Powercor
Further submission to the AER regarding preliminary determination
4 February 2016

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Table of Contents

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1 Summary

We have provided this additional submission to the Australian Energy Regulator (**AER**) which:

- responds to comments made in submissions to the AER's preliminary determination; and
- provides further information on matters contained in our revised regulatory proposal, lodged on 6 January 2016.

We have not responded to all matters raised in the various submissions made to the AER, rather we have only focused on issues of greatest importance to our business.

Furthermore, we note that some submissions contained misrepresentations of costs, data and facts, and/or made claims that were not supported by any evidence. While we have not responded to these claims, our silence should not be interpreted as agreement or acceptance of these matters. Should the AER seek further information from us on particular matters raised in submissions, we would be happy to provide a response prior to the final determination.

In this submission, we clarify the following matters:

- benefits from the deployment of smart meters have been realised and are already being shared with our customers. Network savings leveraged from smart meters are reflected in our operating and capital expenditure forecasts for the 2016–2020 regulatory control period;
- smart meter services have enabled early identification of outages and this provides benefits to customers. However, earlier identification has not lead to reduced frequency or duration of outages as measured for the purposes of the Service Target Performance Incentive Scheme (**STPIS**);
- we support the Australian Energy Market Operator's (**AEMO**) development of its demand forecasting methodology and we continue to work with AEMO to improve its methodology. However, at this stage, AEMO's forecasting approach is still a work in progress and is not yet sufficiently reliable to be used as a substitute for our forecasts;
- the installation of Rapid Earth Fault Current Limiters (**REFCLs**) will not deliver any reliability benefits in the short term, and may potentially worsen reliability;
- we consider our base year vegetation management expenditure is consistent with the expenditure required to comply with the 2015 Electric Line Clearance regulations;
- we provide further information in support of our step change for the introduction of cost-reflective tariffs;
- we will not pre-suppose the outcome of the Australian Taxation Office (**ATO**'s) private ruling relating to the appropriate taxation treatment of customer contributions provided by through the Victorian Government's Powerline Replacement Fund; and
- we agree with the Victorian Government submission that it is incumbent on the AER to ensure costs are allocated appropriately between metering and standard control services to prevent cross-subsidies and inefficient market outcomes.

2 Benefits from smart meters

The Victorian Government's submission states that the AER should expect the Victorian distributors to realise efficiency gains from the rollout of smart metering and these efficiency gains should be passed through to consumers as they are realised.[1] The Victorian Government seeks to quantify the benefits of smart metering by reference to a study of the forecast benefits undertaken over five years ago by Deloitte. We note that Deloitte's report provided the present value of the forecast benefits across all Victorian distributors in aggregate and over a 20 year period, 2008–2028. It is therefore difficult to compare Deloitte's aggregated figures with our network specific progress, either to date or forecast over 2016–2020 regulatory control period.

In the following sections we set out our progress to date on each of the categories of smart meter benefits identified in the Victorian Government submission and how the benefits are being shared with customers.

Importantly, our smart meter rollout was undertaken efficiently, prudently, and within the timeframes set out by the Victorian Government. As shown in table 2.1 below, our smart meter roll out program was 96 per cent completed by 31 December 2013 and we had reached a critical mass of smart meters covering our network by 2012.

Table 2.1 Smart meter roll out

Year ending December	2010	2011	2012	2013	2014
Proportion of smart meters installed	23%	46%	75%	96%	97%

Source: Powercor

Once reaching a critical mass of smart meter coverage, we commenced implementation of a number of business initiatives aimed at leveraging smart meter benefits, discussed below. The savings achieved through these initiatives are already being passed onto customers through our operating and capital expenditure requirements and enhanced customer experiences. Notably, many of the business initiatives to leverage smart meter benefits were not funded either under the Advanced Metering Infrastructure (**AMI**) Order in Council (**OIC**) or included in standard control services allowances approved by the AER.

Our 2016–2020 regulatory proposals already factor in the realised benefits of smart metering, including:

- our 2014 actual operating expenditure is used as the base for forecasting our 2016–2020 operating expenditure requirements. Smart meter benefits achieved before and during 2014 are therefore already fully reflected in our operating expenditure forecast for the 2016–2020 regulatory control period; and
- our method for forecasting our capital expenditure requirements for the 2016–2020 regulatory control period is forward looking and already takes account of business processes implemented and the savings achieved through the roll out of smart meters.

We therefore consider there is no basis for further adjustments to our operating and capital expenditure forecasts for the 2016–2020 regulatory control period. Further, we do not support pre-emptive and unsubstantiated productivity adjustments which undermine the objectives of the incentives schemes.

Further, we note that the introduction of metering contestability on December 2017 raises doubt over whether we will be able to continue to leverage smart meter benefits in future and maintain the benefits achieved to date. In particular, we note that the national minimum meter specification does not include meter outage notification which is the key service upon which we have leveraged savings to date. We will also be required to

[1] Victorian Government, *Submission on the Victorian electricity distribution pricing review preliminary determinations - 2016-2020*, January 2016, p. 1.

purchase meter data and services from third party metering co-ordinators which will reduce the net benefits of implementing potential smart meter leverage projects in future.

Avoided costs associated with accumulation meters

Given our roll out program was largely completed by 31 December 2013, the avoided costs associated with accumulation meters have already been realised and are fully captured in our 2014 operating and capital expenditure. Our customers are therefore already receiving the benefits from the avoided costs of accumulation meters.

Importantly, we do not forecast any operating or capital expenditure associated with accumulation meters for the 2016–2020 regulatory control period.

The table below sets out our avoided costs of accumulation meters achieved in 2014.

Table 2.2 Avoided costs associated with accumulation meters ($ nominal)

Avoided cost	Expenditure	2014
Avoided non AMI meter supply cost for new connections and meter replacements	Capex	$2,660,209
Avoided non AMI meter supply & installation cost for fault meter replacements	Capex	$345,726
Avoided cost of time switch replacement	Capex	$1,382,548
Avoided non AMI meter replacements resulting from solar installations	Capex	$5,633,376
Avoided cost of routine meter testing costs	Opex	$948,260
Avoided cost of routine non AMI meter reading	Opex	$3,614,457
Avoided cost of non AMI special reads	Opex	$828,335
Total		**$15,412,911**

Source: Powercor annual Regulatory Information Notice (RIN), Schedule 1.

Network efficiencies

<u>Monitoring transformer overload</u>

In 2013, we implemented a new process that relied upon smart meter data to estimate overloading on distribution transformers. This avoided the labour costs of manually installing loggers on the network constraint points. Prior to 2013, where we suspected that a distribution transformer was likely to be overloaded, we would manually install a logger to measure the voltages at that network point. The voltage readings were recorded over a period of time, such as a week, to estimate the level of overload. Access to smart meter data to estimate overloading without requiring manual installation of a logger is an operating expenditure saving. We estimate the saving to be approximately $100,000 per annum. Our 2014 base year operating expenditure fully reflects the savings from not requiring manual installation of loggers.

We have not realised capital expenditure savings in this regard however because where a distribution transformer is identified to be overloaded, the solution to address the network constraints continues to be changing the circuit routing or upgrading the transformer. There has been no change to the capital solution as a result of the smart meter data.

As noted in Deloitte's report, there is limited ability for distributors to use supply capacity limiting functions of smart meters to prevent transformer overloading.[2] At this stage we are not planning to use supply capacity control for managing distribution transformer loads. This is because of the need to negotiate supply limitation and compensation with a large number of residential customers. Large customers are already limited in supply via supply agreements.

<u>Faster outage detection</u>

While we agree that smart meter data has enabled faster detection of outages, we disagree that STPIS targets should be adjusted. Faster outage detection does not result in a change in the number or duration of outages recorded for STPIS purposes.

Prior to the roll out of smart meters the first notification of an outage was the customer calling into the contact centre. Consequently, low voltage customers could have been off supply for some time before the customer became aware (i.e. until they get home) and call the contact centre. We therefore started recording the outage for STPIS purposes, and commencing restoration procedures, i.e. dispatching crew, from the time of the first customer call.

As a result of the meter outage notification capability in the Victorian smart meter specification, for area faults we now start recording the outage for STPIS purposes from the time of receiving the smart meter notification, and we commence responding accordingly. We do not need to wait until we receive a customer call into the contact centre. Notably, we only use meter outage notification to identify area faults and not for single customer premise faults. This is because notification from a single meter does not provide reliable evidence of a fault.

The earlier notification of the fault therefore means we start recording the outage sooner and commencing restoration procedures faster, however **this does not result in a reduction in the duration of the outage for STPIS purposes because our response process is the same.** This is shown in figure 2.1 below.

The key benefits resulting from faster outage detection are:

- a reduction in the duration of the outage overall because there is no longer a period of time where we are not aware that supply is off. However, as noted above, this does not reduce the duration of the outage from a STPIS perspective as restoration processes remain unchanged; and
- an enhanced customer service experience because supply may be restored before customers even become aware an outage occurred and the customer no longer needs to call the contact centre to initiate a fault response.

Deloitte's quantification of the potential STPIS impacts are simplistic and should not be relied upon to adjust our STPIS targets.

Deloitte's analysis assumed we used meter outage notification for both area faults and single customer premise faults. Additionally, Deloitte stated that this benefit would be unlikely to significantly reduce System Average Interruption Duration Index (**SAIDI**) due to the small number of customers affected by a low voltage (**LV**) fault.[3]

Deloitte also noted 'potential' benefits of reduced restoration times. However, Deloitte caveats this by saying:[4]

> *…innovation strategies will need to be developed over time to improve outage times. However, this additional benefit is difficult to quantify…*

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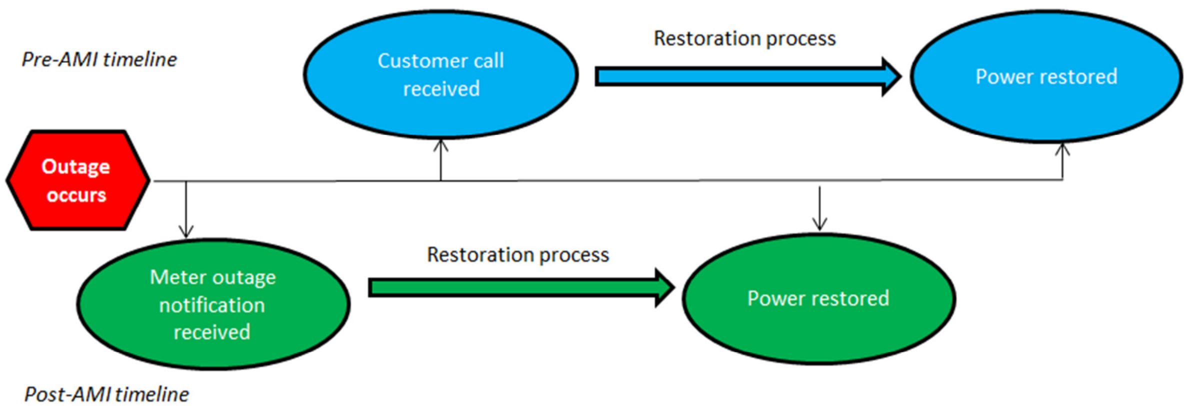
2 Deloitte, *Department of Treasury and Finance, Advanced metering infrastructure cost benefit analysis*, August 2011, p. 65.

3 Deloitte, *Department of Treasury and Finance, Advanced metering infrastructure cost benefit analysis*, August 2011, p. 60.

4 Deloitte, *Department of Treasury and Finance, Advanced metering infrastructure cost benefit analysis*, August 2011, p. 61.

Importantly, the meter outage notification service is not part of the minimum national meter service specification required under the new meter contestability rules commencing on 1 December 2017. Therefore there is a real risk that we lose the capability to receive early identification of outages.

Figure 2.1 Impact of earlier fault notification using smart meter outage notifications



Source: Powercor

Other smaller benefits

The Victorian Government's submission lists a number of 'other smaller benefits' from smart meters.

The table below summarises the business initiatives we implemented to achieve the identified network efficiencies and how these benefits are already reflected in our 2016–2020 operating and capital expenditure forecasts. We note that many of these initiatives were not funded under the AMI OIC.

Table 2.3 Other smaller benefits from smart meters

Smart meter benefit identified	Business initiative	Explanation of initative	Reflected in 2016–2020 expenditure forecasts
Avoided cost of investigation of customer complaints about voltage and quality of supply	Responsive voltage monitoring program Implemented during 2013	This initiative involves using AMI data to undertake initial profiling of voltage issues raised by customers. Prior to this initiative we initiated a site visit as the initial investigation step for all cases. The initiative therefore enables earlier resolution of the customer issue because desk based analysis of AMI data can commence sooner than scheduling a site visit. The initiative therefore enhances the customer experience by resolving the problem faster.	Does not result in significant network cost savings as reduced cost of initial site monitoring is offset with increased resource required for desk based analysis and a site visit may still be required in complex cases. Any net savings achieved are already reflected in 2014 operating expenditure.
Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	Contact centre ping tool Implemented November 2012	The contract centre ping tool enables the customer service analyst to ping the customers meter to identify whether the fault is on the customer or network side. Additionally, as a result of the meter ping tool, we no longer send a fault truck to the site if the fault is identified as being on the customer side.	Savings reflected in 2014 operating expenditure. The reduction in wasted truck visits is a customer saving, as wasted truck visits are directly billed to the customer.
Reduction in calls to faults and emergencies lines	Interactive Voice Response (**IVR**) Implemented May 2013	Customers continue to call our contact centre when supply is interrupted, even though this is not necessary. However, the meter outage notification service enabled us to implement outage messaging automatically. The IVR allows a customer to identify oneself and receive a message confirming the outage without having to speak to an operator.	Savings reflected in 2014 operating expenditure.

Smart meter benefit identified	Business initiative	Explanation of initative	Reflected in 2016–2020 expenditure forecasts
Reduced cost of network loading studies for network planning Avoided cost of replacing service fuses that fail from overload Avoided cost of proportion of HV/LV transformer fuse operations on overload	SAP HANA Implemented Q1 2013	The SAP HANA system provides a network electricity model mapping every household connection to the physical connection point in the network, and overlaying that model with network data. While the SAP HANA system provides greater data and data granularity, and consequently improved network planning, it also requires greater resourcing of data analysis and processing. The use of AMI data does not lead to reduced costs of replacing service fuses or HV/LV transformers as these must still be replaced on overload. The data analysis simply allows for better monitoring and network planning.	Benefits are fully reflected in our 2014 base year operating expenditure.
Avoided cost of end of line monitoring	Retire DCI meters DCI meters deactivated in 2014	We now use AMI data on momentary outages and quality of supply for end of line monitoring. This enabled us to retire our ageing DCI meters which were previously used for end of line monitoring.	Customers will realise the benefit as we have not forecast expenditure for new or replacements DCI meters in the 2016–2020 regulatory control period.
Avoided cost of communications to feeder automation equipment	Use 3G rather than AMI mesh communications network	We do not use the AMI mesh communications network to enable communication between network equipment, such as high-voltage remote-controlled reclosers, with the control room. Instead we use the 3G communications network because 3G is a lower cost solution in this situation. The Otways are the only location where 3G is not available and we are using the AMI mesh.	No savings identified.

Source: Powercor

The following benefits were also listed by the Victorian Government, however these are not realised via the distribution network:

- avoided costs of installing import/export metering - benefit accrues directly to customer;
- customer able to switch retailer more quickly and with more certainty - benefit accrues directly to customer;
- reduction in calls related to estimated bills and high bill enquiries - benefit accrues directly to retailer; and
- avoided cost of supply capacity circuit breaker - benefit accrues directly to customer as supply capacity control devices are installed and owned by customers in accordance with the Victorian Service and Installation Rules.

3 Demand

3.1 Introduction

Submissions from the Victorian Energy Consumer and User Alliance (**VECUA**), Origin and AGL supported the AER's preliminary determination to apply AEMO's demand forecasts in place of the distributors' forecasts. A key reason cited by stakeholders was that AEMO's forecasts are independent.

We support AEMO's development of its demand forecasting methodology and we continue to work with AEMO to improve its methodology. We agree that in the future AEMO's forecasts may be able to provide a suitable comparison point for assessing the reasonableness of distributors' forecasts. However, at this stage, AEMO's forecasting approach is still a work in progress and is not yet sufficiently reliable to be used as a substitute for our forecasts. Importantly, AEMO has only just embarked on the task of forecasting demand at the transmission connection point level, the first forecasts were produced in 2014, and the methodology is in its infancy and still being refined.

We note that on 22 December 2015, AEMO updated its 2015 connection point forecasts. The revised forecasts resulted in major changes to two of Powercor's connection points and reduced the difference between Powercor's demand forecasts and AEMO's.

Our key concern with AEMO's 2014 and 2015 connection point forecasts are that they are developed by reference to simple historical time trends and then proportionally adjusted to ensure the growth across all connection points in Victoria matches AEMO's forecast of state-wide demand growth. The method does not take account of local demand drivers, such as population, income or prices, or known constraints on the network at the connection point, zone substation and feeder levels. We do not consider AEMO's current method provides a realistic expectation of demand requirements at each connection point. As acknowledged by the AER, it is the spatial-level demand forecasts that are most critical to assessing our capital augmentation requirements.

Importantly, our forecasts are also developed independently. We engaged the Centre for International Economics (**CIE**) to develop our demand forecasts at the transmission connection point and system level. We also engaged ACIL Allen to review our methodology for reconciling CIE's forecasts with our internally developed bottom-up zone substation and feeder level forecasts. ACIL Allen found our approach to be in accordance with best practice.

Further, Cambridge Economic Policy Associates (**CEPA**) reviewed our forecasting methodology and AEMO's against the AER's best practice demand forecasting principles and the requirements in the National Electricity Rules (**Rules**) and National Electricity Law. CEPA found AEMO's forecasting approach to be less satisfactory than our approach in meeting the AER's best practice forecasting principles. CEPA concluded that:[5]

> *After reviewing both AEMO's and the Businesses' approaches we consider that the Businesses' approach to demand forecasting at the connection point level is more likely to achieve the NER and hence the NEO than AEMO's.*

Given our concerns with AEMO's 2015 forecasts, we consider it appropriate that the AER relies upon our own demand forecasts rather than those of AEMO in its final determination for the 2016–2020 regulatory control period.

3.2 Changes in AEMO forecasts since our revised regulatory proposal submission

As noted above, AEMO revised its 2015 connection point forecasts on 22 December 2015. AEMO however only notified us of the change on 20 January 2016. The analysis in figure 5.3 and table 5.1 of our revised regulatory proposals are therefore based on AEMO's original forecasts and not the final forecasts.

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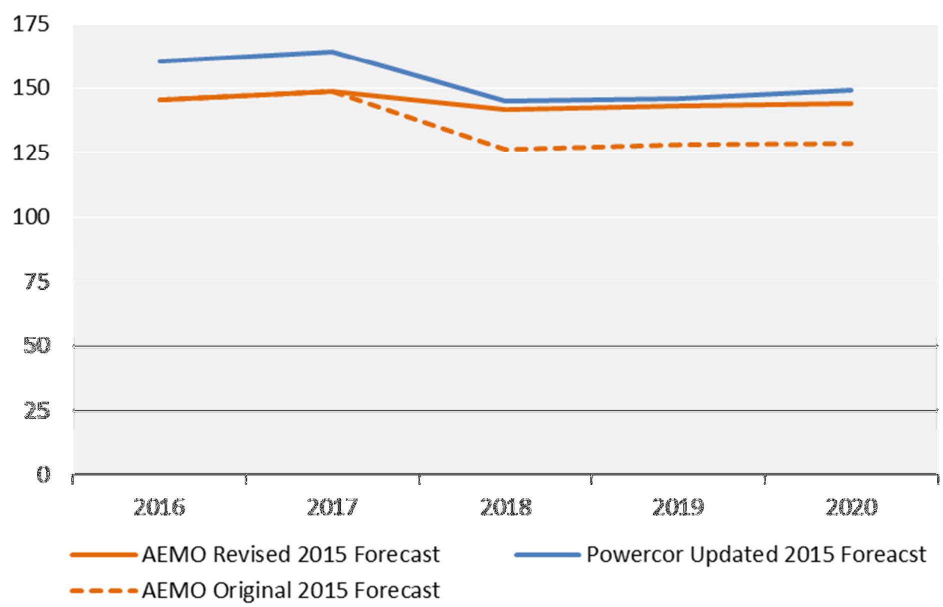
5 CEPA, *Review of demand forecasting approaches*, December 2015, pp. iv and 36.

AEMO revised its forecasts for the purpose of bringing industrial load forecasts at Geelong and Altona-Brooklyn in-line with the industrial forecasts in the 2015 National Electricity Forecast Report (**NEFR**). As shown in the figures below, AEMO's revision results in major increases to the forecasts at Geelong and Altona-Brooklyn connection points. These connection points are servicing areas where Powercor is experiencing significant growth and augmentation projects are planned.

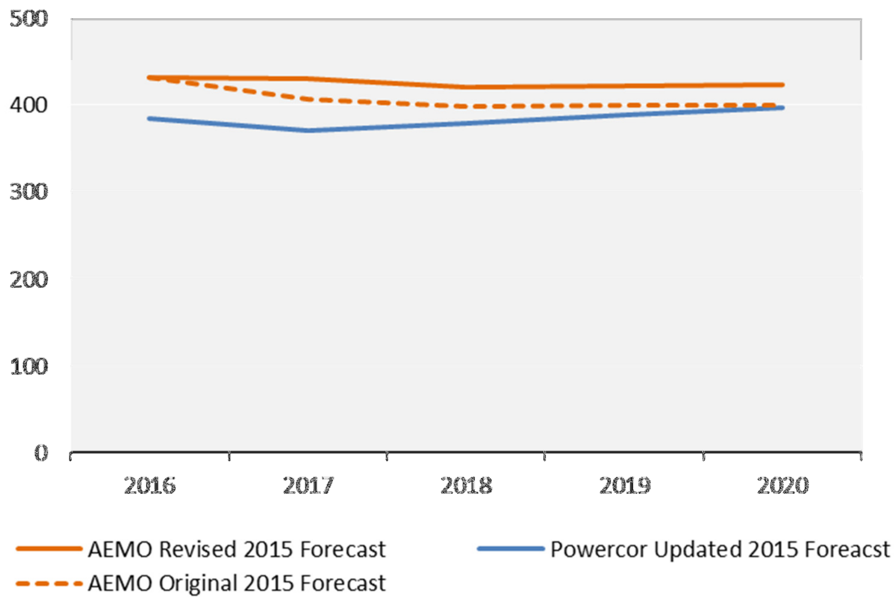
AEMO's revisions result in its aggregate forecasts for the Powercor network becoming closer to our updated 2015 forecasts. Our forecasts are now on average five per cent higher than AEMO's raw forecasts (which exclude a major direct connect customer) and only 2.7 per cent higher when AEMO's forecasts are adjusted to include one of our major direct connect customers. These figures should be used in place of table 5.1 of our revised regulatory proposal.

Figure 3.1 Maximum demand forecasts, Altona-Brooklyn connection point, non-coincident MW, 50% POE



Source: Powercor analysis, AEMO connection point forecasts published September 2015 and December 2015.

Figure 3.2 Maximum demand forecasts, Geelong connection point, non-coincident MW, 50% POE



Source: Powercor analysis, AEMO connection point forecasts published September 2015 and December 2015.

3.3 Differences between our methodology and AEMO's

As noted above, the differences between the distributors' forecasts and AEMO's arise primarily due to differences in the forecasting methodology. In the AER's preliminary determination it cited reasons for preferring AEMO's forecasting methodology which we address in our revised regulatory proposal. The AER's preliminary determination accepted Jemena's demand forecasts on the basis that the methodology 'is clear and transparent and has the capacity to respond to recent apparent changes in demand drivers'.[6]

Our forecasting methodology is similar to Jemena's. In particular, we:

- undertake bottom-up forecasting at the zone substation and feeder level, which is essential for assessing our capital augmentation requirements and incorporates local knowledge. AEMO does not undertake spatial bottom-up forecasting;
- forecast connection point level growth using econometric models which relate demand to demand drivers. We use similar demand drivers and the same historical time period. AEMO does not relate connection point level demand to demand drivers; and
- apply a conservative approach to reconcile our connection point and bottom-up forecasts, by adjusting forecasts down where inconsistency arises.

The below table sets out the key features of AEMO's, Jemena's and our forecasting methodologies.

[6] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020*, October 2015, p.6-109.

Table 3.1 Key features of demand forecasting methods

Forecast level	AEMO	Powercor	Jemena
State-wide forecasts	Econometric model linking state-wide peak demand per capita to economic drivers, including: • Gross State Product (**GSP**) per capita • Electricity prices • Temperature variables State-wide demand given by multiplying per capita demand by population. Data period from 2002 to 2015. Post model adjustments for PV and energy efficiency.	NA	NA
Network-wide forecasts	N/A	Econometric model linking network-wide average and peak demand per capita to demand drivers, including: • GSP per capita • Electricity prices • Temperature variables • Air conditioner penetration • Dummy variables for seasons, days of the week, weekends and public holidays Network demand given by multiplying per capita demand by population. Post model adjustments for windfarms, solar PV, block loads and limiting industrial loads.	Econometric model linking network-wide demand to demand drivers, including: • GSP • Electricity prices • Temperature variables • Dummy variables for specific days of the week and months of year Post model adjustments for solar PV.

Forecast level	AEMO	Powercor	Jemena
Connection point forecasts	Historical trend in growth based on linear or cubic relationship or set to zero. Growth rate applied to most recent observation Post model adjustments for block loads, PV and energy efficiency Reconciled to state-wide forecasts (see above). Growth rates based on data over period 2005 to 2015 where available.	Growth rate developed using econometric modelling linking weather normalised connection point demand per capita to demand drivers, including: • GSP per capita • Electricity prices • Temperature variables • Air conditioner penetration • Dummy variables for seasons, days of the week, weekends and public holidays Connection demand given by multiplying per capita demand by population. Half hourly models for each of summer and winter. Data period covering 2004-05 to 2014-15. Growth rate applied to trend line. Post model adjustments for windfarms, solar PV and block loads, limiting industrial load growth.	Growth rate developed using econometric modelling linking weather normalised connection point demand to demand drivers ,including: • GSP • Electricity prices • Temperature variables • Dummy variables for specific days of the week and months of year Running separate models for summer and winter demand. Data period covering 2004-05 to 2013-14. Growth rate applied to most recent observation. Post model adjustments for block loads.
Bottom-up forecasts	NA	• Weather normalise most recent demand data at each feeder sub transmission line and zone substation. • Apply historical growth rates. • Adjust for known load changes, new connections and load transfers. • Use diversity and power factors to aggregate forecasts at each feeder sub transmission line and zone substation.	• Capturing expected load changes based on new connections, customer consultation, local information sources and load transfers between feeders. • Reconcile feeder demand to the previous year zone substation maximum demand. • Use diversity factors to aggregate feeder and zone substation forecasts. • Including load not captured at feeder level such as air-conditioning growth. • Use diversity factors to aggregate zone substation forecasts to connection point level.

Forecast level	AEMO	Powercor	Jemena
Reconciliation process	Connection point forecasts adjusted by a proportional allocation of the state-wide demand growth forecast.	Connection point forecasts adjusted down where: • forecasts were inconsistent with the judgement of expert local planners • aggregated connection point forecasts exceeded the network-wide forecasts Bottom-up forecasts adjusted down where exceeded the connection point forecasts.	Connection point forecasts are adjusted by reconciliation factors to reconcile the connection point forecasts with the network-wide forecasts. Adjusting bottom up forecasts to match connection point forecasts.

Source: Jemena regulatory proposal Attachments 3-1 and 3-5, April 2015. Powercor Revised Regulatory Proposal, January 2016, PAL PUBLIC ATT 8.3 and PAL PUBLIC RRP ATT 5.5.

4 REFCLs and reliability benefits

The Victorian Government submission states that there are reliability benefits associated with the installation of REFCLs and that the AER must take into consideration any potential revenue increments that the distributor will receive under the STPIS.[7]

The Victorian Government's view is influenced by the Regulatory Impact Statement (**RIS**) published on 23 November 2015 that outlined proposed amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013. This included the proposed requirement for Powercor to install REFCLs in 22 zone substations by the end of 2022.

We do not consider reliability benefits referred to by the Victorian Government will be realised. As set out in our response to the RIS, extended operation of the REFCLs on days other than Total Fire Ban (**TFB**) days could potentially result in negative reliability on our network. Therefore, the AER should not take into account REFCLs in setting the STPIS target.

Importantly, RECFLs will not be installed until late in the 2016–2020 regulatory control period and most RECFLs being installed are located in relatively sparsely populated areas.

4.1 Background

The RIS identified the following benefits associated with the installation of REFCLs:

- an improvement in bushfire risk;
- a reduction in the number of minutes that customers are off supply due to electricity interruptions; and
- a reduction in the number of momentary interruptions (those less than a minute in duration).

The primary objective of installing the REFCLs is in response to the recommendations of the Victorian Bushfire Royal Commission to reduce the risk of our assets starting a bushfire.

The changes proposed in the RIS are not for the purposes of delivering a more reliable network to our customers. Indeed, any assumptions that the deployment of REFCLs will result in reliability benefits are predicated on a number of assumptions with respect to the operating mode and the outcomes from unrelated overseas studies. This is further discussed below.

Compensation mode

The reliability benefits that were calculated in the RIS appeared to assume that the REFCL will operate on more than just TFB days. Operation of the REFCLs on only TFB days meets the recommendations of the Powerline Bushfire Safety Taskforce. We have not committed to extended operation of the REFCLs on more than just TFB days.

We set out below how we intend to practically operate the REFCLs in "limited compensation" modes when they are first introduced.

<u>Normal operating mode (non-TFB days)</u>

This operating regime is similar to that used at United Energy’s Frankston South zone substation. Following the detection of a fault:

- the REFCL applies initial compensation to the conductor for a period of three to five seconds; and

[7] Victorian Government, *Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20*, undated, p. 9.

- after this time, the zone substation switches from the REFCL back to a neutral earth resistor (**NER**) or direct earth mode, whereby conventional protection equipment is used to isolate the fault through normal discriminative means.

Consequently, in this operating mode, the REFCL would only beneficially impact momentary outages on the network during the compensation period. That is, the REFCL would only be in use for several seconds and any subsequent protection operation would occur in less than 60 seconds.

<u>Total Fire Ban (**TFB**) only operating mode</u>

The purpose of this operational mode is to minimise the likelihood of fire start. Following the detection of a fault:

- the REFCL applies compensation to the conductor for a period of three to five seconds;
- following the period of initial compensation, the REFCL invokes a "soft" fault confirmation test:
  - if the fault is gone, the REFCL compensation is removed and the network continues to operate as usual; or
  - if the fault is detected to be a permanent fault, then the circuit breaker of the affected feeder is tripped at the zone substation.

This operating mode will result in more customers being disconnected than normal, as downstream devices, such as fuses and reclosers, are not being utilised.

This operating model may also lengthen the time to restore supply to customers. Crews would be required to patrol the entire length of the 22kV feeder to identify the fault location. Our existing fault indicators are also unlikely to function effectively with the REFCL, as they rely on significant changes in current.

4.2 Reliability benefits set out in the RIS

The Victorian Government's RIS provided no transparency as to the assumptions or calculations employed to determine the reliability benefits.

The RIS claimed that we should expect a 30 per cent improvement in reliability for phase-to-earth faults, and that this equates to an overall improvement of 21 per cent in reliability.[8]

There was very little supporting information to validate the claimed percentage improvement in reliability. The RIS claimed that it was based on data from a report by Marxsen Consulting on the trials at Frankston South zone substation, and also references overseas studies and a study by Auckland University. We do not consider these studies to be robust or applicable to our network, for the following reasons:

- Frankston South zone substation is not representative of the average Victorian zone substation where REFCLs are required to be deployed;
- the results of the Frankston South trial were captured over a very short period of time and may reflect seasonal influences, thereby decreasing confidence in the results;
- distributors also have numerous maintenance and reliability improvement programs in place, therefore it is difficult to attribute any quantifiable reliability improvements to one single initiative;

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8 PAL PUBLIC RRP ATT 12.2 – ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 79.

- the Marxsen report contains considerable comment about the potential sources of reliability improvements, it does not discuss the compensation mode to deliver any such benefits;
- the only reference in the Marxsen report to an actual improvement was a study undertaken by Auckland University where they saw a 62 per cent improvement in SAIDI, however it appears that the REFCL in the zone substation was operated with compensation on until the fault was found; and
- while permanent compensation may offer reliability benefits, it introduces other public safety risks — for example, where a pole is hit by a car and comes down, such that one phase is on the ground at zero voltage, and the remaining two phases are close to the ground but remain energised. The RIS offered no commentary on this issue.

Our Electricity Safety Management System (**ESMS**) confirms our protection policy of isolating faults on the network. Operating REFCLs with an extended compensation mode does not isolate a fault on the network, as the network remains energised as the fault condition exists. This operating mode would also be contrary to our legal obligations, such as under the *Electricity Safety Act 1998* (Vic) or the *Electricity Safety (Installations) Regulations 2009* (Vic).

4.3 Our view of reliability benefits

Given our proposed operating regime for the REFCLs that we set out above, we consider that there may be some improvement in MAIFI however in the medium term there is unlikely to be any benefit to SAIDI — in fact, the reliability could be worse.

In terms of MAIFI, the REFCL should eliminate momentary outages caused by phase-to-ground faults on the 22kV feeder network in those zone substations where REFCLs have been deployed. This would occur whether the REFCL is operating in normal or TFB operational mode.

In terms of SAIDI, there may be some longer term benefits as current-related stresses on the network will be reduced for phase-to-ground faults as the fault current will be reduced. However, this benefit may be offset by an increase in equipment related faults due to over-voltages arising from the operation of the REFCL.

Furthermore, the operation of REFCLs on TFB days will result in additional customers losing supply, and experiencing extended outages, compared with the normal operating mode using traditional protection equipment. On TFB days, the detection of a fault will result in the REFCL de-energising the entire 22kV feeder rather than isolating the outage to the portion of the line that would otherwise be de-energised by fuses and automatic circuit reclosers (**ACR**s).

Experience overseas and in Australia has shown that finding faults once the REFCL operates is more difficult and outage durations are likely to increase while the field crew find the fault. Restoration times may also increase as different restoration procedures are followed to reduce the risk of fire ignitions, which increases the time between when a faults occurs and when the distributor attempts to restore supply.

Importantly, RECFLs will not be installed until late in the 2016–2020 regulatory control period and most RECFLs being installed are located in relatively sparsely populated areas.

5 Other matters

5.1 Vegetation management

In its submission in response to the AER's preliminary determination, the Victorian Government compared our vegetation management expenditure in 2009 to that incurred in 2013. The Victorian Government appears to suggest the 2015 Electric Line Clearance (**ELC**) regulations reflect a reversion to the 2005 ELC regulations, and accordingly, our vegetation management costs for the 2016–2020 regulatory control period should decrease to the same extent they increased over the 2011–2015 regulatory control period.

The 2015 ELC regulations, however, do not simply reflect a reversion to the 2005 ELC regulations. Further, as set out in our revised regulatory proposal, the exceptions granted to Powercor during the 2011–2015 regulatory control period resulted in our 2014 vegetation management practices and expenditure being reasonably consistent with the 2015 ELC regulations as a whole (including in regard to the clearance requirements for structural branches). These exceptions include the following:

- in 2011 and 2013, we received exemptions from Energy Safe Victoria (**ESV**) that permitted a transition to compliance with the 2010 ELC regulations by 31 December 2014; and
- as a result of community concern regarding the extent of tree pruning required to be undertaken to achieve and maintain compliance with the 2010 ELC regulations, ESV engaged in discussions with us from late 2012 regarding permitting us to take advantage of exceptions to clearance requirements such as those contained in the 2005 ELC regulations, and approved our Electric Line Clearance (Vegetation) Management Plan for 2014 to 2015 which set out modified clearance practices, including exceptions for structural tree branches.

The 2015 ELC regulations also include enhanced requirements for compliance with Australian Standard (**AS**) 4373, as well as enhanced notification and consultation requirements.

Additionally, the Victorian Government submission referenced our 2013 vegetation management expenditure. The AER's preliminary determination used our 2014 expenditure as the base year for determining our operating expenditure forecast. For the reasons set out in our vegetation management attachment submitted as part of our regulatory proposal, we consider our 2014 revealed costs represent a reasonable basis for determining our operating expenditure forecast for the 2016–2020 regulatory control period. Our base year vegetation management expenditure is also consistent with GHD's independent forecast of our prudent and efficient vegetation management expenditure for the 2016–2020 regulatory control period that was provided with our regulatory proposal.

5.2 Introduction of cost-reflective tariffs

On 21 December 2015, the Victorian Government announced that cost reflective pricing arrangements will be implemented in Victoria through an opt-in approach.[9] Given the timing of this announcement, the impact of this policy decision was not explicitly considered in our revised regulatory proposal.

The introduction of cost-reflective network tariffs—particularly the introduction of a demand charge—will encourage our residential and small and medium enterprise customers to manage their energy usage during particular periods. This is consistent with the pricing principles set out in the Rules, that network charges be reflective of the efficient costs of providing network services. Our approach is expected to lower maximum demand, and subsequently reduce future infrastructure requirements and future costs for all users.

The policy announcement by the Victorian Government increases the need to actively promote the benefits of cost-reflective pricing. For example, as stated by EnergyAustralia in its response to the AER's issues paper on our

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9 Victorian Energy Minister, *Distribution network pricing arrangements*, 21 December 2015.

Tariff Structure Statement (**TSS**), the previous Victorian experience with time of use pricing suggests that many (if not the vast majority) of customers are reluctant to take active steps to opt-in to an alternative approach where the operation and impact is uncertain.[10]

To ensure the benefits of cost-reflective pricing are realised under an opt-in approach, our customer education program and need to actively promote cost-reflective tariffs (including with retailers) are expected to be greater than forecast in our revised regulatory proposal. This is consistent with other submissions provided in response to the AER's TSS issues paper. That is, AGL Energy submitted that an opt-in policy means that customers need to be aware of the benefits of the new demand tariffs.[11] Similarly, the Clean Energy Council stated the benefits of an opt-in approach include that the onus will be distributors (as well as retailers) to educate customers about the benefits of the new tariffs.[12]

Our engagement activities are also expected to result in high volumes of customer enquiries. This reflects the correlation between our engagement processes and customer enquiry volumes, the complexity of network tariffs and the high level of public interest in tariff reform. For clarity, while we consider our costs may now be higher than stated in our revised regulatory proposal, we do not propose amending our forecasts.

5.3 Customer contributions for the Powerline Replacement Fund

AusNet Services has previously received a positive pass through amount based on the tax that was payable on grant funding provided by the Victorian Government through the Powerline Replacement Fund (**PRF**). Following a private ruling from the Australian Taxation Office (**ATO**), AusNet Services made a negative pass through application to the AER to reverse out the positive pass through allowance.

The Victorian Government queries why the AER has not applied AusNet Service's negative pass through decision to the positive pass through amount that the AER provided to Powercor in September 2014. In response to this point, we note that we have made an application to the ATO for a private ruling on the grant that we received relating to the PRF. Given that different nature of the works that we undertake compared with AusNet Services, the taxation treatment of the PRF grant may differ. Following receipt of the ATO private ruling, Powercor will determine whether any further application to the AER is required.

We are compliant with our taxation obligations. Unless the ATO private ruling determines otherwise, we consider that the contributions received from the Victorian Government through the PRF grant (both historic and forecast) will have an associated tax liability. At this point in time, it is not appropriate for either the AER or ourselves to pre-suppose the outcome of the ATO ruling.

5.4 Allocation of costs between metering and standard control services

The Victorian Government raised concerns with the AER's preliminary determination not to allow the reallocation of costs previously recovered under the AMI OIC to standard control services. We agree with the Victorian Government's key concerns that:

- allocating costs relating to the provision of distribution services to metering services resulted in cross subsidies between metering customers and distribution customers, and consequently small customers would subsidise large customers; and

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10 EnergyAustralia, *Tariff Structure Statement proposals – Victorian electricity distribution network service providers*, 20 January 2016, p. 5.

11 AGL Energy, *Tariff Structure Statement proposals of the Victorian electricity distribution network service providers*, 20 January 2016, p. 3.

12 Clean Energy Council, *Submission to the Australian Energy Regulator Issues paper on the Tariff Structure Statement proposals by Victorian electricity distribution network service providers*, 20 January 2016, p. 3.

- metering charges will be higher than they should be and this may lead to new entrants entering the metering market where it would have been inefficient for them to do so if the cross subsidies were removed.

Further, as set out in our revised regulatory proposal, we propose that operating expenditure associated with the provision of our IT systems required for the purpose of delivering distribution services should be allocated to standard control services because:

- our proposed allocation is consistent with the AER's cost allocation guideline and our approved cost allocation method, which the Rules expressly obligate us to prepare of operating expenditure forecasts in accordance with;
- failure to correctly allocate costs to the appropriate causes will lead to inefficient price signals following the introduction of metering contestability and inefficiently encourage substitution away from our existing metering service. This would be inconsistent with the National Electricity Objective;
- failure to correctly allocate costs is contrary to the revenue and pricing principles in section 7A of the National Electricity Law, which states we should be provided with effective incentives in order to promote efficient investment in our distribution system; and
- failure to correctly allocate costs is inconsistent with the national pricing objective in the Rules which states that prices we charge for direct control services should reflect the efficient costs.

We therefore strongly agree with the Victorian Government's submission which states that it is incumbent on the AER to resolve cost allocation issues now and not defer until the completion of the updated ring fencing guidelines.