Submission to Victorian electricity distribution pricing review – 2016 to 2020

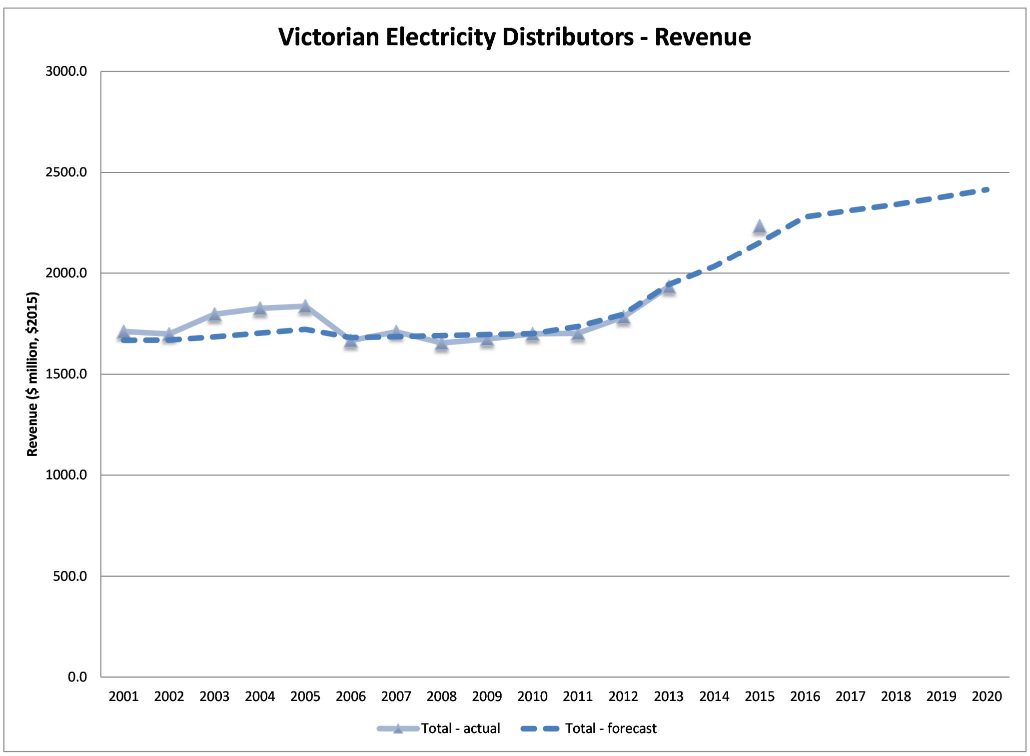
Submission by the Victorian Department of Economic Development of Economic Development, Jobs, Transport & Resources

This submission is provided by the Department of Economic Development, Jobs, Transport and Resources (DEDJTR) on behalf of the Victorian Minister for Energy and Resources and offers comments on the following aspects of the DNSPs' regulatory proposals:

— the proposed revenue for distribution services (other than metering services)
— metering services
— proposed capital expenditure for distribution services (other than metering services)
— proposed operating expenditure for distribution services (other than metering services)
— demand forecasts
— depreciation
— the Service Target Performance Incentive Scheme
— the Capital Expenditure Sharing Scheme
— the Demand Management Incentive Scheme
— the impact of the Victorian Government's Powerline Bushfire Safety Program on the revenue required by the DNSPs in the 2016-20 regulatory control period
— the model used to determine public lighting charges.

Revenue

The revenue for distribution services (other than metering services) that has been forecast by the Victorian DNSPs in aggregate for the 2016-20 regulatory control period is compared to the actual (where available) and forecast revenue from 2001-15 in the figure below (in 2015 dollars).



The Victorian DNSPs have forecast an increase in revenue in 2016-20, albeit at a lower rate of growth than in the 2011-15 regulatory period, despite:

— an improved investment environment compared to 2010 when the current revenue determination was made, which translates to lower financing costs necessary to attract investment

- weakening demand growth that places less pressure on the DNSPs than in previous regulatory control periods to expand the network to meet the needs of additional customers or any increased demand from existing customers
- the investment by Victorian electricity customers in the rollout of smart meters, which is now substantially complete, and provides the technology platform for the DNSPs to realise network operational efficiencies and provide incentives for customers to further reduce demand and thereby defer capital expenditure to expand the network.

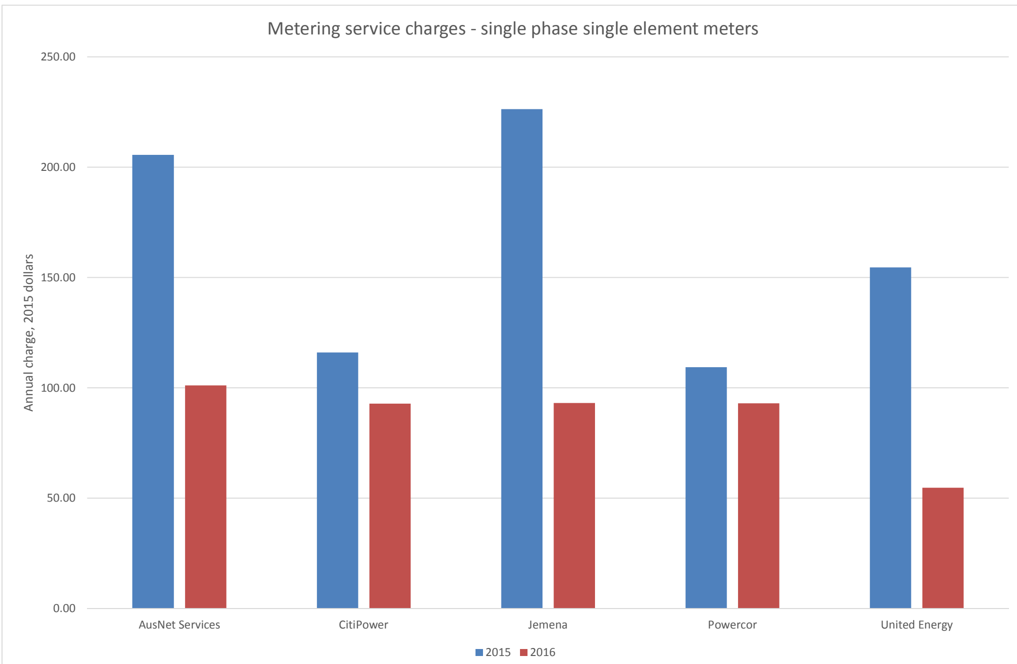
DEDJTR notes that the Weighted Average Cost of Capital (WACC) proposed by each of the Victorian DNSPs is higher than the AER's recent decisions on the WACC for the DNSPs in NSW and the ACT and recent draft decisions on the WACC for the DNSPs in Queensland and South Australia. Accordingly, DEDJTR expects that the AER will critically assess the WACC for the Victorian DNSPs to ensure that it meets the rate of return objective and is appropriate for the current investment environment.

The passing through of the benefits to customers of the smart meter rollout is discussed further in the following section.

Metering services

Metering service charges

With the rollout of smart meters now substantially complete, DEDJTR is pleased that the DNSPs are forecasting a substantial reduction in metering service charges from 2015 to 2016, as illustrated for single phase single element meters in the figure below (in 2015 dollars).



DEDJTR notes that these charges are likely to reduce further with a reduction in the WACC as discussed above.

Realising the benefits of smart meters – network operational efficiencies and deferral in network augmentation

DEDJTR is also pleased that the DNSPs have recognised in their regulatory proposals the benefits that will be realised from the rollout of smart meters. For example, CitiPower and Powercor have stated in their regulatory proposals that[1]:

> *We are already realising network benefits from our smart meter program and will continue to do so. These network benefits provide long term benefits to our customers.*

United Energy identified a range of benefits from the AMI rollout, including[2]:

— identifying faults remotely to avoid wasted truck visits and restore supply more quickly
— having improved voltage data to better understand equipment failure risks
— having improved data on transformer peak load and the likely requirement for transformer upgrades to facilitate more efficient use of existing capacity and more efficient investment
— calculating dynamic cyclic ratings for distribution transformers to achieve greater use of spare capacity in the network
— rebalancing over-loaded phases to improve network utilisation on peak demand days and reduce the need for network augmentation.

United Energy has identified that its "key task now is to ensure that the AMI program delivers maximum benefits to our customers"[3]. The AER's key task in making this revenue determination is ensuring that the benefits realised by the DNSPs are passed through to Victorian electricity customers.

Notwithstanding the benefits identified by the DNSPs, none of the Victorian DNSPs have forecast a negative step change in operating expenditure to reflect the network operational efficiencies that can be realised with the rollout of smart meters, and only Jemena has explicitly forecast a productivity improvement in its operating expenditure over the 2016-20 regulatory control period.

The UK economic regulator, Ofgem recently considered the efficiencies that should be forecast as part of its revenue determination for the UK Distribution Network Operators (DNOs) that will apply from 1 April 2015 to 31 March 2023. In summary, Ofgem stated:

— "*We continue to consider that there are substantial additional savings which DNOs can achieve through smart grids, smart metering and innovation in RIIO-ED1. We have not received evidence to convince us that DNOs have embedded sufficient savings in their business plans. By making an adjustment to the DNOs' allowances, we are ensuring consumers receive a fair return on their investments in innovation projects.*"[4]
— "*Given the level of investment consumers have made in innovation projects and the smart metering programme, we would expect savings from these to be on top of historical levels of ongoing efficiency. ... The adjustment for smart grids and other innovation, represents, on average, an additional frontier shift of 0.2% per year for slow track DNOs. The total smart savings (embedded and additional) are 0.6% per year, compared to the DNOs' ongoing efficiency assumptions of between 0.8 and 1.1% per year.*"[5]

DEDJTR similarly considers that the AER should expect the Victorian DNSPs to realise efficiency gains from the rollout of smart meters. These efficiency gains should be passed through to customers as the benefits are realised given that it is their customers, rather than the DNSPs, that have funded the investment in smart meters through a cost recovery regulatory regime. If these efficiency gains are not passed through to customers through reduced expenditure forecasts as part of this revenue determination, the DNSPs will retain 30 per cent of the benefits resulting from the smart meter rollout through the operation of the expenditure incentive schemes.

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[1] CitiPower, *CitiPower Regulatory Proposal 2016-2020,* April 2015, pages 257-8; Powercor, *Powercor Regulatory Proposal 2016-2020,* April 2015, pages 277-8
[2] United Energy, *2016 to 2020 Regulatory Proposal,* 30 April 2015, page 18
[3] Ibid, page 17
[4] Ofgem, *RIIO-ED1: Final determinations for the slow-track electricity distribution companies; Overview; Final Decision;* 28 November 2014, para 4.70
[5] Ibid, para 4.73, and noting that Ofgem considers operating and capital expenditure in aggregate.

The Victorian Government has recently undertaken an independent assessment of the benefits of the AMI program realised to date and likely to be realised over the longer term. This work shows that the benefits associated with the installation of the smart meters have now largely been realised and that the value added benefits, which are now a focus of the program, are starting to be realised. Further benefits are expected to be realised over the next regulatory control period, subject to actions being taken and some risks.

Other than electricity customers in AusNet Services' area, Victorian electricity customers are realising the benefits from smart meters by having meters remotely read, and through remote de-energisation and re-energisation. To ensure that all Victorian electricity customers are able to realise these benefits on a timely basis, the AER should ensure that:

— the DNSPs' forecast operating expenditure for metering services does not include the costs for manual meter reading readings, except where a customer or technical issue has prevented a smart meter being installed.

— the DNSPs' fees for special meter reads, re-energisation and de-energisation are set on the basis of remote services only, except where a customer or technical issue has prevented a smart meter being installed or where manual services are provided to ensure safety.

In making a determination on the level of manual versus remote services, the AER will need to take into consideration the difficulties experienced by AusNet Services with providing remote services to some of its customers, and that AusNet Services is planning to rollout remote services progressively to all its customers by the end of March 2017. The AER's determination should provide an incentive to AusNet Services to meet its timeframe for providing remote services, without inadvertently increasing the costs that are expected to be incurred by AusNet Services in meeting this timeframe.

Realising the benefits from smart meters – customer portal

CitiPower and Powercor have proposed to[6]:

> *… invest in a customer relationship management system and online customer portal so customers can access their electricity usage data and manage their electricity bills.*

CitiPower's and Powercor's proposals are consistent with recent changes to the National Electricity Rules by the Australian Energy Market Commission to make it easier for consumers to obtain information from the DNSPs in an easy-to-understand, affordable and timely way.[7] As CitiPower and Powercor are the only Victorian DNSPs that currently do not have an online customer portal, DEDJTR supports these proposals and the associated costs.

Regulatory framework for metering services

DEDJTR notes that some of the DNSPs have quoted the following from the AER's Framework and Approach paper:

> *Clause 11.17.6(a) of the [National Electricity Rules] NER requires the AER to regulate smart meters and their associated equipment in the first year of the next regulatory control period under the form of regulation which applies under the [Advanced Metering Infrastructure] AMI [Cost Recovery Order in Council] CROIC.*

Some of the DNSPs' regulatory proposals infer from this that metering services will be regulated in accordance with a cost recovery regulatory regime during the first year of the next regulatory control period, rather than an incentive-based regulatory regime. This is not consistent with the Victorian Government's intent. As stated in a submission from the (former) Victorian Department of State

[6] CitiPower, *Regulatory Proposal 2016-2020,* April 2015, page 66; Powercor, *Regulatory Proposal 2016-2020,* April 2015, page 68

[7] Australian Energy Market Commission, *National Electricity Amendment* (*Customer access to information about their energy consumption) Rule 2014; National Energy Retail Amendment* (*Customer access to information about their energy consumption) Rule 2014; Final Rule Determination,* 6 November 2014

Development, Business and Innovation on the AER's preliminary positions on a replacement Framework and Approach for the 2016-20 revenue determination[8]:

> *What that clause actually provides is that "services to which exit fees under clause 7" and "services to which restoration fees … under clause 8" of the CROIC apply are to be regulated by the AER on the same basis as applied under the CROIC.*
>
> *The drafting of clause 11.17.6(b) reflected three things: that the derogation formerly contained in clause 9.9B of the NER expired on 31 December 2013 (the new derogation in clause 9.9C expires on 31 December 2016); the date for completion of the roll-out of AMI was also 31 December 2013, which has not been met; and that the CROIC would in general cease to apply after 31 December 2015. Thus what the clause was intended to ensure is that after the ending of exclusivity on 31 December 2013 and throughout the regulatory control period 2016-20, the AER would provide for exit fees and restoration fees as alternative control services. It was not intended that the AER continue to regulate all metering services on the basis that the CROIC continues to apply in that regulatory control period.*

To clarify the Victorian Government's intent that metering services should be regulated under an incentive-based regulatory regime from 1 January 2016, the Victorian Government is currently in the process of amending the CROIC.

Potential introduction of contestability

DEDJTR notes that the DNSPs have taken different approaches to the potential introduction of metering contestability in 2017 with:

- AusNet Services assuming that metering contestability will not be introduced during the 2016-20 regulatory control period
- CitiPower, Powercor and Jemena proposing that the end of the derogation that provides the DNSPs with "metering exclusivity" be the trigger for a pass through event
- CitiPower and Powercor excluding the costs for meters installed after 1 January 2017
- United Energy including its best estimate of the forecast costs for introducing contestability and excluding the costs for new connections.

DEDJTR is of the view that a consistent approach to the introduction of metering contestability should be adopted by all DNSPs. DEDJTR considers that this should be treated as a pass through event, given the uncertainty as to when metering contestability will commence and the costs that will be incurred by the DNSPs.

Transfer of costs from metering services to other distribution services

DEDJTR notes that some of the DNSPs have proposed increases in operating expenditure and/or capital expenditure with the transfer of expenditure from metering services to other distribution services. It is also noted that AusNet Services has proposed to roll assets related to AMI IT and communications into its regulatory asset base for other distribution services from 2016.

DEDJTR considers that in deciding whether the transfer of costs is appropriate, the AER needs to apply the principle that was originally adopted in determining the first separate price control for metering services for the 2006-10 regulatory period[9]:

> *… the costs of those IT systems that are required for all customers, regardless of whose meter is installed, should be recovered through the [Distribution Use of System] DUoS price control … The costs of those IT systems that are required only for customers who have the distributor's meter installed should be recovered through the metering price control.*

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[8] Submission from the Victorian Department of State Development, Business and Innovation on the Preliminary positions on replacement framework and approach (for consultation), pages 5 and 6 (available at http://www.aer.gov.au/sites/default/files/DSDBI%20EDPR%20F%26A%20submission%20%28Final%29%28v2%29_1.pdf)

[9] Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons,* October 2005, page 533

DEDJTR accepts that the appropriate application of this principle may result in the transfer of some expenditure from metering services to other distribution services.

However, in assessing the metering service transition charges that will apply in 2016 and 2017, the AER needs to examine whether the expenditure that the DNSPs are now seeking to transfer from metering services to other distribution services was included in the forecast expenditure allowance for other distribution services in the 2006-10 and/or 2011-15 regulatory control periods. If it was, then customers have been paying for the expenditure twice – once through metering services and again through other distribution services. This is a factor that the AER should consider in making its determination on the transition charges.

Capital expenditure (capex)

The AER's inaugural annual benchmarking report identifies that[10]:

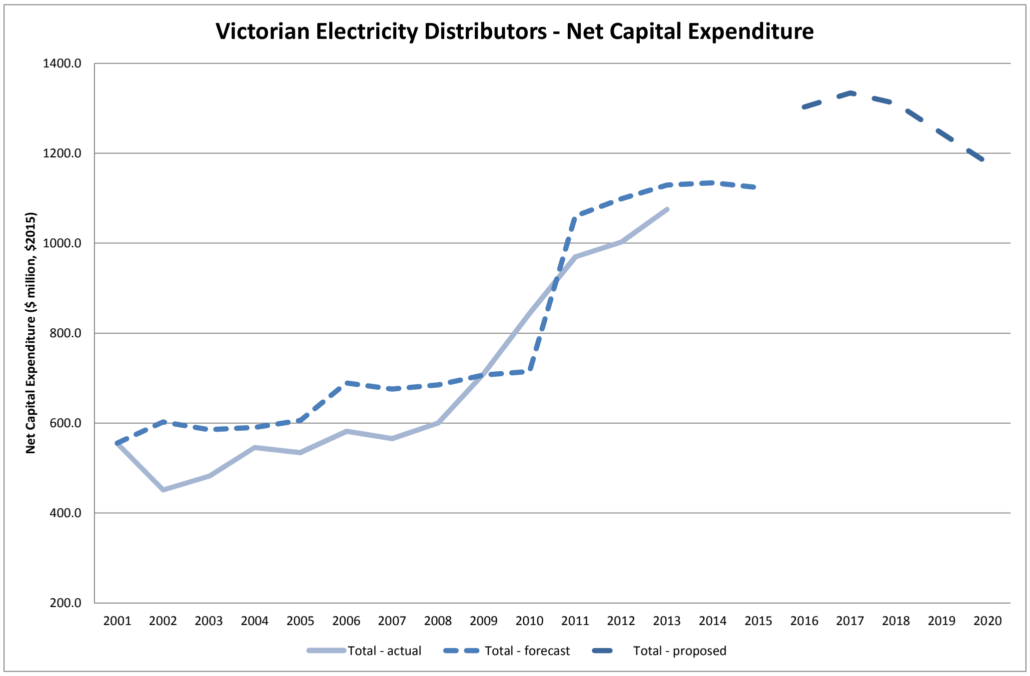
> *the Victorian distributors appear the most efficient in the use of assets because they have the lowest asset cost per customer regardless of customer density.*

A multifactor total factor productivity index for 2006-13 also indicates that the Victorian DNSPs, particularly CitiPower, United Energy and Jemena, are productive relative to the other DNSPs regulated by the AER, although it is noted that productivity has been declining since 2006.[11]

It is not unsurprising that the Victorian DNSPs are productive relative to other DNSPs as they were privatised nearly 20 years ago and have been subject to an incentive-based economic regulatory regime during this period. With the rollout of smart meters in Victoria, the Victorian DNSPs are able to realise further productivity gains that DNSPs in other jurisdictions without near universal smart meter roll outs are not able to realise. Therefore the Victorian DNSPs should continue to be the most productive.

However, despite the DNSPs being relatively productive, the weakening demand growth (due in part to successful demand management programs[12]), a reduction in the Value of Customer Reliability (VCR) and a change in capitalisation policy by CitiPower and Powercor which reduces capital expenditure[13], the net capital expenditure (capex) proposed by the DNSPs for 2016-20 regulatory control period has increased relative to the actual and forecast net capex over the 2001-15 period, as illustrated below (in 2015 dollars). DEDJTR would expect the AER to take these factors into consideration when examining the DNSP's proposed capital expenditure.

[10] Australian Energy Regulator, *Electricity distribution network service providers, Annual benchmarking report,* November 2014, page 26
[11] Australian Energy Regulator, *Electricity distribution network service providers, Annual benchmarking report,* November 2014, pages 29 and 31
[12] Australian Energy Regulator, *Issues Paper, Victorian electricity distribution pricing review, 2016 to 2020,* June 2015, page 28
[13] CitiPower and Powercor are proposing to expense overhead costs that were previously capitalised. As a result, their capital expenditure is lower than in the absence of this change and their operating expenditure is higher than in the absence of this change.



Given the change to CitiPower's and Powercor's capitalisation policies, the AER will need to assess their proposed total expenditure (capital and operating) to ensure that their customers are not paying more as a result of this change in the capitalisation policy, and that they continue to be productive relative to other DNSPs.

CitiPower's regulatory proposal notes that there have been delays in its CBD security upgrade and metro projects arising from community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station.[14] CitiPower has indicated that 9 per cent of its augmentation expenditure[15] (or around $16 million) in the 2016-20 regulatory control period is for the security of supply project. Given the delays that have been experienced with this large project, and customers ultimately paying more as a result, the AER needs to consider whether any of the DNSPs have proposed any large projects that should be classified as a contingent project.

Operating expenditure (opex)

The AER's inaugural annual benchmarking report also considered the partial productivity index ratio of the average operating expenditure per customer over the 2009-13 period. It concluded that[16]:

> *Under this measure the Victorian and South Australian distributors appear the most productive in their use of opex.*

However, the DNSPs are forecasting a significant step increase in operating expenditure in the 2016-20 regulatory control period as illustrated in the figure below (in 2015 dollars). As CitiPower and Powercor are changing their capitalisation policies in 2016, the graph illustrates the operating expenditure for 2016-20 with and without the change in the capitalisation policies.

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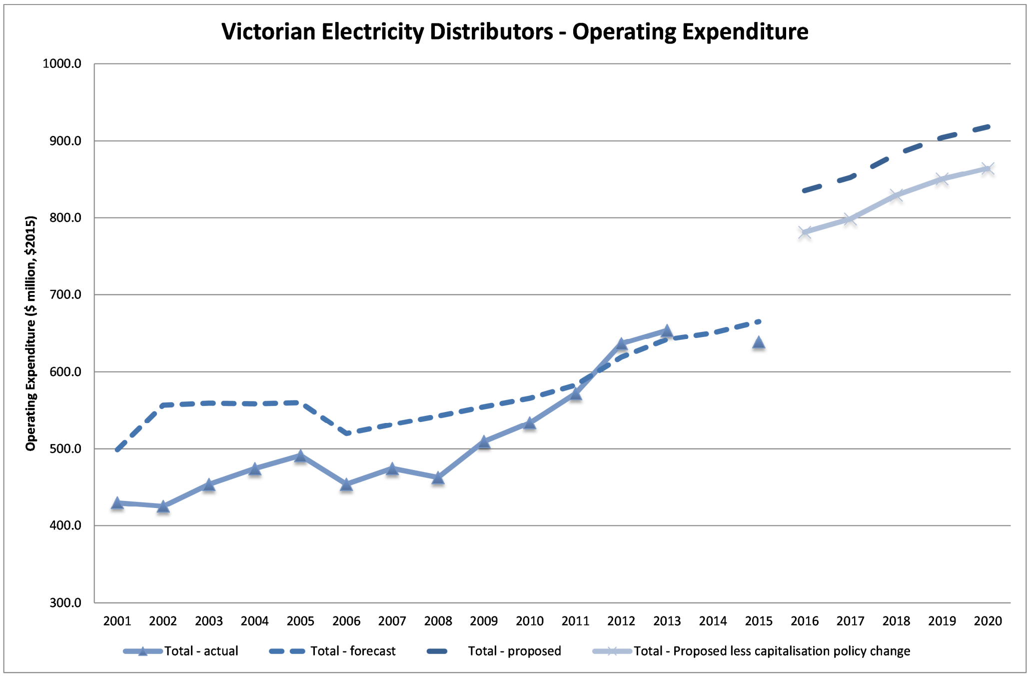
[14] CitiPower, *CitiPower Regulatory Proposal 2016-2020,* April 2015, page 97
[15] CitiPower, *2016-2020 Price Reset, Appendix E: Capital expenditure,* April 2015, page 96
[16] Australian Energy Regulator, *Electricity distribution network service providers, Annual benchmarking report,* November 2014, page 24



The AER will need to assess the increases proposed to ensure that they meet the operating expenditure objectives, noting that the DNSPs have historically underspent relative to forecast.

The AER has stated that it is proposing to use 2013 as the base year for assessing the DNSPs' proposed operating expenditure.[17] Given that audited 2014 data should be available, it is unclear why 2014 is not being used as the base year.

Only Jemena has explicitly included a productivity improvement in its proposed operating expenditure over the 2016-20 regulatory control period, while AusNet Services has indicated that it has implicitly included a productivity improvement by absorbing step changes. DEDJTR expects that, in the absence of a smart meter rollout, there will be some productivity improvements as would be expected by firms operating in a competitive environment. The DNSPs should be rewarded through the Efficiency Benefit Sharing Scheme (EBSS) for productivity improvements that are greater than those expected in a business as usual environment, but should not be rewarded for achieving a level of productivity improvements that should, in effect, be a business as usual level of productivity improvement.

As discussed above, DEDJTR expects an additional level of productivity improvement associated with the rollout of smart meters so that the DNSPs' customers are able to realise the benefits for their investment in the smart meter rollout.

DEDJTR notes that Jemena has proposed a step change in operating expenditure of $1.01 million to provide assistance for vulnerable customers.[18] On 18 February 2015, DEDJTR announced an inquiry into best practice financial hardship programs of energy retailers. "*The inquiry's primary goal is to provide confidence that energy customers who cannot pay their bills in full and on time get the assistance to which they are entitled from their energy retailer*"[19]. If this inquiry reveals there is a role for the DNSPs in providing assistance to vulnerable customers, the AER should consider the level of expenditure required at that time, rather than seek to pre-empt the outcomes of the inquiry.

Demand forecasts

[17] Australian Energy Regulator, *Consumer guide to Victorian electricity distribution pricing review, 2016-20,* May 2015, page 15
[18] Jemena, *Regulatory Proposal, 1 January 2016 – 31 December 2020,* 30 April 2015, page 88
[19] Essential Services Commission, *Inquiry into the Financial Hardship Arrangements of Energy Retailers, Our approach,* March 2015, page 1

The DNSPs' peak demand forecasts have been compared to the Australian Energy Market Operator's (AEMO's) Transmission Connection Point forecasts in the AER's Issues Paper. The footnote to Table 3.2 highlights the difficulty for stakeholders in comparing peak demand forecasts across DNSPs and over time – the DNSPs provide peak demand forecasts on a different basis. While some use coincident peak demand, others use non-coincident peak demand; while some provide the 10 per cent probability of exceedance (POE) forecast, others provide the 50 per cent POE forecast.

DEDJTR would urge the AER to require the DNSPs to provide peak demand forecasts on a consistent basis over time, noting that the non coincident peak demand, 50 per cent POE forecast is the most relevant to the DNSPs' capex forecasts.

In its Issues Paper, the AER has stated that the uncertainty in future energy consumption will:

> *… have implications for the risks faced by the businesses, the nature and amount of capital expenditure required and, to an extent, the level of operating expenditure.*

Given that the form of price control will be a revenue cap in the 2016-20 regulatory control period, it is unclear how the DNSPs will face risk from their energy consumption forecasts. The amount of capital expenditure required is largely driven by peak demand and the number of new customers (and the condition of assets), rather than energy consumption. Operating expenditure is also not driven by energy consumption.

Depreciation

AusNet Services has proposed to accelerate the depreciation on assets "*which have been, or are planned to be removed from service*"[20]. However, AusNet Services has recognised that its regulatory asset base (RAB) is "*aggregated at a level (e.g. Sub-transmission Assets, Distribution Assets) and it is not possible to identify the value associated with individual assets or asset classes. Hence the remaining RAB value for each of the identified asset classes must be estimated*"[21].

Given the uncertainty in the value of the assets for which depreciation is proposed to be accelerated, the AER will need to carefully consider whether it is fair and reasonable for customers to be paying the amount proposed for accelerated depreciation in the 2016-20 regulatory control period, and whether there is a risk that they will be paying accelerated depreciation on assets that remain in service.

Jemena has proposed to "*replace some SCADA and billing IT systems that have come to the end of their useful or economic life*"[22]. DEDJTR would expect that the SCADA and billing IT systems are at the end of their useful life, rather than at the end of their economic life, noting that the economic life is only an estimate of the life of the systems for the purposes of depreciating the asset and that depreciation *"doesn't refer to any actual wear-and-tear on the assets – it is purely the repayment of the amount owed."*[23]

Service Target Performance Incentive Scheme (STPIS)

DEDJTR is pleased that the AER recognises that a key issue it must address is the balance between the cost of the services provided and reliability, quality and security.[24]

Change in the Value of Customer Reliability

AEMO reviews the Value of Customer Reliability (VCR) on a five year basis. A VCR of $30,000 per MWh (2004 dollars) was used as the basis for determining the reliability-based incentive rates for the service incentive scheme for the 2006-10 regulatory period[25], and a VCR of $47,850 per MWh (2008

[20] AusNet Services, *Electricity Distribution Price Review 2016-20,* 30 April 2015, page 382
[21] Ibid, page 385
[22] Jemena, *Regulatory Proposal, 1 January 2016 – 31 December 2020,* 30 April 2015, page 62
[23] Australian Energy Regulator, *Consumer guide to Victorian electricity distribution pricing review, 2016-20,* May 2015, page 10
[24] ibid
[25] Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons,* October 2005, page 88

dollars) was used for the 2011-15 regulatory control period[26]. The most recent study by AEMO indicates that the Victorian state-wide VCR is now $39,500 per MWh (2014 dollars)[27]. A reduction in VCR implies that customers are not willing to pay for the current level of reliability.

AusNet Services, CitiPower and Powercor have proposed that the targets for the STPIS should be decreased in line with the reduced VCR, despite not seeking an increase in targets in line with the increased VCR for the 2011-15 regulatory control period.

The AER needs to ensure that the targets for the STPIS are consistent with the expenditure forecasts that are provided. If the AER provides expenditure to maintain reliability, then the targets should not be adjusted and the DNSPs should be penalised for any reduction in reliability through the STPIS. If the AER does not provide expenditure to maintain reliability as a result of the lower VCR, then the targets should be adjusted accordingly.

Impact of the Powerline Bushfire Safety Program on reliability

In assessing the targets, the AER also needs to take into consideration the improvement in reliability that will result through the Victorian Government's Powerline Bushfire Safety Program.

The Victorian Government is funding powerline replacement[28] in the most dangerous areas of the state and is currently considering regulating the installation of Rapid Earth Fault Current Limiters (REFCLs) in the highest consequence bushfire risk areas and automatic circuit reclosers on Single Wire Earth Return powerlines in rural areas. Both the powerline replacement and REFCLs are expected to improve the supply reliability in the areas targeted.

Guaranteed Service Level payments scheme

DEDJTR notes that the AER will not be applying the Guaranteed Service Level (GSL) component of STPIS to the Victorian DNSPs as they are subject to a jurisdictional GSL scheme.

The AER indicated in its Framework and Approach that the Victorian Government supported this approach.[29] This misrepresents the Victorian Government's position. The (former) Victorian Department of State Development, Business and Innovation's submission to the Framework and Approach stated that it[30]:

> *… would prefer that a national GSL scheme be applied to the Victorian distributors. However, given the concerns that [the Victorian Government] has previously raised with the current national scheme, the previous jurisdictional GSL scheme has been retained.*

Given the continuing reluctance by the AER to address the Victorian Government's concerns with the national GSL scheme, the ESC will review the jurisdictional GSL scheme. The review will ensure that the jurisdictional GSL scheme continues to be consistent with the principles originally determined for the GSL scheme and is updated to reflect any changes that have occurred since it was last reviewed in 2005. When the review is complete, the AER will need to adjust the operating expenditure forecast for the payment of GSLs accordingly.

Amendments proposed to the STPIS

The DNSPs have proposed a number of amendments to the STPIS:

— CitiPower and Powercor have proposed that the number of momentary interruptions (MAIFI) be excluded

[26] Australian Energy Regulator, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision,* October 2010, pages 716-717

[27] Australian Energy Market Operator, *Value of Customer Reliability – Application Guide, Final Report,* December 2014, page 5

[28] Putting powerlines underground or replacing bare overhead wires with insulated conductor.

[29] Australian Energy Regulator, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2009,* 24 October 2014, page 97

[30] Submission from the Victorian Department of State Development, Business and Innovation on the Preliminary positions on replacement framework and approach (for consultation), page 6 (available at http://www.aer.gov.au/sites/default/files/DSDBI%20EDPR%20F%26A%20submission%20%28Final%29%28v2%29_1.pdf)

— CitiPower, Powercor and United Energy have proposed to amend the definition of the frequency of sustained interruptions (SAIFI) or MAIFI
— United Energy has proposed to amend the definition of an urban feeder
— AusNet Services has proposed an additional exclusion (contracted demand reduction).

CitiPower and Powercor has proposed that MAIFI be excluded from STPIS because there are few cost effective technical solutions available to improve MAIFI, it undermines the positive incentive to improve SAIFI, and it is consistent with the AER's Framework and Approach and the AER's Draft Decision for the NSW/ACT electricity distribution networks.[31]

DEDJTR does not support the exclusion of MAIFI from the STPIS. The STPIS is not only about funding improvements in performance but also to penalise the DNSPs for any deterioration in performance. If MAIFI is removed, there is a risk that the frequency of momentary interruptions will increase and customers have indicated their frustration with resetting clocks and other electronic equipment regardless of whether the interruption is momentary or sustained. While there are currently few cost effective technical solutions to improve MAIFI, there may be technical advances in the future which enable improvements in MAIFI.

There is a trade-off between SAIFI and MAIFI – a reduction in SAIFI can lead to an increase in MAIFI. For example, the installation of Automatic Circuit Reclosers may lead to a reduction in SAIFI, but an increase in MAIFI where faults occur but are not permanent. The incentive rates reflect that customers are willing to pay more for a reduction in SAIFI than MAIFI.

While the AER's Framework and Approach did not specifically state that MAIFI would be included in the STPIS, there is no discussion on its exclusion. DEDJTR assumes this was an oversight in the drafting of the Framework and Approach rather than a deliberate decision by the AER to exclude MAIFI.

MAIFI has been included in the Victorian STPIS (or its equivalent) since 2006, while the NSW and ACT electricity distributors have not been subject to a STPIS during that period. The absence of MAIFI from a STPIS that is applied in NSW and the ACT is therefore not a strong rationale for now excluding MAIFI from the STPIS that is applied in Victoria.

CitiPower and Powercor have proposed that the definition of a sustained interruption be amended so that it is an interruption of duration greater than 3 minutes rather than 1 minute[32] while United Energy has similarly proposed that the definition of MAIFI be amended so that it includes interruptions of duration of up to 3 minutes rather than 1 minute.[33]

The DNSPs have previously proposed to amend the definition of MAIFI (and therefore SAIFI) so that it includes interruptions of duration of up to 3 minutes, as part of the 2006-10 and 2011-15 revenue determinations. The definition has not previously been amended due to a lack of performance data based on the amended definition[34] and the lack of information on the impact of a customer's willingness to pay for a 3 minute interruption as compared to a one minute interruption[35].

DEDJTR supports a change to the definition if the data is now available to amend the targets and incentive rates accordingly.

United Energy has proposed that the definition of an urban feeder be based on weather normalised maximum demand rather than actual maximum demand so that feeders do not churn between feeder

[31] CitiPower, *2016-2020 Price Reset, Appendix H, Service target performance incentive scheme,* April 2015, page 6; Powercor, *2016-2020 Price Reset, Appendix H, Service target performance incentive scheme,* April 2015, page 6
[32] CitiPower, *2016-2020 Price Reset, Appendix H, Service target performance incentive scheme,* April 2015, page 5; Powercor, *2016-2020 Price Reset, Appendix H, Service target performance incentive scheme,* April 2015, page 5
[33] United Energy, *2016 to 2020 Regulatory Proposal,* 30 April 2015, page 140
[34] Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons,* October 2005, page 45
[35] Australian Energy Regulator, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision,* October 2010, pages 725

categories based on changes in climatic conditions from one year to the next.[36] This is an eminently sensible suggestion which DEDJTR supports.

AusNet Services has proposed an additional exclusion event for the STPIS[37]:

> *Load shedding or load interruption due to the failure of a new contracted non-network solution entered into the current regulatory control period.*

A similar exclusion was included in the service incentive scheme for the 2006-10 regulatory control period. However, the exclusion criterion was subject to approval by the regulator and that approval was dependent on the proponent demonstrating that customers likely to be impacted by any resultant deterioration in reliability had been identified and agreed to the exclusion criteria.[38] This ensures that the DNSP continues to be held accountable for customers' reliability of supply, regardless of whether a network or non-network solution is adopted, while noting that the DNSP has the option to transfer the risk of any deterioration in supply reliability to the contracted non-network solution provider.

DEDJTR supports the use of non-network solutions as an alternative to augmenting the network, particularly in an environment of weakening demand growth. However, customers should not be unduly adversely affected.

Capital Expenditure Sharing Scheme

DEDJTR has previously raised its concerns regarding the introduction of a capital expenditure sharing scheme (CESS) into the regulatory framework in a submission to the Australian Energy Market Commission's Directions Paper on the Economic Regulation of Network Services. In that submission, DEDJTR referred to the reasons for the ESC discontinuing to apply a similar scheme (the efficiency carryover mechanism) to capital expenditure in 2006. The ESC found that[39]:

> *Reductions in capital expenditure below forecast can be the result of any, or a combination of: efficiency gains; the deferral of capital expenditure projects between regulatory periods; changes in external expenditure drivers (for example, lower than anticipated peak demand); or overstatement of expenditure requirements when the 2001-05 forecasts were set.*
>
> *In light of these various sources of spending below forecast, it is difficult to isolate whether or not the efficiency carryover mechanism has provided any greater efficiency incentive than that already provided within the current five year regulatory review cycle.*
>
> *…*
>
> *However, where capital expenditure overspends arise from unsustainable rates of investment deferral (or inaccurate forecasts), customers are at risk of potentially funding efficiency carryover rewards on efficiencies that are not sustainable (or not genuine efficiencies). Where efficiencies are not sustainable (or have not occurred in the first place) customers will not benefit from lower prices arising from the sharing of efficiency benefits through the efficiency carryover mechanism and regulatory review. This differs from operating and maintenance expenditure where the incremental calculation of the efficiency carryover amounts and the clear translation of revealed costs into the next period forecasts ensure that customers only reward sustained efficiencies and that customers share in efficiency benefits via lower prices.*

DEDJTR's concerns regarding the CESS were reinforced by comments in CitiPower's regulatory proposal of the delays in its CBD security upgrade and metro projects arising from community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station.[40]

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[36] United Energy, *2016 to 2020 Regulatory Proposal,* 30 April 2015, page 140
[37] AusNet Services, *Electricity Distribution Price Review 2016-20,* 30 April 2015, page 246
[38] Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons,* October 2005, page 126
[39] Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons,* October 2005, pages 431-432
[40] CitiPower, *CitiPower Regulatory Proposal 2016-2020,* April 2015, page 97

CitiPower has underspent the forecast gross direct capital expenditure for the 2011-15 regulatory control period by approximately 18 per cent largely due to the deferral of this project and lower than expected levels of growth in peak demand.[41] This underspend equates to approximately $170 million in 2015 dollars. Customers have paid a return on and of this amount during the 2011-15 regulatory control period but without having the works delivered.

CitiPower has indicated that 9 per cent of its augmentation expenditure[42] (or around $16 million) in the 2016-20 regulatory control period is for the security of supply project. If provided for in CitiPower's forecast capital expenditure, customers will be paying a return on and of this amount during the 2016-20 regulatory control period.

In determining the CESS payment to be made to a DNSP, the AER will be able to make adjustments to account for the deferral of capex. However, the AER will need to have sufficient transparency of the capex proposed to be able to make an informed decision as to whether a future underspend is due to a deferral of capex or for some other reason. The AER will need to collect sufficient data during this revenue determination process to be able to make those decisions in the next revenue determination process.

Demand Management Incentive Scheme

DEDJTR notes that the DNSPs have sought increases in the Demand Management Innovation Allowance. While DEDJTR supports genuine early stage research and development on demand management initiatives, the AER should ensure that:

— any funding is consistent with the objectives of the demand management incentive allowance
— demand management initiatives are not funded through the demand management incentive allowance when it is more appropriate for them to be funded through an opex or capex allowance, or through expenditure incentive schemes

Powerline Bushfire Safety Program

As discussed above, DEDJTR is currently preparing a Regulatory Impact Statement on a potential regulatory obligation to require DNSPs to install REFCLs in the highest consequence bushfire risk areas (while noting that the DNSPs may elect to install REFCLs in other areas of the state based on improvements in reliability or public safety). If the Government proceeds with the regulatory amendments, they are not expected to be made prior to the AER making its Preliminary Determination in October 2015.

This regulatory amendment will largely impact AusNet Services and Powercor, and to a lesser extent, Jemena. While AusNet Services has proposed a potential pass through event for the installation of REFCLs, Powercor has proposed that they be considered a contingent project.

DEDJTR supports that a consistent approach be adopted across the Victorian DNSPs for recovering the costs associated with the REFCLs from their customers.

Public lighting

DEDJTR notes that the AER is using a cost model that includes a range of assumptions to determine the public lighting charges.

DEDJTR expects that the AER is reconciling the outputs from the model to the actual cost data reported by the DNSPs in their regulatory accounting statements to determine whether the assumptions in the model continue to be fair and reasonable.

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[41] CitiPower, *2016-2020 Price Reset, Appendix E: Capital expenditure,* April 2015, page 7
[42] CitiPower, *2016-2020 Price Reset, Appendix E: Capital expenditure,* April 2015, page 96

Authorised by the ___________________ (example Hon.)
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