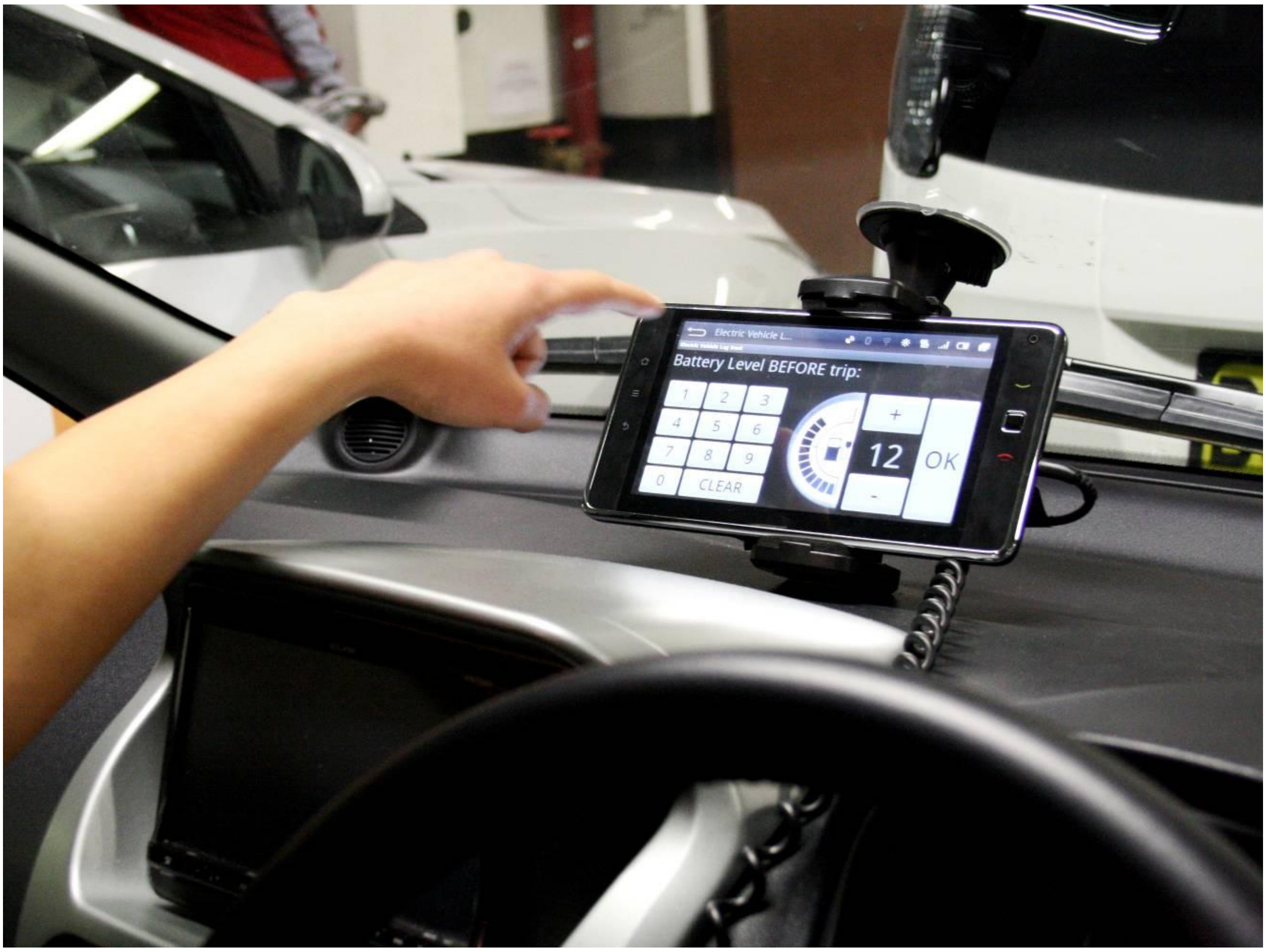
Smart Grid, Smart City Project

Electric Vehicles

Preliminary Data Analysis

14 July 2011



Contents

1 Commentry

1.1 Introduction

The Smart Grid Smart City Electric Vehicle Trial (SGSC EV Trial) has commenced and the first data sets have been returned from the vehicles. This document contains some preliminary analysis performed on this initial data set, which ranges from February –June 2011.

All data within this document is to be considered preliminary and for early and indicative analysis only.

The following data was collected per trip:

- Vehicle ID
- Driver Name
- Driver ID Number
- Start Date & Time
- Start Location
- End Date & Time
- End Location
- Distance Travelled
- Battery Bars Start
- Battery Bars End
- Driving Condition
- Number of Passengers
- Accessories Used

The data used in this document was gathered from 9 vehicles over a period of 139 days of vehicle use, a total of 1357 trips were recorded.

1.2 Vehicle Usage

The nine vehicles studied in this analysis have been assigned to either a section within Ausgrid to be used as a “pool vehicle” or have been allocated to a specific staff member requiring a vehicle for business purposes. Therefore these vehicles are primarily used as fleet vehicles and the majority of their use is during working hours. However they are also available for staff to travel between work and home, this opportunity is frequently used by staff and is reflected in the results seen in the analysis. Charging facilities are not available at staff homes at this stage.

This means that at this stage the data is not reflective of a typical residential vehicle use, but rather a mix of fleet and commuter use.

1.3 Data Source

All the data in this analysis (excepting the charge profiles) was sourced from the initial version of the in-vehicle Electronic Logbook developed for the trial. This logbook is in the form of a tablet running the Android Operating System with a custom developed application. This Electronic Logbook requires manual input from the driver to collect the majority of its data points. For this reason the data is open to human error and subjectivity.

To address this, there will be system installed in each vehicle to log parameters directly from the vehicles computer – giving much more consistent data. In addition a major overhaul of the electronic logbook application will be deployed that will significantly improve the user experience and data validity.

1.4 Data Quality

A number of data quality issues were identified during analysis. This is to be expected in the first iteration of the data collection process, and will be refined in the next iteration, which will commence Q3 2011. Key issues with the data were:

- A significant number of zero distance or zero time trips
- Data missing due to lack of driver input
- The trip duration being much longer than the actual trip
- Invalid start & end locations

All of the above issues are being addressed in the next iteration.

To preserve data quality, a significant number of trips had to be culled – those with zero duration or distance, and any trips with invalid or impossible data (average speed >100KM/h, trips with start or end points in the ocean). Of 1357 trips, 240 had to be removed from the data set, bringing the total number included in the analysis to 1117.

1.5 Findings

Notwithstanding the above data quality issues, and the preliminary nature of the trial at this very early stage, analysis of the data enables us to draw some conclusions at this time.

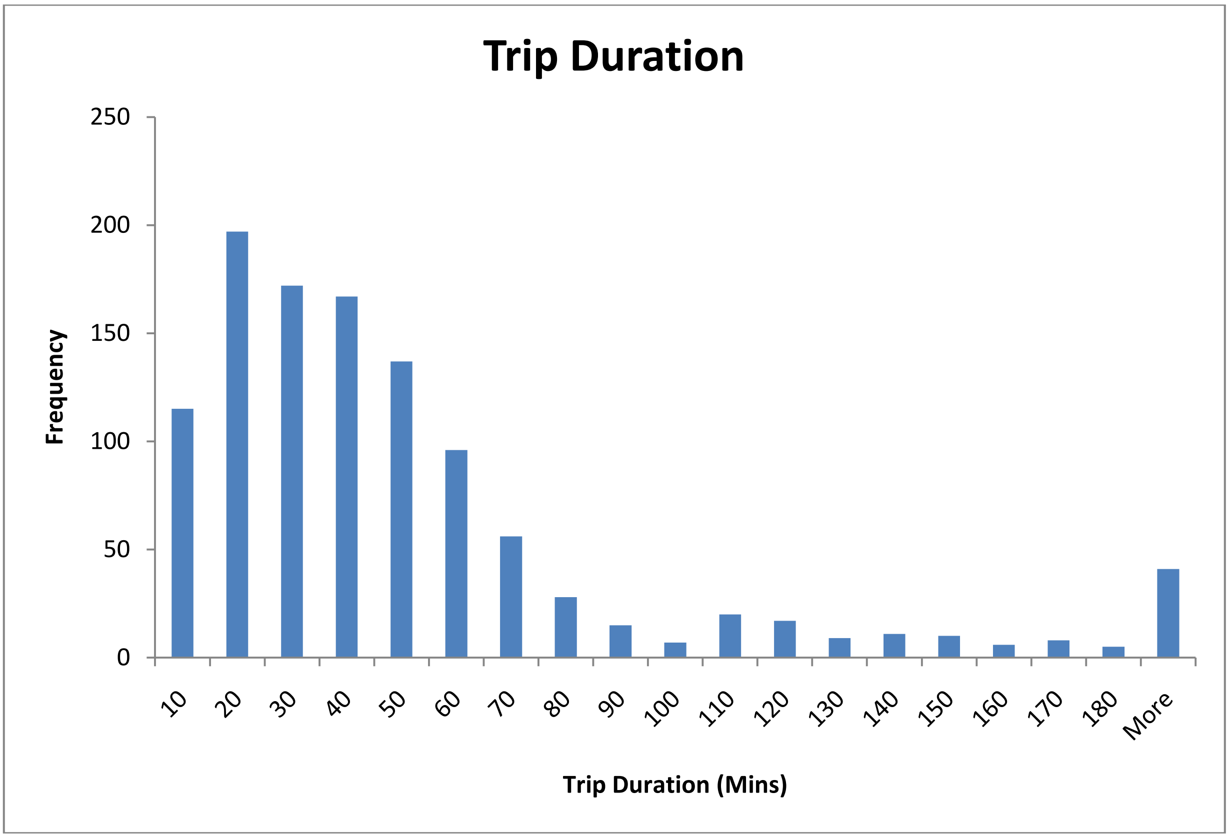
- The EVs are seeing significant usage, with an average of over 30 minutes per day of driving time
- Drivers are not afraid to take the EVs on medium length journeys, 60-70KM, before returning to a charger
- The EV does not appear to be placing significant restrictions on trips within city limits (note a detailed survey on drivers perceptions is planned for later in 2011).
- Most charges are “top ups”, going from ~65% capacity to 100% rather than from close to flat;
  Meaning that EVs are being charged even with significant spare range available; over 60KM on average.
- The majority of EV charging is performed during times of peak electricity demand.
- The EVs have a constant current charging profile.
- The data entered by the driver regarding driving conditions is highly subjective.

1.6 Findings in the Context of EV’s SGSC

This data represents the first steps towards understanding likely driver and car behaviour for early adoption of electric vehicles. Over the course of the SGSC trial data will be collected on a continuous basis and used to create a model for forecasting the impact of Electric Vehicle charging under different growth scenarios. The data presented here would appear to validate the key information data points such as vehicle efficiency, distance driven, energy remaining at charge and time of charge.

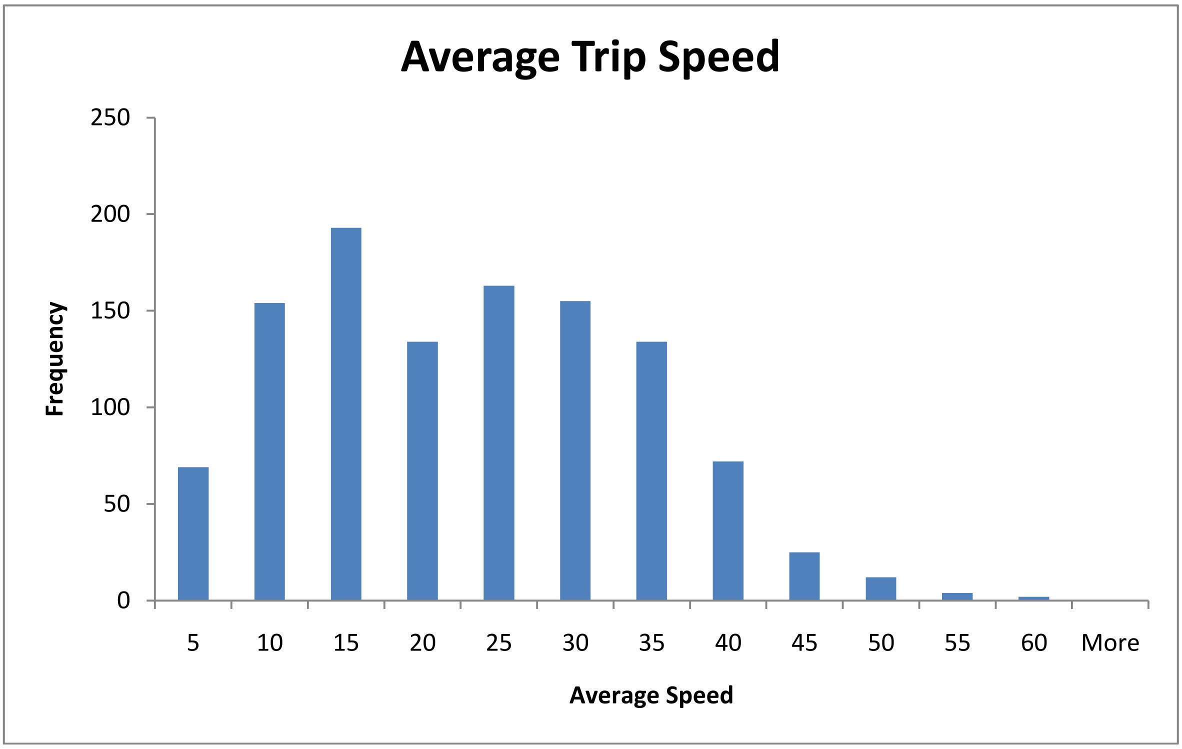
2 Data Analysis

2.1 Duration



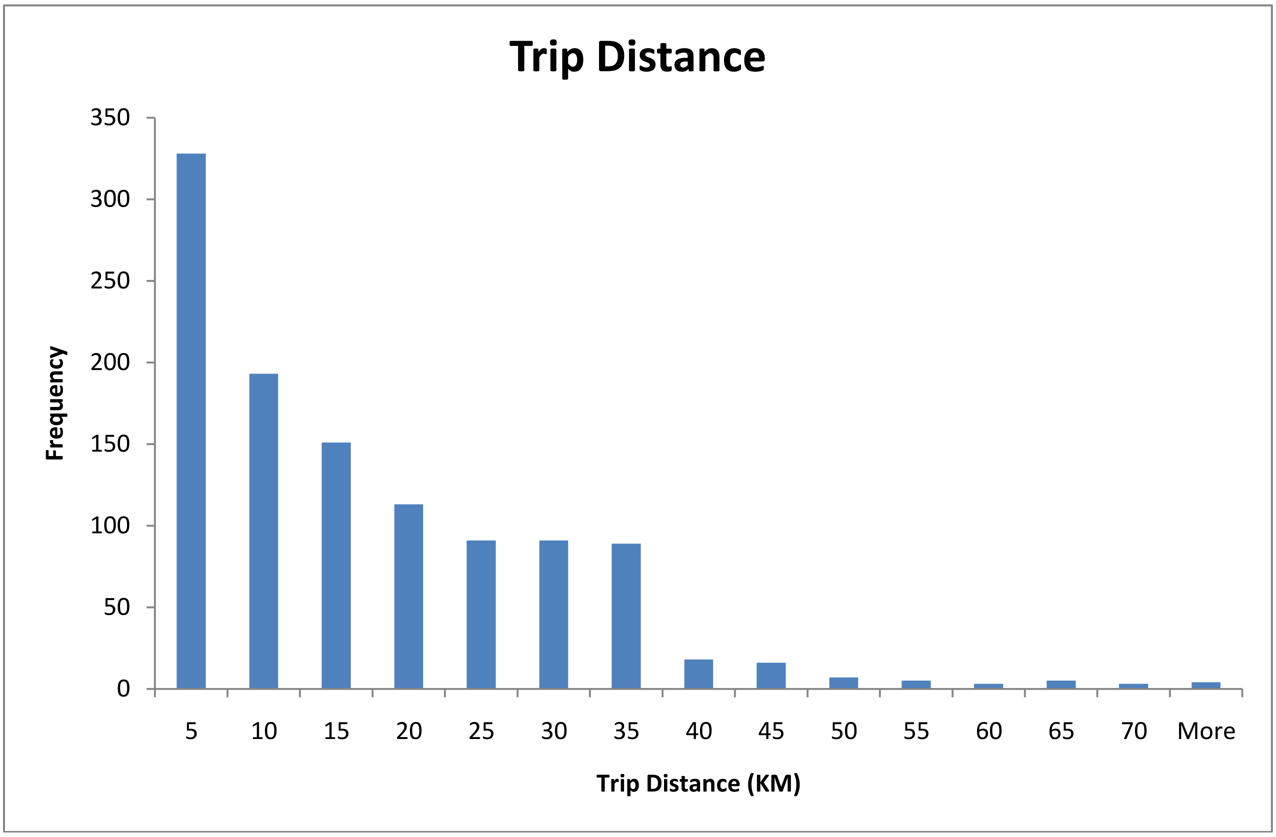
The trip duration paints a picture similar to typical Sydney commuting with the median trip being 34 minutes long. The EVs are not only being used for “short runs” but for general city commuting, similar to any internal combustion engine (ICE) vehicle.

2.2 Average Trip Speed



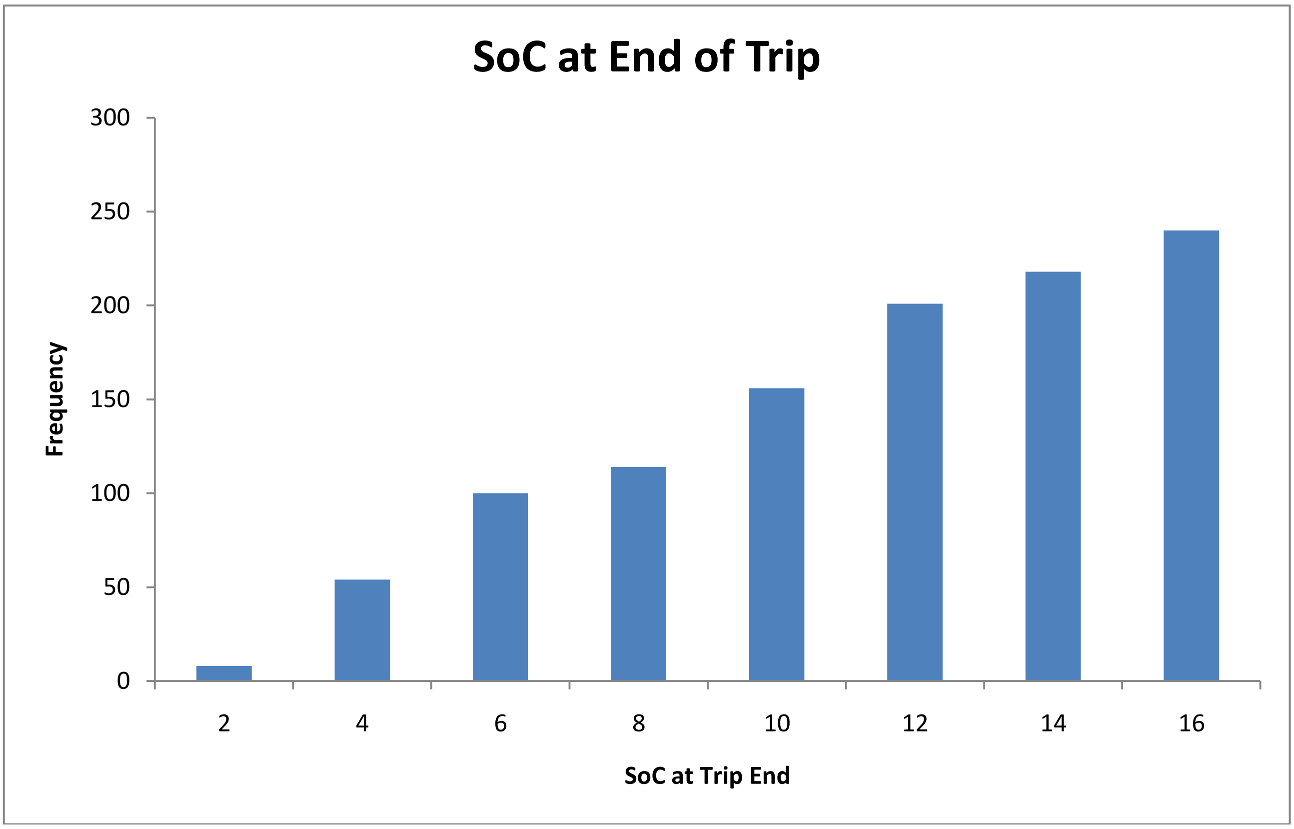
Calculated from distance traveled divided by trip duration. It can be seen that the majority of EV driving was performed within city limits, with an average velocity of 21KM/h.

2.3 Distance



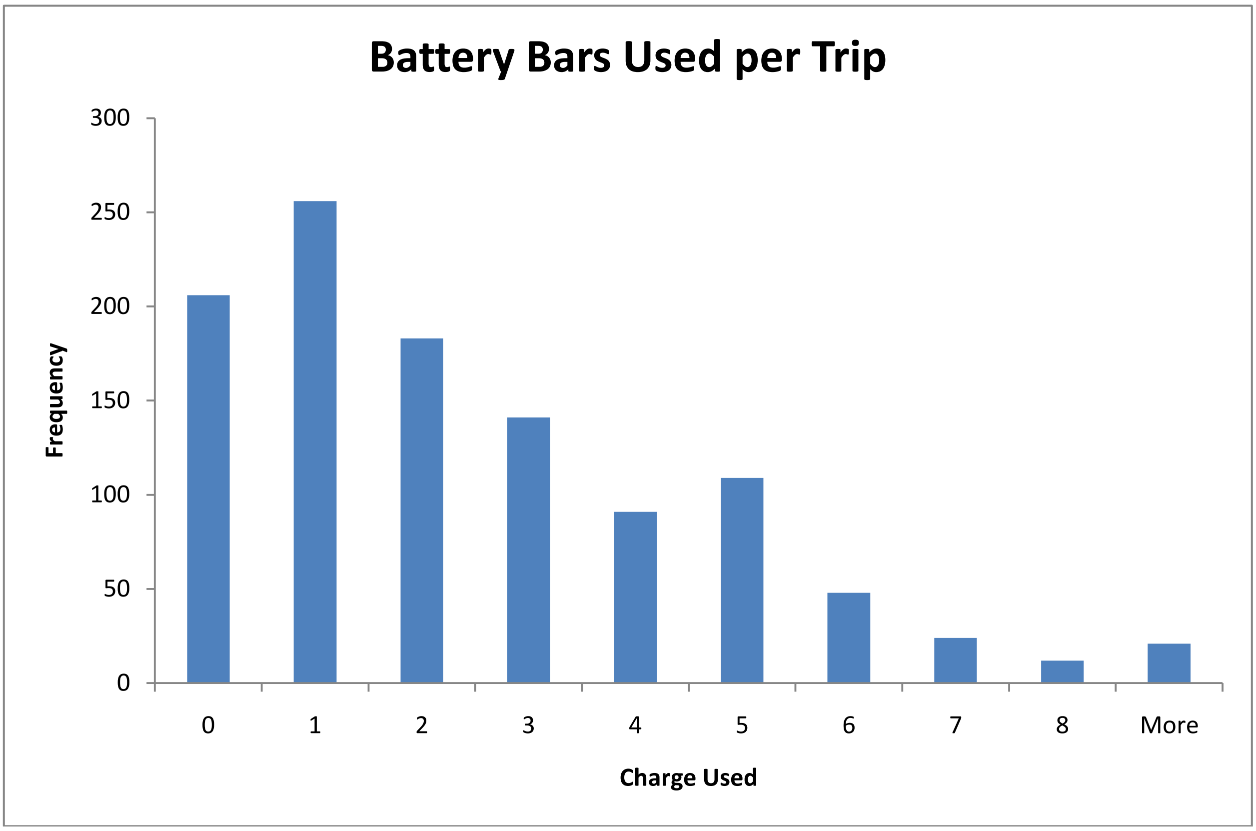
It can be seen that while there are a significant amount of short trips (< 5KM), usage is not restricted to short trips only. The average trip length was 15KM – a typical journey within city limits.

2.4 State of Charge at Trip End



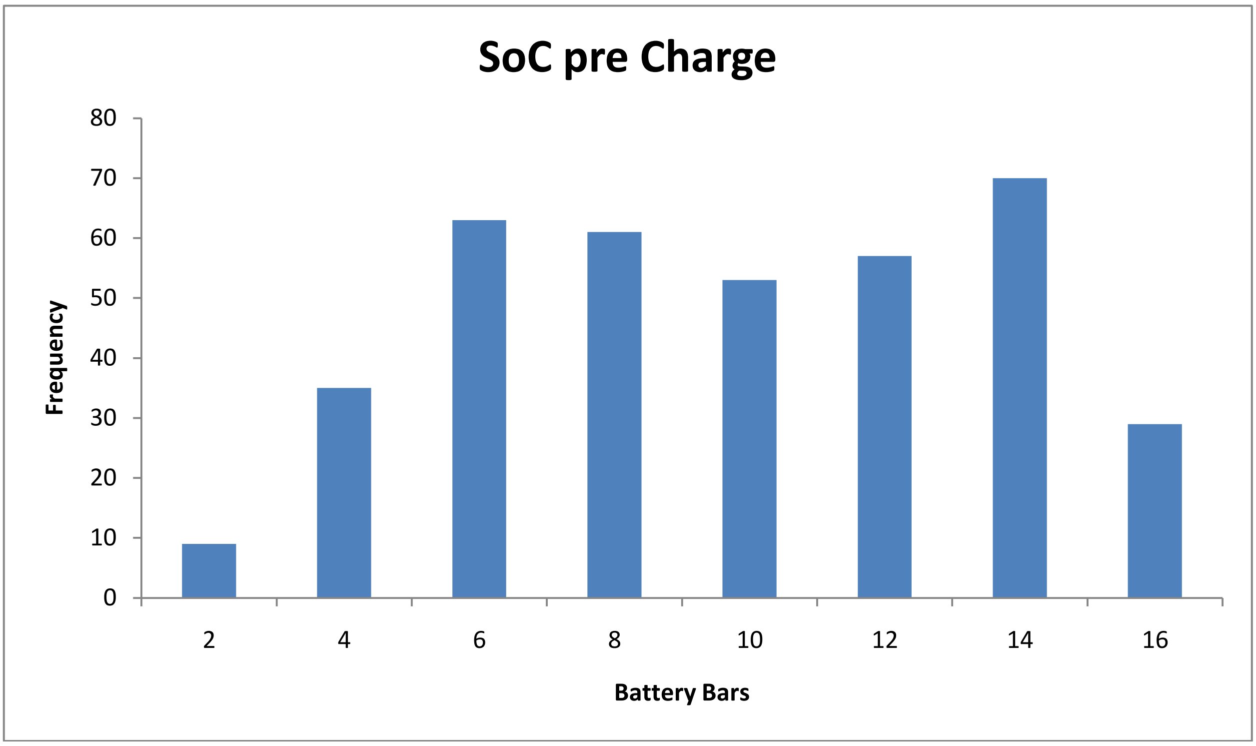
The above shows the number of battery bars out of 16 remaining at the end of each trip. Note; most EV journeys will have more than one leg, or trip, before returning to the garaged location to be charged.

2.5 Charge Used per Trip



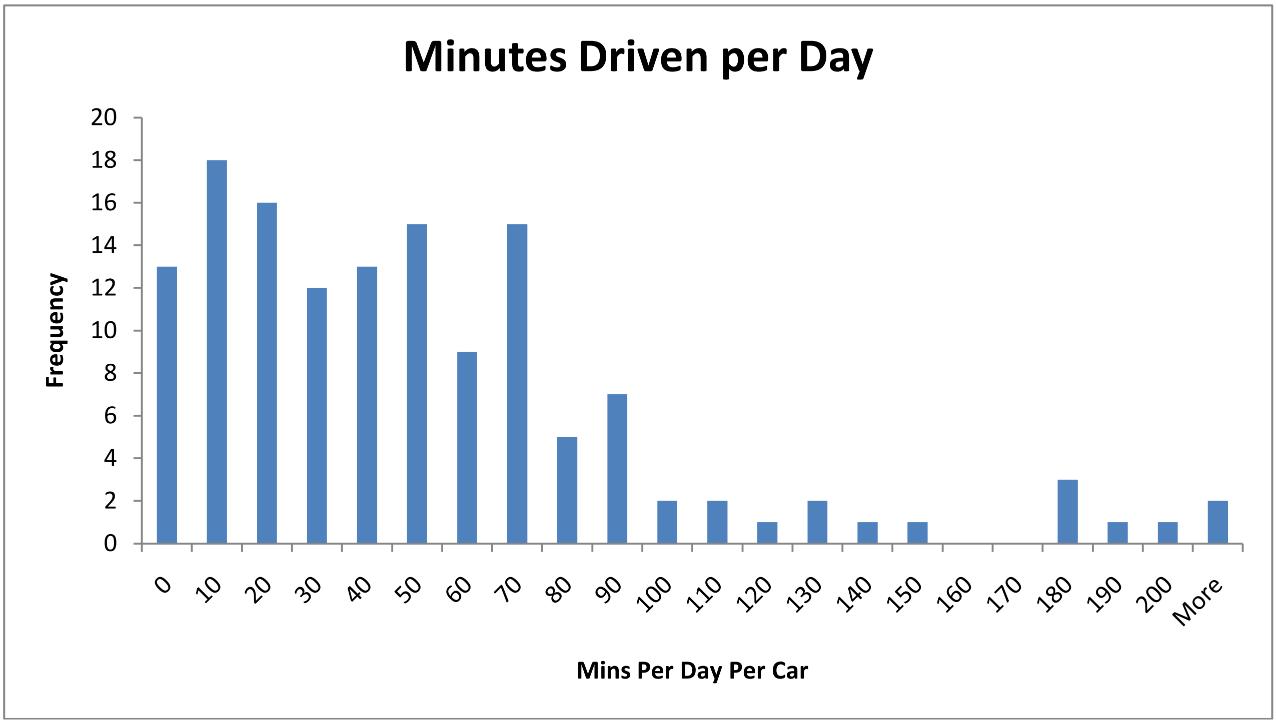
It can be seen that the majority of trips use only 2-3 bars out of the 16, this coincides with approx. 10-15KM trips.

2.6 No. Battery Bars Before Charge



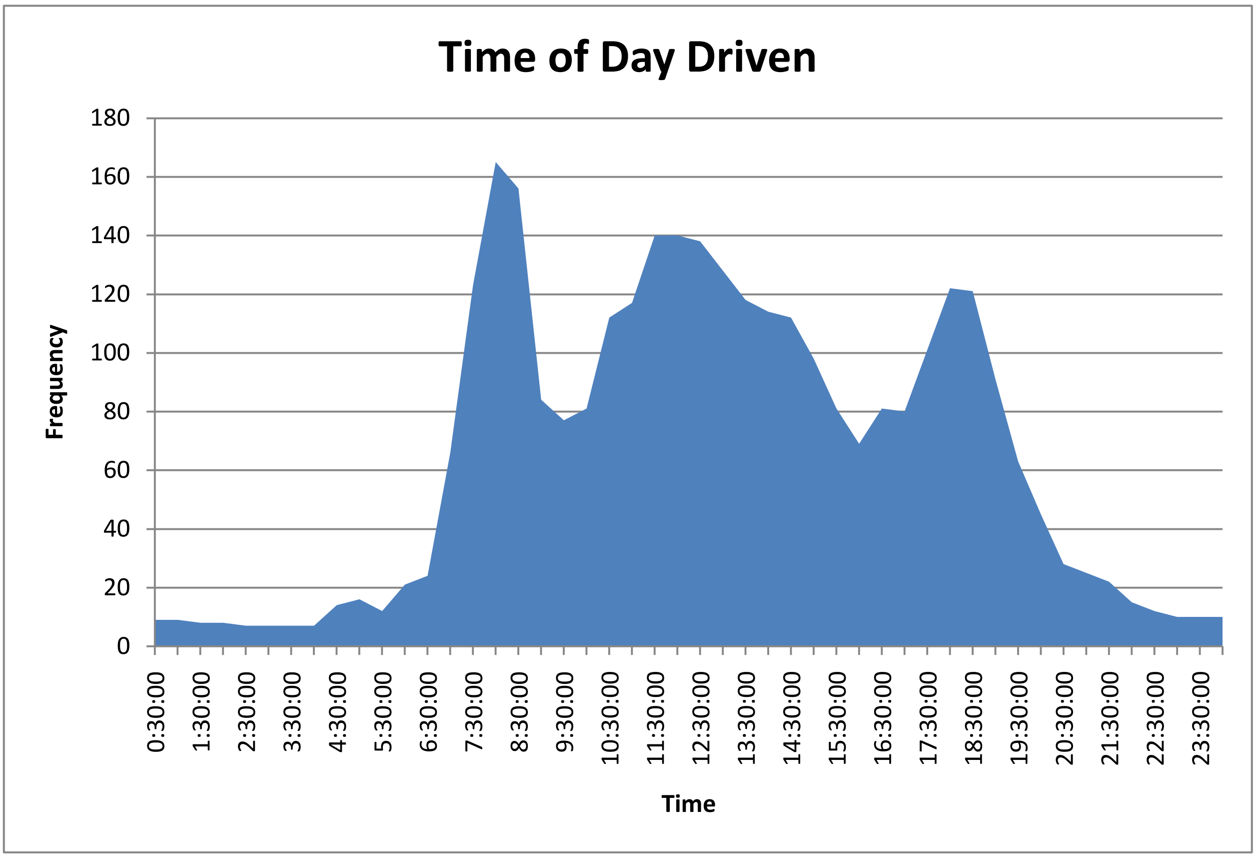
This graph shows that the majority of charges are a “top up” rather than a complete charge. With an average of 9 bars at the commencment of a recharge, EVs generally have significant remaining driving range and are therefore not restricting drivers from completing journeys they would have otherwise taken. This graph also shows that drivers are not afraid to run the EV down to between 4 and 6 bars before recharging, however drivers recharge before going below 3 bars the vast majority of the time. This is not surprising considering 3 bars represents an average trip of about 15KM. With only 3 bars, the EV is in danger of not being able to complete this trip.

2.7 Daily Usage



On an average day, the median trip for each EV is 37 minutes. This confirms the EVs are getting significant use, and are not being left idle.

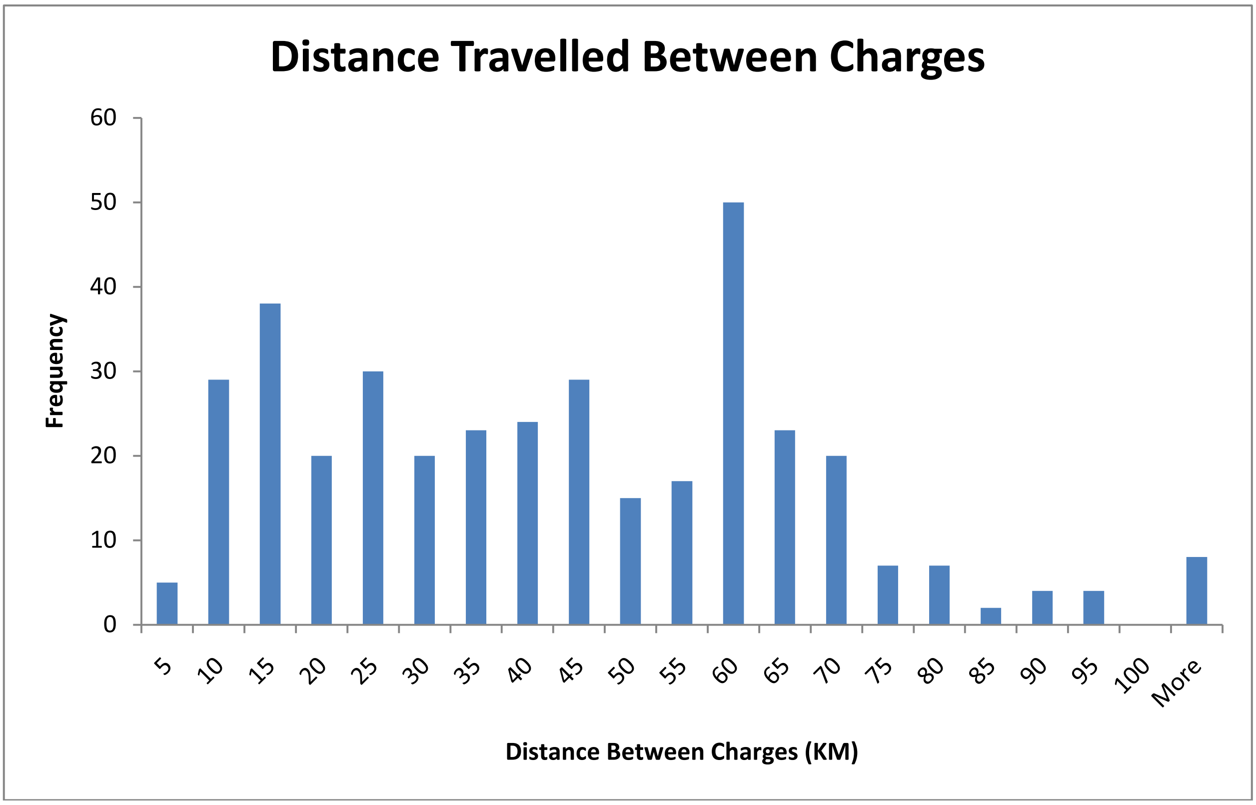
2.8 Time of Day Driven



It can be seen here that the bulk of driving is during the day time, with peaks coinciding with the morning and afternoon peak hour and a lump during the middle of the day.

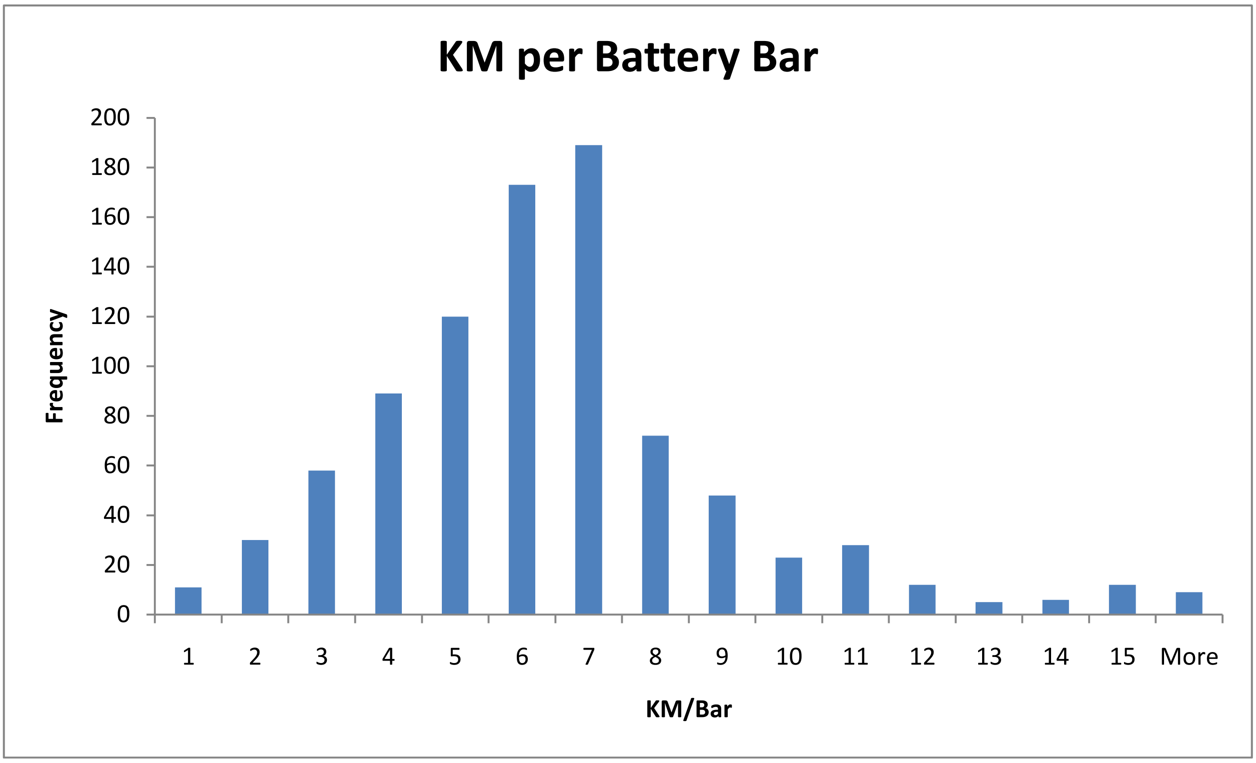
Mean	12:34
Min	0:00
Q1	8:39
Median	12:10
Q3	16:25
Max	23:59

2.9 Distance between Charges



It can be seen from this graph that the EVs are being used on short to medium length trips, with an average of 40KM. People are not hesitant to take the EVs on trips up to 70KM before returning to a charging station.

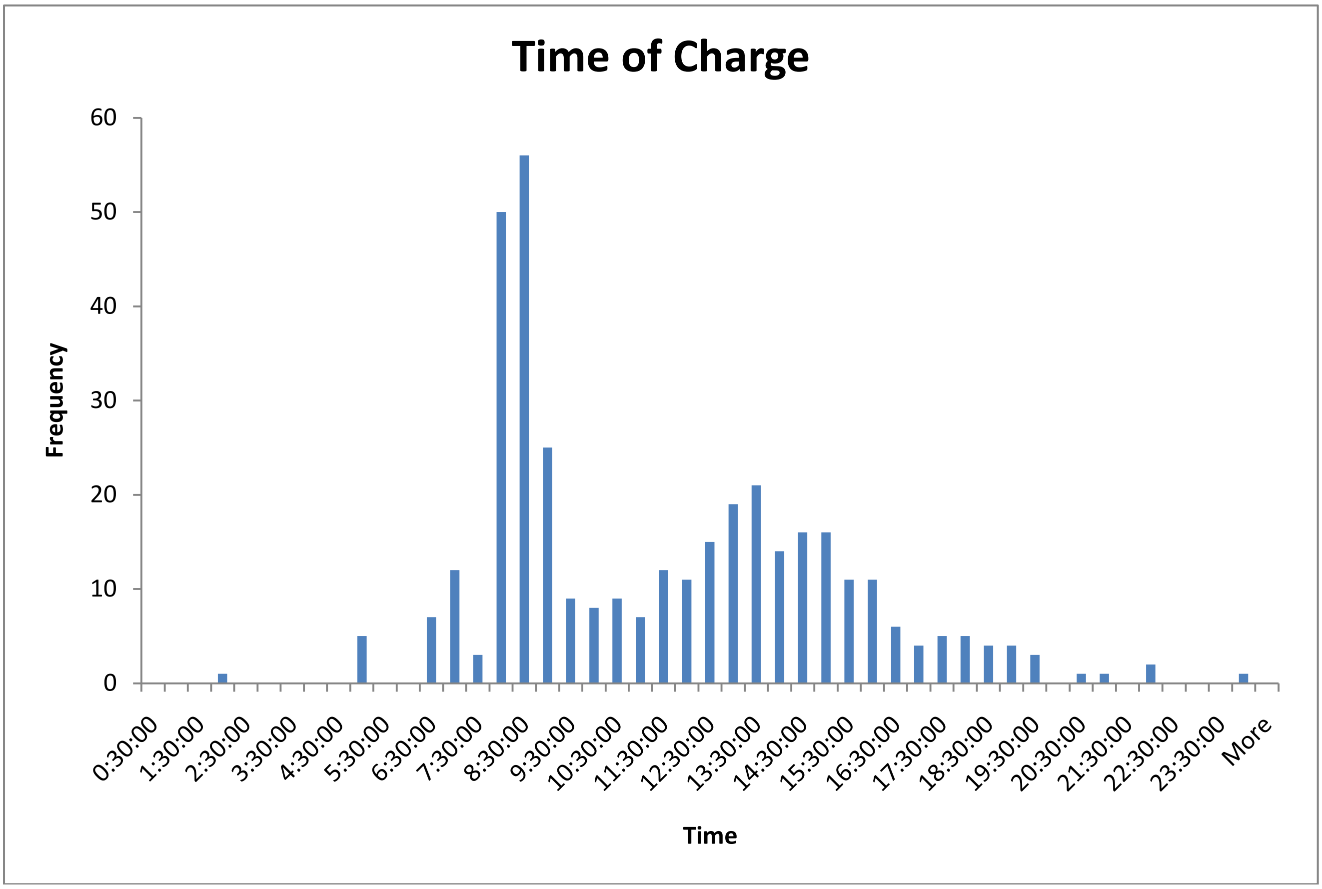
2.10 KM Per Battery Bar



For this and all analysis involving KM/Battery Bar, all trips with zero battery bars used were removed from the results. These trips can't be used in the economy calculations since doing so would result in an attempt to divide by zero. While a significant number of trips were removed, these trips only equate to about 3.7% of the total energy used, a negligible level.

As can be seen, the distance travelled per battery bar has an approximately normal distribution, weighted towards the lower end of the range. This is due to varying driving styles, conditions and other factors. A mean of 6.0 gives the EV a range of ~96KM, exactly in line with Ausgrid's controlled testing. For this data set, trips with zero bars used were excluded, since they comprise of only a small percentage of total KMs travelled, and to include them an assumption on economy would need to be made.

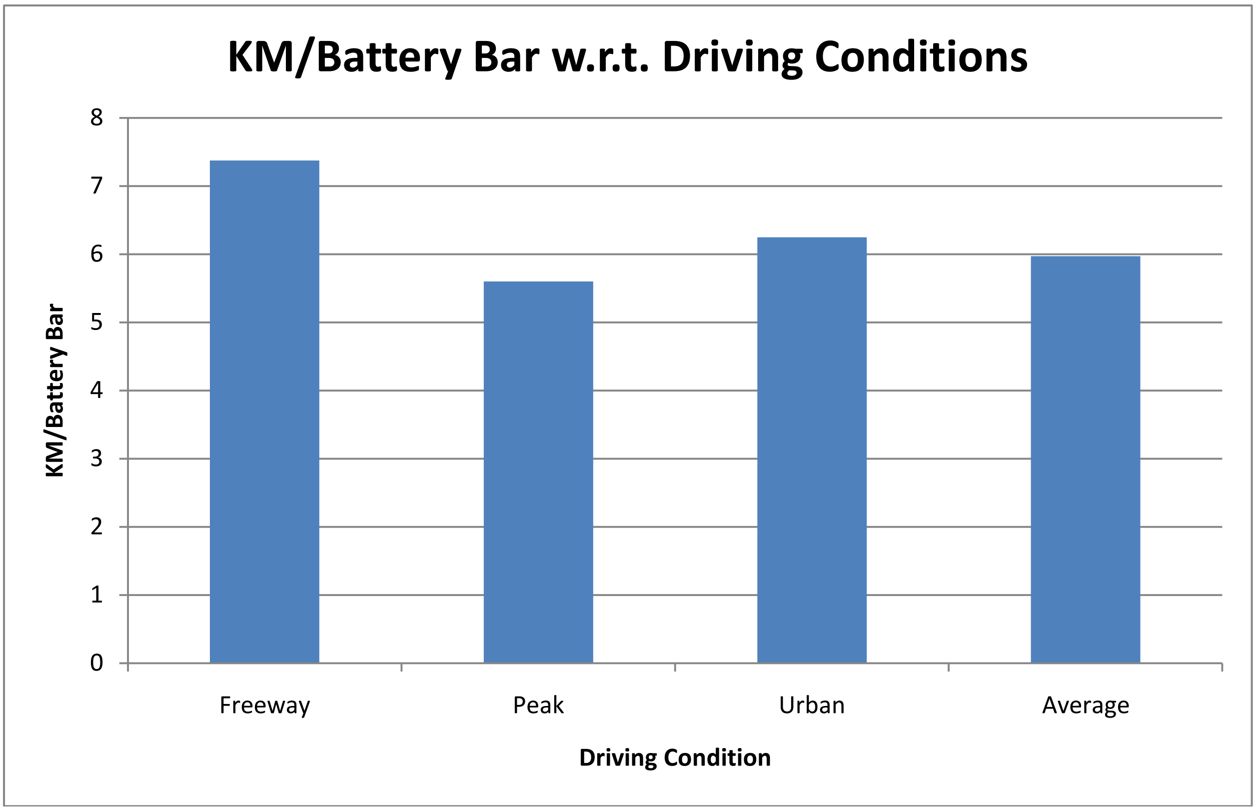
2.11 Time of Charge



Here it can been seen that there is a significant peak centered around 9AM. This coincides to the time when people are arriving at work and connecting their EVs to the charger. This is a unique charactaristic of the vehicles in this stage of the EV trial, since they are being taken to peoples homes overnight, however these people have no facility to charge the vehicles at home. Therefore when the EVs return to work in the morning, they are immedietly connected to charge. It is expected that this would differ significantly if charging facilities were installed at EV drivers homes.

Mean	11:12
Min	1:49
Q1	8:05
Median	10:37
Q3	13:51
Max	23:59

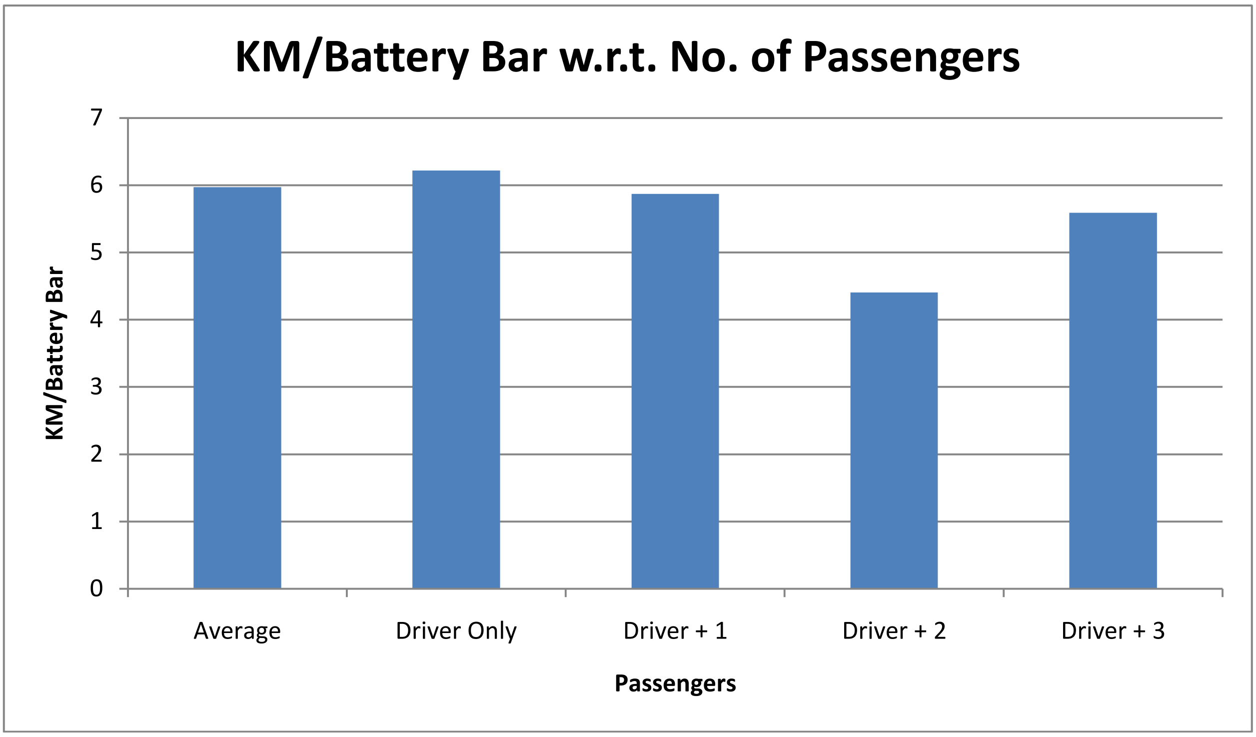
2.12 Efficiency vs Driving Condition



It can be seen that peak hour driving consumes slightly more energy than urban driving. Freeway driving appears to be the most efficient, however the sample size for freeway driving was small in this data set, so this may not be representative of true efficency.

Condition	%Of Total
Peak	45.08%
Urban	53.67%
Freeway	1.24%

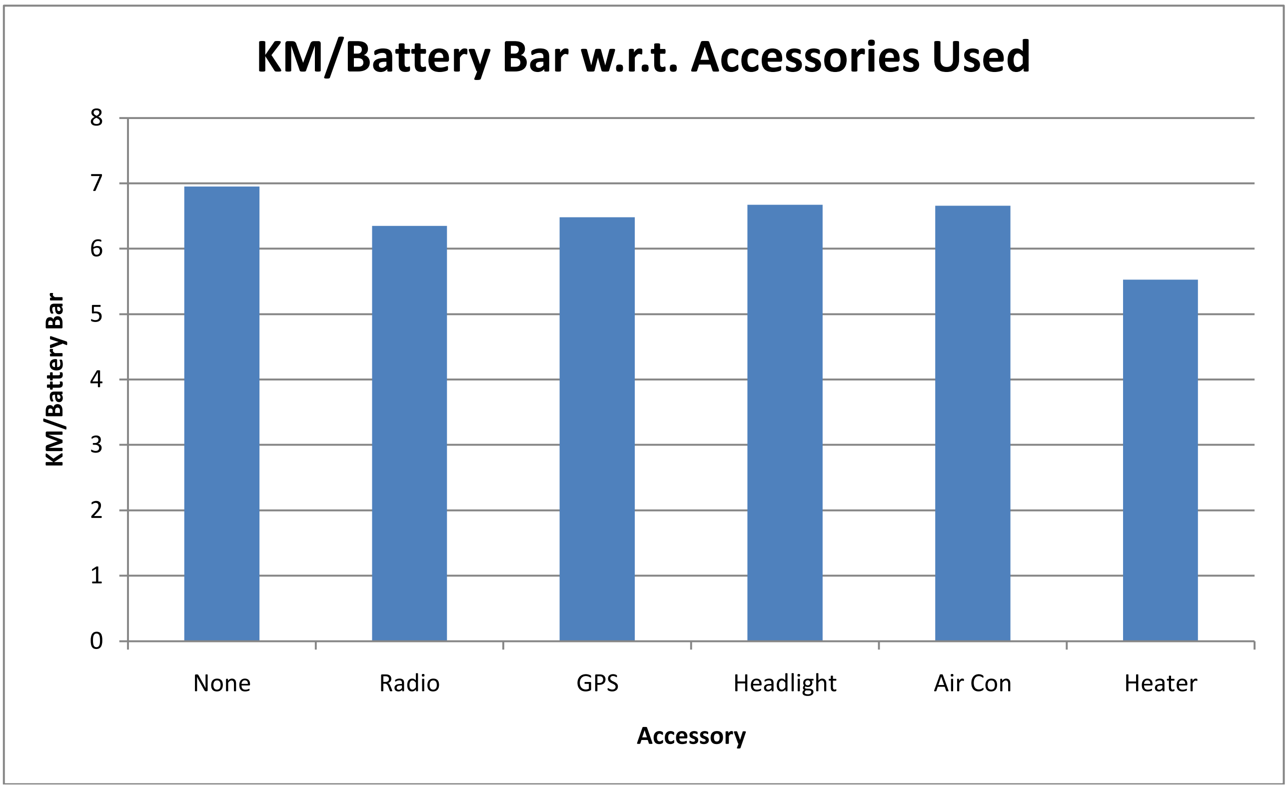
2.13 Efficiency vs Number of Passengers



As expected, increasing the number of people carried by the vehicle increases the energy it consumes per KM. The exception is with four people in the EV – this can be explained by the small sample size for this condition.

Passengers	%Of Total
Driver Only	67.68%
Driver + 1	21.47%
Driver + 2	8.93%
Driver + 3	1.92%

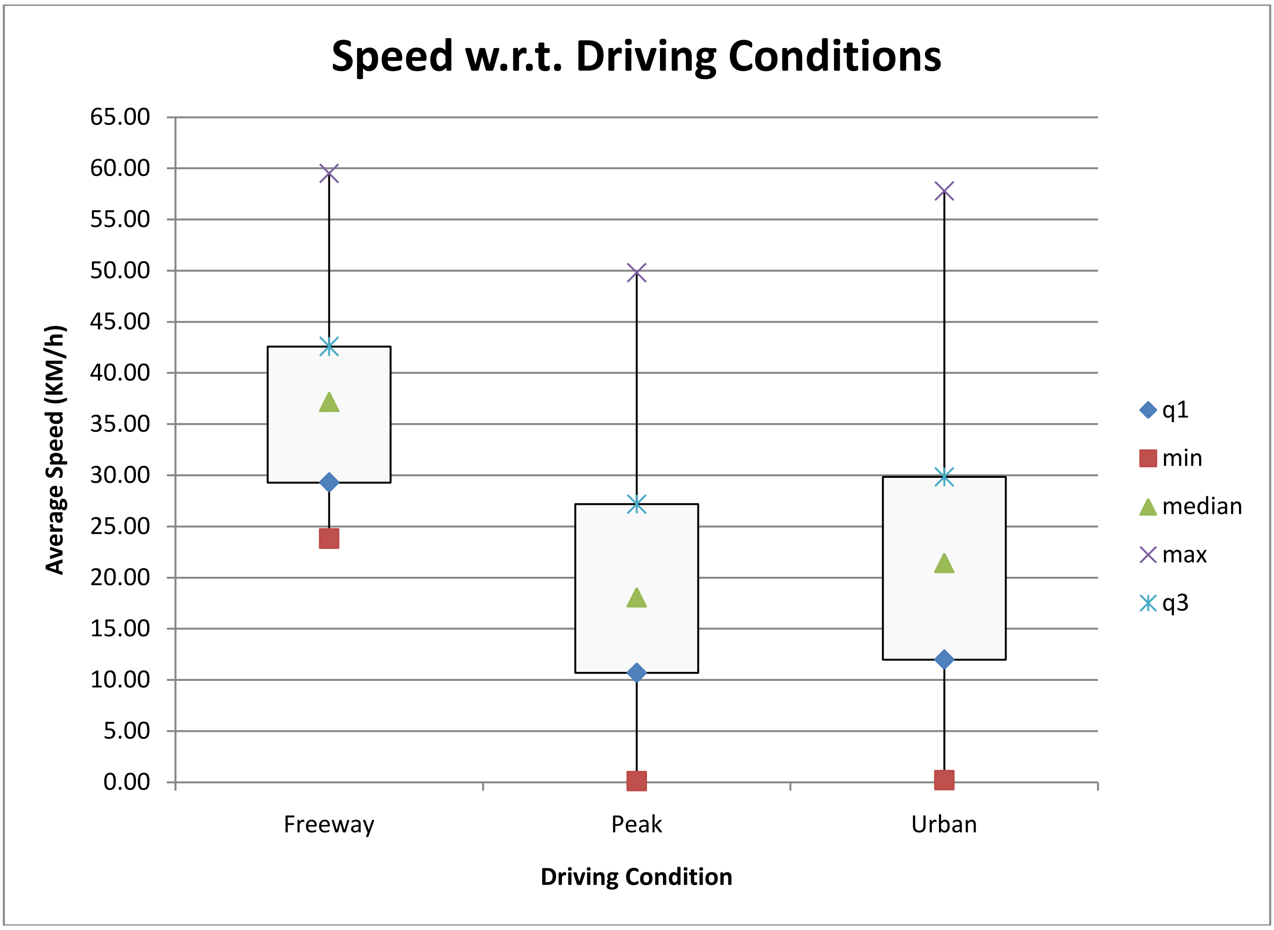
2.14 Efficiency vs Accessories Used



Since more than one accessory can be used at once, a multi-variable regression analysis was perfomed to de-correlate the impact of each accessory from each other. This graph shows the Air Con and Headlights having *less* of an impact on economy than the radio or GPS. This is not as expected and is likely due to data quality issues. The accessory in question may have only been used for a small percentage of the total trip, however the driver still may have entered it as used, skewing the results.

Accessory	*KM/Battery Bar*
None	6.95
Radio	6.35
GPS	6.48
Headlight	6.67
Air Con	6.66
Heater	5.53

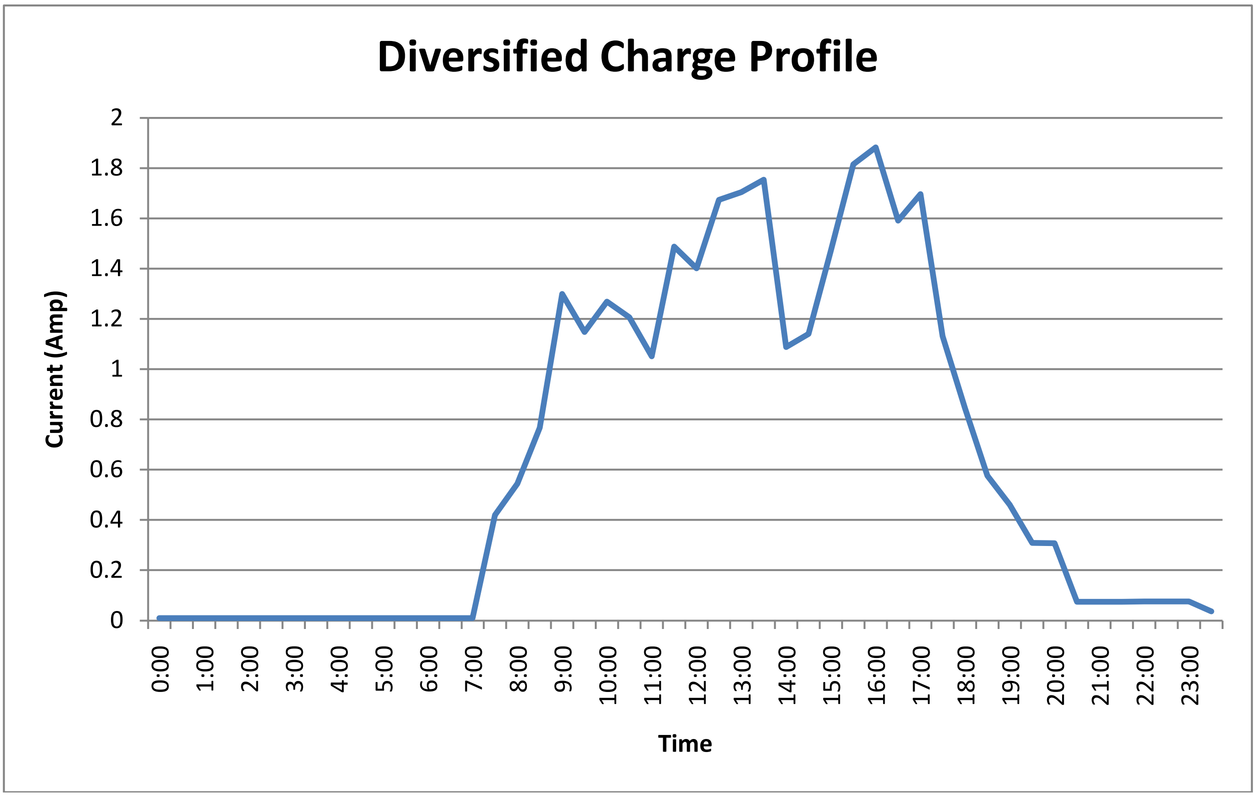
2.15 Average Speed vs Driving Conditions



These values are calculated from average trip speed. It can be seen that the driving condition entered by the driver is subjective to a large extent, giving large differences between the minimum and maximum values and overlaps between the categories.

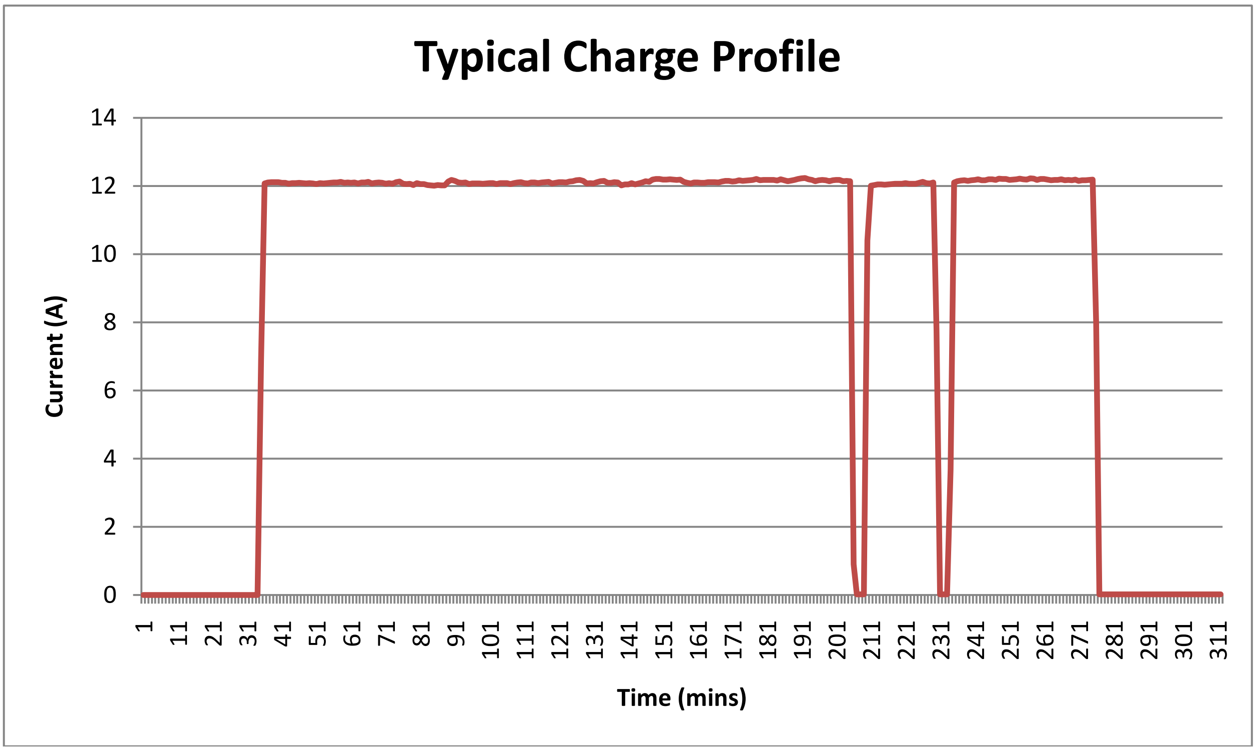
	Freeway	Peak	Urban
q1	29.29	10.68	11.98
min	23.82	0.12	0.22
median	37.18	18.09	21.45
max	59.51	49.81	57.78
q3	42.59	27.19	29.85
Mean	37.28324	19.41778	21.67414

2.16 Diversified Charging Profile (One Vehicle)



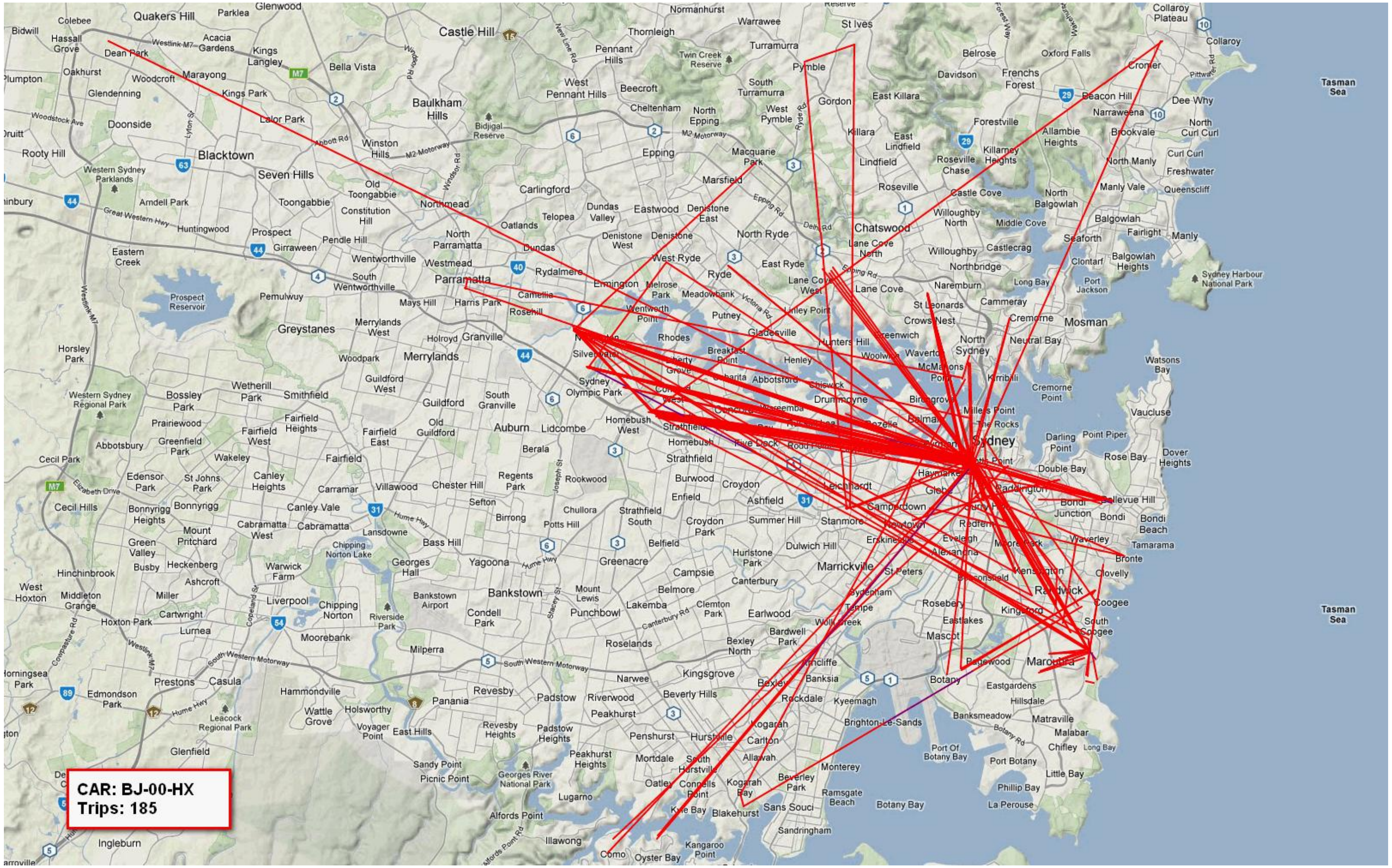
This profile is generated from data collected from one vehicle in a pool car scenario. As can be seen, the majority of charging is performed during the day, coinciding with peak electricity demand.

2.17 Typical Charge Profile (One Vehicle)



As can be seen from the above graph, the vehicle charges at a constant current with a mean of 11.7A when connected to a 15A outlet. The small periods where the current dips to zero can be explained by charging being paused by the vehicle for 3-4 mins to allow the charging system to cool.

2.18 Map of total trip journeys (One Vehicle)



This image shows all the start and end points for each trip taken by a single vehicle in the data collection period with lines joining the points. This vehicle is usually garaged in the Sydney CBD, as evident by the lines radiating from this point.

3 Appendix: Data Tables

Trip Duration (Mins)	*Frequency*	*%Of Total*
10	115	10.30%
20	197	17.64%
30	172	15.40%
40	167	14.95%
50	137	12.26%
60	96	8.59%
70	56	5.01%
80	28	2.51%
90	15	1.34%
100	7	0.63%
110	20	1.79%
120	17	1.52%
130	9	0.81%
140	11	0.98%
150	10	0.90%
160	6	0.54%
170	8	0.72%

Table 2: Trip Duration Data

Average Speed	*Frequency*	*%Of Total*
5	69	6.18%
10	154	13.79%
15	193	17.28%
20	134	12.00%
25	163	14.59%
30	155	13.88%
35	134	12.00%
40	72	6.45%
45	25	2.24%
50	12	1.07%
55	4	0.36%
60	2	0.18%
More	0	0.00%

Table 1 Average Speed Data

Trip Distance (KM)	*Frequency*	*%Of Total*
5	328	29.36%
10	193	17.28%
15	151	13.52%
20	113	10.12%
25	91	8.15%
30	91	8.15%
35	89	7.97%
40	18	1.61%
45	16	1.43%
50	7	0.63%
55	5	0.45%
60	3	0.27%
65	5	0.45%
70	3	0.27%
More	4	0.003581

Table 4 Trip Distance Data

SoC at Trip End	*Frequency*	*%Of Total*
2	8	0.73%
4	54	4.95%
6	100	9.17%
8	114	10.45%
10	156	14.30%
12	201	18.42%
14	218	19.98%
16	240	22.00%
Mean	11.05	

Table 3 SoC at End of Trip Data

Charge Used	*Frequency*	*%Of Total*
0	206	18.88%
1	256	23.46%
2	183	16.77%
3	141	12.92%
4	91	8.34%
5	109	9.99%
6	48	4.40%
7	24	2.20%
8	12	1.10%
More	21	1.92%
Mean	2.50	

Table 6 Charge Used per Trip Data

Battery Bars	*Frequency*	*%Of Total*
2	9	2.39%
4	35	9.28%
6	63	16.71%
8	61	16.18%
10	53	14.06%
12	57	15.12%
14	70	18.57%
16	29	7.69%
Mean	9.23	

Table 5 SoC pre Charge Data

Mins Per Day Per Car	*Frequency*	*%Of Total*
0	13	9.35%
10	18	12.95%
20	16	11.51%
30	12	8.63%
40	13	9.35%
50	15	10.79%
60	9	6.47%
70	15	10.79%
80	5	3.60%
90	7	5.04%
100	2	1.44%
110	2	1.44%
120	1	0.72%
130	2	1.44%
140	1	0.72%
150	1	0.72%
160	0	0.00%
170	0	0.00%
180	3	2.16%

Table 8 Minutes Driven per Day Data

Distance Between Charges (KM)	*Frequency*	*%Of Total*
5	5	1.33%
10	29	7.73%
15	38	10.13%
20	20	5.33%
25	30	8.00%
30	20	5.33%
35	23	6.13%
40	24	6.40%
45	29	7.73%
50	15	4.00%
55	17	4.53%
60	50	13.33%
65	23	6.13%
70	20	5.33%
75	7	1.87%
80	7	1.87%
85	2	0.53%
90	4	1.07%
95	4	1.07%

Table 7 Distance Between Charges Data

KM/Bar	*Frequency*	*%Of Total*
1	11	1.24%
2	30	3.39%
3	58	6.55%
4	89	10.06%
5	120	13.56%
6	173	19.55%
7	189	21.36%
8	72	8.14%
9	48	5.42%
10	23	2.60%
11	28	3.16%
12	12	1.36%
13	5	0.56%
14	6	0.68%
15	12	1.36%

Table 9 KM/Battery Bar Data

Smart Grid, Smart City Project

Monitoring and Measurement Report

Report I

01 January 2011 – 30 June 2011

Foreword

The *Smart Grid, Smart City* project was created to investigate the potential benefits of smart grid technologies for Australian consumers and industry when applied across the electricity network on a commercial scale. Adopting smarter technologies across the grid could help efficiently address important challenges being faced by the electricity sector.

These challenges include managing rising peak demand for electricity, the need for affordable and reliable electricity supply and an adaptable electricity network that can support an increasing number of distributed resources being added to it.

We are very pleased to be sharing our findings from the *Smart Grid, Smart City* project with the Australian Government and industry. This document is one of a number of key outputs from the project that we believe will give real world insights into smart grids. We hope it will accelerate and inform the future adoption of smart grid technologies in Australia.

We hope that in making these findings available that Ausgrid, the consortium partners who have assisted us and the Australian Government can demonstrate lessons that will put Australia at the forefront of smart grid development.

George Maltabarow

Managing Director

Ausgrid

IMPORTANT NOTE:

In a number of attachments, Ausgrid has removed certain material that we do not consider appropriate to release, such as personal information and commercially sensitive financial information. Ausgrid believes the removal of this information does not detract from the general value of the information or findings in the attachments.

This document has been approved for publication by Ausgrid and the consortium partners who contributed to it. The document has been prepared with all reasonable care and responsibility. Ausgrid believes these findings to be technically and factually accurate when applied to Ausgrid's network as at the date of those findings.

However it should not be considered a recommendation and naturally, it would be prudent for anyone who wishes to rely on, or use the information in this report to independently verify its accuracy, completeness and suitability for use for their own purpose.

Consequently, Ausgrid makes no representation or warranty as to the accuracy, currency, reliability, completeness or suitability, of the information in this report. You acknowledge that Ausgrid (and its officers, employees, agents and consultants) to the full extent permitted by law, excludes all liability: (a) (including liability to any person by reason of negligence or negligent misstatement) for any statement, opinion, information or matter (expressed or implied) contained in, and for any omissions from, this document; and (b) arising out of your use of or reliance on this document and any information contained in it.

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Contents

Attachment List

The Monitoring & Measurement Report (MMR) is provided in the format of an overarching summary document that appends a number of key additional reference materials. The content and structure of these additional materials fall into two broad categories and are identified as one of the following information types.

The categories are:

a. ***In-kind*** – this refers to information that has been collected and provided by Ausgrid without the use of any funding from the Australian Government. It is either provided as part of historic smart grid activities or funded as new investment during the period of the trial.

b. ***Activity material*** – this is information that has been created through the use of Australian Government funds.

The information types are:

a. ***Implementation artefact*** – this refers to key artefacts that are created as part of the project. Ausgrid is committed to making these documents, along with areas in which we have highlighted in-kind projects that will assist to inform industry on how the project has been delivered.

b. ***Analysis & conclusions*** – Ausgrid has committed to undertaking analysis, relevant to the Ausgrid network that can inform conclusions against the original hypotheses or key benefits that were ascribed to the trials.

c. ***Access to raw data*** – as part of the project Ausgrid will collect data that will assist in analysis. A subset of raw data that is relevant for industry will be made available via the portal for further review.

The following information is being released as part of this Monitoring & Measurement Report.

AREA	TITLE	CATEGORY	TYPE	ATTACHMENT NUMBER
CA	EA & IBM: AMI Business Case - Network Benefits & Costs	IN-KIND	ARTEFACT	MMR1.CA1
CA	EA & IBM: AMI - Business impacts to be tested	IN-KIND	ARTEFACT	MMR1.CA2
CA	EA & IBM: AMI - Network Impact Analysis	IN-KIND	ARTEFACT	MMR1.CA3
CA	EA & IBM: AMI Pilot Project – Technology Report	IN-KIND	ARTEFACT	MMR1.CA4

AREA	TITLE	CATEGORY	TYPE	ATTACHMENT NUMBER
CA	EA & IBM: AMI Pilot Project - Data & Systems Integration Report	IN-KIND	ARTEFACT	MMR1.CA5
CA	Ausgrid: Network Pricing Study - Customer Research	IN-KIND	ARTEFACT	MMR1.CA6
CA	Ausgrid: Strategic Pricing Study Report	IN-KIND	ARTEFACT	MMR1.CA7
CA	Ausgrid: Network Pricing Study - Advanced Metering Solutions - Operational Performance	IN-KIND	ARTEFACT	MMR1.CA8
CA	Frontier: Impact of TOU pricing on EnergyAustralia customers	IN-KIND	ARTEFACT	MMR1.CA9
CA	Frontier: Impact of TOU pricing on EnergyAustralia customers - extension	IN-KIND	ARTEFACT	MMR1.CA10
EV	EA & IBM: Electric Vehicle Report	IN-KIND	ARTEFACT	MMR1.EV11
EV	Curtin University of Technology: Electric Vehicles Trial	IN-KIND	ARTEFACT	MMR1.EV12
EV	Ausgrid: Electric VehicleTrial - Preliminary Analysis	ACTIVITY MATERIAL	ANALYSIS	MMR1.EV13
EV	Ausgrid: Electric Vehicle Trial - Raw Data	ACTIVITY MATERIAL	RAW DATA	MMR1.EV14
GA	Ausgrid: Distribution Monitoring & Control Program	IN-KIND	ARTEFACT	MMR1.GA15
GA	EA & IBM: Transmission Enhancement Program - Executive Summary	IN-KIND	ARTEFACT	MMR1.GA16
GA	EA & IBM: Transmission Enhancement Program - Business Case	IN-KIND	ARTEFACT	MMR1.GA17
ERM	Curtin University of Technology: Distributed Energy Storage for Smart	IN-KIND	ARTEFACT	MMR1.ERM18

AREA	TITLE	CATEGORY	TYPE	ATTACHMENT NUMBER
	Distribution Grid			
InterOp	Ausgrid: IP/MLPS High Level Design Summary	IN-KIND	ARTEFACT	MMR1.InterOp19
InterOp	Ausgrid: Network Engineering Guidelines and Network Standards	IN-KIND	ARTEFACT	MMR1.InterOp20
InterOp	Cisco: Substation LAN - High Level Architecture	IN-KIND	ARTEFACT	MMR1.InterOp21
InterOp	Cisco: Substation LAN - Requirement Traceability Matrix	IN-KIND	ARTEFACT	MMR1.InterOp22
InterOp	Cisco: Substation LAN - Use Cases	IN-KIND	ARTEFACT	MMR1.InterOp23
IT	Ausgrid: Operational Technology Architecture for *Smart Grid, Smart City*	IN-KIND	ARTEFACT	MMR1.InterOp24

1 Introduction

1.1 Objective

The outcomes of the *Smart Grid, Smart City* trial are presented to the Australian Government, and broader industry within this Monitoring & Measurement Report (MMR).

This Report is prepared in order to:

1. Report on the *"… outcomes of deploying a demonstration and/or commercial scale rollout that informs a business case for key Applications and technologies of a smart grid"*;

2. Be used to *"… build public and corporate awareness of the economic and environmental benefits of smart grids and obtain buy-in from industry and customers";*

3. Provide access to "… robust information and data to inform broader industry adoption of smart grid applications across Australia"; and

4. Report on the outcomes of investigating *"… synergies with other infrastructure (such as gas and water) and the National Broadband Network"*.

This is the first release in a series of six reports for the project. These will be subsequently provided on a six monthly basis throughout the project's duration.

1.2 Overview of this release

This, the first Report for the *Smart Grid, Smart City* trial, focuses predominantly on releasing information from existing Ausgrid funded smart grid initiatives. These in-kind artefacts and analysis will help provide a common understanding of technologies, the benefits and implementation approach for some of Ausgrid's underpinning smart grid investments. By releasing this information Ausgrid is honouring the commitment to share our learnings with the industry as part of this important project.

In addition there is some preliminary information that has been developed specifically related to the *Smart Grid, Smart City* trials around Electric Vehicles and the Customer Applications areas.

Some of the highlights of this Report include:

- The analysis of Ausgrid's activities to test Time of Use pricing, operational learnings from smart metering and network pricing investigations;

- Ausgrid's model smart metering business case and impact assessment which provides a network distribution business perspective on the costs and benefits to be validated for a rollout of smart metering;

- A study of the Distribution Monitoring & Control project that will be useful to inform other network distribution businesses on this rollout;

- The benefit areas and strategy for Ausgrid's Transmission Enhancement program that describes the approach being taken to implement and identify benefits areas on the high level distribution network voltage levels;

- A suite of implementation and planning materials from the deployment of telecommunications networks. Including standards, network architecture and the use cases developed to provide smart grid services;

- Preliminary results of the Electric Vehicle trials have been collected and some early analysis prepared in the report based on data from January to June 2011; and

- Design documentation that outlines the Ausgrid smart metering design and testing approach for customer applications delivered as part of the *Smart Grid, Smart City* trial.

It is expected that future Reports will contain a much higher proportion of *Smart Grid, Smart City* specific information. As the trials are conducted, the level of data and analysis conducted will increase.

1.3 Structure of the Monitoring & Measurement Report

Each section of this Report has been prepared to summarise the key learnings from the materials released as part of this Monitoring & Measurement Reporting period. The materials are presented using the key application areas, such as customer applications, grid applications and supporting infrastructure. Each summary attempts to answer the following questions where relevant:

a) How does the data inform the business case for key smart grid applications and technologies?

b) How does the data inform regulatory and policy mechanisms for broader adoption of smart grid networks in Australia?

c) How does the data inform consumers and the community of the benefits of smart grid networks?

d) What are the residual knowledge gaps that still need to be addressed?

1.4 Acknowledgements

The material prepared in this Report has been produced by Ausgrid with the assistance of a number of consortium members and associated partners.

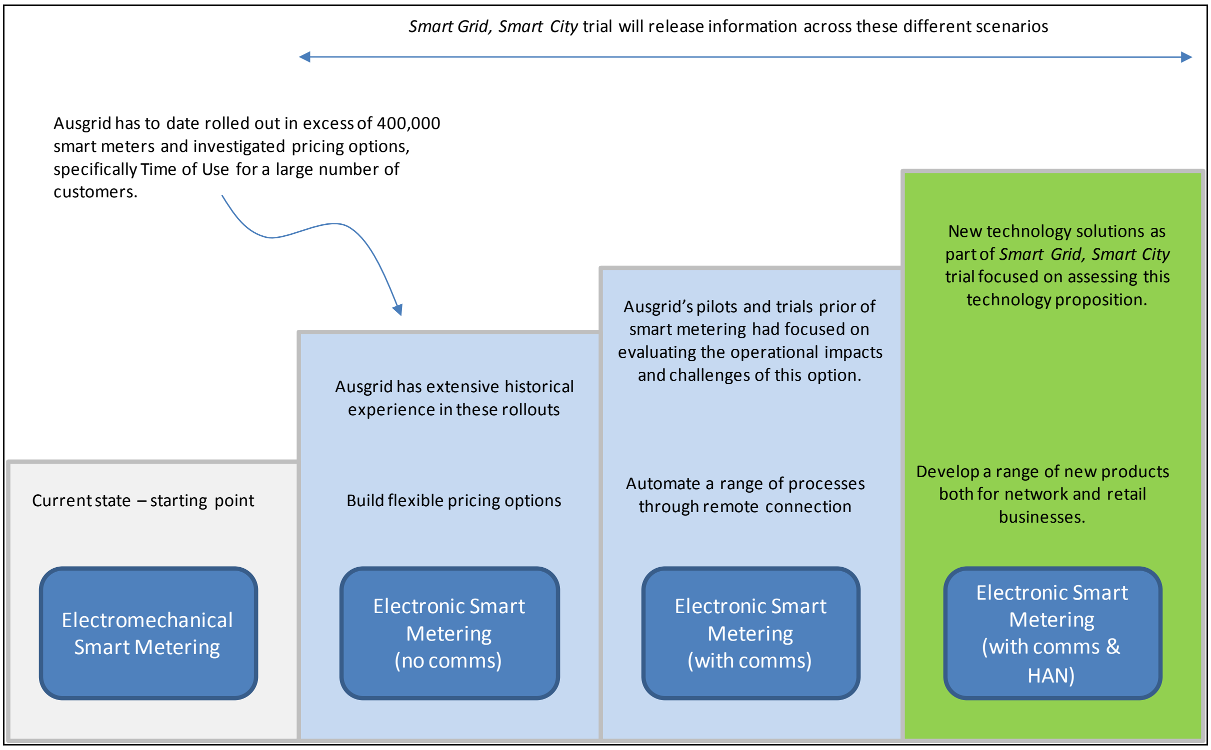
In particular, the information in this release of the Report acknowledges the contributions of:

- Cisco for releasing their Local Area Network Use Cases
- Alcatel-Lucent for granting permission to publish the information contained in the Telecommunications Architecture and Technology Report
- Curtin University for granting permission to publish their studies
- Frontier Economics for granting the permission to publish the studies on Time Of Use Pricing; and
- IBM for granting the permission to publish the studies on Electric Vehicles, Advanced Metering Infrastructure and documents on the Transmission Enhancement Program

2 Customer Applications Summary

The customer application component of the *Smart Grid, Smart City* trial builds on the existing Ausgrid initiatives in smart metering, network pricing and load control.

The industry is looking at different cost and benefit scenarios based on the varying types of smart metering, pricing tariffs and new feedback technologies available to customers. Each of these approaches will be assessed based on four different smart metering technology platforms shown below. The *Smart Grid, Smart City* trial will provide this assessment, either as in-kind or specific testing over the three years.



Our approach will be measured in terms of:

- The level of acceptance and longevity of that acceptance by customers for each solution; and
- Quantifying the total resource available (usefulness) to the utility under load control from each approach.

The *Smart Grid, Smart City* trial will offer the following basic value propositions across varying customer segments in order to validate the available technology options. These are:

- Providing real-time energy information to the appliance level that enables customers to make informed decisions about their energy consumption;

- Providing easy-to-use devices and advanced technology that customers embrace, combined with effective communication in their usage, including education and tips in better energy management;

- Providing consumer programs and the right packaging to make energy efficiency, conservation, and demand response programs attractive to customers and draw them in; and

- Providing a satisfying customer experience that keeps the customer engaged with the program.

2.1 Overview of Information Released

The Customer Application information released as part of this first MMR is primarily related to in-kind findings from existing Ausgrid initiatives. This information will enable the industry to better appreciate many of the underlying costs and benefits of some of the historic Ausgrid programs, such as the implementation of Time of Use products. It also highlights some of the operational experiences and responses in working within the Australian market to progress these types of technologies.

Building a Smart Metering Business Case

Ausgrid and our consortium partner IBM have prepared a model smart metering business case that has been provided as part of the MMR. This business case was prepared in 2009. It is a starting point; providing a framework that is being used by Ausgrid to validate the costs and network business benefits of a smart metering rollout.

In addition to the business case, Ausgrid and IBM have prepared and released a network business impact assessment based on a future smart metering rollout.

Understanding How the Technology Operates

Alongside this Ausgrid has prepared a series of reports that assess the technology and operational performance of smart metering programs to date. This series of reports are:

- AMI Pilot Project Phase 1 – Technology Report (June 2006 – July 2008);

- AMI Pilot Project Phase 1 – AMI Data & Systems Integration for Market Settlement and Billing Report (August 2008 to November 2009); and

- Smart Metering Operational Performance Report (June 2011).

Network Pricing

A key in-kind project that informs the *Smart Grid, Smart City* objectives is the existing work being conducted by Ausgrid to investigate new approaches to pricing.

As part of this release of the MMR Ausgrid is publishing a number of reports that provide insight into Time of Use, Critical Peak Pricing and our broader strategic pricing initiatives.

The information released evaluates the impact of Ausgrid's existing Time of Use pricing program and analyses customer response towards network demand based benefits. It also includes analysis collected to better understanding customer pricing, demographics and retailer response to different pricing solutions. Ausgrid has been assisted in undertaking this research by Frontier Economics and it is with their permission that this in-kind data is reproduced.

Ausgrid's Smart Metering Specification

An early deliverable for Ausgrid as part of the *Smart Grid, Smart City* trial has been the development of a smart metering specification. This has been created to prepare technology capabilities that support the advanced requirements being tested. This specification was derived from the National Smart Metering Specification produced as part of the Ministerial Council Energy led program. It has been further adapted to reflect Ausgrid's operational learnings and requirements.

It is published as part of this MMR.

CA1 AMI Business Case – Cost Benefit Assessment

In 2009 Ausgrid was assisted by IBM to develop a model AMI Business Case. This framework identified the network benefits and costs of a potential future mandated AMI program. The Business Case was prepared to provide guidance on the key Business Case parameters and impacts that should be considered for testing during the Newington Smart Village trial and to provide a framework and model that could be reused/ updated by Ausgrid as new information on the likely Network benefits and costs of an AMI rollout becomes available.

Note, while the dollar amounts were point-in-time estimates from 2009, they still provide valuable indication of the investment required to build this capability across the Ausgrid network.

To develop the Business Case, a range of key inputs and data sources were used, including:

- a standard framework of AMI benefits and costs provided by IBM;
- data that IBM has observed in AMI Business Cases from overseas jurisdictions;
- the Cost Benefit Analysis of Smart Metering and Direct Load Control developed by NERA and others for the Ministerial Council on Energy; and
- information provided by EnergyAustralia subject matter experts.

The key findings of the Business Case were as follows:

- A future AMI program for Ausgrid was projected to cost approximately $1,081 million in capital costs (approximately $573 per meter);
- Network benefits were calculated at the time to amount to $41 million per annum, or $22 per meter p.a. This is at the lower end of global and local benchmarks, in part because of alternative smart grid investments such as the DM&C project and interval metering programs are likely to realise a significant portion of the potential benefits normally attributed to AMI; and
- Operating costs are projected to amount to $31 million per annum, which can be offset by the expected benefits.

A key objective for the *Smart Grid, Smart* City trial will be to validate many of the assumptions within this business case. It will be an important framework to review changes over time, new benefits that maybe possible to quantify and more holistic industry wide benefits.

CA4 AMI Pilot Project – Technology Learnings

In 2006 Ausgrid commenced a program to trial Smart Metering Infrastructure (SMI) including the rollout of over 3,000 smart meters. These meters have been supplying daily metering data to the National Electricity Market (NEM) and retailers on a production basis since 2009.

The following reports have been released previously to industry as part of Ausgrid's participation in the Ministerial Council of Energy's Smart Metering Program. These are reproduced as part of this MMR to provide further background and a complete suite of documents on this trial. They are:

- 01/04 AMI Pilot Project Phase 1 – Technology Report (June 2006 to July 2008) released in October 2008; and
- 01/05 AMI Pilot Project Phase 1 – AMI Data and Systems Integration for Market Settlement and Billing Report (August 2008 to November 2009) released in March 2010.

In June 2011 Ausgrid completed a study on the operational performance of the metering solutions that have been operating for several years as part of two communicating metering trials. These findings are provided as part of the series of technology learnings.

This study has been by Ausgrid to develop the smart meter testing program used for the *Smart Grid, Smart City* trial.

The report includes data from testing and assessing the performance of the systems between the meter through to the Meter Management System (MMS) and back, the capability and functionality of the meters and the integration of the meter to the MMS in a fully operational support environment. The daily interaction with the existing Meter Data Provider (MDP) Back Office has also provided useful operational experience.

Investigations into additional SMI services that can be provided by the existing SMI solution have been the subject of a number of detailed in-depth reports and have informed the design the *Smart Grid, Smart City* trial feedback technologies.

CA6 Network Pricing Study - Customer Research

Network pricing research was carried out from Winter 2006 - Winter 2009 to assess how TOU pricing, enabled through smart metering infrastructure, impacted customer consumption.

As part of the next phase of this project Ausgrid conducted some customer research to develop a new network tariff options. There are three phases of this customer research program:

Phase 1 (completed) - Impact of TOU pricing on customers, which analyses customer response to TOU pricing from a network perspective.

Phase 2 (completed) - Customer pricing and demographics survey, which involved surveying electricity customers, retailers as well as previous pricing research and pricing solutions from other industries to gain insights into customer and retailers network pricing preferences.

Phase 3 (underway) - Customer pricing and tariff trial, which has the objective of narrowing down the definition of a network tariff which is acceptable to both customers and retailers.

The key findings from each of these phases of the customer research program are discussed below.

Impact of Time of Use Pricing on Customers

Ausgrid has a large portfolio of customers with meters that record half hour interval consumption data. A substantial proportion of those customers are billed using retail Time of Use (TOU) prices. Analysis of this data has enabled Ausgrid with an opportunity to understanding how customers respond to TOU pricing signals and importantly how those customer responses impact the long term network investment costs.

Ausgrid was assisted in this analysis by Frontier Economics (Frontier).

Frontier undertook analysis both for residential and business customers to investigate whether there was a difference in the behaviour of customers on TOU pricing and Inclining Block Tariff (IBT) pricing in the period Winter 2006 to Winter 2009 (four winter and three summer seasons), and what some of the drivers of those differences were.

The research used the traditional Ausgrid network planning definitions of summer and winter which gives a seven month long winter and a five month long summer. Temperature trends over this period implies that these definitions for future analytical purposes may be revised to a summer and winter in which both seasons have durations of six months.

The study found that there was a reduction in the residential customer's coincident maximum demand for TOU customers compared with IBT customers. The average difference in residential customer coincident maximum demand for TOU customers compared with IBT customers for the last two winter and summer seasons in the study ranged between 1.94% and 6.33%. In addition the coincident maximum demand impact appears to reduce over time and seems only to impact larger

TOU residential customers. The study did not find a reduction in coincident maximum demand for business customers on TOU tariffs compared with IBT customers.

Customer Pricing and Demographics Survey

The research considered the range of network price structures that could be enabled with SMI and the likely customer behaviour in response to any change in the pricing arrangements. The aim of the study was to identify the price structures that provide appropriate price signals, whilst being acceptable to customers and retailers.

This study started by considering the range of price types that could be introduced with smart metering in both national and international utility markets. This allowed a long list of price structures to be produced from which a suitable set of options was compiled. These were assessed against a number of acceptance criteria to determine the most applicable price structures to be tested in the retailer and customer surveys.

The retailer survey was conducted with five national companies using a mixture of face to face interviews and telephone responses. Four of these were relatively large suppliers, whereas one provided the views from a small niche supplier who had a different marketing perspective. Eight potential network price structures were tested with additional questions on customer education, load control and new product offerings.

Most retailers could understand the theoretical need for the new price structures, but ideally need prices to be simple to understand and easy to explain to mass market customers. They were concerned on the potential impact of new prices on their cost to serve with an increase in billing costs and customers queries. A number of retailers were keen to work with Ausgrid to understand the objectives of any new price structures and consider how any new prices could have retailer as well as network benefits. Despite concerns on vulnerable customers most retailers did indicate they would pass through the new prices as they could not internalise the risk. However, some may choose to strengthen or dampen the price signals within the price structure depending on the likely customer perception.

The customer survey was conducted by the specialist customer research company instinct & reason using a technique called choice modelling, which allows for consideration of the trade-offs between different attributes within a pricing structure. The survey collected data on 1,023 residential customers and 340 SME customers and considered three alternative price structures which were:

- **Critical Day** – this is a Time of Use price which would have higher prices on 20 peak days for the whole duration of the day and lower prices on other days.
- **Critical Peak Pricing** – this pricing structure would have high prices for a short period (e.g. 6 hours) at times of network / market peak with discounted rates in other periods.
- **Capacity Charge** – this type of pricing structure would have the bill for network charges only based on the amount of electricity used on a few occasions per year that would be times of

network peak. Reducing electricity during these few periods will result in lower network charges.

The customer survey demonstrated a positive reaction to the new pricing concepts if there were compensating benefits. Both residential and SME customers indicated a willingness to change pricing structures in large numbers (70% residential / 59% SME) for savings of 10-20% off their electricity bill. Some caution should be taken with the actual percentage numbers as customer apathy may result in much lower levels being achieved in a pilot trial as some customers may determine they can't benefit from the new pricing options.

However, it does provide a guide that there is significant interest in alternative tariffs for the appropriate level of saving as well as information on customer preferences between pricing options. In terms of choosing between alternative options the residential customers had a relatively even split across the pricing choices. In contrast the SME customers were strongly in favour of the Critical Peak Pricing option with 40% of customer preferring this option.

The customer surveys provided positive evidence that customers could be engaged in new network pricing structures, but the retailer surveys did indicate some concerns from retailers. Key recommendations and observations to test in the tariff trial phase of this project are:

The survey suggested that significant bill saving levels of 10% for the Critical Peak Pricing and Critical Day pricing options and 20% for the Capacity Charge pricing may be sufficient incentive for customers to consider changing their pricing product.

Control of appliances should remain with the customer as this was a key determinant of the market share of new pricing structures. Provision of information via an In-Home Display (IHD) is not critical, but the use of some form of website / portal would be useful to ensure customers are informed.

Retailers should be involved in the process for the design and establishment of network prices. An assessment should also be made on how retailers could utilise any price structures to their advantage and avoid implementation difficulties.

A pricing trial should be developed that is large enough to be statistically significant and also include control groups.

A detailed evaluation plan for the pricing trial should be developed including an analytical framework to be able to compare the results of the research to actual customer participation in a pilot.

Customer Pricing and Tariff Trial

This phase of the customer research program was undertaken by instinct & reason in conjunction with Energeia and had the objective of narrowing down the network pricing options based upon customer preferences and the previous stages of customer research.

This phase included an online "choice modelling" survey of approximately 1000 small customers, plus in-depth one-on-one customer interviews with eight small customers. The survey tested possible attributes of a demand/capacity based network tariff.

This research found that the largest influence on the choice of preferred pricing structures was the availability of information about electricity use. Customers have not been highly engaged with electricity and are not well informed as to what electricity appliances use and how electricity could be best managed.

In the last few years this has begun to change but customers' efforts have been made difficult by the lack of an effective information feedback loop. Customers report having tried to reduce electricity use only to find over the course of a three month billing period that little has changed. Increased interest in electricity has been affected by the ongoing rising prices. Nevertheless without positive reinforcement on behaviour change people tend to relapse to their old habits. By coupling a pricing change with information and insight about electricity use the electricity utility is offering more control to its customers. This is highly desirable and adds significant value to the customer.

The end of peak periods in winter was the next largest influence on the choice of preferred pricing option. Winter time sees more customers spending time in the house in the peak periods and so shortening the winter peak generates a higher level of appeal than does shortening it in summer when people believe they will be out of the house more.

The next factor is how the peak electricity use (maximum demand) is measured. Almost all selected more of an average rather than a single one off pricing period per season. Most customers live with the fear of leaving appliances on by accident and fear that a one off event would mean a significantly higher bill.

The length of the billing period plays little role in customers minds when selecting the pricing options they would prefer.

The research found the pricing structure attributes most preferred by customers was not necessarily unaligned with those of network businesses.

CA7 Network Pricing - Strategic Pricing Study

This study was conducted to explore tariff structures that enable greater alignment between cost and revenue. The report is released as part of the MMR to inform the implementation of tariffs that may provide benefits to Ausgrid and customers, both domestic and business.

The Strategic Pricing Study (SPS) investigates tariffs that have such potential, and in particular:

- Measures tariff uptake by customers;
- Measures the peak load reductions achieved by customers responding to the price signals; and
- Compares peak load reductions due to information only and price signals, and between customers with and without in-house displays.

Key Learnings from Strategic Pricing Study

Both DPP and Seasonal Time of Use (STOU) tariffs have potential as global (whole network) tariffs, as significant system peak time reductions were realised for residential customers. The potential for a local Dynamic Peak Rebate tariff has been investigated separately and was proposed to retailers as part of the testing of *Smart Grid, Smart City*.

The key findings from Ausgrid's study are:

1. Domestic customers who signed up to DPP and STOU tariffs responded well, and are willing to reduce their energy usage during uncomfortable weather.
2. Despite the fact that a DPP tariff is much different in nature to current tariffs, customers understand them enough to respond well and express satisfaction.
3. 0-160MWh p.a. business customers showed no response to the DPP tariff.
4. DPP's dynamic price could probably be set at 50-70c/kWh for domestic customers and still achieve comparable reductions. Certainly above $1/kWh the demand response is saturated.
5. Domestic peak reductions strongly correlated to temperature: the further away from the comfortable 18° to 21° Celsius range, the greater the demand response.

A more detailed summary of the findings in this report are outlined below.

Dynamic Peak Price Tariff

The Dynamic Peak Price (DPP) tariff is a highly cost reflective tariff, where retail and network prices increase significantly (10 to 20 times) for the top few hours of peak demand each year. Outside these hours, DPP tariff prices are cheaper than default tariffs, to target revenue neutrality on an annual basis. Customers save money if they reduce load during DPP periods.

The Residential customers on the DPP tariff were:

- Attracted - the 'sign-up' rate was 10%, comparing well to typical retail campaigns (3-5%);
- Highly engaged - 87% of customers had their expectations met or exceeded;
- Responsive in uncomfortable temperatures – customers reduced their demand by 30% (Winter) and 36% (Summer) due to reducing their use of heating / cooling appliances; and
- Rewarded with savings – 99.44% of customers saved money, typically 18% of their retail bill.

Results strongly related to temperature

The residential peak demand response varied little with the amount of notice time (between 2 and 24 hours). Demand response increased as temperature moved away from comfortable (18°C to 31°C), and variable responses in the CBD region in winter and Bankstown in summer were likely to be due to data from weather stations being unrepresentative of domestic conditions.

Due to unusually mild weather during the study, response in the critical range above 40°C remains untested. The maximum tested temperature was only 31°C (Bankstown, 11 January 2007). Extrapolation of the actual results to extreme temperatures indicates peak demand reductions of 40% in Summer (35°C) are achievable. Encouragingly, these response rates were observed in Scone, with three instances of demand reductions greater than 40%, all achieved on occasions when the temperature was in the range 33°C to 35°C. Scone is excluded from the main results due to the small number of participants (two Control and seven DPP).

Residential STOU tariff results

The Seasonal Time Of Use tariff (STOU) is a time of use tariff with peak prices emphasised in Summer and Winter, and discounts during other times to target revenue neutrality. Residential customers on the Seasonal Time Of Use tariff reduced their peak demand by 13% (Summer) and 5% (Winter) during the top 20 network demand days for each season. In addition, they reduced their total energy by around 4%.

Value of In Home Displays (IHD)

The study showed no benefits of IHDs as a means of reducing peak demand – the peak demand reductions for customers were not statistically different from customers without IHDs. While this result could be due to the fact that the DPP price points tested were sufficiently high to saturate response, the survey revealed 15% of IHD recipients did not set up the IHD, and only half of the remaining customers checked the IHD once a day or more. At $50-$200 per unit, there is no evidence to support IHD's being a worthwhile demand management investment.

Business DPP and STOU results

Results support the theory that businesses don't respond because electricity is a small part of their costs:

- DPP and STOU take up was lower than residential (uptake in the 4%-7% range, compared to 10% for residential); and

- No peak demand reduction was achieved on the DPP tariff3 or the STOU tariff.

Applications of a Dynamic Peak Pricing tariff

There are two distinct alternatives in implementing a Dynamic Peak Price:

- **Local** – for demand management purposes. A locally implemented DPP tariff is specifically designed to reduce load at key assets, to gain value from deferring specific augmentation projects. It requires all Retailers, or at least the dominant Retailer, to engage with voluntary customers and pass on the price signal.

- **Global** – for cost-revenue alignment purposes. A global DPP implementation involves dynamic events for the whole, or at least sizable parts of, EnergyAustralia network area at once. This form of tariff is less effective at achieving specific project deferrals, however it does have value in ensuring that Network revenue tracks peak demand driven costs, and in generally dampening peak demand growth. Global application of DPP does not require Retailers who agree to pass on the signal to end consumers. The Network simply charges a mandatory dynamic peak price to the Retailers, and each Retailer can decide how, and to what extent, it passes the dynamic charges onto its customers.

Potential for local demand management using other forms of Dynamic tariffs

There are forms of dynamic tariffs suitable for Demand Management other than Dynamic Peak Pricing. For example, an alternative is to provide dynamic peak rebates. The implications of using a rebate are significant – customers are easier to sign-up, due to the no-lose value proposition, and Energy Retailers are not required, as it is possible for a Network to provide rebates directly to customers. For these reasons, a Dynamic Peak Rebate has been investigated in detail and was proposed to be tested as part of the *Smart Grid, Smart City* trial.

Potential for global application of innovative tariffs to align revenue with costs

Global application of DPP is more practical than local application of DPP. As the Regulator is likely to support the DPP's cost reflective nature, the Network doesn't need to convince Retailers to market the tariff. A decision on implementing a global DPP tariff needs to consider alternative tariffs which achieve the same result of aligning income with globally growing demand. One of these tariffs is Seasonal Time Of Use. This study shows that if a retailer passes on seasonal prices, domestic response can be significant.

3 Electric Vehicle Summary

Ausgrid is using the *Smart Grid, Smart City* trial of electric vehicles to investigate on a limited scale technical and regulatory issues that need to be addressed in order to create a consistent policy for electric vehicles in Australia.

There are two fundamental benefits being considered for electric vehicles. Firstly, they are seen as an alternative fuel technology for the transportation industry. Secondly, there is growing interest, particularly in countries with a high proportion of intermittent renewable generation, for utilising the batteries as a source of distributed storage.

The *Smart Grid, Smart City* trial provides an opportunity to better understand the impacts of electric vehicles on the grid and investigate a range of challenges that are emerging with their expected increase in adoption.

It is highly likely that rapid development of electric vehicle (EV) technology will require the electricity industry in Australia to make gradual changes to ensure that:

- The demand on the grid can be managed effectively utilising smart grid technology;
- Appropriate tariffs are developed to match the technology; and

  Network operators are able to accommodate a number of potential recharging business models.

3.1 Overview of Information Released

The initial MMR provides two pieces of information to assist in the evaluation of electric vehicles. This information is based on publishing existing research conducted by Ausgrid and a report that outlines some preliminary findings as part of the trials to date.

Existing Ausgrid Research

In preparing Ausgrid's *Smart Grid, Smart City* proposal leveraged two key research studies on electric vehicles. These were undertaken by IBM and Curtin University and are being made broadly available for other parts of the industry to learn from this analysis.

Preliminary Findings

Ausgrid has been supported by Mitsubishi with access to 20 of the first electric vehicles operated in Australia. These vehicles have been driven as part of a "fleet model" across Ausgrid sites where charging points have been installed. The data and subsequent analysis has been performed over a period of 6 months during the first half of 2011.

EV11 & EV12 Electric Vehicle Research

The IBM/EA 2009 report was developed to assess likely growth and corresponding impacts of Electric Vehicle penetration over the subsequent 10-20 years in Australia, drawing on IBM's global research in the automotive sector.

The Curtin University report looks at background information on Electric Vehicle and plug-in hybrid charging technology, specifically in Australia.

EV13 Analysis of Preliminary SGSC Results (Jan-Jun 2011)

This preliminary analysis is taken from data gathered from 9 vehicles over a total of 1357 trips recorded during the period. The data would appear to validate the key information data points such as vehicle efficiency, distance driven, energy remaining at charge and time of charge.

4 Grid Applications Summary

The *Smart Grid Smart City* (SGSC) program will investigate a range of grid applications associated with utilising smart grid technologies within the energy sector. The key grid applications being tested that will be reported in future reporting are:

- Fault Detection Isolation and Restoration;
- Active Volt Var Control;
- Substation and Feeder Monitoring; and
- Wide Area Measurement.

These applications are primarily of interest to network operators. The benefits vary across different geographies and distribution business, however many of the benefits are characterised by the following areas:

- incentive regulation – performance recording and reporting with penalties and rewards associated with network performance (regulatory driver);
- the need to provide substantive information to customers affected by outages and faults (regulatory, and customer driver);
- maintaining network performance – both system-level (average) and also that experienced by the 'worst-served' customers (regulatory and customer driver);
- the encouragement of demand-side solutions (including embedded generation) as a means of achieving carbon (emission) reductions (government driver) and capex management;
- increasing network reliability and resilience without incurring significant increases in capex and opex (regulatory driver); and
- reducing network capital and operating costs (shareholder driver) and reducing payments to distribution network operators (customer driver).

Ausgrid's has made a number of investments aligned to deploying smart grid technologies. These initiatives will be provided as in-kind learnings as part of the *Smart Grid, Smart City* trial. The advanced applications specifically tested as part of the trial will expand on these existing projects, with learnings from both influencing the assessment of costs and benefits in future MMR analysis.

4.1 Overview of Information Released

Ausgrid has prepared two key areas of information as part of the first MMR to assist in developing a better understanding of the benefits of grid applications. These areas are based on Ausgrid's existing projects are focused on benefits within the distribution network. The initiatives are divided based on their target on different parts of the Ausgrid network.

Distribution Monitoring & Control Project (DM&C)

The DM&C project has targeted the 11kV and 415V network with advanced monitoring. This project has identified a range of benefits that can be achieved by targeting new monitoring and fault restoration equipment in the lower sections of the network. The report prepared as part of the MMR provides an overview of the learnings Ausgrid has obtained to date from the implementation of this project. There are range of technical recommendations, analysis of benefit areas and the types of issues that were faced in developing this project.

Transmission Enhancement Project

The Transmission Enhancement project was created to focus on the Ausgrid 33kV, 66kV and 132kV network. This part of the network has traditionally had monitoring and control capabilities provided using SCADA systems. Unlike the DM&C project that focused on rolling out new sensors, this project has predominantly looked at back-office capabilities to better use data that is already being collected. The project was split into three key initiatives:

- Phase 1 – deployment of common back-office capabilities;
- Phase 2 – a specific cost and benefit assessment approach for analytics to be applied across different functional areas of the business; and
- Phase 3 – the implementation of an advanced DMS platform.

The first phase has been completed and is being used to deliver the applications as part of the *Smart Grid, Smart City* trial. Ausgrid is currently undertaking Phase 3 and this will also provide a key platform for the further trials, as the DMS will provide a centralised platform for many of the planned tests.

The cost and benefit areas originally identified are provided in this MMR. These assessments were conducted in 2009 and are indicative.

GA15 Learnings from the Distribution Monitoring & Control Program

Ausgrid operates approximately 30,000 street level substations, and like most utilities around the world currently has limited information on the operational status of this part of the network. By remotely collecting data at each substation, Ausgrid will develop real time visibility of the street level network in order to better plan, operate and maintain the network.

This will automate processes used to switch the network, respond to network faults and collect historical data from the network. This information will be used to deliver a range of short term requirements such as improved reliability, replacing resource intensive operational processes and providing improved longer term planning and asset management decision making tools.

The report has been prepared to provide a progress report on the learnings to date from the implementation. Ausgrid is still in the process of deploying devices and capturing many of the key benefits, these are discussed in the report.

Through the strategic placement of equipment, the DM&C program is targeting two key benefit areas, these are summarised below.

- The first was to obtain operational efficiencies by automating the manual reading of maximum demand (MDI) meters in distribution substations. MDI meters are installed in distribution substations primarily in Sydney and are recording the maximum demand supplied by each substation since the last read and reset of the meter. The meters are manually read twice a year to understand the summer and winter demands on each substation. These measurements form the basis for forecasting future demand and drive the maintenance, upgrade and planning processes for distribution substations. The DM&C equipment rollout makes it possible to get real-time demand measurement data from any substation fitted with the equipment. This data rich environment combined with a powerful visualisation and reporting environment are delivering significant benefit to Ausgrid.
- The second strategic benefit is improving the reliability of the Ausgrid distribution network. This is achieved in two ways. Firstly, through the better understanding of equipment utilisation, it is possible to refine the maintenance requirements of each substation, ultimately resulting in less unplanned outages occurring. DM&C equipment further assists System Control with fault finding activities by assisting in the identification of the feeder sections that were responsible for the outage. This is achieved by monitoring Earth Fault (EFI) and Line Fault Indicators (LFI) remotely, making it possible to dispatch field crews to the correct location in far less time and thereby improving the time it takes to restore an outage.

Going forward, all new pad-mount substations will be pre-fitted with DM&C equipment. It is estimated that approximately 400 new pad-mount substations will be built each year to grow the initial DM&C deployment on the network.

The report provides learnings on:

- The technologies selected, their maturity and the findings that Ausgrid gained from undertaking the project;

- The operational support and skillsets required to rollout the project, including placement and configuration of devices;
- The technical specification used to deploy and maximise benefits; and
- The benefits associated with the project.

GA16 Transmission Enhancement Program

The Transmission Enhancement program was established to deliver Operational Technology (OT) capabilities including the improvement of asset management and increased control and monitoring of system-wide operations on the 33kV, 66kV and 132kV network. This project delivered OT capabilities to support the existing SCADA environment through:

- More timely data acquisition and control to meet network outage management and restoration requirements;
- More mature condition based maintenance capabilities;
- A greater level of accuracy with regard to information and prediction;
- Better use of the many data sources that already exist, but which are not generally available;
- A repository for new IED data which will grow significantly as the capital works program deploys;
- The ability to correlate these various data sources to provide a more reliable, evidence based view of the health and performance of the transmission network;
- A technology architecture that will facilitate less complex and lower cost integration of transmission applications and data in the future; and
- Progress on the path to developing a smarter grid.

Ausgrid has released as part of the MMR a report developed with the assistance of IBM the overall strategic approach developed for the Transmission Enhancement program. In particular this provides key insights into the technology solution and vision.

The other key learnings from this document is the results of an organisational wide review of benefit areas that will benefit from the adoption of technology capabilities. These areas were assessed to form a series of "mini business cases". Each of these are indicative and are a useful guide to building a more detailed business case for *Smart Grid, Smart City* applications.

5 Energy Resource Management Summary

This Application is made up of both Distributed Storage and Distributed Generation Support, both of which facilitate better management of variances between supply and demand on the grid.

There is limited information that Ausgrid is able to release as part of this initial MMR. Outlined below is a summary of a research study that Ausgrid commissioned with Curtin University as part of the development of the *Smart Grid, Smart City* proposal in 2009. Ausgrid is releasing this document as it is a good overview of the technology areas and is still quite relevant for research in this area today.

ERM18 Battery Research Study

The Battery research study was completed by Professor Peter Wolfe from Curtin University. This study provides an overview of different storage options. Each storage option is discussed with respect to their suitability and availability to test as part of the *Smart Grid, Smart City* trial timeframes.

The key findings of this report are:

- Electric energy storage is expensive. Substantial research and demonstration investments are currently being made. These investments will improve the near term availability of mature commercial products and may lead to some gradual medium term improvements in price;
- Deferrable load and demand response should always be explored as an effective alternative to energy storage;
- Electric vehicles are expected to form a significant network load within a decade. Vehicle to Grid and Smart Charging are emerging applications. The report recommends Smart Charging but not Vehicle to Grid due to impact on battery lifecycle;
- Storage provides distribution networks with potential to defer capital costs, reduce system losses and improve power quality. The benefits are very network specific. In Australia, rural networks may provide the most economic solutions; and
- The preferred battery technologies on a cycle life cost basis for distribution network load levelling are vanadiumredox, sodium sulphur and zinc bromine.

Ausgrid has also used this report to provide guidance around the design of appropriate testing regimes for battery solutions.

Distributed Storage will play an increasingly important role in managing the future grid, as it will enable both economic and quality benefits to the power grid.

6 Supporting Infrastructure Summary

This section provides information from the *Smart Grid, Smart City* trial with respect to the implementation of common infrastructure that is used to support a smart grid. This is primarily aimed at the telecommunications and IT platforms that are built to transport two way data between smart devices and users of the data; as well as transform data into useful information.

The business case for these investments is often difficult to develop as the benefits are not directly related to investing in these platforms themselves. In addition, these investments are quite costly and in order for a positive return on investment, Ausgrid has found that they should be spread across as many different functional uses to maximise the benefits.

Ausgrid has learnt a number of important lessons from investing in these supporting infrastructure platforms to date. These have been the underpinning success of Ausgrid's program, starting with the deployment of a fibre optic based telecommunications network between major substations. The maturing of this platform to develop operational capabilities, extension of the network via last mile communications technologies and the adoption of standards based IT infrastructure are key in-kind learnings that Ausgrid is committed to sharing broadly with the industry.

6.1 Overview of Information Released

Ausgrid is releasing a number of key in-kind documents that will help other industry participants to understand the requirements and implementation of similar telecommunications and IT platforms. There are three key areas in which information is being released. These are the "Pinc network", the Last Mile telecommunications project and an overview of the Ausgrid OT architecture for *Smart Grid, Smart City*. The key information from each area is discussed below.

The Pinc Network

Ausgrid built an IP/MPLS telecommunications platform using predominantly fibre infrastructure deployed between 2006-2009. This network was world leading and has enabled a number of future smart grid investments. As part of this MMR Ausgrid is releasing information with respect to:

- An architecture and technology overview paper;
- The Ausgrid network standards used to build and maintain the infrastructure; and
- A series of requirements, use cases and architecture for operating smart grid functions.

The Last Mile Communications Project

Ausgrid is investing in a last mile communications strategy that includes extending capabilities to distribution and customer endpoints. This is enabled through a deployment of 4G wireless technology. As part of this MMR, Ausgrid is releasing information that outlines the testing of WiMAX within the Newcastle region that assisted in assessing the suitability of these technologies.

Operational Technology Architecture

Ausgrid has adopted industry best practise IT architectures to develop the operational technology environment that will support the *Smart Grid, Smart City* trial. This architecture is a “Services Oriented Architecture” approach that integrates a number of new interfaces and systems. It was originally developed and deployed to support the smart grid investments discussed in the earlier section on grid applications. It is now being extended to support the services for *Smart Grid, Smart City.*

InterOp19 Telecommunciations – IP/MPLS Architecture & Technology Report

This document presents a technical overview of the architecture and technologies used by Ausgrid to operate the IP/MPLS capabilities between substations. It has been adapted from a number of key project documentation for dissemination as an in-kind learning as part of the *Smart Grid, Smart City* trial.

This document presents a summary of how Ausgrid’s IP/MPLS wide area network (WAN) has been designed, as well as providing some examples of how it can be configured to support service traffic such as SCADA.

The information is provided with the intent to inform the industry of key principles and implementation learnings that Ausgrid discovered through the delivery of this project. The audience is specifically targeted at network engineers working for vendors, systems integrators and utilities.

InterOp20 Telecommunications – Network Standards

In developing and maintaining the telecommunications network, primarily the Pinc network described above, Ausgrid has developed a suite of network standards. These standards describe how Ausgrid has implemented the network specific to an electricity network business.

Ausgrid has published these standards as part of the MMR in order to inform industry of the approach that has been taken on this project. The standards that are published are:

- NEG TC06 Undergrounding Ausgrid Pinc Optical Fibre Cables in Conjunction with Distribution Mains
- NEG TC07 Requirements for Testing and Commissioning of Optical Fibre Communications Systems
- NEG TC19 Allocation of Optical Fibre Tubes
- NS201 All Dielectric Self Supporting Fibre Optical Cabling for Installation on Distribution Assets
- NS204.7.1 Communications Pits – Specifications and Installation Guidelines
- NS208.2.1 Telecommunications Substation Communications Cabinets Architecture Design Work Instruction

- NS208.2.2 Telecommunications Substations Communications Cabinet Interconnectivity Design Work Instruction
- NS215 Telecommunications Design – Work Instruction Allocation and Recording of Fibre Use

InterOp 21-23 Telecommunications – Smart Grid Requirements, Use Cases & Architecture

Ausgrid has a current project to investigate the design and implementation of a Substation Local Area Network within future major zone and sub-transmission substation designs. This is being developed to progress a possible uniform architecture that caters for a range of future smart grid requirements.

The project looks at how telecommunications can support key requirements within substations such as condition monitoring, Fault Detection Isolation and Restoration, the IEC61850 suite of applications, mobile workforce, monitoring and control, monitoring systems, building automation, physical security and wide area measurement. By publishing these requirements, use cases and high level architecture it will enable other industry participants with similar requirements to develop these use cases for their own implementation.

These outcomes have been documented in consultation with Ausgrid's consortium partner, Cisco Systems, who have agreed to the publishing of this document as part of the MMR.

There are three key documents provided in this MMR. They are:

- Use cases – these are provided to describe how the key system components interact to deliver the benefits of each application within the substation;
- Requirements Traceability Matrix – this is an overview of the requirements that have been defined for building a smart substation derived from the use cases; and,
- High Level Architecture – this is an overview of a vendor agnostic, possible architecture to support meet the requirements derived from the use-cases.

This MMR provides the initial deliverables as part of this project as in-kind as this project is funded by Ausgrid and has been initiated primarily to meet Ausgrid's emerging communications requirements within the substation environment. However, it is anticipated that learnings from this project will facilitate delivery of the Smart Substation LAN required for the Substation and Feeder Monitoring project.

IT24 Operational Technology Architecture for *Smart Grid, Smart City*

Ausgrid has released an overview of the operational technology environment that is being used to deliver the *Smart Grid, Smart City* trial. The Operational Technology solution specific to Ausgrid's wider Smart Grid program has been integrated with Ausgrid's corporate technology solution via a common service bus technology. The architecture outlined in the document will assist to inform other industry participants of the approach.

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EnergyAustralia®

1 July 2010

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear ~~Mr Pierce~~ John,

Response to Second Stage Consultation – National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010

Project reference ERC0092
EnergyAustralia welcomes the opportunity to respond to the AEMC regarding the Draft National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010.

EnergyAustralia supports the general policy direction of the rule change and previously identified a number of implementation issues for consideration in our response to the first round consultation on this rule change proposal on 19 October 2009. At that time we also identified a number of related matters that would improve the regulatory design of Chapter 7 of the National Electricity Rules.

EnergyAustralia notes that the AEMC has determined that it is not necessary to address the issues that we raised with respect to the responsible person for wholesale metering points and child NMIs in embedded networks. We are concerned that such an approach will continue existing uncertainty in the market and undermine the benefit of the other aspects of this Rule change.

In relation to the embedded network issues, EnergyAustralia has obtained external legal advice which sets out the basis for EnergyAustralia's concerns and explains why neither the existing Rules nor the Draft Rule provide for a Responsible Person within such networks. A copy of the advice is attached for your consideration. EnergyAustralia would be pleased to present further to the Commission on this issue once the Commission has had an opportunity to consider the advice.

The attached consultation response set outs EnergyAustralia's detailed comments on the draft Rule.

Please contact Mr Keith Yates on 4951 9359, if you require any further information or would like to discuss our response.

Yours sincerely

TREVOR ARMSTRONG
Executive General Manager
System Planning and Regulation

Attachments:
1. Comments on National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010.
2. External legal advice on Responsible Person and Embedded Network issues.

NER Chapter 7: National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010.
Consultation Response Project Reference ERC0092

Consultation review comments submitted by: EnergyAustralia Date: 1 July 2010

Clause	Issue	Comment
7.2.3 of AEMC rule determination.	Responsible person for Transmission points.	EnergyAustralia believes for MPB services only that the default RP for transmission network connection points (TNCPs) should be the LNSP not the FRMP. TNCPs require specific knowledge and maintenance to ensure correct settlement on the NEM. TNCPs are a “network” of metering points for a specific LNSP and local retailer area not just a single connection point, as would be the case for a “normal” Type 1-4 customer (e.g. a supermarket). This involves a detailed knowledge of the current and future configuration of the LNSP network to successfully manage TNCPs. A number of issues support this proposal: 1. LNSP network security issues – LNSPs would be reluctant to supply detailed network configurations to a FRMP. Also networks at this level are integrated and can be have a dynamic configuration and change regularly to reflect operations, maintenance and capital works. 2. FRMP knowledge of the LNSP network – The FRMP does not have the detailed knowledge of the configuration of the LNSPs network (i.e. interconnections and open points). In addition to the existing network configuration, the FRMP will not have the details of new substation and feeder construction which could influence the location of TNCPs. With the amount of proposed capital works over the next 5 -10 years in the EA LNSP network, a large number of changes to TNCPs will occur. 3. Access to metering installations – TNCPs are located at the transmission/distribution boundary, they are located within the LNSPs substation and hence access to these metering installations may not be permitted for a FRMP. The LNSP would need to

Clause	Issue	Comment
		provide a standby person to observe an FRMP representative who is conducting necessary work. 4. Rule compliant metering equipment – As stated above these metering installations are located within the LNSPs substation, as such the LNSP owns, purchases and maintains the metering and associated instrument transformers. As the LNSP has to produce specifications, purchase and maintain these instrument transformers, it is logical that the LNSP to be the RP for the metering installation. 5. Rule compliant metering equipment – The instrument transformers used for metering are housed in the same physical equipment as instrument transformers necessary for the protection, control and management of the substation. 6. Legacy systems/equipment – Due to the range of equipment in LNSP substations specific skills and safety requirements are necessary for the safe and accurate testing of TNCP metering installations. Table S7.6.2 in the proposed marked up version of chapter 7 identifies 2 categories of type 1 – 4 MDP accreditation, Category 1D – 4 D and 1T – 4T. This identifies that there are specific requirements pertaining to transmission connection points in the NEM and as such supports such a request to have the LNSP appointed as the default RP for TNCPs.
7.3.1 of AEMC rule determination.	Audits of the MDP by the RP.	This could impose a number of issues for MDPs if each RP conducts audits on the MDP. An annual unified audit should be conducted and EnergyAustralia submits that AEMO should conduct these audits on behalf of registered participants. This way all MDPs will be audited under the one auditing regime and each MDP will be audited equally.
7.3.2 of AEMC rule determination.	FRMP appointing the MDP for MDS.	EnergyAustralia submits that the Market Participant appointing the MDP to provide MDS may lead to confusion with respect to the correct terminology. The appointment of the "person responsible" for appointing a MDP to provide MDS and a "responsible person" to appoint the MPB could lead to confusion with the two terms being so similar and will inadvertently be used interchangeably. EnergyAustralia suggests that clarification and/or rewording is required to avoid this confusion.

Clause	Issue	Comment
		EnergyAustralia is also concerned as to how AEMO and other participants are going to be aware of who has appointed the MDP to provide MDS. In addition how are AEMO or other participants going to know who to contact as the RP or person responsible for the installation when AEMO is not privy to the offer between the LNSP and the Market Participant? Under this rule change proposal the two key fields in MSATs which would be used to identify the Responsible Person and the person responsible for appointing the MDP are the FRMP (for appointing the MDP) and RP (for appointing the MPB) NMI Participant relations fields. Example scenarios: 1. if the LNSP is the RP and FRMP appoints the MDP, then fields will be correct; 2. if the LNSP is the RP and also appoints the MDP, how will other parties know that the MDP was appointed by the LNSP as the FRMP and LNSP would be the same as in example 1? Under this rule change proposal would an additional MSATs NMI Participant relations field be required to identify who has appointed the MDP (i.e. the FRMP or LNSP)? A further issue with respect this clause is the need to close the process loop between the proposed clause 7.2.2 (c) and 7.2.3, to make it clear that LNSPs have the option to make an offer with respect to MDP services but are not under an obligation to do so. EnergyAustralia suggests the inclusion of clause (d) under Types 1 – 4 metering installations to refer to the possibility of the LNSP making an offer with respect to MDP services along the lines of: (d) if requested by the Market Participant, the LNSP may provide an offer to the Market Participant for appointing a Meter Data Provider for the provision of MDS.
7.3.3 of AEMC rule determination.	Responsible person for embedded networks.	The Rules do not recognise embedded networks and do not effectively assign the role of the RP for metering installations within an embedded network. Embedded networks are referred to in various subsidiary instruments prepared by AEMO, such as the National Metrology Procedure, NMI procedures and the MSATs procedures. These instruments seek to make provision for embedded networks to enable customers who are connected to an embedded network to choose their retailer from whom electricity is

Clause	Issue	Comment
		purchased and to enable settlement of energy purchased by such customers. To facilitate this, these instruments contemplate the LNSP issuing NMIs for the child meters. Whilst not clearly provided for by the rules, generally DNSPs have cooperated in this approach to facilitate competition for these customers. However to extrapolate out this approach to support such DNSPs being the responsible person has never been properly considered or determined by the market or rule processes. LNSPs have also been cooperative in the past with regard to the issuing of NMIs and Consumer Administration and Transfer Solution (CATS) Embedded Network Identifier Codes (EMBNETIDCODE) to Embedded Network Operators without the appropriate regulatory framework. EnergyAustralia believes that the issue of NMIs by the LNSPs is appropriate as only LNSP are issued with NMIs by AEMO, however as stated previously in this submission, the child connected NMIs for which these NMIs have been allocated are NOT connected to the LNSPs network and the LNSP responsibility under the Rules should be limited to issuing NMIs for connections within the Local Network. Such an obligation should be clearly stated in the Rules. The attached external legal advice from Blake Dawson sets out the basis for this interpretation of the Rules with respect to embedded networks, the key point being that the LNSP to which the embedded network is connected (at the parent connection point) cannot be regarded as the Responsible Person for connections points within the embedded network (i.e. for child connection points). Those connection points are not connection points to the local distribution network service provider's network and it is not appropriate for that network service provider to be responsible for such points for practical reasons such as access as well the market design reasons explained further below. This issue is most critical where the child connections points have metering types 5-7 as the "LNSP" is Responsible Person for such meters. No changes should be made to the Rules to make the "LNSP" the Responsible Person for metering types 5-7 within embedded networks without a full assessment of the cost implications for network service providers. For example, there are many caravan parks, retirement villages and the like connected in EnergyAustralia's distribution district which in turn have customers connected to those embedded networks. EnergyAustralia does not

Clause	Issue	Comment
		own and has never taken responsibility for meters within such networks which are estimated to be in the many thousands. It is likely that the metering within such networks would not meet the required standards for either meter type 5 or 6 and that taking responsibility for such metering as the responsible person would be a very significant cost that have not been allowed for under the EnergyAustralia distribution determination. The LNSP in the case identified above would need to: 1. conduct a site audit on each meter to identify the property number of each meter for registration in MSATs; 2. incorporate the metering equipment in their meter asset management plan, which could involve additional meter testing; 3. obtain valid test reports for each meter that may not be available; 4. arrange to either test or replace the meter if a current valid test is not available; 5. arrange for the site details to be created in their meter reading systems and arrange for appropriate time frames for regular collection of the meter energy data. Recovery of these costs would be complex. Given that these costs are not provided for in the distribution determination they would need to be recovered separately from the FRMP as these costs are payable by the FRMP under proposed clause 7.3A(a) of the Rules, currently clause 7.3.6(a). Proposed clause 7.3A(f) provides that "Paragraph (a) does not apply to the recovery of costs by a *Local Network Service Provider* that are associated with type 5, 6 or 7 *metering installations*, but only to the extent that these costs can be recovered by the *Local Network Service Provider* in accordance with a determination made by the *AER.*" [1] The existing provision is clause 7.3.6(f). However as a type 5 – 7 connection within an embedded network is not connected to the LNSPs network and cost recovery is not available through the distribution determination any additional costs would need to be recovered from FRMP, which would be an unanticipated

[1] National Electricity Rules Ver 37, p. 757

Clause	Issue	Comment
		outcome for FRMPs and reinforces the need for the AEMC to carefully consider its proposed approach on this issue. For Type 1-4 metering installations within an embedded network, the FRMP should be the RP for both the parent and child connection points unless the FRMP requests the LNSP to be the responsible person for both sets of metering points and an agreement is entered into with respect to such an appointment. In the example provided by the AEMC in clause 7.3.3 where the Commission states: "For example, if a child metering point is a type 5 metering installation, then the Responsible Person is the LNSP and if it is a type 4 metering installation then the Responsible Person is either the Market Participant or the LNSP."[2] In this example EnergyAustralia submits that the Responsible Person must be the embedded network operator or FRMP not the LNSP of the parent NMI. Clause 7.2.3 (a) (2) of the National Electricity Rules states that an LNSP is the RP for: "a type 5, 6 or 7 metering installation connected to, or proposed to be connected to, the Local Network Service Provider's network in accordance with paragraphs (d) to (i)."[3] As stated above, a child NMI is not connected or proposed to be connected to the EnergyAustralia network, it is connected to the embedded network, therefore EnergyAustralia cannot be the RP for type 5-7 metering installations for a child NMI within an embedded network. It might also be noted that in a recent document published by AEMO, Small Generator Framework Design Principles the following quote confirms the confusion currently in the NEM regarding the roles within an embedded network: "AEMO considers that parent-child metering for small generation in embedded networks

[2] AEMC Rule Determination – National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010, P. 24
[3] National Electricity Rules Ver 37, p. 733

Clause	Issue	Comment
		plays a role that is distinct from that of traditional embedded network metering. AEMO understands that current embedded network procedures are being used to accommodate gross metering of embedded generation, a use for which embedded networks were not originally intended. AEMO believes that greater clarity in relation to embedded networks in the Rules, Metrology Procedures, MSATS, National Metering Identifier Procedure and other areas is needed to remove ambiguity in the registration of small generators in the NEM. It is also necessary to ensure both proponents and Network Service Providers are aware of their obligations under the Rules and other related procedures."[4]
7.1.3 (a), 7.2.1 (b), 7.2.2 (e), 7.2.3 (l) and 7.14.1A. from mark up of draft rule	Procedures, Service levels and Guidelines.	EnergyAustralia supports procedures, service levels and guidelines to provide assistance and where appropriate more detail in relation to the Rule provisions. However where such procedures, service levels or guidelines are contemplated the rule should specify the content and nature of the matters to be addressed in the guidelines to ensure that they do not operate to impose obligations or requirements on market participants that are not contemplated under the Rules and which may impose significant system or other costly obligations.
7.2.3 (c) (2) from mark up of draft rule	Notification of MPB to the Market Participant.	It is not clear why the Market Participant needs to be separately notified of the appointed MPB as this information will be identified in MSATS. EnergyAustralia would submit this requirement is not necessary.
7.3.1 (a) (7) and 7.3.1 (i) (1) from mark up of draft rule	Ensuring that meter data is captured where a metering installation has the possibility of generating into the NEM.	To capture the situation where there is the capability for bi-directional flows EnergyAustralia suggests that the following words be added to the end of the clause: (7) be capable of separately recording *energy data* for energy flows in each direction where bi-directional *active energy* flows occur or could occur;
7.4.2 (bc) from mark up of draft rule	Typographical error in 4th line and relevance of matters for meter provider obligations.	Energy Australia suggests that the reference be to metering data service database rather than agency metering database. Also EnergyAustralia query whether all of these matters are relevant for a Meter Provider, in

[4] AEMO - Small Generator Framework Design Principles, Document No: MD_SG_001, p. 12

Clause	Issue	Comment
		particular the references to databases maintained by Meter Providers and the delivery up of data to AEMO as these are not functions associated with the provision, installation and maintenance of a metering installation as contemplated by clause 7.2.5. These matters appear to more properly relate to the role of Metering Data Providers specified in clause 7.11 and Schedule 7.6.
7.4.2A (f) from mark up of draft rule	Typographical error in 4th line.	Energy Australia suggests that the reference be to metering data service database rather than agency metering database.
7.7 (c) from mark up of draft rule	Typographical error in 3rd line.	Replace "of metering data servicesperson." with "of metering data services".
7.8.4 (b) from mark up of draft rule	Typographical error in 3rd line	Replace "metering data services databases" with '"metering data services database".
7.9.4 (d) and (e) from mark up of draft rule	Clarification of notification time	These clauses refer to a notification time of 24 hours, and it is not clear if this notification timeframe include weekends and public holidays. Clause 7.11.2 (a) (10) of the marked up version of the rules states: (10) notifying the *responsible person* of any *metering installation malfunction* of a *metering installation* within 1 *business day; and* EnergyAustralia contends that to ensure standarisation in the Rules, it would be preferred if days are used. EnergyAustralia suggests 1 business day.

Clause	Issue	Comment
7.9.5 (c) from mark up of draft rule	Typographical error in second line.	Replace "… responsible person financially responsible Market Participant…" with "… responsible person or financially responsible Market Participant…"
7.11.3 (j) from mark up of draft rule	Typographical error in 5th line.	There is a full stop and a comma after the unavailable.
7.14.4 (e) (5) from mark up of draft rule	Typographical error in 3rd line.	Remove inverted comma after … Metering Data Provider".
Schedule 7.1 from mark up of draft rule	Error in drawing.	In the middle "service provider" box this should read Meter Data Provider not financially responsible Market Participant.
Schedule 7.2 General Comment from mark up of draft rule	Identification of Metering Type.	The general understanding and approach in the market o date has been that Schedule 7.2 effectively sets out how meters are classified for the purposes of the Rules. EnergyAustralia requests that the Commission satisfy itself that the Rules do actually operate in this way. Clause 7.3.4 states that the type of metering installation and the accuracy requirements for a metering installation which must be installed in respect of each connection point are to be determined in accordance with Schedule 7.2. S7.2.1 states "this Schedule 7.2 sets out the minimum requirements for metering installations". Table S7.2.3 1 in turn only provides the minimum requirements for a meter not the defining characteristics of such meters and therefore it is not apparent how these provisions provide a basis for delineating between metering types. The view has generally been taken that adding remote reading capability to a Type 5 meter would convert that meter to a type 4 meter. However on its face there is nothing in clause 7.3.4 and Schedule

Clause	Issue	Comment
		7.2 which state that a type 5 meter with remote reading capability would be a type 4 meter. We note that some provisions in the Rules such as existing clause 7.3.4(g) indicate that alternation of a type 5 or 6 meter to make it capable of remote acquisition would alter the classification, but as stated above, it is not apparent how this actually occurs.
Schedule 7.2.1 (b) from mark up of draft rule	Suggestion for clearer wording.	EnergyAustralia suggests the following clearer wording: (b) If a *Registered Participant* requires the *responsible person* to arrange for a *metering installation* to meet ~~may install a *metering installation* with~~ a higher level of accuracy than required by the Rules, ~~with~~ the full cost~~s~~ of this work must be ~~being~~ met by that *Registered Participant*.
Table 7.2.3.1 Type 4 clock error of marked up rules	Table note Item 2a refers to whole current meter only.	Currently Item 2a states: "For the purpose of clarification, the clock error for a type 4 *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving whole-current technologies that are acceptable in accordance with rule 7.13(a)." EnergyAustralia submits that Item 2a should also include Type 4 CT metered installations as well.
Table 7.2.3.1 Type 5 clock error of marked up rules	Currently states +- 20 sec and table note Item 3a refers to whole current meter only.	Currently Item 3a states: For the purpose of clarification, the clock error for a type 5 *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving whole-current technologies that are acceptable in accordance with rule 7.13(a). Either Item 3a should also include Type 5 CT metered installations as well or Item 3a removed and the clock error changed to 300sec as stipulated in schedule 2 ID 4.8 of the Metrology Procedure.
Table 7.2.3.1 Minimum acceptable class or standard of components	Refers to a whole current connected general purpose meter Wh: • meets requirements of clause 7.3.1(a)(11); and	"data logger" has been removed as a requirement, as such a general purpose meter does not collect interval data so cannot meet the requirements of a Type 5 meter.

Clause	Issue	Comment
from mark up of draft rule	• meets the requirements of clause 7.11.1(d).	

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30 June 2010

Your reference
AEMC Submission

Our reference
02 2021 6988

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Dear Jane

Responsible Person and Embedded Networks

You have asked us to advise on the extent to which chapter 7 of the National Electricity Rules (**Rules**) provides for the allocation of a Responsible Person for metering installations at connection points within embedded networks.

More specifically, you seek advice as to:

1. whether or not the Rules provide for the Local Network Service Provider (**LNSP**) to be the Responsible Person for metering installations at connection points within an embedded network; and

2. the extent to which the Rules provide for, or enable anyone else, to act as the Responsible Person for metering installations at connection points located within embedded networks.

Set out below is an Executive Summary of our advice with our more detailed advice set out in the sections that follow. In section one, we address each of the above two questions in more detail. In section two we address some related issues and, in section three, we then draw some conclusions.

EXECUTIVE SUMMARY

1. Embedded Networks and the Responsible Person

1.1 LNSP's and Responsible Persons within embedded networks

In our view, the Rules do not empower, or require, the LNSP to be the Responsible Person for metering installations located within an embedded network.

This is because the provisions of the Rules allocating the role of the Responsible Person do not apply to metering installations which are not connected to the LNSP's network.

1.2 Can anyone else be the Responsible Person for metering installations within embedded networks?

A Market Participant may effectively elect, under Rule 7.2.2, to be the

Responsible Person for a metering installation within an embedded network for a type 1-4 meter.

The Rules do not identify anyone to act in the role of the Responsible Person for type 5-7 metering installations within embedded networks.

2. Related issues

2.1 Status of Metrology Procedures, MSATS and CATS

In our view, the Rules do not support assumptions contained in the Australian Electricity Market Operator's (**AEMO**) Embedded Network Guidelines,[1] and reflected in other documents published by the AEMO and the Australian Electricity Market Commission (**AEMC**),[2] that the Rules effectively allocate responsibility for embedded networks to the LNSP.

To the extent that provisions in such documents purported to empower or require the LNSP to be the Responsible Person for such metering installations (which we don't think they do), they would probably be beyond power.

2.2 Status of LNSPs currently performing tasks within embedded networks

To the extent that LNSPs currently issue NMIs (at the request of retailer Market Participants) for metering installations at connection points within embedded networks, it is not entirely clear to us that LNSPs are in fact obliged to do so under the Rules.

If an LNSP nevertheless proceeds to do so, then it is necessarily only doing so in its capacity as the LNSP for the geographical area in which the embedded network is located, not because it has some how or other become the Responsible Person for a metering installation at that connection point. In our view this is not in fact possible under the Rules as currently drafted (as indicated in 1.1 above).

Further, to the extent that some LNSPs may contractually agree to perform other tasks for metering installations within embedded networks that would typically be performed by a Responsible Person, such actions should nevertheless not be understood as being performed by the LNSP in the capacity of a "Responsible Person" under the Rules.

2.3 What impact (if any) does the contestability of metering arrangements have?

Whether or not contestable arrangements are put in place within an embedded network is entirely at the discretion of the embedded network operator and, absent any legislative requirements to the contrary, may be withdrawn at any time.

3. Conclusions

The AEMC's conclusion in its Rule Determination National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010 published 6 May 2010 (**Rule Determination**) that the Rules already adequately

[1] AEMO, Embedded Networks Guideline published 23 July 2009

[2] See, for example, Rule Determination National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010 published 6 May 2010, AEMO's Embedded Networks and Retail Competition Determination of 22 August 2009, the Metrology Procedure and the MSATS/CATS Procedures.

prescribe the role of the Responsible Person within embedded networks[3] appears to be misconceived.

As indicated above, the Rules do not currently empower or require the LNSP to act as Responsible Person for metering installations within embedded networks, nor do they provide for anyone else to act in that capacity.

Any amendment to the Rules to place this obligation on LNSPs should be subject to the LNSP being granted sufficient powers (or reaching agreement with embedded network owners and operators) to gain access to and control over the metering installation connection point on the embedded network.

ADVICE

1. Embedded networks and the Responsible Person

1.1 LNSP's and Responsible Persons within embedded networks

The extent to which an LNSP can become the Responsible Person for a metering installation at a connection point is dealt with by Rule 7.2.3 as follows:

(a) Rule 7.2.3(a) provides that either the Market Participant or the LNSP (if the Market Participant accepts an offer from the LNSP to be the Responsible Person) is the Responsible Person for type 1-4 metering installations <u>connected to or proposed to be connected to the LNSP's network</u>.

(b) Rule 7.2.3(b) sets out a process whereby the LNSP becomes the Responsible Person for type 5-7 metering installations <u>connected to or proposed to be connected to the LNSP's network</u>.

In understanding the extent to which Rule 7.2.3 can apply to empower or require the LNSP to be the Responsible Person (for both type 1-4 and 5-7 metering installations) the following defined terms are critical:

- "connected" means that a physical link must be formed between the metering installation and the LNSP's network;
- "network" means the apparatus, equipment plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets; and
- in the context of an LNSP, "network" means the network owned, operated or controlled by that Network Service Provider.

When these several terms are considered together it is clear that irrespective of what type of metering installation is under consideration, the Rules only empower and require the LNSP to become the Responsible Person for those metering installations connected or proposed to be connected to the LNSP's network.

The question in the context of embedded networks then is whether metering installations within an embedded network are "connected to the LNSP's network". While the expression "embedded network" is not defined under the Rules it is well understood that an embedded

[3] Rule Determination National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010 published 6 May 2010, pages 24-25.

network is a network not owned and operated by an LNSP, but which is nevertheless connected to the LNSP's network.[4]

There can be no doubt that an embedded network is not part of an LNSP's network. It follows that:

- metering installations located within an embedded network are not connected to the LNSPs network; and
- the Rules do not empower, or require, the LNSP to be the Responsible Person for such metering installations.

This seems to us to be a reasonable position for the Rules to take because an LNSP does not own or control any of the relevant "connection points" within an embedded network and could not, without the cooperation and agreement of the embedded network owner, perform Responsible Person obligations at metering installations for those connection points.

1.2 Can anyone else be the Responsible Person for metering installations within embedded networks

(a) Type 1-4 metering installations

It is possible for a Market Participant who wishes to register (as the financially responsible Market Participant) for a connection point within an embedded network to effectively elect, under Rule 7.2.2, to be the Responsible Person for a metering installation within an embedded network for a type 1-4 meter.

This is because, under Rule 7.2.2(a), the Market Participant may themselves elect to be the Responsible Person or get the LNSP to do it (under Rule 7.2.3).

However, as we discussed in section 1.1 above, the LNSP cannot be the Responsible Person under Rule 7.2.3. Whether an LNSP might nonetheless agree to perform some or all of the tasks that a Responsible Person would perform for metering installations located within an embedded network (despite not being empowered or required to do so) is a matter we consider in section 2.2 below.

If a Market Participant does decide to become the Responsible Person for type 1-4 metering installations within an embedded network, it will need to engage its own Metering Provider under Rule 7.2.5 and generally comply with the requirements of chapter 7 of the Rules.

(b) Type 5-7 metering installations

For types 5–7 metering installations, the Rules:

- do not entitle the Market Participant to be the Responsible Person; and
- do not identify anyone other than the LNSP for the role of Responsible Person (but only, as indicated above, for metering installations connected to the LNSP's network).

In our view:

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[4] See for instance, references to "embedded networks" in the Embedded Networks Guideline, the Metrology Procedure, the Embedded Networks and Retail Competition Determination of 22 August 2009 and the MSATS Procedures.

(i) as the LNSP cannot be the Responsible Person for metering installations within embedded networks; and

(ii) the Rules do not otherwise provide for any else to become the Responsible Person for type 5-7 metering installations,

no one is in fact empowered under the Rules to act as the Responsible Person for type 5-7 metering installations located within embedded networks.

2. Related issues

2.1 Status of Metrology Procedures, MSATS and CATS

We note that a number of AEMO's procedures and guidelines appear to have adopted the position that the Rules effectively make the LNSP the Responsible Person for metering installations within embedded networks (at least for metering installations that have become contestable).

There does not appear to us be any clear basis in the Rules to support this position. Rather, it appears an incorrect assumption has been made at some point that the Rules operate in this way. For example, AEMO's Embedded Network Guidelines lists, as a key assumption, that:

> Metering requirements and responsibilities for downstream NMIs [located within embedded networks] registered in MSATS are the same as for all other market NMIs under the Rules and the Metrology Procedure. Including if child meters are eligible to be manually read this will be the responsibility of the LNSP associated with the parent connection point.[5]

In our view, for the reasons we indicated above in section 1.1:

- the Rules do not support this assumption because metering installations within embedded networks are not connected to an LNSP's network; and
- to the extent that provisions in such documents purported to empower or require the LNSP to be the Responsible Person for metering installations (which we don't think they do), they would probably be beyond power.

2.2 Status of LNSPs currently performing tasks within embedded networks

(a) LNSPs issuing NMIs

We understand that LNSPs, on occasions, issue NMI's for type 1-4 metering installations for connection points within an embedded network, upon request from retailers who wish to register those connection points in the NEM.

We make the following observations about this:

(i) As indicated in 1.2(a) above, it is possible for a retailer Market Participant to elect to be the Responsible Person for a type 1-4 metering installation for a connection point within an embedded network.

(2) That Market Participant, as the Responsible Person for that embedded network connection point, might argue that, on the face of clauses 3.1(d) and (e) as literally drafted:

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[5] AEMO, Embedded Network Guidelines, 23 July 2009, section 1.2, p4, Key Assumption 6.

(i) it is entitled to apply to the LNSP (for the geographical area in which the embedded network is located) for a NMI for a metering installation for that connection point, even though it is not connected to the LNSP's own network; and

(ii) the LNSP would then be obliged to issue one.

(3) However, it is not clear to us that clauses 3.1(d) and (e) should in fact be read in this way, given that the framework established for LNSP metering installation responsibility under Rule 7.3.2 clearly applies only to connections points on the LNSP's own network (as set out in 1.1 above).

(4) Nevertheless, if an LNSP does proceed to issue a NMI in response to such a request, then the LNSP is necessarily only doing so in its capacity as the LNSP for that geographical area, not because it has some how or other become the Responsible Person for a metering installation at that embedded network connection point which (as indicated under 1.1(a) above) is not in fact possible under the Rules as currently drafted.

(b) LNSP's voluntarily undertaking Responsible Person tasks

In our view, an LNSP may, if it so chooses, agree contractually with a Market Participant to provide some of the services that a Responsible Person might provide under chapter 7 of the Rules for metering installations within embedded networks. However, an LNSP cannot formally act in the role of the "Responsible Person" for metering installations in these networks as that role can only be conferred in accordance with Rules 7.2.2 and 7.2.3.

Fundamentally, it must be acknowledged that the role of the Responsible Person is a creature of statute, and can only come into being under the relevant provisions of the Rules. In the absence of the Rules providing for the creation and conferral of the role, it is not possible to become the "Responsible Person" as defined under the Rules.

To the extent that LNSPs undertake or perform tasks that would be performed by a Responsible Person it would be prudent for an LNSP to satisfy itself that it is in a position to do so before agreeing to perform such a task. That is, that the embedded network operator has given the LNSP a level of access and permission sufficient to afford the LNSP an appropriate level of control over the relevant metering installations and connection points to perform the obligation.

2.3 What impact (if any) does the contestability of metering arrangements have?

Leaving aside any jurisdictional specific arrangements for contestability in each jurisdiction, contestable arrangements in respect of a connection point can only be regulatorily required through the operation of Rules 7.2.2 and 7.2.3. These are the vehicles that both deliver mandatory contestability and circumscribe its limits.

This means that, within an embedded network, contestability can only be put in place if:

- the law requires it (Rules 7.2.2. and 7.2.3); or
- the embedded network operator voluntarily agrees to allow it.

This means that, leaving aside any State-based jurisdictional specific arrangements for contestability,[6] the Rules currently only allow for contestable arrangements within an

[6] Consideration of State based jurisdictional arrangements (such as those under the *Electricity Supply Act 1995* (NSW)) are beyond the scope of this advice

embedded network for type 1-4 metering installations – and only to the extent that a Responsible Person puts them in place.

Ultimately, whether a Responsible Person (Market Participant) is able to put contestable arrangements in place is entirely at the discretion of the embedded network operator. In the absence of any legally binding obligation to maintain contestable arrangements the embedded network operator could withdraw them at any time.

3. Conclusion

Based on the matters set out above, the AEMC's conclusion in its Rule Determination National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010, published 6 May 2010, that the Rules already adequately prescribe the role of the Responsible Person within embedded networks, appears to be misconceived.

The AEMC 's position that "the Commission does not consider that there is a 'gap' in the regulatory framework surrounding the Responsible Person for child metering points in embedded networks" appears to be based on some assumptions about the creation and allocation of Responsible Person obligations under the Rules, which are not in fact supported by the Rules.

As indicated above:

- the Rules do not currently require or empower the LNSP to be the Responsible Person for metering installations within embedded networks; and
- responsibility for metering installations within embedded networks are not currently addressed under the Rules.

To the extent that it is considered appropriate to impose Responsible Person obligations within embedded networks on an LNSP by changes to the Rules, those arrangements should not:

(a) be imposed in a way which is inconsistent with what the Rules already say about Responsible Person obligations; or

(b) seek to place mandatory obligations on the LNSP that the LNSP is not necessarily in a legal position to fulfil (because, for example, the LNSP needs the co-operation and consent of the embedded network owner, to gain access to the connection point). Such obligations would need to be expressed to be subject to (for example) the LNSP reaching satisfactory arrangements for access to and control over the connection point for the purposes of being responsible for the metering installation.

Please do not hesitate to contact either of us if you have any questions or would like to discuss any of the issues we've raised.

Yours sincerely

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