Demonstrating Demand Management:
How Intelligent EV Charging Can Benefit Everyone

Julian de Hoog[1], Kristian Handberg[2], Raman Jegatheesan[3]

[1]*Mechanical Engineering, University of Melbourne, Melbourne 3010 Australia. julian.dehoog@unimelb.edu.au*
[2]*DiUS Computing, Level 10, 99 Queen St. Melbourne 3000 Australia. khandberg@dius.com.au*
[3]*United Energy, 43-45 Centreway Place, Mt.Waverley 3149 Australia. raman.jegatheesan@ue.com.au*

Abstract

This paper establishes the case for Electric Vehicle (EV) charging demand management through in-field demonstration, electricity network modelling and financial assessment. As part of the Victorian Government Electric Vehicle Trial, DiUS Computing demonstrated EV charging demand management using United Energy's Smart Grid. Modelling of the United Energy network by the University of Melbourne found that uncontrolled charging would require network augmentation once EVs are adopted by 10% of households. In contrast, managed charging would allow the network to support in excess of 50% uptake using existing capacity and infrastructure. Furthermore, the end-to-end EV charging demand management solution demonstrated by DiUS could be implemented for one tenth the cost of the network augmentation. Although success factors were identified during the demonstration that may serve as an input for demand management program design, electricity market arrangements may be the strongest determinant of adoption generally.

1   Introduction

With the slow but steady rise in market share of electric vehicles (EVs), utilities are starting to take their impact on the electricity grid very seriously. A variety of recent studies suggest that EVs can contribute to increased peak load, voltage instability, harmonics, and thermal overload [1-4]. However, if controlled properly, EVs can also be used as tools for demand management, allowing for more efficient use of existing assets and reducing the need for further infrastructure or generation investment.

Demand Management (DM) is of growing interest to governments, regulators, and network operators around the world. This can take the form of either end-user demand response in reaction to incentives, or direct load control via central utility decisions. Essential to both of these mechanisms is availability of Advanced Metering Infrastructure (AMI). In the Australian state of Victoria, a mandated AMI roll-out was begun in 2010 and will be completed at the end of 2013.

In addition to the AMI roll-out, Victoria has been active in the evaluation of electric vehicles via the Victorian Government's Electric Vehicle Trial [5]. A five-year, $5 million program, the Victorian EV Trial has involved over 80 organisations, and overseen extensive trialling of electric vehicles and their related infrastructure by a wide variety of stakeholders.

A recent important phase of the Victorian EV Trial brought these two trends – Smart Meters and electric vehicles – together as part of a single unified exercise. This involved the installation and testing of AMI Demand Response / Load Control (DRLC) functionality. In this trial, the charging of electric vehicles was controlled by the electricity utility, who issued DRLC messages to a network of charging terminals via the household Smart Meter infrastructure. The partners involved in this phase have been **DiUS Computing**, who developed the grid-integrated EV charging system and led the project design and delivery; **United Energy**, an electricity distribution company who monitored and issued the DRLC events on the network where the trial took place; the **Victorian Department of Transport Planning and Local Infrastructure**, who coordinated the trial and provided logistical support; and the **University of Melbourne**, who provided post-trial modelling and analysis.

This paper presents the results from the Demand Management (DM) project. We discuss why DM will be an important tool for network operators; we describe the hardware, software, and communication protocols that were implemented to allow for central control of vehicle charging; we detail the range of DM scenarios tested, along with their impacts on the vehicles' charging profiles and the underlying distribution network; and we present household participants' responses to the concept of DM. Finally, we examine the business case of implementing a DM solution versus other approaches, the contextual influence of electricity market arrangements, and insights pertinent to the design of a successful grid-integrated EV charging demand management program.

2 Why manage EV charging?

Managing electric vehicle charging is important towards avoiding adverse impacts that may result from EV charging. Furthermore, EVs may in fact provide network operators with additional tools to address existing network issues.

2.1 Network operating parameters

To better understand the risks and opportunities for networks, it is helpful at the outset to understand the relevant parameters within which networks operate.

For residential customers, Victorian electricity distribution network businesses ('Distributors') must maintain a nominal voltage level at the

Interval	Upper limit	Lower limit
Steady state	+10% = 253V	-6% = 216V
< 1 minute	+14% = 262V	-10% = 207V
< 10 seconds	Phase-to-earth +50%=345V Phase-to-phase +20%=276V	Zero
Impulse voltage	6kV peak	Zero

Table 1. Regulated 230V nominal electricity supply limits at the 'point of supply' for a Victorian customer's electrical installation [6].

point of supply to the customer's electrical installation of 230V, 400V or 460V nominal (with 230V the most common). For 230V supply, variations from this nominal voltage are permitted according to Table 1.

Victorian electricity customers are themselves subject to a number of obligations under the Electricity Distribution Code. Obligations of relevance to consideration of EV charging are described by United Energy [7] as follows:

You must also inform us (or request that your retailer informs us) as soon as practicable, if you plan to:

- *change wiring or equipment in your electrical installation which may affect the quality of the supply of electricity to any other person*

- *change the major purpose for which the electricity is used at your address*

- *significantly increase the amount of electricity likely to be used at your supply address*

Distributors play an important role in developing the demand side of the market [8]. They do this through directly undertaking Demand Management (DM) projects as an efficient alternative to capital infrastructure investment. They also support the delivery of DM by other parties, such as aggregators, through efficient and flexible network tariffs, and by publishing planning information. These obligations are formalised under the Australian National Electricity Rules [9].

Under the current arrangements, Distributors may not be fully capturing the value of demand management [8]. There are a number of reasons for this, ranging from how financial incentives are applied, to how network tariffs are set.

Finally, the Distributor business model is subject to a range of emerging challenges [10]. A characteristic of this change is a negative feedback loop – increasing electricity costs result in reduced electricity use which, as an outcome from volume-based pricing, creates upward pressure on electricity costs due to the reduced cost recovery for the fixed costs of transmission and distribution [11]. This situation is creating an increasing imperative for action by Distributors to address declining revenues, increasing costs and the consequences for shareholder value.

2.2 EV charging grid impacts

Electric vehicle charging may impact on the electricity grid in a number of different ways:

Peak and total demand: A vehicle having an average daily travel distance of 46.6 km (US national average, as per 2009 survey [12]) will need to recharge for approximately 3-4 hours if recharging at a standard rate of 3.3 kW. The total daily demand on the network will be between 9 and 12 kWh, and if people plug in when they arrive at home (typically between 5 and 7pm), vehicle charging will coincide with peak demand. In other words, each electric vehicle under uncontrolled charging conditions is likely to contribute roughly the same to total and peak demand as a full household (Fig. 1).
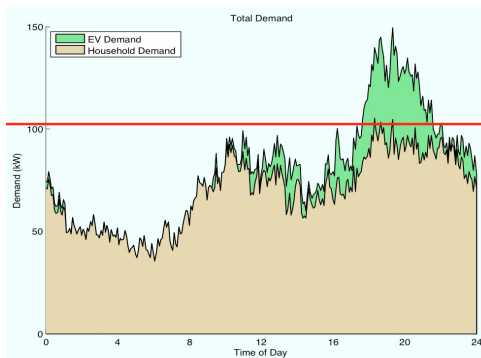

Figure 1: Impact of electric vehicle charging on peak demand. If vehicle charging is left uncontrolled, the impact on peak demand will be significant and asset lifetimes will be reduced. Here an EV penetration of 40% leads to a 40% increase in peak demand.

Component overload: In the electricity grid, a distribution transformer steps down high voltage to the voltage required at the household level (230V in Australia). Both the distribution transformer and the utility lines connecting houses to the grid have nominal current ratings and capacity limits. If these are exceeded due to additional current required by electric vehicles, there is an adverse impact on the lifetimes of these assets.

Voltage drop: Each line in the distribution network has an impedance of its own and acts as a constant impedance load. As a result, voltage at each house in a network decreases when moving away from the distribution transformer (assuming no distributed generation). As more current is drawn through the lines due to charging of electric vehicles, this decrease in voltage is exacerbated (Fig. 2). At houses receiving a voltage below regulated limits, appliances may fail or suffer.
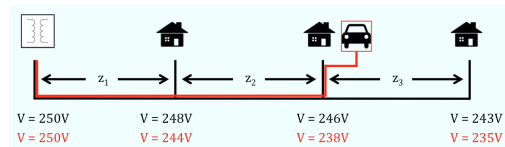

Figure 2: Impact of electric vehicle charging on voltages throughout the network. Without an EV present, voltages are as specified in the top row (black). With an EV present, voltages are as specified in the bottom row (red).

Phase unbalance:

Most countries supply power in three phases, with each household connecting to one phase only. When all three phases are equally loaded, they sum to zero in the neutral (return) line. However, when unbalanced, they lead to additional current in the neutral, which leads to additional voltage drop. There are many unpredictable fluctuations in each phase throughout the day, and in practice a distribution network is rarely perfectly balanced. However, large loads like electric vehicles, particularly if they are distributed in an unbalanced manner, can have a large contribution to phase unbalance, exacerbating problems of voltage stability.

If left to charge uncontrolled, the impact of EVs on each of these factors will be significant. The general consensus among a variety of studies in several countries is that at present, distribution networks can only handle EV penetration rates of between 5-15% before networks begin to fail according to one of the above criteria [4,13,14]. In general, voltage falling below required levels seems to be the first point of failure in many networks.

2.3 EV charging opportunities

EV charging is likely to contribute significantly to a household's electricity demand, but it may be transferred to off-peak periods without overly affecting use of the vehicle. In contrast, there is little opportunity for time-shift in the use of household air-conditioning – the recognised cause for much of the increase in electricity costs [15].

In addition, EVs can also be used as tools to solve both the problems they themselves cause and those originating from other causes. If charging rates may be controlled, EVs would allow network operators to gain a high degree of control over their networks:

- To prevent excessive peaks and thermal overload, charging could be delayed until there is available capacity in the network, for
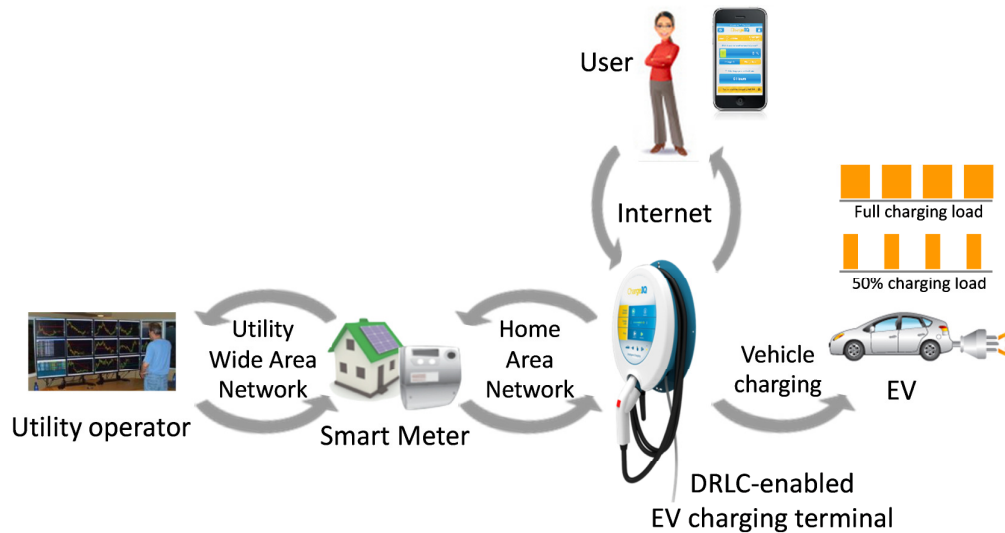
Figure 3. The end-to-end demand management system as implemented by DiUS Computing and United Energy.

example during the demand trough that generally exists after midnight.

- To prevent excessive voltage drop, charging rates could be adjusted in such a way that voltage stability is maintained within required limits, while still providing fair charging times to all electric vehicle owners.
- To prevent phase unbalance, vehicle charging could be scheduled in a way that excessive unbalance is prevented. In fact, the charging of vehicles could be used as a tool to *rebalance* the existing unbalance in the network arising from uncontrollable loads, thereby improving voltage stability.
- Finally, there is widespread speculation on the potential of using electric vehicles as distributed storage units that draw from the grid at times of low demand and supply to the grid at times of high demand.

In short, the ability to control vehicle charging rates and timing would allow network operators to use existing networks at much higher levels of efficiency, without having to install excessive additional infrastructure. A more efficient network is cheaper to run, requiring less generation and providing longer asset lifetimes. These savings could be shared with end-users as part of a system approach to achieving optimum outcomes for all.

3 How to manage EV charging?

In 2012 DiUS Computing delivered a demand management demonstration project using United Energy's Smart Grid [16]. The project formed part of the Victorian Government Electric Vehicle Trial [5], and was delivered in partnership with the Victorian Department of Transport, United Energy and the University of Melbourne.

3.1 End-to-end system

The technical solution devised for implementing Demand Management (DM) through the United Energy network is presented in Fig. 3 and operates as follows:

- At times of high demand or during emergency situations, United Energy sends a signal via the Utility Wide Area Network to the Smart Meter installed at the customer premises.
- The home charging terminal that the EVs plug into – designed and operated by DiUS Computing (Fig. 4) – connects to the Smart Meter via the Consumer Home Area Network using the Zigbee Smart Energy communications protocol.
- If a DRLC instruction is received, charging of the EV may be reduced or deferred.
- The charging terminal is also connected to the internet, allowing network operators to alert vehicle owners of DRLC event notifications via an online portal, their smartphones, via email and SMS, or directly on the charging terminal's user interface.

- EV drivers may respond to the DRLC events in a range of ways, including opting-out by initiating charging on-demand via the terminal interface, their smartphone, or the online portal.

Figure 4. A DiUS Computing grid-integrated charging terminal at a participant household.

3.2 Charge management scenarios

Charge management scenarios were designed as a reflection of real-world operating conditions:

1. **Peak charge management**: on days when parts of the distribution network might be at risk of exceeding plant ratings (e.g. particularly hot summer weekdays), a utility load control event could be triggered. As this scenario can be predicted ahead of time, it would likely be possible to notify consumers 24 hours in advance of the load control event. The duration of the event would cover the peak demand period of around 3-4 hours, vehicle charging rates would be reduced by 50%, and consumers would be permitted to opt out with some accompanying cost impact.

2. **Emergency charge management**: in rare situations under extreme weather conditions such as heat waves or lightning strikes causing unplanned or forced outage of a plant, the network may require significant load reduction to avoid failure of remaining plants. For such events consumers may be notified only at short notice (10-15 minutes), events would take 3 hours, EV charging would be reduced by 100%, and participation would be mandatory. For the demonstration project the decision was made to provide an 'opt-out' option in recognition of wider sensitivities related to unfolding AMI roll-out.

3. **Smart charging**: to reduce peak charging on a day-to-day basis, operators use price signals such as time-of-use that incentivise drivers to charge during off-peak periods. When selected, this management scenario schedules charging to occur between 11pm and 7am.

4. **Demand charging**: also called "uncontrolled charging", in this scenario users have the opportunity to override the default Smart charging mode to charge 'on demand' (or in other words, EV charging is initiated by the user regardless of the time of day/cost implications).

Although configured with Smart charging as the default mode, household participants had the option to reconfigure this to Demand charging via the charging terminal, web portal or smartphone application. Simulated Peak and Emergency charge management events were scheduled by the network operator, United Energy, at a variety of times and days, and participants received notifications in advance according to the nature of the event.

3.3 Charge management results

The end-to-end system was successfully deployed and operated in eight project participant households. Response times from the utility demand manager to household Smart Meter were mostly within 5 seconds, with a lesser number of events taking up to 25 seconds. Response times from the Smart Meter to the charging terminal were generally instantaneous, although a small number of outlier events took much longer. The messages that had unexpectedly long response times were investigated as part of a post-trial analysis; for the most part these were due to issues that are being resolved in the next generation of the DiUS charging system.

A noteworthy challenge involved a ninth participant whose Smart Meter was installed in a common meter area at the entrance to their housing precinct. The charging terminal was installed at their parking location, which was separated from the Smart Meter by 20 meters and two brick walls. As an outcome, the charging terminal exhibited poor radio connectivity with the Smart Meter, such that the household was excluded from the load control aspects of the trial. In such situations, additional communication infrastructure would need to be installed to enable load control.

The breakdown in the charging event selection made by the participants is provided in Table 2. The bias towards Smart charging was felt to be due to the default setting of the charging terminal to this mode.

Charging activities	No.	%
Smart charging events	365	56
'On-demand' charging events	291	44
Total vehicle charging events	656	100

Table 2. Aggregated charging events for ten households over their three month EV 'ownership' experience [16].

A total of 64 load control events, split 50/50 between Peak and Emergency charge management, were delivered to eight household participants over four weeks – refer to Table 3 for results.

Of these 64 events, six affected vehicle charging through load control, on 28 (of 64) occasions the vehicle was either not connected or fully charged, and on 29 occasions Smart charging had been selected as the operating mode (i.e. charging took place outside of the DM event period).

On three occasions the charge management event messages reached the Smart Meter, but failed to reach the charging terminal. One of the failed events coincided with an on-demand charge, and consequently the vehicle charged normally.

Charging activities	No.
Total charge management events issued by utility demand manager during demonstration period	64
Total charging events undertaken by participants during charge management demonstration period	128
Smart charging events undertaken by participants during demonstration period	29 of 64
Vehicle charging activities impacted by charge management events during demonstration period	6 of 64
Incidence of vehicle not charging during charge management events	28 of 64
Incidence of charge management event messages not received by charging terminal	3 of 64

Table 3. Aggregated charging events for eight households over the demonstration period [16].

3.4 Consumer interactions

To gain insights into the Household Participants opinions and experiences, a qualitative survey was delivered to those who took part in the charging DM events.

Although the limited number of responses (seven) suggests that the results be treated as anecdotal, some observations can be made as follows – Participants:

- received the Peak charge management event notifications, and *where affected took steps* to manage their charging/vehicle use;
- were *only occasionally aware* that the Emergency charge management events were taking place, and were largely unaffected;
- were *mostly accepting of load control* by the utility, even if there were no financial benefit;
- were *less likely to accept mandatory load control*, but could be influenced by a financial benefit;
- mostly felt that the *DiUS charging system was a key enabler* for charge management; and
- found the *SMS notifications* to be the most useful of the user-facing applications.

4 What would happen with lots of EVs?

Post-trial modelling and analysis conducted at the University of Melbourne using data gathered during this trial made it possible to examine some alternate scenarios that could not be tested in the real trial, such as exploring what the impact of higher penetration rates of electric vehicles might be. Economic modelling forecasts that plug-in vehicle uptake could grow to between 15-30% of new vehicle sales in Victoria by 2020 [17]. This section details our simulator, discusses the outcomes, and provides the data for the EV charging demand management business case.

4.1 Simulator

The simulations presented in this section were conducted using POSSIM (POwer Systems SIMulator), an in-house solution developed at the University of Melbourne for this purpose [18]. POSSIM uses a MATLAB SimPowerSystems backend for load flow calculations.

Using information gained during the trial, we developed a model of the part of the United Energy network in which the DRLC events took place. The network in question is a typical suburban neighbourhood having 114 houses connected to a single 300kVA distribution transformer. Individual phase connections were not available and had to be estimated using aggregated load data. A diagram of the network is presented in Fig. 5a.

To simulate electric vehicle demand, we used data collected by the Victoria Department of Transport in a 2009 Travel Survey [19]. We refined this dataset, first to only those 24-hour vehicle travel

(a) Network diagram

(b) Histogram of daily vehicle travel distances (likely charging needs)

(c) Frequency of home arrivals (likely start of charging)

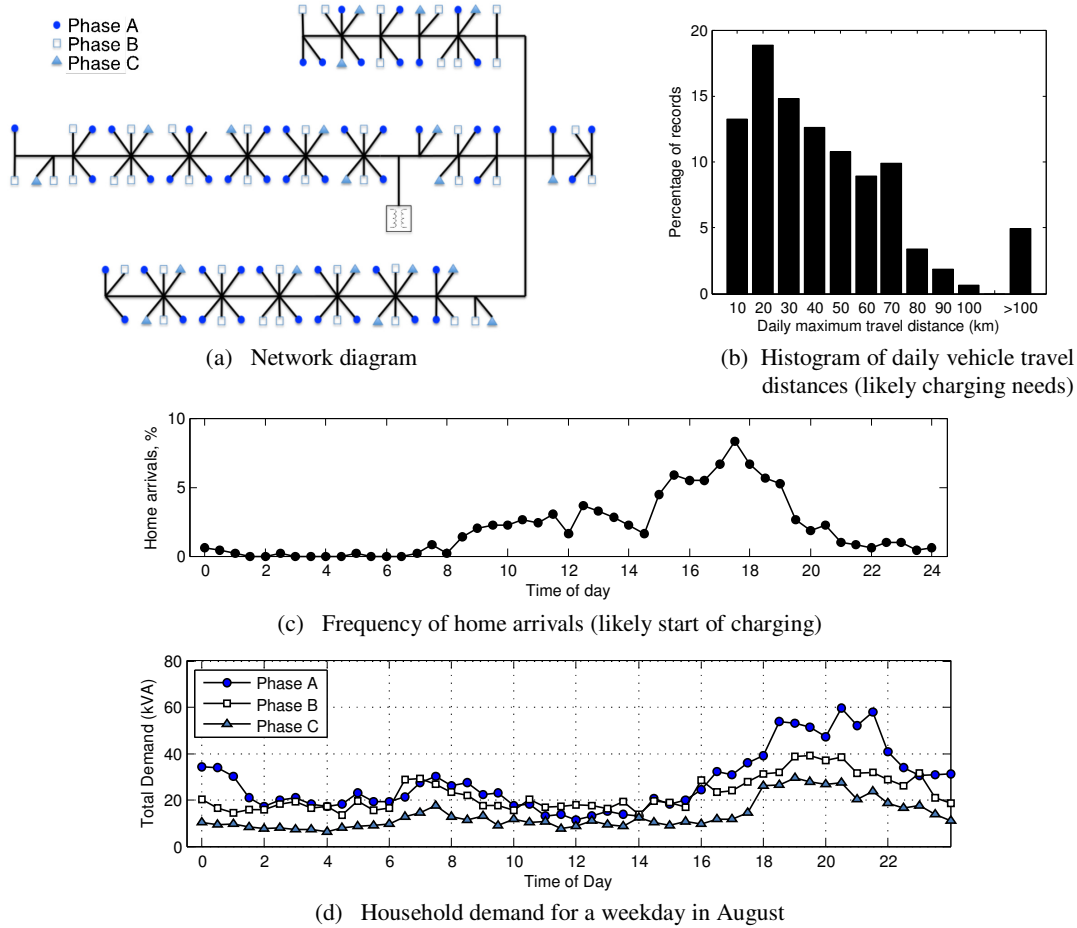(d) Household demand for a weekday in August

Figure 5. Simulating the network.

profiles consistent with an EV range (less than 160km), and second, to only those travel profiles originating from the local government area that our network is located in. In other words, we know *when* vehicles in our network are likely to be at home and available for charging, and we know *how far* they have driven while away, to estimate battery state of charge. A histogram of likely daily vehicle travel distances (i.e. charging needs) is presented in Fig. 5b; frequency of arrivals at home (i.e. charging timing) is presented in Fig. 5c.

Finally, to estimate typical daily household demand profiles, we used data collected at the distribution transformer of our network during this trial, and established average household profiles separately for each phase – these are presented in Fig. 5d.

To ensure that this was a realistic way of simulating household demand, we undertook a validation cycle in which we compared our simulated voltages and currents to those

measured in the real trial using special instrumentation. On average, our voltages were within 1-2 V (<1% difference), and our currents were within 4-6 A (5-7% difference) – in other words, a fairly close correlation between simulation and reality.

4.2 Uncontrolled Charging

In our uncontrolled charging approach, vehicles were assumed to connect as soon as they arrived at home, and to charge to completion at a rate of 3.45kW (maximum possible at a standard 15A, 230V outlet). We simulated EV penetrations of 5, 10, 15, 20, and 25%. For each penetration, we assigned the relevant number of vehicles randomly to houses in the network, and assigned to each vehicle one of our available travel profiles, also at random. Since vehicle locations and charging profiles make a significant difference regarding grid impacts [14], we ran at least 10 simulations for each scenario to accommodate random effects.

Each simulation run involved a full time-series over a 24 hour period, with a steady state load flow calculation at each interval. We chose 30-minute intervals as per the AMI sampling frequency for Victorian Distributors.

The Victorian Electricity Distribution Code [6], and network specifications provided by the Distributor provided the basis for the failure criteria as follows:

- Voltage dropping below 207 V at any house, at any time.
- Voltage dropping below 216V at any one house twice within 24 hours.
- Voltage dropping below 216V at any three houses, at any time within 24 hours.
- Phase current exceeding 300A on any phase at any time.
- Total demand exceeding transformer capacity at any time.

Any run *not* exhibiting the above conditions was considered a success.

Our first failures occurred at 10% EV penetration due to voltage falling below 216V at one house for 2 or more intervals. This occurred in 2 of 10 simulation runs. In other words, if only 10% of households were to buy electric vehicles, some networks would already be at risk of failure without additional upgrades or changes to the network.

Regular failures for uncontrolled charging were encountered from 15% onwards, with 6 of 10 runs not succeeding at this level. Interestingly, with increasing EV penetration there was not a linear decrease in the number of successes. At 25% EV penetration, for example, half of our runs succeeded. We believe this may be due to an interesting side effect of adding electric vehicles to unbalanced networks: when vehicles are added to the underloaded phase, they actually help to improve voltage stability by rebalancing the network and bringing voltage up on the overloaded phase. This underscores the value that electric vehicles might bring to network control.

However, the main conclusion of these simulations is that without additional infrastructure investment or network management tools, electric vehicles pose a potentially significant risk to distribution networks in the near future.

4.3 Controlled Charging

In our controlled charging approach, vehicles were assumed to connect as soon as they arrived at home. However, each vehicle's charging rate was decided by a central solver with access to key network state parameters, such as demand at each house (available via the AMI), and impedance in the lines between houses.

The scenario was investigated as an optimisation problem in which the limitations in the grid (voltage drop, maximum load per phase, maximum transformer load, etc.) were formulated as linear constraints, and the objective was to provide as much available current as possible to all vehicles. Expressing the problem in this form meant that standard linear program solvers could be used to find the best possible solution to the problem.

Using the optimal charging method, we simulated EV penetrations of 10, 20, 30, 40, 50, and 60%. As before, for each penetration vehicles were assigned to the network randomly, with each vehicle having a randomly chosen travel profile.

Due to the way our solution was formulated we could not use the same classification systems for successes or failures as we did for the uncontrolled runs: there would be no failures at all, by definition. Our optimal solver does not allow for charging rates to be chosen that will lead to voltage drop, excessive phase current, etc.

However, to accommodate high vehicle penetrations within existing network limitations, a better measure of the optimal solver's effectiveness is: *are vehicles being charged enough*? We might not be adversely impacting the grid, but can we still have all vehicles fully charged by a particular target?

To evaluate this, we chose 7am as a target based upon the average 'plug-out' times from the field trial participants. Examining all of our runs, we found that in the vast majority of our simulations – even up to 60% penetration rates – our charging target was met. Only in very rare cases did a vehicle not receive a 100% charge by 7am, and this was usually due to the vehicle having arrived at home shortly before 7am.

A common misconception among some EV studies is that people assume the battery needs to be charged from 0 to full each day. However in a suburban road network with typical daily travel distances of 30-40 km, there is ample charging capacity in the network overnight to charge all vehicles, even when electric vehicle uptake is high.

Using our optimal solver there are side effects: vehicles may charge at unpredictable or slow rates, meaning that users can't necessarily expect a full charge within 1-2 hours of charging. However, with the right user plans and incentives, allowing demand charging at a higher price and controlled

charging at a lower price, we believe this problem can be solved.

5 What does this mean for the future?

The case for fully grid-integrated EV charging Demand Management (DM) will reflect the underlying business case, market arrangements and program design.

5.1 Business case

In order to understand the business case for demand management of EV charging, an understanding of the costs associated with both this and the non-DM option is required.

The non-DM approach can be understood through examination of the uncontrolled charging scenario outcomes. Once EV penetration reaches 10% of households, the modelling in Section 4.2 indicates that network augmentation will be required. High-level costings for this augmentation can be understood in terms of the following options:

(i) Transformer upgrade/new transformer – estimated costs may be $AUD 50,000-60,000 for a pole-mounted unit, or $AUD 100,000-120,000 for a ground-mounted kiosk. Note: This option is applicable in a location where there is High Voltage (HV) infrastructure available; if not, estimated costs are $AUD 150,000-200,000.

(ii) Low Voltage Regulator (LVR) installation – estimated cost $AUD 150,000. This option should be applicable in a location where there is no HV network available to install a new transformer. United Energy is currently trialling this new LVR technology on its network.

In contrast, the DM approach may be understood in the context of both the controlled charging scenario modelled in Section 4.3, and the costs associated with the end-to-end system implemented in Section 3. Controlled charging would allow over 50% of households to adopt EVs without requiring network augmentation.

For a cost comparison, the DM solution for the 10% of households that would require a network augmentation solution as identified previously would equate to around $AUD 7,000 (10% of 114 households, multiplied by $AUD 600 per grid-integrated charging unit). Note also that this estimate captures the entire cost of the dedicated

EV charging units, not simply the utility load control functionality.

A comparison between the two results provides a clear business case in favour of the DM approach, which can be approximated as around one tenth the cost of the non-DM (network augmentation) solution.

5.2 Market arrangements

Despite the clear business case, existing Victorian market arrangements suggest that significant barriers may exist for implementation of the DM solution [15].

The benefits associated with investment in DM technology are spread across the electricity market – generators, transmission and distribution businesses, retailers and end-users. As a result, no one market participant can realise all the benefits from investment in DM, a problem known as 'split incentives':

- Victorian EV drivers have little incentive to invest in 'grid-integrated' charging technology capable of being remotely controlled by the network operator.
- For Distributors, there are persistent doubts relating to the reliability of DM performance by consumers as a means for addressing network capacity constraints (this issue is discussed further in section 5.3 below).
- For third-party aggregators, the transaction costs associated with contracting a critical mass of residential customers are a deterrent.

In addition, due to the emphasis on network solutions based on capital expenditure, the Australian market rules currently disincentivize distribution businesses from investing in DM [20].

Despite these challenges, opportunities for grid-integrated DM of EV charging exist within the current market arrangements:

- EV charging loads are both significant and transferrable within the large windows of opportunity that exist when the vehicles are parked/plugged in, making them well-suited to DM.
- EV drivers may be obligated to work with their Distributor on integration of EV charging loads into the system [7].
- As part of the rate review process, Distributors may be obliged to consider DM alternatives to network augmentation in support of EV charging demand [9,15].
- Electricity utilities may promote EV uptake as a means of promoting electricity demand/revenue [21].

- The Australian market rules allow Distributors to propose innovative tariff arrangements as a means of promoting EV uptake [9].

The issues and opportunities outlined above suggest that the role of the regulator may prove to be crucial in promoting grid-integrated DM of EV charging and realisation of the benefits identified previously.

While rule-makers offer a Demand Management Incentive Scheme in Victoria, Distributors sought approval of $AUD 550,000 of expenditures in 2011 – equivalent to only around 5% of the allowance [22]. In a contrast that has been explained in terms of the disaggregated character of the Victorian electricity market [20], the three main Californian network operators had $USD 1 billion in (analogous) Demand Response program expenditure approved for the 2012-14 period [23].

This disparity in uptake suggests that the market settings associated with demand management (response) may be the strongest influence on adoption of fully grid-integrated EV charging.

5.3 Program design

A key challenge for adoption of grid-integrated EV charging lay in program design effectiveness, particularly from the perspective of both utilities and regulators.

Anecdotal results from this project indicate that EV drivers may accept load control, even without a financial incentive. However, they may be less likely to accept *mandatory* load control – an observation also made elsewhere [24].

For distribution businesses, peak load management must be sufficiently reliable to justify this approach over network augmentation. Regulators are unlikely to compel utilities to adopt DM in the absence of a compelling argument in favour of this approach.

Although these observations suggest a fine balance between the needs of EV drivers and distribution businesses, other insights promote confidence in the DM approach:

- Peak demand periods are typically infrequent and short-lived [15].
- Price signals that clearly disincentivize charging during peak demand periods are likely to be effective at promoting cooperation by most EV drivers, while still providing an 'opt-in' option.

- Timely, relevant and reliable information about DM events is likely to promote acceptance and cooperation by EV drivers.
- Real-time, remote monitoring and control capabilities for EV charging allow drivers to easily and conveniently respond to DM events.
- Modelling (Section 4.2) indicates that up to 10% of drivers may choose to 'opt-out' of a utility DM event before network capacity becomes an issue.

Noting the wide range of direct load control programs already being offered by U.S. utilities [25], these insights should inform design for tailored EV charging demand management programs.

Furthermore, EV uptake is likely to be gradual, such that refinement and validation of the program design can occur over time. This is consistent with recommendations on demand response program design more generally [26].

6 Conclusions

The case for management of EV charging demand has been established for the Australian state of Victoria. A viable technical solution has been demonstrated using the Victorian Smart Grid. Modelling found that this solution could support in excess of 50% EV uptake by households without requiring network augmentation. A financial assessment illustrated how the demand management solution could be implemented for around one tenth the cost of the network augmentation that would be required for the unmanaged charging scenario. Insights have been gathered from the demonstration that may inform design of a successful demand management program. Market arrangements may however be the strongest determinant of adoption for a fully grid-integrated approach to EV charging demand management.

These conclusions may be specific to the Victorian context, but are likely to have much wider relevance.

generous support of the Victorian Government as part of the Electric Vehicle Trial.

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Authors

Dr. Julian de Hoog (BSc McGill University, MSc and PhD University of Oxford) is a member of the Electric Vehicles Research Group at the University of Melbourne. His research focuses on the impacts of electric vehicles on electricity grids and the development of smart charging methods.

Kristian Handberg (BEng Monash University and MEng Royal Melbourne Institute of Technology) is a Principal Consultant at DiUS Computing and Senior Research Officer at Monash University. He designed and delivered the Victorian Electric Vehicle Trial while with the Victorian Government Department of Transport, 2009 – 2013.

Raman Jegatheesan (BSc Eng University of Sri Lanka) is a Principal Engineer, Network Planning at United Energy. He is a member of the Victorian Electric Vehicle Trial Planning Working Group