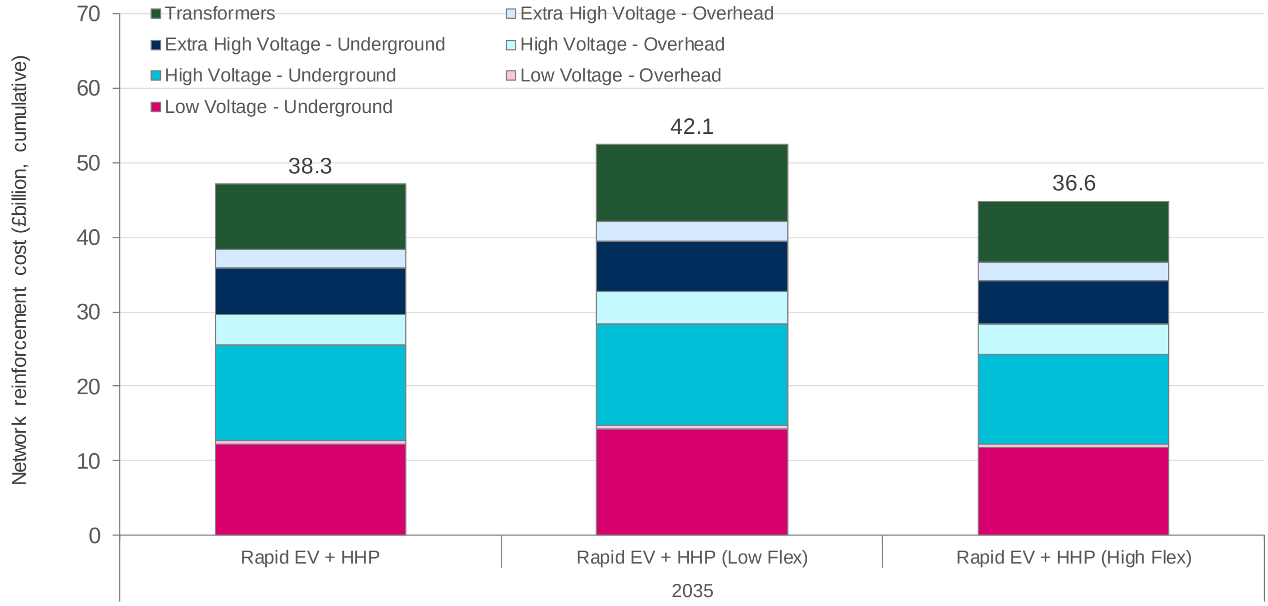


Source: Vivid Economics, Imperial College

4.3 Alternatives to network reinforcement

Flexible resources can substantially reduce the cost of the necessary network reinforcements. Demand response and storage can avoid congestion on electricity networks by shifting demand for electricity from congested to uncongested periods. As a result, these technologies can reduce the cost and volume of network reinforcements needed. Figure 26 shows the cost of network reinforcements needed at each voltage level in the Rapid EV+HHP scenario, under different levels of demand response and storage. The Rapid EV+HHP scenario already uses demand response and storage to reduce the cost of network reinforcements. To illustrate this, we modelled a Low Flex variant of this scenario, representing current levels of electricity system flexibility. The Low Flex variant reflects limited battery storage and demand response (2 GW of battery storage and 1 GW of demand response from industrial and commercial customers). Due to the limited availability of flexible resources in the Low Flex variant, total network reinforcement costs in 2035 are 9% higher than in the core Rapid EV+HHP scenario. Additional demand response and storage can further reduce the cost of network reinforcements. The additional demand response and storage in the High Flex variant of the Rapid EV+HHP scenario reduces the cost of network line reinforcement by a further 4% in 2035.

Figure 26 Flexible resources can substantially reduce the cost and volume of the necessary network reinforcements

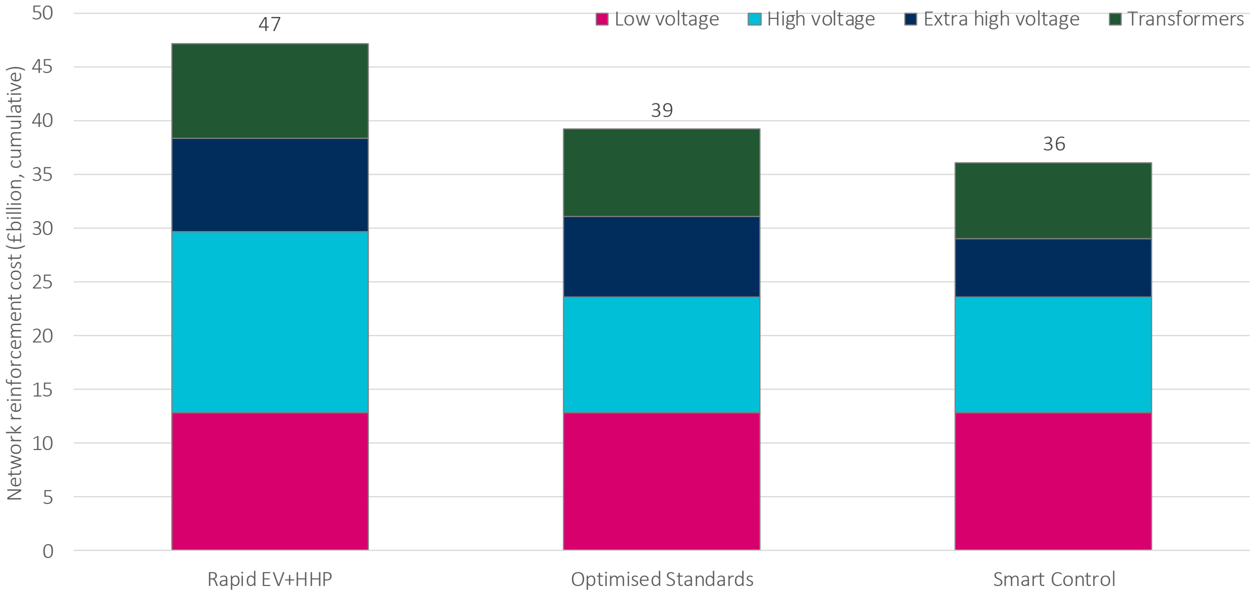


Source: Vivid Economics, Imperial College

The current network security standard could be too stringent, unnecessarily increasing reinforcement costs. The current network security standard, P2/6, requires a degree of redundancy in network assets, to ensure that the failure of an individual network asset does not result in supply interruptions. Specifically, the current standard requires investment in excess capacity of network resources at the high- and extra-high voltage levels in order to ensure that demand can be met in the event of equipment failure. However, previous analysis by Imperial College (2014) indicates that such a requirement is not cost-effective, as the cost of the additional network infrastructure that it requires is greater than the value of the enhanced security that they confer. The Optimised Standards scenario represents the impact of relaxing the P2/6 standard. Instead of the 'n-1' requirement, additional network infrastructure investment only occurs where the benefits (in terms of the enhanced security and protection against supply interruptions) are greater than the costs, measured at the Value of Lost Load (VoLL). Figure 27 shows that total network reinforcement costs in the Optimised Standards scenario are around £8 billion (17%) lower than in the Rapid EV+HHP scenario in 2035.

Smart network control could deliver further cost reductions. The value of secure energy supply is not the same to all users. For example, London Economics estimated that the value of secure, uninterrupted electricity was highest for small and medium-sized enterprises (at £33-44,000/MWh); lower for domestic consumers (at £7-12,000/MWh) and lowest for industrial and commercial consumers (at around £1,500/MWh). Smart network control, like demand response, allows users to be compensated for voluntarily reducing their electricity consumption to address an unexpected shortfall in network capacity, in a manner similar to demand response. If users who place a low value on electricity consumption at the moment a shortfall in network capacity are rewarded for reducing their electricity demand, the volume of reinforcement needed can be reduced further. The Smart Control scenario represents the impact of both relaxing the P2/6 standard, and implementing smart network control. As with the Smart Control scenario, additional network infrastructure investment only occurs where the benefits are greater than the costs. However, as smart network control allows users who place a low value on electricity consumption at the particular time a shortfall in network capacity occurs to reduce their consumption, the needed investment is lower than if the costs are valued at the VoLL. Figure 27 shows that smart network control could reduce costs by a further £3.1 billion (8%) relative to the Smart Control scenario, and a total of £11.1 billion (24%) relative to the Rapid EV+HHP scenario.

Figure 27 Optimising security standards and smart network control could further reduce reinforcement costs



Source: Vivid Economics, Imperial College

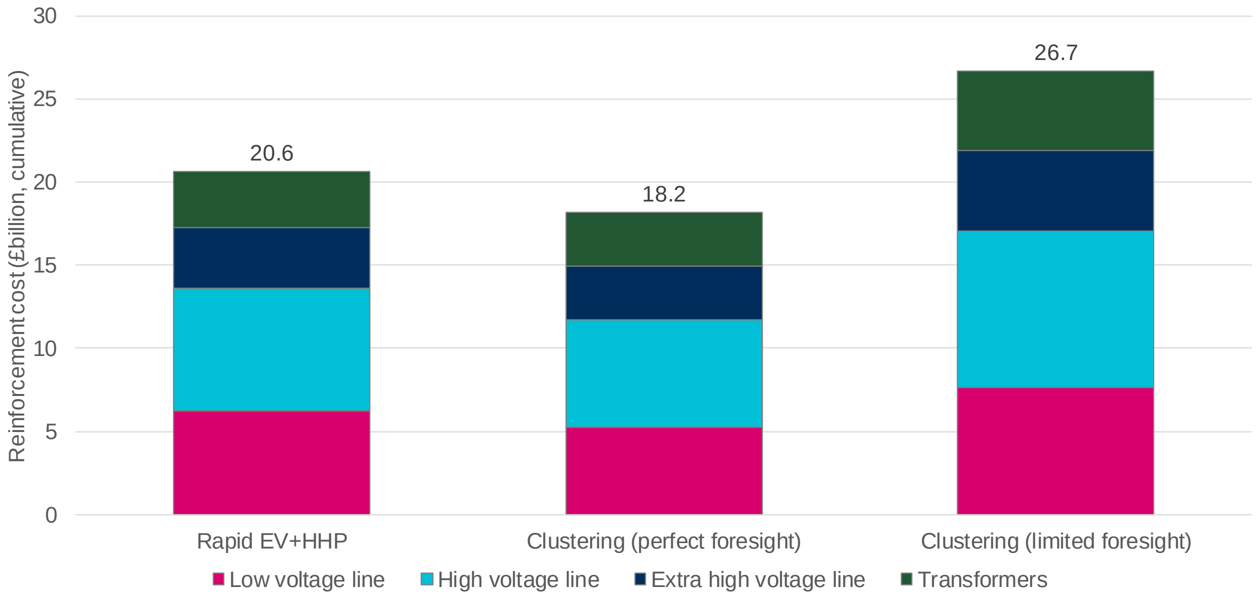
Further measures to reduce the need for network reinforcements include changing voltage levels, splitting network lines and smart voltage control. The traditional approach to distribution network reinforcement detects a voltage or thermal issue for a component, and replaces this component with the one with a higher rating. Historical network design philosophy however does not question the appropriateness of the currently used voltage levels, nor whether the existing network design philosophy is appropriate for the future, which may result in an inefficient network design. There are several alternative reinforcement strategies that have the potential to reduce the future reinforcement cost:

- Changing voltage levels. In this concept the 33 kV voltage level would be made redundant by introducing a direct 132/11 kV transformation, or by replacing 33 and 11 kV levels with an intermediate level of 22 kV. The benefits of this approach with fewer transformation steps could include lower network cost due to reduced number of transformers required.
- LV network splitting. Instead of replacing feeder sections on a like-for-like basis, it may be possible to insert additional distribution substations into the LV network in order to reduce the lengths of LV feeders and thus mitigate overloading and inadequate voltages, while reducing the need to reinforce LV feeder sections. Although the cost of inserting additional distribution transformers with accompanying switchgear would be higher than the cost of transformer upgrade in the like-for-like approach, this cost would normally be greatly outweighed by the savings from lower feeder reinforcement cost. The network splitting option may however not be available in all locations due to various potential physical constraints on building new substations. Therefore a realistic efficient reinforcement strategy would be somewhere between the like-for-like and the unconstrained network splitting strategy.
- Smart voltage control: A significant proportion of network reinforcement cost, particularly in rural networks, is driven by voltage constraints. This creates considerable opportunities for reducing network reinforcements through implementing LV voltage control solutions such as in-line voltage regulators or distribution transformers with an on-line tap changing capability. The effect of smart voltage control would be broadly equivalent to relaxing the voltage statutory limits (the lower limit in the UK's LV distribution networks is currently 6% below nominal value).

4.4 Clustering of electric vehicles and hybrid heat pumps

In the near term, uncertainty over where clustering will occur could increase the cost of reinforcement. Clustering of electric vehicles and heat pumps is defined in Section 3. If the location of clustering could be predicted in advance, clustering could reduce the cost of reinforcing distribution networks. If uptake of electric vehicles and hybrid heat pumps occurs faster in some areas than others then areas of the network where uptake is faster would need to be reinforced with higher capacity, while some areas where deployment is slower may not need to be reinforced at all. Furthermore, clustering could occur in areas of the network which are less than fully utilised (there is significant headroom in network capacity), further reducing needed reinforcements. However, if the location of clustering cannot be predicted in advance, it would be necessary to reinforce larger areas of the network with higher capacity to ensure that faster uptake of heat pumps and electric vehicles could be accommodated wherever this might occur. To identify the impact of uneven uptake of electric vehicles and heat pumps on reinforcement costs, we develop two Clustering scenarios. Figure 28 shows the total network reinforcement cost in the Rapid EV+HHP scenario in 2025, and two approaches to considering the impact of clustering. In both scenarios, overall uptake of electric vehicles and heat pumps is consistent with the Rapid EV+HHP scenario, but uptake is highly uneven, ranging from zero in some areas, to three times average levels in others. Figure 28 shows that if the location of clustering could be predicted in advance ('perfect foresight'), clustering could reduce the cost of network reinforcement by about 12%. However, if the location of clustering cannot be predicted in advance ('limited foresight'), clustering could increase the cost of network reinforcement by about 29%.

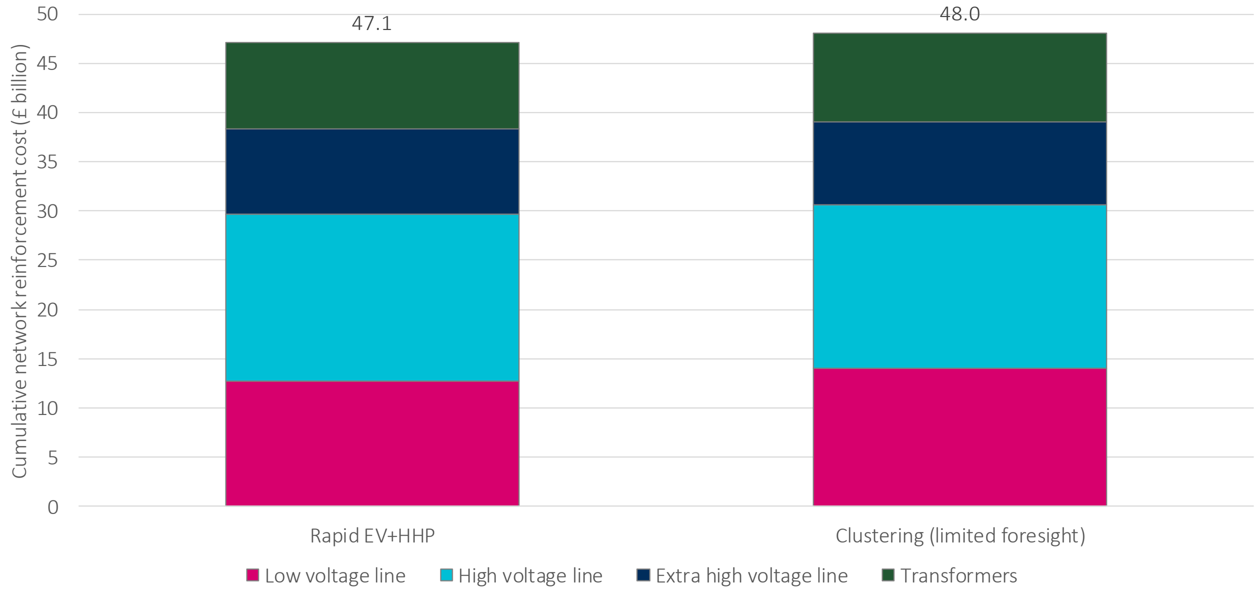
Figure 28 In 2025, clustering of electric vehicles and heat pumps could significantly increase reinforcement costs



Source: Vivid Economics, Imperial College

However over the longer term, clustering would not materially increase the cost of reinforcement. Figure 29 shows the total network reinforcement cost in the Rapid EV+HHP scenario in 2035, under both uniform uptake and clustering with limited foresight. By 2035, overall uptake of electric vehicles and hybrid heat pumps reaches such high levels across the network that uptake is highly uniform, and the scope for clustering is limited. As a result, very few additional reinforcements are needed to account for the possibility of faster uptake of heat pumps and electric vehicles in some areas. Figure 29 shows that even if the location of clustering cannot be predicted in advance, clustering might only increase the cost of network reinforcement by around 2%.

Figure 29 By 2035, clustering would not significantly increase reinforcement costs



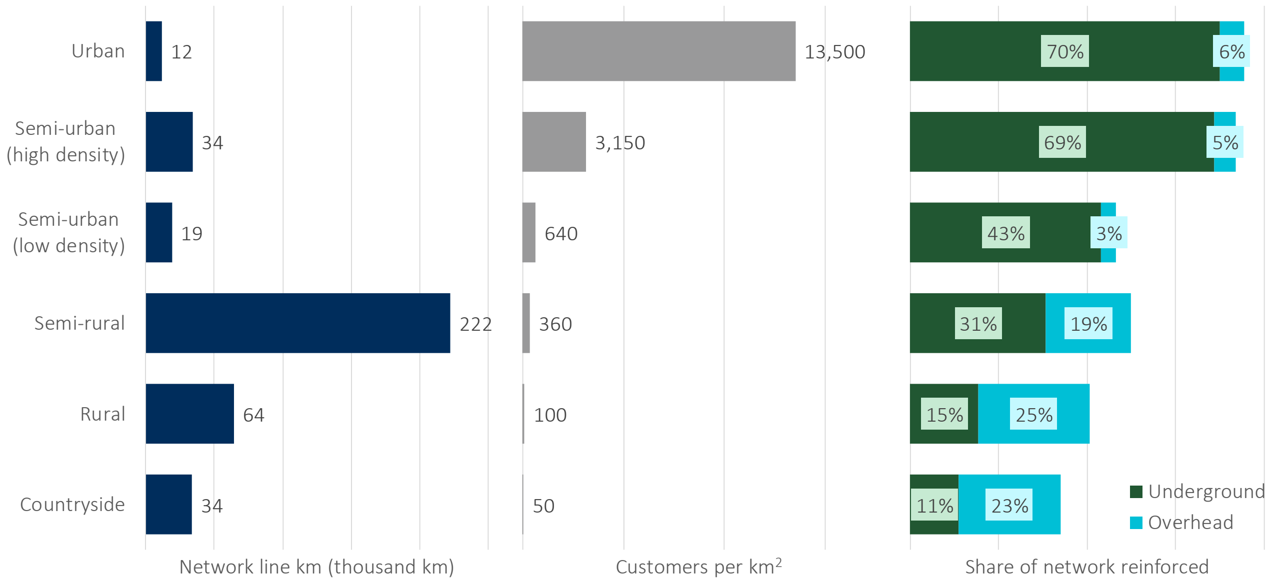
Source: Vivid Economics, Imperial College

4.5 Disruptiveness of distribution network impacts

The majority of upgrades occur in semi-rural networks, where disruption will be low. The LRE model estimates the quantity of network upgrades needed across several different network topologies. Network topologies differ in terms of their customer density, as well as their composition of network assets (low and high voltage lines, and transformers). Figure 30 shows the total length of the GB distribution network by network topology, the customer density of each network topology, and the share of total network line km in each network topology that is reinforced in the Rapid EV+HHP scenario. The highest share (58%) of upgrades occur in semi-rural networks, where customer density is relatively low. Of these upgrades, around 50% of the network will require reinforcement, and around 30% of the reinforcement is to underground network lines. Due to the low customer density of networks in semi-rural areas, and the relatively modest need to reinforce underground lines, the majority of upgrades will involve low levels of disruption.

While only a small share of upgrades will occur in urban and semi-urban areas, these are likely to create some disruption. Only 3% of upgrades are projected to occur in urban areas, and a further 9% in semi-urban areas with high density. However, these upgrades are likely to be particularly disruptive. First, due to the high customer density in these areas, any outages that occur during the course of network reinforcement would affect a large number of customers. Second, the share of network reinforcement needed in these areas could be very high; in the Rapid EV+HHP scenario, 75% of network lines in urban areas and 74% in high density semi-urban areas would need reinforcing. Third, almost all of this network reinforcement (93% of total) is to underground lines, which creates more physical disruption for a longer period than reinforcement to overhead lines.

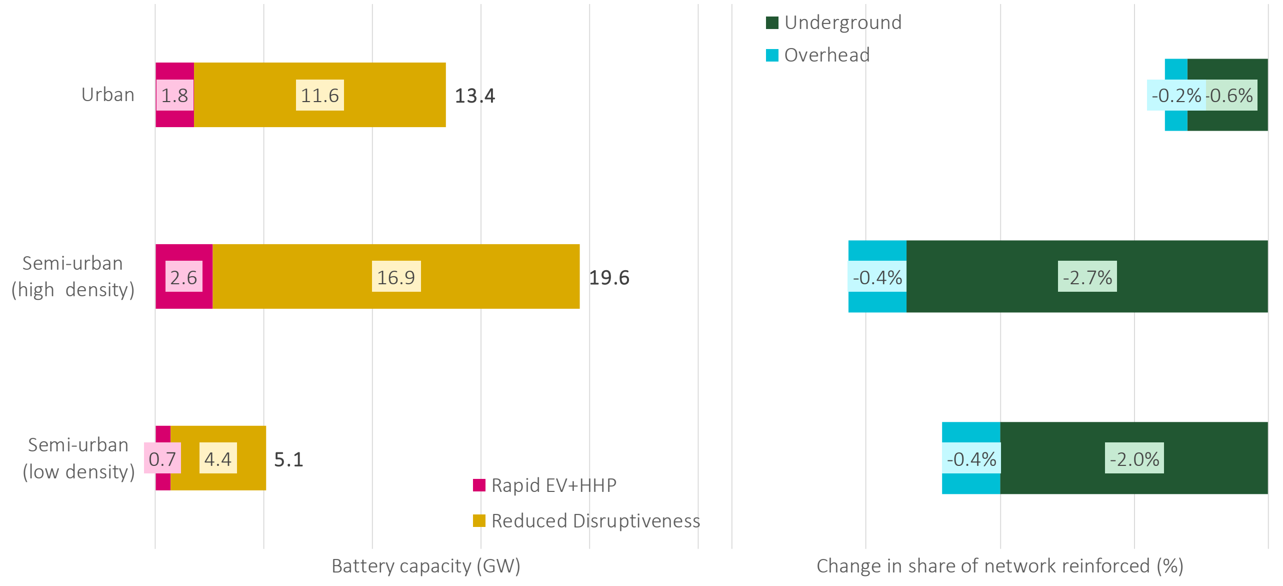
Figure 30 Network line reinforcement by network topology in 2035, Rapid EV+HHP scenario



Source: Vivid Economics, Imperial College

The scope for battery storage to mitigate the disruptiveness of network reinforcement is limited. As set out in Section 4.1, non-network solutions can play an important role in reducing the quantity and cost of network reinforcement. However, as the flexibility of electricity demand increases, the potential for further reduction in peak demand becomes more limited. To assess the scope to mitigate the need for network reinforcement in urban areas, we develop a new scenario, the Reduced Disruptiveness scenario. Unlike the Rapid EV+HHP scenarios, the Reduced Disruptiveness scenario does not constrain battery storage capacity, but estimates the level of capacity that could minimise the total cost of the electricity system; and allocates the additional capacity (over and above the 19.5 GW in the Rapid EV+HHP scenario) exclusively to semi-urban and urban networks. Figure 31 shows the change in battery capacity in semi-urban and urban networks between the Rapid EV+HHP and Reduced Disruptiveness scenarios, and the impact of that additional battery storage on the total length of network line reinforcement in the Rapid EV+HHP scenario in 2035. Figure 31 shows that increasing battery capacity in urban networks (where disruption is highest) from 2 GW to 13.5 GW reduces the share of total network line km in urban networks that must be reinforced by less than 1%.

Figure 31 In a flexible electricity system, the scope for additional storage to reduce needed reinforcement is limited

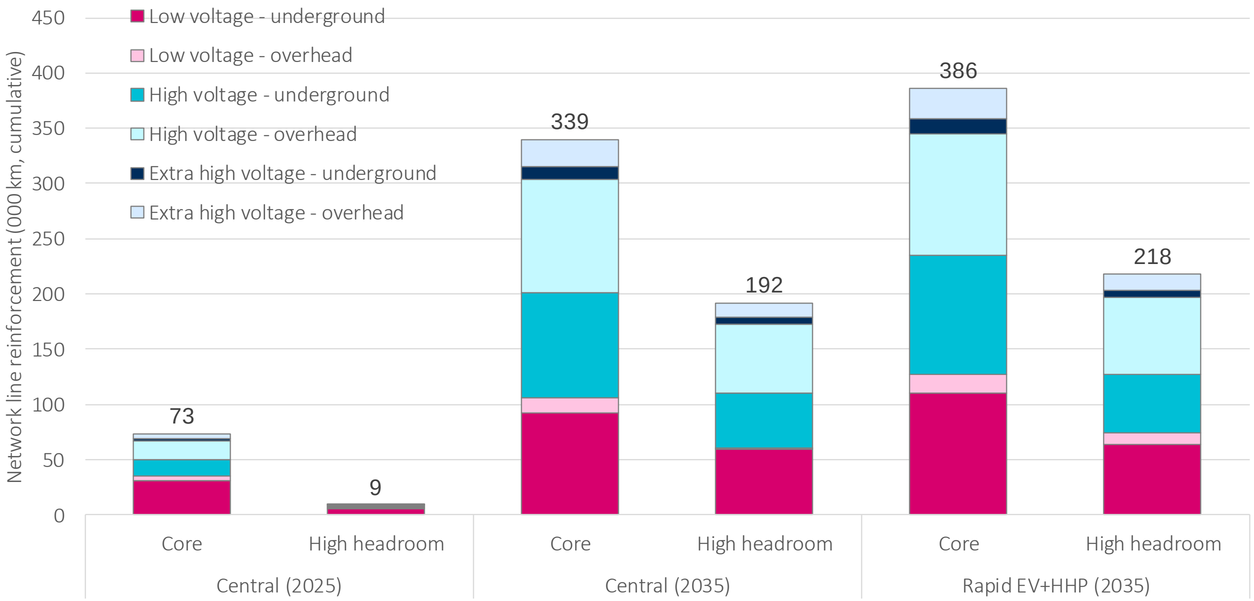


Source: Vivid Economics

4.6 Implications of lower network utilisation

If there is significant headroom in network capacity, an increase in demand could have a more moderate impact on the quantity and cost of reinforcements. Utilisation of the GB distribution network is poorly understood. This section has considered the impacts of accelerated electrification on the assumption that there is no headroom in distribution network capacity. However, it is possible that there is significant headroom, and that an increase in demand could have a more moderate impact on the quantity and cost of reinforcements. To illustrate the implications of a significant degree of headroom, we develop a High Headroom variant of the Central and Rapid EV+HHP scenarios. In the High Headroom variant, the amount of headroom is aligned to the level observed in an anonymised DNO subset of distribution substations and analysed by Imperial College. Figure 36 shows the implications of a significant degree of headroom for the quantity of network line reinforcements, while Figure 37 shows the implications for total network reinforcement costs. In the Central scenario in 2025, total line reinforcement in the Headroom variant is 88% lower than in the core scenario. In both the Central and Rapid EV+HHP scenarios in 2035, total reinforcement is 56-57% lower than in the core scenario, with comparable impacts on costs.

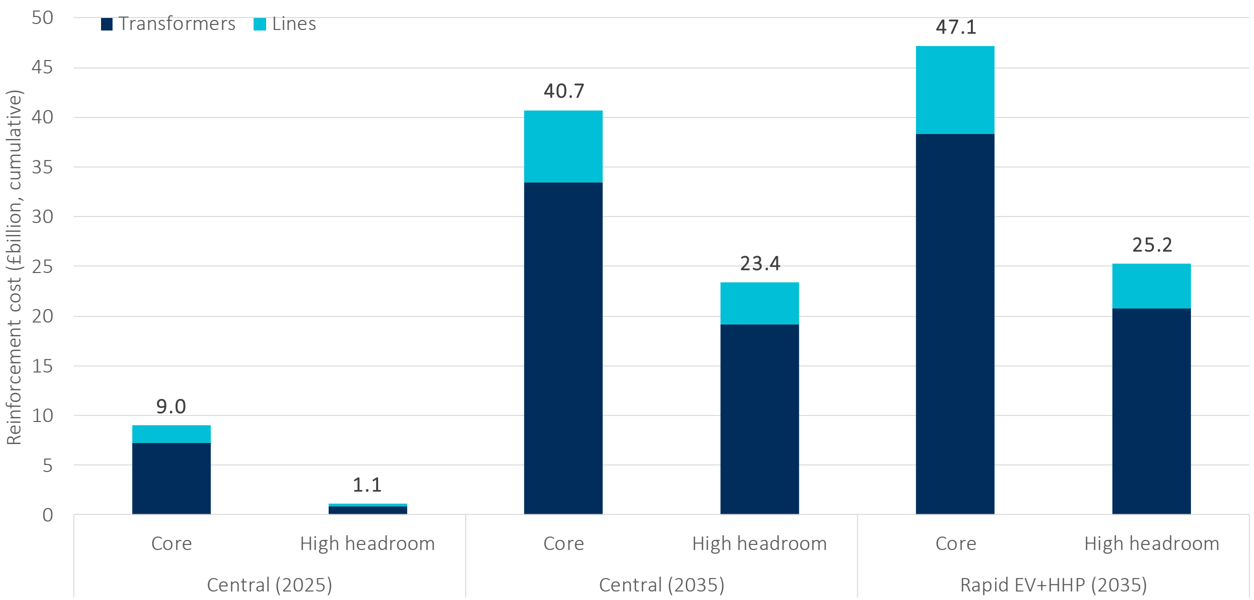
Figure 32 Fewer network reinforcements could be needed if there is significant headroom in the current network



Note: In line with an anonymised DNO subset of distribution substations, network utilisation in the High Headroom variant is set at is set at 25% for 16% of the distribution network; 50% for 47% of the network; 75% for 31% of the network and 100% for only 6% of the network

Source: Vivid Economics

Figure 33 Network reinforcement costs could be lower if there is significant headroom in the current network



Source: Vivid Economics, Imperial College

5 Delivering generation capacity

Box 3 Key messages

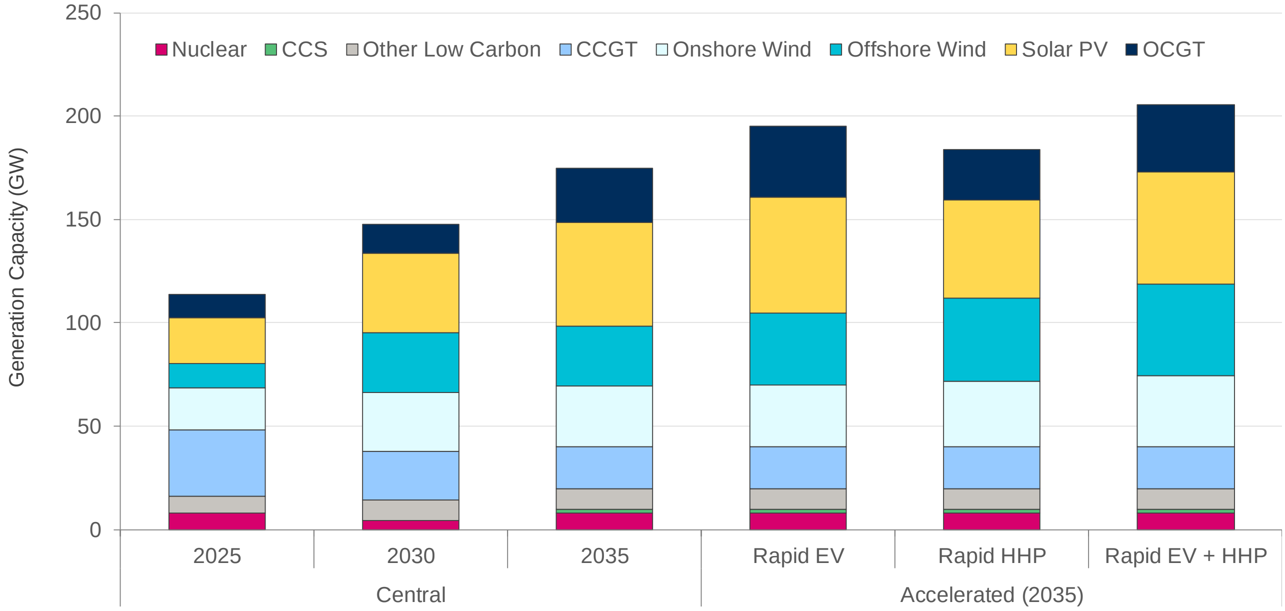
The UK has adequate onshore wind, offshore wind and solar PV resource, and past build rates are sufficient to deliver an expanded and decarbonised electricity system.

- Significant new renewable generation capacity is needed to accommodate rapid uptake of electric vehicles and hybrid heat pumps. Over the period to 2035, up to 35 GW onshore wind, 45 GW offshore wind and 54 GW solar PV could be needed. Further deployment is likely to be needed over the period to 2050.
- The UK onshore wind, offshore wind and solar PV resource are likely to be more than adequate to deliver an expanded and decarbonised electricity system to 2050. However, the onshore wind resource is highly sensitive to public acceptability and further work is needed to develop a realistic and accurate estimate of the offshore wind resource.
- Past build rates are sufficient to deliver an expanded and decarbonised electricity system.
- While large levels of backup capacity would have a minimal impact on the cost of electricity, they may be challenging to deliver. Flexible resources are cost-effective solutions to moderate backup capacity requirements.

5.1 Delivering renewable generation

As set out in Section 3, significant new renewable generation capacity is needed accommodate rapid uptake of electric vehicles and hybrid heat pumps. Figure 34 shows the level of generation capacity needed to meet electricity demand between 2025 and 2035 in the Central Scenario, and in 2035 in the Rapid EV, Rapid HHP and Rapid EV+HHP scenarios. In the Rapid EV+HHP scenario, renewable generation capacity consists of 35 GW onshore wind, 45 GW offshore wind and 54 GW solar in the Rapid EV+HHP scenario.

Figure 34 New capacity will be needed to meet the new demand

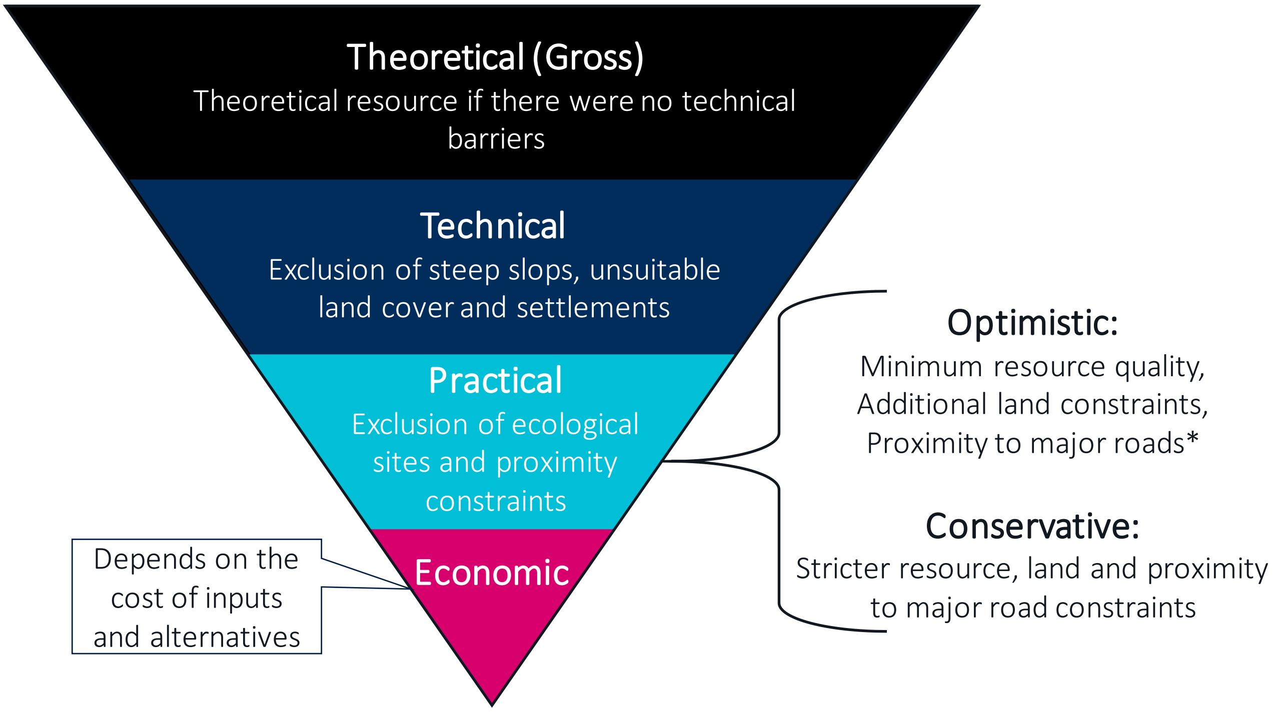


Source: Vivid Economics, Imperial College

Significantly more renewable generation capacity could be needed over the period to 2050. Over the period to 2050, electricity demand could continue to increase significantly, while full or near-full decarbonisation of electricity generation could be needed to meet the UK's current climate targets, and a potential net zero target. For example, in the Hybrid [10] scenario developed by Imperial College for the Committee on Climate Change (Imperial College, 2018), renewable generation capacity consists of 98 GW wind (onshore and offshore) and 99 GW solar PV.

Resource can be defined as theoretical, technical, practical or economic; we focus on the economic resource. Figure 35 illustrates different measures of the renewable resource. The theoretical resource is the energy embodied in the source, for example the total energy of wind over the UK landmass. The technical resource measures deployment potential in areas where deployment is technically possible, excluding locations with unsuitable land cover or steep slopes. The practical resource measures deployment potential in areas where there are no major barriers to deployment such as protected sites, and flood risk. Finally, economic resource measures the resource that can be recovered economically. This estimate excludes sites which could be developed in principle, but would be unlikely to be developed in practice due to high costs, driven by such factors as distance from the transmission network, or poor quality of the renewable resource. This analysis focuses on the economic resource.

Figure 35 Deployment potential pyramid



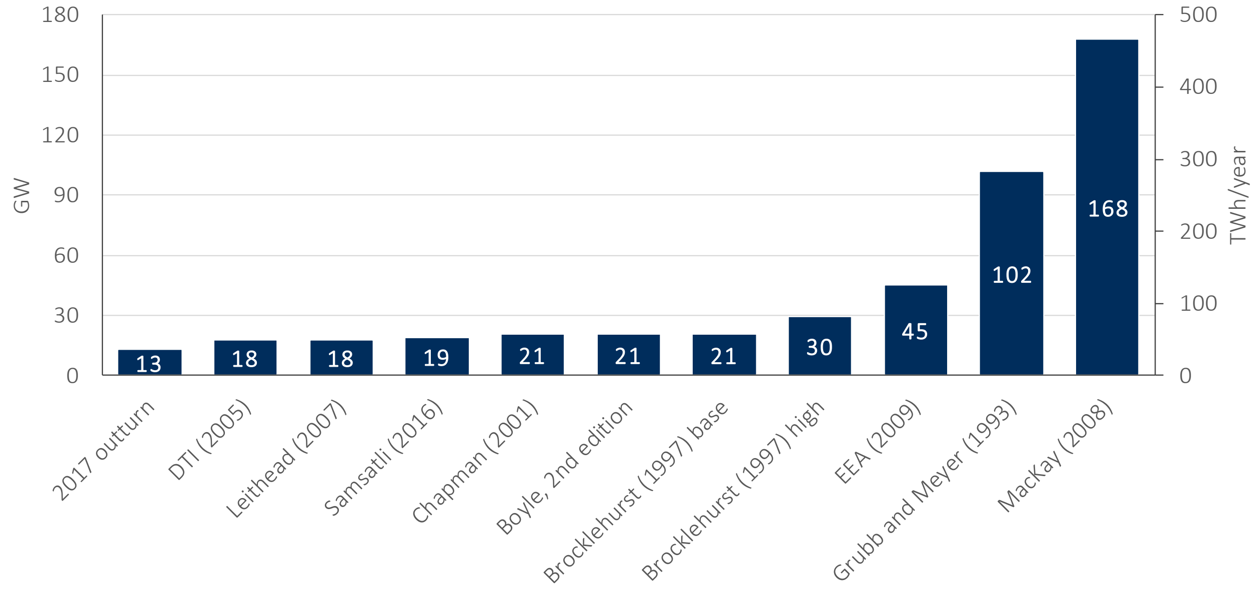
Note: Based on the resource pyramid from CCC (2011)
Source: Vivid Economics

This section considers the feasibility of delivering adequate volumes of onshore wind, offshore wind and solar PV. First, we review the evidence on the size of the renewable resource for each of these technologies. Second, we consider the feasibility of achieving the build rates required to deliver the generation capacity needed over the period to 2050.

5.1.1 Onshore wind

Previous estimates suggest the onshore wind resource is highly uncertain. Figure 36 presents the resource potential identified across a number of studies, relative to the 13 GW of onshore wind capacity in place in 2017. The majority of estimates suggest a range of 18-30 GW. At the upper end of this range, Brocklehurst (1997) estimated a resource potential of 30 GW, which CCC cited in their Renewable Energy Review (CCC, 2011).

Figure 36 Previous estimates suggest a significant uncertainty over the size of the onshore wind resource



Note: TWh estimates from the literature are converted to GW using capacity factor of 32% from BEIS (2017)
Source: Vivid Economics

Multiple factors determine the size of the onshore wind resource. Factors include the quality of an area's wind resource, its slope, type of land cover, designation as a protected site, accessibility, size and visual impact. Sites with higher quality wind are better suited to onshore wind deployment (Brocklehurst, 1997, Samsatli et al., 2016, Kalmikov, 2015 and NREL, 2017). Areas with steep slopes are poorly suited to wind development due to the difficulty of transporting and installing turbine components (Samsatli et al., 2016). Only some types of land cover are suited to onshore wind deployment, typically comprising flat undeveloped areas, such as pastures, grasslands, pastures and agricultural land (Brocklehurst, 1997, Hoogwijk, 2004); high grade agricultural land and greenbelt areas are generally considered to be unsuitable for renewable development (Palmer et al., 2019). Protected sites such as national parks, areas of outstanding natural beauty (AONB), national scenic areas (NSAs) and sites of special scientific interest (SSSIs) are widely considered to be unsuitable (Brocklehurst, 1997, Samsatli, 2016). Sites closer to major roads are generally more suitable for development, both to facilitate site access and because the transmission network tends to be relatively close to major roads (Samsatli, 2016). Wind turbines require a minimum site size to operate unobstructed (Brocklehurst, 1997; Palmer et al., 2019). Visual impact is a major concern for onshore wind, and could significantly restrict the size of the resource (Brocklehurst, 1997). Other constraints include noise impacts and potential to create shadow flicker (Brocklehurst, 1997, Samsatli, 2016); interference with airport radar systems (Brocklehurst, 1997, Samsatli, 2016); impacts on safety of motorists (Brocklehurst, 1997, Samsatli, 2016); and exposure to flood risk (Brocklehurst, 1997, Samsatli, 2016).

We estimate a range for the onshore wind resource. It is difficult to specify a set of objective constraints that accurately determine the onshore wind resource. In practice, there are trade-offs between various aspects of a site's economics, as well as its environmental and visual impact, and under different conditions these trade-offs could imply a larger or smaller overall resource. To illustrate the impact of these conditions we provide two estimates of the onshore wind resource. Our conservative estimate applies the more stringent constraints from the research literature, while our optimistic estimate relaxes some of these constraints in line with recent evidence about the actual conditions of sites used for onshore wind development to date.

In general, our estimates of the onshore wind resource use constraints derived from the research literature:

- **Slope.** Previous estimates of the onshore wind resource tend to exclude areas with slope greater than 10-20 degrees (Brocklehurst -NREL). Our estimates exclude slopes greater than 15 degrees.

- **Land cover.** Previous estimates of the resource tend to exclude areas characterised by urban and suburban, green belt, and mountainous or forested land cover types. In reality, wind farms are located on a range of land cover types. Analysis of the location of existing wind farms indicates that non-irrigated arable land is the most common type of land cover (18% of GB wind capacity), with significant capacity located in pastures (14%), coniferous forest (14%), peat bogs (13%), moors and heathland (12%), industrial and commercial areas (10%) and natural grasslands (9%)[2]. In line with the literature, our optimistic resource estimate excludes areas characterised by urban and suburban, green belt[3], mountainous or forested land cover types. Our conservative estimate further excludes peat bogs (due to the risk of releasing stored carbon) and high grade (Grade 1 and 2) agricultural land.

- **Protected sites.** In line with the literature, we exclude national parks, areas of outstanding natural beauty (AONB), national scenic areas (NSAs) and sites of special scientific interest (SSSIs).

- **Site size.** Previous estimates typically exclude sites smaller than 1km^2 (Palmer et al., 2019). In line with the literature, we adopt this constraint.

- **Wind farm density.** Previous estimates typically assume a wind farm density of 9-5MW/km^2 (Brocklehurst 1997, NREL, 2017). Our estimates conservatively assume a wind farm density of 5MW/km^2.

- **Other constraints.** Previous estimates exclude areas within 400-500 metres of areas of human settlement, within 5-6 km of airports and with 100-200 metres of roads and rivers. In line with the literature, we exclude areas within a 5km radius of airports, 500 metres from urban and suburban areas and within 200m of major roads and rivers.

For other constraints, the evidence base has changed in recent years:

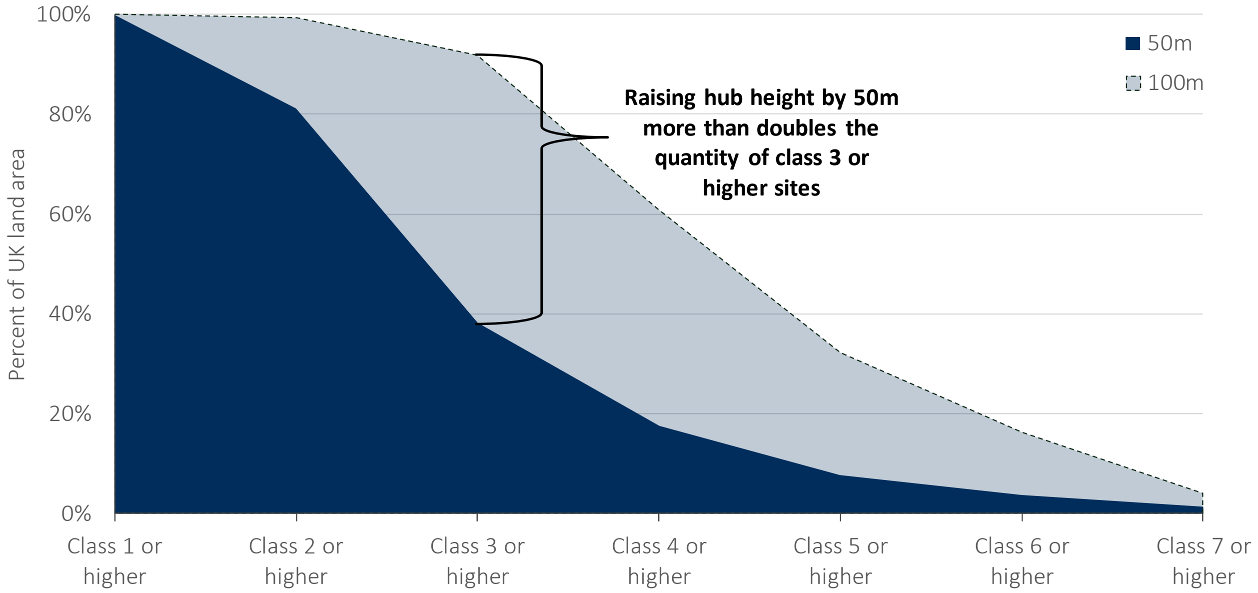
- **Wind resource quality.** The quality of the wind resource varies across the UK. Wind resource quality is largely determined by average annual wind speed and is often measured as wind power density (WPD). WPD indicates that quantity of wind available for conversion by a wind turbine at a specific site and is measured in watts/m^2 and subdivided into seven classes. Wind resource quality varies between class one ('poor' quality of 0-200W/m^2) and class seven ('superb' quality, >800W/m^2). Suitable sites for wind deployment typically have WPD of class 3 and above, which approximately corresponds to wind speeds of 6.8m/s or more (Kalmikov, 2015). Previous estimates of the onshore wind resource typically apply a wind speed threshold of 6-7m/s, or a wind power density threshold of class 3 or above ('Fair' quality of 300-400 w/m^2, corresponding to an average wind speed of 6.8-7.5 m/s). While wind quality is clearly of critical importance, previous estimates typically consider wind quality at a height of around 50 metres, in line with the hub height of a typical wind turbine available previously. However, wind quality increases with height, and in recent years turbines have grown larger and taller to access the higher quality wind resource. In 2017, the average hub height of a turbine installed in the US was 86m (DOE, 2017) and in Germany was around 125m (Fraunhofer, 2017). Figure 37 shows the relationship between hub height and GB wind resource by wind class. At a height of 100 metres, the total area with wind quality of class 3 or higher is more than double the area with comparable wind quality at a height of 50 metres. Therefore, while we apply a threshold of class 3 wind power density in line with the research literature, we apply this threshold based on wind quality at a height of 100 metres, reflecting the scope for larger wind turbines today.

- **Accessibility.** Previous estimates of the resource typically exclude areas more than 1.5 km from major roads. However, analysis of the location of current wind farms indicates that this constraint is too restrictive. In practice, 73% of existing wind capacity is located more than 1.5 km from major roads; 36% of capacity is located more than 4 km from major roads; and some capacity (5% of total) is

[2] Based on data from the Renewable Energy Planning Database (2019) and Corine land cover for the UK (2012).
[3] Our estimates incorporate green belt areas for which data is available (England only).

located more than 9 km from major roads. In line with the evidence base, our optimistic resource estimate excludes areas more than 9 km from major roads, while our conservative estimate excludes areas more than 4 km from major roads.

Figure 37 The quality of the wind resource at a height of 100m is significantly higher than at 50m



Source: Vivid Economics

We do not attempt to directly account for the political acceptability and visual impact of onshore wind. Previous estimates of the onshore wind resource typically make an assumption on the extent to which the political acceptability of visual impact could limit the onshore wind resource. For example, Brocklehurst (1997) assumes that wind farms would need to be located at least 7 km from each other to limit visual impact. While the political acceptability and visual impact of onshore wind are clearly important constraints to deployment, there is no strong evidence on the precise impact of this constraint on the available resource today, or the extent to which demographic and attitudinal change could drive a shift in the political acceptability of onshore wind. Therefore, while we do account for some aspects of visual impact by excluding protected sites (such as areas of outstanding national beauty) and land close to urban and suburban areas, we do not take a view of the degree of visual impact that could be politically acceptable in determining our resource estimates.

We find that previous estimates of the onshore wind resource are conservative. We examine estimates of the size of the onshore wind resource in the research literature and consider how these estimates might change given the change in the evidence base on wind resource quality and accessibility, and a change in the political acceptability of onshore wind and public perception of its visual impact. Adjusting for these factors, we find that the size of the onshore wind resource could increase to 96-214 GW, with 8-19% of GB land area potentially suitable for development. Our conservative estimate considers sites with wind class 4 at a height of 100m; sites larger than 1km^2, and sites within 4km of a major road; and excludes peat bogs and high grade agricultural land and areas within 5km^2 of airports. Based on this criteria, the onshore wind resource could be around 96 GW. We then consider the implications of relaxing constraints on deployment. We reduce the minimum wind class threshold at a height of 100m is reduced to wind class 3 and above; increase the minimum distance from major roads from 4 to 9 km; and remove the constraint on development on high grade agricultural land. Based on this criteria, the onshore wind resource could be around 214 GW. The full set of assumptions underpinning these estimates are set out in Annex 3. These estimates are higher than previous estimates due to three different factors:

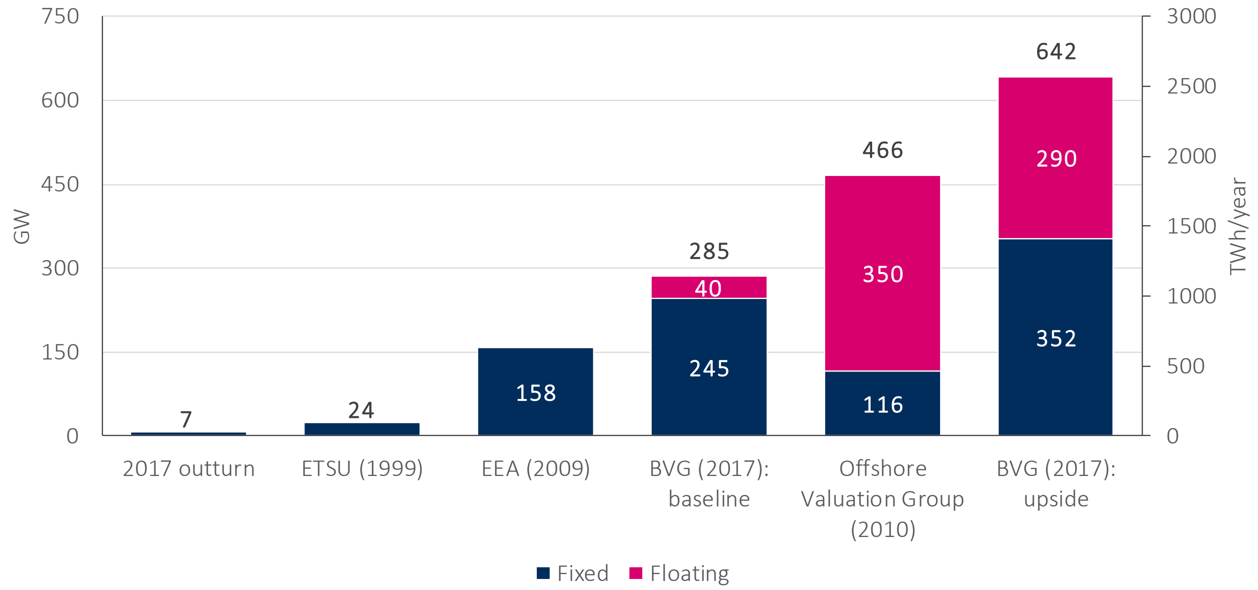
- Updating constraints on wind resource quality to take account the scope for taller turbines increases the estimate of the available resource by a factor of around 2.5.
- Updating constraints on accessibility to take account of the distance from major roads of current wind farms increases the estimate of the available resource by a factor of around 1.7-2 (at 4km and 9km, respectively).
- Removing constraints on visual impact increases the available resource by a factor of six.

Our overall assessment is that the practical onshore wind resource is highly sensitive to public acceptability, but in principle is more than adequate to deliver an expanded and decarbonised electricity system to 2050.

5.1.2 Offshore wind

Previous estimates suggest the offshore wind resource could be very large. Figure 38 presents the resource potential estimated in a range of studies, relative to the 7 GW of offshore wind capacity in place in 2017. At the lower end of the range, ETSU (1999) suggest a resource of 24 GW. The ETSU study was based on a set of technical parameters (for example, hub height, water depth and distance from shore) which have since been superseded. For example, Crown Estates have leased sites capable of supporting 46 GW of capacity, and are preparing a further leasing round. In contrast, several recent studies suggest a much larger resource. Some studies suggest a range of 116-352 GW, considering fixed wind only. At the lower end of this range, the Offshore Valuation Group estimates 116 GW of fixed offshore wind potential, which CCC cited in their Renewable Energy Review (CCC, 2011). A number of these studies also consider floating wind, suggesting an additional resource of 40-350 GW.

Figure 38 Previous estimates suggest the offshore wind resource could be very large



Note: TWh estimates from the literature are converted to GW using capacity factor of 48% from BEIS (2017). The Offshore Valuation Group provided GW estimates, which are not adjusted with the capacity factor from BEIS.

Source: Vivid Economics

The size of the offshore wind resource is determined by multiple factors. Factors include the quality of an area's wind resource, its water depth, existing use, distance from land and visual impact. As with onshore wind, higher quality sites are better suited to offshore wind deployment (NREL, 2017, BVG, 2017). Sites at greater depth are more challenging to develop (The Offshore Valuation Group, Crown Estate, NVG), though there is some evidence that floating wind could allow development at substantially greater depths than fixed wind (The Offshore Valuation Group, 2010, NREL, 2017, BVG, 2017). Existing offshore infrastructure and access routes, such as such as subsea cables, pipelines and O&G infrastructure and shipping lanes, are less suited for offshore wind deployment (The Offshore Valuation Group, 2010, BVG, 2017). Protected areas, such as Marine Protected Areas, Special Protection Areas, MOD Practice and Exercise Areas and MOD Munitions dumps, are considered to be unsuitable for offshore wind development (The Offshore Valuation Group, 2010, BVG, 2017). Sites that are further from the UK mainland are more challenging to develop (The Offshore Valuation Group, 2010, NREL, 2017, BVG, 2017). Although the visual impact of offshore wind is less contentious than that of onshore wind, offshore wind farms are typically not built close to shore to mitigate their visual impact (NREL, 2017). Undesignated shipping lanes, fish spawning and nursery sites, and anchorage areas are considered to be less suited to offshore wind development (The Offshore Valuation Group, 2010, BVG, 2017).

Development of floating wind could significantly increase the available resource. Floating offshore wind uses wind turbines that are not set in fixed foundations on the seabed, but in floating foundations that are moored to the seabed. Floating offshore wind farms could increase the available resource for two reasons. First, they allow development at greater water depths, which are unsuitable for development of fixed foundation turbines. Second, wind speeds are typically stronger and steadier further from shore.

A recent study estimated that the resource could be between 245-642 GW. BVG (2017) estimated the gross, technical and economically attractive offshore wind resource for a range of European countries, including the UK. BVG concluded that the economically attractive offshore wind resource could be between 245-642 GW.

In general, BVG's approach is consistent with the constraints identified in the research literature:

- **Current site uses.** Previous estimates of the onshore wind resource typically exclude existing infrastructure and site uses, such as subsea cables, pipelines and other oil and gas infrastructure, or shipping lanes (The Offshore Valuation Group, 2010). In line with the research literature, BVG's estimate excludes designated shipping lanes, and assumes a reduction in the density of development in areas near oil and gas pipelines and electrical and telecommunication cables.

- **Protected areas.** Previous estimates typically exclude marine protected areas, special protection areas, MoD areas and areas of dumped munitions (The Offshore Valuation Group, 2010). In line with the literature, BVG's estimate excludes marine protected areas and special protected areas, and MOD Munitions dumps, and assumes a reduction in the density of development in areas of special conservation interest.

- **Visual impact.** Previous estimates typically exclude areas that are less than 5 nautical miles from shore to account for visual impact (NREL, 2017). BVG similarly exclude areas within this distance from shore.

However, further work is needed to take account of water depths and the full set of constraints to offshore wind deployment. BVG's analysis suggests the economically attractive offshore wind resource could be 245-352GW for fixed wind, and 40-290 GW for floating wind. However, uncertainties around water depths and wider constraints suggest that both the fixed and floating resource remain difficult to establish with a high degree of certainty:

- **Water depths.** For fixed wind, estimates suggest deployment at depths of up to 50m is possible with current technology. BVG's estimate of the fixed wind resource is based on a slightly greater maximum depth of 70 metres. The maximum water depth for floating wind is highly uncertain. Development of oil and gas fields at depths of up to 3,000m suggest that deep water deployment of floating wind could be possible. BVG's estimate considers sites with a water depth of up to 1,000m. However, current floating wind projects, such as the Hywind pilot park in Scotland, are sited at a water depths of 95-120m (Equinor, n.d.), and the challenges and costs of deeper deployment are not fully understood.

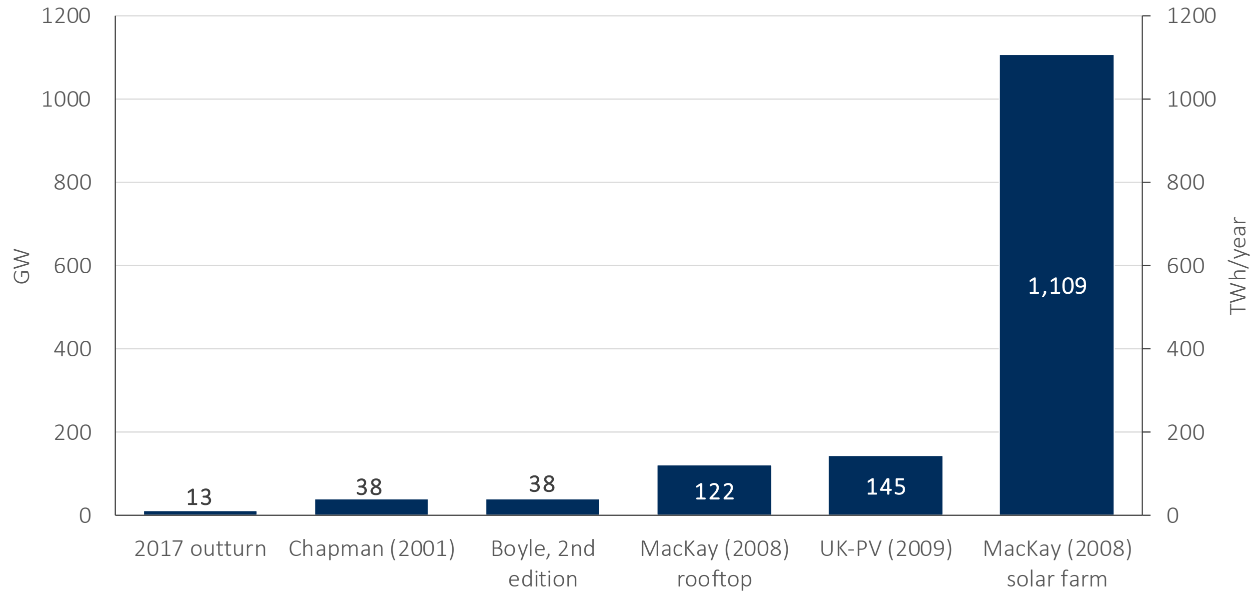
- **Wider constraints.** Although existing studies take account of the major constraints to offshore wind deployment, in practice, additional constraints could rule out further sites entirely ('hard constraints') or reduce the density of offshore wind deployment for which a given site is suitable ('soft constraints'). BVG's estimate does not consider key hard constraints such as aquaculture leases or protected wrecks. Further, BVG's estimate does not consider a number of soft constraints, such as fish spawning areas, MOD Practice and Exercise Areas s, anchorage areas, helicopter routes and sailing areas (The Offshore Valuation Group, 2010, BVG, 2017)

Our overall assessment is that the practical offshore wind resource is likely to be more than adequate to deliver an expanded and decarbonised electricity system to 2050, but further work is needed to develop a realistic and accurate estimate.

5.1.3 Solar PV

Previous estimates have suggested a moderate resource for rooftop solar, and a very large resource for utility-scale solar. Figure 39 shows the estimates from the literature and capacity in place in 2017. The majority of studies consider the rooftop solar resource only. To our knowledge only MacKay (2008) has estimated the UK's large-scale solar resource.

Figure 39 Previous estimates have focused on rooftop solar, but suggest the large-scale solar resource could be large



Note: TWh estimates from the literature are converted to GW using capacity factor of 11% from BEIS (2017)
Source: Vivid Economics

The size of the solar resource is determined by multiple factors. Factors include the quality of an areas' solar resource, its slope, type of land cover, designation as a protected site, accessibility, and size. Higher levels of solar irradiance are better suited to solar deployment (European Commission, 2015). Palmer et al. (2019) describe a range of other constraints. Areas with steep slopes are poorly suited to excluded to solar farm development due to the difficulty of transporting and installing solar farm components. Further, the direction of the slope influences the solar harvest, with highest harvests on south-facing slopes and lowest harvests on North-facing, where the slope configuration may cause shading. Only some types of land cover are suited to solar deployment, such as flat undeveloped areas, such as pastures, grasslands, pastures and agricultural land, while high grade agricultural land and greenbelt areas are generally considered to be unsuitable. The rooftop solar resource is limited by rooftop area, with south-facing roofs proving the highest quality resource. Protected sites such as national parks and protected areas are widely considered to be unsuitable. Larger sites are more economic to develop, and very small sites are likely to be unsuitable for commercial development. Finally, Solar PV should not be built in areas of flood risk.

As with onshore wind, we estimate a range for the solar PV resource. We provide two estimates of the solar PV resource. Our conservative estimate applies the more stringent constraints from the research literature, while our optimistic estimate relaxes some of these constraints in line with recent evidence about the actual conditions of sites used for solar PV development to date.

Our estimates of the solar PV resource use constraints derived from a review of the literature:

- Solar resource quality. In the UK, annual average horizontal solar irradiance ranges from 80W/m^2 in the north of Scotland to 140W/m^2 in the South of England. Previous estimates of the solar PV resource typically apply an average solar irradiance threshold of 100-120w/m^2 (Mackay, 2008 and Palmer et al., 2019). In line with the literature, we adopt a minimum constraint of 120W/m^2.

- Slope. Previous estimates of the solar PV resource tend to exclude areas with slope greater than 2-11% (Watson and Hudson, 2015, Palmer et al., 2019). In line with the UK specific literature (Watson and Hudson, 2015), we adopt a constraint of 10%.

- Land cover. Previous estimates of the resource have excluded areas characterised by urban and suburban, green belt, mountainous or forested land, and brownfield land cover types, as well as high grade (Grade 1 and 2) agricultural land (Palmer et al., 2019), though around 25% of existing solar farms are located on high grade agricultural land. In line with the literature, our optimistic resource estimate excludes urban, green belt, mountainous and forested land cover types. Our conservative estimate further excludes peat bogs (due to the risk of releasing stored carbon) and high grade (Grade 1 and 2) agricultural land. For rooftop solar, previous estimates tend to include only rooftop area. We consider only south facing rooftop area, which is assumed to be 25% of total rooftop area.

- Accessibility. Palmer et al. (2019) excluded sites that are within 2.5 km of bulk supply points on the transmission network. As data on bulk supply points was not available, our assessment used proximity to roads as the relevant accessibility indicator, in line with Samsatli (2016). Analysis of the location of current solar farms indicates that 29% of existing solar farm capacity are located more than 2km from major roads; and 17% of capacity is located more than 3 km from major roads. In line with the evidence base, our optimistic resource estimate excludes areas more than 2 km from major roads, while our conservative estimate excludes areas more than 3 km from major roads.

- Site size. Palmer et al. (2019) excluded sites smaller of 1km^2 in size. In line with the literature, we adopt this constraint.

- Flood zones. Previous estimates typically exclude sites in large flood zones over 40 km^2, though 12% of existing UK solar farms were found to be located in flood zones (Palmer et al., 2019). In line with the literature, we exclude areas within 200m of rivers.

We also draw on the latest evidence on solar density and solar panel efficiency.

- **Solar density.** Only part of the area covered by a solar farm is occupied by solar panels. Solar density refers to share occupied by solar panels. Solar density is determined by two factors:
  - ◊ **Packing factor.** Solar panels are angled and spaced to maximise the amount of solar irradiance captured. The extent of angling and spacing depends on latitude, and greater angling and spacing is required in northern latitudes. The ratio of solar panel area to the area of siting is known as the packing factor. At a latitude of 50 degrees a 30% packing factor is considered optimal (TRANSrisk, 2017).
  - ◊ **Generator to spacing ratio.** In addition to the optimal packing of panels, the site must also allow spacing for operations and maintenance and adequate space between panels and objects, such as trees, that cast shadows on the panels. The share of a site area used for panels is known as the Generator to spacing ratio. A generator to spacing ratio of 0.7 is typical (TRANSrisk, 2017).
- Based on the optimal packing factor for UK latitudes, and the typical generator spacing ratio, we assume a solar density of 21% of site area or 4.5MW/km^2 for GB solar farms.
- **Solar panel efficiency.** Since previous estimates of solar resource were made, the efficiency of solar panels have improved. For example, Mackay (2008) assumed a solar panel efficiency of 10%. Currently installed panels have a solar panel efficiency of up to 18% (Korfiati et al., 2016). In line with this recent evidence, we assume a solar panel efficiency of 18%.

We find that the solar PV resource is line with previous estimates. We examine the evidence base on constraints to solar PV deployment in Great Britain and estimate the size of the solar PV resource based on excluding sites that do not fit these constraints. We estimate that 616-1,102 GW of large-scale solar and 37 GW of roof top solar could be deployed if necessary, with 6-11% of GB land area potentially suitable for development. Our conservative estimate considers sites with average daily solar irradiance of 120w/m^2 and above; sites larger than 1km^2, and sites within 2km of a major road; and excludes peat bogs and high grade agricultural land. Based on these criteria, the utility scale solar resource could be over 600 GW. We then consider the implications of relaxing constraints on deployment. We increase the minimum distance from major roads from 2 to 3 km; and removes the constraint to deployment on high grade agricultural land and peat bogs. Based on these criteria, the utility scale solar resource could be over 1,102 GW. The full set of assumptions underpinning these estimates are set out in Annex 3.

Our overall assessment is that the practical solar PV resource is more than adequate to deliver an expanded and decarbonised electricity system to 2050.

5.1.4 Build rates

Historical rates of new capacity deployment indicate that the build rates needed to achieve accelerated electrification are feasible.

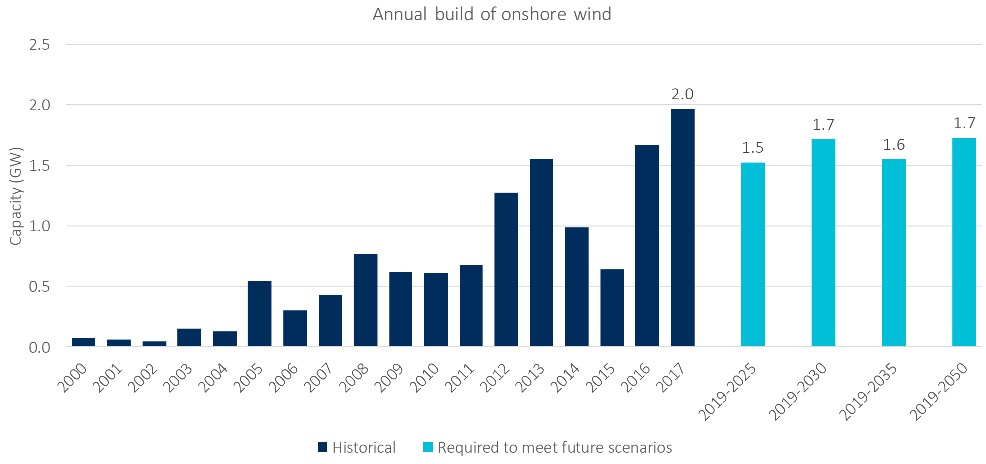
- The onshore wind sector has demonstrated it can deliver new capacity at the rate needed to achieve rapid electrification. Figure 40 shows the historical build rate of onshore wind in the UK, and average annual build rates (including repowering of existing generators) needed in future to meet the Rapid EV+HHP scenario over the period 2025-2035, and the CCC's Hybrid [10] scenario over this period to 2050. 2 GW of new onshore wind capacity was built at its peak in 2017, demonstrating that it would be possible to deliver the 1.5-1.7 GW per year of new capacity needed to achieve accelerated electrification to 2035.
- The offshore wind sector would need to scale up slightly to deliver new capacity at the rate needed to achieve rapid electrification. Figure 41 shows the historical and necessary future build rate of

offshore wind in the UK. 1.7 GW of new offshore wind capacity was built at its peak in 2017, while 2.3-2.4 GW per year of new capacity would be needed to achieve accelerated electrification.

- The solar PV sector has demonstrated it can deliver new capacity at the rate needed to achieve rapid electrification. Figure 42 shows the historical and necessary future build rate of solar PV in the UK. 4.1 GW of new solar PV capacity was built at its peak in 2015, demonstrating that it would be possible to deliver the 2.7-3.7 GW per year of new capacity needed to achieve accelerated electrification to 2035 and beyond.

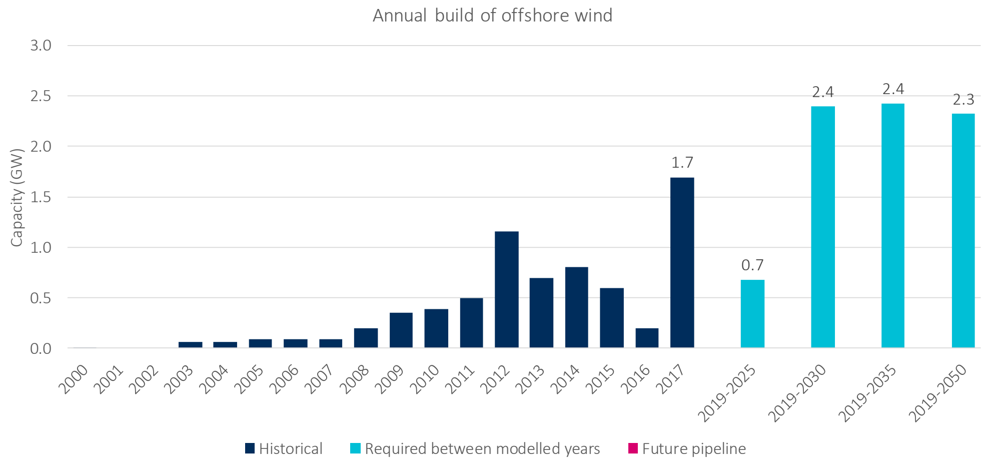
- Furthermore, the global markets for onshore wind, offshore wind and solar PV are likely to be large enough that higher UK deployment levels could be achieved without breaching global supply chain constraints. Total onshore wind capacity in the Central and Accelerated scenarios could represent 2% of total global capacity, based the IEA's 2 degrees scenario, while total solar PV capacity could represent 3-4% of total global capacity. Total offshore wind capacity could represent 16-23% of total global capacity based the IEA's 2 degrees scenario, a larger share than onshore wind and solar PV, but nevertheless indicating scope to achieve higher UK deployment levels by increasing imports if necessary.

Figure 40 Historical build rates for onshore wind are sufficient to achieve electrification and decarbonisation



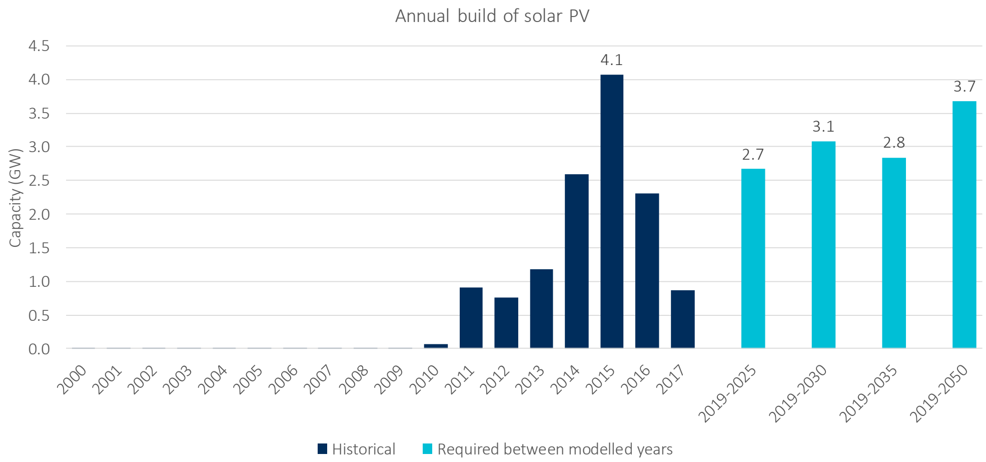
Source: Vivid Economics, Imperial College, BEIS

Figure 41 A slight increase in offshore wind build rates is needed to achieve electrification and decarbonisation



Source: Vivid Economics

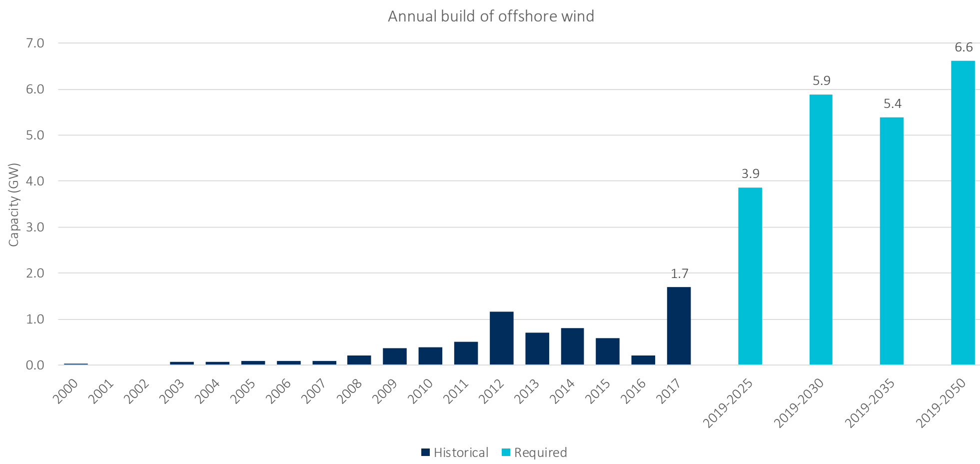
Figure 42 Historical build rates for solar PV are sufficient to achieve electrification and decarbonisation



Source: Vivid Economics, Imperial College, BEIS

Should deployment of onshore wind and solar PV be constrained, offshore wind would need to achieve significantly higher build rates. Although historical rates of new onshore wind, and solar PV capacity deployment indicate that the build rates needed to achieve accelerated electrification are feasible, it is not clear that Government policy will allow and encourage investment in these technologies. As discussed in Section 5.1.1, planning constraints on onshore wind are limiting the potential for new deployment, while the lack of CfD auctions creates risks for both onshore wind and solar PV. Should deployment of onshore wind and solar PV be constrained, offshore wind would need to achieve significantly higher build rates. Figure 43 shows that in the event that onshore wind and solar PV are constrained, offshore wind build rates would need to reach 5.4 GW per year to achieve accelerated electrification by 2035. The 1.7 GW of new offshore wind capacity built at its peak in 2017 falls far short of these figures.

Figure 43 A significant increase in offshore wind build rates would be needed in an offshore-led scenario



Source: Vivid Economics, Imperial College, BEIS

A significant increase in build rates could raise costs in the near-term due to UK supply chain weaknesses, and costs of sourcing some components and activities from outside the UK. The UK supply chain has proven itself to be capable of supporting the delivery of 1.7 GW of offshore wind in a year. However, the supply chain would need to scale up significantly in order to achieve build rates of up to 5 GW per year. Until scale up has been achieved, delivering such build rates would require sourcing components and activities from outside the UK. For some components and activities, sourcing from outside the UK would be unlikely to significantly increase the costs of offshore wind. However, for others, sourcing from outside the UK could be costly. BVG (2017) assessed the case for UK supply for UK projects for the full range of components and activities that make up the offshore wind supply chain. This analysis identifies the components and activities for which there is no significant logic UK supply, and those for which there is strong logic for UK supply, and sourcing from outside the UK could increase deployment costs.

For some components and activities, UK supply chain weaknesses are unlikely to present a barrier to higher build rates. BVG identified a number of components and activities for which developing UK supply was unlikely to confer major advantages relative to sourcing from the European or global supply chain. The assessment concludes:

- There is **no significant logic** for developing UK supply for foundation installation, subsea cable installation and turbine installation. These activities are carried out by vessel operators which typically provide services globally to ensure high utilisation rates for their vessels.
- There is a **limited logic** for developing UK supply for castings and forgings, drive train, HVAC substations and monopile foundations. For example, castings and forgings and drive train components are small enough to be transported by road, reducing the necessity for on-site

manufacture; and monopile foundations have typically been imported, for example from the Netherlands.

For other components and activities, higher build rates could increase costs in the near-term, given current weaknesses in the UK supply chain. In their assessment of the case for UK supply for UK wind projects BVG also identified a number of components and activities for which developing UK supply was likely to confer major advantages relative to sourcing from the European or global supply chain. The assessment concludes:

- There is a **good logic** for developing UK supply for Surveys, turbine nacelle assembly, subsea array cables, non-monopile steel foundations, concrete foundations, installation ports and major service activities. UK supply for these components and activities is advantageous for cost reduction. For example, surveys are better suited to UK-based design teams; turbine nacelle assembly, subsea array cables, non-monopile steel foundations, are ideally located close to major markets due to high transport costs; concrete foundations could benefit from the UK's suitable port facilities and relatively flexible and cheap labour markets; location of installation ports in the UK could offer advantages due to shorter distances to the wind farm; and the vessels needed to carry out major service activities are more economic when located locally.

- There is **strong logic** for developing UK supply for wind farm design, blades, tower, subsea export cables, operation, maintenance and minor service activities. Wind farm design and maintenance and minor service activities are better suited to UK-based design teams; while blades, towers and subsea export cables are ideally located close to major markets due to high transport costs.

While a significant increase in build rates could raise costs in the near-term, such costs may not be prohibitive. While the UK offshore wind market is important, the European and global markets are expected to grow significantly. The International Energy Agency's 2 Degrees Scenario envisages the global market for offshore wind could reach 51 GW of total deployed capacity by 2025, 152 GW by 2030 and 343 GW by 2050. There is therefore scope to import even larger, more costly components if necessary. For example, offshore wind blades were not produced in the UK prior to the opening of the MHI Vestas manufacturing plant on the Isle of Wight in 2015 and Siemens factory in Hull in 2016. Moreover, BVG note that UK suppliers will be in competition with producers in China for several components, including non-monopile steel foundations and concrete foundations; that in 2014, the majority of offshore wind towers were built outside the UK; and that use of continental installation ports may be more cost-effective than UK ports if these are co-located with manufacturing.

5.2 Delivering backup capacity

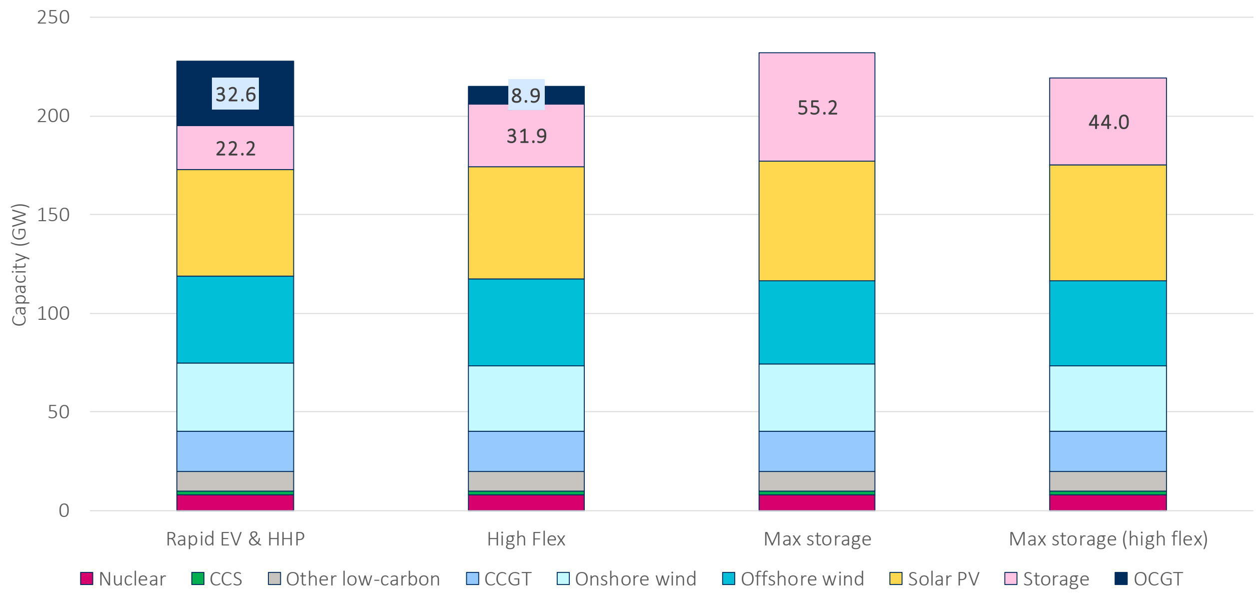
Backup generation capacity is capacity that is needed to balance supply and demand when output from variable renewables is low. Backup capacity may run at mid-merit, at peak, or may not run at all during a normal year.

Typically, modelling studies indicate that high levels of backup capacity are needed to balance large volumes of variable renewables, and accommodate infrequent but large peaks in heating demand. In modelled studies, the volume of backup capacity is determined by the ability of variable renewables to reliably meet peak demand. In the Rapid EV+HHP scenario, around 33 GW of Open Cycle Gas Turbine (OCGT) capacity is needed as backup to balance 35 GW onshore wind, 45 GW offshore wind and 54 GW solar. In the Elec [10] scenario in 2050, 98 GW of OCGT capacity is needed to balance 104 GW of wind, and 128 GW of solar. It should be noted that projections of backup capacity needs may vary depending on the modelling approach. In this study, backup capacity needs are assessed based on the UK security of supply reliability standard, the impact of a cold '1 in 20 year' winter heat demand, and assumptions on the extent to which different generation technologies and flexible resources can meet peak electricity demand.

As backup capacity may run at very low load factors, it may be difficult to secure the needed investment. The Given low load factors, wholesale market revenues are likely to be too low and too risky to justify investment in new capacity. And while the capacity market is in principle designed to deliver investment that cannot be delivered through the wholesale market, there may be political difficulties in securing tens of gigawatts of backup capacity that may see minimal utilisation over its lifetime.

Flexible resources are cost-effective solutions to moderate backup capacity requirements. Options to moderate backup capacity requirements include substitution of variable renewables with firm low-carbon capacity (CCS, nuclear, biomass); additional battery storage; additional demand response; and additional interconnection. Firm low-carbon capacity is likely to be a very costly solution, as backup capacity operates at very low load factors; while interconnection is not a reliable source of backup, as it is not always available to meet peak electricity demand due to competing demand for electricity in interconnected markets. However, flexible resources are cost-effective and reliable solutions. To identify the potential of battery storage to moderate backup capacity requirements, we developed a new scenario, the Max Storage scenario. Unlike the Rapid EV+HHP scenarios, the Max Storage scenario does not constrain battery storage capacity, but estimates the level of capacity that could minimise the total cost of the electricity system. Figure 44 shows the level of backup capacity needed in the Rapid EV+HHP scenario and the Max Storage scenario, and their High Flex variants. In the High Flex variant of the Rapid EV+HHP scenario, the additional storage and demand response reduces the volume of OCGT capacity from around 33 GW to 9 GW. In the Max storage scenario, the additional storage reduces the volume of OCGT to zero, while in the Max Storage High Flex variant, the additional demand response reduces the volume of storage needed from 55 to 44 GW. Removal of the constraint on storage capacity results in a new storage capacity both because storage is assumed to be lower cost than OCGT per GW of capacity, and because storage provides additional benefits in terms of load shifting and frequency response. However, it should be noted that in practice, a more flexible electricity system is unlikely to fully eliminate the need for thermal backup capacity. While the modelled scenarios reflect the capacity mix needed to ensure security of supply under a range of contingencies, in practice some thermal capacity should be needed to ensure security of supply under extreme system stress events. An extreme system stress event might include some combination of am an extreme peak demand, both domestically and in interconnected markets (for example, a cold snap in North West Europe); the failure of a large generator; and a sustained period of low wind output.

Figure 44 Flexible resources can significantly moderate the backup capacity needed to deliver security of supply



Source: Vivid Economics, Imperial College, BEIS

6 Assessment of demand response potential

Box 4 Key messages

The demand response and smart charging of electric vehicles necessary to support accelerated electrification are technically feasible.

- The long-term potential for demand response is significant. Analysis shows that up to 53% of residential electricity demand, 32% of commercial electricity demand and 22% of industrial electricity demand are movable.
- Smart charging could significantly reduce peak electricity demand. Analysis of driving patterns shows that overnight charging could meet the majority of charging needs, minimising the need to charge during the evening peak.

As set out in Section 2, the Accelerated scenarios are underpinned by significant uptake of demand response. Table 5 shows assumptions on the level of demand response in the Core and High Flex variants of each scenario in 2025, 2030 and 2035.

Table 5 Maximum potential and uptake of demand response in the modelled scenarios

Segment	Maximum potential (shift in peak demand)	Share of maximum potential					
		Core			High Flex		
		2025	2030	2035	2025	2030	2035
Residential appliances	41%	25%	50%	50%	50%	100%	100%
Industrial and commercial	10%						
Electric vehicles	80%						

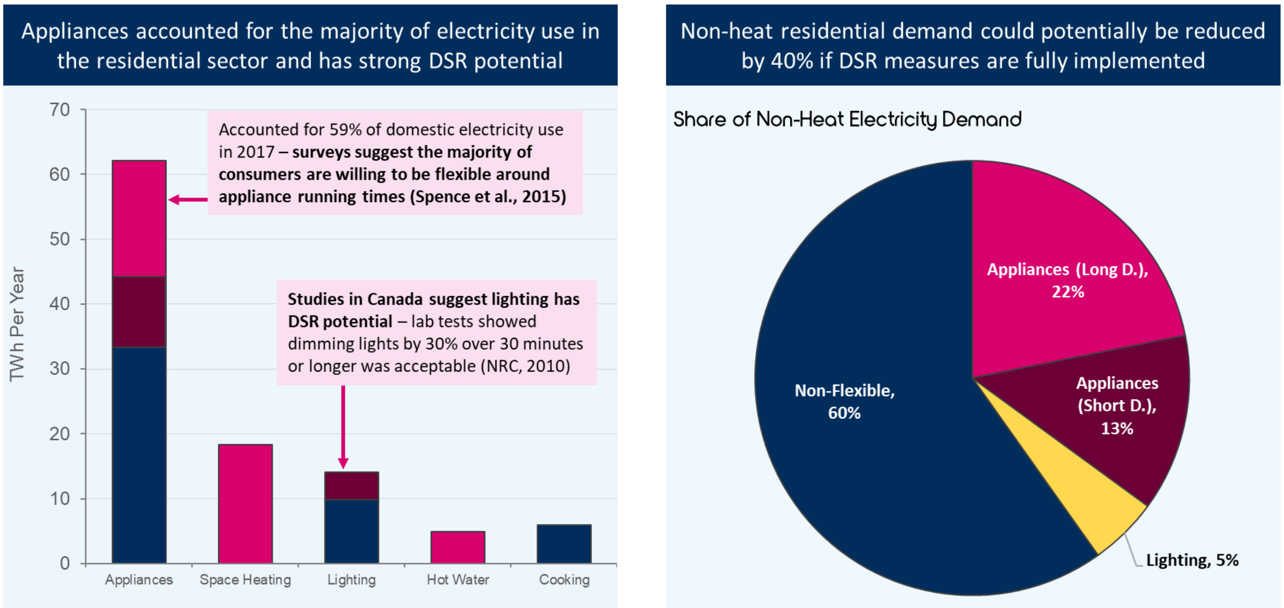
Source: Vivid Economics, Imperial College

We examine the evidence on the future potential of demand response in the residential, commercial, industrial and transport sectors. We find that:

- In the residential sector, up to 53% of current electricity demand is potentially movable, comprising appliances, space and water heating and lighting.
- In the commercial sector, up to 32% of current demand is potentially movable, comprising cooling and ventilation, space and water heating and lighting.
- In the industrial sector, up to 22% of current demand is potentially movable, comprising industrial processes, space heating and refrigeration.
- Smart charging could reduce peak electric vehicle charging demand by over 80%.

In the residential sector, up to 53% of current electricity demand is potentially movable, comprising appliances, space and water heating and lighting. Space heating and hot water can provide long duration DSR if they can be controlled centrally – average water tanks can provide 3 hours of heat demand (Nera, 2010) and so pre-heating can create large peak energy use reductions. Surveys suggest that consumers are generally happy to be flexible around the timing of their wet appliance use (Spence et al, 2015) and several studies show the significant DSR capacity this can generate (Nistor et al., 2015). This analysis estimates 35% of appliance energy use excluding fridges to be flexible for long durations. Some shorter duration DSR sources are also available in the sector but have stronger barriers to uptake. Fridges can be curtailed for 15-30 minutes without material impacts but there is clear consumer preference against central control. There is field test evidence that reducing lighting by up to 30% for short periods of time is a viable DSR option (DRC, 2010). However, there have not been any larger scale studies into the overall acceptability of this, particularly at the domestic level. Figure 45 shows the share of current electricity demand that is potentially movable with demand response. As electricity demand from heat pumps and electric vehicles increases, the share of residential demand that is movable could rise.

Figure 45 In the residential sector, up to 53% of current electricity demand is potentially movable

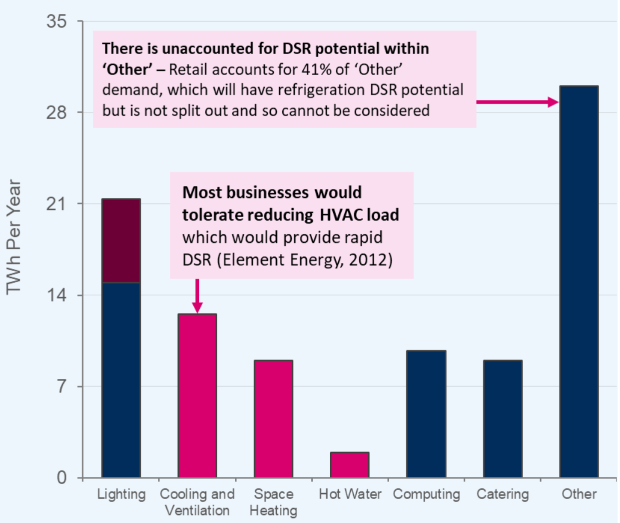


Source: Vivid Economics

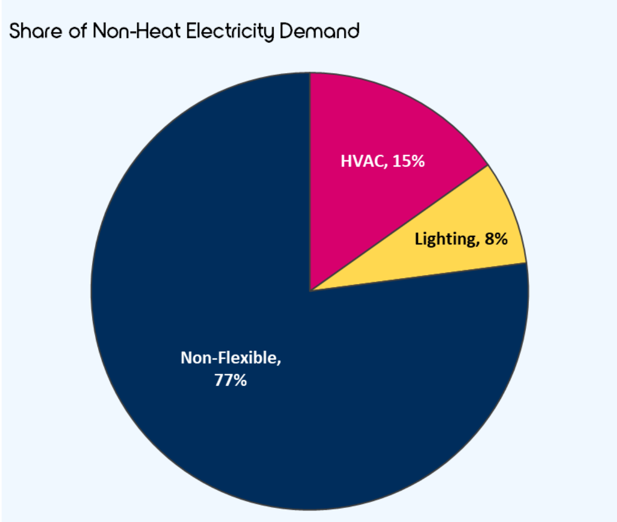
In the commercial sector, up to 32% of electricity demand is potentially movable, comprising cooling and ventilation, space and water heating and lighting. The majority of electricity use in the commercial sector is time sensitive and inflexible, but shifting lighting, HVAC and heating electricity demands still creates large DSR potential. Studies indicate that heating, ventilation and air conditioning (HVAC) can be curtailed for up to 60 minutes with minimal impact on comfort levels (Element Energy, 2012) and around 15% of surveyed businesses already providing DSR identified HVAC as a source (theenergyst, 2018). Full take up of DSR for HVAC use could make 15% of non-heating electricity demand in the commercial sector flexible and is the only long duration DSR option identified in the sector. Lighting accounted for 23% of electricity consumption and could deliver short duration DSR, but there has yet to be deployment of lighting DSR beyond the field test setting and none of the UK companies surveyed identified lighting as a DSR source. Commercial refrigeration is not separated in the data and so cannot be assessed, but is likely to be a large share of 'other' demand and have short duration DSR potential. Figure 46 shows the share of current electricity demand that is potentially movable with demand response. As with residential demand, as electricity demand from heat pumps increases, the share of commercial demand that is movable could rise.

Figure 46 In the commercial sector, up to 32% of current demand is potentially movable

HVAC energy use is a significant share in commercial demand and is potentially flexible for periods of time



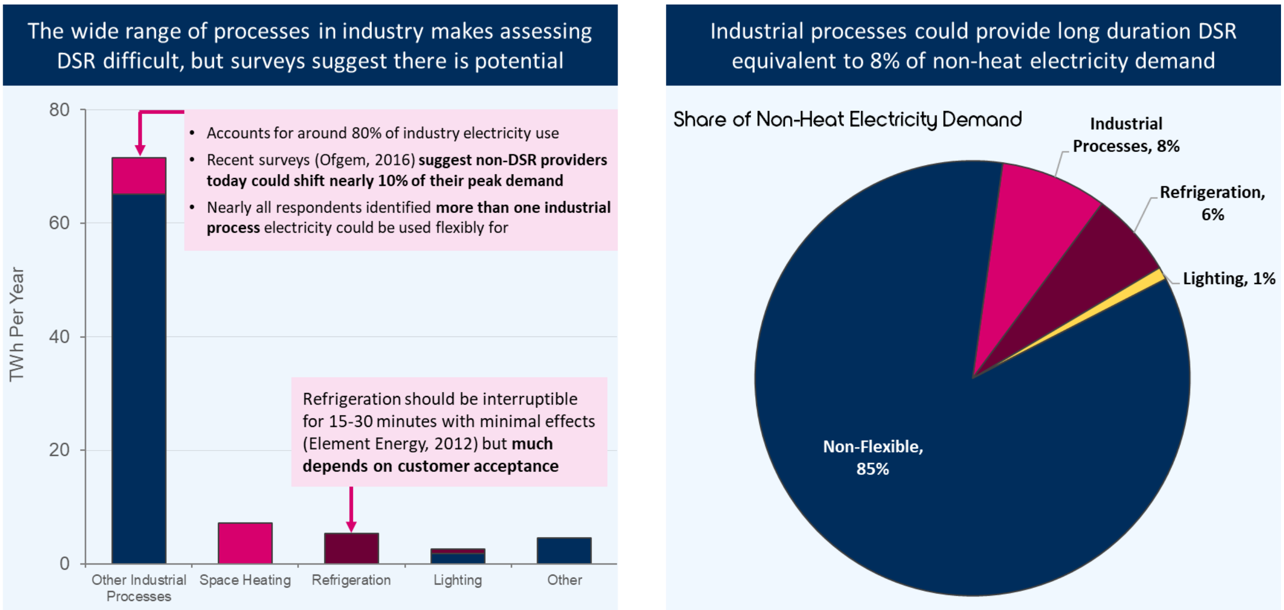
Long duration DSR from HVAC could enable up to 15% of non-heat electricity demand to be shifted



Source: Vivid Economics

In the industrial sector, up to 22% of electricity demand is potentially movable, comprising industrial processes, space heating and refrigeration. Industrial processes have long duration DSR potential (Giles, 2014) and accounted for the vast majority (80%) of industrial electricity use in 2017, but it is challenging to assess each process for each unique use case. Survey data implies that there is generally a significant amount of flexibility amongst industrial consumers. Non-DSR providers state they could shift nearly 10% of their overall peak demand with pumps and motors, which is the largest process by electricity end use, being identified as the most flexible processes overall (Ofgem, 2016). Overall, industrial processes could provide enough long duration DSR to make 8% of non-heat electricity demand in industry flexible. Refrigeration and lighting accounted for 8.7% of electricity consumption in the sector and could potentially deliver short-duration DSR. Lighting can be dimmed and industrial refrigeration should be interruptible for up to 30 minutes or pre-super cooled and interrupted for up to an hour but this will depend on the need for precise temperature control and customer acceptance. Of businesses surveyed, 10% claimed to be providing some DSR services through freezers and chillers (theenergyst, 2018) which suggests these barriers are not insurmountable. Figure 47 shows the share of current electricity demand that is potentially movable with demand response.

Figure 47 In the industrial sector, up to 22% of current demand is potentially movable

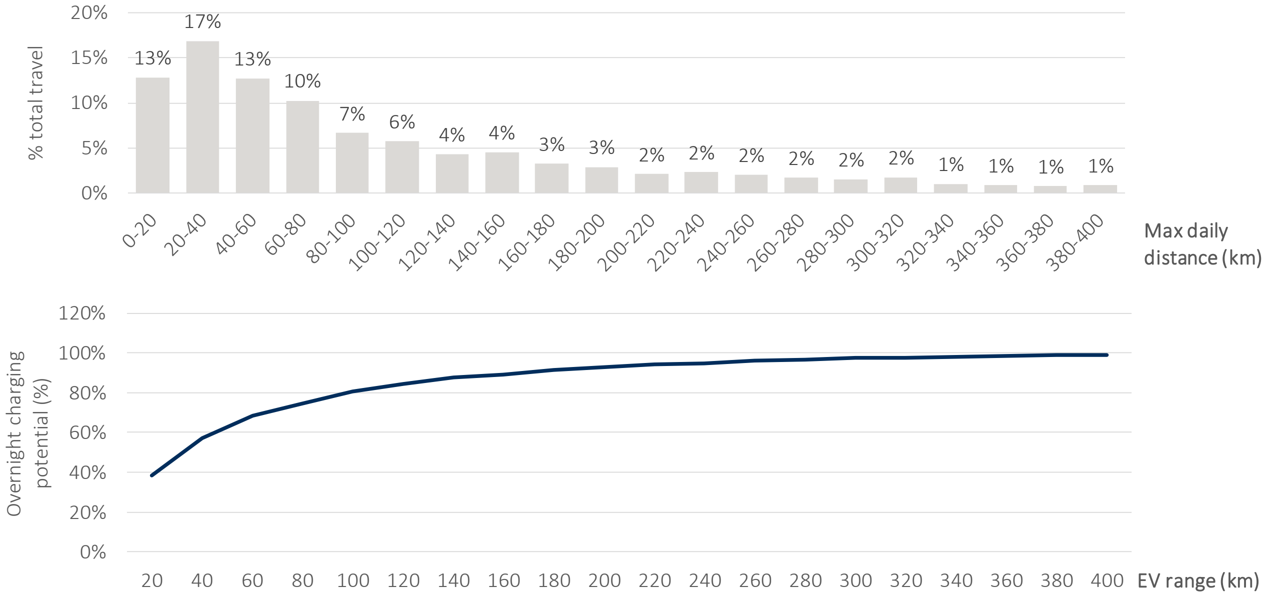


Notes: Dark colour segments are short duration DSR measures

Source: Vivid Economics

Smart charging could reduce peak electricity demand by over 80%. Smart charging could reduce the impact of electric vehicles on peak electricity demand, if large numbers of electric vehicles charge overnight or during the day in periods of high renewable generation. The potential for smart charging is poorly understood due to the small number and scale of trials carried out to date. An alternative source of evidence is the National Travel Survey, which contains detailed data on patterns of car use. Analysis of National Travel Survey data on distances travelled by 8,000 cars over a seven-day period provides an understanding of the distribution of trips of different lengths, and therefore the share of total charging needs that could be met with a single charge, if the car were charged overnight. The share of charging needs that can be met with a single overnight charge is determined by patterns of car travel, and the share of car travel that is carried out on days in which a car travels no more than the range it can cover in a single charge. Figure 48 shows the share of car travel that is carried out on days with different total distances, and the resulting share of charging needs that can be met with a single overnight charge, depending on the electric range of the vehicle. Figure 48 shows that days in which cars travel a short distance account for a large share of total car travel. Days in which cars travel under 20 km account for 13% of total travel; while total travel accounted for by days with a maximum distance of 80km account for around 53% of total, rising to 74% of total travel with maximum distance of 160km. Figure 48 also shows how the share of total charging needs that could be met with a single overnight charge varies with the range of an electric vehicle. For an electric vehicle with a 120km range, 84% of charging needs could be met with overnight charging, while 14% of charging needs would need to be met by charging during the day. For a vehicle with a 280km range, 97% of charging needs could be met with overnight charging. Even at low ranges, at least 80% of charging needs could be met overnight, and a significantly greater share at higher ranges.

Figure 48 The share of charging that can be met overnight increases with the range of electric vehicles



Source: Vivid Economics, National Travel Survey

The demand response and smart charging of electric vehicles necessary to support accelerated electrification are technically feasible.

7 Policy implications

Box 5 Key messages

To minimise the cost and disruptiveness of distribution network reinforcement, investments need to be future-proof. The current price control framework does not cover the required multi-decade time horizon.

- With electrification of heat and transport, electricity demand is likely to grow over the period to 2035, and potentially beyond. Investments that are adequate to accommodate near-term demand growth may not adequate to accommodate electrification over the longer term.
- Network reinforcements are a major investment, and are disruptive. Further, the costs of over-sizing network infrastructure are very low. As a result, future-proofing investments by over-sizing network infrastructure is a very low-regrets option.
- Uncertainty over electric vehicle and heat pump uptake is a major challenge to accurately projecting network investment needs. Great Britain's regulatory framework for distribution networks (the 'RIIO' framework) should be flexible enough to allow distribution network operators to respond to emerging evidence on future uptake, even during a single price control period.
- Batteries and demand response can reduce the need for distribution network reinforcement. The RIIO price control framework should continue to incentivise distribution network operators to reduce total expenditure (TOTEX) and make use of these solutions where possible.

To deliver the necessary low-carbon generation at current build rates, sustained build of new onshore wind, offshore wind and solar PV are needed. If constraints on onshore wind and solar PV continue, a major ramp up in new offshore wind build is needed.

- While policy is delivering new offshore wind, planning constraints on onshore wind are limiting the potential for new deployment, while the lack of CfD auctions creates risks for both onshore wind and solar PV. New solar capacity in 2017 was under 1 GW, around 80% below its 2015 peak.
- To support delivery of onshore wind and solar, planning restrictions on new onshore wind would need to be relaxed, and a route to market provided for onshore wind and solar PV.
- To deliver the necessary investment, Government needs to anchor expectations around the volume of capacity needed, and address remaining market failures to deploying renewables. It is not clear that new capacity on this scale could be delivered by merchant investment, and a sustained programme of CfD auctions may be needed.
- If constraints on onshore wind and solar PV continue, new offshore wind would need to rapidly increase to around 5 GW per year, nearly three times its 2017 peak. A significant scale up in the supply chain would be needed to deliver these volumes.

Large-scale policy reform and market design are needed to deliver a flexible electricity system.

- Current market arrangements are not adequate to deliver large-scale battery storage and demand response. Ofgem, BEIS and National Grid are working to ensure storage and demand response providers can be rewarded for the value they deliver, and to remove barriers to their participation in the electricity system. These objectives will need to be achieved by the by the early 2020s to support the necessary investment.

- In parallel, a shift in consumer and attitudes will be needed to support demand response. Consumers will need to accept to move from fixed to time of use electricity pricing, and to engage with new technologies and business models to vary their electricity demand in line with the value they place on it.

7.1 Future-proofing distribution network investments

To minimise the cost and disruptiveness of distribution network reinforcement, investments need to be future-proof. Network reinforcements are costly and disruptive. Disruptiveness is likely to be particularly acute in urban and semi-urban areas with high customer density, due to the large number of customers affected by outages, high share of the network likely to need reinforcing, and predominance of underground lines. Network capacity requirements will increase over time as uptake of electric vehicles and hybrid heat pumps increase electricity demand. However, the cost and disruptiveness of the reinforcements can be minimised by ensuring that investments are future-proof, and that the reinforcements provide adequate network capacity to meet electricity demand not only in the near- to medium- term (to 2035) but in the long-term (to 2050 and beyond):

- If network reinforcements are planned and delivered based only on near-term demand projections and fail to consider the possibility of longer-term demand increases, there is a risk that additional reinforcements could be needed in future, potentially almost doubling the total cost and disruptiveness of reinforcements. For example, in the Central scenario, 73,000 km of network line reinforcement is needed to 2025 at a total investment cost of around £9 billion; by 2030 this rises to 217,000 km and a cost of £25 billion; and by 2035 to 339,000 km and £41 billion. In the Rapid EV+HHP scenario, reinforcement increases further to 386,000 km at a cost of £47 billion. If investments to 2025 and 2030 are not oversized to take demand in 2035 into account, and further upgrades to the same assets are needed to accommodate rising demand, the total cost of network reinforcements could reach up to £81 billion, with £34 billion of unnecessary expenditure.

- In contrast, if network reinforcements are planned and delivered based on long-term demand projections, accounting for the possibility that future demand could be higher than expected, a small cost premium could avoid the need for additional reinforcements in future, and the consequent cost and disruption. Such pre-emptive reinforcements would also accommodate any particularly rapid uptake of electric vehicles and heat pumps in certain areas of the network.

- Analysis by Imperial College London based on the P2 Review study indicates that the cost of a 420 Amp cable on the low-voltage network could be around £8,000-10,000 per km of cable, or around 8-10% of the estimated £101,000/km total cost of upgrading an underground cable on a low-voltage network. Similarly, the cost of a 640 Amp cable on the high-voltage network could be around £12,000-18,000 per km of cable, or around 11-17% of the estimated £110,000/km total cost of upgrading an underground cable on a high-voltage network.

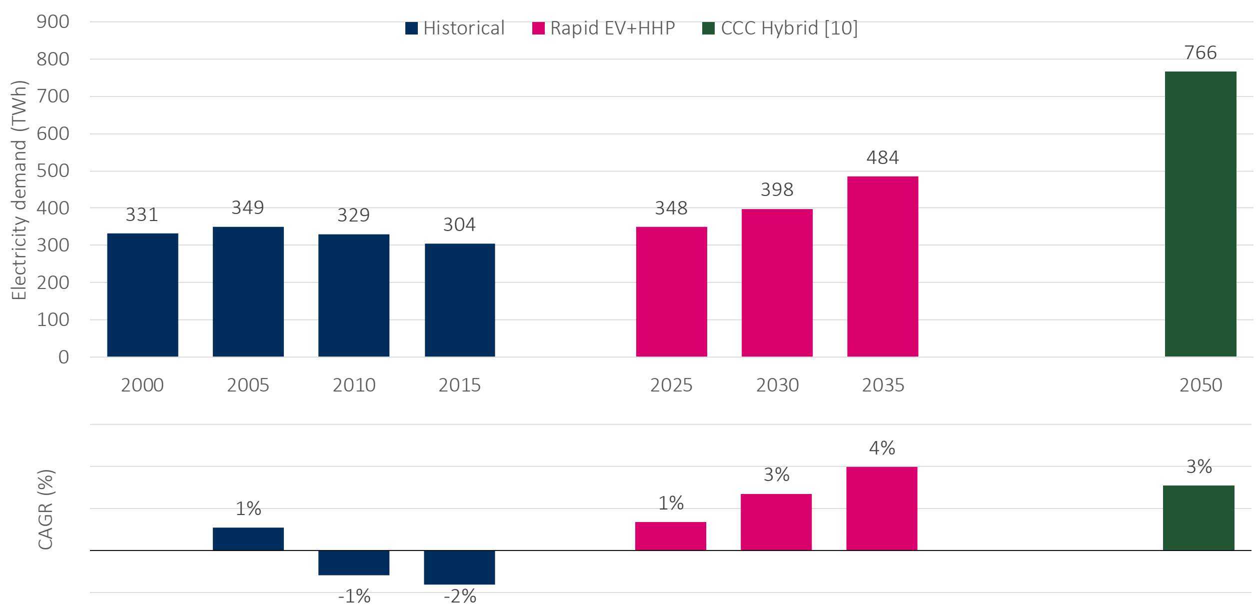
- As a result, oversizing network capacity by a factor of two would increase the total cost of upgrading an underground cable by 8-17% (depending on network voltage). If all underground network reinforcements in the Rapid EV+HHP scenario were oversized by a factor of two to reduce the risk of incurring unnecessary cost and disruptiveness from additional future reinforcements, the total cost of reinforcing the distribution network could increase only slightly, and avoid the need for further costly and disruptive reinforcements due to future growth in demand.

- The degree of oversizing needed will depend on current and potential future levels of demand, which will differ across areas of the network. However, electricity system scenarios suggest that overall electricity demand could more than double between 2025 and 2030 (see Figure 49), suggesting that on average oversizing by a factor of more than two may be necessary.

The existing price control framework has accounted for incremental load growth over short time horizons. Under the RIIO-ED1 price control framework, DNOs developed business plans covering the eight-year price control period (2015-2023). As part of these business plans, the DNOs forecast load growth over the RIIO-ED1 price control period, and identified the network reinforcements that would be needed to accommodate this load growth. However, load growth over this period is likely to be incremental. Figure 49 shows historical electricity demand, and projected electricity demand to 2035 in the Rapid HHP+EV scenario and to 2050 in the CCC's Hybrid [10] scenario. To date, and to 2025, the price control framework has had to accommodate only incremental load growth. Between 2000 and 2015, electricity demand has seen only slight increases and decreases, and the RIIO-ED1 price control framework may need to accommodate a load growth of around 1% per year to 2025.

However, it is not clear that the current framework is adequate to accommodate a step change in load growth over several decades. Beyond 2025, load growth may need to increase very significantly to a rate of accommodate electrification of heat and transport. Electricity demand in the Rapid EV+HHP scenario growth by around 3% per year between 2025 and 2030, and 4% per year between 2030 and 2035. Electricity demand in the CCC's Hybrid [10] scenario represents additional growth around 3% per year between 2035 and 2050. While the RIIO framework has some provisions for anticipatory investment, such investments have been small to date, and it is not clear that the framework is adequate to deliver anticipatory investment at the scale needed to electrify a very significant share of end-use energy demand. If RIIO-ED2 operates in broadly the same way as RIIO-ED1, network reinforcements primarily targeted at load growth over the price control period, the reinforcement plans and regulated revenues emerging from the price control process will fail to take account of the reinforcements needed beyond the end of the price control period. As a result, there is a risk that further reinforcements are needed to the same network assets beyond the end of the price control period, increasing the total cost and disruptiveness of the future upgrade programme.

Figure 49 The distribution network price control framework will need to accommodate a step change in load growth



Source: Vivid Economics, Imperial College, BEIS

The totex approach to determining DNO revenues will be increasingly important to delivering investment in battery storage and demand response. The revenues DNOs are allowed to receive are partly determined by the regulatory asset value of their assets. Under a regulatory model where only capital expenditure increases the regulatory asset value, DNOs would have the incentive to favour capital investment over alternative solutions to managing network constraints. However, under RIIO, both capital and operating expenditure contribute to the regulatory asset value, based on the concept of Totex (total expenditure). Section 4 has shown how battery storage and demand response could reduce the total cost of network reinforcements in the Rapid EV+HHP scenario by up to 13% in 2035, by avoiding the need to reinforce parts of the distribution network. As the scope to use battery storage and demand response increases, it is vital that the regulatory framework continues to incentivise DNOs to use these solutions as an alternative to new network investment, where these are cost-effective.

7.2 Delivering renewable generation capacity

To deliver the necessary low-carbon generation at current build rates, sustained build of new onshore wind, offshore wind and solar PV are needed.

Current policy could be adequate to deliver 1-2 GW of offshore wind per year. In 2018 the Government announced its intention to run CfD auctions around every two years from 2019 with a total budget of £557 million per year. In the Offshore Wind Sector Deal, Government has committed to working to ensure that 'up to 30GW of offshore wind can be delivered by 2030, delivering 1-2GW of new offshore wind per year, in a sustainable and timely way'. A build rate of 2 GW per year could be adequate to deliver the Accelerated scenarios, provided onshore wind and solar PV are also deployed at the upper end of their historical build rates.

Planning constraints on onshore wind are limiting the potential for new deployment. In line with the commitment in the Conservative Party Manifesto to end any new public subsidy for onshore windfarms and change the law so that local people have the final say on windfarm applications, the Government in 2015 introduced new rules governing the construction of onshore turbines. Under these rules, onshore wind development is only eligible for planning consent in areas designated suitable by local authorities. As a result of these rules, only 0.1 GW of new wind capacity has secured planning approval in England, compared with 2.1 GW in Scotland.

For both onshore wind and solar PV, the lack of CfD auctions creates risks. Following the Conservative Party commitment to end any new public subsidy for onshore windfarms in 2015, and closure of the Renewables Obligation in 2017 and the Feed In Tariff scheme from 1 April 2019, no price support is currently available for onshore wind or solar PV. While the costs of these technologies are not fully known, they are widely considered to be among the cheapest forms of generation and competitive with gas on a levelized cost basis. Therefore in principle, it is possible that these technologies could be delivered on a 'merchant' basis, without a contract for difference. However, it is not clear that in practice market incentives will be adequate to develop onshore wind and solar PV on this basis. The CfD mechanism was designed to reduce the exposure of renewable generators to the risk of low wholesale electricity prices, which could result from multiple factors including low gas prices, low carbon prices, or the dampening effect on prices of large volumes of renewable generation. The appetite of merchant investors to face these risks remains unproven.

Should risks to delivery of wind and solar PV not be addressed, a massive ramp up in new offshore wind build would be needed. The Government has very recently agreed a sector deal with the offshore wind industry, committing to supporting the delivery of up to 2 GW of new offshore wind per year, to achieve a total capacity of 30 GW by 2030. To this end, Government has signalled its intention to hold CfD auctions every two years from 2019. Achieving the accelerated electrification scenario without a significant contribution from onshore wind and solar PV would require the build rate over the period 2019-2035 to increase to 5 GW per year. Delivering these volumes would require very significant scale up in the UK or European supply chain and could substantially increase the costs of delivery.

Providing onshore wind and solar PV with a route to market could significantly reduce costs and risks of relying on offshore wind. Relying exclusively on offshore wind for the new generation necessary to support accelerated electrification would raise serious challenges. To allow support onshore wind and solar PV to providing this generation, it is necessary to offer these technologies a route to market.

7.3 Delivering a flexible electricity system.

While flexible resources are needed to deliver accelerated electrification, current investment levels are very low. The Central and Accelerated scenarios involve significant uptake of flexible resources. In these scenarios, uptake of demand response reaches 25% of maximum potential in 2025 and 50% by 2035 across residential, industrial, commercial and electric vehicle demand, while storage reaches around 9 GW by 2025 and 19.5 GW by 2035. The High Flex variants of these scenarios involve even higher uptake, with demand response reaching 100% of maximum potential by 2035 and storage reaching around 29 GW. The additional flexible resources in the High Flex variants reduce the average cost of electricity by around 1-2%. These levels of uptake are significantly higher than what is expected to be delivered in the near-term. For demand response, around 2.6 GW of de-rated capacity pre-qualified for the T-4 Capacity Market auction for delivery in 2022, up from the 2.1 GW that pre-qualified for the T-1 Capacity Market auction for delivery in 2019. For battery storage, around 1.3 GW of de-rated capacity pre-qualified for delivery in 2022, up from the 0.2 GW that pre-qualified for delivery in 2019.

A range of barriers currently inhibit the necessary investment in flexible resources. Barriers include inadequate markets for electricity system services; the early stage of the DSO transition; the lack of cost-reflective consumer tariffs; limited deployment of smart technologies; and an inefficient charging regime for battery storage:

- **Inadequate markets for electricity system services.** The inadequacy of the current market arrangements to procure and adequately reward provision of electricity system by battery storage and demand response is widely recognised. For example, the quantity and complexity of products creates a barrier to entry; for example, National Grid procure 14 different products for reserve services and 7 for frequency response services, each with different technical requirements and routes to market. Product tenders are poorly specified, with little clarity over value National Grid's place on key product characteristics such as the length of contract period or how quickly an asset ramps up in response to a frequency deviation. Work is underway to address these issues: National Grid has published roadmaps on frequency response and reserve, restoration, reactive power and wider access to the balancing mechanism; Ofgem has approved a package of reforms to the Balancing and Settlement Code (BSC) being introduced in preparation for the introduction of the European Balancing Project TERRE (Trans European Replacement Reserves Exchange), a new Europe-wide balancing platform, which will enable access for aggregators as well as flexibility providers connected to the distribution network. Government has enabled the stacking of value between the Capacity Market and balancing services. Distribution Network Operators (DNOs) have committed to opening up network requirements to markets and competition, and several DNOs have already launched tenders for flexible solutions to network issues.

- **The early stage of the DSO transition.** Distribution Network Operators will increasingly need to transition to Distribution System Operators, working together with the Electricity System Operator, aggregators, storage providers and consumers to manage supply and demand on their networks. The market model for the DSO transition, governing the roles and responsibilities of the DSO and the other principal actors, has yet to be determined. The Energy Networks Association has consulted on a range of market models for the DSO transition. Government and Industry will need to agree and implement a market model to support the DSO transition and allow the main actors to work together to manage supply and demand.

- **Lack of cost-reflective consumer tariffs.** Currently, consumers face minimal temporal price signals. The majority of consumers are on flat tariffs, while some are on economy 7. A move from the current system to half-hourly settlement, where prices vary between each half-hour period, would allow consumers to vary their electricity consumption in response to changes in supply and demand.

Ofgem is due to make a decision on how to proceed with market-wide settlement reform in the second half of 2019.

- **Limited deployment of smart technologies.** Demand response requires smart meters and smart appliances. Government has committed to ensuring that every household and small business is offered a smart meter by the end of 2020, and has signalled its intention to set regulatory requirements for smart appliances through primary or secondary legislation. Full roll out of smart meters and development of substantial market offerings for smart appliances will be needed to unlock meaningful levels of demand response at the consumer level.

- **Inefficient charging regime for battery storage.** Currently, electricity market arrangements do recognise the role of battery storage as a solution to generation and network adequacy issues. As a result, storage incurs consumer levies (such as levies to fund the Renewables Obligation and Feed In Tariff schemes) and overpays residual transmission (TNUoS) and distribution (DUoS) charges. This places storage at a disadvantage relative to generators and network infrastructure, which do not incur these levies. Progress to address these issues is underway: the Government is preparing to define electricity storage as a type of generation to exempt it from consumer levies, and industry is finalising code modifications on transmission, distribution and balancing charges for storage and is due to submit to Ofgem for approval.

Delivering the necessary investment in flexible resources will require large-scale policy reform and market design in the near term. Work is underway to address the barriers inhibiting investment in flexible resources. However, it is not clear that the timeframe to resolve these barriers is consistent with delivering accelerated electrification. It is therefore a policy priority to:

- build on progress to date by Government, Ofgem and National Grid by National Grid, and complete the reform of markets for electricity system services;
- determine and implement the market model for the DSO transition;
- proceed with market-wide settlement reform, ensuring a move to half-hourly settlement;
- complete the rollout of smart meters across all homes and businesses, and set regulatory requirements for smart appliances and smart functionality for EV chargepoints; and
- finalise initiatives currently underway to ensure a level playing field for battery storage, ending the payment of consumer levies and overpayment of network charges.

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Annex 1: Modelling suite

To develop whole electricity system scenarios that co-optimise investments in generation, transmission, distribution and flexible resources, two sophisticated modelling tools were used in this study:

- Imperial College's Whole-energy system Investment Model (WeSIM). WeSIM is an electricity system optimisation model that estimates the pattern of investment in and operation of electricity system resources which minimises the overall electricity system cost, given constraints to ensure reliability and respect the characteristics of the electricity system.
- Imperial College's Load Related Expenditure model of electricity distribution networks (LRE). The LRE model is a fractal network model: it uses fractals to reproduce realistic network topologies and lengths and therefore allow for the characterisation of distribution networks of different types.

These models are described further below.

Whole-energy system Investment Model (WeSIM)

To estimate the additional capacity and cost of the electricity system resources required under the earlier electrification scenarios we used Imperial College's Whole-energy system Investment Model (WeSIM). WeSIM estimates the pattern of investment in and operation of electricity system resources which minimises the overall electricity system cost while meeting a carbon target. Key features of WeSIM include:

- Detailed characterisation of all relevant electricity system resources. WeSIM models generation, network, storage, demand response and interconnection resources.
- Detailed characterisation of electricity system reliability. WeSIM models reliability needs in detail, including adequacy, inertia, reserve and response.
- Accurate modelling of important electricity system characteristics. WeSIM accurately represents power flow limits, dynamic characteristics of generation plants, and operational constraints of storage and demand response.
- Representation of multiple energy carriers. WeSIM model captures the interaction across different energy carriers, for example: where actions in the heating system (such as retaining hot water stores) can complement measures in the electricity system, the model can use the opportunities to minimise the overall energy system costs.

Load Related Expenditure (LRE) model of electricity distribution networks

To estimate the additional capacity, cost and feasibility of the distribution network infrastructure required under the earlier electrification scenarios we used Imperial College's Load Related Expenditure (LRE) model of electricity distribution networks. The model estimates the volume and cost of distribution network resources (network lines, transformers and substations) needed to support a given scenario. By comparing the volume and cost of these assets with current assets, the LRE model is able to calculate the additional volume and cost of distribution network assets needed in each scenario.

Distribution networks are complex. Within a single distribution network, network characteristics typically range from high-load density city/town networks to low-density rural networks. These different parts of the network will vary in terms of the density and mix of both customer types (and resulting demands), and network assets (network lines, substations and transformers), and network lengths. Furthermore, these features will differ between networks, as well as within them.

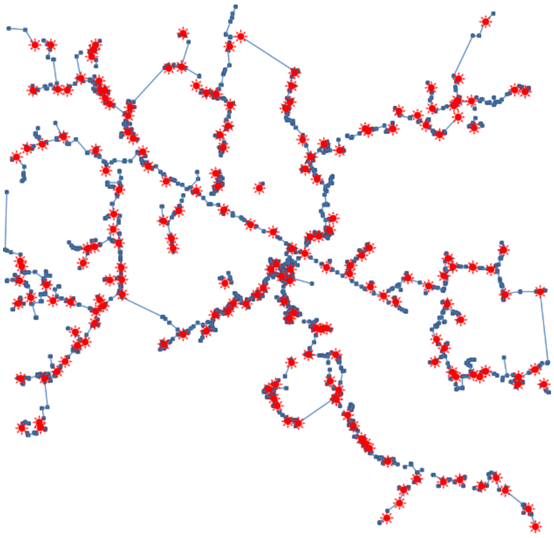
Given this complexity, the LRE model uses fractals to produce simulated networks whose statistical properties closely match those of real distribution networks. It represents networks as groups of network topologies: areas of the network that share similar characteristics in terms of their key features. Specifically, the LRE model represents areas of the network using 24 distinct network topologies, based on analysis of actual GB distribution networks. Each network topology represents a different combination of both customer density, and density of the various network assets (low and high voltage lines, and transformers). The 24 network topologies can be aggregated into five broad network types: countryside, rural, semi-rural, semi-urban and urban. Further details are provided in Table A1.1, and four examples are provided in Figure A1.1.

Table A1.1 The LRE model covers five broad network types, with 24 distinct topologies

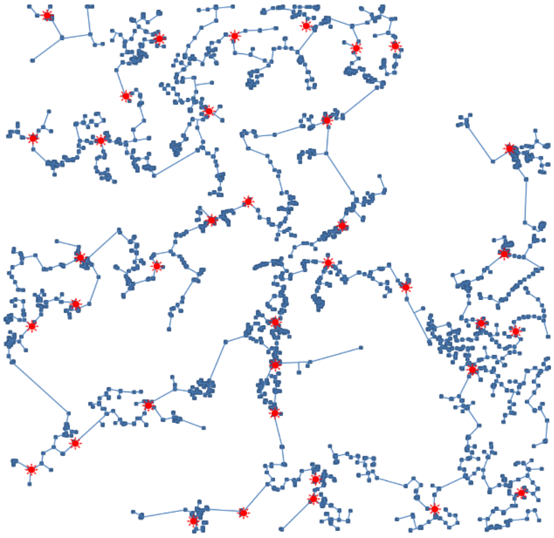
Variable	Customer density (customers per square km)	Number of topologies
Countryside	Very low (50)	3
Rural	Low (around 100)	6
Semi-rural	Moderate (around 300)	9
Semi-urban	2x Moderate (around 600) 2x High (around 3,000)	4
Urban	Very high (over 10,000)	2
Total		**24**

Source: Imperial College

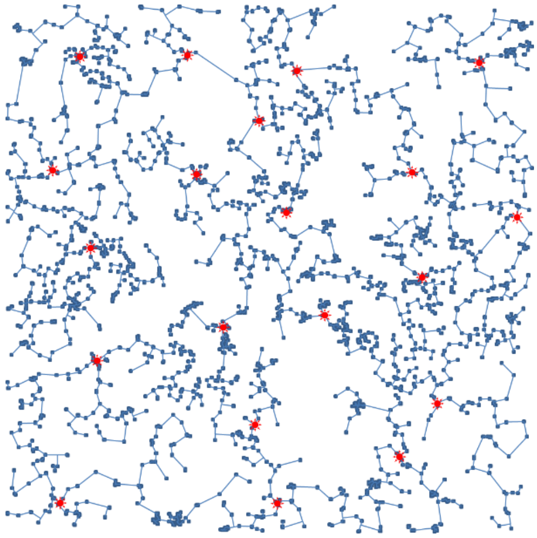
Figure A1.1 Click here to enter title



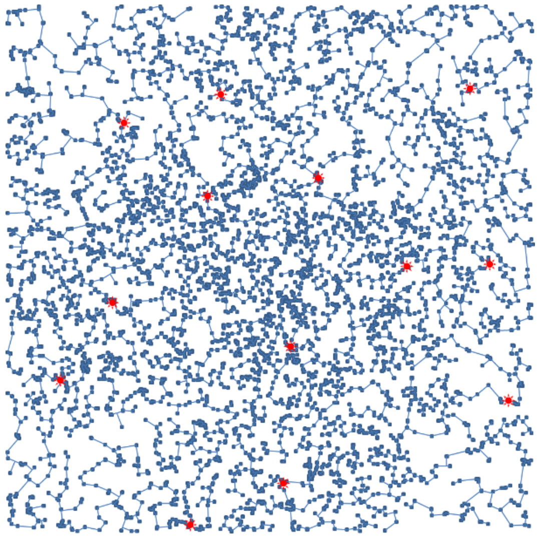
Rural type 2 (20 square km)



Semi-rural type 5 (7 square km)



Semi-urban type 2 (4 square km)



Urban type 2 (1.2 square km)

Note: Scale is different for each network type
Source: Imperial College

The resolution of the LRE model is described in Table A1.2. To ensure a high degree of statistical accuracy, the simulated networks are calibrated to data for real distribution networks, with a difference of under 1% for each variable.

Table A1.2 The LRE model represents the distribution system at high resolution

Component	Resolution
Customer types	Domestic: Unrestricted and Economy 7 tariff customers Non-domestic: small, medium and large customers
Distribution network voltages	0.4, 11 and 33 kV
Distribution network lines	Number, capacity and length of overhead and underground lines, at each network voltage
Transformers	Number of pole mounted and ground mounted transformers, at each network voltage
Substations	Number of substations, at each network voltage
Network topologies	24 different network topologies, covering a range of countryside, rural, semi-rural, semi-urban and urban networks

Source: Imperial College

For a given scenario, the LRE model calculates the power flow across the low and high voltage lines in each representative network, and identifies where key constraints are breached.

Annex 2: Modelling assumptions

Section 2 sets out the characteristics of the electricity system scenarios modelled in this study. This Annex sets out additional assumptions underpinning the electricity system modelling.

Renewable technology generation costs

BEIS' estimates of generation costs date from 2016 and are out of date. While CfD auctions provide an indication of near-term costs of offshore wind, comparable data is not available for onshore wind and solar PV. In order not to bias the model results towards one particular generation technology, the CCC provided a single set of generation costs for each technology.

Table A2.1 Renewable technology generation costs

	2025	2030	2035
Onshore wind, offshore wind and Solar PV	£60/MWh	£55/MWh	£50/MWh

Source: Committee on Climate Change

Unit costs of network reinforcement

Table A2.2 Click here to enter title

Asset		Unit cost
Network lines		
Extra high voltage (33V+)	Overhead	£91,000/km
	Underground	£453,000/km
High voltage (11V)	Overhead	£38,000/km
	Underground	£118,000/km
Low voltage (0.4V)	Overhead	£29,000/km
	Underground	£111,000/km
Transformers		
Grid transformer		£1,830,000 per unit
Primary transformer		£840,000 per unit
Distribution transformer	Pole-mounted	£4,300 per unit
	Ground-mounted	£27,000 per unit

Source: Imperial College

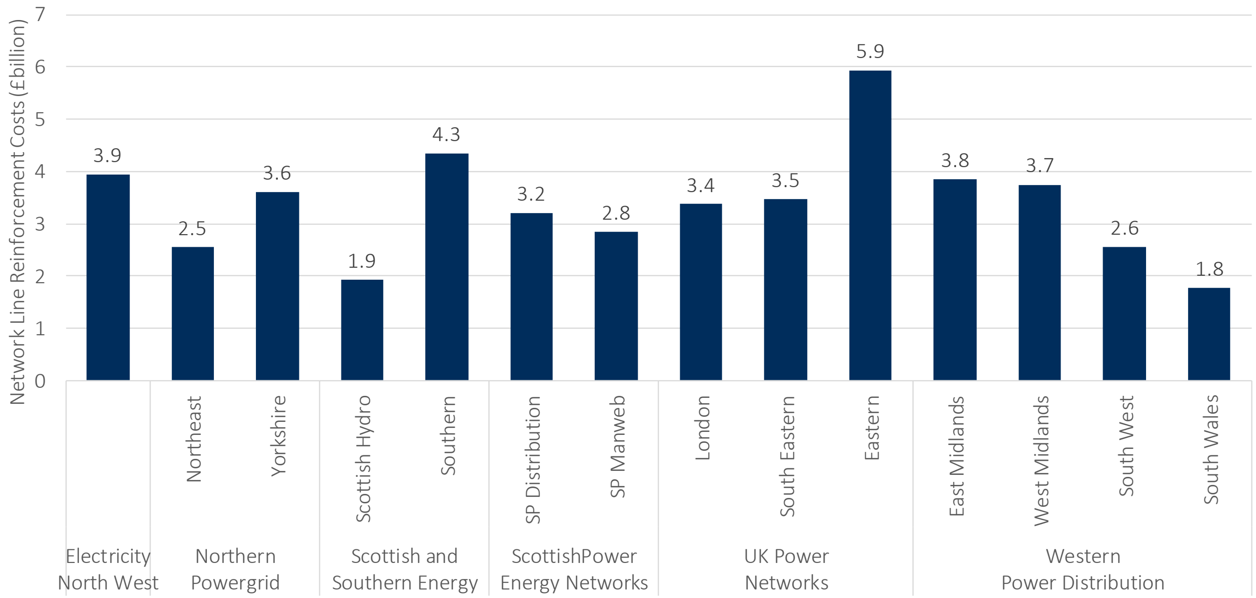
Heating demand

In order to test the adequacy of the system capacity to deal with the extreme weather conditions, the heating demand profile includes a 1-in-20 year event, in which three consecutive cold days (with the average daily temperature across GB of -7 °C) coincide with a low output of renewables.

Annex 3: Distribution cost breakdown by DNO

Section 4 sets out impacts of accelerated electrification on distribution networks. Figure A3 below shows how total distribution network reinforcement costs are spread across the 14 licensed distribution network operators in Britain.

Figure A3 Total cumulative distribution network reinforcement costs to 2035 by distribution network operator



Source: Vivid Economics, Imperial College

Annex 4: Assumptions underpinning resource potential

Section 5.1 considered the feasibility of delivering adequate volumes of onshore wind, offshore wind and solar PV. This Annex summarises the evidence base on the constraints to UK onshore wind and solar PV resource, and the constraints used to derive our estimates of the resource.

Table A3.1 Constraints to onshore wind deployment

Constraint	Range in the literature	Vivid Economics
Land cover	Exclusions: irrigated crop lands, forest, water bodies, urban areas, permafrost, land above 2,500m Suitability factors: rainfed cropland, mosaic vegetation, mosaic grassland, shrubland, grass land, sparse vegetation, bare areas	**Conservative:** wind deployment permitted on: pastures, non-irrigated arable land, moorlands and heathland, natural grasslands Exclusions: high grade agricultural land (ALC 1&2) **Optimistic:** wind deployment also permitted on: peat bogs and high grade agricultural land (ALC 1&2)
Slope	10-20%	15%
Protected sites	NPs, ANOBs, NSAs (Scotland), SSSI, NNRs, Greenbelts, IUCN I-III, Natura 2000	NPs, ANOBs, NSAs, SSSIs, Greenbelts
Buffers	Roads: 100-200m Rivers: 100-200m Settlements: 400-500m Airports: 5-6km	Roads: 200m Rivers: 200m Settlements: 500m Airports: 5km
Turbine density	4-9MW/km^2	5MW/km^2
Hub height	45m	100m
Wind resource quality	Minimum: 4-7m/s	**Conservative:** minimum WPD class 4 **Optimistic:** minimum WPD class 3
Proximity and clustering	Separation: 7km centroid spacing Roads: within 500m of a minor road and 1.5km of a main road	**Conservative:** within 500m of a minor road and 4 km of a major road **Optimistic:** within 500m of a minor road and 9 km of a major road

Source: Vivid Economics

Table A3.2 Constraints to solar deployment

Constraint	Range in the literature	Vivid conservative (*optimistic*)

Land cover	Excludes: urban regions, woodland, moorland, mountainous areas and high grade agricultural land	Solar deployment permitted on: pastures, non-irrigated arable land, moorlands and heathland, natural grasslands (*peat bogs*) Exclusions on: permitted high grade agricultural land (*not excluded in optimistic*)
Slope	2-11%	10%
Protected sites	National parks	NPs, ANOBs, NSAs, SSSIs, Greenbelts
Flood zones	Exclude large flood zones (>40km^2)	Buffer: rivers: 200m
Panel/site spacing	Density: 50MW/km^2	Packing factor: 30% GSR: 0.7 Resulting density: 5MW/km^2
Panel efficiency	10-21%	18%
Solar resource quality	Minimum: 100-120W/m^2	Minimum: 120W/m^2
Proximity and clustering	Roads: access to the site BSP: within 2.5km	Roads: within 500m of a minor road and 2km (*3km*) of a main road
Site size	1km^2	1km^2

Source: Vivid Economics

Company profile

Vivid Economics is a leading strategic economics consultancy with global reach. We strive to create lasting value for our clients, both in government and the private sector, and for society at large.

We are a premier consultant in the policy-commerce interface and resource- and environment-intensive sectors, where we advise on the most critical and complex policy and commercial questions facing clients around the world. The success we bring to our clients reflects a strong partnership culture, solid foundation of skills and analytical assets, and close cooperation with a large network of contacts across key organisations.

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