Value creation by local energy markets and the implications for the transition to a distribution system operator

‘Customer-Led Distribution System’ project

Northern Powergrid, 2019

Contents

Executive Summary

Distribution Network Operators (DNOs) face challenges around how to manage the increasing volume of Distributed Energy Resources (DERs) connecting to the grid. Increasingly, DNOs will need to adapt their responsibilities and take on the role of Distribution System Operators (DSOs) to better manage these flexible resources.

This report is deliverable by the Customer-Led Distribution System (CLDS) project[1]. The project's aim is to explore the future structure of the distribution sector, placing the customer at the centre; and this report describes the initial results of some quantitative analysis on the value of local markets. Local markets here are made of energy market (incentivising flexible demand to connect and to follow locally produced clean energy), and of network market (payment for flexible response to support local network).

The analysis focuses on two types of DER: Electric Vehicles (EVs) and photovoltaics (PVs). Rising levels of EV and PV utilisation can place strains on the distribution network. Excess EV demand can breach the network's capacity locally, potentially leading to a requirement for network reinforcement. PV generation cannot be scheduled to match demand, so supply may exceed demand in a local area. In the model, EV users receive price signals which provide different incentives depending on the market set up. Three markets are explored:

- Energy market: The commodity on this market is energy and the unit kWh. This is both the retail and whole system piece of the energy supply chain. Through this market, for the purpose of the study, EVs are provided with a price incentive to charge as much as possible from PV output. The measure applied to assess the success of this market, in the context of DSO challenges is PV energy absorbed locally, as a proxy for:
  - the value to the PV owner(more sold at higher price),
  - the value to the EV user (more bought at lower price).

- Network market: The commodity on this market is capacity, traded as kW. This is the distribution networks piece of the energy supply chain. Through this market, for the purpose of the study, EV users are provided with a price incentive at the time of local system peak to take action to reduce peak demand, either through reducing their charging and/or or through discharging. The measure applied to assess the success of this market, in the context of DSO challenges is network reinforcement avoided, as a proxy for:
  - the network charges paid for by the EV user,
  - payment received by them from the network.
- Combined Energy and Network market: EV users are provided with simultaneous price incentives both to charge from PV output, and to reduce their charging or to discharge at the time of local system peak.

[1] For more information, visit www.northernpowergrid.com/innovation/projects/customer-led-distribution-system-nia-npg-19

Our main findings are:

- The value of DERs for their owners, users and for the energy system varies with their mix, their penetration level, and their time of operation.
- The appropriate market arrangements can increase the value of DERs for their owners, users and for the energy system.
- But the reverse is also true: market arrangements that fail to correctly value both network and energy costs may worsen system performance.
- DER owners and users can get significantly more value from their assets by participating in local energy markets compared to providing services to the distribution network, by a factor of between 20 and 63 times dependent on the network conditions e.g. whether the networks are dominated by domestic or commercial load and whether they are lightly or heavily loaded. The benefits from local energy markets are estimated to be £87bn during the period 2030 to 2050.
- The implications for the DNO to DSO transition are twofold:
    - In a world where networks operate a flexibility market on top of a local energy market, is important to identify the pieces of the energy supply chain that we are seeking to maximise value from (i.e. what asset and for who?)
    - Local market arrangements should be put in place and designed with the objective of maximising the value of DERs for their owners and users and for the energy system as whole. These arrangements should be appropriate for the local DER mix and penetration levels, their times of operation, and the characteristics of local demand
    - Establishing market principles to coordinate different local markets is a necessity, particularly if there are competing objectives (for instance between network and balancing needs) – especially because price signals alone may not reflect the preferred prioritisation.

1. Introduction

1.1 About the Customer-Led Distribution System project

The energy sector is undergoing substantial change. These changes require Distribution Network Operators (DNOs) to adapt their responsibilities and increasingly take on the role of Distribution System Operators (DSO) to best to deliver value to customers. DSOs will have an important role to play in managing flexible resources in the future, but at present there are many uncertainties about what the DSO role and transition will involve.

The Customer-Led Distribution System (CLDS) project is an iterative three-year innovation project. It will provide evidence to increase understanding of what the DNO to DSO transition looks like. CLDS aims to identify and demonstrate the most appropriate market design and industry structure for the future, by contributing evidence from desktop and laboratory studies.

Customers are the focus of this project. We are therefore looking to understand how value can be created for customers for example by reducing the need for costly network reinforcement and by increasing photovoltaic (PV) utilisation. We are also looking to understand how this value will be distributed across those customers, depending on ownership of Distributed Energy Resources (DERs).

1.2 About this report

The first stage of the project has been focussed on increasing understanding of local energy markets (marketplaces that enable customers with generation or storage to trade energy within local communities) using quantitative analysis from desk-based modelling undertaken by Professor Furong Li and her team at the University of Bath[2]. This early deliverable aims to improve understanding of DER value for customers and critically the key drivers. The main questions this work has sought to address are:

- What drives the value of DERs and how is this affected by different mixes of DERs and network loading conditions?
- What is the value of introducing local energy markets and how does this value vary if different market arrangements are put in place? What problems may arise if these market arrangements are not optimised? What impacts are these markets likely to have?
- What does this imply for the DNO to DSO transition?

This report provides a summary of some of main results from this work[3].

As well as informing thinking on our own DSO development plan, we believe that this work will provide useful learnings for a number of current industry programmes including

[2] Professor Furong Li, Dr Chenghong Gu, Can Tang, Haiwen Qin, and Dr Zhong Zhang

[3] The full paper "Benefit Assessment from Introducing Local Energy Markets", which provides more detail on the modelling undertaken and the results achieved (including further sensitivities), is available .on: www.northernpowergrid.com/innovation/projects/customer-led-distribution-system-nia-npg-19

Ofgem's Targeted Charging Review and future thinking on the implications of the transition to Electric Vehicles (EVs).

2. Methodology

2.1 Approach

The analysis centres on EVs as a source of flexibility in the electricity system. Focusing on the actions of EV users is particularly interesting, given that decisions they make about when to charge and to discharge their batteries will have consequential impact on the efficiency of the local energy system (for example, the impact on network investment requirements and in the utilisation of PV generation).

The focus of this study has therefore been to investigate how EV users will react to differing market conditions when deciding when to charge (and potentially discharge) their vehicles, the impact this will have on changing network load profiles, and how this will in turn affect the efficiency of local energy systems. This is investigated under a variety of DER levels and network loading conditions, including for networks that may be characterised as being predominantly “domestic” and those that would be characterised as “commercial”.

2.2 The sample system

This work uses a small sample system to model a simplified energy system over a single day. This energy system consists of the different components of energy generation and usage “beyond the meter” (EV demand, PV generation, classical demand) and the energy sold to and purchased from the national electricity market, as illustrated in Figure 1.

In this model, demand is met by a combination of national and local supply, the latter made up of local PV generation[4], and of the discharge of EV batteries.

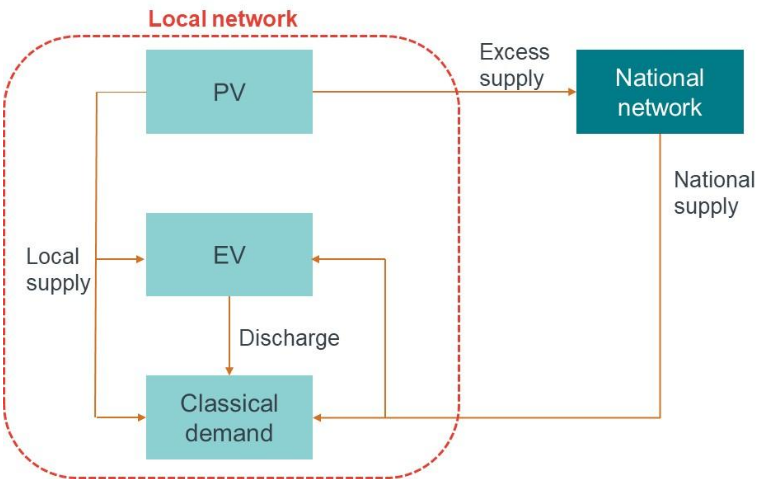


Figure 1: ***Agent relationships***

Key assumptions made

1 The local PV generation is inflexible, only generating when weather conditions permit.

[4] Other forms of distributed generation, e.g. wind, are not included. We note that these may have very different temporal patterns to PV and therefore different implications for the analysis.

2 It is assumed to be the cheapest generation available on the system meaning that, if there is sufficient local demand, it will be used locally.
3 There is a retail business model in place that maximises the use of locally generated electricity. This is through a local energy market that enables direct trade between EV users and PV owner, where the PV user can buy energy from the local energy market and/or the national energy market when their own PV cannot meet their own demand.
4 If local demand is insufficient to use all PV generation, it is exported to the national network.
5 Supply side flexibility is provided to the local network by the discharge of EV batteries and from the national energy market.
6 Demand on the network comes from two sources:
    ➢ First, there is a fixed amount of demand that is assumed to follow a given profile throughout the day. There is no flexibility associated with this.
    ➢ Second, there are EVs. These provide a source of flexibility on the network: EV charging and discharging profiles can be moved within the day through the use of vehicle-to-grid smart technology. These are subject to a set of modelling assumptions regarding their time to charge and discharge and the required state of charge of the batteries.
7 No diversity: all EV users respond to the signal to move charging to follow PV generation.
8 Outside of the EV batteries, there is no storage connected in the same system.

Variables

There are three inputs to this model:

- PV generation;
- EV demand; and
- other network demand.

Each input has three possible values (low, medium, high), which gives a total of 27 input combinations.[5]

[5] These scenario inputs are taken from National Grid's Future Energy Scenarios.

2.3 Energy and network impacts

In this sample system, EV users can change the time at which they charge to affect both the use of local PV generation, and the load on the network. When assessing the impact of these charging decisions, it is therefore helpful to characterise these two impacts separately.

- **Energy impact**: Local PV generation is assumed to be inflexible. If local EV users can charge their vehicles when this energy is available, then more of the PV generation is consumed locally. If there are constraints that prevent that generation being transported to the grid to be resold via the national market, and if local demand is insufficient to utilise it at the time it is produced the PV output will need to be curtailed, which would result in less PV generation being consumed locally.[6.]
- **Network impact:** There is a physical limitation to the capacity of the network (without additional investment). Given the potential scale of EV demand, when these vehicles charge or discharge will impact on whether the network capacity will be breached, requiring further investment. Reducing overall system peak demand by moving the time at which EVs charge/discharge could mean that network reinforcement can be avoided, provided that this behaviour is reliable and sustained.

It is easy to see that EV users' decisions to move charging to take advantage of cheap local PV and therefore increase energy benefits to themselves, as well as to the PV owner, could either benefit the network (if it takes charging away from peak network use) or be an issue to the network (if it was moving charging to a time when the network was already close to capacity). In the event of a conflict, we assume that EV users will respond blindly by "following the money", i.e. moving the time of charge to whichever provides the higher value (paying less for charging or receiving a payment to reduce charging or to discharge at the time of system peak).

2.4 Price signals

Unit prices act as a signal to EVs about when to charge and discharge. There are two price signals that EV owners face in this model:

- a signal to charge EV batteries when local PV is available (on the assumption that represents the time when generation costs will be lowest); and
- a signal to reduce charging or to discharge EV batteries at times of local system peak (paid by the network, driven by the assumption that this will provide the highest value associated with discharging the batteries, through lowering network costs)[7].

[6] As per Key Assumption 8, we do not consider storage in this analysis.

[7] The value to EV owners for the energy they supply is not included in this analysis, which focuses on the value arising from a reduced system peak.

Signposting the potential for further research

In the model, EV users are assumed to respond perfectly (and to the same extent) to any price signal that provides them with a monetary incentive for moving the time at which they charge, regardless of the size of the price signal. It is helpful to think about what could drive EV users to respond in the way that this rule requires. One way to interpret this behaviour is to assume that they were responding perfectly to a market signal that was provided to encourage such behaviour (with no other conflicting market signals seeking to promote an alternative action). Another interpretation would be to think of the response being automated. For example, this could be part of a supply contract that allowed the supplier to move customer demand in this way. While either interpretation is clearly a simplification, looking at the different optimisation strategies allows us to isolate the impact of different value drivers. It also provides a benchmark against which we can measure relative differences between each of the strategies. Future work could explore alternate assumptions about customer behaviour.

Given that EV charging decisions are assumed to respond perfectly (and to the same extent) to any price signal, whether it is small or large, the value of the price signal simply scales the results: for example, if we halve the size of the price saving that comes from charging when there is excess PV generation, the size of the benefit will halve, given that the volume of charge that has moved to use up that excess PV has stayed the same.

The exception to this result is when EV users face both energy price signals and network price signals, and there is a conflict between simultaneously optimising EV charging. Where there is a conflict between the energy and network impacts, the relativity between the prices does matter. Therefore, a price change that increases the value of energy benefits could be sufficient for it to “tip” the EV user into following PV generation, even if that requires an increase in network capacity.

Unit prices for energy exchanges between the key actors have been set in the base case to approximately reflect the relative costs of different energy sources. These prices are detailed in **Error! Reference source not found.**.

The network price signal applies only at times of local system peak and is intended to incentivise EV users to reduce demand on the system through three mechanisms:

- A payment for reducing their charging at times of system peak relative to their usual behaviour
- A charge for increasing their charging at times of system peak relative to their usual behaviour
- A payment for discharging at times of system peak

An EV user who would normally charge at the time of system peak but who changes this to discharging instead receives a reward for the reduction in charging AND a reward for discharging.

Table 1: Summary of price assumption used

Operation	Price
EV charging from national supplier	10 p/kWh paid by EV user to national supplier
EV charging directly from PV = PV sells energy directly to EVs	6.5 p/kWh paid by EV user to PV owner
EV discharging to local network	51 p/kW/day paid by local network to EV user
EV reduces charging	51 p/kW/day paid by local network to EV user
EV increases charging	51 p/kW/day paid by EV user to local network
PV sells energy to national supplier	3 p/kWh paid by national supplier to PV owner
EV discharging and selling energy back to national supplier	Assumed £0

The differential between the prices paid by EV users for energy from the national supplier and direct from PVs is a key feature of the analysis. In the base case, this results in an EV user being able to save 3.5p/kWh by moving its charging to times of excess PV with a PV generator receiving an extra 3.5p/kWh for its generation.

This benefit to the EV user and PV generator represents a price differential due to the additional actions (and so additional cost) needed to integrate DG energy into the national system and the national market, compared to the much lower cost of integrating DG energy into the distribution system if it can be used locally by the EV user.

The costs of integrating the DG into the national system and which could be avoided are: distribution system costs for exporting the DG energy to other distribution areas or to the transmission system boundary; balancing costs at the boundary which includes the costs of inefficiently flexing central generation in response to intermittent DERs; and transmission system costs for making the energy available throughout whole system i.e. on the national market.

So if local markets exist which enable flexible local load to use the local DG, the costs of integrating the DG into the national system are reduced or avoided. This is a genuine cost reduction from a reduction in the scale of the central generation plant, transmission and distribution networks and their operations when flexibilities are aligned with DGs, and which benefits all parties who buy or sell energy. This price differential does not represent EV user and PV generator avoiding network charges or taxes/levies at the expense of other customers.

The network benefit arising from EV discharging (or reducing charging at peak) is valued at 51 p/kW/day. The value of flexibility is very variable and depends on the use case (e.g. whether the flexibility is required for deferring reinforcement, or for managing unplanned outages etc.) and the time and location where the flexibility is required. We have calculated the value of flexibility for avoiding reinforcement, based on the following components:

- We assume an asset cost for network line of £3million, which is discounted over a 40-year lifetime using a discount rate of 6.9% to result in an annual asset cost of £222k/year;
- An annual asset cost of £5,558/year/MW based on an assumed asset capacity of 40 MW;[8]
- The network benefit is then assumed to be equal to the annual asset cost divided by the number of peak days assumed in a year. In the base case, the number of peak days over a year are assumed to be 11, resulting in a value of £505/MW/day or 51p/kW/day[9].

If all of this is paid to EV users to discharge (or to reduce charging) 11 days per year for the next 40 years, then essentially the cost to all network users is the same as it would have been if the network company had invested in the line instead. But EV users receive an additional benefit because, although network charges in total will be the same, they will have received the payment.

Signposting the potential for further research

The example we set out here is one of EV users providing Vehicle-to-grid (V2G) services. As an alternative, EV users could provide Vehicle-to-home (V2H) services: using the energy stored in their batteries as the source of energy for their homes. The value for doing this resides in avoiding the cost of energy supply at peak time (if the car battery was previously charged at a cheaper rate), and decreasing network peak (hence keeping costs down for all customers, and potentially unlocking a payment). V2H services could potentially provide higher value to EV users which would potentially further advantage EV users (compared with other network users who would be left to pick up the system wide costs of meeting peak demand).

[8] The full calculation leading to this value is provided on page 22 of the full report "Benefit Assessment from Introducing Local Energy Markets" available at www.northernpowergrid.com/innovation/projects/customer-led-distribution-system-nia-npg-19

[9] When we interpret the results that follow, it is important to remember that this payment is only made on the 11 days of peak. On other days, the only price signal provided is the energy market signal. This is important because customers may become used to adapting charging behaviour to take advantage of the energy benefits and therefore be more reluctant to adapt these on the 11 days where the network benefit is in play.

2.5 Introducing alternative market arrangements

The price signals described above have been put together to form four alternative markets that are modelled as part of this work:

- No market (the counterfactual): There are no specific price signals provided to EV users, outside of the standard charges for energy and network charges.
- Energy market: The commodity on this market is energy and the unit kWh. This is both the retail and whole system piece of the energy supply chain. Through this market, for the purpose of the study, EVs are provided with a price incentive to charge as much as possible from PV output. The measure applied to assess the success of this market, in the context of DSO challenges is PV energy absorbed locally, as a proxy for:
    - the value to the PV owner(more sold at higher price),
    - the value to the EV user (more bought at lower price).
- Network market: The commodity on this market is capacity and the unit kW. This is distribution networks piece of the energy supply chain. Through this market, for the purpose of the study, EVs are provided with price incentives to reduce their charging and to discharge when the system peak occurs. The measure applied to assess the success of this market, in the context of DSO challenges is network reinforcement avoided, as a proxy for:
    - the network charges paid for by the EV user,
    - payment received by them from the network.
- Combined Energy and Network market: EVs are provided with simultaneous price incentives both to charge from PV output, and not to charge when the system peak occurs.

The results consider the impact that these different markets have on:

- the charging patterns of EV users,
- the use of local PV generation, and
- the network load profiles that result.

Seeing how these differ, and what that means in terms of value that flows to owners of DERs and the future network investment, is the focus of this study.

3. Results

3.1 Base case: profiles without any market intervention

This scenario illustrates how different levels of EVs, PVs and classical network demand can contribute to energy and network system problems. While it is obvious, that more EVs will lead to a greater chance of network peak capacity being exceeded, we show here how the extent of this problem varies depending on the type of network (domestic or commercial) and the associated assumption about how users will charge in the absence of any local price signals. For example, in a domestic area it may be reasonable to assume that the default is for charging to occur during the evening (when people return from work). But in a commercial area, the default assumption could be to charge during the day (when people are at work).

The base cases illustrate what would happen, without any additional price signals/markets. We consider two such base cases:

- Domestic: Here the demand profile for non-EV demand is akin to an area of the network that has a predominantly domestic demand profile, with peak demand in the evening.
- Commercial: This one has a pattern of residual demand that would be associated with a part of the network that is likely to feature largely commercial demand. This means that classical demand peaks in the middle of the day.

The PV Base Case profiles are the same for both commercial and domestic areas, as is capacity of the network cable. The EV Base Case profiles peak in the evening for domestic areas, and at midday for commercial areas. In domestic areas, we assume that people charge at home after the working day. In commercial areas, we assume that people charge at work.

Figure 2 shows domestic and commercial base case ‘medium’ classical demand. The different EV input levels (low, medium, high) are also shown along with the maximum line capacity.

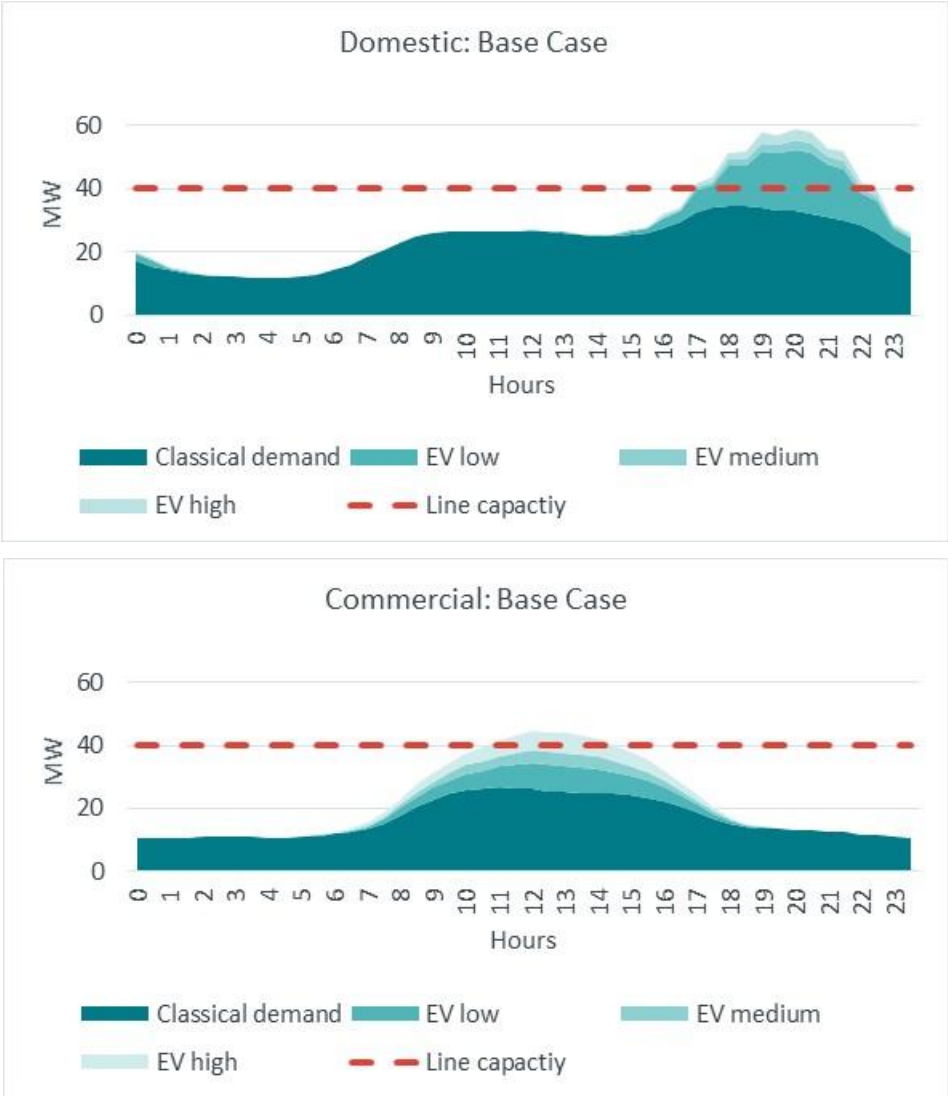


Figure 2: Domestic and commercial base case profiles

As the level of EV charging demand increases, the line capacity becomes increasingly breached, increasing the problem faced by networks.

Figure 3 shows the different PV generation input levels (low, medium, high) with medium classical demand and low EV demand. Without any market intervention, EV demand and PV supply generally do not coincide in domestic areas. PV supply exceeds classical demand for some input levels, e.g. when PV is low and classical demand is medium in the domestic base case. As a result, some PV energy will not be utilised by local demand. However, in commercial areas EV demand coincides with PV supply.

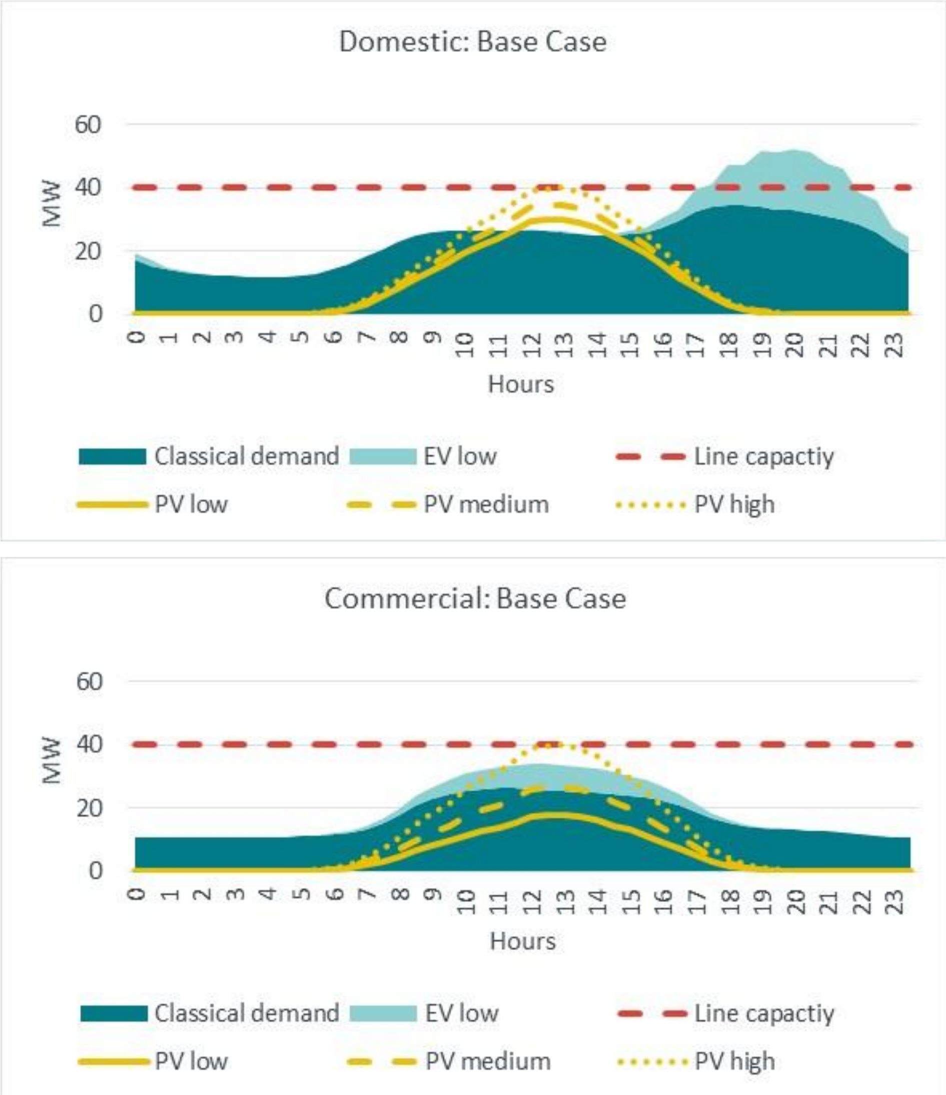


Figure 3: EV and PV inputs

In the commercial base case, classical demand peaks at midday. Therefore more PV energy is absorbed by local demand than in the domestic base case.

These simple charts illustrate the two potential problems that could occur in the system:

- Energy problem: whereby there is surplus PV supply in the network that isn't being used locally.
- Network problem: whereby network demand exceeds the line capacity.

It also shows that if distribution networks are made up of vastly differing sub-networks, with differing EV charging/discharging profiles and EV/PV penetration levels, different problems will be faced in different areas at different times. This may lead to one of four states: i) no problem ii) energy problem only iii) network problem only iv) both energy and network problems.

3.2 Market interventions: energy and network markets

Energy market

The goal of the energy market is for EV to absorb as much local PV energy as possible. Applying this optimisation rule will move the time of EV charging to the time of PV generation to the extent that there is PV generation available[10]. Figure 4 shows the new EV charging and discharging profile for the domestic case.

Instead of peaking in the evening as in the base case, EV charging now follows the PV generation curve. As a result, all PV generation is absorbed.

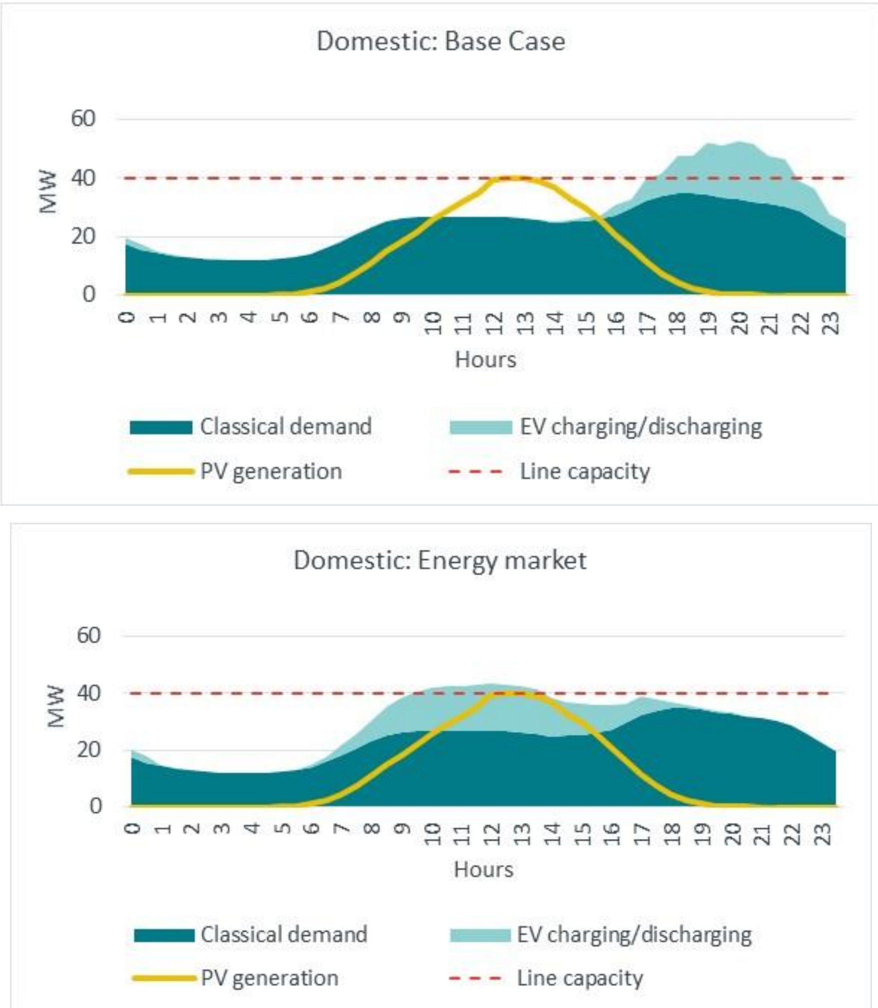


Figure 4: Energy market in a domestic area[11]

With the combination of inputs used in this base case, the EV charging profile can move to utilise the excess PV generation and reduce the amount by which network capacity is

[10] Note that it is assumed that all EV users respond to this signal and move charging to follow PV generation, even if only a proportion of that demand is actually needed. The model optimises to maximise PV absorption by EV without reference to classical demand. This is why EV demand moves to absorb PV generation even when the PV generation was already being consumed by classical demand.

[11] All graphs presented are for input levels: EV low, PV high, classical demand medium.

exceeded. In other words, by introducing an energy market, the local usage of PV generation can be maximised (reducing “energy problems”) while simultaneously reducing network problems. However, in this example this does create a new, although smaller, network problem at lunchtime.

The picture is different when looking at a commercial area, where classical demand and EV demand is already high at midday. The introduction of the Energy Market has a very small impact, because EV demand already coincides with PV supply under the no-market case. In the base case, total demand (EV + classical demand) peaks at 34.3 MW in hour 12. Under the energy market, total demand peaks at 35.4 in hour 11.

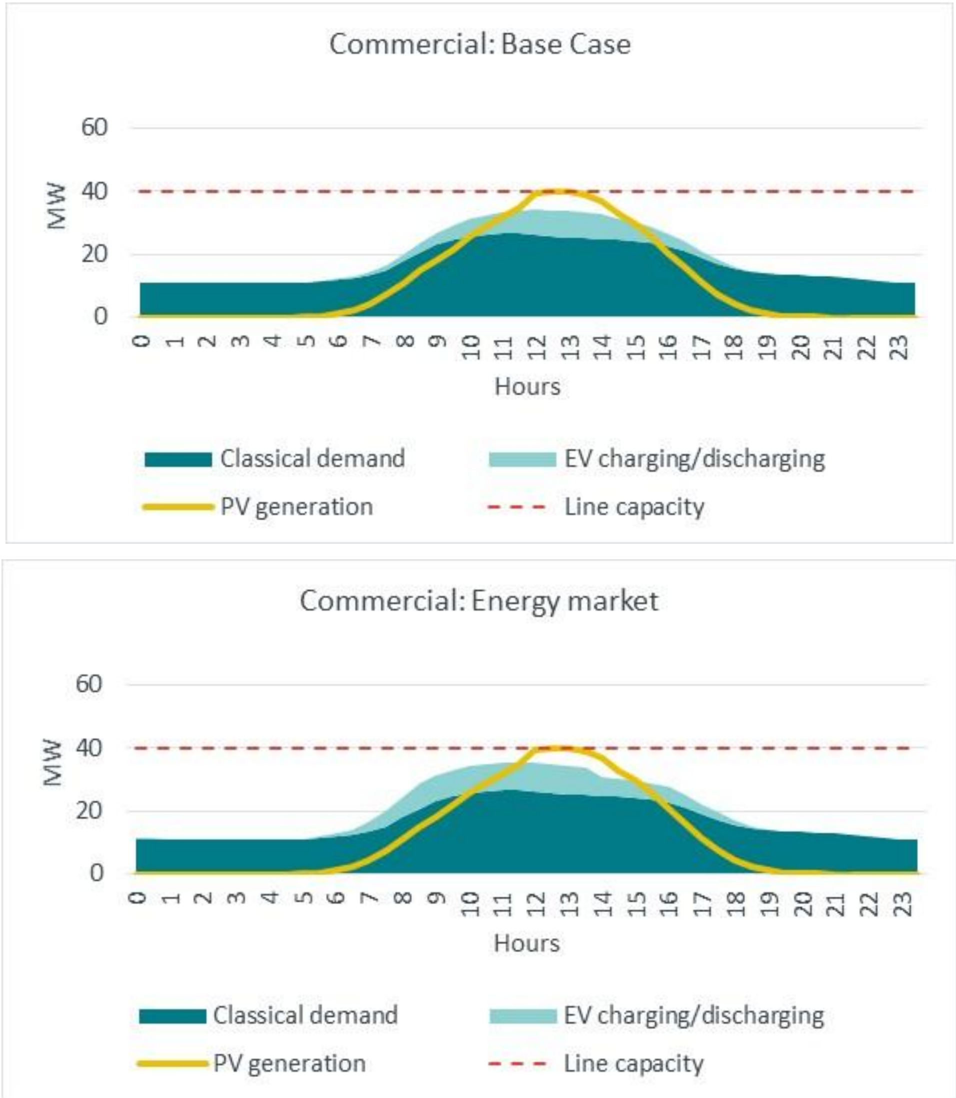


Figure 5: Energy market in a commercial area

Looking first at the Energy Market, Figure 6 shows what happens as EV and PV levels increase, compared with the base case for a domestic-dominated area[12]. “PV absorbed” is the total PV energy that is absorbed by local EV users while “reinforcement avoided” is the reduction in the amount of total demand (EV + classical demand) which exceeds the line capacity. For example, in a domestic area when PV is low and EV is low, 129 MWh of PV is absorbed locally under the energy market, and this change in the time of charging has also reduced the amount of demand exceeding the network line capacity by 7 MW.

As EV levels increase, more PV is absorbed by EV, and the amount absorbed does not vary by levels of PV. This is because the maximum amount that EVs can absorb is the limiting factor and the level of PV generation available even at low penetration exceeds the total demand of EVs even when EV penetration is high.

Under the energy market, EV charging demand creates a new peak at midday when PV is producing. Because this peak is lower than the no-market evening peak, there is a positive amount of avoided network reinforcement in all input scenarios. This means that an action led by the Energy Market (to absorb more PV) has an additional beneficial impact for the network in reducing the peak demand on that part of the local network. Counter-intuitively, the network benefit reduces in the high EV scenario.

With more EVs there is greater EV charging. In the no market scenario this additional charging is spread across the usual no market evening peak increasing network problems. With the energy market EV charging is shifted to the middle of the day and away from the evening peak, reducing network problems. However, it reduces the network problems by less than in the medium EV case because the additional EV charging is concentrated in the middle of the day and pushes up the new midday peak. Therefore the reduction from the old evening peak to the new midday peak is lower when there is high EV penetration.

[12] Modelled energy benefits are calculated based on the total volume of PV absorbed where there is an energy market. If there is no energy market, it is assumed that the value from EVs charging from PV is not captured.

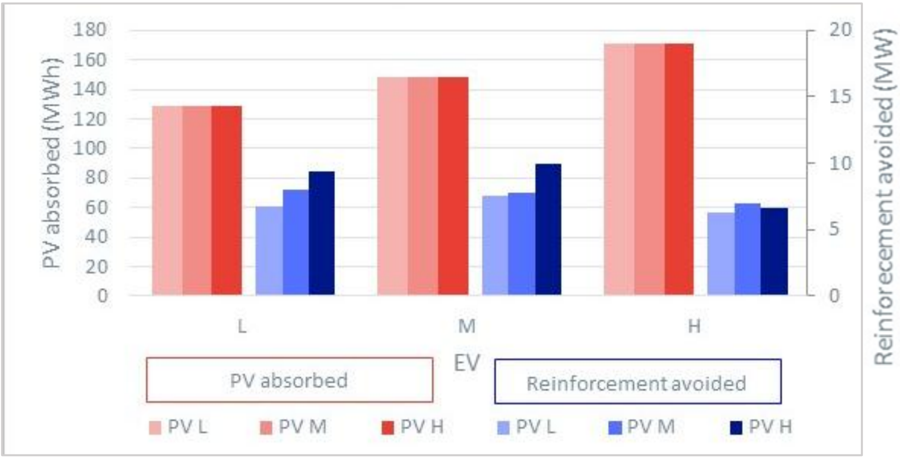


*Figure 6: Difference between outcomes under **energy market** and no market in a **domestic** area*

Figure 7 shows the same scenario but this time in a commercial area. Increasing EV levels from low to medium increase PV absorbed equally for all levels of PV. This is because the limiting factor is the volume of energy PVs can absorb. Once EV levels increase to high, the PV generation becomes the limiting factor if PV is low. For medium and high levels of PV penetration, EV absorption capacity remains the limiting factor as shown by the equal level of PV absorption for medium and high levels of PV given high levels of EVs.

More network reinforcement is needed as EV and PV levels increase (hence the negative figures for avoided reinforcement) because the midday demand peak increases. Greater network reinforcement is needed when PV supply is medium than when it is high. This is caused by the shape of the PV supply curve: when PV is high, generation occurs at a high level over more hours and so EV charging demand can be spread out evenly. This results in a lower peak than when PV is medium, and EV demand must be concentrated in fewer hours to absorb the PV.

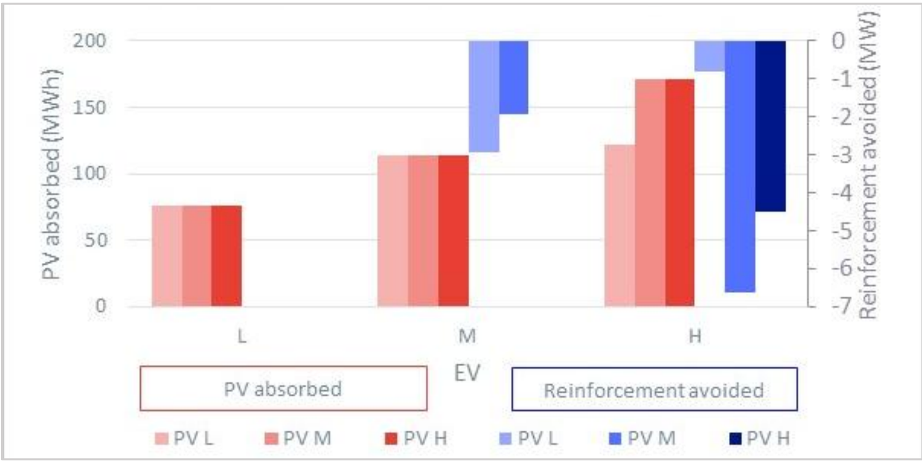


*Figure 7: Difference between outcomes under **energy market** and no market in a **commercial** area*

Network market

Under a network market, the price signals are set with the aim of reducing overall system peak. This will have the effect of reducing the amount of network reinforcement required.

Figure 8 compares the no-market and network market case in a domestic area. Under the network market, EVs shift their charging from evening to the early hours of the morning13. This ensures total demand does not breach the network line capacity. However, this shift means surplus PV generation remains unused locally in both the base case and the network market.

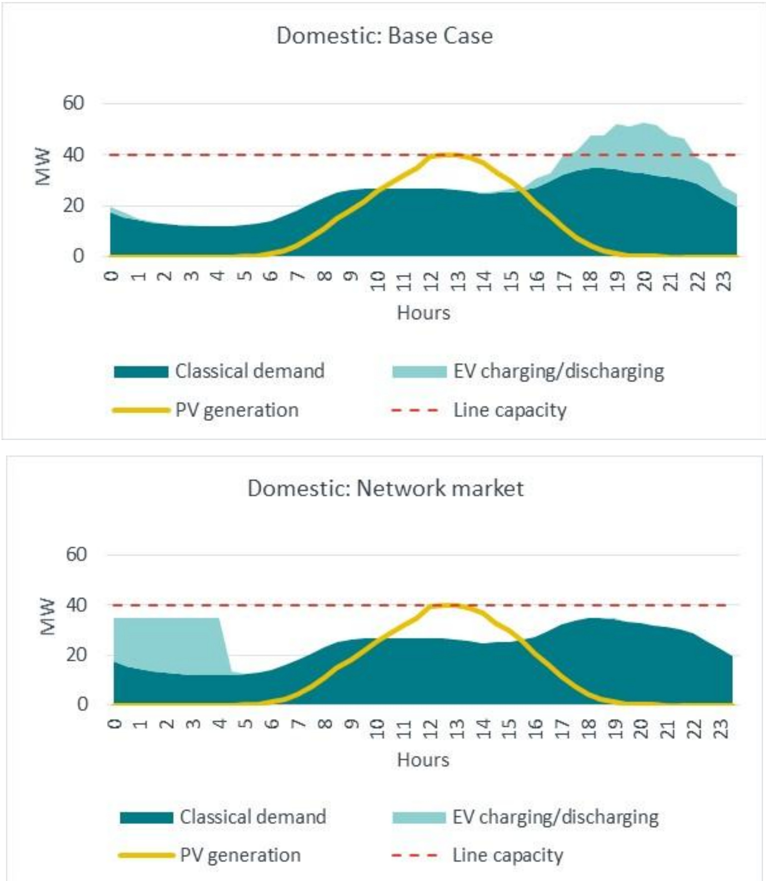


Figure 8: Network market in a domestic area

In the commercial base case, total demand (EV plus classical demand) peaks at midday when PV is producing. Under the network market, EV charging demand shifts to the morning when classical demand is lower.

[13] Note that the model seeks to minimise network peak demand rather than to hold peak demand below the capacity constraint. This means that even if there is no overloading of the network, the model will still try to move EV charging to reduce any potential peak demand (i.e. to flatten the load curve as much as possible). There are a wide range of possible EV charging profiles that result in the same minimum network peak demand and the model values each of these results as equally good. This is why EV demand appears concentrated in the morning and rather than spread over the day, as spreading EV demand cannot reduce peak demand any further.

No reinforcement is required in either the base case or the network market. However, a lower amount of PV is absorbed locally under the network market.

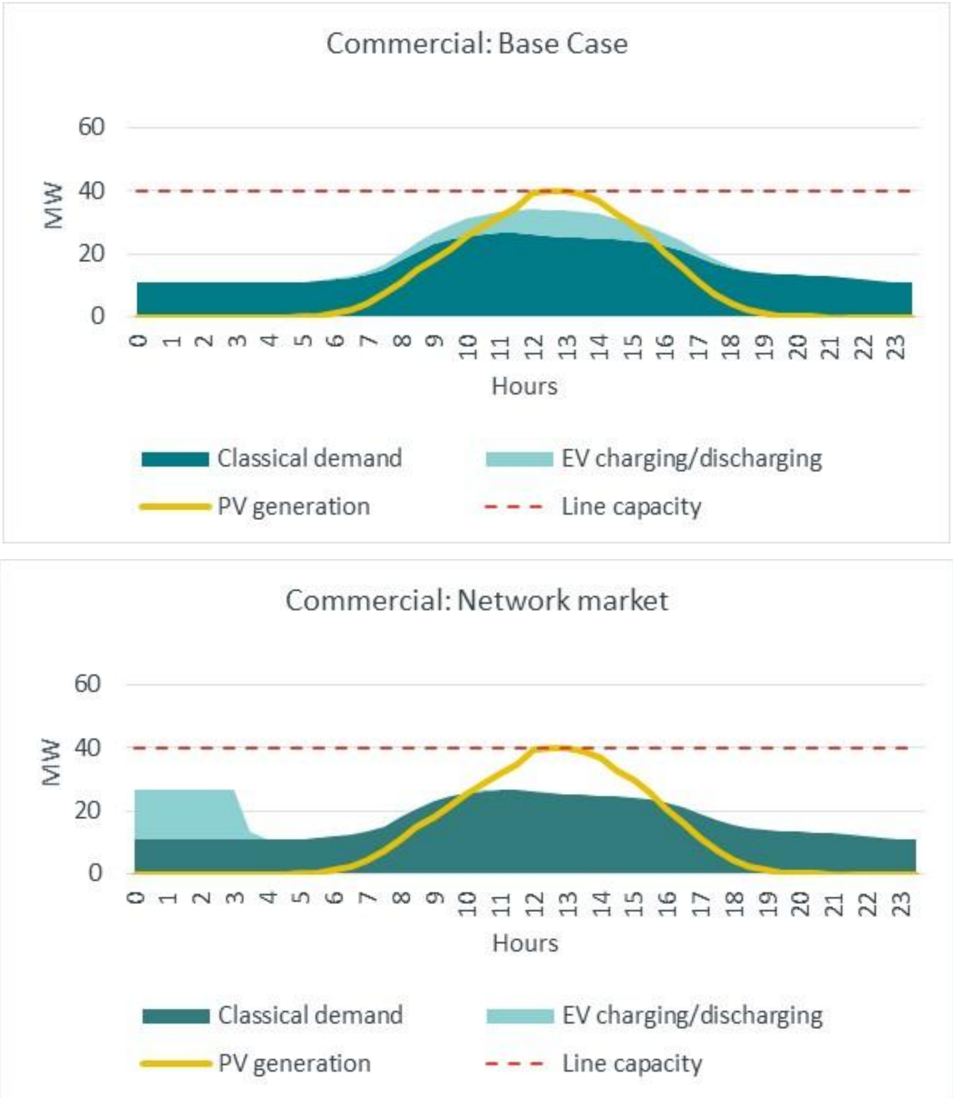


Figure 9: Network market in a commercial area

Figure 10 shows the volumes of PV absorbed and network reinforcement avoided under the market scenarios. Under the network market scenario less than 1MWh of PV is absorbed by EV for all levels of PV and EVs. That small amount that is captured in the earliest period in the day in which there is PV generation (around 5am). This is driven by the modelling optimising only for network costs and attaching no value to PV absorption.

Avoided reinforcement increases as EV levels increase because in the no-market case, higher EV means a higher breach of line capacity. There is no difference between the three PV levels because these do not affect EV behaviour in this scenario, or therefore whether or not the line capacity is breached.

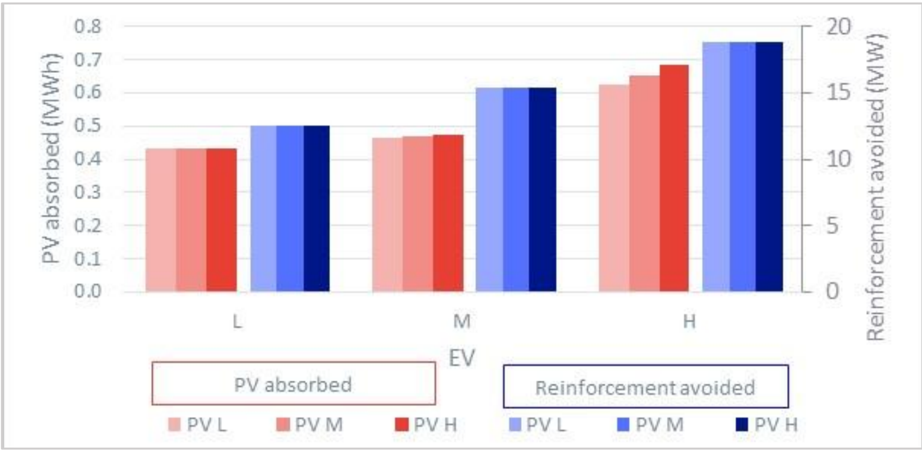


*Figure 10: Difference between outcomes under **network market** and no market in a **domestic area***

Figure 11 now shows the same scenario but this time in a commercial area. For low and medium levels of EVs the level of PV absorption is very low as in a domestic area and the result is driven by the same modelling factors. At high levels of EVs in the commercial area higher PV absorption is reported. This is primarily driven by lower observed peak charging rates in the commercial area than in the domestic area. This means that for high levels of EV demand full charge cannot be achieved before PV starts generating in the morning.14

Avoided reinforcement is only achieved for high levels of EVs. This is because at lower levels of EV penetration the network capacity constraints are not breached. Therefore, the moving of EV demand from midday to the morning does not generate value other than in the high EV case.

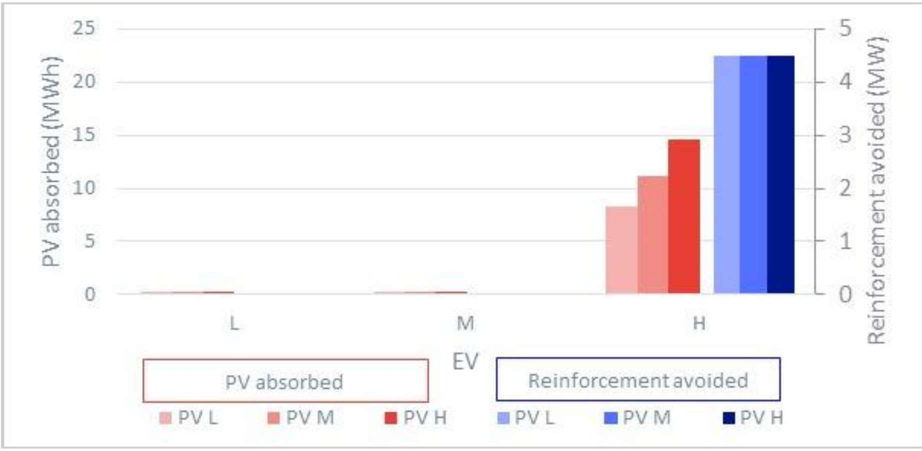


*Figure 11: Difference between outcomes under **network market** and no market in a **commercial area***

[14] The maximum charging power consumption observed in the domestic sector is 22.9MW. The equivalent for the commercial sector is 15.8MW

Energy and network market

We now combine the energy and network markets. EVs face a set of price signals to incentivise them to charge when PV is generating, and another set of price signals to incentivise them change their charging times and to discharge to avoid the maximum line capacity being breached.

Figure 12 shows the domestic area profiles in the base case and under the energy and network market. EV demand shifts from the evening to midday, which fulfils both aims of avoiding reinforcement and utilising local PV energy.

This outcome is preferable to either the energy only or network only markets. In the energy only market, all PV was absorbed but the line capacity was exceeded, meaning network reinforcement would be required. In the network only market, total demand remained under the maximum line capacity but almost no PV energy was utilised locally.

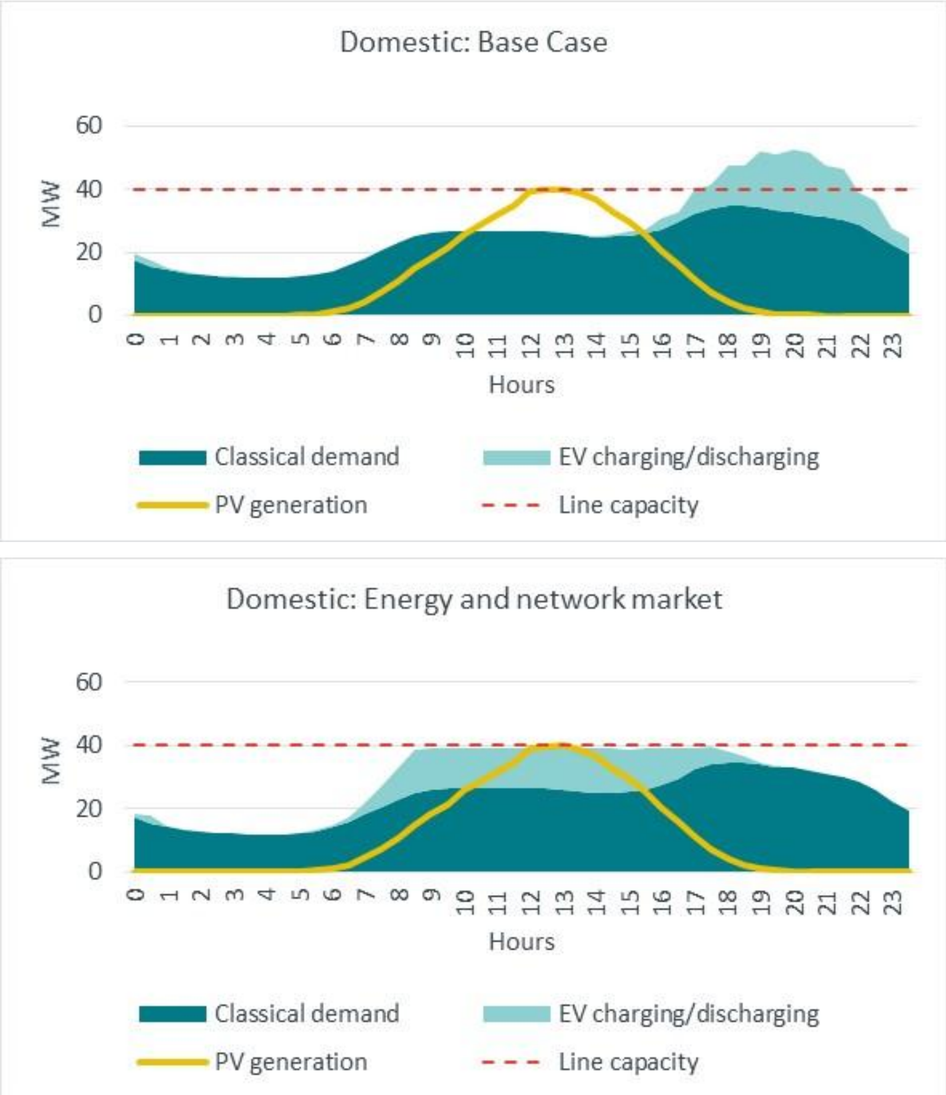


Figure 12: Energy and network market in a domestic area

Figure 13 shows the commercial area base case compared to the combined energy and network market. EV demand does not shift substantially under the market because in the base case, it is absorbing PV energy without breaching the maximum line capacity.

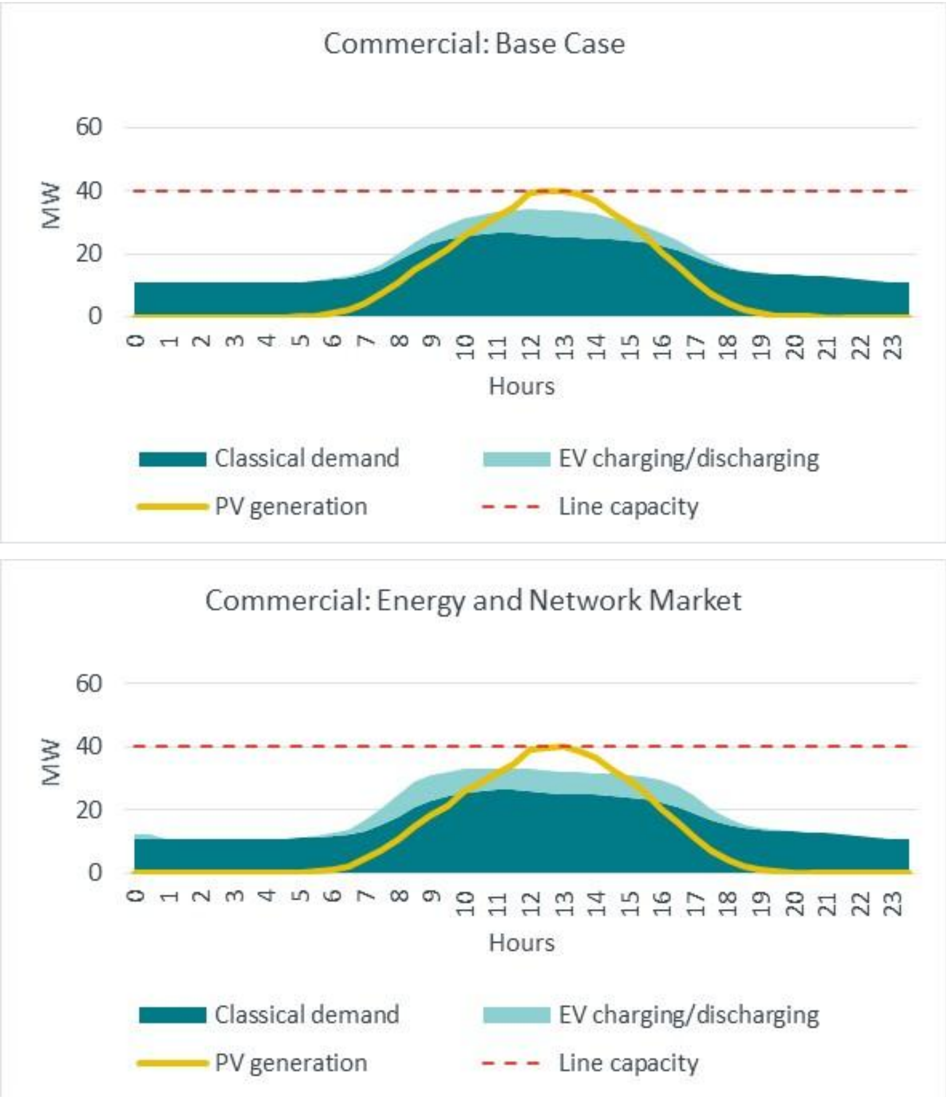


Figure 13: Energy and network market in a commercial area

At low levels of EV penetration it is the limiting factor and additional PV penetration does not increase total PV absorbed by EV. Once EV's reach medium penetration PV generation combined with the classical demand profile become the limiting factors. This means that further increases in EV penetration to high levels do not increase the volume of PV that is absorbed by EVs as no further EV charging at times of PV generation is possible without breaching the network capacity constraint.

Avoided reinforcement increases as EV levels increase, because in the no-market counterfactual the line capacity is exceeded by a greater amount when there is more EV demand on the network.

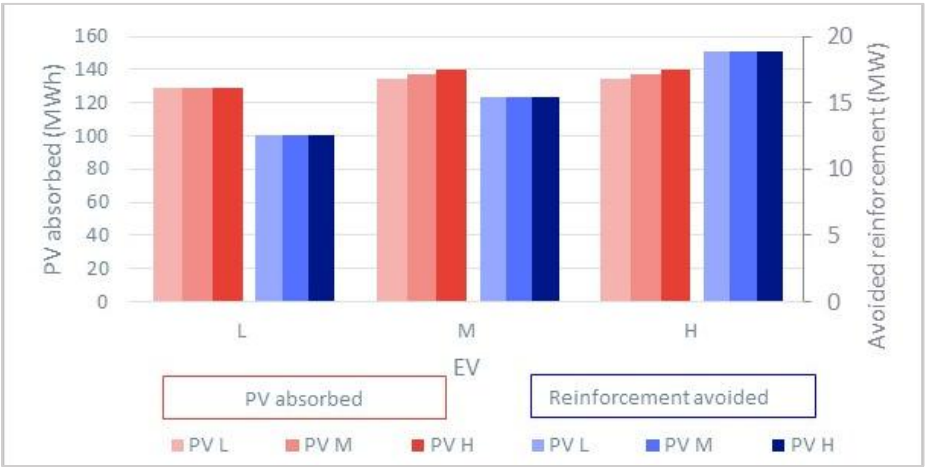


*Figure 14: Difference between outcomes under an **energy and network market** and no market in a **domestic** area*

Figure 15 shows that as with an energy only market, increasing EV levels under the energy and network market in a commercial area initially lead to more PV being absorbed by EVs equally for all levels of PV penetration. However, once a high level of EV penetration is reached the level of PV generation also starts to matter. This is in contrast to the energy only market where the level of EVs is the only driver of PV absorption. The reason for this is that the network price signal dis-incentivises EV charging at the time of peak PV generation to prevent the network capacity constraint being breached. Effectively this pushes EV charging into the shoulder periods of PV generation. In the shoulder periods of PV generation at high levels of EV penetration there is excess PV demand and so increases in PV generation are absorbed by EVs.

The level of avoided network reinforcement is the same as under the pure network market only and is not influenced by the level of PV generation. This result reflects the fact that the incentive in the model to avoid breaching the network capacity constraint is stronger than the incentive to absorb more PV.

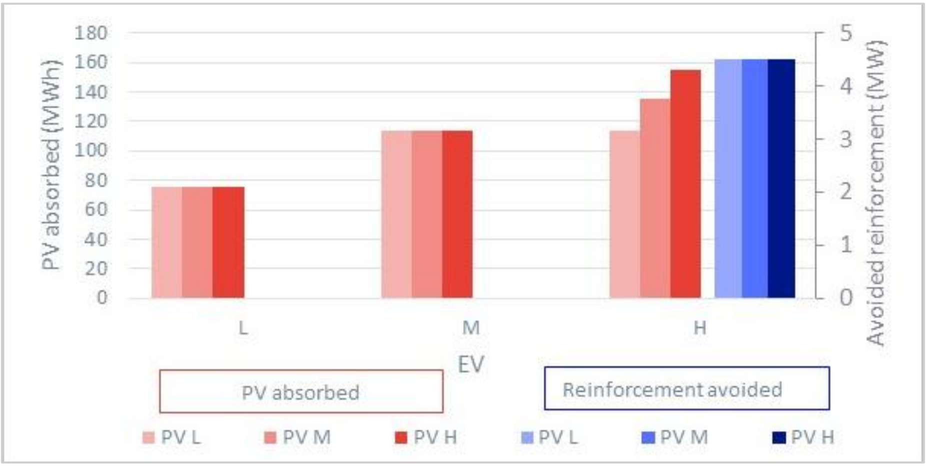
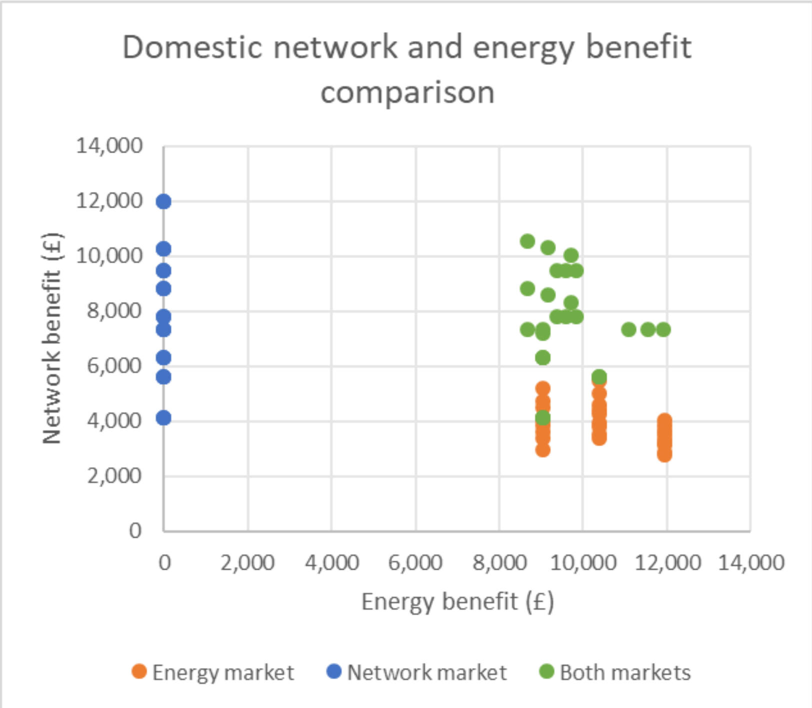


*Figure 15: Difference between outcomes under an **energy and network market** and no market in a **commercial** area*

3.3 Monetary value analysis

The results we have illustrated so far just look at the volume of PV absorbed by EV or the capacity of network reinforcement avoided in response to being provided with market incentives to do so. We now look at the value of this, given the values we set out in **Error! Reference source not found.**. Note that the modelling works on the assumptions that the amount of demand that is moved is invariant to the size of the price signal provided, and that when EV users face a conflict between moving demand in response to an energy market signal or a network market signal, they respond to whichever signal provides the higher value.

The values we present are calculated for a single day. It is also important to remember that the network benefits only occur on 11 days of the year when the network is system peaks occur. Similarly, the energy market will only have a value on the days the PV is producing at the levels assumed in the base case.



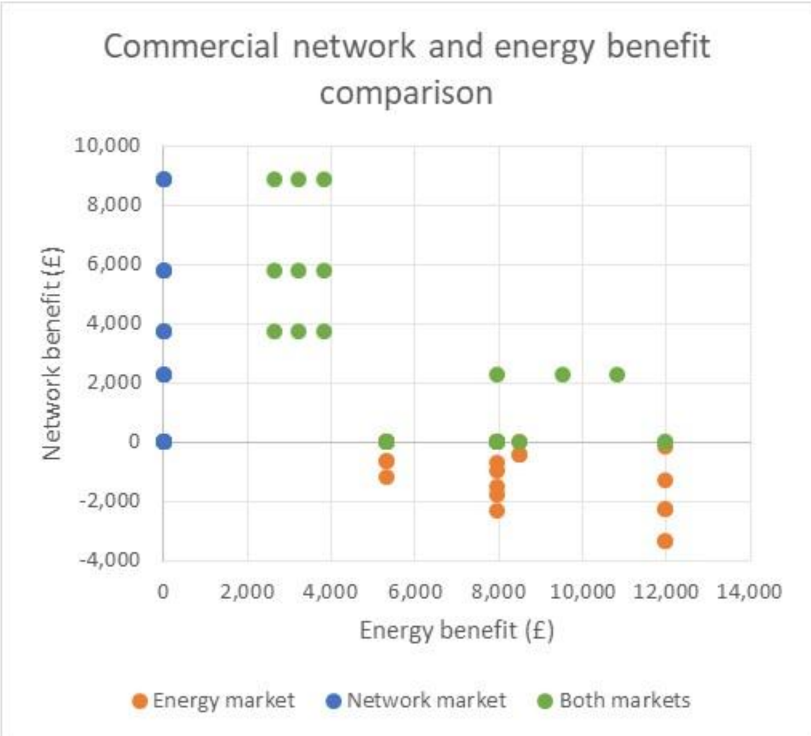


Figure 16: Energy benefit against the network benefit for all markets and input sets

When only the network market is in place, no energy benefit is created. This is because without an energy market the modelling assumes that no value can be realised.

When only the energy market is in place, as well as resulting in an energy benefit, there will also be an impact on the network benefit.[15] This is because if EV owners shift their charging from evening to midday to absorb more PV, this also has an impact on the networks. In the domestic area, there is a positive network benefit because EVs shift usage away from the evening peak to charge at midday where there is surplus network capacity. However, in the commercial area the peak in classical demand is in the middle of the day. Therefore, encouraging greater EV charging in the middle of the day exacerbates rather than reduces network capacity problems.

When both energy and network markets are in place, there are non-negative energy and network benefits in all input sets for both the commercial and domestic cases. This shows the importance of exposing EV users to both sets of price signals. This is in part because the network benefit is likely to be the dominant force on for EV users in this example, given the assumptions of value in Table 1 – so no EV user will want to breach this limit. If the value was much lower, then this may not be the case.

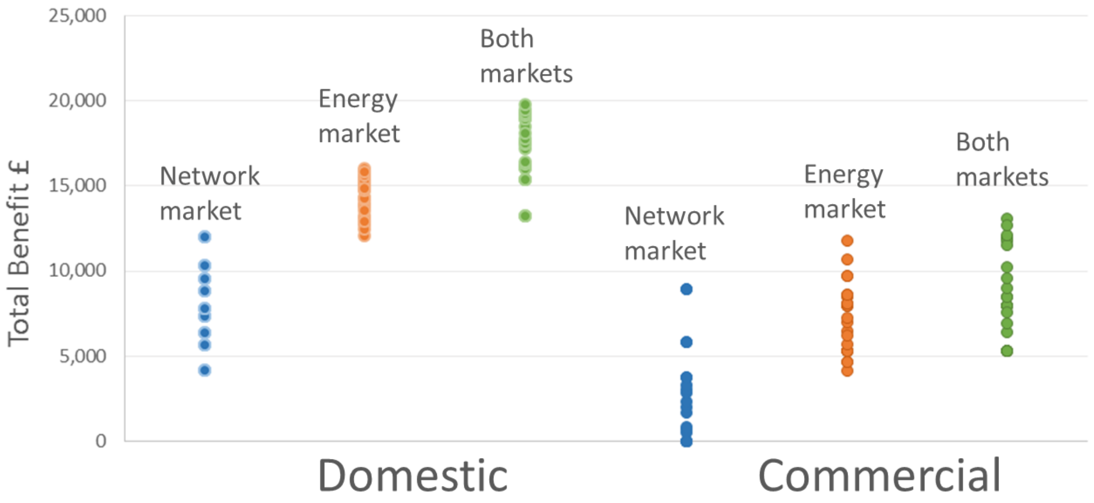


Figure 17: Total benefit of each market against all input scenarios

Figure 17 illustrates that the benefit is highest when both markets are deployed together. Domestic areas see a higher benefit in all market contexts than the commercial areas. This is because of the greater network benefits that are realised in domestic areas from the introduction of markets for either energy, or network or both together than is realised in commercial areas. Domestic areas have larger network challenges in the no market

[15] Network benefits and disbenefits are considered in the energy only market as this reflects the physical reality of the effect of customer behaviour which will have a financial impact even if there is no active network market.

scenario and therefore greater scope to address these by moving EV charging demand. Conversely, in commercial areas network capacity constraints are typically not breached in the no market scenario.

This analysis is an initial investigation into how energy and network markets could impact PV absorption and network reinforcement. It included sensitivity analysis of the relative strength of the network and energy price signals when both markets are in operation, finding that the relative strength should reflect the level of network congestion in order to maximise the total benefits.

4. Long term value of energy market and network market

The previous section analysed benefits on a single day where there were network issues alongside energy issues. This section extends the analysis from a single day to a whole year to determine the total benefit from introducing network and energy markets, the relative benefits between energy and network markets across the whole year, and an estimate of the total benefit over the period 2030-2050.

4.1. Methodology

While energy problems exist to some extent on every day of the year, network problems do not occur every day. To calculate the annual benefit from the network market, it is necessary to find out the number of days when there are network problems.

Extending from one day to one year is not a simple linear extrapolation, but requires considering different types of days as energy problems are closely related to the weather and seasonal conditions, and the network problems are largely related to loading conditions.

The whole-year analysis involves the following process:

Annual benefit from introducing energy market

i) To calculate the annual benefit from the energy market, a sunny day and a cloudy day are used for each of the four seasons, giving a total of 8 typical days.

ii) The benefit from energy market for each typical day is analysed using the same approach as in the previous section. Then the annual benefit is obtained by extending the benefit from 8 typical days to one year.

Annual benefit from introducing network market

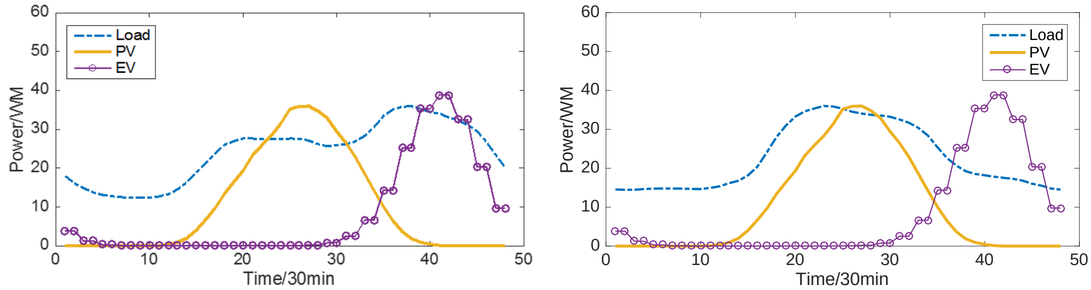
i) Network problems do not occur every day. To calculate the annual benefit from network market, it is necessary to find out how many days there are with a network problem.

ii) A network problem is considered to occur when the load exceeds a certain threshold such as 95% of the annual peak load. Based on the annual load profile from national grid, the number of days when the load exceeds 95% of the annual load peak is 11. The electrification of heat and transport will push this number up very substantially, so we also considered a scenario with 127% network problem, under which the number of congestion days increased to 110 as well as the congestion problem being more severe.

iii) The benefit from a network market on a typical day is extrapolated to the whole year by extrapolating the daily network benefits to the whole year by multiplying the daily benefit by the number of days with a network problem in a year.

4.2. Benefit calculation and extrapolation

The relationship between benefits from an energy market and a network market is investigated for two areas: a domestic-load dominated area and commercial-load dominated area. Fig. 18 presents the PV, EV and traditional load profiles in both areas, where EV charging is in the evening. Two load levels are considered: under low load level, there are 11 days with network problem and under high load level, there are 110 days with network problem. The network congestion under high load level is more severe than that under low load level.



(a) Domestic (b) Commercial

Fig. 18 Domestic & Commercial dominated area- original EV charging in the evening

Energy and network benefits in low loading conditions:

1) *Domestic dominated area with a low loading level*

On a typical sunny day, the total benefit of PV and EV from the energy market is £12,173. The benefit from the network market is £13,187.

For the energy market, extending the benefit from 8 typical days to a year, the annual benefit from energy market is £4,583,487. For the network market, we consider 11 days with a network problem in the low loading condition. The annual benefit from network market is £177,824. In this case, the annual benefit from the energy market is 26 times that from the network market.

2) *Commercial dominated area with a low loading level*

In the commercial dominated area, the annual benefit from energy market is £4,583,487. The annual benefit from network market is £72,215, significantly less than in the domestic dominated area because the original load peak in commercial dominated area is low. The annual benefit from energy market is 63 times the benefit from network market.

Energy and network benefits in high loading conditions:

1) *Domestic dominated area with a high loading level*

In conditions with high loading levels, there are 110 days with a network problem, and the network congestion is more serious than under low loading levels so the network market can deliver more value than under low loading levels. The annual benefit from the network market is £227,755. The annual benefit from energy market is unchanged and is 20 times that from network market.

2) *Commercial dominated area with a high loading level*

In the commercial dominated area with 110 days with network issues and more severe network congestion, the annual benefit from network market is £127,765. The annual benefit from energy market is 36 times the benefit from the network market.

Comparison of benefits under different conditions and for different areas

The relationship between the benefits from independently introducing an energy market and a network market in different types of areas and at different loading levels are summarised in Table 2. The original load peak in the commercial dominated area is lower than in the domestic dominated area so the benefit from the network market in commercial dominated area is significantly less, corresponding to a higher ratio of the benefit from the energy market over the network market. In the high loading condition, the congestion problem is more serious so the benefit from the network market is higher than under the low load level; hence, the ratio between energy market and network market is reduced compared to the high load level.

Table 2: Ratio of benefits from energy market compared to network market

Area type	Low load level	High load level
Domestic dominated area	26 times	20 times
Commercial dominated area	63 times	36 times

4.3. Extrapolation of benefits to the whole country and up to 2050

An early Poyry/Bath study[16] indicated a potential GB-wide benefit of £2.9bn from demand side response supporting the distribution network (i.e. network market) over a 20 year period from 2030 to 2050 when following the Alpha pathway to decarbonise the GB electrical supply system. The Alpha Pathway assumes the most aggressive deployment of renewable wind and solar and major electrification of heat and transport, providing the appropriate conditions for local markets and the local energy system to flourish.

A simple extrapolation to determine the benefit from introducing energy markets is to assume the GB system has an equal share of systems with low and high loading levels and that within each of these there are equal proportions of domestic and commercial dominated areas. This gives an energy market to network market benefit ratio of 30. Applying this ratio to the £2.9bn network benefit indicates the potential value from introducing energy markets to be £87bn in the period 2030-2050.

[16] DECC, "Demand Side Response: Conflict Between Supply and Network Driven Optimisation", Poyry/University of Bath, in August 2011

5. Implications

5.1 DER value depends upon levels of DER uptake and network loading conditions

Energy and network problems vary with differing levels of DER uptake and at different network loading conditions, and this impacts DER value. Not all DERs cause energy and network problems in the same way: the problems vary depending on the relative time displacement between when EVs would naturally charge and when PV generation happens, and between EV demand and other demand. The problem also varies with the relative penetration level between PVs and EVs and the network loading conditions.

Requirements will differ across the network depending on network capacity, existing load and DER penetration. Also, sometimes DER requirements are in sync without additional charging signals (e.g. in commercial areas where demand and PV production may already be aligned). Indeed, DER “value” is higher, the more problems it creates that you then need to solve. So EVs have a network value when they would cause a network constraint unless they charged at a different time, and they have an energy value when they wouldn’t use PV generation if they charged without the influence of TOU pricing signals. Also, their value is linked: EVs become more valuable as a way of utilising PV, but only if there is excess PV to use.

5.2 Impact of market arrangements on DER and system value

Appropriate market arrangements increase the value that can be captured by DERs (and potentially the system as a whole). You are always at least as well off, and often better off, if you provide accurate signals for both networks and energy market simultaneously. You would only not do this if there were high costs associated with setting up a market to provide those signals, and one set of values (either energy or network) that was clearly dominating the others.

It is important to establish whether solving a problem in one location/time period creates benefits or costs in another location/time period. As well as highlighting that appropriate market arrangements should increase the value that can be captured by DERs (and potentially to the system as a whole), the reverse is also true: market arrangements that fail to correctly value both network and energy costs may worsen system performance. Indeed, the results illustrate that markets should have locational parameters to ensure that they solve problems rather than simply moving them around.

5.3 Impact of conflict between energy and network value

There are circumstances where there is a conflict between energy and network requirements for when EV users charge. In these cases, it is important to consider the implications of that. In particular, if the value of potentially curtailed PV generation was high, it is likely to be the case that there would be value in increasing network capacity to be able to utilise it, given that EV users cannot simultaneously use the PV generation and discharge to reduce the system peak at this time.

In this model, we assume that the network benefit is only available on 11 days of the year: therefore, for most days (at least when PV is generating), EV users will only be responding to an energy market price signal. There is a question whether EV users will be able to react in such a way that they change behaviour on only a minority of days unless the value to doing so is significantly higher than is available from the energy market.

5.4 Relative size of benefits from energy markets and from network markets

While the benefits available on any day from an energy market or from a network market vary according to the local load characteristics and on the weather and seasonal conditions, over a year DER owners and users can get significantly more value from their assets by participating in local energy markets compared to providing services to the distribution network.

The benefits to DER owners and users from participating in local energy markets are between 20 and 63 times greater than the benefits from participating in the network services market, dependent on the network conditions e.g. whether the networks are dominated by domestic or commercial load and whether they are lightly or heavily loaded.

5.5 Implications for DNO to DSO transition

We expect the electricity industry to evolve so that, in addition to the dominant national energy market, there will be new and growing markets where distribution connected customers can participate in:

- Local markets to trade flexibility in demand and generation that reward customers for providing services to the regional DSO and/or the national Electricity System Operator to manage their networks;
- Local energy markets that enable customers with generation or on-site storage (including V2G capability) to trade energy within local communities; and
- Regional energy balancing markets which balance energy supply and demand on the network

With this complexity, it is important to understand the various pieces of the energy supply chain that we are seeking to maximise value from (i.e. what asset and value for whom?). Further, establishing market principles to coordinate the different markets is a necessity, particularly if there are competing objectives (for instance between network optimisation and energy optimisation) – especially because price signals alone may not be adequate to deliver overall optimisation of the electricity system.

5.6 Future builds on the modelling work

This early stage modelling work provides some initial insights into the impact shifting EV charging behaviour. Possible future extensions to the modelling work could explore the following areas:

- **Prices** More complex analysis could extend the price sensitivity tests to situations where EVs face a conflict between charging when PV is producing and exceeding the network capacity.
- **Behaviour** An elasticity of response could be modelled whereby EV owners shift their charging by a greater degree when faced with a stronger price signal. In addition, not all EV owners will have the ability or the desire to change their charging times in response to price signals and this could be modelled by assuming only a proportion of EV owners respond to the price signals, while the rest do not change their charging behaviours
- **Distribution** This analysis starts to highlight some of the important distributional issues associated with DER expansion. For example, in this model, DER owners are the ones that are being paid to avoid the costs of network expansion, with other network users picking up those costs. Owners of PV and EVs may be from a different socio-economic group to other customers and so where the cost incidence of paying EV owners to change their charging behaviour falls will have distributional impacts. There is a particular concern regarding behind the meter activity (e.g. V2H) where DUoS charges and VAT are avoided. This raises issues of tax avoidance, and the need for understanding who pays/avoids paying for social and environmental levies that are applied to energy bills. Different charging and payment arrangements could be investigated to understand the full impact of introducing these energy and network markets on all customers, not just PV and EV owners.