THE DRIVE TOWARDS A LOW-CARBON GRID

Unlocking the value of vehicle-to-grid fleets in Great Britain

Authors

Nissan Motor GB: Frank Oldfield, Krunal Kumpavat, Rebecca Corbett, Andrew Price

Imperial College: Marko Aunedi, Goran Strbac, Cormac O'Malley

E.ON Drive: Darren Gardner, Dominik Pfeiffer, Jan-Torben Kamphus

This report has been prepared by Nissan Motor GB, E.ON Drive and Imperial College London as part of the e4Future project. The content and recommendations presented in the paper represent the views of these project partners alone.

The e4Future project is part of the Vehicle-to-Grid (V2G) competition, funded by the Department for Business Energy and Industrial Strategy (BEIS) and the Office for Zero Emission Vehicles (OZEV), in partnership with Innovate UK, part of UK Research and Innovation. The project consortium consists of Nissan Motor GB, E.ON Energy Solutions, Imperial College London, Newcastle University, UK Power Networks, Northern Powergrid and National Grid ESO.

In January 2018, OZEV and BEIS announced that 21 projects (8 feasibility studies, 4 collaborative research and development projects, and 8 real-world V2G trial projects) were to receive funding of £30m to develop the business proposition and the core technology to support V2G deployment in the UK, including its demonstration with large scale trials.

The projects involve more than 50 industrial partners and research organisations from both the Energy and Automotive sector, marking the largest and most diverse activities on V2G in the world, and trialing more than 1,000 vehicles and V2G charger units across UK.

The V2G projects represent a significant step towards the transition to a low carbon transportation and a smart energy system. Allowing EVs to return energy to the power grid when parked and plugged for charging, will increase grid resilience, allow for better exploitation of renewable sources and lower the cost of ownership for EV owners, leading to new business opportunities and clear advantages for EV users and energy consumers.

Contents

1 Executive Summary

This paper explores the present-day opportunity and challenges for aggregators of vehicle-to-grid (V2G) fleets in Great Britain. The long-term power system benefits possible through V2G are also analysed, and recommendations provided on how to realise the full potential of this technology.

The opportunity and challenges for V2G aggregators today

The financial benefits for aggregators of back-to-base commercial V2G-enabled EV fleets are assessed by E.ON. Through stacking several different value streams, the analysis estimates aggregators could generate financial benefits of £700-£1250 per V2G-enabled EV. This comprises of both cost savings compared to an unmanaged charging regime, and direct revenues from providing grid services. Exact financial benefits vary depending on the driving and charging patterns of fleet vehicles.

There remains, however, several challenges to realising these benefits and creating a reliable business case:

- Energy consumption patterns at the premises where V2G chargers are installed can impact overall viability.
- Certain economic benefits are contingent on the aggregator also acting as the energy supplier to premises where chargers are installed.
- Complexities exist around sharing V2G financial benefits between the aggregator, fleet customers and the automotive company.
- Due to the nature of the technology and the early market stage, DC V2G chargers have a higher upfront cost compared to standard EV AC chargers.
- Many of the use cases that V2G aggregators rely upon to generate economic benefit will be impacted by planned changes in the next 2-3 years, though it is not yet clear to what extent. New market products such as Dynamic Containment and DNO flexibility products could provide an alternative source of revenues.

Future benefits of V2G

In the context of the British power system in 2025 and 2030, the long-term economic benefits and carbon reduction potential have been assessed by Imperial College for a back-to-base fleet of 1 million commercial EVs operating under three different charging scenarios: Unmanaged, Smart and V2G charging. Operational cost savings through V2G providing grid services are also quantified.

Whole-system economic benefits

- Modelling results show V2G can unlock substantial whole-system cost savings in the range of £412-883m/year.
- The additional cost associated with meeting the electricity demand of a million fleet EVs can be offset by the value of flexibility from V2G in the form of:
    - Avoided capital expenditure in generation;
    - Reduced need for distribution network reinforcement;
    - More efficient provision of balancing services, with reduced curtailment of renewable energy.
- In contrast, Unmanaged and Smart charging scenarios are shown to result in increased system costs of £567-773m/year and £102-150m/year respectively, due to the higher demand placed upon the power system by these vehicles, and the limited flexibility they offer.

Carbon benefits

- Results show V2G-enabled EV fleets can have a significant *negative* carbon impact i.e. reduce overall power system CO_2 emissions.
- Incremental carbon emissions of fleet EVs with V2G can be as low as -243gCO_2/km.
- In contrast, Unmanaged or Smart charging regimes are shown to trigger additional power system emissions in the range of 36-52gCO_2/km, as a result of the additional power demand created by EV fleets.
- The benefits of V2G are highest in scenarios with high renewable penetration and low uptake of other flexible options.
- Carbon savings from V2G fleets would make it possible to install lower volumes of low-carbon generation capacity while still meeting current system-level decarbonisation targets.

Value of V2G for electricity system operation

- Analysis presented in this paper also suggests that with a lower penetration of 50,000 V2G-enabled EVs, each EV could reduce system operation costs by approximately £12,000 per annum and CO_2 emissions by around 60 tonnes per annum.
- Reduced wind curtailment and more efficient frequency response provision through V2G are the main drivers of these cost and emission savings.
- The value offered by V2G EVs for system operation falls with larger fleet sizes. With 150,000 EVs on the system, the marginal value per EV is approximately £600. Competing flexibility sources could also diminish overall operational cost savings from V2G.

Recommendations

Vehicle-to-Grid (V2G) technology has the potential to add huge value to the UK's power system and support a cost-effective transition to a low-carbon future. For this to happen, it will be vital that appropriate market and regulatory conditions are in place for widespread adoption of V2G to be achieved. With this in mind, the following recommendations are made:

- A holistic approach to transport and energy policy must be taken such that the whole-system benefits created by V2G find their way back to providers of V2G flexibility.
- Future changes to OFGEM network charges should consider likely V2G use cases, such as that of back-to-base commercial fleets.
- Ancillary and flexibility services should be designed with participation from small-scale EV fleets in mind.
- Sales of EVs should be bolstered through a consumer incentive roadmap: a plan for the evolution of the Plug-in Car Grant, changes to the taxation scheme to embed the zero-for-zero principle, and 0% VAT for EV purchases.
- Industry and government must ensure consumers and businesses are well-informed about the energy and mobility choices they make.
- Government should prioritise V2G charging architecture when developing EV charging regulations, in order to ensure an optimal decarbonisation strategy for the long-term.
- Greater financial support should be offered towards the up-front cost of purchasing and installing V2G chargers.
- Type approval of V2G chargers for provision of frequency response services should be established.

2 Introduction

Today, transport is the UK's most polluting sector with the majority of greenhouse gas emissions coming from road transport[1]. With sustainability high on the public agenda and driven by policy such as the government's Road to Zero and Clean Air Strategy, the landscape looks set to transform with millions of zero-emission electric vehicles anticipated to come on to the roads over the next decade. This will create a new challenge as the existing grid is unlikely to have sufficient capacity to cope with the increased demand for electricity at peak times.

In parallel, the power sector is undergoing significant changes to decarbonise and integrate more renewable energy sources. However renewable generation such as solar and wind are variable by nature and cannot simply be turned on at will. There is a need to find viable solutions to help provide more flexibility in the electricity grid to help balance fluctuations in renewable generation.

Given that many vehicles spend a high percentage of time idle, both during the working day and overnight, vehicle-to-grid (V2G) technology offers an ideal solution to ease grid capacity constraints and provide flexibility to the power system. V2G enables energy to be discharged from EV batteries in order to power buildings or the electricity network during peak periods. Batteries can be recharged when demand is lower, and renewable energy is in greater abundance. In doing so, V2G-enabled EVs can limit the need for expensive investments in additional generation capacity and grid reinforcement, while providing the necessary flexibility to support a smarter, more sustainable energy system.

Given expectations that V2G-enabled EV fleets can have an integral role to play in the UK's future electric ecosystem, it is imperative that appropriate market and regulatory conditions are in place to ensure there is sufficient value available for all stakeholders involved to make V2G a commercially viable proposition.

With this in mind, this paper will address the current opportunity for a utility operating as an aggregator of back-to-base V2G commercial fleets. Additionally, the future economic and environmental benefits available through widespread adoption of V2G fleets are explored. In doing so, it is hoped this paper will highlight not only the huge opportunity V2G presents, but also the challenges to be overcome in order for the benefits of this nascent technology to be fully realised.

[1] Department for Business, Energy & Industrial Strategy, '2019 UK greenhouse gas emissions, provisional figures'

3 The opportunity and challenges for V2G aggregators today

3.1 Introduction

V2G enables bi-directional flows of electricity between EVs and the grid. By pooling together the collective power of many EV batteries and controlling (dis)charging operations, aggregators can utilise this flexibility to generate economic benefits which can be shared with customers.

This section investigates the prospects for an aggregator of commercial V2G fleets in the UK today. With many business fleets remaining plugged-in to chargers at work premises for long periods after the end of the working day, their profile is well suited for V2G applications. It is assumed that the role of aggregator is taken up by a utility company, such as E.ON.

Market channels and key drivers for V2G are explored, showing the results of E.ON's commercial analysis and highlighting challenges which may potentially impact the financial benefit possible from V2G.

3.2 V2G use cases

V2G flexibility can be utilised in various ways to create financial benefits. Certain V2G use cases lead to cost savings when compared to a standard unidirectional charging solution. Alternatively, revenues can be directly generated from trading in energy markets or offering specific flexibility products. In general, these use cases can be marketed simultaneously in order to boost overall economic benefits. This is known as revenue stacking.

The following use cases are considered in this paper in order to calculate potential financial benefits:

1) **Day-ahead power market trading:** This involves exploiting price differences ('arbitrage') on the day-ahead market by using the flexibility of the EVs to minimise the procurement cost for charging purposes from an energy supplier perspective. Intraday trading would follow a similar principle – but is not considered explicitly in the analysis presented here.

   Note, Day-ahead (or intraday) trading is only possible when the aggregator is also the energy supplier for the fleet customer. If this is not the case, an aggregator may instead look to optimise vehicle charging/discharging patterns against time-dependent electricity tariffs (time-of-use tariff optimization) to create savings on energy bills for fleet customers.

2) **3rd party cost component avoidance:** V2G can take advantage of time-dependent grid fees (e.g. DUoS, CM levy or BSUoS), by discharging the EV batteries when these component costs are high mainly during periods of high demand on the grid, and recharging EV batteries while these charges are lower. Doing so can generate savings on the energy bill of the fleet customer or savings for the energy supplier.
3) **Triad savings:** National Grid charges an additional levy on energy consumption which occurs during the three half-hours throughout a year with the greatest grid load. By reducing the energy consumption through discharging EVs during these time periods, savings can be achieved. Due to planned regulatory changes, this use case will no longer be possible after Winter 2022/23.
4) **Firm Frequency Response (FFR):** National Grid ESO procures FFR to ensure a continuous balance between electricity demand and supply, in order to maintain grid frequency within required limits. V2G-enabled EVs can provide FFR through modulating their charging and discharging power in real-time according to grid frequency. Providers of FFR flexibility are remunerated in the form of availability payments, with further remuneration for actual delivery.

Apart from the above use cases, newly emerging flexibility services procured by distribution network operators could provide an additional source of revenue for aggregators, but are not considered in the financial analysis presented in section 3.3. More details on this nascent use case can be found in section 3.5.2

3.3 V2G financial benefits

The financial benefit coming from V2G when compared to unmanaged standard charging can be seen in Figure 1. Details of the fleet driving profile and modelling assumptions used can be found in Appendix I.

Through stacking of different use cases, benefits are found to be in the range of £700-£1250. The financial benefit coming from V2G is observed to be sensitive to the following aspects:

- EV Battery state of charge (SoC) at arrival and departure;
- Arrival and departure times of the EVs;
- Volatility of relevant price data (e.g. electricity tariff, day-ahead prices, 3rd party components).

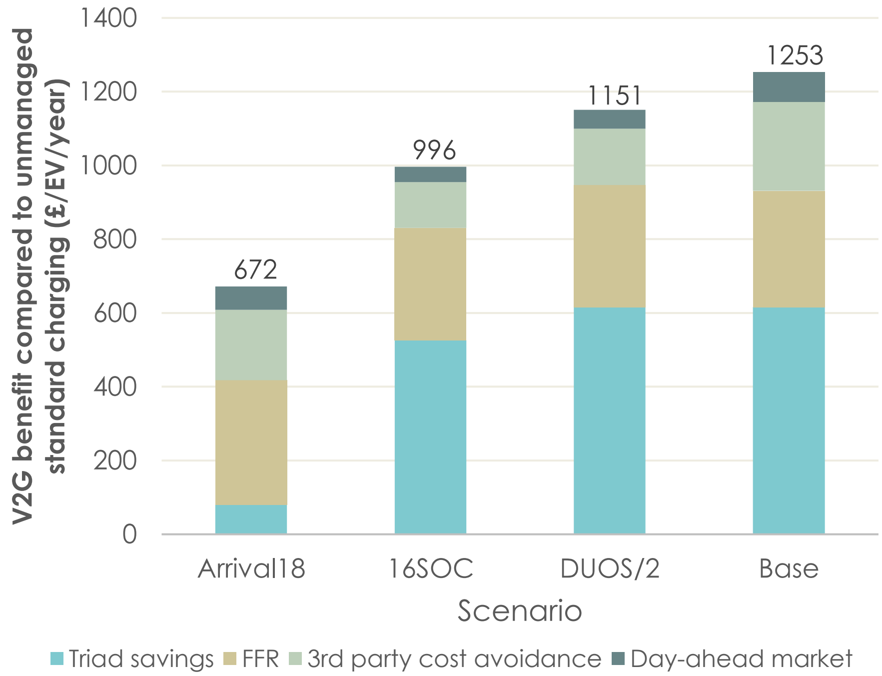

Figure 1: V2G benefits for different scenarios

The scenario analysis shown in Figure 1 is based on the 'ceteris paribus' approach meaning that only one parameter is varied while the remaining variables of the model remain constant.

For the 'DUOS/2' scenario the time-dependent DUoS charges were multiplied with a constant factor of 0.5 leading to smaller benefits when doing V2G as the spread between peak and off-peak charges is reduced. This scenario was introduced as the DUoS charges differ between DNO regions in the UK with respect to the spread between on-peak and off-peak times.

The '16SoC' scenario assumes that the EVs drive greater distances leading to a lower SoC when arriving at the depot. In this scenario EVs arrive with a SoC of 16 kWh (40%) at the depot compared to the base case where the EVs arrive with a SoC of 25 kWh (62.5%). The Triad savings are reduced for the '16SoC' scenario due to EVs being unable to continuously discharge with full power during potential Triad events.

The scenario 'Arrival18' demonstrates a scenario where vehicles are plugged in at 18:00 rather than the base case of 16:00 and reflects the lower savings due to missing Triad events (which usually occur before 18:00). In addition, the benefit which comes from the optimised trading on the day ahead market and 3rd party costs is reduced since the EVs cannot be discharged during the times for which the price on these market channels reach their peak, meaning opportunity to exploit prices differences is less throughout the charging session.

The large benefits coming from Triad and 3rd party cost components, can only be realised if the EV fleet is available during peak (typically 4-7 p.m.) as well as for off-peak times (12-5 a.m.). Arriving with a nearly empty battery at the charging station diminishes potential savings due to the limited potential for battery discharge. This highlights the fact that financial benefits can vary significantly between customers due to different driving and charging patterns.

3.4 Current challenges

Beyond fleet driving and charging patterns influencing V2G financial benefits, a number of other challenges exist with respect to successfully implementing V2G solutions for commercial EV fleets in the UK.

3.4.1 Critical role of site energy consumption

With V2G, energy from EV batteries can either be exported back to the grid or used to offset on-site power consumption at the premises where the chargers are located (often referred to as 'vehicle-to-building' or V2B). In order to evaluate which of these options is financially more attractive, the relevant electricity import and export prices (where applicable) need to be considered. These prices comprise of multiple components as shown in Figure 2.

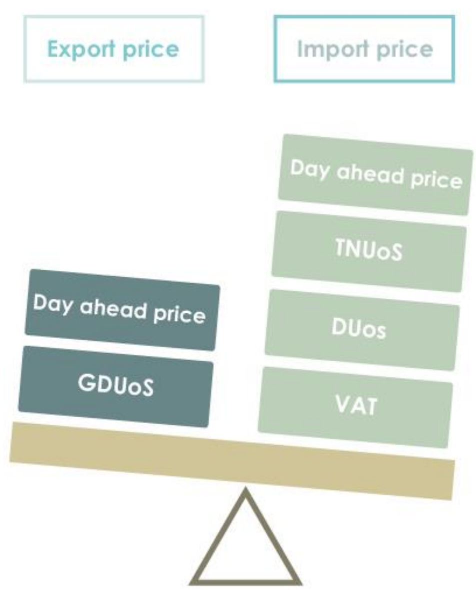

Figure 2: Import versus export electricity price

The relationship between the export and import price presented in Figure 2 is only valid for cases where the aggregator has sold energy on the day-ahead market and agreed to export the required power one day prior to delivery. When 'accidently' exporting to the grid (in cases where energy was not actively traded) and no export agreement with the DNO is in place, the exported energy will not be remunerated at all.

As import prices are greater than what can be received for exporting, at present there is no financial incentive for exporting energy to the grid (unless considering FFR or DNO flexibility services). Any exported energy would have to be bought back at higher cost in order to recharge the vehicle – ultimately leading to higher energy bills.

In contrast, there is financial benefit to be gained from offsetting on-site energy consumption through discharging batteries during high price periods, with vehicle charging shifted to low price periods. This benefit is only possible when the premises in question has a sufficiently high electricity demand, such that discharging does not result in energy being 'spilled' to the grid.

This means installing V2G chargers at a site with little overall energy consumption (a car park for example) may not make sense financially with discharging activities leading to additional costs. For such sites, it would be better to shift charging operations to periods with the smallest import price, i.e. 'smart charging' rather than V2G.

It should be noted, participation in DNO flexibility markets may change the picture presented here. In such cases, aggregators could receive both availability payments and delivery payments for any energy exported back to the grid. Such revenues would offset any additional costs caused by the different in export and import prices.

3.4.2 Customer and aggregator relationship

There are a number of different use cases which contribute to the overall financial benefits of V2G. Whether these benefits manifest at the aggregator or fleet customer side depends on the nature of the contractual relationship between the two entities – as shown in Table 1. These benefits may subsequently be shared between the aggregator, fleet customer and automotive company depending on what agreements have been put in place.

Certain use cases, such as trading on the day-ahead market, are only possible when the aggregator also acts as the energy supplier to the customer. The financial benefits here are realised by the aggregator (energy supplier) directly.

In cases where the fleet customer is not supplied with energy by the aggregator, trading on the day-ahead market will not be possible. Instead, aggregators could carry out time-of-use tariff optimisation – assuming a suitably large price spread between peak and off-peak prices on the customers tariff. However, the aggregator would not directly see the benefit from carrying out such a use case.

In contrast, 3rd party cost component savings may be realised either in the energy bill of the fleet customer *or* by the energy supplier - depending on the structure and terms of the energy contract between these two entities.

Table 1: Location of V2G benefits by use case

	Aggregator = Energy Supplier of fleet customer		Aggregator ≠ Energy supplier of fleet customer	
	Aggregator realises benefit	Customer realises benefit	Aggregator realises benefit	Customer realises benefit
Day-ahead trading	✓	✗	-	-
Time-of-Use Tariff optimisation	-	-	✗	✓
3rd party cost avoidance	✓	✗	✗	✓*
Triad savings	✓	✗	✗	✓*
FFR/DC	✓	✗	✓	✗

* Only if the relevant charges are explicitly passed through on the customer's energy bill

Irrespective of the contractual relationship between aggregator and fleet customer, benefits can also vary significantly due to factors such as the pattern of energy usage, the DNO region and the fleet's driving and charging behaviour as shown in Figure 3.

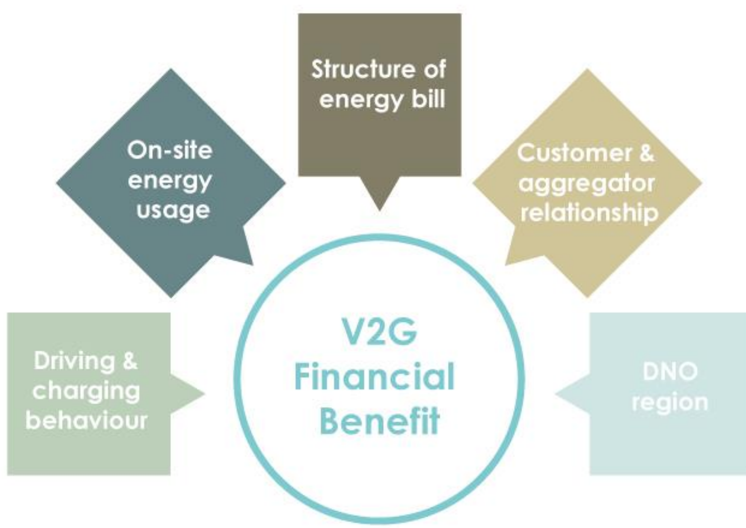

Figure 3: Import versus export electricity price

Such complexities mean a 'one-size-fits-all' approach towards a V2G fleet customer business model is difficult in practice. Aggregators need to ensure they can cover their cost base and make a profit, while providing fleet customers with sufficient financial incentive to opt for a V2G charging solution. With potential benefits varying for each customer, significant effort may be required in creating customer-specific propositions, sharing financial benefits and conducting settlement.

3.4.3 V2G set-up costs

In order to evaluate the business case for V2G, costs associated with the installation and commissioning of V2G chargers must also be considered. Generally, the cost of installing a V2G charger today is higher than that of a comparable standard unidirectional charger. Several elements contribute to this cost differential:

1. **Charger hardware & installation**
   V2G charger hardware costs are significantly higher compared to standard unidirectional chargers due to the fact that the number of produced chargers today is relatively small (and the more complex power electronics required within the unit itself). However, it is reasonable to assume that these costs will reduce over time due to economies of scale. V2G installation costs (covering electrical and civil works) will be similar to those for comparable standard charging solutions.

2. **Distribution Network Operator (DNO) costs**
   As V2G chargers enable export of electricity to the distribution network, a G99 application must be submitted to DNOs to obtain approval for connection to the grid. Depending on the specifics of the connection request, there may be associated assessment and design fees from the DNOs. The costs for this differ across the various DNO regions.

   As with other generation and storage devices, the DNO may need to witness the V2G commissioning checks at the cost of the customer. Witness testing requirements depend on whether the devices are fully type tested or not, the capacity of the generation/storage on site and whether an export limiting scheme (G100) is required to safeguard the network. Specific requirements are detailed in Engineering Recommendation G99.

3. **Prequalification of Firm Frequency Response (FFR)**
   In order to be able to provide FFR services, National Grid ESO requires *each* unit within a given portfolio to be pre-qualified separately. While such a requirement is suitable for conventional power plants, it is not ideal for small decentralised

assets. For a V2G aggregator this means that *every* individual V2G charger would require physical on-site testing before being approved for FFR.

This becomes a critical problem when scaling the solution, as the integration of each new charger would lead to additional effort and costs. In contrast, other European countries like Denmark[2] allow for type testing, whereby a particular type of unit need only be tested and approved for providing frequency response once, before being approved for wider deployment.

In order to create a commercially attractive proposition, the cost premium for V2G solutions must be offset by the financial benefits derived from the V2G use cases presented earlier.

3.5 Outlook for V2G use cases

The financial benefits of V2G presented earlier in the paper are based on the present-day regulatory framework and market regime. Ongoing developments in these areas could have a significant impact on future benefits from V2G.

3.5.1 Regulatory changes

A large portion of the financial benefits shown in Figure 1 comes from Triad and the 3rd party components use cases - both of which will be impacted by the following regulatory changes from Ofgem:

- The "Targeted Charging Review (TCR)" will remove savings coming from reducing the energy demand during Triad events after the winter season 2022/23.

- The "Access and Forward Looking Charges Significant Code Review" (SCR) will impact how DUoS and TNUoS are charged, with changes due to come into effect from April 2023. The actual impact on 3rd party component savings cannot be assessed currently as outcomes from the review have not yet been published.

3.5.2 Alternative V2G use cases

With changes to existing V2G use cases expected in the near future, alternative use cases for V2G may help bolster V2G revenues. Two such use cases are examined here.

[2] Energinet, 'Prequalification of units and aggregated portfolios'

1. Dynamic Containment (DC)

Dynamic Containment (DC) is a new frequency response service which will be deployed by National Grid ESO in 2021. It will replace FFR - which will gradually be phased out by the end of 2022. While future revenues from DC are as yet unknown – the market is likely to be competitive with flexibility from alternative technologies (such as stationary battery storage units) offering to provide such services.

DC will have stricter technical requirements around metering and signal exchange than FFR - leading to higher costs for commissioning a V2G portfolio to supply DC than for FFR. Combined with the current intention of National Grid ESO to maintain similar pre-qualification requirements as for FFR, provision of DC may prove to be unattractive for V2G aggregators on the basis of high costs for participation.

2. Distribution Network Operator (DNO) flexibility services

DNO flexibility markets are increasingly emerging as an important pillar for securing cost-effective decarbonisation of networks and providing an economic and efficient alternative to traditional network upgrades.

Such markets can provide an additional source of revenue for aggregators. The growing volumes of flexibility procured in UK Power Network's recent tenders (123 MW in the April 2020 tender[3]) included flexibility procured from a number of EV aggregators for the first time.

There are several factors to consider when determining the extent to which V2G aggregators could participate in such services:

- Charge points need to be located in zones where flexibility is required.
- The vehicle availability window needs to coincide with the times the service is required.

The specific service requirements may vary between DNOs depending on the products which they have available, the minimum eligible capacity, dispatch schedule and metering requirements. Services auctioned closer to actual delivery may be more favourable for aggregators.

[3] UK Power Networks, 'Flexibility Services Post-Tender Report June 2020'

4 Future Benefits of V2G

4.1 Introduction

This section presents an assessment of system benefits of V2G-enabled fleet EVs in the context of a decarbonised GB electricity system on a 2025-2030 time horizon. A whole-system optimisation framework is used to assess the economic and environmental implications of supplying electricity to EV fleets across different charging scenarios, including Unmanaged, Smart and V2G charging.[4]

Despite a general consensus on the benefits of flexible solutions and technologies such as V2G in the context of electricity system decarbonisation and integration of variable renewables, its technical capability and the implications for its value to the system are not entirely understood. Therefore the long-term economic benefits as well as carbon reduction potential of V2G are quantified here. Commercial fleet EVs can be well suited for the provision of V2G services due to the volume advantages and higher predictability of connection times.

4.2 Modelling the impact of fleet EVs on electricity systems

The quantitative analysis presented here is based on a whole-system optimisation model extended with a range of constraints and variables specifically associated with fleet EV charging and discharging (more details on the modelling approach are provided in the Appendix). The analysis assumes 1 million fleet EVs operating in GB, which is a sufficiently large number to drive noticeable changes in system cost and emissions, while not being an overly optimistic projection for the uptake of fleet EVs over the next decade or so. See Appendix I for details on the assumptions used with respect to fleet driving patterns.

Three fleet EV charging scenarios are considered in the analysis:

1. **Unmanaged scenario**: this does not allow for any discharging or Frequency Response (FR) provision by fleet EVs, with charging assumed to commence immediately upon return to the depot until the batteries reach the target level of 90% state-of-charge (SoC).

[4] Note that the analysis presented in this section draws upon a conference paper submitted by the research team at Imperial College London:
M. Aunedi and G. Strbac, "Whole-system Benefits of Vehicle-to-Grid Services from Electric Vehicle Fleets", *15th International Conference on Ecological Vehicles and Renewable Energies (EVER)*, Monaco, September 2020.

2. **Smart charging scenario**: assumes no discharging or FR provision, but allows charging to be optimised subject to constraints given by charger ratings and allowed SoC range.

3. **Vehicle-to-Grid (V2G) scenario**: assumes that both charging and discharging are allowed subject to charger capacity limits, as well as FR contribution of fleet EVs. Only upward FR was assumed to be provided through ensuring EVs are capable of injecting power into the grid when required, thus either offsetting the local demand or even acting as net source of electricity. FR provision was limited by the headroom between the maximum discharge capacity and scheduled net discharge, as well as by the volume of energy stored in batteries above the minimum allowed level.[5]

The incremental cost and carbon emissions driven by fleet EV demand are quantified by comparing a scenario with fleet EVs (following one of the three charging scenarios), and a counterfactual system scenario in which there are no fleet EVs. The difference in total annual system cost and in total annual system carbon emissions is divided by the number of fleet EVs assumed to be connected to the system.

Given that the total system cost provided by the model is reported separately across various categories (e.g. investment in generation and in networks, system operation cost etc.), it is further possible to disaggregate the incremental cost of supplying fleet EVs across these components.

When expressing incremental carbon emissions, the annual incremental emissions per EV are further divided by the assumed annual distance driven by each EV (around 18,500 km), in order to express incremental emissions in gCO_2/km and enable a direct comparison with tailpipe emissions from conventional vehicles.[6]

V2G case studies presented here focus on the GB power system on a 2025 and 2030 time horizon. The studies also look at two levels of system flexibility, Low Flexibility and Central. These scenarios differ in the level of energy storage and demand response available in the system – with the Central scenario assuming higher available volumes of these technologies. Key assumptions on generation and demand are provided in Appendix III.

[5] Note that the model only schedules the availability to provide FR rather than simulate the actual utilisation of this service, which is probabilistic and assumed to occur relatively infrequently over the course of the year.
[6] Direct (tailpipe) carbon emissions from EVs were assumed to be zero.

4.3 Impact of fleet EVs on aggregate system demand

The impact of fleet EVs on the aggregate electricity system demand in the 2030 scenario is illustrated for a winter week in Figure 4 for the Low Flexibility case across all three charging scenarios (Unmanaged, Smart and V2G). See Appendix I for assumptions relating to fleet driving patterns.

All three charts demonstrate how the net demand at the distribution network level changes after the addition of charging and discharging actions of fleet EVs. Net demand at distribution level is quantified as the difference between gross demand and net injections of distribution-connected battery storage and solar PV generation. The charts also depict variations in aggregate SoC for fleet EV batteries.

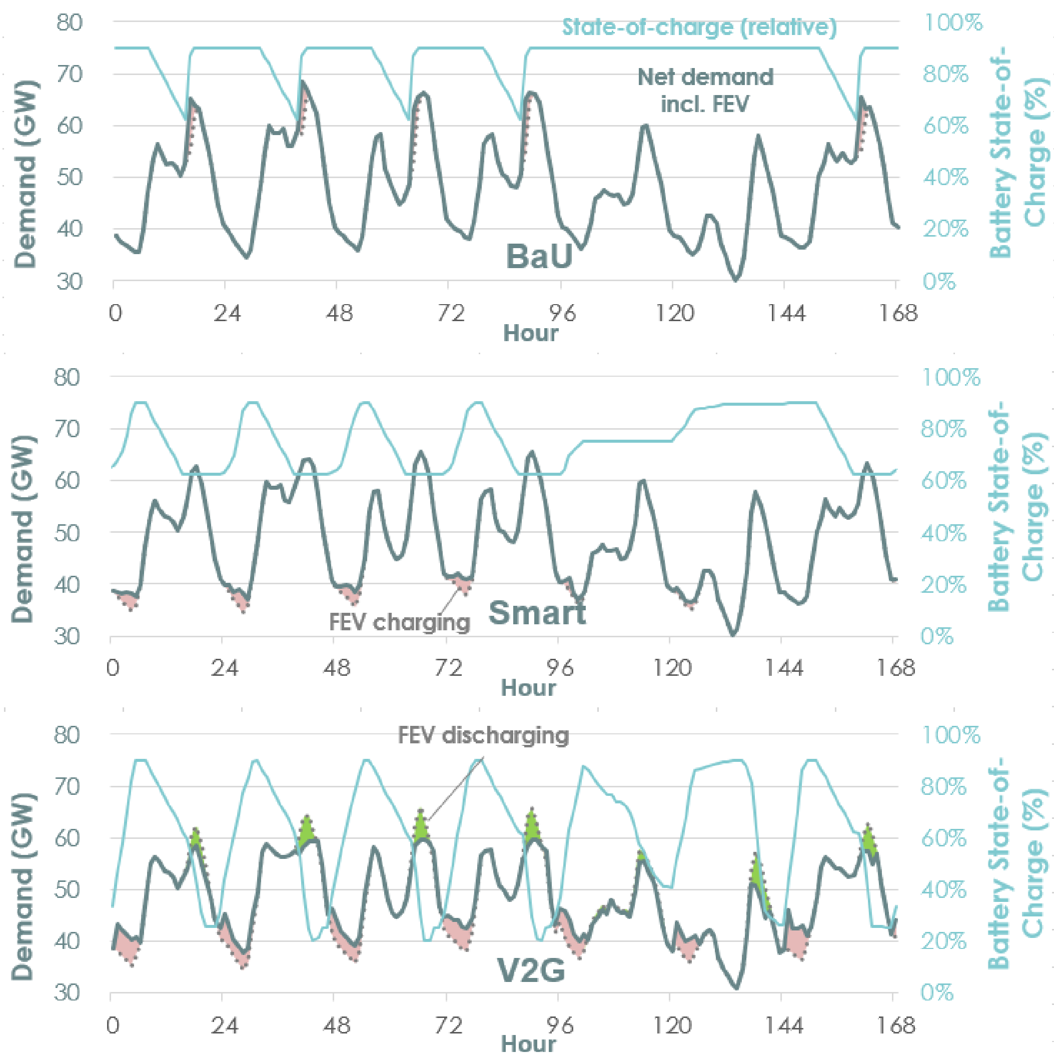

Figure 4: Hourly variations in aggregate system demand and SoC of fleet EVs (FEV) for three charging scenarios over a winter week in 2030 (Low Flexibility case)

In the Unmanaged case the SoC of fleet EVs follows a simple and regular pattern every workday, reducing linearly from 90% to 62.5% during an 8-hour driving pattern, and recharging back to 90% in the shortest possible time upon return to the depot. Timing of additional energy required for charging fleet EVs broadly coincides with system peak demand, which in the Low Flexibility case results in an increase in peak demand from 66.2 GW in the baseline case to 68.4 GW in the Unmanaged case. Increased peak demand will also result in higher total system cost resulting from the need to ensure additional generation and network capacity to meet the new fleet EV demand.

In the Smart charging scenario the fleet EV charging demand is effectively shifted away from peak periods towards night time in both Low and Central Flexibility cases, given that the marginal cost of supplying extra demand in those hours tends to be the lowest due to low baseline demand. The SoC variation pattern reflects this by remaining at its arrival level of 62.5% for several hours before replenishing the energy during the night to ensure the SoC of 90% is reached before the next departure. Given that the Smart charging scenario avoids increases in peak demand, it is also likely to result in significantly lower incremental system cost.

Fleet EVs following a V2G operating regime see a substantial change in their charging patterns compared to the other two charging approaches. Upon returning to the depot and reconnecting to the charge points, fleet EVs start to discharge energy from their batteries back into the grid during a few critical evening peak hours. Discharging makes use of the full allowed operating range of the battery, allowing the SoC to drop to the minimum threshold of 20%. As in the Smart scenario, all charging takes place during the night, however the energy demand for charging is now higher than in the Smart scenario to compensate for the energy discharged during peak demand hours. Charging and discharging cycles also repeat during the weekend. V2G operation results in the highest reduction in net peak demand compared to baseline, from 66.2 to 59.5 GW in the Low Flexibility case.

The utilisation of V2G to manage peak demand during a winter week is likely to be higher than during low-demand weeks in summer. Still, regardless of season, results for system-optimised V2G operation strategies suggest daily charge-discharge cycles with relatively large depth of discharge. Whether this could lead to issues and potential costs associated with battery degradation (also lowering the system benefits quantified in this section) is an area for future research.

4.4 Incremental system cost driven by fleet EVs

Incremental cost of supplying fleet EV demand, obtained by dividing the change in total system cost in a given charging scenario with the number of fleet EVs, is shown in Figure 5. Note that the values presented in the chart represent both the change in system cost in £m per year as well as annual extra cost per fleet EV given the assumption of 1 million fleet EVs. The same figure also provides a breakdown of the incremental cost into investment (CAPEX) components for generation and distribution networks and operating cost (OPEX).

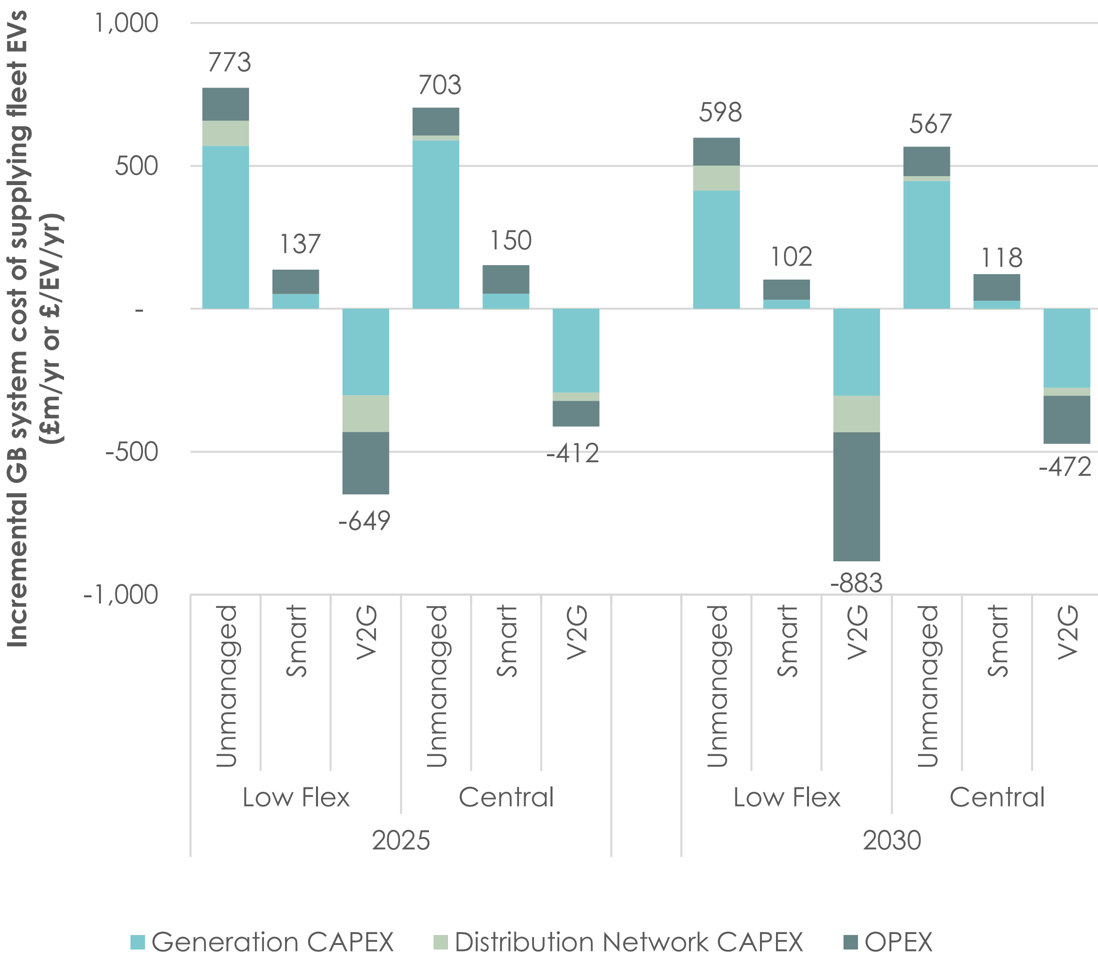

Figure 5: Incremental system cost of supplying fleet EVs across various scenarios

The *Unmanaged charging scenario* results in positive and relatively high incremental cost, varying between £700-770m in 2025 and £570-600m in 2030, equivalent to annual additional costs of £700-770 and £570-600 per EV respectively. Higher costs are observed in Low Flexibility cases (see Appendix III for Low Flexibility and Central scenario assumptions).

The dominant component of the Unmanaged incremental cost is the increase in generation CAPEX, mostly because of the need to add peaking generation capacity to maintain security margin after an increase in peak demand driven by fleet EVs. Another component is the operating cost (OPEX), given that the additional energy required by fleet EVs over the year results in an increased output of gas (CCGT) generation. Finally, in Low Flexibility cases there is also a notable cost component of distribution CAPEX, reflecting the reinforcement cost required to accommodate the increase in peak demand driven by fleet EVs.

The incremental cost in the *Smart charging scenario* is substantially lower, around £140-150m in 2025 and £100-120m in 2030. While it still includes an OPEX component, as it imposes an additional energy requirement on the system, the increase in generation CAPEX is only marginal and there is no additional distribution investment required. This is because Smart charging avoids placing additional energy requirements during system peak periods.

Finally, in all *V2G scenarios* there is a distinct reduction in total system cost i.e. a *negative incremental cost* of fleet EV, suggesting that the system value of V2G flexibility greatly outweighs any cost associated with supplying the fleet EV demand in this case. There are several key drivers for this:

1. There is reduced need for generation CAPEX due to discharging actions that reduce net peak demand Figure 4.
2. Distribution reinforcement cost is also reduced due to energy being injected during peak hours, although this reduction is significantly lower in Central Flexibility case where other flexible options are also present in the system.
3. Operating cost reduces substantially as V2G-enabled fleets displace up to 50% of FR otherwise provided by part-loaded and therefore less efficient thermal generators. This also results in lower renewable curtailment due to fewer generators needing to be synchronised to the grid. The OPEX reduction declines in the Central Flexibility case due to the presence of other flexible options supporting system operation.

The overall cost saving from V2G broadly drops by a third in 2025 and halves in 2030 as a result of moving from Low to Central Flexibility case i.e., when V2G is exposed to competition from other DSR ana dd energy storage resources. Nevertheless, the overall effect of V2G on the system cost is overwhelmingly positive, despite the need to deliver additional net energy to fleet EVs.

4.5 Incremental carbon emissions

Although EVs do not emit carbon when driving, the electricity used to charge their batteries causes carbon emissions that depend on the carbon intensity of the electricity grid. Incremental carbon emissions from the electricity system to supply fleet EV demand are quantified in a similar way to system cost, by comparing emissions between various fleet EV scenarios and the corresponding baseline (counterfactual) scenario with no fleet EVs. Note that this analysis does not consider lifecycle emissions associated with EV manufacturing, and only accounts for carbon emissions associated with the electricity used by EVs for driving.

Figure 6 shows a waterfall chart for system carbon emissions, illustrating the change in emissions when moving from baseline to various fleet EV charging scenarios.

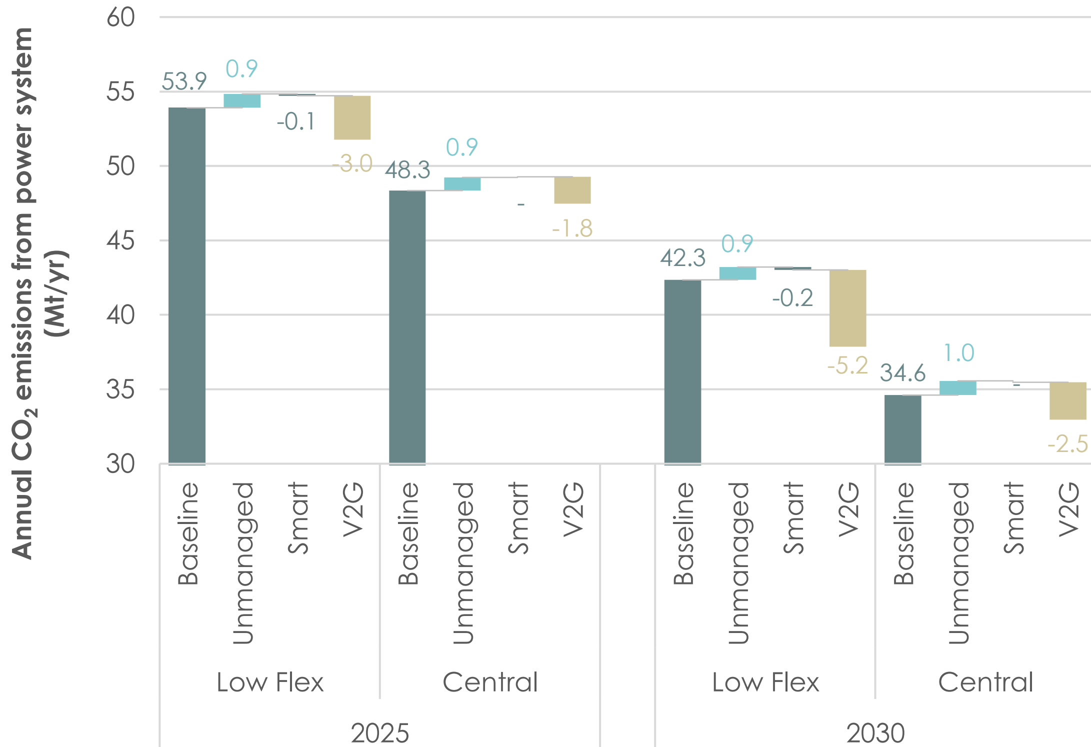

Figure 6: Waterfall chart for system carbon emissions across various scenarios

Carbon benefits of V2G are about twice as high in the Low Flexibility system then for Central Flexibility due to more opportunities to support system balancing and renewable integration and less competition from other flexible options. Also, the benefits of V2G are considerably higher in 2030 than in 2025, driven by higher renewable penetration and consequently higher requirements for flexibility.

If the net incremental carbon emissions for a given charging scenario are divided by the annual distance driven by fleet EVs, it is possible to express the incremental emissions in gCO_2/km, which enables a comparison with the emission performance of conventional vehicles. Figure 7 shows the incremental emissions associated with power supplied to fleet EVs across various charging scenarios.

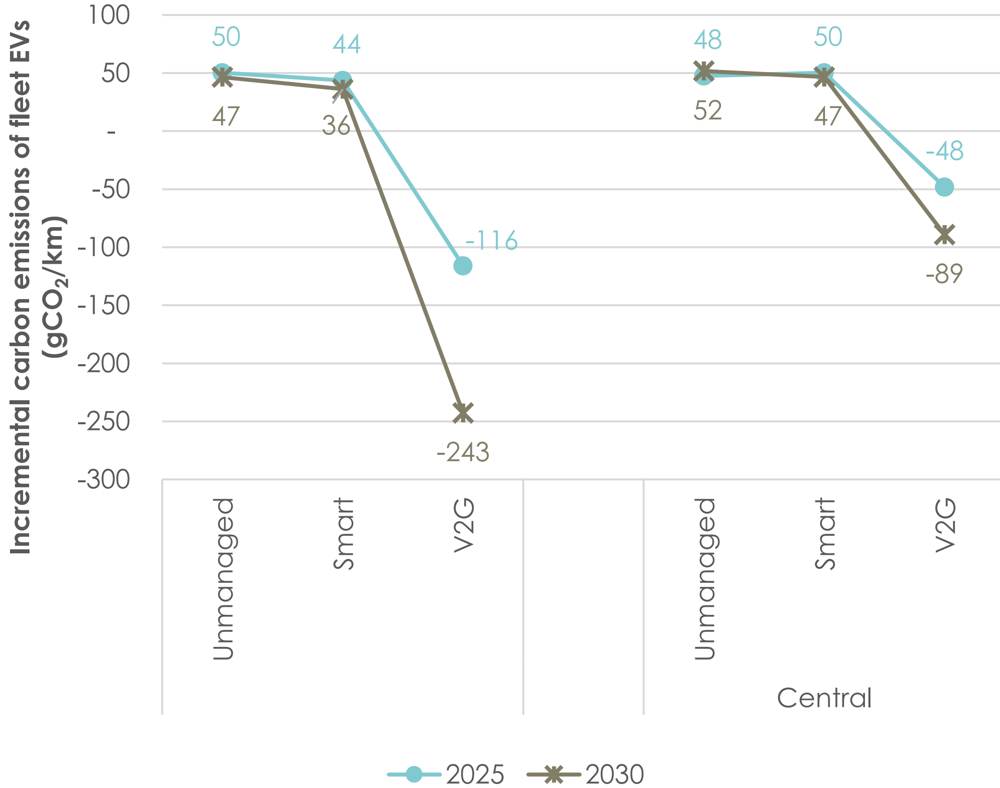

Figure 7: Incremental emissions of fleet EVs per unit of distance driven

The results suggest that Unmanaged and Smart charging scenarios trigger additional power system emissions in the amount of 36-52 gCO_2/km.[7] For comparison, the European Union's 2020 emission standard for new passenger cars is 95 gCO_2/km, and for light commercial vehicles it is 147 gCO_2/km.

V2G-enabled EVs, however, are observed to have a significant negative carbon impact i.e. reduce the overall power system emissions. This reduction is higher in 2030 than in 2025 (driven by higher renewable penetration), but is also significantly higher in Low Flexibility (between 116 and 243 gCO_2/km) than in Central Flexibility cases (between 48 and 89 gCO_2/km).

Another important implication of carbon savings delivered by V2G is that with the additional flexibility provided by V2G fleets it may be necessary to build less low-carbon generation capacity to achieve the same system-level decarbonisation targets, i.e. that it is possible to decarbonise the system at a lower cost.

[7] The increase in emissions is due to additional EV charging demand being mostly supplied through higher utilisation of gas generation. Note that the capacity of renewables was kept fixed between Baseline and different EV charging scenarios.

4.6 Value of V2G for electricity system operation

The value of V2G grid services provided to the ESO are assessed in more detail, using an advanced stochastic optimisation model[8] to quantify potential operating cost savings from ESO service provision. These benefits are also quantified for the GB system in the 2025-2030 horizon, but for a lower number of fleet EVs, ranging between 50,000 and 300,000.[9] For each fleet EV penetration and each of the three charging regimes (Unmanaged, Smart and V2G) the system value of EVs are found as the difference in annual operating cost between a given fleet EV case and the benchmark case with zero EVs, divided by the assumed number of EVs.

As shown in Figure 8, V2G is much more valuable to support system operation than Smart charging, across all EV penetrations. At a low penetration of 50,000 fleet EVs on the system, each V2G-enabled EV can reduce the system operation cost by more than £12,000 per annum and CO_2 emissions by around 60 tonnes per annum whilst still meeting all driving requirements. As expected, unmanaged charging increases system costs (i.e. results in a negative value per EV) because it increases the system energy demand without offering any ESO services.

[8] The analysis of the value of V2G for ESO grid services presented here draws upon a conference paper by the e4Future team at Imperial College London:
C. O'Malley, M. Aunedi, F. Teng, G. Strbac, "Value of Fleet Vehicle to Grid in Providing Transmission System Operator Services", *15th International Conference on Ecological Vehicles and Renewable Energies (EVER)*, Monaco, September 2020.

[9] Note that this is significantly below the 1 million fleet EV number assumed in whole-system assessment studies.

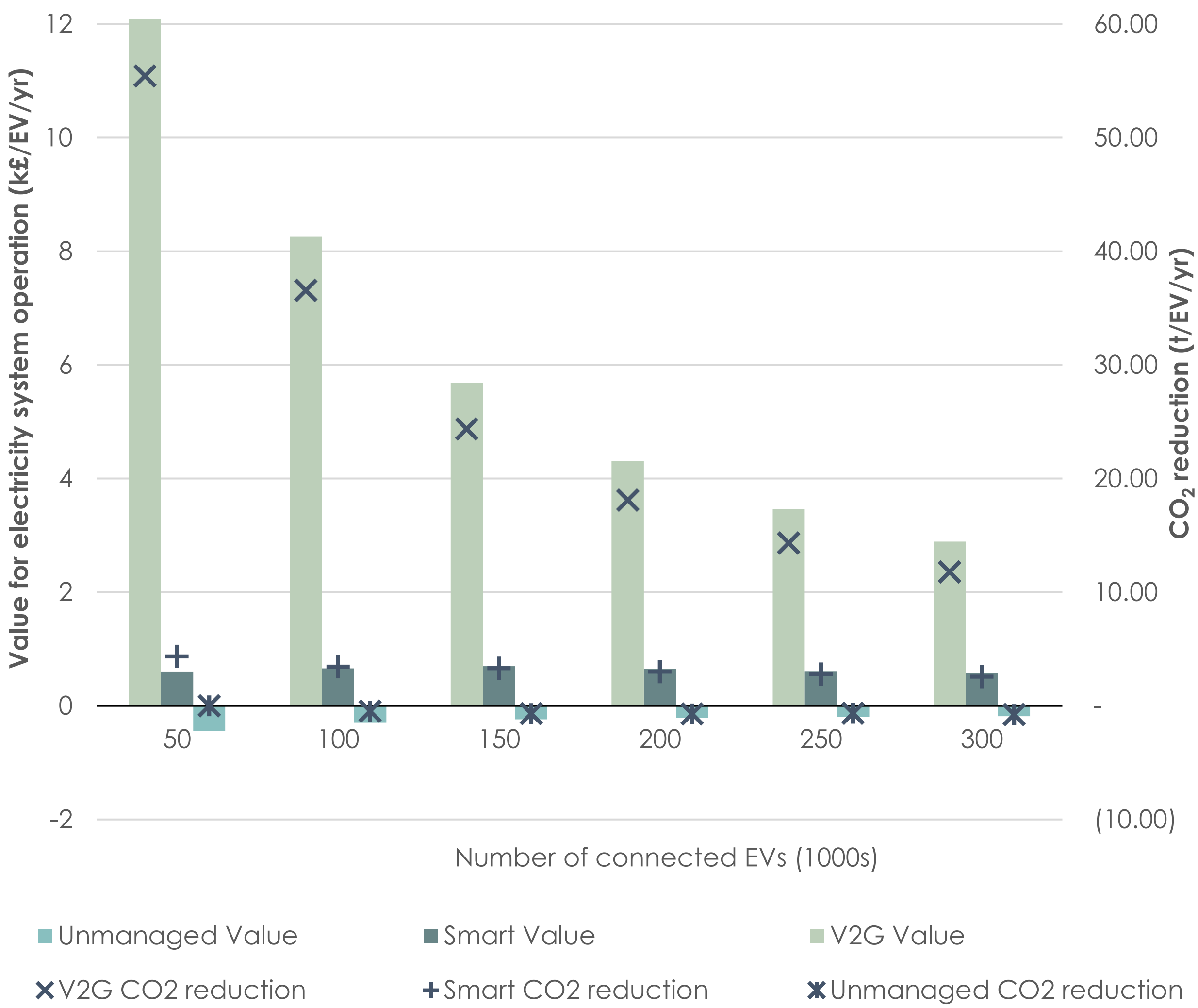

Figure 8: Annual net operating cost savings and CO2 emission reduction per EV for various charging regimes and EV penetrations

The results demonstrate that provision of fast FR (within 1 second) with V2G-connected EVs can represent a significant source of value for electricity system operators. Additional sensitivity studies show that the value per EV reduces by about two thirds if the FR delivery time increases from 1 to 10 seconds. This drops further to only 5% of the original value (i.e. to £643) if EVs do not provide any FR.

The key mechanism for delivering high cost and carbon savings through V2G is the avoidance of renewable output curtailment (in particular wind generation) through more efficient provision of grid services. For instance, with 50,000 fleet EVs the system is able to absorb about 7% more of annually available wind output if these EVs were V2G-enabled than if they just allowed smart charging.

It has to be noted though that while the average V2G value per EV is high at low penetrations and reduces gradually as the penetration increases, the marginal system value per EV, obtained by finding the cost difference between two adjacent EV penetrations and dividing it with the difference in EV numbers for the two penetrations, drops very rapidly beyond about 100,000 vehicles. As an illustration, the marginal value per EV at 150,000 EV penetration is only about £600, or about 20 times lower than at 50,000 penetration. This suggests there is limited marginal benefit of V2G at high EV penetrations, and confirms findings in line with those obtained from whole-system modelling, where the system value of V2G per EV is in the order of hundreds rather than thousands of pounds per year (note that whole-system value also includes non-operating cost benefits such as avoided investment cost of generation capacity or distribution grids).

Several other important drivers are identified that could affect the value of V2G for grid services:

1) Doubling the wind capacity on the system from 30 to 60 GW would also broadly double the value of V2G at 50,000 penetration from £12k to £23.8k, driven by higher requirements for FR services.
2) Exposing V2G to competition from other flexibility sources could radically reduce the value of V2G grid service. For instance, with 2 GW of additional battery storage on the system the V2G value (for 50,000 EVs) would reduce from around £12,000 to only £335 per EV.

5 Making V2G a reality

5.1 Conclusions

The transition of V2G technology from niche application to scale will have a tangible impact on the operation of the electricity grid and decarbonisation in the coming decade, with real economic and environmental benefits possible for the energy sector and consumers.

Leveraging V2G technology will be critical in helping the UK to achieve net zero carbon emissions by 2050. V2G-enabled EVs represent a significant source of flexibility for the future energy system. As the EV market transitions in line with the UK Government's ambition to end the sale of petrol and diesel vehicles by 2030 and hybrids by 2035, the charging and discharging of millions of new electric vehicles will necessitate better engagement between vehicles and the future decentralised energy system.

Our results suggest that implementing V2G solutions can deliver significant net cost savings to the electricity system while reducing system carbon emissions, as a result of reduced requirements for infrastructure capacity, improved integration of renewables and more efficient provision of balancing services.

For 1 million commercial fleet EVs, cost savings with V2G can be as high as £883m per year, with carbon emission reductions of 243 gCO_2/km per vehicle possible. The greatest benefits are observed in scenarios with high renewable penetration and low uptake of other flexible options. Analysis also showed that at a low penetration of 50,000 fleet EVs the value of providing ESO services could be as high as £12,000 per EV annually.

These are significant benefits when considering the increased demand for electricity and need for flexibility that can be expected in the coming decades. It is clear that large-scale electrification of road transport following an unmanaged charging approach would be detrimental to the electricity system and that more flexible charging regimes should be pursued. If V2G is widely implemented, it would be possible to build less low-carbon generation capacity to reach current system decarbonisation targets, implying that V2G can help decarbonise the system at a lower cost.

In parallel, V2G aggregators and importantly customers with V2G-enabled EV fleets stand to reap their share of economic benefits for capturing and providing the flexibility itself. To capture the full potential of V2G, there must be an attractive commercial proposition for business fleets.

Financial benefits for aggregators of V2G fleets are sensitive to multiple factors such as fleet driving behaviour, energy consumption patterns, electricity contract structure and site location. As many of these are not influenceable, creating a standardised proposition becomes difficult – especially with benefits from V2G potentially manifesting at both the customer and aggregator side.

With many of the current use cases that V2G aggregators rely on to generate benefits impacted by planned changes in the next 2-3 years, the environment for V2G may become more challenging in the near-term. New market products such as Dynamic Containment and DNO flexibility services have the potential to offer a new and viable source of revenue and should be supported.

We welcome the work the government is undertaking to prepare for the transition to zero emission mobility; much more will need to be done to realise the vital contribution V2G will make to decarbonisation. The following section makes a series of recommendations that government, regulator and power system stakeholders should take to support the energy and mobility transition and unlock the full benefits of V2G.

5.2 Recommendations

When one and one equals three – Full integration of energy and mobility to delivery whole system benefits

As the electrification of transport accelerates, policy making to deliver low-carbon transport and energy sectors must no longer be dealt with separately or in isolation. The analysis presented in this paper has shown that V2G fleets can substantially reduce whole system costs. Widespread adoption of V2G will make it possible for lower volumes of low carbon generation capacity to be installed, while still being able to meet emissions targets. Substantial savings in system operation and network investment costs could also be realisable.

Yet under the present regime, such benefits created by V2G would be spread out across the system (in the form of lower bills for *all* customers for example) rather than being directly accessed by providers of V2G flexibility themselves. Once V2G has become mainstream, changes will be needed to ensure that a sufficient proportion of the benefits attributable to V2G finds its way back to aggregators. This will help ensure a reliable business case – a necessary pre-requisite for V2G to take off at the scale required for its full potential to be unlocked.

Cost-reflective network charges will be essential to harnessing the potential of V2G charging. As outlined earlier in the paper, upcoming changes to the Ofgem charging regime could impact the business case for V2G by reducing the benefit coming from the 3rd party cost avoidance. The "Access and Forward Looking Charges Significant Code Review," should ensure cost-reflective network pricing and take into consideration likely V2G use cases when considering changes to network charges.

Requirements and specifications for future ancillary and flexibility services procured by the ESO and DNOs should be designed such that they do not hinder participation from (V2G-enabled) EV fleets. A considered approach towards EV fleets could help boost the volume of flexibility offered by such sources through improved market access.

Aggregators of EV fleets have many factors to consider when determining what level of flexibility to offer to the market – such as the battery state of charge, battery capacity, and arrival and departure times of EVs. Not all these factors are controllable in real-world scenarios with driving patterns and schedules of EVs often prone to deviations. The inherent uncertainty faced by aggregators optimising a large number of mobile flexibility sources should be considered in the design of future market services.

Given the unpredictability of EV driving patterns, a move towards procuring ancillary or flexibility services closer to actual delivery or accommodating real-time provision of services – in contrast to guaranteeing provision in advance over a long pre-defined time window – should be considered. Thresholds for minimum bid size, and the means by which contributions of EV aggregators is measured and validated will also determine overall success in boosting participation.

Accelerate the zero emissions mobility transition

Consumer demand for EVs has increased over time and is now set to accelerate with the new date for ICE end-of-sale. It is clear that an increased volume of electric vehicles on our roads allows us to quicken the pace towards full transport and energy decarbonisation. The environmental benefits of V2G presented earlier in the paper will only be possible with sufficiently large volumes of (V2G-enabled) EVs being on the roads.

The Government's new 2030 target to end ICE sales sets the UK apart from other countries in ambition. France and Spain have both announced 2040 end-of-sale dates. The UK's ambition confirms the Government's intention to lead in the transition to Net Zero, but this intention must be matched with a plan to achieve it and close partnership with industry and consumers.

In response to the COVID-19 pandemic, governments worldwide have identified an opportunity to increase momentum towards net zero, implementing robust EV incentive programmes that have successfully stimulated EV sales even whilst the market remains constrained. An increase in the UK's EV market share post-COVID has not been similarly observed, suggesting a missed opportunity to capitalize on new consumer awareness of emissions and air quality as the economy reopened after the initial crisis. It is crucial that consumers are brought along in the transition to zero emissions mobility and to do this policy makers must address the blockers that prevent drivers from buying EV.

We welcome the Government's ongoing investment into the Plug-in Car Grant; supporting consumers to make the transition to electric vehicles affordable in the mass market is essential. Changes to the taxation scheme to embed the zero-for-zero principle, and 0% VAT for EV purchases would provide certainty in the market and address the existing misalignment between ambition and action. Specifically, government should consider:

1. **Increasing both financial and non-financial incentives for retail and fleet purchasers of electric vehicles**. A significant proportion of new vehicles go into the fleet market first before entering the second-hand market to further support transport decarbonisation. A plan for the evolution of the plug-in grant schemes beyond 2023 as part of a strategic incentive package would give businesses confidence to electrify large fleets and industry the confidence to invest.

2. **Tax-based incentives applied to new and used EV purchases** have the benefit of helping alter consumer behaviour without being dependent on available public funds. Grants for zero emission vehicles for both new and used vehicles should be retained in the short term with a clear plan for replacing them with a tax regime that rewards the cleanest vehicles on our roads with 0% VAT for EV purchases and a VED regime that disincentivises consumers from choosing cars with higher emissions over their lifetime, with the benefit of removing the upfront cost of grants to the public purse.

3. **It is the joint responsibility of industry and government to ensure consumers and businesses are well-informed about the energy and mobility choices they make**. As recently highlighted in a CENEX report, education around the benefits and value of V2G can make a significant difference to uptake rates of the technology.[10] Empowering consumers through awareness campaigns and technology demonstrations will help accelerate EV, V2G and smart charging adoption to the benefit of consumers and the wider electricity system.

Accelerate the roll-out of V2G charging infrastructure across the UK

To realise the benefits of a whole system approach to the UK's electric vehicle transition, the UK government should prioritise V2G charging architecture when developing EV charging regulations.

The research presented in this paper has clearly shown the benefits of V2G on electricity system costs and carbon emissions in stark comparison to standard charging stations. Although installing standard chargers may be cost-effective in the short term, it

[10] Cenex, 'A Fresh Look at V2G Value Propositions', June 2020

will be sub-optimal in the long run compared to a scenario where V2G chargers are installed by default in new charging installations.

V2G assets are well placed to support local distribution grids and improve utilisation of existing network capacity, which could lead to avoided or postponed reinforcements. In light of the recent P2 review of network design standards carried out by the Energy Networks Association (ENA)[11] V2G could be used to support network congestion management, so that instead of enforcing an "n-1" standard (i.e. installing redundant assets) it is possible to enhance asset utilisation. In case of a component failure V2G could supply electricity for a limited time to avoid overloading the network.

With the EV charging sector at a relatively early stage of development, coordinating a holistic approach now will avoid having to incrementally replace large numbers of standard EV chargers with V2G-compatible hardware in subsequent years.

Furthermore, the following is proposed:

1. **A larger purchase subsidy should be allocated for installing V2G charging stations** to take into account the additional cost of these chargers compared to standard smart chargers. At present, V2G chargers are eligible to receive the same £350 grant as smart chargers through OLEV's Workplace Charging Scheme (WCS) or Electric Vehicle Homecharge Scheme (EVHS). However, the cost of a V2G charger today is substantially higher than that of a smart charger.

   A larger purchase subsidy would support cost parity to standard EV chargers so that the huge economic and environmental benefits can be realised as soon as possible and in time to support the transition to net zero.

2. **Establish type approval for V2G chargers to accelerate their roll-out onto the market.** As previously mentioned in the paper, National Grid ESO currently requires each V2G charger to be prequalified separately for provision of frequency response services, instead of allowing type testing of chargers which can be done in other European markets such as Denmark.

   This will undermine the marketability of V2G chargers given the additional effort and costs required. Changing this requirement will be critical given the important contribution V2G can make in providing frequency response in power systems with a high penetration of renewables.

[11] Imperial College London, "Review of Distribution Network Security Standards Extended Report", report for the Energy Networks Association, 2015.

Glossary

3rd party costs	The prices on energy bills are driven by both the cost of wholesale energy and 3rd Party Costs. 3rd Party costs consist of various charges to account for the cost of transporting electricity (e.g. DUoS, TNUoS), government schemes (e.g. capacity market levy) and power system balancing costs (BSUoS).
Aggregator	An organisation which controls the operation of flexibility sources (such as EV fleets) in order to provide energy services, and in doing so, capture the economic value of flexibility.
BSUoS	Balancing Services Use of System is a charge that National Grid levy in order to balance the electricity system and recover the costs incurred as the System Operator.
CM levy	Capacity Market levy. Used to cover the payment to capacity providers.
DCR	Direct Containment Reserve - a new fast-acting frequency response service being introduced by National Grid ESO.
DNO	Distribution Network Operator
DSR	Demand side response - refers to changes in electricity consumption patterns by consumers in response to a signal or incentive.
DUoS	Distribution Use of System charges are made on energy bills to recover the costs of DNOs for installing and maintaining the local electricity distribution networks. DUoS charges can vary depending on volume and time of electricity consumption, as well as the contracted connection capacity, connection voltage level and whether a half-hourly meter is in place.
ESO	Electricity System Operator. In the case of Great Britain, this is National Grid ESO
FEV	Fleet Electric Vehicle
EV	Electric Vehicle
FFR	Firm Frequency Response - a service procured by National Grid ESO from energy users to help balance the grid by quickly reducing demand or increasing generation in response to deviations in the power system frequency.
FR	Frequency Response
GDuOS	Generator Distribution Use of System charges relates to the positive charges and negative credits associated with the local distribution of exported electricity on to the grid. GDUoS differentiate depending on where the units are located and where they connect to the local electrtcity distribution network.
ICE	Internal Combustion Engine
NG ESO	National Grid Electricity System Operator
Ofgem	Office of Gas and Electricity Markets - The UK's energy regulator
SCR	Significant Code Review - An Ofgem-led review covering DUoS, TNUoS, access rights for transmission and distribution network users, and distribution connection charging boundaries.
SOC	State-of-charge
TCR	Targeted Charging Review - An Ofgem-led review making reforms to the way residual charges and BSUoS are charged to users.

TNUoS	Transmission Network Use of System is a charge made by National Grid to recover the costs for installing and maintaining the transmission system. Customers are charged-based on demand on the transmission network during its peak periods (Triads).
Triad	Triad periods refer to the three half-hour settlement periods between November and February with the highest system demand. Each period must be separated by at least ten clear days. Triads are used to calculate the TNUoS charges that an organisation will incur.
V2G	Vehicle-to-grid - a technology system enabling bi-directional power flows to and from electric vehicle batteries. Requires a V2G-enabled EV and a V2G charger.

Appendix I – Modelling assumptions

Fleet driving profile

Fleet EVs are assumed to follow regular driving patterns characterised by times of departure from and arrival to depot, and State of Charge (SoC) of their batteries at the time of departure.

- Fleet EVs leave the depot at 8am with 90% SoC
- Fleet EVs return to the depot at 4pm with 62.5% SoC
- Vehicles are not in use during weekends
- Charger rating is 10 kW, both for charging and discharging (where V2G is allowed)
- Charger efficiencies are 95% for charging and 95% for discharging
- Battery size per EV is 40 kWh, and its SoC while connected to the charger is allowed to vary between 20% and 90%

Unmanaged charging

The Unmanaged charging approach assumes that the EV fleet is charged with full available power directly after arrival at the charging station (at 4pm).

It is utilized as a benchmark in order to calculate the savings coming from V2G (Savings = Costs V2G – Costs Unmanaged Charging).

Modelling assumptions

The financial benefits presented in Section 3.3 are based on perfect forecasts in terms of the price data on the power market and the availability of the EVs. In reality, the driving and charging behaviour can deviate from the forecasts potentially leading to lower benefits.

Appendix II - WeSIM model

System impact assessment of charging fleet EVs is carried out by extending and applying Imperial's Whole-electricity System Investment Model (WeSIM) to include specific features of fleet EV demand. WeSIM determines cost-optimal decisions to invest in generation, network and/or storage capacity in order to satisfy the real-time supply-demand balance while ensuring security of supply.[12]

Capturing the interactions across various time-scales and across various asset types at sufficient temporal and spatial granularity is critical when analysing future low-carbon electricity systems as it allows for proper consideration of flexible technologies such as energy storage and demand-side response (DSR). WeSIM is a whole-system analysis model that is able to simultaneously optimise long-term investments into generation, network and storage assets, and short-term operation decisions in order to satisfy the demand at least cost while ensuring adequate security of supply, sufficient volumes of ancillary services and compliance with system-wide carbon emission targets. WeSIM can quantify trade-offs between using various sources of flexibility, such as DSR and energy storage, for real-time balancing and for management of transmission and distribution network constraints, thus capturing the synergies and conflicts between local-level and national-level infrastructure requirements. A distinctive feature of WeSIM is the quantification of investments in distribution networks based on the concept of statistically representative distribution networks.

Power balance constraints in the model have been extended to account for the net demand of fleet EVs (i.e. their charging minus discharging) alongside other demand on the system that needs to be met by a combination of generation, storage and transmission assets in the system. Depending on the charging scenario assumed, fleet EVs have also been allowed to contribute to meeting system-level requirements for *frequency regulation* (FR). This results in displacing FR provided by part-loaded thermal generators and thus potentially reduces the operating cost and carbon emissions from the system.

Distribution network investment cost in WeSIM is driven by incremental net peak demand on the distribution grid over the baseline demand level. Net peak loading is determined by the local demand including DSR actions, operation of any distributed generation or distributed storage connected to the network, as well as charging and discharging of fleet EVs.

[12] A detailed formulation of the model can be found in the literature:
D. Pudjianto, M. Aunedi, P. Djapic, G. Strbac, "Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems", *IEEE Transactions on Smart Grid*, vol. 5, pp. 1098-1109, March 2014.

Appendix III - Electricity system scenarios

Case studies presented in the paper focus on the GB power system in 2025 and 2030 time horizons. Key assumptions on electricity generation and demand for the two scenarios, summarised in Table 2 are consistent with recent scenarios proposed by the Committee on Climate Change.[13] In addition to two time horizons, the case studies presented in the paper also considered two different levels of system flexibility, Low and Central, represented by the available volumes of energy storage and DSR, as these flexible options can also be expected to affect the value provided by flexible fleet EVs.

Note that the two storage capacity numbers reported for each scenario in Table 2 represent Low and Central Flexibility cases, respectively. In both time horizons the assumed DSR uptake level in Low Flexibility cases was 0%, while in the Central cases it was 25%. The assumed DSR penetration refers to the uptake level of DSR relative to its maximum theoretical potential for demand shifting across flexible non-fleet EVs, HPs, residential appliances and industrial and commercial demand.

Table 2: Power system scenario assumptions

	2025	**2030**
Generation capacity (GW)		
Wind	36.2	58.0
PV	15.8	30.9
Nuclear	7.9	4.5
Biomass	5.8	7.1
Other RES	2.2	2.7
Gas	46.8	46.6
Storage	4.7 (Low Flex.) / 11.4 (Central)	4.7 (Low Flex.) / 19.9 (Central)
Annual demand (TWh)		
Baseline	316.9	319.8
EVs (non-fleet)	7.8	18.8
HPs	4.8	9.9

In each case study the model was allowed to add more or remove gas generation in the form of Combined-Cycle (CCGT) and Open-Cycle Gas Turbines (OCGT) if cost-efficient and/or necessary to meet the security criteria. The assumed cost of gas was £6/GJ. No carbon price or carbon constraints were assumed.

[13] Vivid Economics and Imperial College London, "Accelerated electrification and the GB electricity system", report for the Committee on Climate Change, April 2019. https://www.theccc.org.uk/publication/accelerated-electrification-and-the-gb-electricity-system/

NISSAN

e·on Drive

Imperial College London