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Impact of optimal charging of electric vehicles on future generation portfolios

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Abstract—Battery electric vehicles are considered by many to be part of a series of measures necessary to reduce global carbon dioxide emissions and dependence on fossil fuel resources. The extent to which this is possible depends on how successfully they can be implemented into the broader system. This paper considers the power systems impact of different vehicle charging regimes. A test system with a high proportion of variable renewables was considered. Charging profiles were developed for slow, fast and controlled optimal charging and optimal generation portfolios were developed using a least-cost optimisation algorithm. It was found that over-night charging at the slow rate resulted in a reduction in the average cost of electricity by between 4.2 and 6% compared to the base-case. For the high charging rate cases, the average cost of electricity rises by between 3 and 7%. When the charging is controlled centrally and optimised so as to increase the minimum system load maximally, it is found that the average cost of electricity is reduced by between 4.5 and 8.2%. None of the above cases resulted in significant changes in the average CO₂ emissions per unit electricity output. However, it was found that by increasing the minimum system load, optimal charging could facilitate additional inflexible generation such as variable renewables or nuclear fission plant. Where nuclear capacity is added to the generation portfolios based on optimal charging, average CO₂ emissions per unit of electricity are seen to fall between 22 and 41% for the cases studied, with the average cost of electricity reducing by between 9.5 and 21.5%.

I. INTRODUCTION

COMBUSTION of hydrocarbon fuels results in unwanted products (carbon dioxide) and bi-products (oxides of nitrogen and sulphur, un-burnt fuel etc.). In the transport context, the use of combustion as a power source in vehicles, especially in densely populated areas, can result in significant visibility, noise and air-quality issues [1]. On the national level, dependency on petroleum for transport fuels exposes the economy to significant price-risk. Transport is central to the productive capacity of the economy and energy is major component of the cost of transport. Economies that can liberate themselves from transport fuel dependencies and ensure long term transport energy price stability are more likely to guarantee general economic stability into the future.

Battery Electric Vehicles (BEVs) are proposed as one means of achieving this transition away from conventional transport

fuels. By storing electrical energy in batteries—generated by any particular means—the energy source is passed upstream from the vehicles to the power system. This in itself however does not reduce emissions or fuel dependency. Coal generation, for example, generates a high level of emissions per unit output, while substituting petroleum use for greater use of natural gas will not decrease an economy's exposure to fluctuating oil prices when natural gas prices are themselves so strongly linked to oil prices [2]. However, with the adoption of well-diversified generation portfolios with significant amounts of renewables, emissions and fuel dependency can be reduced.

The net benefit arising from the introduction of electric vehicles depends on the specifics of implementation, particularly with respect to vehicle charging. For the power system, battery charging across the system could be controlled so as to maximise the utilisation of existing generation assets. By increasing the system load when thermal generation output is at its lowest, total system costs and emissions can be reduced and additional inflexible generation, such as variable renewables and nuclear power can be facilitated. However if the charging load is uncontrolled on the system level, these benefits may not be realisable and total system costs and emissions could increase, especially at higher rates of vehicle charging.

This paper assesses these questions by developing electrical demand profiles for a test system with a large quantity of BEVs. Profiles are developed for centrally controlled optimised charging as well as non-controlled charging at different fixed charging rates. Optimal generation portfolios are developed for each case. A final set of generation portfolios including nuclear fission capacity is included to assess the potential for additional inflexible generation under optimal BEV charging.

It is important to note that the term Battery Electric Vehicle is used throughout this paper to refer to both all-electric and plug-in hybrid vehicles, as both can be treated in the same way with respect to the power system.

A. Cycling Costs under High Levels of Renewables

The outputs of renewables such as wind and wave power are variable and uncontrollable and so cannot be dispatched in the same way that thermal plant can be. In determining then the amount of dispatchable generation that must be available to system operators to meet demand, it is typical to consider the difference between forecasted demand and forecasted variable-renewables output. Figure 1 depicts a simulated time-series for renewables output and electricity demand for the test system

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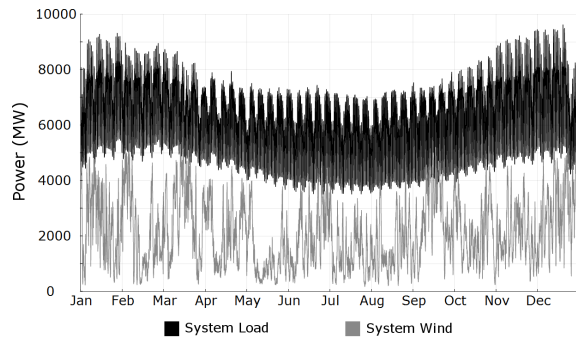


Fig. 1. System load and renewables time-series for test year, taken from All-Island Grid Study work stream 2A.

considered in this study. Subtracting the renewables output from the electricity demand yields what is referred to here as the dispatchables curve, the quantity of load to be met by the dispatchable generators (Figure 2). What can be seen is that this curve is extremely variable and in parts falls below zero, where renewables output exceeds system demand. This sort of operation is undesirable for a number of reasons:

First, to maintain system inertia and provide spinning reserve, a certain amount of units must stay online. This minimum quantity of thermal generation would mean that a significant amount of renewable output would have to be curtailed (i.e. discarded).

Second, any power system will have a large number of units available. If the system regularly varies between near max thermal output and near minimum thermal output, the plants will have to successively reduce and increase their output to match, many spending much of the year offline entirely. Once a plant goes offline, it has a minimum down time and a further synchronisation time before it can resume output. This varying output behaviour is referred to as cycling and poses significant costs. Reducing the output of any plant below its rated power decreases its thermal efficiency and this increases its emissions per unit of electrical output. Operationally, minimum down times, synchronisation times and ramp rates—the rate at which plant can vary output—impose constraints on unit commitment and dispatch leading to higher system costs [3]. Physically, large or rapid load variations reduce the life-time of components through fatigue and corrosion and in some cases can lead to catastrophic failure of e.g. turbine or compressor blades.

Finally, the thermal plant with the lowest unit generation costs, i.e. combined cycle gas turbine and nuclear fission plant are designed to run in continuous or base-loaded operation, which is especially the case for fission plant. If there are many hours where very little thermal output is required then this base-load plant becomes less preferable. As the fixed costs are significantly higher for these plants they must operate for a certain minimum amount of hours to have lower total costs than other plant types.

B. Charging Regimes and Implementation

If BEV charging can be used as flexible load, the dispatchables curve can be smoothed and the troughs raised so as to mitigate these negative effects. However, if a large amount of

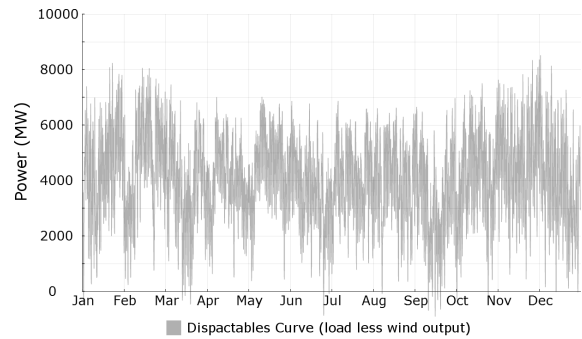


Fig. 2. Dispatchables curve for test year

BEVs were introduced to a system without central control over charging many of these negative effects may be accentuated. This is a consequence of the interaction between typical patterns of vehicular travel and electricity use. Assuming that the peak in evening vehicle arrival leads the peak in electricity demand by a short interval, the increasing load of vehicle charging will exacerbate the peak load demand, in particular at higher rates of battery charging. This additional load would have to be met by additional flexible capacity which would otherwise not be necessary. System demand profiles are developed for controlled and uncontrolled charging. For controlled charging, an algorithm that raises the minimum load hours maximally is used, while for uncontrolled charging, profiles are developed for a regular rate of charging (10 hours for full charge) and a faster (1 hour) rate to assess the impact of charging rate. This is the fastest charging rate that could be considered in this paper given the temporal resolution of the data, notwithstanding that faster charging rates would imply very high power requirements, perhaps necessitating excessive network reinforcement. Faster charging rates could, for example, be facilitated by way of large intermediate energy sinks at charging stations. These sinks could be charged at reduced but continuous rates by the grid and could charge vehicles at much higher rates for short periods. The actual effects of such a system merits further study.

The actual implementation of controlled charging might be as follows. On the consumer end, it is assumed that the user would plug their car into a smart switch which is itself plugged into an electrical outlet. The switch could communicate through a home router with a remote server, recording usage, state-of-charge of the battery and other parameters. The remote server would send control signals to the smart switches of blocks of vehicles so as to charge the system optimal amount of vehicles at each instant. Such equipment is available at present, utilising inexpensive technologies [4], [5].

C. Vehicle-to-Grid

For this study, BEVs are considered only as flexible load and not as flexible sources. Distribution-level electrical infrastructure was not designed to facilitate energy transfer back to the grid. Batteries could be charged and discharged when the vehicle is not in use, but the batteries must have an acceptable quantity of charge by the time the vehicle user

needs to use the vehicle. This in essence means a larger battery than would otherwise be necessary. This might affect the economics of vehicle-to-grid if the cost of batteries capacity is high into the future. Finally, battery discharge implies two energy conversion steps with their associated losses. Assuming a 10% loss at each step, the real cost of the vehicle-to-grid energy is approximately 1.23 times the cost of the energy to charge the battery in the first instance. However, in systems with a significant night-day price differential or where reserve generation is relatively costly, the net benefit may still be substantial, even if night-time vehicle charging erodes this price differential somewhat. It is therefore necessary that further study be undertaken in this area.

II. METHODOLOGY

A summary of the procedure undertaken is as follows. Time-series for the test-year were developed for the BEV charging load based on a daily total system BEV energy requirement. This BEV load was added to the dispatchables curve yielding a time-series for the amount of load that must be met by the dispatchable generation in the system over the year. An optimisation algorithm was then ran to produce generation portfolios to meet this load, minimising for cost.

A. Test System

The Irish power system was chosen as the test system for this study. This system has some unique characteristics which make it well-suited for a study such as this. Ireland is a small, largely isolated power system which is increasingly accommodating large amounts of variable renewable generation, in particular wind power. Arising from the All-Island Grid Study [6], an assessment of Ireland's potential energy resources, a government target has been set for Ireland to generate 40% of electricity from renewable sources. In terms of capacity this may translate to almost 50% renewables.

B. Generation Portfolio Optimisation

The least-cost generation portfolios were developed using Doherty's generation resource planning optimisation algorithm [7] with a discretised version of the dispatchables curve including the BEV charging load as an input. The dispatchables curve is discretised by sorting the hours into bins, each bin accounting for a portion of the load range. The centre of the range for each bin is taken to be the load requirement for each of the hours in the bin. This step essentially generates a discrete load duration curve. Finally, the fixed and variable costs of each generation technology is defined and included in a linear programming optimisation. When executed this program generates the plant portfolio that meets all of the binned hours, minimising total costs. The fixed costs, variable costs and emissions per unit output for each type of generation were taken from Doherty [7].

C. Charging Load Profiles

This section discusses the development of the charging profiles in more detail.

BEVs differ from more traditional forms of dispatchable loads, such as pumped storage stations in that their primary function isn't in the power systems domain. The use of BEVs as a flexible load is constrained by the pattern of their use as vehicles. This introduces constraints and simplifications. Firstly, the total daily energy requirement will be directly proportional to the total distance travelled by all the vehicles over the day. This is expressed by equation 1, with the values used here given in table I:

$$E_d = N * d * f \quad (1)$$

TABLE I
INPUT PARAMETERS

		Value
E_d	Daily vehicle energy requirement	20 <i>GWh</i>
N	Number of BEVs	2,000,000
d	Average distance travelled	50 <i>km</i>
f	Average energy rate	0.2 <i>kWh / km</i>

The inputs in the table I are based on plausible future values but have been intentionally rounded to emphasise that all of the inputs are subject to significant uncertainty and that a thorough estimation of the inputs has not been attempted here. The latest available data for average distance travelled in Ireland is provided by the Central Statistics Office [8] for 2007 which lists an average of approximately 47 km per registered private car. The same volume states that there were 1.88 million registered private cars out of a total of 2.4 million registered vehicles in the state in 2007. The average energy rate is taken from vehicle modelling undertaken by EPRI [9].

The daily vehicle energy requirement is then to be applied to the dispatchables curve. A set of results is produced for $E_d = 20 \text{ GWh}$ and $E_d = 10 \text{ GWh}$. For each E_d , three charging regimes were considered: slow and fast uncontrolled charging, which assumes vehicles charge at some fixed rate once grid-connected and controlled charging, where the batteries are charged optimally according to an algorithm that raises the minimum daily values maximally. The algorithm starts at the first day and distributes the load over the hours in this manner before moving on to the next day and so on. For any particular day the energy can be applied up to 5 hours before the start of the day and up to 7 hours after, i.e. 7pm day (i-1) through to 7am day (i+1). This adds to the flexibility of the algorithm without violating feasibility. Charging cannot be optimised over the whole year as that would assume a perfect forecast one year ahead where this method assumes one day.

For this method to be realisable, the algorithm cannot place an infeasible amount of energy in any one charging period nor exceed a feasible total charging power. In the absence of travel data for the test region, an assumed pattern is used. It is assumed that the mean home departure time is 8am, normally distributed with a variance of 2, mean home arrival time is 6pm, similarly normally distributed and journey time is one hour. An average charge energy of 10kWh per day can be achieved at modest rates of power between home arrival time and work departure time—14 hours on average—so if charging

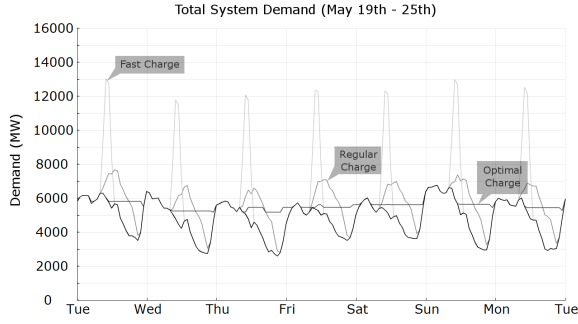


Fig. 3. Impact of charging regimes on total system demand.

should optimally take place at a time when a lot of vehicles are in transit, the charge power of the parked vehicles can increase to accommodate. This is reasonable given the relatively high charging rates that are believed to be achievable on the Irish system [10]. Taking the travel behaviour of vehicles as above, it can be seen that the minimum number of grid connected vehicles does not drop very much, given that late departures are matched by early arrivals.

A sample of the charging profiles generated for this study is presented in figure 3.

After the energy was applied to the dispatchables curve with the algorithm, a sample of the days with the greatest amount of charging took place, corresponding to a combination of high wind output and low electricity demand. The top three days over the year are displayed in the table II where it can be seen that no more than an average of 18kWh is ever required of the vehicles, which itself is an extreme case. This in effect shows that introducing an energy constraint would not change the results much as the expected battery capacities would accommodate all but a small fraction of the days in the year. Table III takes a sample of BEVs to go into production and their battery capacities.

TABLE II
CHARGING ENERGY REQUIREMENT, THREE HIGHEST VALUES AND THREE RANDOM SELECTED VALUES

Date	Total Overnight Charging Energy (GWh)	Average per Vehicle (kWh)
Oct 25	36.3	18.2
Dec 6	36.1	18.1
Nov 30	29.2	14.6
Nov 23	10.2	5.1
Aug 1	22.6	11.3
Mar 9	20.8	10.4

TABLE III
BATTERY CAPACITIES FOR A SAMPLE OF ELECTRIC VEHICLES TO ENTER PRODUCTION

Name	Category	Battery Capacity (kWh)
Chevrolet Volt	Compact Car	16
Mitsubishi iMiEV	City Car	16 / 20
Phoenix SUV	Sports Utility Vehicle	35

Finally, it is assumed that there is sufficient charging infrastructure to meet the battery charging needs. This is perhaps justified as the algorithm places almost all of the energy during the night when the vehicles would be grid-connected at residences of the users.

III. RESULTS

A number of generation options were presented as inputs to the optimisation algorithm, including pulverised coal, fluidised bed peat, integrated gasification combined cycle and open and combined cycle gas turbine plant. However, only Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) plant arose in the final solution.

TABLE IV
TEST CASES

Case#	Daily Charge Energy (GWh)	Charge Time (hours)	Fission Cap. (MW)	Controlled Charging
0 (base-case)	0	-	0	-
1	10	1	0	No
2	10	10	0	No
3	10	n/a	0	Yes
4	10	n/a	1000	Yes
5	20	1	0	No
6	20	10	0	No
7	20	n/a	0	Yes
8	20	n/a	2000	Yes

Referring to table V, it is noted that fast charging (cases 1 and 5) necessitate the provision of 37% and 76% more generation capacity, respectively, than is needed in the base case (case 0). The slower, 10 hour charge cases (2 and 6) require an extra 6% and 15% respectively in extra capacity, while the optimal charging cases (3, 4, 7, 8) require almost no extra installed capacity over the base case. Referring to table VI, it can be seen that the charging regimes under study had very different impacts on plant utilisation. The proportion of the increase in total production met by OCGT plant in the uncontrolled charging cases was large (8-55%) relative to the proportion met by OCGT plant in the controlled charging cases (0-2%). Note, for both of the charge energy groups—10 and 20GWh—there is a small difference between energy served for each of the cases. This is a consequence of the error associated with discretisation of the load curves.

There are three notable features of the tabulated results of table VII.

First, there is very little difference in emissions per MWh between any of the non-fission cases. In the non-controlled charging cases, the open-cycle gas turbine units are running significantly more often which leads to an increase in total emissions as the open-cycle units have a lower thermal efficiency and thus higher emissions per MWh than the combined-cycle units. However the increase in energy served by the open-cycle units is small relative to the total quantity of energy served, so the effect on average emissions is relatively minor. It should be noted that values for average emissions include only the power system emissions and that the 10 and 20 GWh

TABLE V
INSTALLED CAPACITY (MW). OUTPUT FROM GENERATION PORTFOLIO
OPTIMISATION ALGORITHM.

	OCGT	CCGT	Fission	Total
0	3260	5750	0	9010
1	6079	6250	0	12329
2	3823	5750	0	9573
3	3264	5750	0	9014
4	3254	4750	1000	9004
5	9131	6750	0	15881
6	4115	6250	0	10365
7	3287	5750	0	9037
8	3267	3750	2000	9017

TABLE VI
ENERGY SERVED (MWh). OUTPUT FROM GENERATION PORTFOLIO
OPTIMISATION ALGORITHM.

	OCGT	CCGT	Fission	Total
0	882,500	34,616,000	0	35,498,500
1	2,370,500	36,788,000	0	39,158,500
2	1,425,000	37,704,500	0	39,129,500
3	882,500	37,704,500	0	39,164,000
4	882,500	29,493,500	8,784,000	39,166,000
5	4,908,500	37,910,000	0	42,818,500
6	1,509,000	41,291,000	0	42,800,000
7	1,020,500	41,700,500	0	42,721,000
8	1,020,500	24,136,500	17,568,000	42,725,000

cases account respectively for 10 and 20 GWh of transport energy and associated emissions.

Second, non-controlled charging significantly differs from controlled charging in average cost of electricity (COE). In the high charge-energy case of 20GWh, fast uncontrolled charging is 18% more costly than the optimal charging case with no fission capacity while slow charging is 3.5% more costly. This translates into additional total system costs of €491M and €99M respectively.

Third, the introduction of fission capacity has a dramatic impact in terms of emissions and generation costs. In the 20 GWh case, average emissions drop by 40% and COE by 14%.

The final set of results (table VIII) gives an indication of the magnitude of wind power curtailment for each case. It is assumed that the total minimum conventional plant electrical output on the system is 1000MW, or roughly 5 base-load plant at 50% output. It is also assumed, perhaps pessimistically, that the nuclear fission capacity cannot contribute at all to this minimum conventional plant output.

IV. CONCLUSIONS

Centrally controlled charging can be used effectively to increase the system demand minimum. In systems with a large proportion of variable renewable energy such as wind, wave and solar, this may reduce renewables curtailment and for small systems, help maintain system stability. It also minimises the need for additional generation capacity, which in the cases investigated here has a substantial impact on total system costs.

TABLE VII
SUMMARY OF RESULTS: TOTAL SYSTEM COSTS, TOTAL EMISSIONS,
AVERAGE EMISSIONS AND AVERAGE COST OF ELECTRICITY.

	Total System Costs (€)	(Total CO_2) (Emissions (t))	Avg. Emissions (tCO_2/MWh_e)	Avg. COE (€/MWh _e)
0	2,432,178,251	12,876,535	0.363	68.5
1	2,792,387,243	14,357,815	0.367	71.3
2	2,600,025,777	14,243,370	0.364	66.4
3	2,560,421,841	14,196,775	0.362	65.4
4	2,364,720,140	11,035,255	0.282	60.4
5	3,178,333,558	15,954,595	0.373	74.2
6	2,786,816,546	15,573,990	0.373	65.1
7	2,687,421,074	15,491,815	0.363	62.9
8	2,296,017,672	9,168,775	0.215	53.7

TABLE VIII
ESTIMATES OF WIND POWER CURTAILMENT

	Curtailment (MWh _e)	Curtailment (%)
0	162,812	0.46
1	90,625	0.23
2	162,812	0.42
3	3,883	0.01
4	129,304	0.33
5	59,060	0.14
6	162,812	0.38
7	0	0
8	257,375	0.60

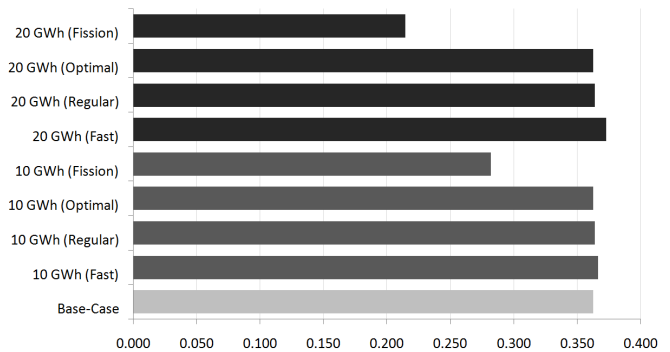


Fig. 4. Average emissions for the test cases (tonnes CO_2/MWh_e)

Modest reductions in fuel use and thus emissions are also noted due to greater utilisation of higher efficiency base-load plant.

A further valuable benefit may be that an increased system demand minimum could allow for further variable renewables or, as investigated here, facilitate nuclear generation capacity.

The rates at which batteries are charged has important power system implications. It was shown here that fast charging (taken as 1 hour for full charge) can lead to significant increases in total system costs as it increases the system demand peak substantially, requiring the provision of extra flexible generation capacity.

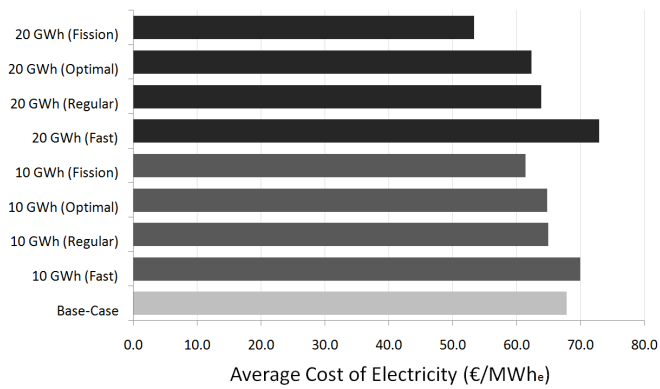


Fig. 5. Average cost of electricity for the test cases (€/MWh_e)

V. FURTHER WORK

It was demonstrated here that optimised BEV charging can lead to greater base-load utilisation which reduces average emissions and costs through higher average thermal efficiencies. What is not modelled here is the reduction in average costs and emissions that would result from reduced start-ups and cycling of the plant. A more accurate assessment of total system costs and emissions could be achieved by a full unit commitment and dispatch simulation. This would also test the reliability of the portfolios.

A restricted set of dispatchable generation technologies was considered here. The variable and fixed costs of e.g. plant incorporating carbon capture could be determined and included in the analysis. The optimisation could then be repeated to identify the conditions under which these and other technologies become part of optimal generation portfolios.

A dataset for travel behaviour in the area under study is required to develop more robust charging profiles.

When considering future generation portfolios, many of the inputs are subject to significant uncertainty. Accurate forecasts for fuel, electricity use, emissions allowances and other parameters would improve the results.

Finally, vehicle-to-grid power flows must be considered in order to identify additional potential value from battery electric vehicles.

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