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The impact of EVs on an electricity system with high renewable penetration

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Abstract

Electric vehicles (EV) constitute a serious attempt to decarbonize the transportation sector, yet their integration with the generation system requires in-depth scrutiny. This work studies the impact of electric vehicles on the British electricity system by 2020, by analyzing nation-wide, hour-by-hour, cost- optimized, all year round system operations featuring a large penetration of wind generation and the use of demand side management (DSM). To this end, an integrated simulation and optimization tool that encompasses an EV model, unit commitment and balancing software, and a DSM algorithm has been developed. Simulations for a wide range of transport and generation scenarios are carried out. Results show how an uncontrolled EV load leads to increased system peaks, and high levels of wind generation impose requirements on the amount of system reserves and flexible generators. Major carbon dioxide emission savings with respect to conventional vehicles can be achieved if a non carbon-intensive generation mix is considered. By implementing DSM, considerable advantages can be obtained through peak shaving, thermal plant capacity reduction, wind power spillage curtailment, and operative cost savings. The value of controlling the power demand of an EV by DSM is assessed by considering the avoided investment in new generation and the capitalized cost savings.

Keywords: list 3-5 keywords from the provided keyword list in 9,5pt italic (LaTeX: "small"), separated by commas

1 Introduction

1.1 Background

Today the case for a "different" transportation system could not be stronger. Transportation accounts for 14% of global greenhouse gases emissions [1], with road transport making up the largest share of them. In particular, 22% of the total emitted carbon dioxide in the UK comes from road transport [2]. The overwhelming scientific evidence on climate change [3] calls for immediate cross-sector emission curbing and electrified transportation is in the portfolio of technology options to solve the carbon conundrum [4].
By shifting currently non-electric loads to the grid, electric vehicles might play a crucial role in intertwining two critical elements of the whole energy system: power generation and transportation.

In a scenario where a commitment is made to reduce emissions from power generation [5], and where ageing nuclear plants are coming off line [6], the build-up of new power capacity is often problematic [7]. The addition on the grid of extra load from electric vehicles in such a system would be challenging to say the least. Whilst electric vehicles are a promising option for decarbonizing the personal transportation sector, their impact on the electricity system might be massive. In addition a generation system traditionally dominated by large scale thermal power plants, and which is now aiming for a higher share of renewable generation would also face significant integration costs that might hinder the penetration of EVs.

The integration of electrified personal transport within a power system featuring an increasing share of renewables must be therefore duly scrutinized and cost-optimal solutions be sought.

1.2 Problem Identification and Methodology

This work is concerned with studying the potential impacts of the electric vehicles on the UK electricity system, with a focus on the power generation emissions associated with EVs and the role of demand side management in supporting their penetration. A system approach is adopted, with impacts assessed from the perspective of a system operator.
This work investigates the impact of the additional electric load EVs would impose in the UK by analyzing cost-optimized, nation-wide, hourly-based, all year round system operations including large penetration of wind generation and the use of demand side management (DSM). This research is looking at the 2020 time horizon. The boundary of this work is the connection between the transportation system and the power generation, and therefore no particular attention will be given to vehicle-specific issues such as battery technology. In other words, the boundary is drawn outside the car bonnet and only high level EV specifications are used. Also, any issues associated with the geographical distribution of EVs in the UK, such as power transmission and distribution, are not addressed here.

2 Electric vehicle modelling

2.1 Transport Statistic

The total number of registered cars in the UK amounts to ca. 27,8 millions [8] and their average daily mileage is 24 miles [8]. This value has been fairly stable in the last decade.
No information about the car mileage distribution in the UK has been found in the literature and a Gaussian distribution around the average value of 24 miles is assumed. Indeed, for simplicity's sake, it is assumed that all daily mileage is found within the $\pm3\sigma$ range. This implies that the maximum daily mileage is 48 miles. The statistical contribution coming from the distribution tails outside the $\pm3\sigma$ range is considered as negligible.
Data about the timing of car trips in progress by hour of the day are reported in Figure 1.

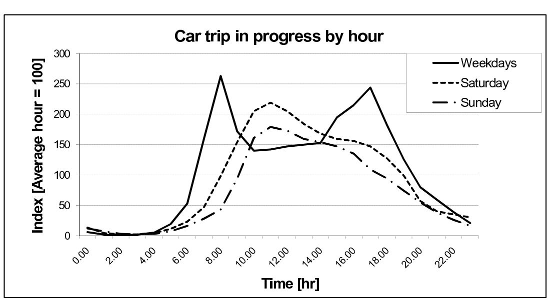

Figure 1: Time of car trips in progress by hour of the day, as in [8]. The reference index is 100, expressing the average trips in progress across all hours throughout the week.

The time of travel for EVs is assumed to follow the same pattern as in Figure 1, albeit with some simplifications. The car mileage is assumed to be made up by a morning trip occurring between 5am and 11am (e.g. from home to work), and an evening trip between 3pm and 2am (e.g. from work to home), both of 12 $\pm3\sigma$ miles. Both weekday and weekend patterns are considered, and the number of cars travelling at the weekend is calculated as an average between Saturday and Sunday.
A trip is assumed to last one hour. The opportunity to reach a plug occurs after the evening trip (night-charging) and, for some drivers, after the morning trip (day-charging) too. For example, a car leaving at 6pm will be available for charging at 7pm.

2.2 EV Technical Specifications

Three different vehicle archetypes are considered as possible representatives of the hypothetical future of mass-produced electric vehicles:

- Small size battery electric vehicle (BEV), running in all-electric mode. Specification for BEVs are taken from the already commercially available Smart EV powered by Zytek [9]
- Mid-size plug-in hybrid vehicle (PHEV) with both the engine and the motor operating in a blended mode (BM). Specifications are taken from telemetry data of the demonstration fleet of retrofitted Toyota Prius owned by the Google Foundation [10].
- Range Extender mid-size PHEV running in all-electric mode (AM) for all of its daily mileage. Data are taken from the FD3M model by BYD [11].

Specifications for the battery pack of the vehicle types described above are given in Table 1. It is assumed that the battery pack is large enough to satisfy up to the maximum expected daily mileage, i.e. 48 miles per day (average plus 3σ mileage value).

	BEV	PHEV BM	PHEV AM
Efficiency [miles/kWh]	5.2	9.0	3.5
Average daily demand [kWh]	4.6	2.7	6.9
Max daily demand [kWh]	9.2	5.3	13.7

Table 1: Vehicle efficiency and daily energy demand.

2.3 Charger Power and Charging Profile

Three different power levels are identified for EV chargers [12]. Considering that the continuous power a given circuit may carry is up to 80% of its maximum rated capacity [13], the standardized charger power levels are:

- Level I. This refers to the domestic connection. In the UK it corresponds to the BS 1363 plug, with 13A, 230V, and ca. 2.4 kW continuous power

- Level II. The vehicle is connected to a 240V, 40A circuit, dedicated to EV charging purpose only. This corresponds to ca. 7.7 kW continuous power.

- Level III. This usually refers to power levels from 75 to 150 kW.

In this work it is assumed that the vehicle battery pack is charged at a constant power corresponding to the maximum rated capacity of the line [10]. Charge duration will last according to the charger power and the state of charge of the battery. A charging efficiency of 87% is taken into account [14].
Maximum battery charging duration (i.e. for 48 miles) depend on charger rated power and the vehicle type, and are summarized in Table 2. In the simulations, an hour resolution is used, so that charging duration is given as a multiple of an hour (approximated by excess), and the power level is adjusted such that the amount of energy delivered remains the same.

Charging type		Duration [hr]		
Level	Power [kW]	BEV	PHEV-BM	PHEV-AM
I	2.4	4.44	2.55	6.59
II	7.4	1.44	0.83	2.14
III	100	0.11	0.06	0.16

Table 2: Maximum battery daily charging duration.

In this work only power levels I and II are considered. Power level III, besides implying the development of charging station infrastructures or a significant upgrade of the distribution network [15], involves a rapidity of charging that is well below the hourly resolution of the proposed simulations.

3 Demand side management

The management of power demand for charging is of paramount importance to the uptake of the electric vehicles. [16]. In the UK there is already adequate generation capacity to meet the power demand of a rising share of electric vehicles, assuming that charging ideally occurs in off-peak periods only [17]. Conversely, if left uncontrolled and to the customers' convenience only, the load from EVs is bound to bring about severe system peaks [18] because of the high time correlation between typical daily journey profile and the existing pattern of electricity demand.
Moreover, the demand side management of a significant number of cars has the potential to be a viable, and even cheaper, alternative to bulk energy storage in a electricity system with intermittent renewables [19]. The DSM of the EVs load can contribute to the management of wind power fluctuation, for example by postponing the charge of a group of EVs to a time when high wind but low demand is expected.
Previous studies usually assess the potential of the demand side management of EVs by proposing a so-called *valley-filling* approach. This approach assumes that the EV load can be completely shifted to fill the typical hollow in the demand profile that occurs overnight. We argue that the valley-filling approach is a gross overestimate of the potential of DSM since neither generation constraints nor driver requirements are accounted for.
We propose a cost-optimal strategy where the DSM may be employed to reduce power generation costs. The DSM algorithm takes into account the generation system, the drivers, and the EV constraints, as well as the availability of intermittent generation such as wind. This allows the assessment of the real potential of DSM and its economic benefits in terms of peak reduction and reduced plant operating costs.

3.1 DSM algorithm

It is assumed that a certain share of EV owners may contract with an electricity utility the possibility of delayed charging, with the constraint that charging shall be completed within a specified time horizon from the plugging in. The reasonable assumption of the charging to be completed within 8 hours has been made. This is likely to be the typical case of an EV driver who charges its car overnight. Charging is allowed to be interrupted and resumed by the utility according to the DSM algorithm outcomes without significantly impacting on the battery performance [10].
The DSM is implemented via the load shifting algorithm derived from the work of [20]. The maximum duration by which the load of an EV can be shifted depends on the charger power level: the higher the charger power, the shorter the charging, the larger the room for delaying the load within the 8 hour constraint. For this reason the effects of the DSM are investigated only for the Level II charger, since the room for shifting offered by a Level I charger is fairly limited, see Table 2.
Also, it is assumed that the utility has no access to information about the state of charge of the battery of its customers. Therefore, although it can estimate statistically the load pattern of a group of customers, it cannot know how long the charging for a *specific* customer will last. In order to ensure that every customer with a DSM agreement, no matter its daily mileage, will find his battery topped up at the end of the contracted period (in this case 8 hours from plugging in), the utility assumes that all the cars might drive the maximum mileage and hence require the maximum charging time. With the help of an example, if the maximum statistical daily mileage (48 miles) driven on electricity requires 3 hours charging, then the utility assumes that *all* the car loads can be shifted by maximum 5 hours (8 hours constraint minus 3), no matter how much each single car has been effectively driven.

4 Unit Commitment and Balancing

The simulation model of the UK electricity system encompasses operations with high wind power penetration and system reserves, both synchronized and standing. A mixed-integer linear programming formulation minimizes year-round system operation costs with a day-by-day iterated procedure. To this purpose hourly time series of demand and wind power are used, along with power demand arising from EVs.
The simulation of the system operations occurs in two consecutive stages:

1. Unit Commitment. A cost-optimal daily plant commitment is carried out in order to meet the demand forecast and ensure adequate system reserves in order to handle the possible imbalances between the forecast and actual demand and wind power.

2. Balancing. Committed plants are dispatched to meet the actual demand. Actual wind power time series are used. Wind power generation is curtailed if the system is not able to absorb it, and load can be shed if the generators cannot satisfy the demand.

The demand side management algorithm is included within the system operations simulator. Both the unit commitment and the balancing stages may use the shifting of EV power demand as described in Chapter 3 for cost optimal operations.
The following assumption are made in the model:

- Simplified generator cost curves, with the marginal generator costs of the plants being independent from the plant output level
- Balancing is performed at the system level rather than at the level of single generation company.
- No plant failure or scheduled maintenance is considered.
- No seasonal variation in generator costs is considered.
- Open cycle gas turbines and storage facilities are modelled as single bulk units
- The employment of storage for arbitrage is ruled out

4.1 Wind and Demand Imbalance

The imbalance between forecast and realized wind power is modelled by a function with normal distribution. It is assumed that the standard deviation of the wind mismatch depends on both the wind power installed and on the wind power forecasted. This implies that the forecast errors increase with both the wind penetration and the amount of wind actually blowing.
A normally distributed error function is used to model the mismatch between forecast and realized demand. The standard deviation is arbitrarily set to be constant and equal to 1% of the maximum yearly demand forecast.

4.2 System Reserve

In order to cope with the imbalance between predicted and realized wind generation system reserves shall be opportunely allocated. Reserve tasks can be carried out either by spinning reserves, i.e. by committing synchronized part-loaded thermal plants, or by standing reserves such as open cycle gas turbines or pumped-hydro storage.
The adequate amount of reserves that shall be provided in order to avoid load shed is a function of the standard deviation of the wind power imbalance and depends on the characteristics of the generators set.
Scheduled spinning reserves, along with storage and OCGT, also contribute to handle the imbalance between generation and demand that arises from the error in demand forecast.

4.3 Unit Commitment

The unit commitment algorithm engages thermal generators in order to satisfy the power demand *forecast* with the minimum daily operating costs. The algorithm takes into account the wind power *forecast*, the availability of storage facilities and OCGT standing plants, and the possible use of demand side management.
Operating costs include the no-load costs of plants that are on, the startup costs of those that have to be switched on, and their marginal (i.e. fuel, maintenance, etc) costs. Start-up costs for thermal power plants are modelled with two power plant states: hot and cold, depending on how long the plant has been off before a new commitment. Cold start-up costs are obviously higher than hot start-up costs.
For open cycle gas turbine plants only the marginal costs are considered. Also, in principle, if the demand cannot be fully met, some load can be shed. A typical high value of the value of lost load ensures that the load shedding is used as a last resource. For wind power, the operating cost is considered to be zero.
The power demand, diminished by possible load shed, has to be met by power supplied by thermal generators, by open cycle gas turbines, by wind generators, by the net power from storage and by the net result of EV loads connected and disconnected according to the demand side management algorithm. If the system is not able to absorb all the wind power available, some wind power spillage occurs.
The output of each thermal generator, if on, is constrained by its maximum capacity and its minimum stable generation. Minimum up- and down-time as well as minimum power ramp-up and down constraints apply for each thermal power plant. Must-run generation constraints for

nuclear plants are modelled with minimum down time of 7 days [21].
Storage is modelled as a generic flexible bulk energy storage plant, with no concern for the technology implemented. Storage is used to provide both *upward* (positive) and *downward* (negative) reserve. The cost of storage itself while discharging is assumed to be zero, while obviously the fuel costs associated with the extra power generation for storage charging are taken into account in the optimization, as well as the storage charging efficiency. Constraints on storage plant ratings and stored energy also apply.

4.4 Balancing

In the balancing stage, thermal power plants are cost-optimally re-dispatched in order to meet the *realized* demand and with the *realized* wind generation. No re-commitment is carried out, so that only the plants that were engaged during the unit commitment stage can be dispatched. As far as regards the system reserves, storage and OCGT facilities can be re-dispatched freely as long as they operate within their limits. The same constraints as for the unit commitment apply.

5 Emission Model

The majority of life cycle carbon dioxide emissions of EVs are associated with the usage phase [17]. If the vehicle operates in all-electric mode usage emissions are associated with power generation only. If instead a plug-in hybrid operating in blended mode is considered, tailpipe emissions have to taken into account, too [14].
With regards to the substances emitted, a complete analysis of the emissions associated with EV should not be limited to CO_2 but should also encompass NO_x, SO_x, particulate emissions (PM10) and volatile organic compounds [15]. Caution must be paid when comparing pollutants such as NO_x, SO_x from power plant against tailpipe emission. Indeed emissions generated in proximity to individuals have a larger impacts on human health than those generated outside urban areas [22].
On the other hand previous studies about the impacts of EVs show that the key parameter chosen in order to assess the relative environmental benefits of EVs to conventional cars is the CO_2 emissions. An extensive study covering the entire range of emission substances goes well beyond the scope of this work, therefore only the carbon dioxide from power generation and at the tailpipe (if applicable) are considered. Also, neither the enforcement of caps on emissions nor the implementation of carbon capture technologies are taken into account.

5.1 Generation Emissions per Plant and Fuel Type

Generation of carbon dioxide emissions per unit of energy produced, depending on the plant and fuel type can be found in [23]. In the model hereby proposed, it is assumed that such emissions refer to a plant operating at its maximum rated output. No emissions are associated with wind generation, nuclear generation, and generation by pumped-hydro storage. Storage efficiency for pumped-hydro is also considered. Emissions are summarized in Table 3.

Plant Type	CO_2 [tonnes/MWh]
Coal-fired	0.876
CCGT stations	0.370
Nuclear	0
OCGT	0.526
Pumped-hydro storage	0
Wind generators	0

Table 3: Carbon dioxide emissions of generators.

5.2 Plant Efficiency

Whenever a thermal power plant runs off its designed operating point, a penalty in efficiency occurs. It is assumed that for a thermal plant the maximum generation output corresponds to the maximum efficiency. A drop in the plant efficiency yields therefore an increase of CO_2 emissions per unit of energy output with respect to the values at the maximum efficiency as given in Table 3.
In Figure 2 the relative plant efficiency drop as a function of the plant output is depicted for coal-fired plants and CCGT. CO_2 emissions are in inverse proportion to the plant efficiency, and plant emissions can be then calculated as function of the plant power output. No drop in efficiency is considered for nuclear plants and OCGT.

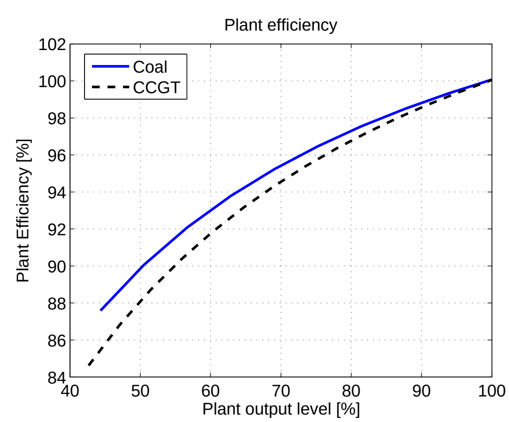

Figure 2: Coal and CCGT plant efficiency drop depending on the output level relative to the plant maximum efficiency.

The CO_2 emissions are in inverse proportion to the plant efficiency and for each coal and CCGT power plant, emissions can be then calculated as a function of the power output.

5.3 Vehicle Tailpipe Emissions

Of the three vehicle types considered, only the PHEV in blended mode generates tailpipe emissions. The emissions for this kind of PHEV are retrieved from the telemetry of the demonstration fleet of retrofitted Plug-In Toyota Prius run by the Google Foundation [10]. The average emissions of this fleet amounts to ca. 91 gCO_2/km.

6 Description of Case Studies Performed

The range of the case studies considered in this work arises from the combination of different scenarios of:

- Electric vehicle penetration
- Electric vehicle type
- Charging operation. On its turn, this depends on:
  - charging opportunity
  - charger power level
  - level of participation in demand side management
- Electricity demand forecast (not from EVs)
- Generators specifications and future possible mixes.

6.1 Electric Vehicle Penetration Scenarios

Three scenarios for EV uptake in the UK by 2020 are scrutinized for this work:

- Low penetration: 10% EV share of total vehicles
- Medium penetration: 20% EV share of total vehicles
- High penetration: 30% EV share of total vehicles

6.2 Electric Vehicle Type Scenarios

With regards to the typology of vehicles, scenarios with:

- only BEVs
- only PHEVs running in blended mode (PHEV-BM)
- only PHEVs running in all-electric mode (PHEV-AM)

are considered. Obviously, we do not attempt to pick winners and the future electric vehicle market is likely to be made up by a combinations of the vehicle types aforementioned (or novel types yet to come). Nonetheless no scenario involving a mix of the vehicle types is considered. This will allow for a clearer assessment of the relative merit of the three different car types.

6.3 Charging Operation Scenarios

Besides vehicle penetration, vehicle type and travel time, the load on the grid generated by EVs depends on the charging operations. Three different scenarios are considered for battery charging operations as suggested by [16] and [18]. In the first two, the EV load is calculated beforehand from mileage and travel time statistics. In the third one, the EV load is given as a result from a demand side management algorithm.

1. *Do Nothing*. Charging occurs at night-time. It is left at the drivers' convenience, i.e. it starts as soon as the vehicle is parked back home. Duration depends on how many miles have been driven since the last charge and on the charger power level. As already stated, a Gaussian distribution of vehicle mileage is considered.

2. *Night Tariff*. An off-peak electricity rate starting from 10pm is assumed to be in place. Charging is postponed after 10pm, or as soon as possible if the vehicle reaches home after 10pm . As for the Do Nothing scenario, duration depends on how many miles have been driven in the day and on the charger power level.

3. *Demand Side Management*. The EV owners have contracted with the utility the possibility of a delayed charging, with the constraint that the charging shall be completed within an 8 hour horizon from the plugging in. Only Level II charging power is considered and no information about the state of charge is available to the utility. Two levels of participation to the DSM scheme are considered: a ”low DSM” and a ”high DSM” scenarios corresponding to 50% and 80% of the total number of EVs respectively.

6.4 Electricity Demand

The time horizon of this work is 2020, and as such the increase forecast in the UK power demand shall be accounted for. According to National Grid ”Base” Forecast [24], an electricity demand increase by 1.1% per annum is expected until to 2013/14. In this work it is assumed that such demand increase will continue unchanged until to 2020. With the average cold spell (ACS) corrected peak demand on the UK transmission system equal to 61.3 GW in 2006/07, it follows an estimated peak demand of 70.6 GW in 2020. The hourly data series of the electricity demand of the year 2007, linearly scaled up so that the peak is equal to 70.6 GW, is used in the simulations. Moreover, it is assumed that the National Grid estimate does not take into account the possible increase in load that might come from electric vehicles, therefore the EV demand will be treated as an additional load onto the National Grid estimate.

6.5 Power Generation

Several factors should be taken into account while outlining power generation scenarios in 2020. First, the UK Government commitment to generate 20% of energy from renewable sources [5], which are likely to come mostly from wind. Second, the recent aspiration to pursue the construction of new nuclear plants [6]. Last, the currently existing power plants which will be still operating in the years to come; the ones subjected to decommissioning because of age and/or regulation; and the new plant projects already on going or deemed likely to proceed to completion.
The following assumptions are made for the power generation system in 2020:

- Wind generators will be able to meet at least 20% of the electricity demand [25], as given in the aforementioned National Grid "Base" Forecast and opportunely scaled up for the year 2020.

  As in [23], the electrical energy supplied in 2007 in the UK amounted to 401,671 GWh. At a constant annual growth of 1.1% the energy supplied in 2020 should be equal to 463,058 GWh. A share of 20% for wind generation corresponds to 92,611 GWh. Now, from the available wind generation data, an average load factor of 34.7% for wind generators should be considered. Factoring all, the wind installed capacity by 2020 would amount to at least 30.5 GW.

- New nuclear power capacity, if any, will amount to 11 GW, thus replacing the existing plants on a one-to-one basis. Indeed, since nuclear plants are expected to run continuously as baseload, in the simulations the declared 11 GW capacity is derated to take into account planned and unplanned maintenances. Assuming a load factor of 70% for nuclear plants [23], only 7.7 GW of nuclear power is considered to be continuously available.

- Both conventional steam generation capacity (assumed to be only coal-fired) and CCGT will be greater than 45 GW

- An unsuccessful nuclear revival plan will be backed up by either wind, CCGT or coal plants

- Hydroelectric pumped storage will remain unchanged, with a peak rated power of 2,726 MW and a maximum stored energy of 21,580 MWh [23]. No other storage technologies other than pumped hydro are considered to make a major contribution by 2020 [26]

- The contribution to the overall generation brought in by the natural flow hydro-electric is neglected.

Four different generation scenarios are then envisaged:

1. *High Nuke* scenario: new nuclear power capacity replaces the existing one (11GW). Wind generation is at 20% share.

2. *High Gas* scenario: the missing capacity from an unsuccessful nuclear revival is provided by new CCGT plants. Wind generation is at 20% share.

3. *High Coal* scenario: the missing capacity from an unsuccessful nuclear revival is provided by new coal plants. Wind generation is at 20% share.

4. *High Wind* scenario: the missing capacity from an unsuccessful nuclear revival is provided by both new CCGT and coal plants. Wind generation is at 30% share.

Generator data per fuel type are summarized in Table 4.

	Generation [GW]			
Scenario	Wind	Nuke	CCGT	Coal
Hi Nuke	30.5	7.7	>45	as CCGT
Hi Gas	30.5	-	as Coal + 7.7	> 45
Hi Coal	30.5	-	>45	as CCGT + 7.7
Hi Wind	45.75	-	>45	as CCGT

Table 4: Generation capacity scenarios by 2020.

7 Energy and power demand from EVs

The total annual energy that would be required to fuel the electric cars in the UK depending on the EV market penetration and the vehicle type is reported in Table 5. For reference, according to [23] the total UK electricity demand in 2006 amounted to 405,764 GWh.

EV energy demand [GWh]			
Penetration	BEV	PHEV BM	PHEV AM
Low (10%)	5,389	3,100	8,006
Medium (20%)	10,778	6,200	16,013
High (30%)	16,166	9,299	24,019

Table 5: Total annual energy demand of electric vehicles.

Table 6 shows how even a relatively high share (30%) of the personal transportation sector can be switched to electricity, yet requiring a modest (less than 6%) increase of the total national power demand.

EV energy demand share			
Penetration	BEV	PHEV BM	PHEV AM
Low (10%)	1.3%	0.8%	2.0%
Medium (20%)	2.7%	1.5%	3.9%
High (30%)	4.0%	2.3%	5.9%

Table 6: Total annual energy demand of electric vehicles as percentage of the total UK electric energy demand.

The EVs load on the grid is calculated with an hourly resolution from the mileage and travel time statistics, and the EV specifications as described in the EV model.

Besides market penetration and vehicle technology, the time profile of the aggregated EV power demand depends also on operational issues such as the daily charging opportunity, the type of the day (weekdays vs. weekend), and the charging power level. Figure 3 shows the estimated electricity demand on the 2020 peak day with the additional load from BEV with charging power level I, and no charging opportunity during the day. Qualitatively similar results are found for PHEVs operating in all-electric mode and blended mode. It is evident the time correlation of existing system peak and of the unchecked EV load.

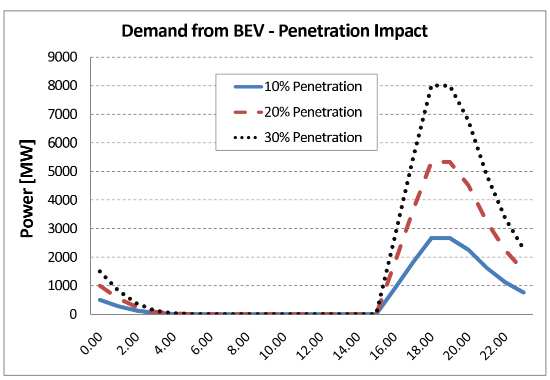

Figure 3: Power demand of BEV depending on market penetration.

8 System operations

The Unit Commitment and the Balancing algorithms determine which plants shall run to satisfy the power demand hour by hour. Results for all year round electricity system operations with electric vehicles load are found for the entire range of scenarios.

For illustrative purposes, the generation mix of the week (Monday to Sunday) of peak demand is given in Figure 4 Figure depicts *High Nuke* generation scenario, high penetration of BEVs, and charge overnight left at the drivers' convenience.

Power plants are grouped according their generation technologies.

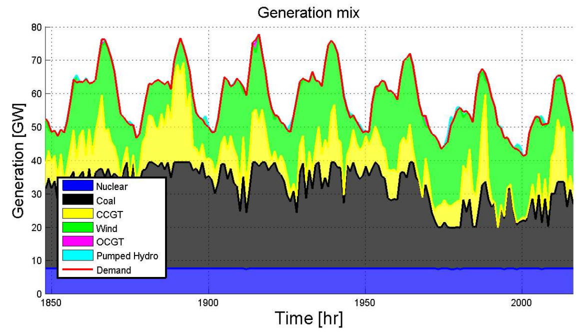

Figure 4: Generation mix for the peak demand week. *High Nuke* generation scenario, high penetration of BEVs, overnight charging only. The x-axis label value refer to the hour in the year.

Figure 5 shows a single day close-up on the results for the generators dispatch. The day is chosen in order to highlight the level of detail of the simulation tool. Operations of pumped hydro-storage facilities, OCGT plants are represented, as well as the spillage of wind generation that cannot be absorbed by the system. Similar results occur throughout the year.

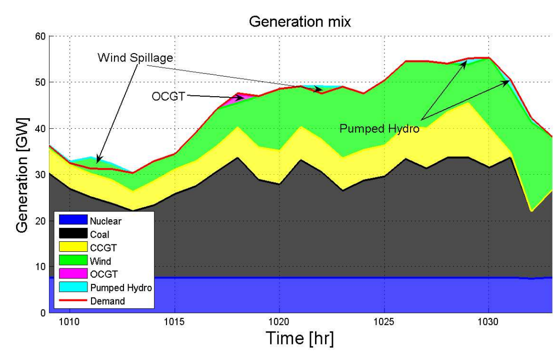

Figure 5: Close up on a single day. *Nuclear Revival* generation scenario, high penetration of PHEV-AM, overnight charging only.

8.1 Thermal plant peak

The peak values of all the thermal power plants (i.e. excluding wind) increase with the EV penetrations, and are maximum for PHEV-AM, the EV type with the highest energy requirements.

8.2 Emissions

From the results of the unit dispatching and according to the emission model described in Section 5, electric vehicle CO_2 emissions are calculated for the simulation scenarios. The real-world

Thermal power plants peak [GW]				
Generation	Penetration	BEV	PHEV BM	PHEV AM
Hi Nuke	Low EV	71.1	70.7	71.2
	High EV	74.8	73.6	74.5
Hi Coal	Low EV	71.1	70.7	71.2
	High EV	73.7	71.6	76.0
Hi Gas	Low EV	71.1	70.7	71.2
	High EV	74.8	73.6	75.1
Hi Wind	Low EV	69.1	68.7	69.2
	High EV	73.3	71.6	75.7

Table 7: Peak value of thermal power plants for Level I charge power.

emissions due to gasoline consumption in PHEV-BM amount to about 91 gCO_2/km. This value is hence added to the generation emissions for PHEV-BM found via simulations.
Carbon dioxide emissions for high EV penetration scenario and charge power level I are depicted in Figure 6 for different generation scenarios and EV types. Emission results are also summarized in Table 8. Similar values are found in the case of low EV penetration. Also, in Figure 6 EV emissions are compared with those from the standard commercially available Toyota Prius, whose real-world emissions are equal to 138 gCO_2/km [10].

CO_2 emissions [g/km]			
Generation	BEV	PHEV BM	PHEV AM
Hi Nuke	53	121	79
Hi Coal	70	131	105
Hi Gas	65	128	97
Hi Wind	62	126	92

Table 8: Carbon dioxide emissions for high penetration of EV and charge power level I.

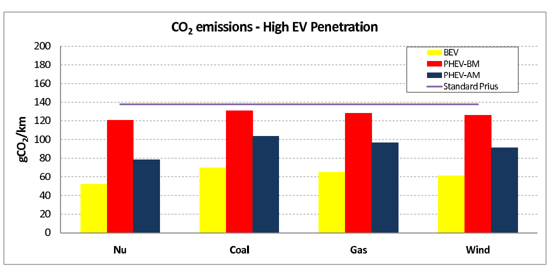

Figure 6: Carbon dioxide emissions for high penetration of EV and charge power level I.

The *Nuclear Revival* generation scenario offers the minimum electric vehicle CO_2 emissions, followed by *High Wind* and *High Gas*. As expected, the coal-dominated generation presents the highest emissions.
As far as the emissions sensitivity to the EV type are concerned, the best results can be obtained with BEV. Indeed a major leapfrog in the transport emission reduction quest can be reached by BEVs, with emissions of less than half the benchmark, the Toyota Prius, for all the generation mixes.
Conversely, plug-in hybrids operating in blended mode (PHEV-BM) entail a very modest emission reduction potential, especially for carbon intensive generation mixes. It can be argued that the moderate emission cut achievable by PHEV-BM can be as well obtained by a wide range of less impacting fuel efficiency measures. The PHEV-AM type - actually a fairer EV model than the BEV to compare the Prius with - features emissions in between those from the BEV and the PHEV-BM type.

9 The effect of Demand Side Management

The DSM is based on a load shifting algorithm which is integrated in the Unit Commitment and Balancing software so that cost-optimal solutions can be found.
As already explained, for the DSM to have a relevant impact on the system operations, electric vehicles subjected to a DSM agreement have to be connected to a Level II charger, Level I connections would simply not offer sufficient room for load shifting. Relative benefits or disadvantages of the DSM are assessed by comparing results of simulations including DSM with those of simulations where no DSM is envisaged.
Two levels of number of subscriptions to demand side management agreements are investigated: a low and a high DSM participation scenarios with 50% and 80% of the EV drivers subscribing DSM contracts respectively. As already highlighted, the combinatorial nature of the scenarios under scrutiny results in a very large range number of simulation cases. For brevity's sake, only the results of the DSM impacts for a high EV market penetration are discussed.

9.0.1 Generation Mix and Power Plant Peaks Reduction

The most significant achievement of the electric load shifting that results from implementing the demand side management is a generalized shaving of the system demand peaks. The DSM algorithm spreads the system peak over the day by shifting the demand in time towards a period when cheaper generation is available. An example of this load spreading is given in Figure 7 where a close up on single day operations is illustrated.
More precisely, the DSM allows for a significant curtailment of *thermal power plant* peaks rather than *system* peaks. Since the operative cost of wind generation is assumed to be zero, the DSM can keep or even increase the daily system peak as long as it is shifted to a time when large wind generation is available, see Figure 8
Power plant peak reductions are summarized in Table 9. In general, the higher the DSM participation, the higher the peak reductions achieved.

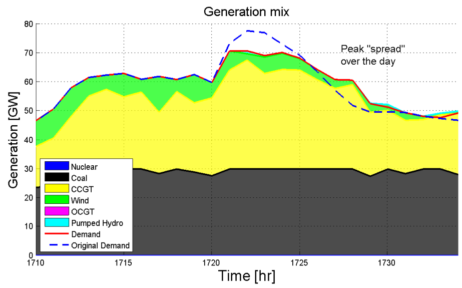

Figure 7: Close up on a single day. *High Gas* generation scenario, high penetration of BEV, high DSM participation.

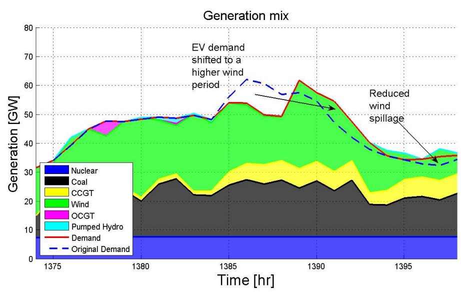

Figure 8: Close up on a single day. *Nuclear Revival* generation scenario, high penetration of PHEV-AM, high DSM participation.

Up to 12.7 GW reduction in thermal capacity can be achieved with a high level of DSM participation. The largest reductions occur when the demand of energy is largest (PHEV-AM) and the system is inflexible (*Nuclear Revival* scenario), or when the energy demand is minimum (PHEV-BM) and a high wind capacity exists (*High Wind* scenario).

Thermal plant peak reduction [GW]				
Generation	DSM	BEV	PHEV BM	PHEV AM
Hi Nuke	Low	4.7	2.3	8.1
	High	7.6	3.7	12.8
Hi Coal	Low	4.3	2.3	7.7
	High	7.4	3.7	9.3
Hi Gas	Low	4.4	1.9	9.4
	High	6.9	3.7	12.7
Hi Wind	Low	3.8	9.1	1.2
	High	6.9	10.0	4.9

Table 9: Reduction of thermal plant peak by DSM.

9.0.2 Impact on Emissions

In a nutshell, the load shifting algorithm tries, within the constraints of the generation system and of the customers demand, to shave the EV demand and *spread* it over the day so that it can be met by plants featuring a lower marginal cost. The UK power plant database used in this work assumes gas and coal prices such that the majority of gas plants have higher marginal costs than coal plants. This implies that when the EV load is spread over the day, a shift toward a larger coal generation share happens. As coal power plants are more carbon intensive than those fired with gas, it follows that the DSM is associated with a certain increase in power generation CO_2 emissions. A reversed coal and gas price structure or seasonal feedstock variations are expected to affect these results.

9.0.3 Value of the DSM

From an electricity utility perspective, the offer of a DSM scheme is associated with certain implementation costs. Examples of these extra expenses can be the administrative cost arising from managing the customers who subscribe to DSM agreements, or the additional costs of the equipment to monitor the time of plugging in the electric vehicles.
More importantly, a meaningful DSM control can be achieved only if electric vehicles are able to connect to a line complying with the Level II charging power. Since the vast majority of the domestic connection in Great Britain do not support this power level, a widespread DSM scheme would entail an upgrade of a large number of power lines, which would come at cost.
In this Section the value of the demand side management, calculated per each electric vehicle, is provided. The value is given by the overall system savings, capitalized over 25 years at a rate of 10%, and divided by the number of EV drivers subscribing a DSM agreement.
The value of the DSM found in this work can be of paramount importance for a utility who intends to invest in power for electric transportation and demand side management.
The value of a DSM contract arising from the operating cost savings depending on the generation and EV type scenarios is given in Table 10

Value of DSM [£/car]				
Generation	DSM	BEV	PHEV BM	PHEV AM
Hi Nuke	Low	99	40	142
	High	47	28	50
High Coal	Low	122	54	181
	High	72	29	88
High Gas	Low	92	41	146
	High	56	37	64
High Wind	Low	111	55	147
	High	65	41	43

Table 10: Capitalized value of DSM agreements (from operational savings only) for high penetration of EV and charge power level II

The implementation of DSM implies a curtailment of thermal plant peaks, thus in principle allowing for postponing or avoiding the investment in new power plants. The economic merit of DSM becomes evident when both the opera-

tive costs savings and the avoided investment in additional power generation are considered.
It is assumed that the avoided new plants consist of pulverized fuel (PF) coal plants with flue gas desulphurization (FGG). The variation in the amount of OCGT required for system operations when the DSM is in place is also taken into account. Plant costs as in [27] and [28] are considered for PF-FDG coal plant and OCGT respectively
The value of a DSM contract arising from both operating costs and investments savings is given in Table 11. From a utility perspective offering a DSM agreement can be worth to up ca. £ 3,100 per car. At this point it can be speculated that electric vehicles can potentially usher tremendous business opportunities for the electricity utilities.

Value of DSM [£/car]				
Generation	DSM	BEV	PHEV BM	PHEV AM
Hi Nuke	Low	1,905	804	2,746
	High	1,211	642	2,160
High Coal	Low	1,405	791	2,268
	High	1,142	14	1,071
High Gas	Low	1,706	309	3,168
	High	831	406	1,576
High Wind	Low	1,841	2,494	1,111
	High	1,519	2,135	811

Table 11: Capitalized value of DSM agreements (from operational and plant investments savings) for high penetration of EV and charge power level II

10 Conclusions

Results show that a non negligible amount of personal transportation can be shifted to electricity by causing only a modest increase in the total national electrical energy demand. Nonetheless the time profile of the EV power load shows a high time correlation with the already existing system peaks occurring in the evening, supporting the belief that a large EV penetration can take place only if widespread demand side management is implemented.
With regards to CO_2 emissions, small battery EVs offer large emission abatement with respect to some of the greenest cars currently available (down to 52 gCO2/km for a BEV in a Nuclear Revival scenario). Conversely, PHEVs running on blended mode lead to very modest emission savings. This holds especially for a carbon intensive generation mix for which emissions reach the maximum of 131 gCO2/km.
Demand side management of the EV load demonstrate the potential of considerably shaving the system peaks. Up to 12.7 GW reduction in thermal capacity is achieved with a high level of DSM participation. The reduction of thermal plant peak, or more in general, the shift of the load towards baseload plants, leads to reduced operating costs and postpone the deployment of new capacity to meet the EV demand. When both the operative costs savings and the avoided investment in additional power generation are considered. By considering the capitalized saving over a 25 years horizon, from a utility perspective offering a DSM agreement can be worth to up ca. £3,100 per EV driver.

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