Programme Area: Light Duty Vehicles

Project: Economics and Carbon Benefits

Title: Energy Scenarios Comparison Report

Abstract:

This project was undertaken and delivered prior to 2012, the results of this project were correct at the time of publication and may contain, or be based on, information or assumptions which have subsequently changed. This is a detailed report on the analysis of the UK electricity system to 2050, to derive the electricity prices and carbon intensity factors used within the Economics and Carbon Benefits project. This report should be read as a supplement to the Scenario Development Final Report. The resulting dataset has been embedded into the Consumer Choice Model (deliverable 1.4-9 from the Consumers and Vehicle project [TR1001]). The latest copy is available on request from the ETI.

Context:

A strategic level analysis of the potential size of the market for plug-in vehicles, the total level of investment needed and the total carbon offset for the UK.

Deliverable Title	Energy Scenarios Comparison Report
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Interim or Final	Final report

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EXECUTIVE SUMMARY

The project “Plug-in Vehicle Economics and Infrastructure” is a collaborative R&D project between partners including Arup, Institute for Transport Studies, E.ON, EDF Energy, Element Energy and Ricardo. Funding support is provided by the Energy Technologies Institute. The overall objective of this project is to evaluate the role and economics of plug-in vehicles (PiV) in a future low carbon transport system, and also to investigate the technologies required to deliver an appropriate charging infrastructure. In this first stage of the project this evaluation is delivered through modelling.

The electricity used to charge plug-in vehicles is an important component of the picture with the potential to significantly affect the economics and system-wide impact on carbon dioxide emissions. In order to understand these impacts, the project includes modelling of the electricity market as it develops to 2050. This report – produced jointly by E.ON and EDF Energy – fulfils deliverable WS3/E.ON/03 by describing the results of detailed modelling of six chosen PiV scenarios. This modelling has investigated the way in which future electricity demand could be met for a set of different capacity mix and commodity price scenarios. The modelling explores two types of PiV charging profile plus a profile with no additional EV demand. The capacity mix scenarios are based on UKERC’s Energy 2050 study and are discussed in more detail in deliverable WS3/E.ON/01.

The installed generation capacity in the chosen UKERC scenarios was not sufficient to supply demand once the loads from plug-in charging modelled within this project were applied: the adopted method of increasing plant capacity by scaling up the capacity of each plant category was chosen so that the scenarios conform as closely as possible to the initial mix in the UKERC scenarios. This scaling was found to be critically important to the outcome of the modelling.

Other work packages will use the results of this modelling as input to models of consumer choice of vehicles and the impact of this on UK carbon dioxide emissions, thus key metrics from this work are power price and emissions intensity. The modelling undertaken by both EDF and E.ON is designed to estimate wholesale power price, but an approximate method for deriving a consumer power price is also given. Power prices and both average and marginal carbon dioxide emission intensities have been provided at both an annual and seasonal level. At the request of other partners in the project, regression curves of wholesale prices on electricity demand and of grid emission factors on electricity demand were estimated, at both annual and seasonal granularity.

Examination of the annual results shows good agreement between E.ON and EDF outputs and the models reconcile well to observed values for 2009. The modelling shows that choice of scenario (i.e. combination of capacity mix and commodity price) and its evolution through the years are much stronger drivers of modelling outcomes than are the different charging profiles. Indeed, the difference between charging profiles is smaller than modelling error as estimated by the variation between E.ON and EDF results. This lack of variation in results between charging profiles might not be evident if alternative regimes for adapting the generating plant mix to fit the demand it is asked to supply were adopted.

In 2050, the predicted annual average emissions factors range from around 0.02 t CO_2/MWh to 0.08 t CO_2/MWh, which is consistent with the levels of carbon abatement considered by most stakeholders. These intensities are also consistent with the corresponding results calculated by UKERC. Total grid emissions at this end-point are reduced by around 70% to 90% compared with current values. Modelled wholesale power prices are more variable: in 2050, modelled annual prices range from around £40/MWh to nearly £120/MWh.

Key recommendations for use of the results of this modelling are:

- Cost of electricity and carbon intensities should only be taken from the No EV demand scenarios. We do not recommend using figures from scenarios with EV charging overnight or at peak times;

- Within day profiles (including regressions) for cost of electricity and carbon intensity should only be used (if at all) for low levels of EV demand (say, less than 2 GW). For larger levels of EV demand, we recommend using a single annual average figure;

- We recommend using average carbon intensities when evaluating the carbon intensity of EVs as these provide the best approximation to the true impact;

- The observed grid emission factor for 2009 should be used as an estimate of 2010 rather than the model output.

The scaling approach adopted here means that meaningful evaluation of the relative impact of different charging profiles is not immediately possible. To address this issue some simple modelling of choice of generating plant to meet demand in 2050 was undertaken and some initial thoughts regarding a more comprehensive approach are presented. Developing such a model would be a significant undertaking and exploration with the simple model showed that energy policy choices and future capital and operating costs of generating plant are both important factors.

Other conclusions from this simple modelling include:

1. The charging regime adopted for electric vehicles has little impact on annual average electricity wholesale prices;

2. Under some, but not all, choices of mechanism for incentivising investment in low carbon electricity generation overnight charging would result in lower emissions than would after-journey charging and the magnitude of this benefit is highly dependent on other scenario conditions;

Noting that there are benefits from overnight charging in the transmission and distribution sectors of the electricity industry and that it seems unlikely that there are credible scenarios in which there is a dis-benefit from overnight charging in the generation sector there seem to be adequate grounds to encourage this behaviour.

The contents of this report are IP associated with the project “ETI Plug-in Vehicle Economics and Infrastructure” – contract reference TR1003.

1 INTRODUCTION

The project “Plug-in Vehicle Economics and Infrastructure” is a collaborative R&D project between partners including Arup, Institute for Transport Studies, E.ON, EDF Energy, Element Energy and Ricardo. Funding support is provided by the Energy Technologies Institute. The overall objective of this project is to evaluate the role and economics of plug-in vehicles in a future low carbon transport system, and also to investigate the technologies required to deliver an appropriate charging infrastructure. In this first stage of the project this evaluation is delivered through modelling.

A previous report by E.ON and EDF Energy [1] introduced the scenarios that were selected to be used in subsequent modelling of the electricity generation schedule. Individual interim reports [2, 3] that described the results of this modelling were subsequently issued.

The current report fulfils deliverables associated with Workpackages WS3.1.4 and WS3.3.3. The report, jointly authored by E.ON and EDF Energy, contains a summary of the results in the interim reports, plus a comparison of the methods used and results obtained from this modelling by E.ON and EDF Energy, including (where possible) comparisons with the UKERC work that provided many of the inputs for this project [4]. It also offers advice regarding the appropriate use of the results.

Although the modelling has been primarily focused on the period from 2020 to 2050, validation has been carried out using modelled and actual results in 2009/2010. Any deviations from observations have been analysed and, where possible, reconciled.

Finally, a brief comparison is made with the DECC Alpha pathway. This comparison is made without attempting to model the DECC pathway, but rather by inspecting the inputs and drawing out the key outcomes that would be expected if the pathway were modelled in detail.

E.ON and EDF have previously submitted interim reports describing many of the results from this modelling work [2, 3]. It is not assumed that readers of the current report have read these previous reports.

1.1 Definitions

All electricity demands reported here are those connected to the Great Britain transmission and distribution networks and measured at power station gate unless otherwise stated. Any inconsistencies between use of UK data (including Northern Ireland) and GB data will be small in scenarios looking ahead forty years and are ignored (in 2008 Northern Ireland consumption of electricity was 2.5% of the UK total [5]).

All quoted costs and prices throughout the report are in real terms, based on 2009£.

2 SCENARIOS AND MODELLING METHODOLOGY

2.1 Rationale for Selection of Existing Scenarios

In 2005, the UK government signed a binding agreement to reduce UK carbon dioxide emissions by 80% by 2050 (from 1990 levels). Achieving these carbon reduction targets will require a radical shift in the way energy is both sourced and utilised; this includes electricity supply but also the rest of the UK energy mix. Clearly take-up of electric vehicles will influence the demand for electricity which will require production capacity to be installed to meet it and that is the main focus of this part of the project. However, other developments such as the penetration of heat pumps, the adoption of hydrogen as an energy vector and efficiency improvements also have implications for the electricity supply industry. A robust scenario analysis of the whole energy system is a major task and did not seem appropriate to this project; rather, the philosophy was adopted that the project should start from energy scenarios already developed and add value to them by analysing them further.

Numerous studies have been carried out (or are currently under development) to explore a range of possible scenarios that could meet this target. Some key examples include:

- UK Energy Research Centre (UKERC): Pathways to a Low Carbon Economy: Energy Systems Modelling report [4]. This UKERC report forms part of the wider UKERC Energy 2050 project, the aims of which are to generate evidence relevant to meeting the UK's long-term energy goals:
    - achieving deep cuts in CO_2 emissions by 2050.
    - developing a 'resilient' energy system that meets consumers' needs reliably.
- ETI Energy Systems Modelling Environment (ESME) project.
- DECC 2020 and 2050 Pathways.

For this study, the decision was taken to source capacity mix and electricity demand scenarios from the UKERC report. This decision was based on a combination of the suitability and availability of this scenario data. A report by E.ON/EDF [1] on the selection of these scenarios has previously been accepted by ETI.

2.2 Scenarios

The UKERC study developed 8 future energy scenarios, each resulting in a different electricity capacity mix depending on the focus of that particular scenario. Four of these 8 scenarios were selected for this ETI study. This selection was based on a combination of the carbon reduction rates achieved in each, and additional value added from selecting a wide range of plausible future capacity mixes. Choice of one scenario rather than another does not reflect the views of the authors or their employers on either the achievability or the advisability of the scenarios.

The UKERC scenarios each contributed a representative capacity mix and electricity demand for years between 2010 and 2050. These generating parameters were then combined with commodity price tracks (provided by Arup [6]), and this combination provided a total of six final scenarios that were chosen to be the subject of cost and carbon modelling by E.ON/EDF.

Table 1 shows the six scenarios modelled in this project, involving four sensitivities around capacity mixes (Base, EG1, EG2, EG3) and two sensitivities around commodity price (T11 and T7). The set of scenarios differs slightly from that initially proposed in Ref.1 after detailed requirements from other project members were specified.

Table 1: Modelled Scenarios

PiVEIP Scenario	Description	UKERC Scenario	Oil Price	Coal Price	Gas Price	Carbon Price
Base	Baseline	CAM	Medium	Medium	Medium	Medium
EG1	Greenest	CSAM	High	High	High	High
EG2	Least green	CLC	Low	Low	Low	Low
EG3	Early action to reduce CO_2	CCSP	Medium	Medium	Medium	Medium
T11	Low growth	CAM	Low	Low	Low	Low
T7	High growth	CAM	High	High	High	High

Ricardo have previously produced forecasts of future EV charging load [7], and profiles for overnight charging and after journey were selected for further study along with a profile with zero EV demand. These profiles were combined with the six PiVEIP scenarios, providing a total of 18 sub-scenarios to be modelled.

2.3 Description of the Models Employed

The specific models used are intellectual property of E.ON and EDF Energy and cannot be described in detail but, broadly speaking, the models are both based upon least-cost dispatch to meet demand. Wholesale power prices at any point are thence estimated as the marginal cost to the system of a small increase to demand at that time; this can be visualised as the short-run marginal cost (SRMC) of the most expensive plant required to run at that time.

The models deviate in their treatment of the days within the year. The EDF model assumes a coarse-grained structure whereby each day in the year is identical to one of six typical days (seasons x weekday/weekend). The E.ON model is similar in ethos but applies stochastic demand variations in order to capture correlations between the weather and electricity demand. A Monte Carlo approach is employed to ensure that the behaviour of the average of all such simulations is as expected.

In both models, season-specific wind generation profiles are employed rather than assuming a flat load factor. Apart from the use of existing pumped-storage plant, the modelling carried out here has not investigated the potential of applying additional demand-side management to the different charging profiles.

2.4 Adapting the Scenarios to the Needs of this Study

It was always anticipated that some adjustment to the generating capacity anticipated by UKERC modellers would be required because their modelling was at a higher level (i.e. whole energy system) and therefore not able to incorporate the same level of detail as E.ON and EDF's market models. Applying these more detailed models was one way in which it was expected value could be added to the UKERC modelling.

In addition, the Ricardo EV charging scenarios involve a significant increase in EV demand relative to UKERC and, because of this, the quoted UKERC plant mix is often insufficient to satisfy the new total annual demand – there is quite a large shortfall in some cases. To ensure that there is always sufficient capacity available to just meet demand, additional plant must be built.

To remain faithful to each UKERC scenario, a scaling approach was applied that ensures that the final mix is in roughly the same proportions as the UKERC mix. The total plant capacity was scaled to just cover the highest hourly demand i.e. the winter peak. This actually means that the amount of plant built varies slightly between the two different charging profiles even though they have the same total annual demand – more scaling is required to fulfil all demand in the peakier After Journey charging profile than the other two options.

No attempt is made at this stage to anticipate how the mix might adapt further to fit the different charging profiles, as any manually applied adaptation would provide a scenario that is no longer in the spirit of the chosen UKERC scenario. The impact of this approach will be discussed below.

2.5 Average and Marginal Carbon Dioxide Emissions Intensities

Key outputs from this project are the carbon dioxide emissions associated with these scenarios, because project partners are intending to use these to estimate the impact of policy measures relating to electric vehicles on the UK carbon dioxide emissions. The preferred measures for comparing emissions in this project are emissions intensities of electricity produced, and there are two natural emissions intensity metrics that can be constructed from the generating schedule: average carbon dioxide emissions and marginal carbon dioxide emissions.

Note that all the values of carbon dioxide emission intensity quoted in this report are in terms of emissions per unit of electrical energy generated, measured at the station gate. To convert these to intensities at the point of consumption allowance must be made for losses in the transmission and distribution networks. Evolution of network losses has not been modelled within this study so a value of 1.08 is suggested for us based on 2009 values reported by DECC.

2.5.1 Average Emissions Intensity

Average emissions intensity at any time is defined as the sum of the emissions from all plant generating divided by the total grid load at that time. It should be noted that this quantity does not necessarily increase monotonically with grid load – for example, in price scenarios where coal plant is cheaper to run than combined-cycle gas plant average emissions intensity can decrease when demand increases beyond the point that it can be fulfilled wholly using coal plant.

2.5.2 Marginal Emissions Intensity

In the original proposal for SP3 of this project, E.ON indicated that an output from the modelling would be the “marginal emissions intensity for EVs” defined as the carbon dioxide emissions with and without EV demand, divided by that demand. Following discussions with project partners, ETI advisors and ETI project management this metric was discarded in favour of a metric based on a more conventional marginal emissions factor.

The general definition of a marginal grid emissions factor is the carbon intensity associated with an incremental increase in generation at any given point in time. Here this quantity has been approximated by finding the grid emissions factor of the most expensive plant[1] running at any hour of the day (in the E.ON modelling, this intensity is then averaged over all Monte Carlo simulations to provide an estimate of the (average) hourly marginal carbon intensity for each

[1] In cases where pumped storage is marginal, the next most expensive plant defines the marginal emissions factor.

hour in the year). This provides a marginal intensity under the assumption of a static generating fleet – an alternative modelling approach would be needed to estimate the marginal emissions intensity consistent with the general definition introduced above.

Further discussions have suggested that a metric of the annual-average marginal carbon intensity might also be of value; small amounts of additional grid load could conceivably be considered as being added at the margin uniformly through the year. This metric has been calculated as simply the arithmetic mean of all hourly marginal emissions factors in each modelled year.

Generally the modellers consider that the average emissions intensity gives the best approximation to the emissions associated with EV charging. However, marginal emission intensity is the correct metric to use to examine the incremental change in emissions for a small, short term, change in electrical demand.

Due to the similarity in E.ON and EDF results and the relatively late agreement on this specific calculation, marginal emissions calculations have been carried out only for the E.ON modelling.

2.6 Uplift to Wholesale Power Prices

The market models employed estimate wholesale electricity prices which might arise in a market that is sufficiently competitive to ensure these are set at short run marginal costs. Fixed and capital costs are recovered for most generating plant through the margin they achieve when dearer plant is marginal. Plant that is less well used but is essential to achieving a secure and reliable system can benefit from ancillary service payments and renewable generation benefits from financial support in the form of sale of Renewable Obligation Certificates (ROCs) under the Renewable Obligation. These additional sources of revenue are not included in the models but do have to be recovered from consumers so are included in the price of electricity to consumers.

In modelling markets in the long term, as in this project, it is appropriate to assume that assets recover their full economic costs. Where this is not achieved through sales at wholesale prices alone it is here assumed that other sources of revenue are available to them without specifying how they will arise. E.ON and EDF have each calculated the additional revenue required for each class of generating plant modelled in order to meet their annualised full-life costs and estimated the uplift to wholesale prices required to provide that revenue. This uplift includes income from sale of ROCs, ancillary service payments and any other revenue source created by future reforms of the market arrangements. It is assumed that the uplift applies as an unvarying addition to all wholesale prices throughout the year.

Capex and Opex costs have been taken from a report by Mott McDonald for DECC [8] (Table 2). It is assumed that existing large coal and nuclear plant does not need to pay back its capex costs but does need to recover its annual running costs.

Table 2: Annualised Costs for Each Plant Type

Plant Type	Capex (£/kW)	Opex (£/kW/yr)	Total Annualised Cost at 10% Discount Rate (£/kW/yr)	Comments
Existing coal	0	56	56.0	Legacy plant – opex only
New coal	1789	56	268.3	
Coal CCS	2434	79	376.9	
Large CCGT	718	26	108.0	
OCGT/Oil	0	26	26.0	Assumed conversion of existing plant
Wind	1520 (onshore) 2840 (offshore)	34 (onshore) 76 (offshore)	310.0	Assume 50:50 mixture of offshore and onshore wind
Biofuels	-	-	562.0	Includes fuel costs. Mott McDonald only provide annualised figures
Marine	2840	76	408.1	Assumed marine costs equivalent to offshore wind costs
Existing nuclear	0	62	61.5	Legacy plant – opex only
New nuclear	2913	62	418.4	

To provide a clearer terminology, we sometimes refer to the wholesale power price (i.e. price based on SRMC, neglecting any uplift) as the “fundamental price”. The “total price” is the fundamental price plus any uplift, while the “consumer price” is the total price plus an additional mark-up for transmission and distribution costs, plus profit.

2.7 Relationship to Consumer Power Prices

In addition to wholesale costs, consumer power prices have to cover the costs of the distribution and transmission of the power, of metering, of supply business activities, of specific support schemes funded by the consumer (e.g. ROCs) and taxes. Consumer prices are further influenced by the marketing strategies of the suppliers and the charging strategies of the distribution network operators, both of which may vary in response to changes in regulatory or commercial environment. Consumer funding of generator support schemes are included in the uplift discussed above but the other elements are beyond the scope of this modelling.

In order to provide a simple and very approximate conversion from the prices estimated here to the price a consumer pays without an additional mark-up is calculated to be applied equally throughout the year and in every year. This mark-up is estimated at 4.2p/kWh based on historic prices for 2008.

2.8 Peak and Off-Peak Prices

Peak and off-peak wholesale power prices have been calculated, based upon the current Economy 7 tariff structure where off peak is defined as the period between midnight and 07:00, seven days per week.

It should be noted that the actual peak and off-peak price differential will depend strongly on the overall shape of the demand profile. For example, the modelling provides fairly similar peak and off-peak prices when considering Ricardo’s Overnight charging profile, because the average grid load in these periods only differs slightly. The differential in wholesale power price predicted in the absence of electric vehicles is unlikely to hold in any situation where grid demand shifts predominantly to off-peak.

It should also be noted that the relationship between peak and off-peak consumer prices is particularly affected by the response by distribution network operators and suppliers to the commercial and regulatory environment.

2.9 Electricity Market Reform

DECC are currently consulting on proposals for reform of the electricity wholesale market arrangements (EMR) [9]. As EMR is still at a very early stage with a number of options proposed the modelling reported here has not taken any explicit account of these proposals.

The UKERC modelling work from which their scenario output arises minimised full economic costs across the whole energy system subject to a variety of constraints on emissions of carbon dioxide and including a set of taxes and policies such as the renewable obligation. The UKERC modelling found renewable energy in total falling short of the EU directive target level; one of the specific aims that DECC give for EMR is increasing the level of renewable electricity generation and a variety of feed-in tariff is proposed so there is likely to be some impact in this area. Proposals for support of the carbon price entail additional flow of money from the electricity supply industry to HM Treasury might also change the scenario output. The UKERC CLC scenario has unabated coal being built in 2025 which may be deterred by the proposal of an Emissions Performance Standard. The energy system is too complex to give any reliable estimate of the impacts of such changes without detailed modelling.

E.ON and EDF's modelling of the electricity market took as their objective the minimisation of costs and incorporated the full economic costs into estimation of prices. Therefore, for a given set of generating assets, reforms which effectively re-distribute revenues are likely to have more impact on the distribution of consumer prices through the day than on their overall annual electricity bills. Policy measures increasing or decreasing the overall costs of the electricity supply industry are more likely to feed into annual bills. Changes in the generating asset base as a result of revisions to the UKERC scenarios discussed above would have some impact on prices; here too it is not possible to be specific without more detailed modelling work.

3 MODEL INPUTS

This section describes the pre-processing that has been carried out in order to ensure that, as far as possible, the UKERC data is used in such a way that it appropriately represents the current problem.

3.1 Electricity Demand

The UKERC scenario report and accompanying spreadsheets provide the **annual** total electricity demand, disaggregated into the demand associated with specific sectors (including transport). Annual demands were converted into hourly demand profiles for each:

- UKERC scenario (x 4) – CAM, CSAM, CLC, CCSP.
- Year (x 5) – 2010, 2020, 2030, 2040 and 2050.

- Season (x 3) – Summer, Winter and Spring/Autumn[2].
- Day of the week (x 2) – Weekday and Weekend (including bank holidays and Christmas to New Year period).
- EV demand profile (x 3) – No EV demand, After Journey charging and Overnight charging profile. All profiles are based upon Ricardo's high EV take-up figures.

This conversion involves the following steps:

1. **Adjust total annual demand**. The annual base demand is defined as:

   $$D_{base} = D_{UKERC} - D_{HP} - D_{H2} - D_{dEV} - D_{import},$$

   where D_{UKERC} is the total UKERC annual demand, D_{HP}, D_{H2} and D_{dEV} are the annual electricity demands of heat pumps, hydrogen and domestic electric vehicles respectively, and D_{import} is the electricity originating from overseas. As agreed previously with ETI, the potential for imports and export of electricity has been excluded from the modelling.

2. **Apply demand profiles**. Adjusted total annual base demands are converted to hourly demand profiles by scaling historic hourly INDO demand profiles

3. **Add heating and hydrogen demand**. The project assumes a flat hourly heat pump within-day profile for each season (the seasonal contribution is dependant upon the number of historic degree-days in each season), with the total annual heat pump demand chosen to match the annual figure quoted by UKERC.

4. **Add EV demand profiles**. Each scenario is assessed against three EV demand scenarios: No EV demand, After Journey charging and Overnight charging.

The effect of combining these different factors is summarised in Figure 1. This particular figure combines the winter weekday electricity demand in 2050 for the Carbon Ambition (CAM) UKERC scenario and the three charging patterns outlined above.

[2] E.ON modelling makes use of an intermediate Winter Shoulder season; these periods are subsumed into the Spring/Autumn season in the final averaging.

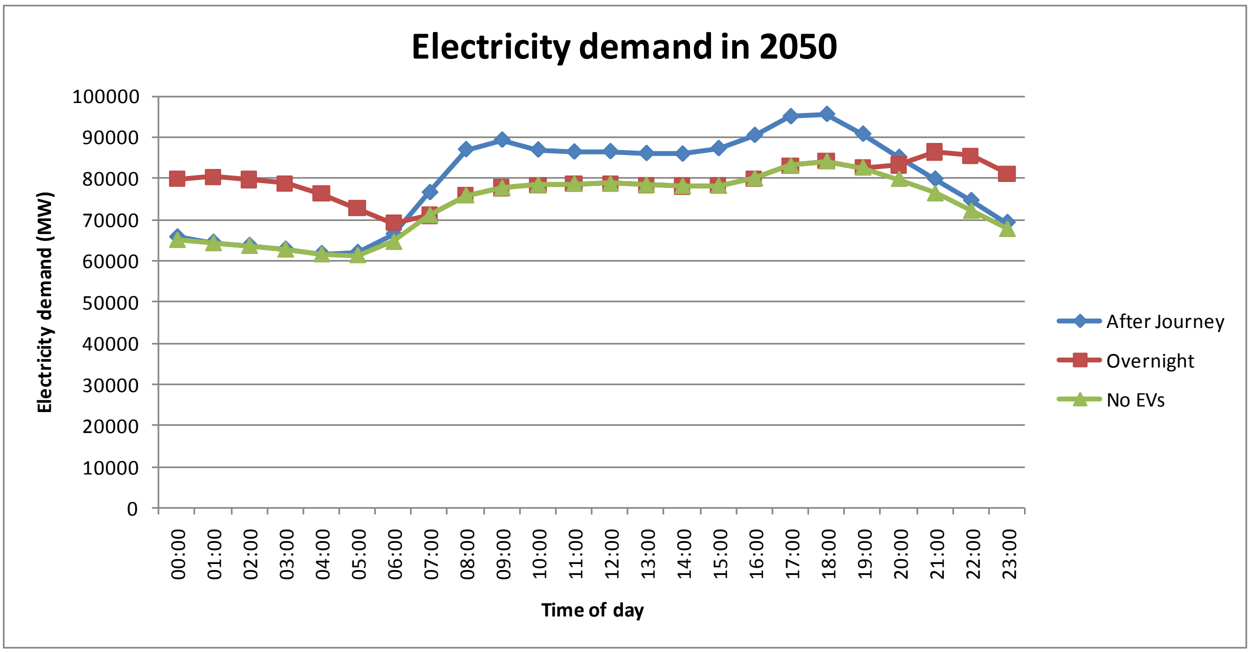

Figure 1: Winter Weekday Electricity Demand for CAM Scenario in 2050 under Three Chosen Charging Patterns

There is a marked difference between the resulting demand shapes. Charging after journey end places most of the additional demand in the peak periods, sharpening the evening peak and inflating the morning step into a slight peak. Overnight charging yields a much flatter overall demand profile and increases the minimum grid demand compared with the No EV and After Journey profiles.

3.2 Capacity mix

Each of the UKERC scenarios quotes an associated capacity mix, and this forms the basis of the plant mix used in the current modelling. Reported generating capacities are made up from a small set of plant categories. These categories are:

- Nuclear plant.
- Unabated coal.
- Coal CCS.
- CCGT.
- Oil/OCGT.
- Biofuel (including energy from waste).
- Wind energy.
- Marine energy.
- Pumped hydroelectric plant.
- Run-of-river hydroelectric plant.

Matching to the near-term assumes that coal plant closes as per the Large Combustion Plant Directive and, following on from this, all remaining FGD coal is closed (or retrofitted with CCS equipment) by 2030. The earliest new nuclear plant comes online according to the current schedule i.e. by 2020, and existing nuclear plant closes according to the current schedule (including the recent AGR life-extensions). The UKERC scenarios all involve an increase in gas plant relative to 2010 levels, therefore it is assumed that any life-extension of the existing CCGT fleet is included within the UKERC plant mix.

In practise each category comprises plant of varying ages and designs and, to reflect this, E.ON and EDF sub-divided some of these categories independently. In addition, a scaling approach was adopted, as described in the previous section.

3.3 Plant Physical Parameters

Plant physical parameters have been taken from Mott McDonald [8]. The figures chosen for use in this project are based upon the quoted "N^{th} of a kind" plant parameters.

Ref. 8 only provides physical parameters for putative new build, meaning that plant parameters for advanced supercritical coal plant are provided but not for sub-critical coal plant. For the purposes of this project, it is assumed that all existing coal is 35% efficient. All of the scenarios have existing unabated coal phased out by 2030, and only the CLC (EG2) scenario includes new unabated coal.

3.4 Commodity Prices

Prices for oil, gas, coal and carbon have been provided directly by Arup [6]. For each commodity, three price tracks have been provided (Low, Medium and High); for oil, an additional Spike price track has also been provided. Fuel oil prices have been assumed to follow the oil price plus ten percent, based on recent publicly available figures [10]. Nuclear fuel costs have been taken from Mott McDonald [8].

Seasonality of gas price has been estimated using the historic relationship between summer and winter prices. Analysis carried out for this project by EDF [11] has found that historically there has been a spread of around 34% in relative terms or 17p/therm in absolute terms, between summer and winter. In the absence of any clearly accepted view on the likely future volatility of gas price, it is assumed that this remains. Applying a relative factor to the high and medium price scenarios provides an unreasonably large spread in the later years, so prices have been modified by the 17p/therm absolute value for the medium and high price scenarios; the low price scenario receives the 34% factor.

Biomass fuel costs have been assumed to be zero. Furthermore, the emissions associated with burning biomass have been assumed to be identically zero. It is assumed that there are no shortages of biomass fuel, permitting biomass to run as baseload throughout the modelling.

4 RESULTS

4.1 Model Validation

As outlined previously, the modelling covers the period from 2010 to 2050 in ten-year steps. In order to assess the general validity of the models, the modelled results in 2010 were compared with observations. Key modelled results are the grid emissions intensity and the wholesale electricity price. Observed values for 2010 were not available at time of writing, so all validation was based on 2009 values. Other than a small change in the amount of wind capacity, these years are similar and therefore comparing with 2009 was deemed to be a sufficient approach to take.

Modelling results using the Arup fuel and carbon prices proved to offer a difference from actual 2009 metrics. Specifically:

- The modelled average grid emission factor was found to be lower than the observed value of 0.45 t CO_2/MWh [5]. E.ON results yielded a result of around 0.34 t CO_2/MWh.

- The modelled wholesale power price was found to be higher than the 2009 value. E.ON results predicted a price of around £44/MWh, while the actual wholesale power price in 2009 was around £40/MWh [12].

Investigation into the first of these differences suggested that the reason for this change was the prevalence in the model for running gas plant ahead of coal. For example, in the Base scenario modelling, coal plant was operating at a load factor of less than 30%, which is well below the observed value of around 50% in 2009. Because the power price depends only on commodity prices and the plant available, the first step in validating the latter quantity was to compare the commodity prices used in the model with those observed.

The validation was carried out by amending the Arup coal, gas and carbon prices to fit the 2009 observed values and re-running the Base scenario for 2009/10 only. It transpires that the actual commodity prices observed showed a larger spread between coal and gas cost per thermal MWh than the 2010 Arup values. The net effect of applying these prices to the model was to increase the load factor of coal plant to around 50%. The modelled grid emissions factor in this scenario increased to 0.414 t CO_2/MWh, which is significantly closer to observations: the additional wind capacity in 2010 over 2009 (roughly 1 GW) is likely to make a small contribution to this reduction in modelled emissions factor compared with the observed value. Wholesale power prices calculated in this run reduced to around £38/MWh.

Further deviations are likely to occur due to factors that are not considered here, such as within-year variations in fuel and carbon prices and plant availability. The opinion of the modellers is that this validation provides evidence that the model performs sufficiently well that the results for future years are likely to be a reasonable representation of the schedule.

4.2 General observations

Numerical and graphical results reported in this chapter are taken from the E.ON modelling work. Section 6 below compares this with EDF modelling results.

Some key general points from the modelling are described below.

- Carbon prices are extremely high in the latter years, and this can lead to high wholesale electricity prices. For example, in the medium price scenario, the SRMC of CCGT plant in 2050 is around £120/MWh, which always places it towards the bottom of the merit order.

- The nuclear plant and wind capacities considered in the scenarios are usually far in excess of the current capacity. Beyond 2030, the next plant in the merit order after these zero-carbon units is coal CCS, and it is very common for coal CCS to set the price much of the time from 2030 onward.

- It is usual for there to be a huge difference between the highest and lowest within-day prices, for example if nuclear plant sets the price at the demand minimum and fossil plant sets the price at the demand maximum. Pumped hydro plant can make extensive use of this differential; in situations where low or zero-cost plant sets the off-peak price, pumped storage tends to operate as much as possible, because it can provide peak electricity at well below the price of unabated gas plant.

- The Medium and High carbon prices offer very little difference in the long-term to the plant dispatch schedule: both are high enough to deliver a strongly carbon dioxide emissions driven merit order. The variation in fuel price is a secondary effect in such circumstances, impacting the power price but not the schedule.

- In the near term, the carbon prices are more conservative and do not generally move coal CCS above gas in the merit order in 2020. In contrast, seasonal fuel price variation does have a palpable effect in 2020 and sometimes 2030, until the carbon price increases sufficiently to nullify this effect. Furthermore, for some scenarios, CCS is actually below unabated coal in the merit order in 2020; the carbon price is too low in the near-term to overcome the depressed efficiency and additional non-fuel variable costs due to CO_2 transport and storage. The modelling assumes generating plant is allowed to run on the basis of SRMC alone and that regulation or other considerations do not impose an effective “must run” constraint forcing CCS coal plant to run before unabated coal.

- Gas price seasonality leads to a strong fuel-switching effect in 2020 and, occasionally, 2030. This is particularly notable in the low price scenarios. The effect of this on emissions is varied, depending on whether unabated coal or coal CCS is displaced in favour of gas. The effect on marginal emissions factor in 2020 and 2030 is similarly varied.

- The oil price chosen makes little difference to the running regime because oil is at the bottom of the merit order anyway. Some electricity prices are affected by oil price in 2020 and 2030, but this is relatively rare, occurring only at the winter peak.

- A general result is that the lowest emissions factor is from after journey charging, followed by no EVs followed by overnight charging. This is a consequence of the scaling approach taken, and is described in the next section.

Narratives describing the plant running regime in each of the scenarios are provided in Appendix A.

4.3 Overall Impact of EV Charging Profiles

As illustrated in Figure 1, the After Journey charging profile leads to an enhanced peak demand around 18:00, whereas the Overnight profile generally provides a flatter within-day grid load. When scaling the UKERC capacity mixes up to match peak demand this therefore means that the After Journey case requires a greater scaling than the Overnight equivalent. **This difference in capacity mix is a key driver in the following trends observed between EV charging scenarios.**

Figures 2 and 3 illustrate how the generation is scheduled to meet demand in a typical winter weekday in the Base scenario in 2050 (After journey and overnight charging respectively). The time of operation of pumped storage can occasionally look unusual – the system elects to pump at times with a specific electricity price (e.g. when Coal CCS is marginal, as in Figure 2), and when there are many different periods that are equally optimal the system chooses these randomly.

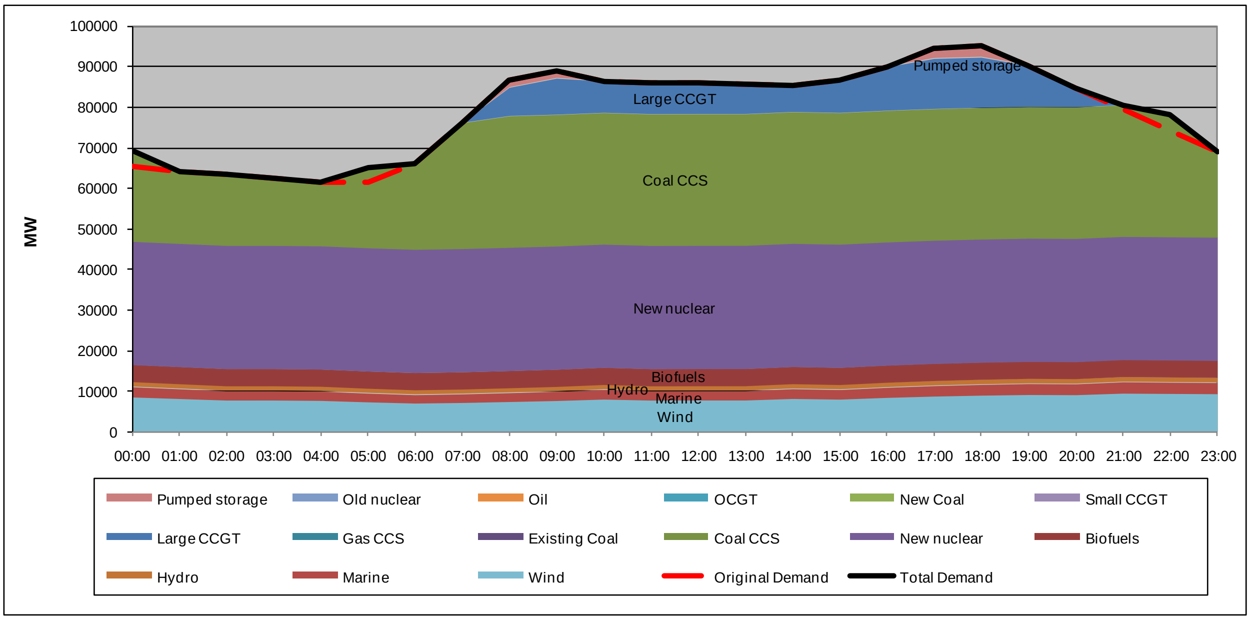

Figure 2: Winter Weekday Demand in 2050 for Base Scenario with After Journey Charging

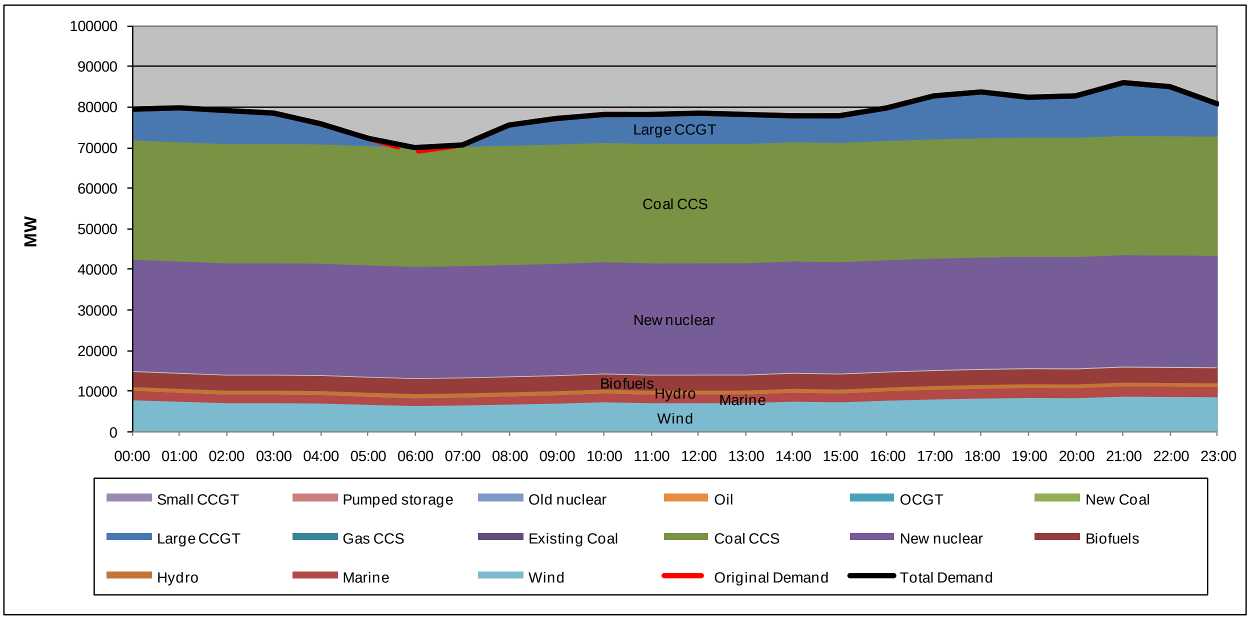

Figure 3: Winter Weekday Demand in 2050 for Base Scenario with Overnight Charging

Key observations from these figures include:

- The relative prices of coal, carbon and gas in this scenario ensure that Coal CCS plant is scheduled before all gas plant in this merit order.
- In the After Journey scenario, CCGTs are only scheduled at peak times, whereas CCGTs are required to run for most of the day in the Overnight scenario because of the lower capacity of nuclear, coal CCS and other cheaper plant.
- This means that CCGT sets the price for the majority of the day in the Overnight profile, while in the After Journey profile there is a more even mix of coal CCS and CCGT at the margin. As a result, power prices in the Overnight profile are higher than in the After Journey profile.
- **The carbon intensity of the electricity generation mix is lower in the After Journey case**. This is because **zero carbon generation is scaled further in the After Journey case** and is therefore able to meet a larger proportion of demand, and, conversely, **the Overnight profile generates a larger proportion of electricity from CCGT plant**.

The demand profile in the absence of EV demand is less peaky than the After Journey profile but more peaky than the Overnight profile. As a result, power prices and carbon intensities for this profile lie between the two EV demand profiles.

These results, and those in the following sections, appear to deviate from the oft-suggested view that charging off-peak is expected to offer lower power prices and emissions than charging at the peak. This seemingly counter-intuitive result is analysed later in this report (section 7.1) – in fact, we argue that this is not a valid conclusion to draw from this modelling.

4.4 Impact on Annual Average Carbon Intensity

Figure 4 illustrates the effect of a change in capacity mix on the carbon intensity of electricity generation in 2050.

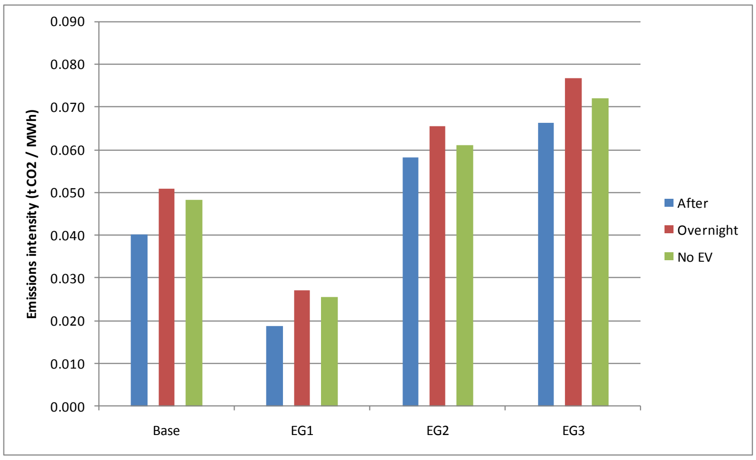

Figure 4: Annual Average Carbon Intensity in 2050 across Capacity Mixes

Key observations from this chart include:

- As already noted: for a given capacity mix scenario, **overnight charging always results in the highest carbon intensity** and **After Journey charging results in the lowest intensity**. This is a consequence of the scaling approach described in the previous section.

- The carbon intensity of all scenarios in 2050 is significantly lower than the current carbon intensity of electricity, which is around 0.45 t CO_2 / MWh. As expected, the lowest carbon intensity occurs in the EG1 (greenest) scenario. Even the least ambitious scenario (EG2) involves aggressive decarbonisation of the electricity sector.

- The EG3 scenario is found to have the highest emissions intensity in 2050. This scenario is associated with early action against emissions (action that is not limited to the electricity industry), allowing emissions to be comparatively high in 2050 while still achieving the required aggregate limit on emissions over the period.

Figure 5 illustrates the impact of different commodity prices on the carbon intensity in the Base capacity mix in 2030 and 2050.

- In 2050, the carbon price is sufficiently high that the merit order is almost completely driven by carbon dioxide emissions. The comparatively small movement in commodity price is not sufficient to change the merit order, and therefore the annual emissions intensity is essentially identical in these three sensitivities.

- In 2030, the T11 scenario is markedly different because the low commodity prices mean that the price order is not yet equivalent to the emissions order. There is still a large seasonal fuel-switching effect present in this scenario.

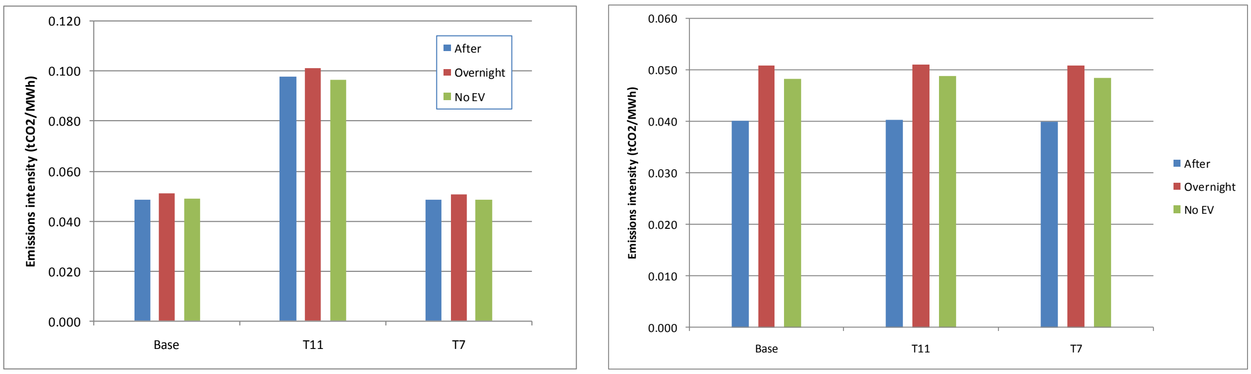

Figure 5: Annual Average Carbon Intensity in 2030 and 2050 across Commodity Prices

Figure 6 illustrates the progressive change in carbon intensity between 2020 and 2050. Some key observations include:

- The carbon intensities associated with commodity price sensitivities (Base, T11 and T7) converge before 2040. After this milestone, the carbon dioxide emissions drive the merit order sufficiently that small fluctuations in fuel price have no material impact on the running order and, consequently, on emissions intensity.

- Scenario EG1 has the lowest carbon intensity through the duration of the modelling – this is mainly due to the large amount of nuclear new-build in this scenario.

- Some scenarios are associated with a slight increase in emissions intensity from 2040 to 2050 due to a large increase in electricity demand in 2050 and also increased CCGT build to balance increased wind capacity. This does not go against the ethos of the UKERC scenarios because the emissions targets therein are based upon the whole energy system, rather than just the electricity sector.

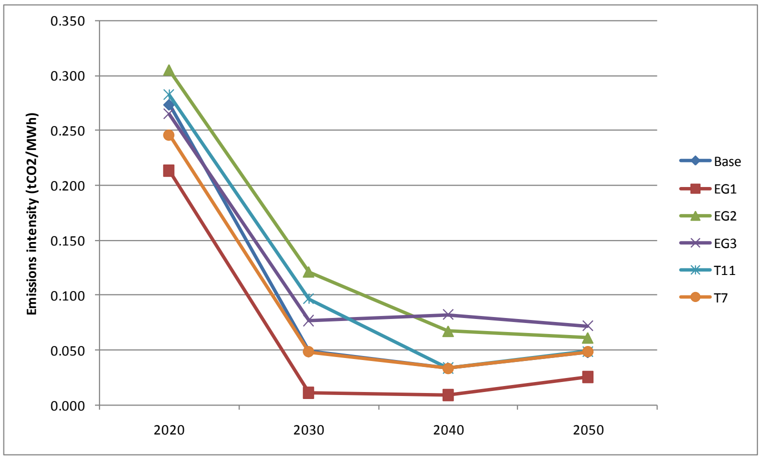

Figure 6: Change in Carbon Intensity across Time (No EV charging)

Figure 7 illustrates the within-day average emissions intensity that is observed in the Base scenario in 2050. The main point of note in this figure is that the emissions intensity generally reflects the shape of the grid load profile – this is because the merit order is completely controlled by carbon dioxide emissions at this point.

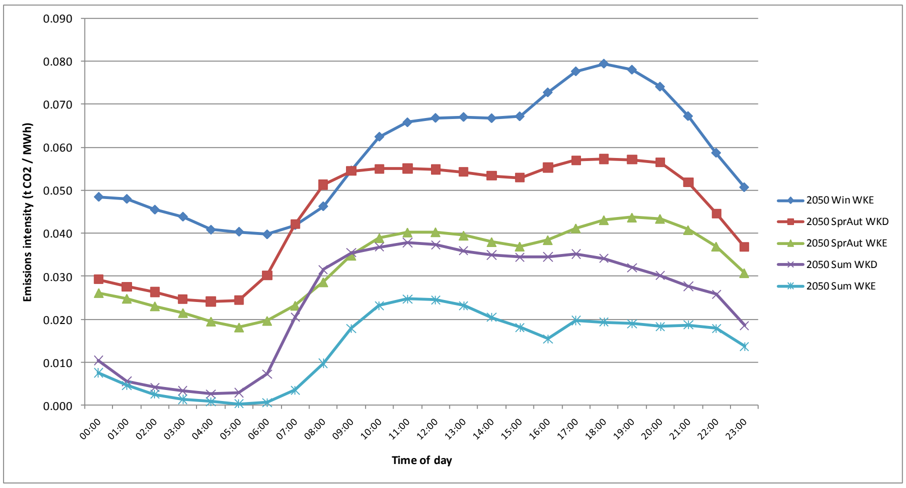

Figure 7: Average Emissions Intensity Profiles in 2050 for each Season and Day Type in the Base Scenario (No EV charging)

4.5 Impact on Marginal Carbon Intensity

Trends within marginal emissions intensity generally reflect those observed in average emissions intensity (Figure 8), albeit with more volatility than the previous results. The reasoning in the previous section remains valid when attempting to understand the trends in marginal emissions factor as well as average emissions.

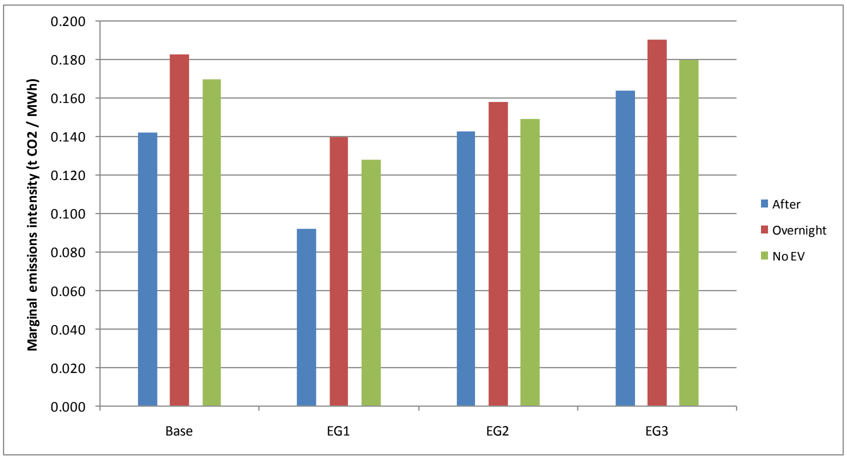

Figure 8: Marginal Emissions intensity in 2050 across Capacity Mixes

Trends in the within-day profile of emissions intensity are less clear-cut. In situations where a strong carbon-driven merit order is in place, the calculated marginal carbon intensity is generally similar in shape to the average carbon intensity. When this is not the case, no clear pattern emerges and the marginal emissions are noisy and results can be non-intuitive. One example of this is that all of the scenarios build a small quantity of coal CCS in 2020, and this plant is marginal for only a tiny window in demand. This can lead to trends in marginal emissions which look superficially quite strange, as the lowest emitting plant sits in the middle of the merit order.

4.6 Impact on power prices

Figure 9 illustrates the impact of capacity mix changes on baseload power price in 2050. Key observations include:

- Generally, baseload power prices follow the ordering suggested by the commodity price track. Scenario EG1 has the highest baseload power prices and scenario EG2 has the lowest prices.
- Overnight charging always offers the highest baseload power price, due to the scaling methodology described previously.
- The comparatively large difference between the three charging scenarios in EG1 results from the fact that this scenario has large amounts of low SRMC plant (nuclear and renewables). Compared with overnight charging, the After Journey profile has more periods where low SRMC units are marginal and price-setting.
- The small difference between the three charging scenarios in EG2 comes from the fact that Coal CCS is almost always marginal, regardless of the level and profile of EV demand.

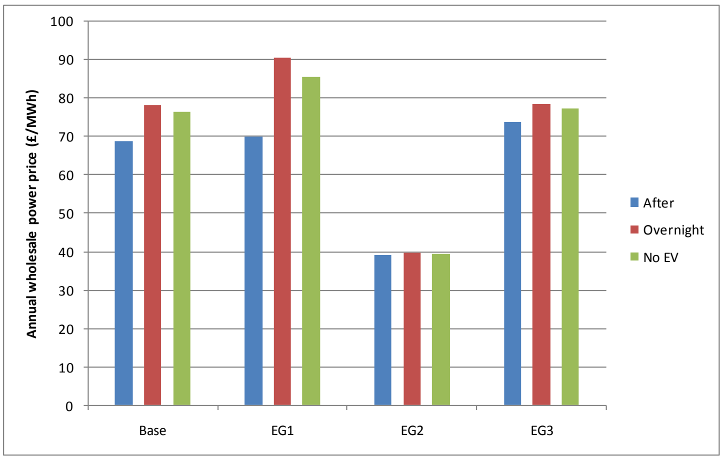

Figure 9: Baseload Power Price in 2050 across Capacity Mixes

Figure 9 shows the impact of different commodity prices on baseload power price. The general trend observed has already been acknowledged: the baseload power price mainly reflects the commodity price track used in that scenario.

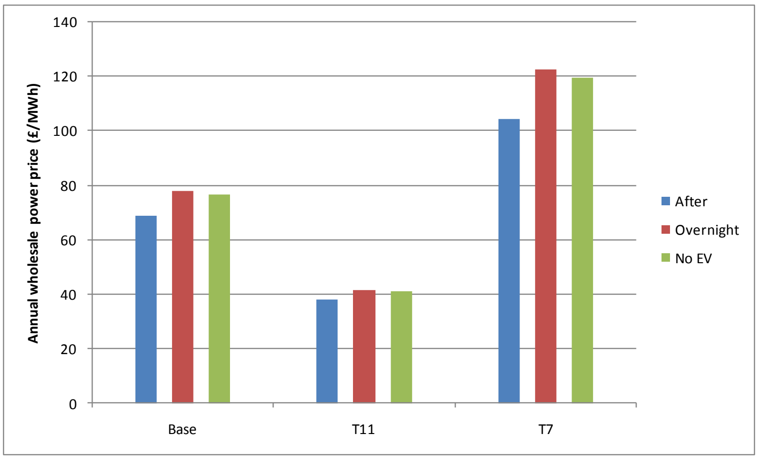

Figure 10: Baseload Power Price in 2050 across Commodity Price Scenarios

Figure 11 shows the variation in baseload power price over time. This figure illustrates the following:

- Scenarios EG2 and T11 provide very similar power prices for the duration of the modelling. These scenarios take the low commodity prices as inputs.
- The deviation between the Base and EG3 scenarios reflects the choice of plant built in these two scenarios. The Base scenario predominantly builds nuclear plant, while EG3 builds Coal CCS.
- A similar effect is present when comparing the EG1 and T7 scenarios in the near-term. The EG1 scenario is associated with high levels of nuclear plant, while T7 has a more balanced mix. This accounts for the marked dip in 2030 for EG1 and the higher prices throughout in the T7 scenario.

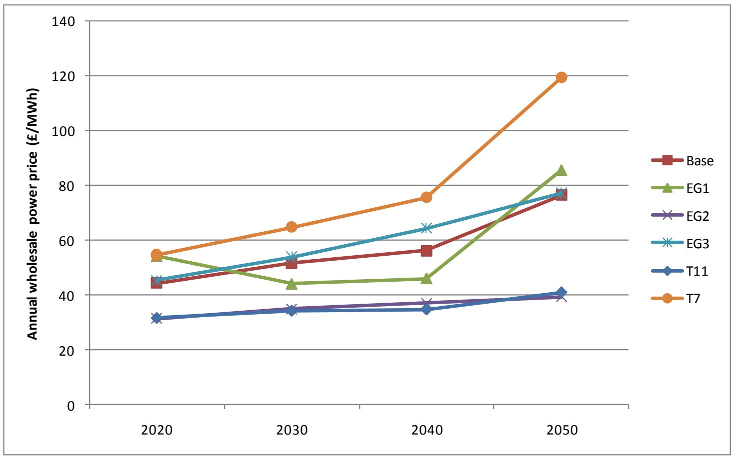

Figure 11: Change in Baseload Power Price across Scenarios over Time (No EV charging)

Figure 12 illustrates the differential between peak and off-peak prices through time for the Base scenario. The charging scenarios offer essentially identical results until 2040, at which point the EV charging demand becomes significant enough to impact upon the prices. Another clear feature is the similarity between peak and off-peak prices in the Overnight profile in the later years, while the After Journey profile and the case with no EV demand exhibit a clear difference in price, and that difference is greater in magnitude than the current value.

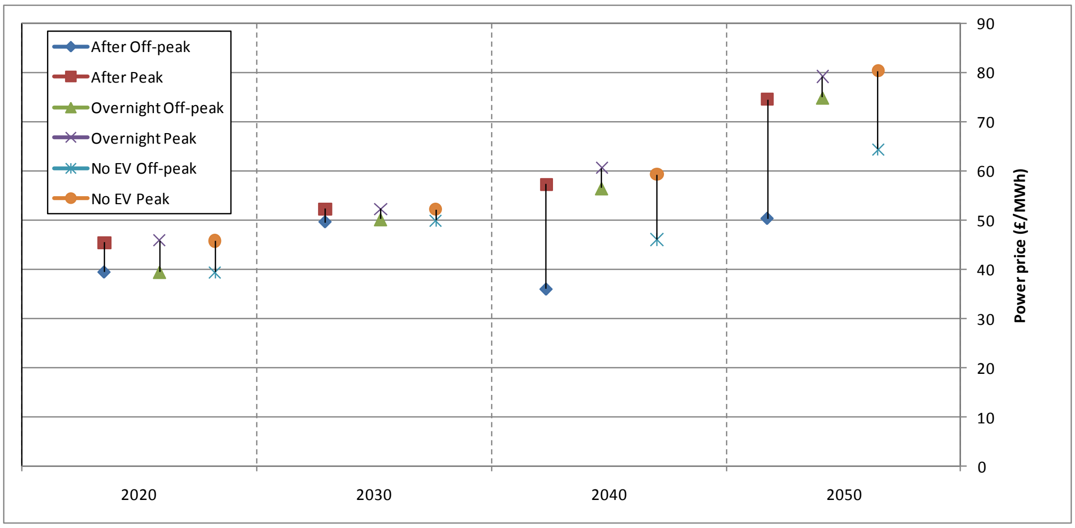

Figure 12: Peak and Off-Peak Price Differential for Different Charging Profiles in Base Scenario

4.7 Price Uplift Calculations

Calculations indicate that, unlike the wholesale price, **after journey charging offers the largest uplift** and **overnight charging offers the lowest uplift**. This is because more expensive plant runs with a higher load factor in the overnight charging scenario and therefore earns more income from generation, requiring a lower uplift to break even. The situation with no EV charging lies between these two extremes.

The size of the uplift in the different demand and capacity scenarios is quite variable – Figure 13 illustrates the relative sizes of the annual average wholesale electricity price, uplift and total annual electricity price for the Base scenario.

The key observation from this figure is that the opposing trends in fundamental price and uplift tend to complement each other in such a way that the total prices of the three charging options actually converge somewhat. There is a tendency for overnight charging to offer a slightly lower total price than the other two options, but the difference between charging profiles is now small – significantly smaller than the difference observed in the fundamental price.

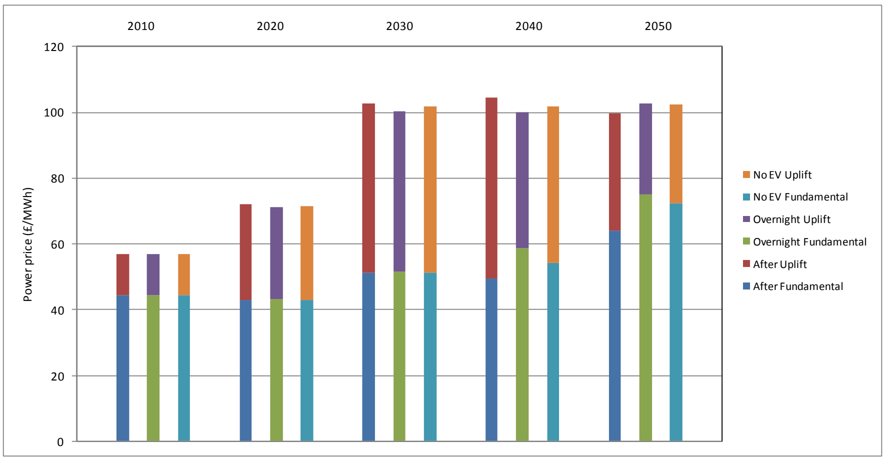

Figure 13: Wholesale (SRMC) Power Price, Uplift and Total Price for Base Scenario

Table 3 contains a summary of the uplift prices for all scenarios and charging profiles. There is a wide variation in the scale of the uplift required – in some cases the size of the uplift is larger than the fundamental price itself.

Table 3: Calculated Uplift for Each Scenario and Modelling Year

Arup Scenario	Charging Profile	Uplift to Wholesale Power Price (£/MWh)			
		2020	2030	2040	2050
Base	After	29	52	55	36
Base	Overnight	28	49	41	28
Base	No EV	28	51	48	30
EG1	After	25	51	60	43
EG1	Overnight	25	43	38	29
EG1	No EV	25	48	50	32
EG2	After	30	64	67	66
EG2	Overnight	30	61	59	58
EG2	No EV	30	63	63	62
EG3	After	33	49	50	47
EG3	Overnight	33	46	41	38
EG3	No EV	33	48	46	41
T11	After	33	62	69	58
T11	Overnight	32	59	58	49
T11	No EV	32	61	64	52
T7	After	26	43	42	26
T7	Overnight	25	41	32	16
T7	No EV	25	42	37	18

Figure 14 illustrates the combination of fundamental and uplift prices for all six of the scenarios modelled herein. Scenarios with the highest fundamental price tend to require lower uplifts because the higher prices offer more potential profit for the non-marginal plant that is running. The result of this is that as well as the prices in different charging profiles, the prices in different scenarios converge slightly.

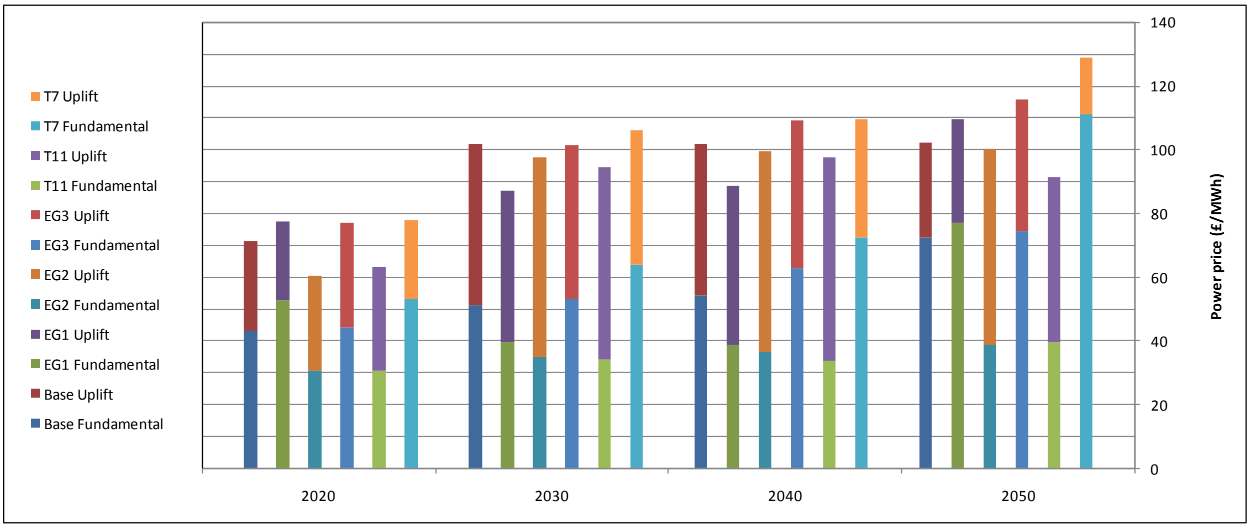

Figure 14: Fundamental Power Price and uplift for all Modelled Scenarios (No EV charging)

4.8 Regression Analysis

Following discussions with ETI and project partners from other work packages, additional outputs have been generated showing the relationships between:

- instantaneous grid demand and emissions intensity, and
- instantaneous grid demand and wholesale electricity price.

Partners therefore have the option of using these to build a simple function into their model which will calculate emissions intensity and wholesale (and, from that, consumer) electricity price from an arbitrary total grid electricity demand however comprised.

The natural technique to produce such relations is to perform regression analysis on the modelled emissions intensity and price. Options explored include fitting a single curve to represent all annual loads and fitting one curve for each season and weekday/weekend. Initial attempts at creating regression curves using some of the modelled results suggested that a linear or quadratic fit is usually appropriate for the current problem.

Figures 15 and 16 illustrate the relationship between grid load and emissions intensity for the T11 scenario – this example is chosen because it exhibits a marked variation in the success of this regression analysis.

- In 2050, a strong carbon-driven merit order means that the relationship between grid load and emissions is consistent throughout the year. In principle, variations between expected wind output between different seasons could lead to discontinuities in the relationship, but this effect is small in this scenario. The regression curve calculated here is a good representation of the relationship between demand and emissions throughout the year
- In 2020, there is a strong fuel-switching effect due to gas price seasonality, meaning that coal plant runs predominantly in the winter while gas plant runs predominantly at all other times. This means that an annual regression curve bisects the seasonal trends. The quadratic term also leads to a sharp reduction in emissions intensity when considering grid loads that are larger than those upon which the regression curve was built.

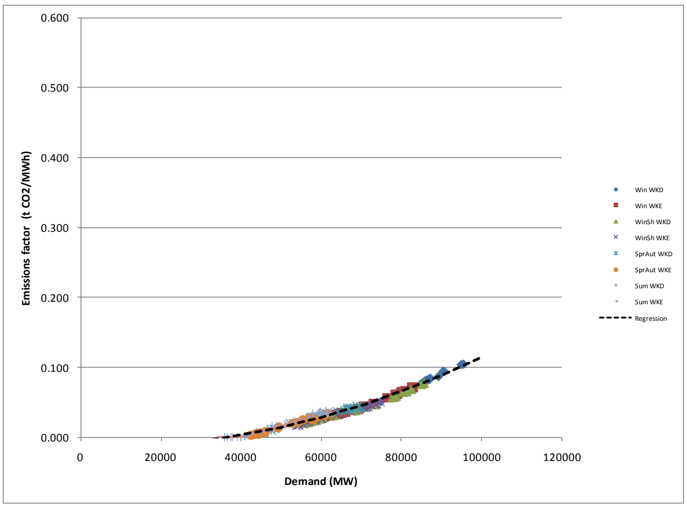

Figure 15: Grid Emissions Intensity Plotted against Grid Load in 2050 for Scenario T11

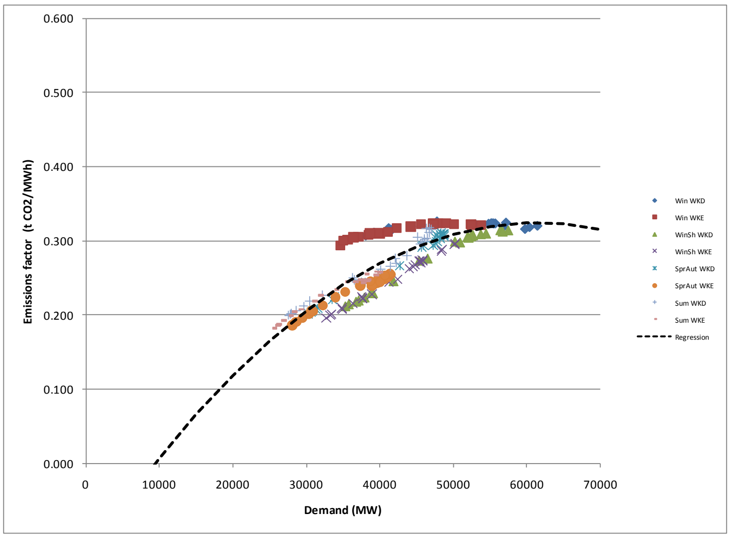

Figure 16: Grid Emissions Intensity Plotted against Grid Load in 2020 for Scenario T11

When attempting to derive a relation between grid demand and wholesale price, it is common that a single price is set for a range of different demands (in the later years, this price often corresponds to the cost of running coal CCS) – this means that rather than following a broadly linear or quadratic form, the price curve is a rotated Z-shape (Figure 17). In reality, variations in heat rate of different plant would act to smooth this curve out but, under the current assumptions, regression fits to price are fundamentally poorer than fits to emissions intensity.

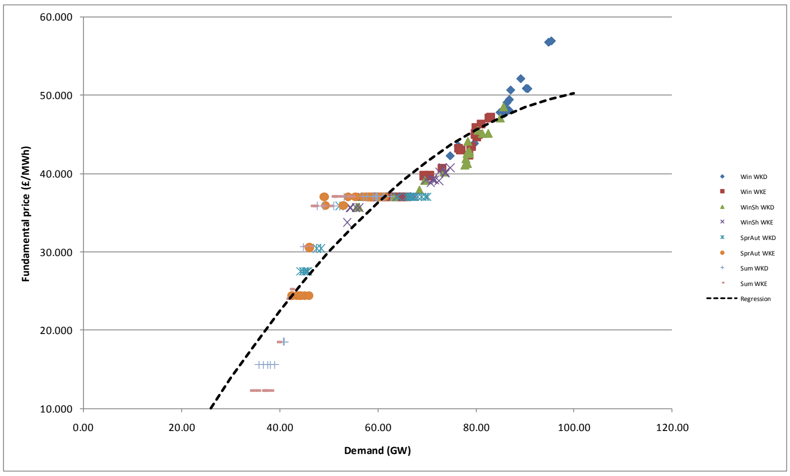

Figure 17: Wholesale Electricity Price Plotted against Grid Load in 2050 for Scenario T11

Discussion around the use of these curves continues in later sections of this report.

4.9 Impact of Choice of Generating Capacity Mix

As an indicator of the impact of choice of generating capacity installed to meet the demand a sensitivity study was performed applying the generating capacity scaled for use with charging after each journey to the case with charging overnight. This illustrates the case in which there is no differential adaptation of the generating fleet to meet the demands of alternative charging regimes. Results are shown in figures 18 and 19 below.

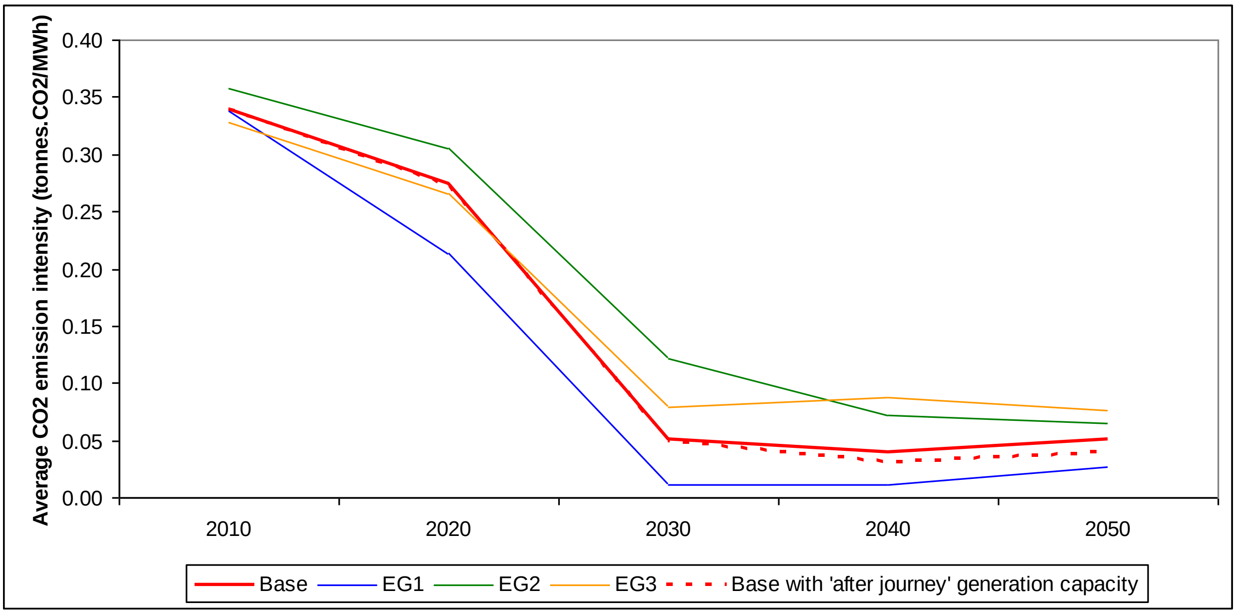

Figure 18: Scenarios for overnight charging - grid emissions intensity

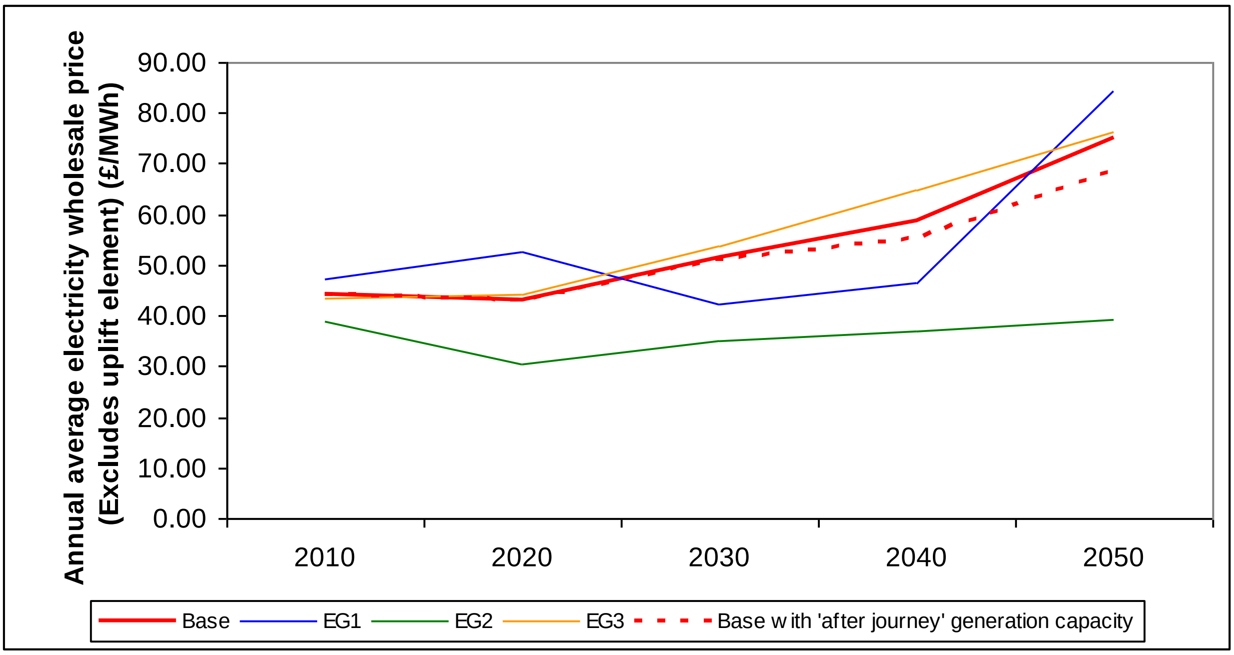

Figure 19: Scenarios for overnight charging - marginal element of wholesale prices

Figures 18 and 19 demonstrate that, in the case studied, this alternative way of adapting the UKERC mix of generating capacity has little impact on either prices or carbon dioxide emission intensity until the penetration of electric vehicles becomes sufficiently large, 2040 in this study, and even then it is less than the impact of the choice of scenario.

Prices based only on the marginal cost element are shown because there are further complications in considering what would be the appropriate treatment of uplift when, using the after journey generation capacity, there is excess capacity in one case and not in the other. It was observed in other scenarios that the addition of uplift tends to bring the prices closer together so would tend to make the impact of charging regime still less significant.

5 COMPARISON WITH DECC PATHWAYS

The initial scenarios report [1] stated that E.ON and EDF would carry out an investigation into the DECC Alpha pathway – a scenario introduced in the DECC 2050 Pathways Analysis [13]. This specific pathway was chosen as it represents a scenario where the main generation technologies are applied in a reasonably balanced manner i.e. coal CCS, nuclear plant and renewables contribute similar proportions of the overall electricity demand. Unlike the MARKAL (whole-energy system) basis of the UKERC scenarios, the DECC scenarios are not based on cost optimisation, but rather the technical ability to achieve carbon reductions under pre-selected build trajectories.

Due to extremely high levels of electrification of heating and transport, the DECC pathways are generally associated with high electricity demands in the long-term. DECC Alpha is no different, requiring over 850 TWh (station gate demand) in 2050. This demand is significantly higher than the highest demand contemplated by UKERC: for reference, the CSAM scenario in 2050 is associated with an annual demand of over 600 TWh. The peak demand implied by such levels of generation is therefore much higher than anything suggested by the UKERC work. Although a large amount of plant is built in DECC Alpha, firm capacity[3] is only around 80 GW in 2050, which suggests that there will be a large shortfall in calm periods. The DECC report suggests that these periods are compensated by increased levels of storage and interconnection, plus a small amount of back-up fossil plant.

DECC Alpha involves considerably more renewable plant than the UKERC scenarios, including over 70 GW of distributed PV generation in 2050. Although such plant can potentially contribute a large amount of electricity, it is not always effective at the highest demand periods without an accompanying level of storage. The E.ON and EDF models would be required to consider periods where renewable output is low but demand is high, and the amount of firm plant available for this is comparatively low.

Furthermore, the levels of capacity scaling required to create a viable plant mix would be larger than in any of the PiVEIP scenarios – a demand in 2050 of 850 TWh corresponds to an average output of around 97 GW, which is already larger than the level of firm capacity available. Assuming that the within-day grid demand profiles scale accordingly – the approach taken in analysing the UKERC scenarios – the DECC Alpha scenario would be associated with peak demands of over 120 GW and the capacity of firm plant would need to be scaled by a factor of almost 1.5 from the starting point in DECC Alpha.

If a capacity scaling approach were still adopted, it is likely that the long-term wholesale prices and emissions intensities would actually be lower than even the most ambitious scenario modelled in this project (EG1). This is because the amount of unabated gas plant available in DECC Alpha (a few GW only) is much smaller than the levels in CSAM (38 GW). This deficit is compensated in DECC Alpha via coal CCS build, which has a cheaper SRMC and lower emissions than gas plant. This means that coal CCS will inevitably run at a lower load factor in DECC Alpha and, consequently, will be subject to a large uplift in order to pay back its annualised running costs.

Because this scenario relies heavily on both exogenous (e.g. electricity imports) and endogenous (e.g. demand-side management) effects to ensure that supply is always available

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[3] By firm capacity we mean that which can be called upon at any time subject only to technical availability. Intermittent sources such as wind and tidal are only available if weather and tidal conditions are right so are not here counted as firm.

to fulfil demand, it is difficult to remove these factors without completely changing the ethos of the DECC Alpha scenario. Given the uncertainties already present in the current work around the effects imparted on the results by the scaling approach, the DECC scenarios were not explored any further.

6 COMPARISON OF E.ON AND EDF RESULTS

6.1 Model Comparison

The details of the modelling are intellectual property of EDF and E.ON and cannot be described in detail here, but some general comments can be made in order to ascertain some of the assumptions inherent to the two models:

6.1.1 Treatment of Demand

E.ON and EDF both used the same within-day seasonal demand shapes and annual electricity demand inputs, avoiding any potentially large differences associated with the location and size of the demand peak. However, E.ON's modelling then applies variations to these within-day shapes to mimic the stochastic variation of demand, while the EDF modelling maintains a static view. This has two key implications on modelling results:

1) EDF and E.ON models require slightly different levels of capacity mix scaling to ensure that demand is always satisfied – EDF's model typically results in higher capacity mix scaling compared with E.ON.

2) Using a Monte Carlo approach and averaging the results from each individual demand simulation (as per E.ON) will always give a slightly different result to modelling the expectation of demand (as per EDF).

This demand fluctuation suggests that the E.ON modelling offers greater variation and therefore a better treatment of the intricacies of the generating schedule; however, it should be noted that there is an implicit assumption that the fluctuations resemble those observed in recent history. In the scenarios under consideration here, having high levels of heat pump and PiV demand, demand fluctuations might look quite different to the present day.

6.1.2 Modelling Wind Intermittency

Both models treat the intermittency of renewables beyond a simple static load factor assumption. The E.ON model treats wind generation as the combination of a finite set of within-day loads and, under this assumption, the most extreme (both highest and lowest) wind output periods are avoided. EDF's model also simulates daily wind output stochastically, conditionally on the time of year. Although the two approaches are similar in line of principle, differences will lie in both these representations of wind output and in the number of Monte Carlo simulations. Variations in the way this wind output is formed are one possible source of differences between scheduling, especially when large amounts of wind capacity are present.

6.1.3 Commodity Prices

Commodity prices were provided by Arup and plant efficiencies in both models were extracted from Mott McDonald [8] therefore there should be minimal differences in plant running costs. There is a slight difference in the choice of gas plant available for the modelling – E.ON and EDF independently split gas plant into several different categories. This could conceivably have a small difference on emissions intensity and price, albeit mainly in the periods where gas plant is marginal. In addition, E.ON elected to disaggregate the efficiency into incremental and no-load heats. This does not have a palpable impact on the outputs from the modelling.

6.1.4 Other

There are some minor differences in terms of nomenclature, for example, E.ON calls "OCGT" one of the gas tranches, separate of "Oil". EDF, instead, called "OCGT" the oil-fired technology. The difference in this case lies on how the technologies have been labelled rather than in their underlying assumptions.

6.2 Emissions Intensity

It is possible to directly compare the emissions intensity calculated from the two models, and a further useful comparison is between the two models and the UKERC annual emissions intensity. As well as providing some insight into the differences between the E.ON and EDF models, this also provides a measure of the kinds of difference between whole-energy system modelling and hourly scheduling modelling that have been observed.

Generally, the trends observed in emissions agree well between the EDF and E.ON models, and both models generally compare surprisingly well with the UKERC emissions factors. Figure 20 provides a graphical view of the types of difference (absolute value) that arise in the Base scenario with no electric vehicle charging.

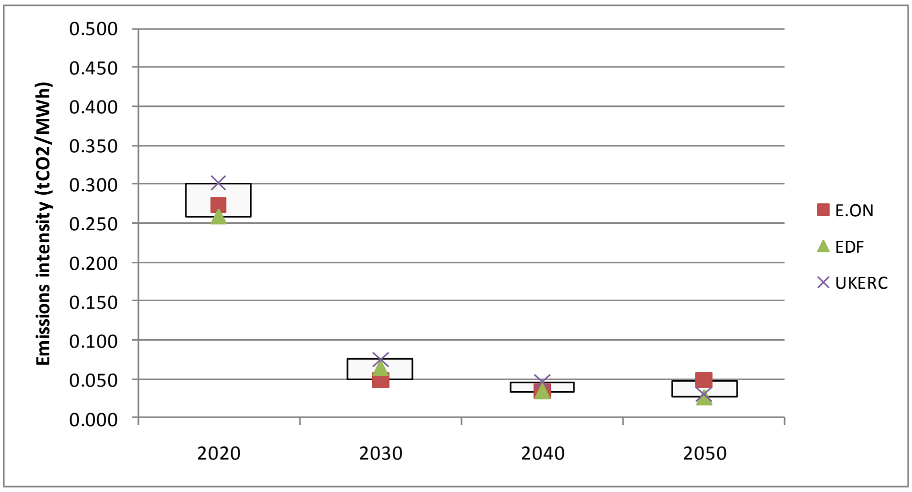

Figure 20: Comparison of Average Annual Emissions Intensity for E.ON and EDF Modelling and Quoted in UKERC Report

Some general differences between the results are:

- In 2050, the E.ON modelled grid intensity is systematically slightly higher than the EDF prediction. This is likely to be the result of systematically higher levels of capacity mix scaling from EDF compared with E.ON. This higher capacity mix scaling means that low carbon renewables and nuclear plants make up a larger proportion of demand in the former than in the latter. It is also possible that this deviation is due to the different way in which the models treat demand, notably the presence of stochastic demand fluctuations in the E.ON model. This effect is most pronounced in 2050 as this year is associated with the largest total annual electricity demand and therefore the peakiest within-day demand profiles, when more thermal generation may be required to come online.

- A fairly large deviation (in percentage terms) between E.ON and EDF results occurs in the EG1 scenario. This scenario is associated with extremely low grid emissions factors from 2030 onwards due to high penetration of wind generation and new nuclear plant. The low emissions factor means that any small deviations necessarily show up as a large percentage difference, and this could conceivably be due to the different way that wind generation is treated in the two models. In absolute terms, the differences between the models in this scenario are small.

- Low price scenarios (EG2 and T11) exhibit a fairly large difference in grid emissions intensity in 2030 of around 0.04 tCO_2 / MWh. The source of this difference is less immediately obvious, but these situations are unique in that they are associated with a strong seasonal merit order shift between winter and summer. The different level of detail associated with the modelling (for example, E.ON modelling of a winter shoulder season and subsequently incorporating this into a larger Spring/Autumn season) is likely to explain some of these differences. E.ON modelling finds a higher emissions factor in this year, which intuitively seems to tally with the additional granularity employed.

- As mentioned in previous reports, the modelled variation between charging profiles is relatively small – certainly smaller than the differences observed between E.ON, EDF and UKERC outputs. Charging profile differences should be considered to be within modelling error and, indeed, a small change in the capacity mix could easily nullify these differences.

6.3 Wholesale Electricity Price

As for emissions intensity, a comparison of the electricity prices predicted by E.ON and EDF offers similar looking trends. A direct comparison with UKERC values is not possible, because electricity price is not a reported output from UKERC.

In this case, although the trends are broadly similar, E.ON modelling systematically predicts slightly higher power prices than EDF. Again, we expect this difference to originate largely from the difference in the capacity mix scaling by EDF and E.ON. The higher capacity mix scaling from EDF compared with E.ON results in cheaper plant being price setting more often in the former than the latter.

Another likely source of difference is the demand fluctuations that are present in the E.ON modelling. For example, fluctuations that drive demand down from the average value are likely to have very little impact on electricity price, while fluctuations upwards could quite conceivably require a more expensive plant to start running. This effect is at its most pronounced in winter, where demand is it its highest.

6.4 Uplift

Both EDF and E.ON followed a similar approach to deriving the cost of electricity uplift (calculated as the difference in the earnings by generator received from the SRMC and earnings needed to cover their annualised capex and fixed costs). However, E.ON uplifts were typically lower on average. Two key reasons for these systematic differences include:

- EDF’s model typically gives rise to lower SRMC power prices that E.ON’s model (as explained in 6.3 above). Higher uplifts are therefore needed to ensure all plant are profitable in the former to compensate for lower earnings.

- As mentioned above, EDF’s model requires a higher capacity mix scaling than E.ON’s model to cover periods of peak demand. Total annual demand is however the same across models, therefore EDF’s model requires a higher level of uplift (per MWh) to subsidise this additional generation capacity.

Another slight difference arises from the different plant types used in the modelling. E.ON used a slightly larger number of plant categories, meaning that it is easier to segregate existing and new plant in the E.ON model. This also contributes to the lower uplifts arising from the E.ON modelling.

6.5 Conclusions from Comparison of EDF and E.ON Modelling

No significant differences were found between the modelling EDF carried out and that performed by E.ON. Partly because of the slightly more detailed representation of the market in the E.ON model and partly for practical reasons, the E.ON and EDF modellers agreed to treat the E.ON results as their consensus estimates. The difference between them gives an indication of the scale of modelling error that should be expected to be present.

7 DISCUSSION

7.1 Impact of Charging Profile and Capacity Mix

The impact of choice of charging profile for plug-in vehicles observed in this modelling was somewhat contrary to that expected by the modellers. The counter-intuitive observation that grid emission factors are slightly lower for charging after each journey rather than overnight needs some careful consideration before drawing any conclusions from it.

As noted above, the installed generation in the UKERC scenarios was not sufficient to supply demand once the loads from plug-in charging modelled within this project were applied. Indeed, because of the more detailed modelling of hourly electricity demands throughout the year and variability due to weather and wind speeds the UKERC generation was not sufficient even in the case with no plug-in vehicle demands.

The assumption was made that the uptake of EV’s and their charging profiles would evolve gradually over the years, thus giving the electricity supply industry the time to respond and invest in new capacity. As noted above, this was done in such a way as to stay as true as possible to the capacities within the original UKERC scenarios – by scaling all capacities up proportionally. This is in accord with viewing each UKERC scenario as being defined by its mix of capacities and overall electricity demand, rather than their target carbon dioxide emissions profile.

It should be understood that alternative methods for increasing the installed capacity could have been adopted such as assuming that all additional capacity was gas-fired CCGT. It is not possible to second-guess what the impact of increased peak demands would have been on the results of the UKERC model runs as their model encompasses a much wider scope, however, the results of some very simple modelling to explore the impact of a cost-minimising adaptation of generating plant are reported in appendix E.

Examination of annual results (Figure 4 to Figure 10) shows variations in carbon intensity and power prices across years, different plant capacity mixes and commodity price assumptions to be far more significant than variations across different EV charging profiles. When the costs to the consumer represented by wholesale price plus uplift are considered the difference between charging profiles is less marked still and the previous tendency for overnight charging to yield higher prices is generally reversed. Comparisons between the E.ON and EDF modelling results indicate that subtle differences in the models used result in larger differences in annual emission factors than those seen between charging profiles.

The modelling results can be understood to tell us that, with the approach to decarbonisation of electricity implicit in each UKERC scenario, and with the commodity prices supplied, emission factors and prices could be expected to lie within the range shown by the results for the three charging profiles modelled. It suggests that the impact of charging regime will be small but does not allow any firm conclusions to be drawn about their relative merits.

The simple modelling of least-cost choice of generating technologies for 2050 reported in appendix E suggests that there is in fact a small advantage in cost to the consumer from overnight charging and a more substantial benefit in terms of reduced carbon dioxide emissions. However, this latter is only achieved in some scenarios and depends in particular on the mechanism used to encourage low carbon electricity generation.

Within-day price and emissions intensity figures have also been calculated for each season and weekday/weekend. It should be noted that these figures have been derived on the assumption of a particular grid load profile, and the argument outlined above suggests that discriminating between different load profiles goes beyond the accuracy of the modelling carried out here. This, combined with the different base demands present in the different UKERC scenarios, leads us to recommend that the within-day metrics be used only with extreme care. In situations where the additional EV load is small, these metrics may be used, as long as it is accepted that the within-day grid load shape used in the E.ON/EDF modelling is fixed and immutable.

7.2 Peak and Off-Peak Prices

It has been noted that the differential between calculated peak and off-peak prices is smaller than that currently observed in commercially available Economy 7 tariffs. Although this observation is true, it is based upon a comparison of modelled wholesale prices and retail prices. Retail prices are affected by a number of different factors, both technical and strategic: for example, distribution service operators levy a different charge for day and night electricity.

Because the calculated peak and off-peak power prices are based upon a specific load profile, the modellers suggest caution if attempting to use these prices to analyse an arbitrary EV charging load – with a sufficiently high load, the capacity mix will adapt to ensure that all demand is fulfilled. As before, it is recommended that an annual price is used where possible, as using the peak and off-peak prices may lead to trends in prices that would not be observed for a specific EV charging profile.

It was suggested previously that a price premium of 4.2p/kWh should be applied to convert between wholesale (total) power prices and consumer prices. This premium is based upon an annual average, and in reality the premium will vary with the time of day – in fact, a more detailed calculation of the price uplift to convert between fundamental and total power price would also exhibit some time of day differences. This complexity has not been explored in this project.

7.3 Application of Results via Regression Analysis

Although linear and quadratic fits have been produced, inspection of the modelled regression results and consideration of the potential impact if they are used shows that they suffer from two significant problems:

- Firstly, any single regression curve can only be based on a single set of generating plant yet it is likely that the generating plant will adapt over time to better supply the demand now being postulated. Since the modelling here does not support quantification of differences between overnight and after journey charging, and the hourly demands change quite substantially between those two cases, neither does it support estimation of grid emission factors or prices from a random alternative set of charging loads.

- Secondly, even with a given set of generating plant, there is no theoretical reason why these functions should be single-valued in either direction; indeed there are good reasons to expect the same demand at different times of year to give yield different values and a single price or emission factor to apply at times of quite different demand. Furthermore, in situations where the merit order is not equivalent to the order of plant carbon dioxide emissions, the best-fit function is often a non-monotonic function of demand. This means that applying the regression outside of the range of demands upon which the fit was built can lead to nonsensical results.

The arguments lead to the suggestion that that these regression curves, if used at all, are **only used for estimating small deviations**, say of no more than 2 GW, away from a known scenario and the modeller must be clear that they are estimating the impact assuming no changes to the generating plant. Using these curves for large deviations is likely to overstate the impact of plug-in vehicle demand on prices and emission factors in the long term. Using seasonal regression curves instead addresses the second point made above, but the first point remains.

7.4 Additional Insight into UKERC Scenarios

This detailed electricity market modelling of the UKERC scenarios has demonstrated a weakness in the results of this kind of whole system economic modelling but validated a key finding.

The detailed modelling of the hourly electricity demand in this present study found the generating capacity used in the original UKERC scenarios to be insufficient to fulfil peak demand. Taking the UKERC scenarios without any PiV demand as baseline, by 2050 we still required around a 5% increase in capacity in order to meet peak demand – this is despite dropping their annual electricity demand by around 15% by removing the quoted UKERC PiV load. This suggests that long term energy system models like MARKAL can understate capacity, and hence investment, requirements by as much as 20% although more detailed analysis of differences between this present study and the UKERC 2050 MARKAL studies is required to substantiate that estimate.

This is likely to be a general feature of such wide scope models unless specifically allowed for in some way. Policy makers should therefore be wary of a potential under-statement of the capital investment required to achieve scenarios produced from such models.

With the generating capacity increased by scaling so as to preserve the relative capacities of each type of generating plant the average carbon dioxide emissions intensities were estimated to be very close to those in the UKERC scenarios. Thus, with an appropriate adjustment of investment in assets, the carbon reductions shown by the UKERC scenarios would be achievable.

8 RECOMMENDATIONS FOR USE OF RESULTS

i. Cost of electricity and carbon intensities should <u>only</u> be taken from the No EV demand scenarios. We do not recommend using figures from scenarios with EV charging overnight or at peak.

In this modelling exercise, additional EV demand was met by linearly scaling up individual UKERC capacity mixes. This approach was chosen to ensure capacity mixes remain as consistent as possible with individual UKERC scenarios. A consequence of adopting this scaling approach is that it overlooks the possibility that the capacity mix evolves in a more cost effective way to meet different demand profiles.

Provided the change to demand is gradual, the electricity mix may evolve differently with a flat GB demand profile (resulting from significant off-peak EV charging), compared to a “peaky” demand profile (resulting from significant peak EV charging). For example, whereas in the former, it may be more cost effective to build large quantities of baseload generators (e.g. Nuclear, Renewables, Coal CCS), in the latter peaking generators (e.g. OCGT) may be more cost effective investments.

This difference in potential evolution of the capacity mix was not captured in this modelling exercise and requires a different modelling approach to be assessed in more detail. A proposed approach to assess the impact of different EV charging profiles on the cost of electricity and carbon intensity is outlined in Section 9 and results of a very simple model along those lines are reported in appendix E.

In order to avoid drawing false conclusions from these differences in EV demand profiles, we recommend that users assume there to be no difference in the cost of electricity and carbon dioxide emissions of charging EV’s overnight or at peak. These parameters should therefore be taken from the No-EV demand scenario for each year and ARUP scenario.

The evidence from the market modelling results reported above and the simple investment modelling reported in appendix E indicate that this is a reasonable approximation in terms of the wholesale element of consumer prices. The choice of charging regime may have a more significant impact, proportionally, on carbon dioxide emissions from electricity generation in some scenarios; this recommendation represents the best available estimate.

ii. Within day profiles (including regressions) for cost of electricity and carbon intensity should only be used for low levels of EV demand (circa 2 GW). For larger levels of EV demand, we recommend using a single annual average figure.

A consequence of the first recommendation above is that these within day profiles can only be used for relatively low levels of EV demand. With larger quantities of EVs the impact on the national demand shape will begin to be significant, therefore impacting the within-day shapes for the cost of electricity and carbon intensity. For example, a flat demand profile (due to overnight EV charging) will give rise to a flatter cost of electricity and carbon intensity than if EVs were charging at peak.

Using these profiles for large quantities of EVs will result in an exaggerated benefit of overnight charging compared with peak charging.

In order to avoid this exaggerated benefit, we therefore recommend using a single annual figure for the cost of electricity and carbon intensity of EV charging. This approach would, in effect, altogether neglect the impact of different EV charging profiles on the wholesale cost of electricity and carbon intensity of EV demand. The impact of different charging profiles will, however, be picked up in other areas of this study (e.g. network reinforcement costs – SP2).

iii. We recommend using average carbon intensities when evaluating the carbon intensity of EVs.

To assess the consequence for carbon emissions of an increased uptake of electric vehicles in the long term the ideal measure would be an estimate of marginal increase allowing for re-optimisation of the generating fleet. This is not available from the market modelling undertaken in the bulk of this study but would require a more sophisticated and comprehensive exercise along the lines of the modelling reported in appendix E.

Marginal carbon intensities estimated from the market modelling have the implicit assumption that any new plant required to meet the increase in demand is of the same kind as the highest cost, and usually highest carbon intensity, plant currently on the system. A more rational assumption would be that new plant similar to the average generators on the system is built.

Average carbon intensities therefore represent the best approximation available.

iv. The observed grid emission factor for 2009 should be used as an estimate of 2010 rather than the model output.

For 2010 the fuel prices within the ARUP scenarios were significantly different to those actually encountered. As discussed above, the impact on power prices is not too great but the impact on emission factors is considerable.

9 OPTIONS FOR FUTURE MODELLING

9.1 Modelling the Impact of Different EV Demand Profiles on Wholesale Cost and Carbon Dioxide Emissions Intensity of Electricity

Should there be interest in furthering the ETI's understanding of the impacts of different EV charging profiles on the cost and carbon intensity of electricity generation, we recommend exploring flexible EV demand as part of a wider study on demand side management (DSM). EV demand is just one of many power demand sources which could help to balance the UK electricity system in the future and investigating EV DSM in isolation would only capture part of this topic.

In this *Plug-in Vehicle Economics and Infrastructure project*, DSM was restricted to static peak and off-peak EV charging. A study focussed specifically on DSM could explore "smarter" forms of DSM in real-time. This may include, for example, balancing intermittent generation or providing back-up services to the UK system operator (National Grid).

In order to assess the impact of increased DSM on the cost and emissions intensity of electricity generation, a two phased modelling approach could be adopted:

1) **Demand model:** Breaking down demand into appropriate segments, this study could develop a model of future UK electricity demand at an hourly granularity, including assumptions on temperature sensitivity, flexibility to shift load and forecasts on future uptake of DSM technologies. This study could also potentially include modelling balancing and reserve services.

2) **Power generation model:** Using these representations of the future electricity demand shape, the study would employ an optimisation model to meet this demand at lowest cost. Options for the choice of model to use are discussed in the following section.

This study could be a logical extension to this study on the economics and carbon intensity of EV charging, Project ESME and other ETI energy storage projects.

9.2 Modelling Investment in Generation Assets

In this current study market models were employed which take the generating assets as given. These models are very good at estimating power prices and the detailed scheduling of generators which gives rise to emissions intensities. However, they are not able to model investment in and closure of assets and hence the long term impact of large changes in electricity demand patterns such as that arising from charging of electric vehicles.

Broad scope economic models such as MARKAL are good at modelling investment decisions to minimise whole system costs but do not represent any single industry in as great a detail, and here that is shown to understate the assets required, nor do they naturally estimate prices.

Marrying the two requirements is not a trivial exercise but has been successfully achieved in models such as the BALMOREL model developed for the Baltic market. A new study could develop a power investment model capable of estimating prices and emission intensities learning from the methods employed by BALMOREL and elsewhere. Inputs into this optimisation model would include: demand parameters from demand model above (i.e. an hourly demand shape, flexibility of demand), commodity prices, generator build rate constraints and plant-by-plant characteristics (economic and physical). It may also be desirable for this model to include costs associated with network upgrades but this may make it overly complex.

10 CONCLUSIONS

This report describes the results of detailed modelling of six chosen PiV scenarios. This modelling has investigated the way in which future electricity demand could be met for a set of different capacity mix and commodity price scenarios. The modelling explores two types of PiV charging profile – After Journey and Overnight – plus a profile with no additional EV demand. The key metrics from this work are:

- Average and marginal emissions intensity, by time of day, day type, season and year.
- Wholesale power price, by time of day, day type, season and year.
- Annual demand-weighted wholesale electricity price.

Initial modelling 2010 using the fuel prices provided by ARUP gave results at variance with observations, which were mostly for 2009. However, much of that variance was shown to be a consequence of the fuel prices used and the variance was much smaller when prices closer to those actually observed were used.

Comparison of the results of modelling by E.ON and EDF showed the differences to be small. This gives some additional comfort on the validity of the models and allows the E.ON set of results to be adopted as the consensus view from this combined work.

Furthermore, once installed capacity is adjusted to cope with the more onerous conditions in this detailed market modelling, the average emission intensities are found to be close to those estimated by UKERC for their scenarios. This provides some additional validation of the feasibility of the UKERC results, but subject to greater investment in generation assets than they allow. The apparent under-statement by MARKAL modelling of the investment required in generation assets should be noted by policy makers and energy system modellers.

Assumptions in the DECC Alpha pathway are found to be too far removed from the modelling here to allow direct comparison but it is clear that much of the generating plant, including coal with CCS, would be running at lower load factors in DECC Alpha so likely to require more support from revenue streams other than wholesale prices.

The process of adapting UKERC capacity mixes to the specific conditions under each charging profile, allowing for slow evolution of the generating plant, leads to some results which are at first sight anomalous. However, more detailed examination shows the results to be entirely rational and the conclusion to be drawn is that the charging profile has little impact on prices or emission intensities in the long run if generating plant is allowed to evolve. The choices of scenario variables, such as level of wind turbine installation, and of fuel and carbon prices have far greater impacts.

The market modelling which forms the bulk of this study suggests that charging profile has less impact on the wholesale element of consumer prices and on grid electricity carbon intensities than the scenario variables: mix of generating plant and fuel and carbon prices. Use of a simple investment model applied to 2050 alone supports that view for prices but suggests that overnight charging may reduce carbon emissions, the magnitude of the benefit depending on the scenario. More sophisticated modelling of asset choices would be required to provide firmer estimates.

Some initial thoughts are presented on the form such a model might take, combining the more detailed market modelling of the E.ON and EDF models used here and the optimisation of investment decisions over time included in MARKAL. Developing such a model would be a significant undertaking.

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APPENDIX A

Scenario Narratives

A1 Base Scenario

The Base scenario is based on the UKERC CAM capacity mix in conjunction with Arup's Medium fuel and carbon prices. As has already been discussed, although these prices are labelled as Medium, the carbon price reaches a value of £200 per tonne in 2050, and this is sufficiently high that the merit order in the later years is generally driven by the plant emissions intensity. Apart from oil, fuel prices remain fairly close to 2010 values in real terms throughout the duration of the modelling.

A1.1 After Journey Charging

Figures 19 through 26 illustrate the mix of plant that satisfies demand on a typical winter weekday and a typical summer weekday for the After Journey charging profile. Note that the modelling included a number of such days for each season with varying wind conditions so "typical" is not here the same as "average".

The Total Demand line differs from Original Demand due to any additional demands due to pumping at storage plant.

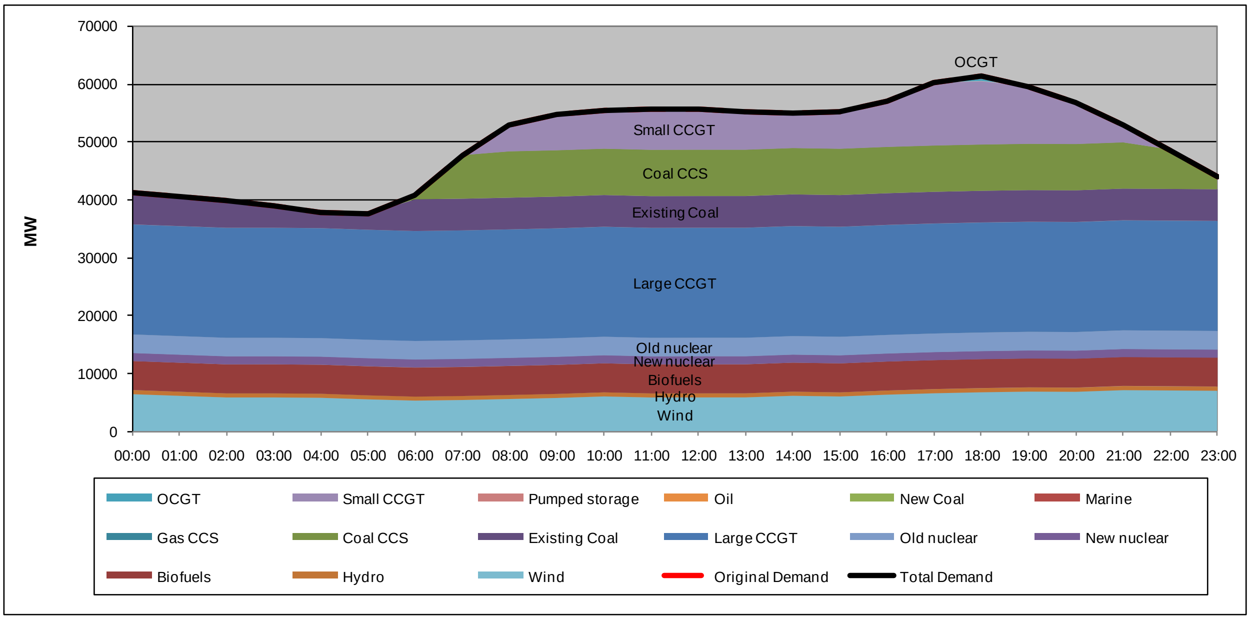

Figure 21: Winter Demand in 2020

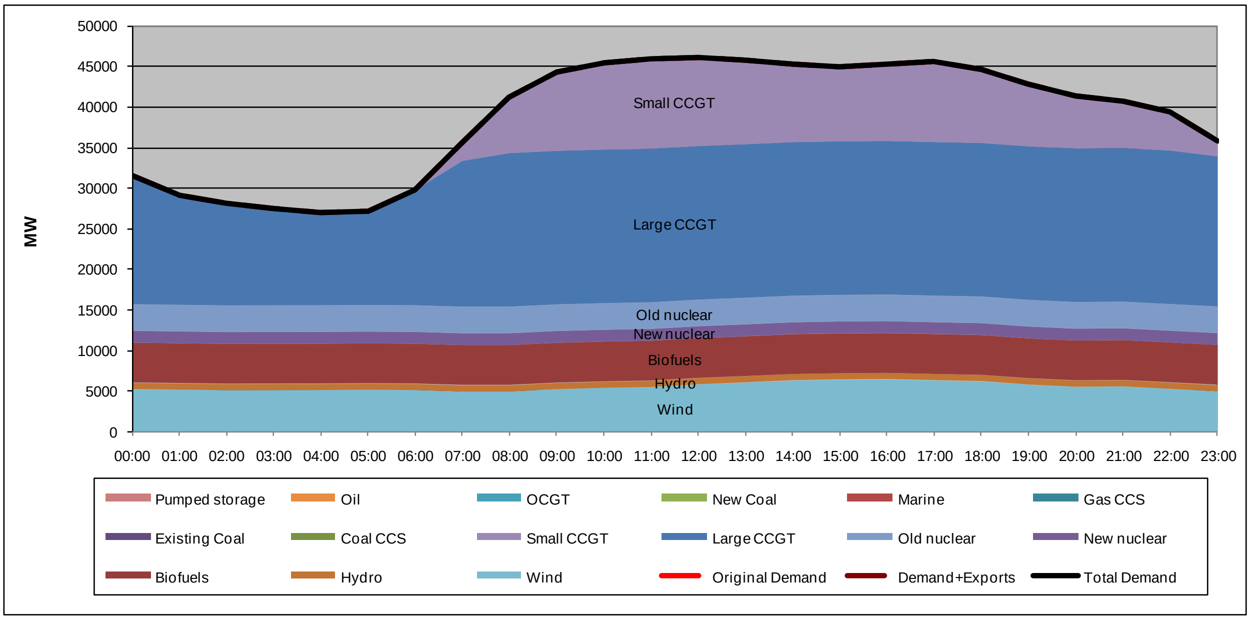

Figure 22: Summer Demand in 2020

In the winter of 2020, coal and gas plant are fairly close in price, with large CCGT running in preference to all other fossil options. The efficiency losses from carbon capture are not yet countered by the still-low carbon price of £16/t CO2, and so coal CCS runs after unabated coal but before the smallest (and least efficient) CCGT plant. The net result of this is that the emissions factor actually begins to flatten when grid load increases sufficiently that CCS plant is required to run.

In summer, lower gas prices mean that CCGT plant is much cheaper to run than coal plant, with CCS lying completely dormant and unabated coal only occasionally brought online to satisfy peak demand.

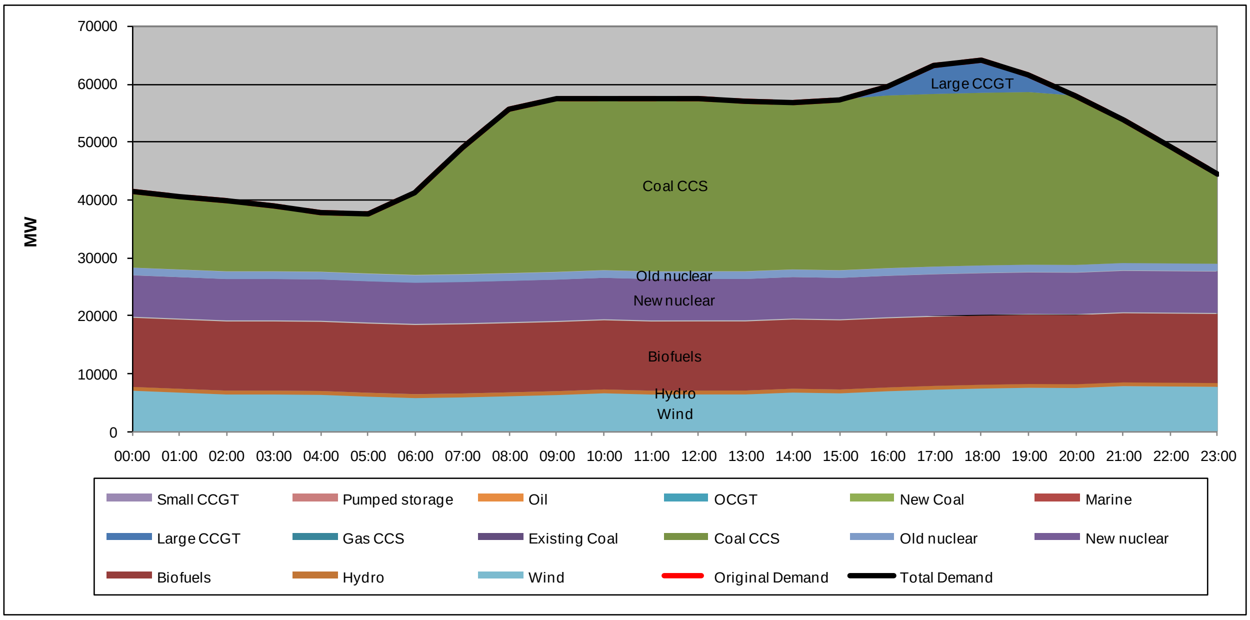

Figure 23: Winter Demand in 2030

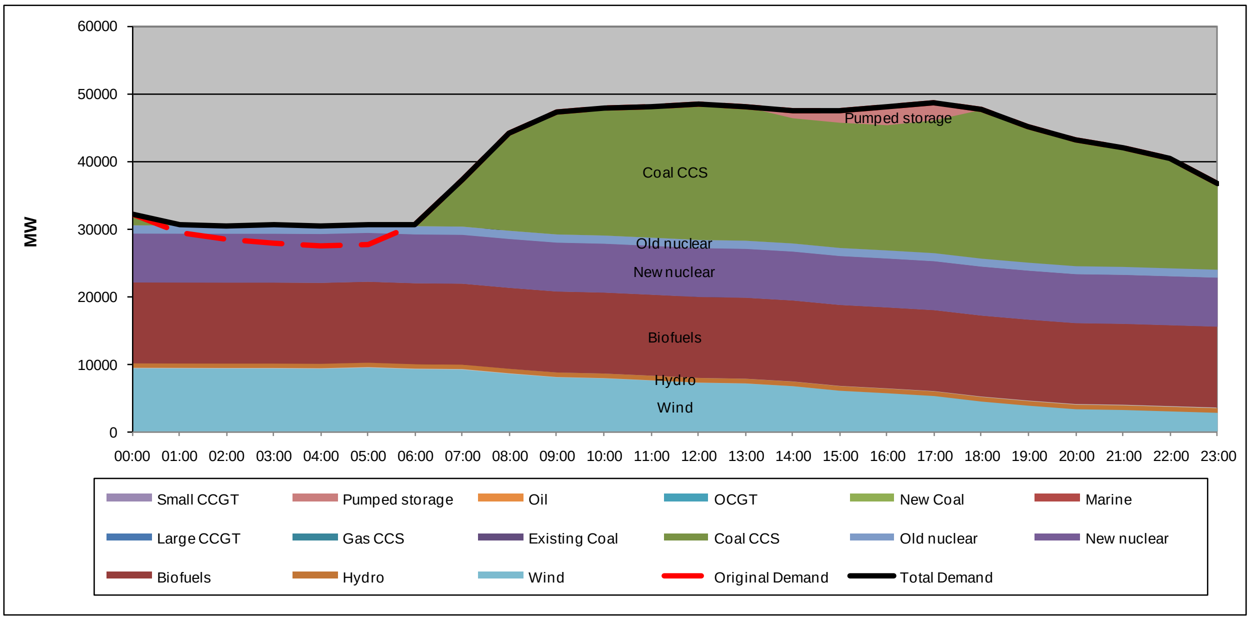

Figure 24: Summer Demand in 2030

In the winter of 2030, a strong carbon-driven merit order first occurs, with coal CCS setting the price much of the time. Unabated gas plant (even the largest CCGT units) is used for peaking only.

In the summer, the same merit order is implied, even accounting for the shift in gas price. The overall grid demand is sufficiently low that gas plant is not required to run at all. It is interesting to observe the role of pumped hydro plant in this period. The low demand periods are associated with an extremely low wholesale electricity price with the price being set by nuclear plant, and pumped storage can make use of these cheap prices to undercut unabated gas plant and avoid backing off nuclear plant. This theme continues through the following decades.

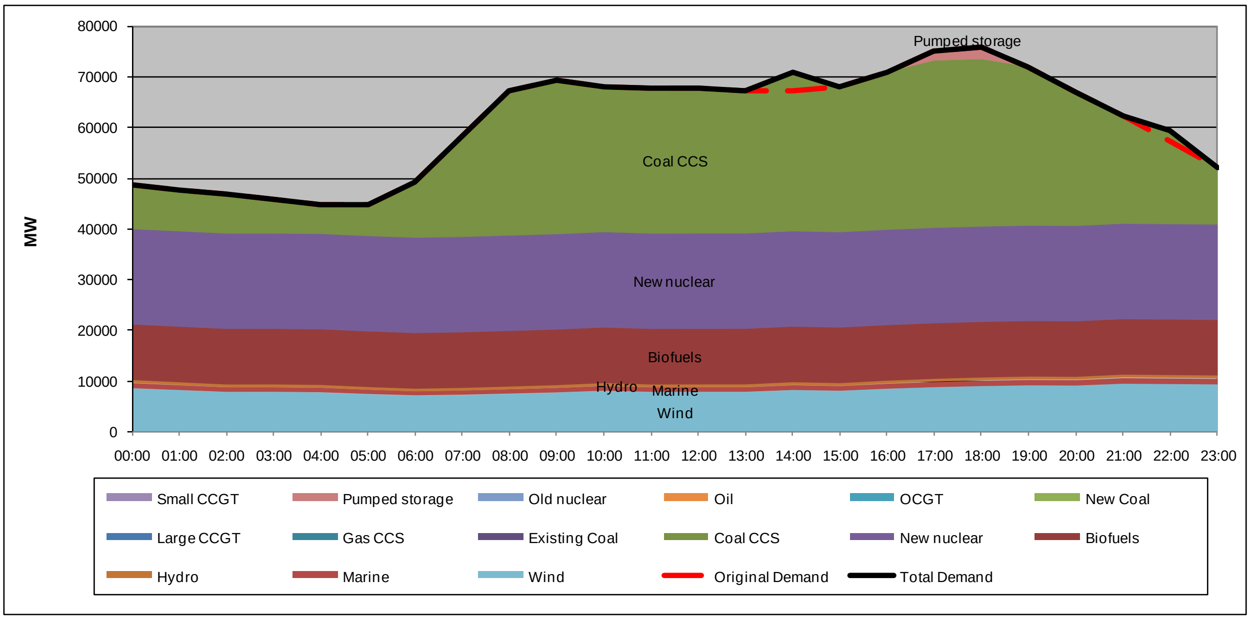

Figure 25: Winter Demand in 2040

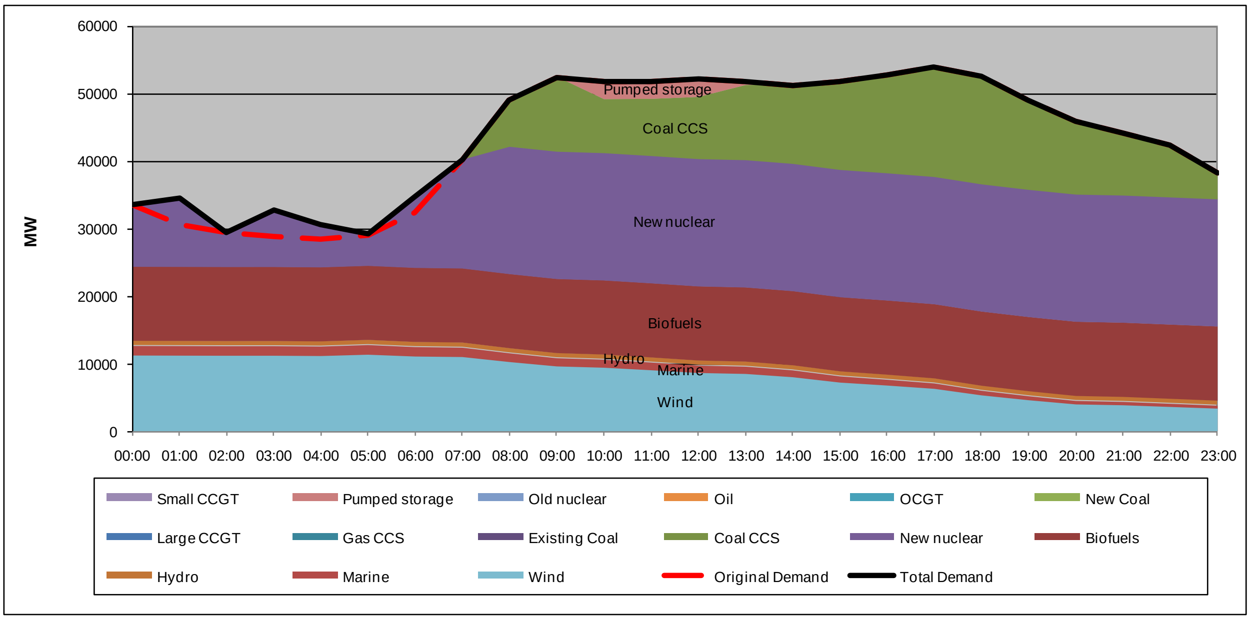

Figure 26: Summer Demand in 2040

The results for 2040 are similar to those observed for 2030. The near-doubling of carbon price – from £70/t to £135/t – moves the power prices upwards but the carbon-driven merit order remains. Unabated fossil plant is only used when absolutely necessary i.e. in peak periods with low wind, and where pumped storage alone cannot cover the shortfall. Most of the time, the price is set by coal CCS at around £56/MWh.

As in 2030, gas plant does not run in the summer of 2040. The previously noted behaviour of pumped storage is even more pronounced here because of an increase in nuclear capacity – even this nuclear plant is required to back away from running baseload at times of low demand, and pumped hydro stations pump maximally where possible to avoid reducing nuclear output.

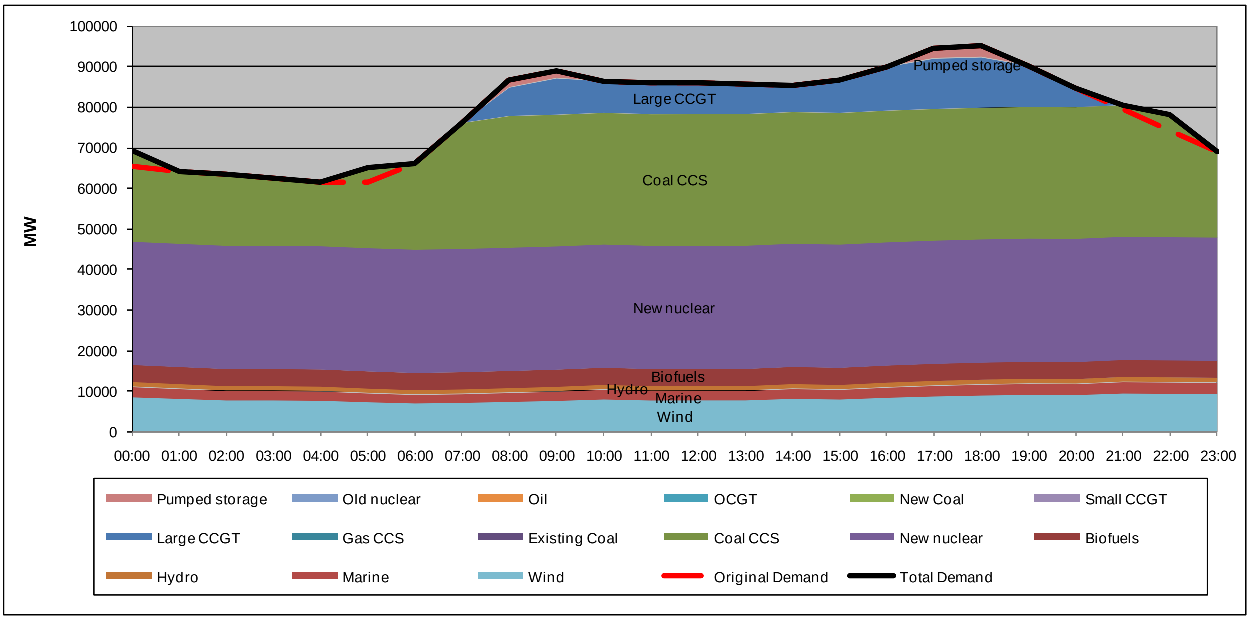

Figure 27: Winter Demand in 2050

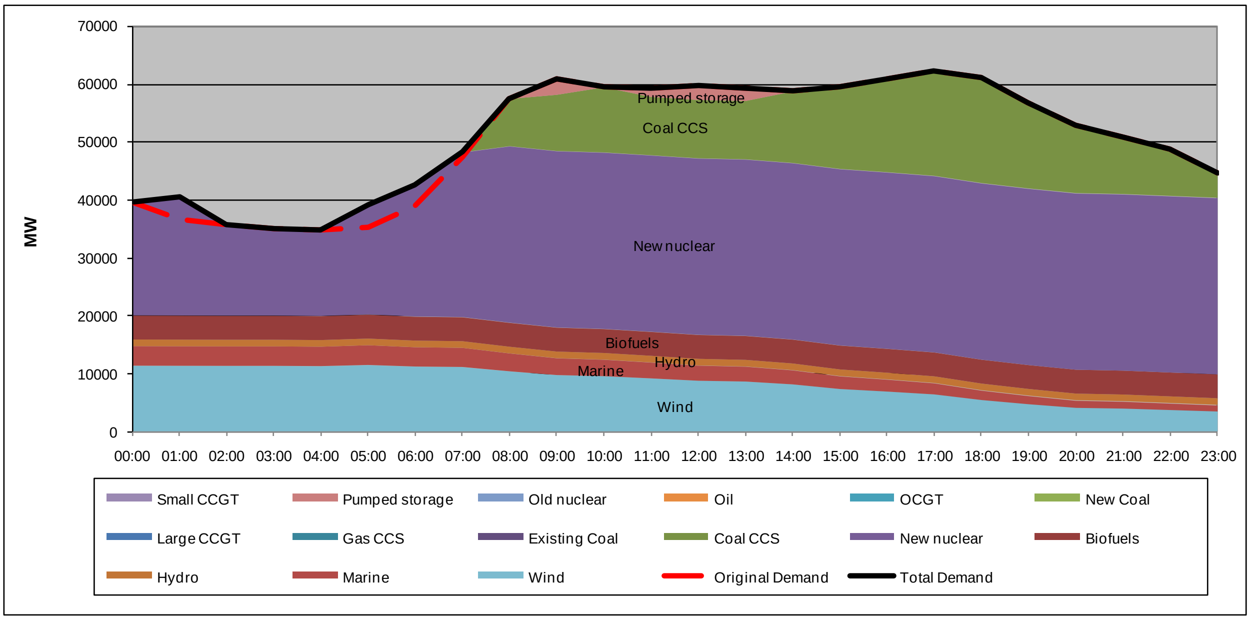

Figure 28: Summer Demand in 2050

In 2050, the total grid demand steps up markedly as the EV and heat pump demands increase. A large amount of nuclear plant is built to account for this. Overall, the running order is essentially unchanged from the 2040 milestone – the carbon price strengthens to £200/t, and even coal CCS has a running cost including carbon of over £60/MWh. The baseload power price is similar to this, at around £64/MWh.

Because of the increase in demand associated with EV charging, the total emissions actually increase between 2040 and 2050. This does not necessarily go against the ethos of the UKERC scenario, because the scenarios are associated with a carbon reduction target across the whole energy sector, and not just electricity. The EV demands modelled are likely to involve a greater shift from petrol and diesel powered vehicles.

A1.2 Overnight Charging

The implied merit order is unchanged when the charging profile moves to Overnight. The main difference between the charging profiles is that overnight charging requires more expensive plant to run for a longer duration. This mainly shows up in the later years, when the EV demand becomes more significant. For example, in 2050, CCGT plant runs at an annual load factor of 11.2%, compared with 6.5% for after journey charging. An illustration of this is provided in Figures 27 and 28.

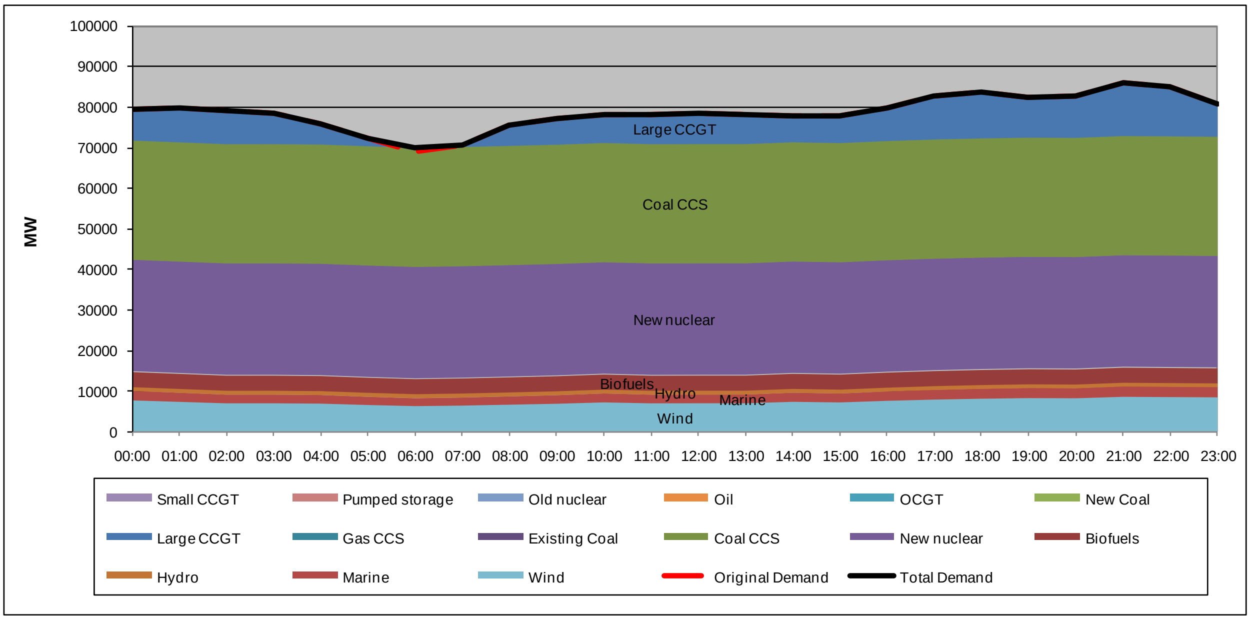

Figure 29: Winter Demand in 2050 for Overnight Charging Profile

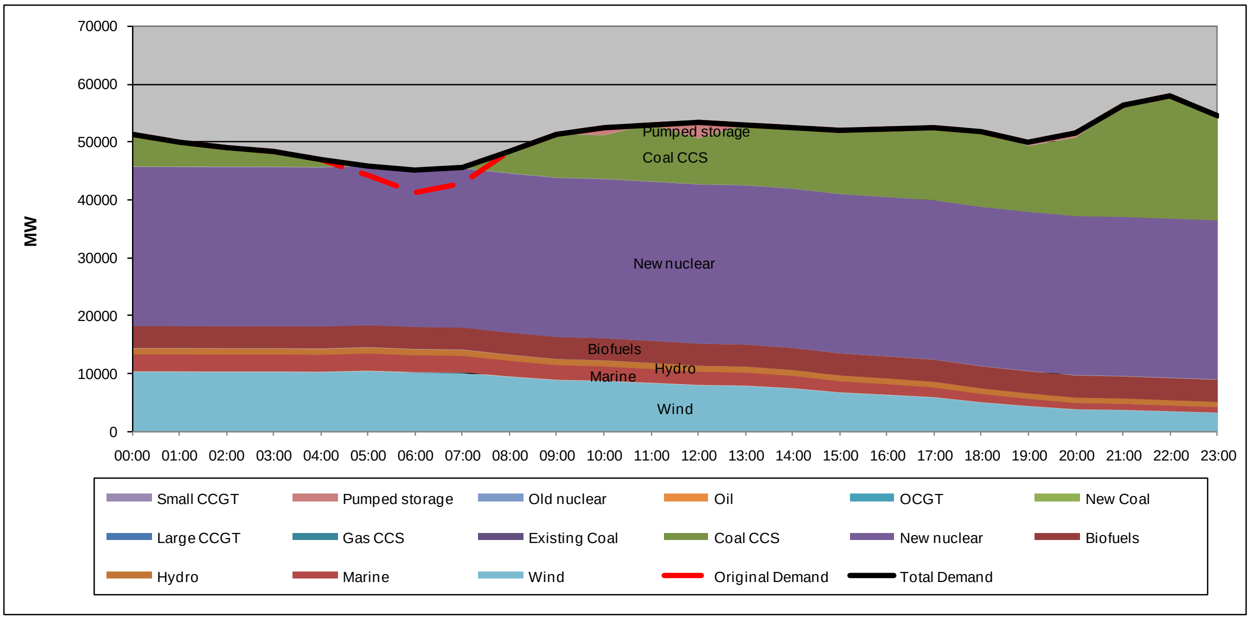

Figure 30: Summer Demand in 2050 for Overnight Charging Profile

As expected, the contribution from CCGT plant is now much greater in the off-peak (overnight) periods. This has the effect of increasing the baseload electricity price and also reducing the difference between peak and off-peak pricing. In addition, the grid emissions factor increases slightly compared with After Journey charging, from 0.04 t CO_2/MWh in 2050 to 0.05 t CO_2/MWh.

This example illustrates the sensitivity of the modelling to the plant capacity mix. The level of nuclear plant could feasibly be increased slightly to cover more of the demand, but this would be introducing strategic decisions which were not part of the UKERC CAM scenario and the intention was to remain as faithful to the UKERC scenarios as was possible.

To provide some additional backup to the results discussed herein, Figure 29 contains price duration curves in 2050 for both the After Journey and Overnight charging profiles. The main feature of this plot is the absence of very low price periods in the Overnight case (because this charging scenario lifts the demand minimum to a much higher value than the After Journey case), and the price step between 1000 and 2000 hours. As alluded to previously, the different position of this step is because the Overnight profile is associated with a higher probability that expensive plant has to run.

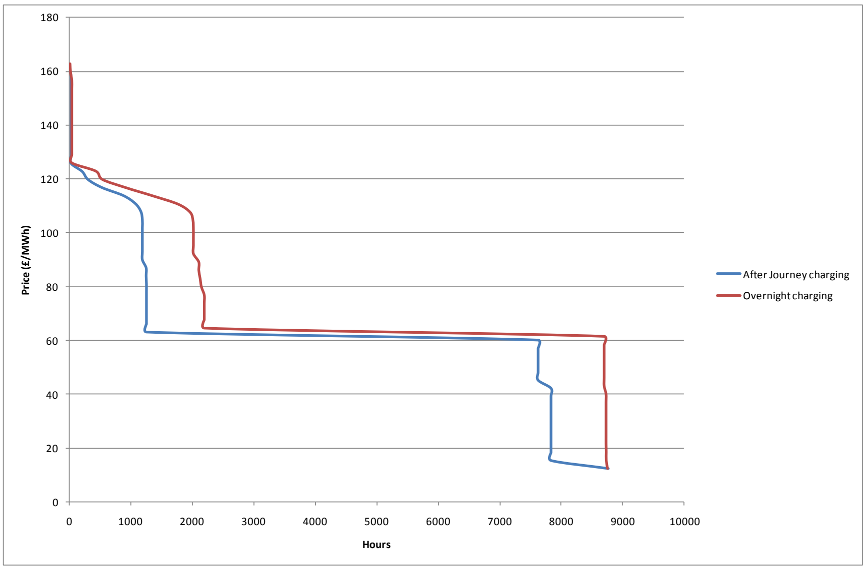

Figure 31: Price Frequency Curve in 2050 for Base Scenario and the Two Charging Profiles

A1.3 No EV Charging

The demand profiles without EV charging are quite similar to the After Journey case, but without the strengthened evening peak and morning step. This means that the profile is, in ethos, somewhere between the peaky After Journey case and the flatter Overnight profile. It should not be surprising, then, that the calculated metrics of emissions and price generally bisect the calculated values for the other cases. For example, the emissions factor in 2050 in the case of no EV charging is 0.048 t CO_2/MWh. Again, this is highly sensitive to the mix of plant chosen.

A2 EG1 Scenario

The EG1 scenario is based on the UKERC CSAM scenario in conjunction with the Arup High fuel and carbon prices. The CSAM scenario delivers a 90% reduction in carbon dioxide emissions in 2050 and, to achieve this, a large amount of zero-carbon plant is built – this scales up to 46 GW of nuclear plant and 77 GW of wind in 2050 for the After Journey profile. The general approach in CSAM is to apply efficiency savings in the early years, before increasing demand in 2040 and 2050 to accommodate greater e-heating and EV demands plus hydrogen generation.

As in the CAM scenario, the merit order is essentially driven by emissions in the later years because of the high carbon price. The high carbon price track delivers carbon prices of around £21/t CO_2 in 2020, and this pushes coal CCS plant to the top of the merit order in winter but not in summer. From 2030 onwards, much higher carbon prices cause a carbon-driven merit order for the whole of the year.

All of the charging profiles are associated with very low off-peak emissions and prices from 2030 onwards. The grid is almost completely decarbonised by 2030 (around 0.01 t CO_2/MWh for all profiles). Emissions actually increase slightly in 2050 as the total annual demand increases to over 600 TWh, but still remain rather low (0.019 t CO_2/MWh to 0.027 t CO_2/MWh).

The reason for the low emissions is that CSAM is associated with high levels of nuclear new build and wind, and these two plant types alone are often enough to satisfy demand. Unlike the other scenarios modelled, nuclear plant is required to back away from baseload quite frequently, reducing to an overall load factor of 68% in 2040 and 2050 for the After Journey profile and 78% for the Overnight profile. An even more striking effect is observed for coal CCS plant, with load factors of 26% and 38% for After Journey and Overnight charging respectively.

There is a marked difference in baseload electricity price between the charging profiles. After Journey charging delivers a wholesale electricity price of around £60/MWh, while Overnight lifts this up to over £80/MWh. The main reason for this difference is the cost of off-peak electricity: expensive plant is forced to run frequently when charging overnight but not when charging after journey and the running costs of expensive plant are even higher when applying the High commodity prices of this scenario.

A3 EG2 Scenario

The EG2 scenario is based on the UKERC CLC scenario in conjunction with the Arup Low fuel and carbon prices. Although this is a comparatively unambitious scenario (achieving 60% carbon reduction by 2050), abatement in the electricity sector remains fairly similar to the CAM scenario – the non-electricity sectors exhibit lower decarbonisation than in the other scenarios.

The CLC scenario is associated with much lower electricity demands in the later years, with only 460 TWh in 2050. Also, this scenario is unique in that unabated coal plant is built, although this plant is not used other than in peak demand periods.

Similarly to the Base scenario, the low carbon price acts to discourage use of CCS plant in the near term. However, in part because of the lower fuel price, this effect now persists into 2030, with CCS remaining below gas in the merit order in the summer (but not the winter). This leads to an unusual observation: in 2020, emissions in winter are higher than in summer but in 2030 this is reversed.

By 2040, a carbon price of £65/t CO_2 is sufficient to drive an emissions-based merit order. From this point onwards plant runs broadly similarly to the Base scenario; the lower levels of nuclear and wind power mean that coal CCS and gas tend to run at a higher load factor than Base. Grid emissions factor is slightly higher than Base, at around 0.06 t CO_2/MWh for both the After Journey and Overnight profiles. A consequence of the low fuel and carbon prices is that baseload power prices are fairly low – under £40/MWh for both charging profiles.

A4 EG3 Scenario

The EG3 scenario is based on the UKERC CCSP scenario in conjunction with the Arup Medium fuel and carbon prices. These prices suggest that the merit order in EG3 will be the same as Base, but the plant mix is quite different.

This scenario is designed to have the same cumulative emissions as CAM, but with significant action taken early on. The early action leads to a large amount of coal CCS and wind build by 2020, in addition to efficiency improvements (annual demand of 345 TWh in 2020). However, in the longer-term, EG3 is associated with lower levels of nuclear build. For that reason, the emissions in 2050 are found to be higher than any of the other modelled scenarios.

The grid emissions factor in 2050 is between 0.07 t CO_2/MWh and 0.08 t CO_2/MWh, depending on the charging profile. Baseload electricity prices in 2050 for both charging profiles are over

£70/MWh, which is slightly higher than the Base results of around £60/MWh, reflecting the different mix of plant between the two scenarios.

A5 T11 Scenario

The T11 scenario is based on the UKERC CAM scenario in conjunction with the Arup Low fuel and carbon prices. In this case, the merit order is similar to that in scenario EG2, providing the same effect of gas price seasonality in 2020 and 2030. EG2 and T11 have a quite different mix of plant in these years, though, meaning that the overall results in these years are quite different – EG2 has a much higher grid emissions factor, mainly because this scenario involves much less nuclear plant.

Beyond this point, the plant dispatch profile is very similar to that observed in Base. The only notably different results in 2040 and 2050 are the scales of the electricity prices, as these are influenced by the commodity prices. In T11, the baseload power price in 2050 is around £36/MWh, compared with £64/MWh for Base. The baseload power price is slightly lower than the EG2 scenario; although the fuel and carbon prices are the same, the greater levels of cheap zero-carbon plant act to reduce the electricity price slightly.

A6 T7 Scenario

The T7 scenario is based upon the UKERC CAM scenario in conjunction with the Arup High fuel and carbon prices. The merit order is similar to scenario EG1, with coal CCS running before all other fossil in winter but switching to gas in summer. Generally coal CCS runs more frequently than in scenario EG1 because of the comparatively low amounts of nuclear plant in T7 compared with EG1, reflecting the lower levels of abatement effort associated with T7.

As with scenario T11, scenarios T7 and Base exhibit similar behaviour from 2040 onwards. In this case, the baseload power price is also the major difference, although in this case the price increases to over £90/MWh, compared with the base value of £60/MWh. The overnight charging option takes this even further, to over £110/MWh. This mirrors the results for scenario EG1, although the prices for T7 are higher because of the comparatively high level of fossil plant running. T7 provides the highest power prices of any of the modelled scenarios.

APPENDIX B

Commodity Prices

Table B.1: Low Scenario

	Carbon ($£/t\ CO_2$)	Oil ($/bbl)	Coal (£/t)	Gas (p / therm) Summer	Winter	Spring / Autumn
2010	7.30	70.0	70.0	40.3	47.7	44.0
2020	8.50	61.3	47.1	26.9	38.0	32.4
2030	35.00	52.5	40.5	19.8	28.0	23.9
2040	67.50	43.8	34.8	14.6	20.7	17.6
2050	100.00	35.0	29.9	10.8	15.2	13.0

Table B.2: Medium Scenario

	Carbon ($£/t\ CO_2$)	Oil ($/bbl)	Coal (£/t)	Gas (p / therm) Summer	Winter	Spring / Autumn
2010	14.10	70.0	70.0	40.3	47.7	44.0
2020	16.30	77.3	65.9	35.5	52.5	44.0
2030	70.00	85.4	62.1	35.5	52.5	44.0
2040	135.00	94.3	58.4	35.5	52.5	44.0
2050	200.00	104.2	55.0	35.5	52.5	44.0

Table B.3: High Scenario

	Carbon ($£/t\ CO_2$)	Oil ($/bbl)	Coal (£/t)	Gas (p / therm) Summer	Winter	Spring / Autumn
2010	17.80	70.0	70.0	40.3	47.7	44.0
2020	20.70	122.5	72.5	47.8	64.8	56.3
2030	105.00	175.0	75.1	63.6	80.6	72.1
2040	202.50	227.5	77.7	83.8	100.8	92.3
2050	300.00	280.0	80.5	109.6	126.7	118.1

APPENDIX C

Final Capacity Mix for Four Selected UKERC Scenarios

C.1 CAM Capacity Mix

This capacity mix is used in PiVEIP scenarios Base, T11 and T7.

C.1.1 No EV

	Capacity (MW)								
	2010	2015	2020	2025	2030	2035	2040	2045	2050
Existing Coal	23,500	19,500	6,000	3,000	-	-	-	-	-
New Coal	-	-	-	-	-	-	-	-	-
Coal CCS	-	-	8,500	13,000	32,000	32,000	33,000	33,000	32,000
Large CCGT	15,200	16,000	20,800	14,400	8,000	8,000	7,200	14,400	16,800
Small CCGT	8,800	9,200	12,000	8,000	4,400	4,400	4,400	8,000	9,600
Gas CCS	-	-	-	-	-	-	-	-	-
OCGT	1,000	1,050	1,400	900	500	500	500	900	1,100
Oil	8,400	7,200	7,200	-	-	-	-	-	-
Old Nuclear	10,800	7,200	3,600	3,600	1,350	1,350	-	-	-
New Nuclear	-	-	1,600	8,000	8,000	8,000	19,200	24,000	28,800
Hydro	2,110	2,000	1,907	1,795	1,714	1,588	1,505	1,505	2,727
Wind	5,000	11,730	14,882	15,769	15,915	15,811	17,490	17,490	18,009
Biofuels	3,800	3,750	5,400	13,300	12,700	12,400	10,700	4,100	4,050
Marine	-	-	-	-	-	-	1,881	3,795	5,310
Storage	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700

C.2 CSAM Capacity Mix

This capacity mix is used in PiVEIP scenario EG1.

C.2.1 No EV

	Capacity (MW)								
	2010	2015	2020	2025	2030	2035	2040	2045	2050
Existing Coal	23,500	19,500	6,000	3,000	-	-	-	-	-
New COAL	-	-	-	-	-	-	-	-	-
Coal CCS	-	-	7,500	7,500	12,000	12,000	12,500	12,500	12,500
Large CCGT	15,200	16,800	17,600	11,200	8,000	8,800	9,600	20,000	24,800
Small CCGT	8,800	9,600	10,000	6,400	4,400	5,200	6,000	11,200	14,400
Gas CCS	-	-	-	-	-	-	-	-	-
OCGT	1,000	1,100	1,150	750	500	600	600	1,300	1,650
Oil	8,400	6,600	6,600	-	-	-	-	-	-
Old Nuclear	10,795	7,197	3,598	3,598	1,349	1,349	-	-	-
New Nuclear	-	-	6,400	16,000	25,600	28,800	38,400	40,000	40,000
Hydro	2,110	2,000	1,889	1,778	1,673	1,550	2,766	2,766	2,825
Wind	5,030	11,730	14,079	15,150	15,055	16,595	16,921	24,887	69,221
Biofuels	3,800	3,750	4,050	12,900	12,000	11,650	11,250	2,400	3,100
Marine	-	-	-	-	-	-	2,725	4,846	5,501
Storage	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700

C.3 CLC Capacity Mix

This capacity mix is used in PiVEIP scenario EG2.

C.3.1 No EV

	Capacity (MW)								
	2010	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Existing Coal	23,500	19,500	9,500	-	-	-	-	-	-
New Coal	-	-	-	6,400	3,200	3,200	3,200	3,200	3,200
Coal CCS	-	-	5,500	17,000	40,500	41,500	39,000	39,000	40,500
Large CCGT	15,200	16,000	20,000	13,600	8,000	8,000	7,200	8,800	8,800
Small CCGT	8,800	9,600	11,600	8,000	4,800	4,800	4,000	4,800	4,800
Gas CCS	-	-	-	-	-	-	-	-	-
OCGT	1,000	1,100	1,300	900	550	550	450	550	550
Oil	8,400	6,600	6,600	-	-	-	-	-	-
Old Nuclear	10,795	7,197	3,598	3,598	1,349	1,349	-	-	-
New Nuclear	-	-	1,600	1,600	1,600	1,600	4,800	9,600	16,000
Hydro	2,110	2,000	1,889	1,778	1,820	1,687	1,456	1,456	1,504
Wind	5,000	11,720	14,473	15,837	17,594	17,349	16,900	16,078	14,929
Biofuels	3,850	3,800	4,550	12,300	13,300	12,950	11,100	3,300	3,400
Marine	-	-	-	-	-	-	-	2,579	5,563
Storage	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700

C.4 CCSP Capacity Mix

This capacity mix is used in PiVEIP scenario EG3

C.4.1 No EV

	Capacity (MW)								
	2010	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Existing Coal	23,500	19,500	6,000	3,000	-	-	-	-	-
New Coal	-	-	-	-	-	-	-	-	-
Coal CCS	-	-	12,500	12,500	35,000	39,500	45,500	45,500	44,000
Large CCGT	15,200	16,000	16,000	16,000	12,000	12,800	13,600	15,200	18,400
Small CCGT	8,800	9,200	8,800	9,200	7,200	7,600	7,600	8,800	10,800
Gas CCS	-	-	-	-	-	-	-	-	-
OCGT	1,000	1,050	1,050	1,050	800	850	850	1,000	1,200
Oil	8,400	6,600	6,600	-	-	-	-	-	-
Old Nuclear	10,795	7,197	3,598	3,598	1,349	1,349	-	-	-
New Nuclear	-	-	3,200	9,600	9,600	9,600	9,600	11,200	11,200
Hydro	1,090	910	1,889	1,778	1,722	1,596	1,498	1,498	1,456
Wind	5,880	15,060	16,847	17,200	17,672	17,672	18,008	18,008	37,648
Biofuels	3,850	3,700	3,450	3,200	2,800	2,700	2,550	2,200	2,800
Marine	-	-	-	-	-	1,449	3,135	4,986	5,387
Storage	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700

APPENDIX D

Results of E.ON Model Runs (annual averages)

		Average Yearly Grid Emissions Factor ($t\ CO_2$ / MWh)				Average Demand-Weighted Wholesale Power Price (£ / MWh)			
PiVEIP scenario	**Charging pattern**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Base	**After**	0.271	0.048	0.030	0.040	44.08	51.69	52.37	68.76
Base	**Overnight**	0.274	0.051	0.039	0.051	44.40	51.82	59.57	78.07
Base	**No EV**	0.274	0.049	0.034	0.048	44.33	51.70	56.12	76.40
EG1	**After**	0.213	0.010	0.007	0.019	53.93	42.01	39.21	69.97
EG1	**Overnight**	0.214	0.012	0.012	0.027	54.17	46.39	54.47	90.64
EG1	**No EV**	0.214	0.011	0.009	0.025	54.16	43.96	46.14	85.35
EG2	**After**	0.302	0.120	0.061	0.058	31.01	34.85	36.52	39.00
EG2	**Overnight**	0.306	0.122	0.072	0.065	31.49	34.98	37.33	39.85
EG2	**No EV**	0.305	0.121	0.067	0.061	31.50	34.90	36.94	39.33
EG3	**After**	0.265	0.072	0.078	0.066	45.17	53.51	62.82	73.68
EG3	**Overnight**	0.266	0.079	0.087	0.077	45.34	54.30	66.43	78.59
EG3	**No EV**	0.265	0.077	0.082	0.072	45.32	53.87	64.30	77.15
T11	**After**	0.281	0.098	0.031	0.040	31.62	34.18	33.19	38.08
T11	**Overnight**	0.283	0.101	0.040	0.051	31.80	34.45	36.43	41.51
T11	**No EV**	0.283	0.097	0.034	0.049	31.71	34.27	34.74	40.92
T7	**After**	0.243	0.048	0.031	0.040	54.29	64.87	70.73	104.20
T7	**Overnight**	0.246	0.051	0.039	0.051	54.66	64.98	81.57	122.43
T7	**No EV**	0.246	0.048	0.033	0.048	54.58	64.79	75.58	119.29

APPENDIX E

A Simple Investment Model of Electricity Generation

E.1 Model Description

In order to provide some indication of the potential impact of alternative adaptation of the generating fleet on the benefit or otherwise of charging overnight a very simple model was developed in Excel. This simulated solely the year 2050 and was given a completely free hand to choose the mix of generating technologies from biomass, nuclear, coal with CCS and gas without CCS; a level of wind capacity installed was prescribed. The model then attempted to minimise the total cost of generation, comprising variable costs plus an annualised fixed cost of installed capacity, subject to meeting demand in load duration form at 100 points in the year. Provision was made to impose a maximum level of carbon dioxide emissions from electricity generation.

The model has not taken into account any of the following features which might be deemed relevant in a more sophisticated study:
- Rate at which assets can be built;
- Public acceptability of each technology;
- Requirements for ancillary services such as short term operating reserve;
- The feasibility of operating the generating plant in the manner indicated (e.g. nuclear plant running at only 50% load factor);
- Availability of fuel and capital resources at the prices assumed;
- Infrastructure required to deliver fuel to the power stations or electricity to the centres of demand;
- Possible trade-offs between reducing carbon emissions from the electricity sector and reducing emissions in other sectors.

The model was implemented in Excel using the Excel Solver to find the minimum cost solution. Some manual checks were applied to give additional reassurance that the Solver had not converged to a local minimum far from the global optimum.

E.2 Scenario Considered

This investigation was based on the base scenario. Key assumptions are:
- 20GW of wind generating capacity installed
- Price of carbon dioxide set at £200/Tonne, as in base scenario
- Fuel prices as in base scenario
- Capital and annual fixed maintenance costs set at central Mott Macdonald estimate as in base scenario
- EV charging profiles from Ricardo and based on high EV uptake, as in the main modelling

E.3 Load Duration Curves from alternative Charging Profiles

Figure 32 below illustrates the impact that choice of charging profile has on the annual profile of electricity demand to be met by non-intermittent generating plant. Overnight charging results in a lower peak demand by about 10% which reduces the capacity of generating plant required. This is offset by an increase in the demand at times of lowest demand. The impact over the year is very much less marked than the impact within a day illustrated by figure 1 above; this is because moving charging demand overnight shifts it from a relatively high demand period to a relatively low demand period but in absolute terms that night-time demand in winter can still be fairly high.

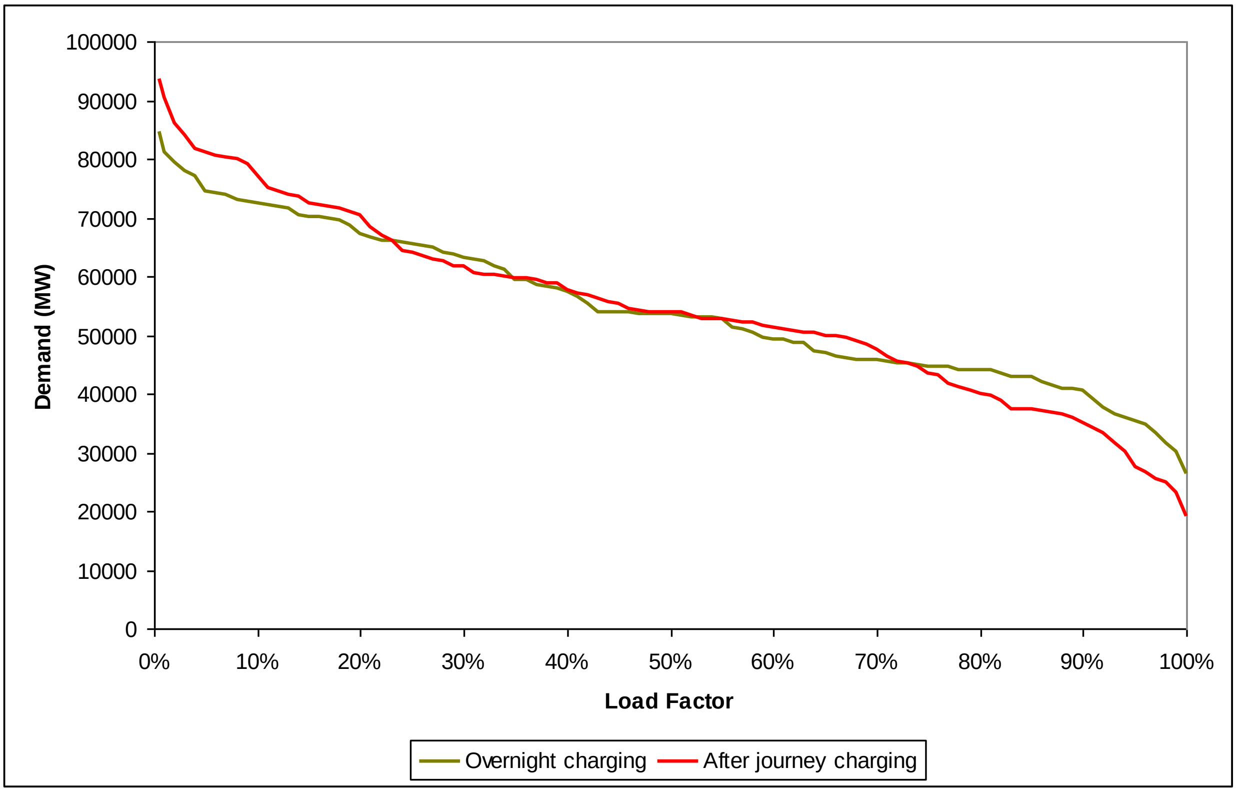

Figure 32: Load duration curves of electricity demand net of wind generation with alternative electric vehicle charging regimes.

E.4 Lifetime Costs of Generating Technologies

Figure 33 shows the cost per unit of electricity generated by each technology considered based on the central estimates of capital and maintenance costs from Mott Macdonald and the base scenario fuel and carbon prices. It shows that for demand that persists for less than about 40% of the year gas fired CCGTs without carbon capture and storage are the cheapest option by some margin. To meet demand which persists for longer periods the choice between nuclear generation and biomass is close. Note that it is assumed here that the whole of the cost of the biomass fuel is met by a renewable subsidy so counted here at zero; if the cost of biomass fuel is included nuclear becomes the significantly cheaper option.

Comparing figure 33 with 32 it is noticeable that the region in which generation technologies compete most closely on cost is a region of the load duration curve which is little affected by choice of charging regime. Thus we expect the dominant impact to be the requirement to install more peaking capacity when charging after each journey.

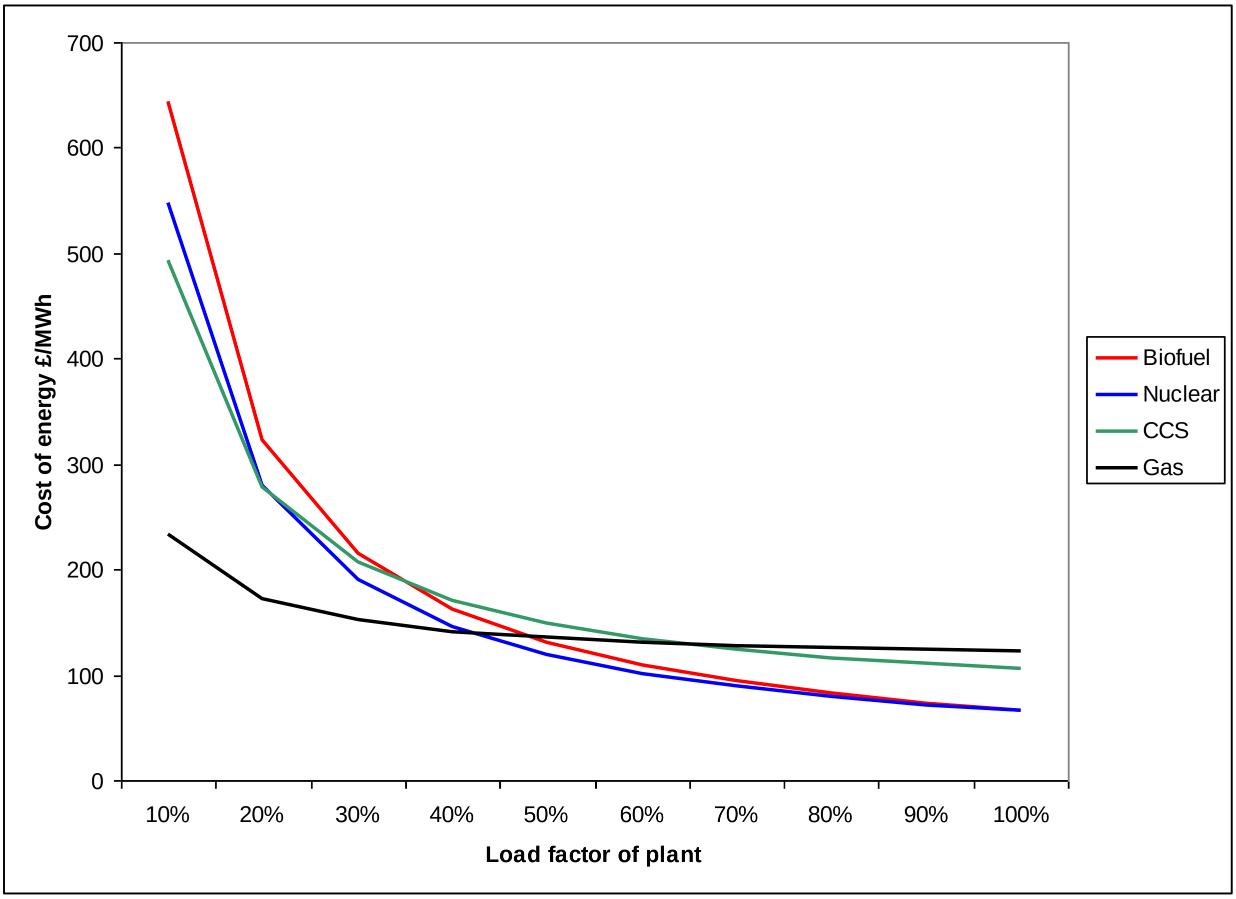

Figure 33: Costs of electricity generation including fixed costs by technology against the load factor achieved for base scenario conditions

At lower carbon prices gas benefits most so that at anything below £50/tonne it becomes the cheapest option at all load factors.

The range of Mott Macdonald n'th of a kind estimates of capital costs is around ±10%. Sensitivities of this magnitude have very little impact; the same technologies remain least cost.

E.5 Modelling Results

Three scenarios have been considered:

1. A case close to the base scenario;
2. A version of this scenario with carbon emissions limited by volume to 22Mt, illustrating an alternative policy approach to incentivising low carbon electricity;
3. A case close to the EG1 scenario;
4. A sensitivity on the base scenario limiting biomass and nuclear build to the maximum levels in the UKERC scenarios.

The capacity of wind generation installed on the system is fixed at the level appropriate to the scenario, not subject to least cost choice because the model does not include the additional financial support that wind gets from the renewable obligation.

The results of these are shown in tables E.1 to E.4 below. The “per unit” increases of cost and carbon dioxide emissions are calculated as the difference in cost between the case with EV charging and the case with no EVs divided by the charging load.

	Charging after journey	Charging overnight	No Electric Vehicles
Installed wind (GW)	20	20	20
Biomass (GW)	0	0	0
Nuclear (GW)	60	59	58
Coal CCS (GW)	0	0	0
Gas (GW)	43	34	33
Estimated electricity wholesale price (£/MWh)	83.6	81.6	83.0
Average grid emission factor (gross) (kg/kWh)	0.041	0.037	0.032
Total CO2 emission by electricity generation (Mtonnes/year)	22.0	19.9	15.9
Increase in cost of electricity production per unit of charging load (£/MWh)	109.5	60.6	
Increase in carbon emissions per unit of charging load (kg/kWh)	0.161	0.105	

Table E.1: Investment Model Results for Base Scenario:
- carbon price £200/tonne

	Charging after journey	Charging overnight	No Electric Vehicles
Installed wind (GW)	20	20	20
Biomass (GW)	0	0	0
Nuclear (GW)	60	58	54
Coal CCS (GW)	0	0	0
Gas (GW)	43	35	37
Estimated electricity wholesale price (£/MWh)	83.2	81.2	82.3
Average grid emission factor (gross) (kg/kWh)	0.041	0.041	0.044
Total CO_2 emission by electricity generation (Mtonnes/year)	22.0	22.0	22.0
Increase in cost of electricity production per unit of charging load (£/MWh)	106.3	59.4	
Increase in carbon emissions per unit of charging load (kg/kWh)	0.0	0.0	

Table E.2: Investment Model Results for sensitivity on carbon target:
- carbon emissions limited to 22Mt.CO_2

	Charging after journey	Charging overnight	No Electric Vehicles
Installed wind (GW)	70	70	70
Biomass (GW)	0	0	0
Nuclear (GW)	48	49	42
Coal CCS (GW)	0	0	0
Gas (GW)	50	38	43
Estimated electricity wholesale price (£/MWh)	96.9	94.9	97.3
Average grid emission factor (gross) (kg/kWh)	0.030	0.022	0.030
Total CO_2 emission by electricity generation (Mtonnes/year)	16.2	11.7	14.9
Increase in cost of electricity production per unit of charging load (£/MWh)	116.1	61.6	
Increase in carbon emissions per unit of charging load (kg/kWh)	0.033	-0.085	

Table E.3: Investment Model Results for scenario close to EG1:
- **carbon price £300/tonne**
- **70GW of wind generation**

	Charging after journey	Charging overnight	No Electric Vehicles
Installed wind (GW)	20	20	20
Biomass (GW)	4	4	4
Nuclear (GW)	40	40	40
Coal CCS (GW)	6	6	1
Gas (GW)	53	43	45
Estimated electricity wholesale price (£/MWh)	90.4	89.8	87.8
Average grid emission factor (gross) (kg/kWh)	0.085	0.079	0.080
Total CO2 emission by electricity generation (Mtonnes/year)	46	43	40
Increase in cost of electricity production per unit of charging load (£/MWh)	138.6	85.7	
Increase in carbon emissions per unit of charging load (kg/kWh)	0.158	0.063	

Table E.4: Investment Model Results for sensitivity on Base Scenario:
- **carbon price £200/tonne**
- **biomass and nuclear generation constrained**

E.5 Findings from Modelling

From this modelling we find that, under the conditions modelled:

- The cost-optimal mix of generating technologies is dominated in this model by the load factor at which it becomes more economic to build and run gas plant than nuclear plant. With a carbon price of £200/t and the CAPEX and OPEX costs used this is around 45% and at £300/t it is 33%. The demand net of wind at this load factor and at the peak determine the solution except in the case where the nuclear build is constrained;

- A consequence of this is that filling in the overnight demand trough with vehicle charging load does not allow more nuclear plant to be built – some nuclear plant is already assumed to be off load, or at least down to a low load, at that point. Running nuclear plant in such a flexible manner may have technical or cost implications not modelled here;
- The estimated wholesale electricity price for overnight charging is consistently £2/MWh (2.5%) lower than for charging after each journey;
- The cost of producing additional electricity for vehicle charging is about £50/MWh more expensive with after journey charging than with overnight charging. Under current market arrangements that additional cost is effectively paid for by all consumers, not just those charging vehicles, which dilutes it to around £3.70/MWh, not far removed from the impact on prices noted above;
- The primary determinants of these cost and price differences are the lower annual peak demand and higher average load factor required of generating plant with overnight charging. Thus the benefit will be seen under a wide range of conditions provided scheduling of generation is aimed at minimising cost to the asset owner;
- If carbon emissions are controlled solely by the carbon price and not directly restricted by a limit on emissions then the net impact of EV charging is less if that charging takes place overnight;
- This benefit from overnight charging varies with the level of wind generation on the system[4] and with very high levels of wind additional overnight charging of vehicles may reduce total emissions as it shifts the economic choice of generation from gas to nuclear;
- Compared to after journey charging, overnight charging is estimated to reduce the carbon intensity of the additional EV load by 0.05 kg/kWh with a moderate level of wind generation rising to 0.12kg/KWh with 70GW of wind installed.
- If carbon emissions are controlled directly, i.e. not primarily by pricing, then there is negligible difference between the impacts of the two charging regimes on emissions. This demonstrates that the outcome is highly dependent on the Government's choice of instruments to encourage low carbon electricity generation.
- Adding constraints on the technology available can significantly alter the results, but in the single sensitivity run here, the general lessons for overnight versus after journey charging still held.

E.6 Conclusions

The following conclusions are drawn:

3. The charging regime adopted for electric vehicles has little impact on annual average electricity wholesale prices;

4. Much of the reason for that is the market design which dilutes cost increases across all consumers and because charging load comprises only 8% of demand even in this high penetration scenario;

5. Under some, but not all, choices of mechanism for incentivising investment in low carbon electricity generation overnight charging would result in lower emissions than would

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[4] It may also vary with other factors which were not explored in this short study.

after-journey charging and the magnitude of this benefit is highly dependent on other scenario conditions;

6. Noting that there are benefits from overnight charging in the transmission and distribution sectors of the electricity industry and that it seems unlikely that there are credible scenarios in which there is a dis-benefit from overnight charging in the generation sector there seem to be adequate grounds to encourage this behaviour;

7. Quantification of benefits is critically dependent on estimates of power station capital and operating costs and on policies affecting the choice of technology and its operation, in particular the support of renewable generation and low carbon technologies.