Submission on the *Queensland Revised Regulatory Proposals 2015-16 to 2019-20*

24 July 2015

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Australian Energy Regulator

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This submission, which is available for publication, is made by:

Ergon Energy Corporation Limited

PO Box 264

FORTITUDE VALLEY QLD 4006

Enquiries or further communications should be directed to:

Graeme Finlayson

Acting Executive General Manager – Strategy, Revenue and Transformation

Ergon Energy Corporation Limited

Email: graeme.finlayson@ergon.com.au

Phone: (07) 4432 8669

Mobile: 0418 763 602

Introduction

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider (DNSP) in Queensland, welcomes the opportunity to provide this supplementary submission to the Australian Energy Regulator (AER) on our revised Regulatory Proposal.

This submission should be read in conjunction with our revised Regulatory Proposal, *Submission to the AER on its Preliminary Determination* and other supporting documents provided to the AER on 3 July 2015.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues raised, should the AER require.

Issues since submission of our revised Regulatory Proposal

Stakeholder submissions

Ergon Energy has reviewed the submissions made to the AER's Preliminary Determination. Many submissions reinforce concerns raised by stakeholders in response to our initial Regulatory Proposal which was lodged in October 2014. We attempted to address many of these concerns in our response to the AER's Preliminary Determination on 3 July 2015.

Several stakeholders have reiterated their preference for substantial electricity price reductions to counter significant price increases between 2010 and 2015.[1] The Alliance of Electricity Consumers seeks a 75 per cent reduction in revenues recovered, by halving the level of operating expenditure and substantially reducing our Regulatory Asset Base and the allowed rate of return.[2] Meanwhile, the Chamber of Commerce and Industry Queensland (CCIQ) seeks around 40 per cent reductions in capital and operating expenditure from what was forecast.

Responses also focused on the AER's preliminary decision to reduce our operating expenditure proposal by 10 per cent, suggesting this was insufficient.[3] Stakeholder submissions reference the inadequacies of reductions in the context of the AER's benchmarking, rather than in the context of Ergon Energy's historic spend or what is required to provide Standard Control Services in our network area. The Energy Retailers Association of Australia (ERAA) and Origin Energy expressed disappointment that adjustments were made by the AER on benchmark levels.[4] QCOSS submits that the allowance should be set with reference to the most efficient network service provider (CitiPower, the network operator in Melbourne CBD) with no allowance for differences in environment. The Total Environment Centre stated that the $191 million reduction in operating expenditure (in addition to any reductions from current expenditure levels already included in the forecast) was minimal.[5]

A number of stakeholder submissions also suggested that the AER rely more heavily on the outcomes of the review conducted by Deloitte Access Economics into our operational expenditure and efficiency in seeking to support their submissions for deeper reductions to our forecast operational expenditure to be made than had resulted from the AER's benchmarking-based assessment. Ergon Energy notes that the results of the review conducted by PWC (EXP 10.08) into the findings made by Deloitte Access Economics highlighted a number of serious and material shortfalls in the data, evidence relied upon and conclusions reached by Deloitte Access Economics.

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[1] Canegrowers ISIS (2015), *AER Draft Determination: Ergon Energy and Energex – Network Distribution Resets 2015*-20, 6 July 2015; CCIQ (2015), *Submission to the Australian Energy Regulator on the Preliminary Determinations for Ergon Energy and Energex Revenue Determination,* 3 July 2015; Cotton Australia (2015), *RE: AER Determination Ergon,* 3 July 2015; Queensland Consumers' Association (2015), *Submission on AER Preliminary Determinations for Energex and Ergon Energy Revenues for 2015-20*, 3 July 2015; Queensland Council of Social Service (QCOSS) (2015), *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, July 2015; and Queensland Farmers' Federation (2015), *Submission to the Australian Energy Regulator (AER) on the Preliminary Determination for the Ergon Energy and Energex Regulatory Proposals for 2015-2020*, 3 July 2015.

[2] Alliance of Electricity Consumers (2015), *Submission to the Australian Energy Regulator's Preliminary Decision (Queensland)*, 3 July 2015.

[3] CCIQ, Op. cit, section 5.

[4] ERAA (2015), *RE: Preliminary Decisions for Ergon Energy and Energex determinations 2015-16 to 2019-20,* 3 July 2015; and Origin Energy (2015), *RE: Submission to AER Preliminary Decision Queensland Electricity Distributors*, 3 July 2015.

[5] Total Environment Centre (2015), *Submission to the AER on the Preliminary Decisions on the QLD DB's Regulatory Proposals 2015-20*, July 2015.

Our submission in response to the AER's Preliminary Determination notes that Ergon Energy's forecast operating expenditure incorporated a reduction to base year overhead costs and ongoing productivity adjustments compared to trend. We noted the challenges in meeting these reductions into the regulatory control period 2015-20.

The customer commitments we brought together and re-emphasised in our revised Regulatory Proposal were based on our conversation with customers across our wide network footprint area and what they saw were their long term interests. There was no reasonable finding that suggested that customers are only interested in large price reductions from Ergon Energy. In fact, the commitment to provide services with Peace of Mind was just as important as price relief for many of our customers.

In this context we have attempted to address these concerns with our customer commitments and supporting documentation to our revised Regulatory Proposal.[6]

We also engaged with customers on the trade-off between lower prices and reductions in operations and service delivery. When faced with the choice of making significant changes to services, reliability or response times, many customers preferred outcomes which did not reduce prices, or alternatively limited reductions to certain areas.

Many stakeholders supported the AER's preliminary decision in relation to the rate of return, with others supporting even lower reductions in allowances for debt and equity returns. Many of the concerns reinforce previous submissions on these matters, which we have attempted to address in our October Regulatory Proposal and July 2015 submissions.

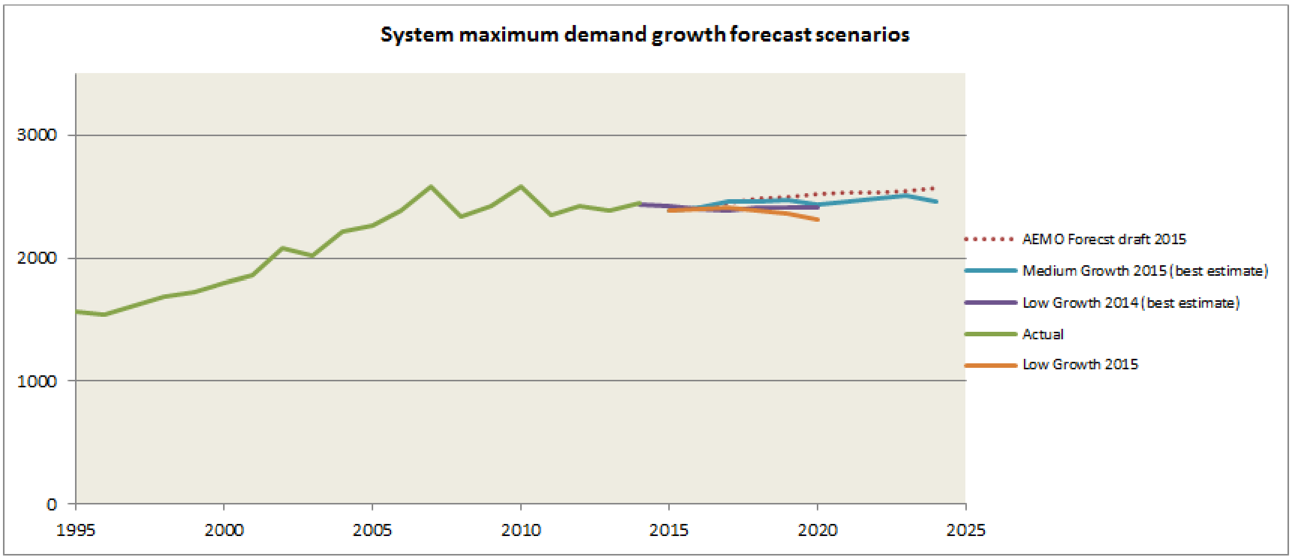
A number of stakeholders also expressed concerns regarding Ergon Energy's system demand forecast and the AER's assessment of our system demand forecast. In the AER's Preliminary Determination Attachment 6-Capital Expenditure P6-115 the AER states: *"We are satisfied the system demand forecast in Ergon Energy's regulatory proposal for the 2015–20 regulatory control period reasonably reflects a realistic expectation of demand. However, in our final decision will take into account the updated AEMO forecasts that are scheduled to be published by July 2015".*

In our Revised Proposal and submission in response to the AER's Preliminary Determination, we included further information regarding the above feedback from the AER on our demand forecasts.

As indicated in the material supporting our October 2014 and July 2015 proposals, Ergon Energy develops Low, Medium and High growth system demand forecasts annually. The analysis is based on the latest peak demand information from the previous Summer(i.e. Up to the end of February) but is normally published in early July. In 2014, a number of economic indicators changed during the development process that resulted in Ergon Energy taking the decision to use the Low growth forecast for Ergon Energy's initial submission for October 2014. This is described as the "best estimate" of the forecasted conditions.

The 2015 system demand forecast has taken account of the changing economic indicators as such the Medium growth forecast is the best estimate of system demand forecasts performance.

[6] Refer to our supporting document, *0A.01.02 – (Revised) Journey to the Best Possible Price.*



As can be seen from the graph above the best estimate system demand forecasts developed in 2014 (Low Growth) aligns with:

1. 2015 actual performance of system demand
2. 2015 (Medium Growth) demand forecast for the 2015-20 regulatory period; and
3. consistent with AEMO forecast.

The AER's Preliminary Determination noted that their final decision will take account of AEMO forecasts. Ergon Energy has taken account of this in its revised proposal by comparing AEMO's draft forecast with its own. The comparison of Ergon Energy 2015 (Medium Growth - best estimate) demand forecast and the draft AEMO forecast demonstrates alignment.

Consequently expenditure forecasts supporting the original proposal are predominantly being maintained at the 2014 level (Low Growth – best estimate) while detailed spatial forecasts are still being reviewed for the whole network.

As we indicated to our customers and key stakeholders in developing our October 2014 Proposal, Ergon Energy moved to the low growth forecast for 2014 to formulate our regulatory proposal when it was clear that economic activity would be below predicted levels in that year.

Economic forecasts for 2015 now account for the low actual growth in 2014 and present economic activity and it is appropriate to move to the 2015 medium growth demand forecast. Should the low economic forecast be used for 2015 Ergon Energy will be at risk of not being able to fully comply with the safety net performance requirements of our distribution license as a result of constraints introduced by slowly increasing demand in a number of areas in the network.

Ergon Energy also notes that Queensland's economy had been one of the outperforming States in recent years, reflecting the boom in resources investment. However, with mining investment now declining together with subdued government spending, activity has since weakened. Overall growth in Queensland will remain below its long-run average as mining investment declines. However, solid growth is still expected for 2015-16. Exports will provide a large contribution to this growth, particularly in the second half of this year as LNG exports ramp up.

The reduction in Gross State Product forecast has resulted from major softening in commodity prices in recent times and the terms of trade will remain soft. Mining investment will continue to decline, and income from commodity exports will be less than previously anticipated. However, prospects for industries outside of mining are improving, if only gradually. The lower Australian dollar is seeing confidence return to the tourism industry.

Household spending growth will gradually pick up as low interest rates will continue to bolster consumer spending and the upswing in Australian housing market will be expected to continue. Exports are set to increase in coming years and are expected to provide a large contribution to growth, particularly from 2015-16 as LNG exports ramp up. The lower Australian dollar will also provide a further boost to other exports, and support Queensland’s tourism sector. A pickup in growth is expected over 2015-16 and 2016-17.

Materially preferable

Ergon Energy has been observing closely recent opinion in respect of the interpretation of a "materially preferable" decision, referred to in the National Electricity Law (NEL). Such interpretation will be argued over the next few months in other decisions and processes, and we note some preliminary comments have already been made by the Tribunal on this concept following the applications for leave considered in relation to the NSW and ACT merits review processes now underway.

Nevertheless, Ergon Energy has had the opportunity to review the Energex submission attachment from Greg Houston who, in looking at the AER's Preliminary Determination for Energex, discussed the economic role of the National Electricity Objective (NEO), the principles that should be adopted in a regulatory regime that promotes the NEO, and the role of the building blocks approach in meeting those principles and the NEO.[7]

Ergon Energy believes that Houston provides valuable insights into the economic interpretations of the NEL – in particular the NEO – and that these insights could similarly be applied to many of the AER's decisions for Ergon Energy. We believe the below extract from this report has direct application for a number of constituent decisions in Ergon Energy's case, particularly operating expenditure.

> "I note that the regulatory task is made more challenging by the fact that the efficient outcome is itself constantly changing, and cannot be objectively determined. Consumer preferences and technologies change over time, thereby altering the most efficient mix of goods and services. Production technology also changes over time, reducing production costs and expanding the potential means by which a given mix of goods and services may be produced. In consequence, what constitutes an efficient outcome is constantly evolving.
>
> …
>
> By contrast, the economics textbook definition of efficiency is underpinned by the concept of perfect competition. A perfectly competitive market ensures that businesses are always producing at least cost, and are constantly entering and exiting to ensure that those that remain are producing the optimal mix of goods and services at least cost over time.
>
> However, beyond the textbook, companies' abilities to enter and exit markets, and to transform inputs into outputs efficiently will be constrained by their particular operating environments, and will vary over time. This is particularly true for businesses operating in industries that are capital intensive and where assets are long-lived, such as infrastructure businesses.

[7] Houston (Houston Kemp) (2015), *AER Preliminary Decision for Energex – Contribution to NEO and NEO Preferable Decision*, Expert report for Energex, 3 July 2015.

In addition, the attainment of perfect, frontier efficiency is not directly observable, and so the determination of what constitutes efficient expenditure is a matter of judgement…in practice businesses operate in markets that are less than perfectly competitive, and so this external gauge of whether a business is achieving frontier efficiency is not available.

In circumstances of less than perfect competition, the assessment of efficiency typically becomes a relative concept. A particular business' efficiency is measured by assessing its costs relative to those of other businesses. However, in practice, it is difficult to gauge the precise extent to which a business is performing efficiently.

Given these challenges, the role of effective incentive mechanisms within the regulatory framework is of particular importance in promoting the threefold efficiency objective at the foundation of the NEO."[8]

[8] Ibid, pp10-11.

Rate of return

Our revised Regulatory Proposal and submission used a rate of return incorporating an updated estimate of the risk-free rate based on a 20 day averaging period that ends on 22 May 2015. We believe the averaging period is sufficiently proximate to the beginning of the regulatory control period. Nevertheless, to the extent the AER has a preference for a more recent observation, we asked Frontier Economics to provide an additional updated report which provides an updated cost of equity using a 20 day averaging period ending on 17 July 2015.

This report, *An updated estimate of the required return on equity (July 2015)*, is attached to this submission (refer **Attachment 1**).

Operating expenditure

Benchmarking

Professionals Australia makes the following comment:

> "Benchmarking in the preliminary determinations consistently confuses low cost with efficiency. A low cost network provider that fails to provide a safe network is not efficient at all, and should not be encouraged by regulators."[9]

In support of our Revised Proposal and submission in response to the AER's Preliminary Determination we commissioned a number of additional benchmarking related studies from Huegin, Synergies and PWC. Since the submission of these materials, we identified some minor technical typographical errors in the Synergies report submitted on 3 July 2015 and incorporate with this submission for the benefit of the AER and stakeholders an updated version of that report (see **Attachment 2**).

We also commissioned Frontier Economics to conduct an independent peer review of the latest Huegin benchmarking studies included with our Revised Proposal and submission in response to the AER's Preliminary Determination. A copy of the Frontier Economics report is attached (see **Attachment 3**). Ergon Energy notes that this Frontier Economics report indicates no material concerns with the conclusions and findings made by Huegin.

We consider this latest Frontier Economics report adds further weight to our concerns about the AER's over-reliance upon a single point benchmarking-based estimate of operational expenditure derived from a model and OEF adjustment process that contains significant flaws.

Safety

The AER makes findings in its Preliminary Determination regarding Ergon Energy's operating costs that many of the firms considered 'at and above' the AER's benchmarking comparison point are also meeting their safety and reliability obligations at lower cost than Ergon Energy (see Attachment 7 to the AER's Preliminary Determination).

In reaching the above conclusion, Ergon Energy notes that the AER did not appear to reference, address or consider in any way the detailed submissions and Q&A responses that Ergon Energy provided to the AER regarding the challenges in effectively benchmarking safety performance and the apparent failure of the EI model to incorporate safety requirements into its benchmarking models.

As a result of the various deficiencies in the EI model, the AER has considered it necessary to make several material safety related OEF adjustments to its benchmarking results to seek to address the failures of the EI benchmarking model to adequately account for the requirements

[9] Professionals Australia (2015), *Response to the Australian Energy Regulator's preliminary determinations, Queensland distribution businesses 2015-2020, 2* July 2015, p9.

NEM DNSPs have to maintain safety. However, these OEF adjustments do not address the fact that safety obligations NEM DNSPs must meet and maintain will be addressed via both capital and operating expenditure, nor do they adequately allow for the various complexities in properly assessing the differences in safety obligations each NEM DNSP faces over time, including the matters highlighted in our various submissions to the AER, including the material contained in Q&Q AER_Ergon002.

As a result of the failure of the AER's analysis to adequately address the concerns Ergon Energy previously raised with the AER regarding benchmarking safety performance and the associated costs, in June 2015, Ergon Energy requested that the AER supply Ergon Energy with the AER's analysis supporting the above-mentioned conclusion, including requesting various statistical and other data supplied to the AER by the NEM DNSPs on vegetation management, LTIFR and fire starts.

At the time of issuing the request, Ergon Energy indicated that it was not clear how the AER's benchmarking assessment had allowed for safety and reliability outcomes that are the product of opex expenditure by itself, capex expenditure by itself or a combination of capex and opex expenditure nor how the relative costs of meeting safety and reliability obligations have been calculated or derived by the AER over the comparison period (2006-2013).

In responding to Ergon Energy's information request, the AER indicated to Ergon Energy on 19 June 2015 that much of its analysis to support this conclusion was contained in Attachment 7 – Opex Expenditure itself. In Attachment 7, the AER distinguishes between safety outcomes that may be linked to operating and capital expenditure categories at a high level only (e.g. replacement capital to address aging assets versus operating costs to conduct asset inspections) but does not seek to quantify or analyse the relative contribution that operating and/or capital programmes may make to changes in safety performance over time.

In fact, in reviewing the additional material supplied by the AER to Ergon Energy and Attachment 7 itself, it seems clear that the AER has not relied upon any information or material that has in fact analysed the safety or reliability expenditure outcomes achieved by the NEM DNSPs broken down across the different levels of capital and operating expenditure incurred by the relevant NEM DNSPs to meet their safety and reliability obligations. Instead, the AER analysis contains a mixture of information which relies on ESV and other data that references programmes and initiatives which represent a combination of capital and operating expenditure, including expenditure programmes supported by government grant funding made available to the Victorian DNSPs to address various bushfire mitigation requirements where such funding sources are not generally available to other NEM DNSPs.

Ergon Energy therefore has been unable to ascertain how the AER assessed that the firms considered 'at and above' the AER's benchmarking comparison point were meeting their safety and reliability obligations at lower operating cost than Ergon Energy over time.

Ergon Energy is concerned that the approach taken by the AER to its assessment of relative safety performance and efficiency of the associated operational expenditure may not generate outcomes that are in the long term interests of consumers.

Other stakeholders raised a similar concern in responding to the AER's Preliminary Determination. For example, Professional Australia highlighted the need to take into account the long term safety and reliability of the network when making decisions on efficient expenditure:

"While Professionals Australia supports efforts to maximise efficiency within energy networks and reduce cost burdens on consumers, these efforts must take into account the long-term provision of safe and reliable networks.

We call on the AER to protect the long-term interests of the community, rather than respond to short-term political pressure around electricity prices."[10]

The AER's findings about the safety performance of DNSPs is based on very limited information

The AER has sought to rely on some aggregated safety and fire start comparison data (LTIFR and fire start data) for the period 2009-2013 to draw conclusions that the safety performance of the private sector DNSPs seems higher than that of Ergon Energy. However, the AER has not examined the safety outcomes achieved by the NEM DNSPs at a more holistic level or considered the impacts of the performance of the DNSPs during the 2006-2009 period.

Nor has the AER considered any measures related to community electric shock incidents, public liability insurance levels, legal actions or fatalities that could be attributable to DNSP network asset failures, inadequate design standards or inadequate maintenance, inspection or operational practices.

For example, in drawing its conclusions that the Victorian networks are operating more safely (and more efficiently) than Ergon Energy, no allowance appears to have been made for the substantially higher public liability insurance costs that Ausnet (averaging $10Million per annum) and Powercor may now face, at least partly as a result of the substantial class action settlement payments made to resolve various claims arising from the 2009 Black Saturday bush fires. Ergon Energy's public liability insurance costs are considerably lower, however, the AER does not appear to consider these sort of litigation and insurance cost differentials in its assessment of the risk management and risk-consequence transfer approaches taken by the various businesses to these sort of safety and liability risks.

Likewise, in concluding that the Victorian businesses are operating at similar or improved safety levels and with greater efficiency than Ergon Energy, there is no discussion or recognition by the AER on the impacts on safety performance of the tragic losses caused by various network asset failures and operating practices before and/or during the 2009 Black Saturday bushfires, or the remaining class actions underway against Ausnet as a result of the 2014 bushfires. Instead, the AER considers the extent of bushfire fatalities and bushfires resulting from various network asset and operating practice failures only within a very narrow context to provide evidence to support the AER's claim of the relative cost disadvantage the Victorian businesses face in addressing bushfire risks.

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[10] Ibid, p2.

Additionally, some of the data relied upon by the AER for LTIFR comparisons has not been presented by the NEM DNSPs on a like for like basis, drawing into question the usefulness of the comparisons made by the AER. While the AER acknowledges the existence of many of these differences, it does not seem to analyse or consider the potential for the absence of like for like data to distort or reduce the overall usefulness of the comparisons it seeks to make. Nor does the AER examine other potential safety benchmarks such as LTIFR, TRI or AIFR to better understand the overall safety issues each distribution business might face.

Equally, the AER does not identify what level of opex cost reductions in safety are actually being achieved by the Victorian businesses relative to the Queensland DNSPs to achieve these LTIFR outcomes or consider the relative severity of the safety incidents across each business.

Ergon Energy's safety performance is comparable to or better than industry averages and many of its peers

Ergon Energy's analysis of industry trends identifies that it is performing well and, generally speaking, at or below the energy industry or distribution business average for LTIFR based on ENA and ESAA benchmarking made available to it (see **Attachment 4**).

In relation to the vegetation contact fire start data relied upon by the AER, Ergon Energy notes that the AER in fact concludes that the Queensland DNSPs perform at similar levels to the comparison firms on a per km line basis. It is not clear how this particular data set measures the relative level of safety operating costs incurred by each business to support a conclusion the Victorian firms are achieving this outcome at lower cost.

Ergon Energy also notes that in relation to the latest asset and ground fire data supplied by AusNet to the AER in its Enhanced Network Safety Strategy (Appendix 7B to its 2016-2020 EDPR) that the major causes of asset and ground fires in its network area are in fact high voltage fuse failures (37%) followed by cross arms failures (13%) – and then tree incidents (10%). It is not clear why the AER has chosen to measure vegetation contacts across the networks when this is not a major cause of asset and ground fires for this comparison firm.

Also, the AER makes little mention of the level of vegetation fire starts across each Victorian DNSP being at higher reported levels than those approved by the AER for the period 2011-2014 [refer to the ESV Reports noted by the AER] so again it is unclear how the AER has drawn the conclusion the Victorian DNSPs operate safely for less operating cost than Ergon Energy.

For example, in the ESV 2013 Report (released June 2014):

- Powercor and Ausnet exceeded the number of vegetation fire starts approved by the AER by 102 per cent and 13 per cent respectively,
- the Victorian electricity businesses overall reported a 159 per cent increase in vegetation fires in HBRAs and a 260 per cent increase in vegetation fires in LBRAs since 2011 [page 70],
- in 2013 the Victorian businesses exceeded the AER f-factor target for fires due to electricity network [925 v target of less than 870],

- the AER’s target number of vegetation fires (five year average) was exceeded [298 v target of less than 157] [see ESV page 61] and

- the total number of asset failures increased by 103% in two years (from 2011-2013) [see ESV page 61].

The AER wrongly attributes Victorian cost increases to regulatory changes following the Black Saturday bushfires

Ergon Energy notes that in undertaking its assessment of the safety outcomes of the various businesses, the AER has not examined the impacts of the 2006-2009 period on opex levels in Victoria, and seems to consider that post-Black Saturday 2009 changes in bush fire regulations have driven up opex levels of the Victorian DNSPs substantially during the latter part of their current regulatory control period.

However, during the 2006-2009 period, both the ESC and Victorian DNSPs acknowledged the need for a step change increase in opex funding to enable the Victorian DNSPs to meet various electrical safety compliance obligations in circumstances where compliance issues already existed. These safety compliance issues pre-date the regulatory changes that followed the Black Saturday bushfires, having been identified as part of a major audit conducted during the 2001-2005 period by the applicable electrical safety regulator at the time, and discussed in detail in the 2006-2010 re-set decision by the ESC [pp 214 ff]. Following these findings, the ESC granted each Victorian DNSP a substantial increase in its opex to enable the applicable DNSP to meet these pre-existing safety compliance obligations.

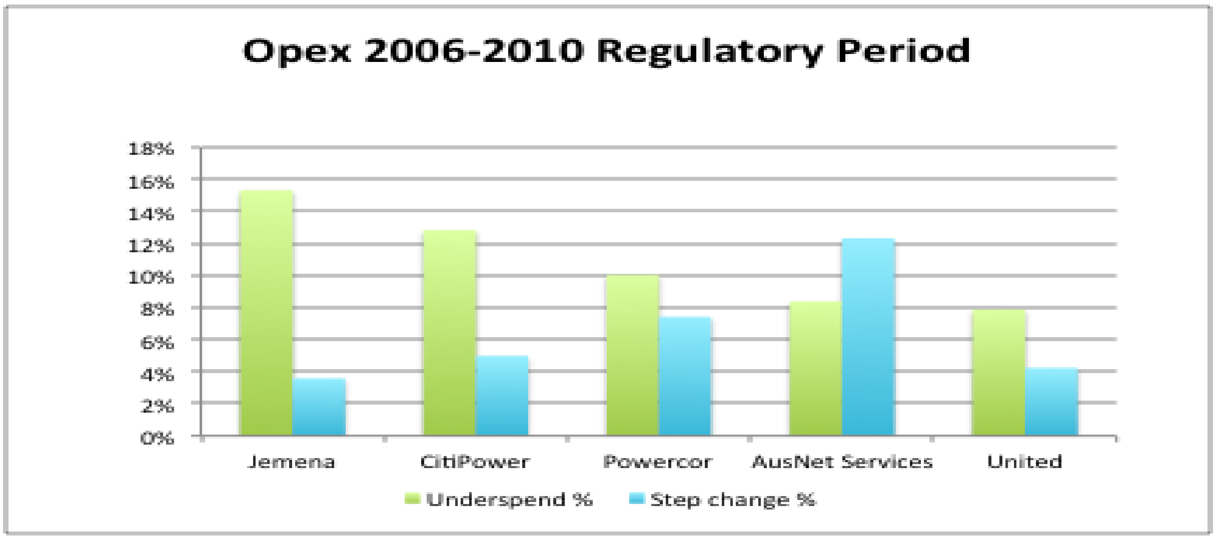
As shown in the attached table, extracted from the ESC 2006 determination, expenditure on aerial service lines and earthing is a major driver of the increase in expenditure for AusNet and Powercor in particular. These increases in costs are associated with bringing compliance *up to* the Electrical Safety Regulation standard, not exceeding it. These costs also have nothing to do with responding to the regulations introduced following the 2009 bush fires in Victoria.

Table 6.20: Step changes in operating expenditure for safety compliance, all distributors, 2006-10, $million, real $2004

	AGLE	CitiPower	Powercor	SP AusNet	United Energy
Aerial service lines	0.0	1.7	8.4	5.0	0.4
Tramway assets	0.1	0.3	0.0	0.0	0.1
Underground lines	0.3	0.3	0.3	0.3	0.3
Aerial substations	0.3	0.4	0.0	0.0	-0.1
Earthing and electrical protection	3.9	2.0	9.5	9.5	8.6
Inspection and testing of earthing	0.3	0.7	4.0	0.8	0.0
Total	**4.9**	**5.4**	**22.2**	**15.6**	**9.3**

Pre 2006 expenditure for the Victorian Distributors therefore reflects the costs associated with **not** meeting various compliance obligations calling into question findings by the AER that the levels of expenditure observed in its benchmarking analysis are realistic and those of prudent and efficient distributors meeting their regulatory obligations. The non-compliance issues identified by the Victorian distributors resulted in the AER awarding significant step change funding to ensure the distributors earned the revenue required to meet their obligations efficiently. Of the $137M (Real $2004) step change allowance awarded to the Victorian DNSPs, as part of the 2006 Regulatory Determination, Real $2004 64M (operating costs only) was provided to meet safety and electric line clearance regulations.

Published data indicates that compliance with the legislation took the Victorian distributors time to achieve and this is reflected in their underspend against the regulatory allowances during the period, particularly in 2006. The graph below (extracted from the 2011 regulatory determination) shows the allowances and actual spend of the Victorian distributors over the 2006-2010 regulatory period, suggesting strongly that their actual expenditure did not fully reflect the efficient costs previously associated with meeting their obligations.



By including actual expenditure data for the Victorian business for the 2006 to 2010 regulatory period without recognising the significant underspends against those allowances and previous evidence accepted by regulators as to the costs necessary to meet compliance, the AER is inappropriately and uncritically assuming the expenditure incurred actually reflects the realistic and efficient costs of a distributor prudently meeting its obligations.

We also note that as part of the 2011 Regulatory Determination the Victorian DNSPs received further step change funding of $378M (Real $2010), of which $206M related to Electricity Safety Regulations. A large proportion of the step change associated with the Electricity Safety Regulations related to the cessation of exemptions that had applied during the 2006-2010 period, suggesting that even with the additional funding provided for the 2006 – 2010 determination, the expenditure allowance still didn’t reflect the true efficient costs associated with complying with regulations.

In light of the various flaws in the AER’s analysis identified by Ergon Energy, and given the overall sensitivity to the time period selected by the AER and its consultants to support its benchmarking models, Ergon Energy commissioned Huegin to undertake a review of the change in opex costs of the Victorian businesses during the 2006-2009 period.

In a report addendum from Huegin included with our submission on the AER's Preliminary Determination, Huegin had previously identified that:

*"Removing the first three years of historical data (2006-09) - the period prior to national regulation and coincident with many changes in obligations - but otherwise applying the AER SFA CD model as per the AER process (Model 8) yields a result of **$1,774 million** (close to the Ergon Energy revised forecast)."*

Huegin was also subsequently asked by Ergon Energy to further review the history and background surrounding other increases to opex accepted by the AER as justifying the need for its BushFire OEF, in order to assess the impacts this has had on the benchmarking results presented by the AER.

A copy of this report is attached [see **Attachment 5**] and this report builds upon and further validates the findings made by PWC on this aspect as part of our submission in response to the AER's Preliminary Determination (EXP 10.10).

In relation to the AER's proposed BushFire OEF, PWC concluded as follows:

"An OEF adjustment for differences in bushfire management practices is not required as there is no evidence of a material cost differential between Ergon Energy and its peers in Victoria.

The cost of managing bushfire risk is not correlated to the severity of bushfire events alone. The costs of managing bushfire risk are similar for all network service providers, due to similar duty of care obligations. Further Ergon Energy has similar practices to the Victorian service providers in exercising its absolute duty of care to its customers and the community."

In their latest report, Huegin (see **Attachment 5**) reach a similar conclusion to PWC:

"The fact that the consequences of a bushfire in Victoria may be more catastrophic than some other states is accepted. However this does not constitute evidence that network bushfire mitigation controls are more expensive in Victoria than Queensland, particularly when the majority of those controls relate to maintaining a distance between vegetation and assets - something all networks must achieve for outage and other safety reasons, not just for bushfire risk management.

Using the aggregated value of the step changes and cost pass through events as the basis of the OEF adjustment erroneously ascribes the costs associated with the change in vegetation clearance requirements to the exogenous conditions that increase bushfire risk management costs. Whilst the bushfire events of 2009 certainly hastened changes in the ELCC in 2010 and the associated focus on compliance that caused the step change in costs, they did not cause the costs. Given that the line clearance code changes account for more than 80% of the costs that the AER use ($205 million12 out of a total of $245 million13) to calculate the bushfire OEF, there is every chance that the AER has overestimated the value of the OEF through incorrectly ascribing a change in compliance and enforcement requirements as an exogenous attribute of the operating environment. This is not to say that the change in enforcement and compliance requirements is not a legitimate difference in circumstance itself, however the AER has not presented any evidence that the requirements before or after the introduction of the 2010 version of the ELCC are more or less stringent as those that Ergon Energy adheres to. Demonstrating a difference between the requirements for Victoria between 2005 and 2010 does not inform any such comparison between Victoria and Queensland. Similarly, there is no evidence that demonstrates that the exemptions allowed under the 2005 version of the ELCC did not represent a cost advantage to the Victorian businesses between 2006 and 2010 rather than a cost disadvantage to the businesses post-2010."

The regulatory obligations relating to bushfire risk mitigation in Victoria and Queensland are similar

In addition to the pre-Black Saturday 2009 issues identified above, Ergon Energy has reviewed a number of the regulatory obligations imposed on the Victorian businesses following the findings of the VBRC, as well as a number of the capital expenditure proposals incorporated into the latest 2016-2021 Regulatory Proposal from AusNet Services. Ergon Energy focussed on AusNet Services in particular, given the reliance the AER places on this firm as a benchmark comparison point.

This review suggests that many of the same safety and engineering drivers that have led Ergon Energy to adopt various SWER safety initiatives and asset renewal programmes have been present on its network and adopted by Ergon Energy well before, and many years after, the 2009 Black Saturday bushfires without the need for prescriptive safety legislation to be established, as apparently was the case in Victoria following those very tragic events.

Based on the material released by the VBRC it also appears that some of the post-Black Saturday obligations cited by the AER as increasing operational costs for the Victorian businesses, to their relative disadvantage, were in fact measures that in the main required the Victorian businesses to:

- resume practices they had been prudently adopting for many years prior to February 2009 to address bushfire risk, but had ceased undertaking in order to reduce costs while keeping risks at an 'acceptable' level (rather than perhaps reduce the risks so far as was reasonably practicable); or

- address identified inadequacies in existing practices.

Below is an extract from the Final VBRC Report that brings into sharp relief the above comments and the impact of the changes in operational asset inspection processes over time by a number of the Victorian DNSPs. This extract also seems to raise questions regarding the appropriateness and rationale of various risk management practices adopted by the Victorian DNSPs:

> *"The State Electricity Commission of Victoria introduced a three-year inspection cycle following the 1977 bushfires. In about 1995 a five-year cycle for areas that were not deemed a fire hazard was introduced. In 1999–2000 both Powercor and SP AusNet moved to a five-year cycle for fire hazard areas, having concluded they could conduct fewer inspections without increasing the level of risk; the rationale for this was the improved reliability of distribution assets and improved inspection processes. In contrast, both expert opinion and the network operators' analyses support a finding that shortening the inspection cycle would appreciably reduce the risk of assets failing in service and consequentially reduce the risk of bushfires starting as a result of failed assets.90 [Ergon Note: This style of footnote contains a hyperlink to the source document from the VBRC report]*
>
> *International expert Professor Nicholas Hastings explained that an inspection regime's suitability for limiting asset failure should be assessed by reference to the extent to which the regime allows incipient failures to be detected before they proceed to full functional failure—that is, the asset failing while in service. The regime should take into account how the assets fail, how failures can be detected and the effect of failure. Some failure modes*

lend themselves to early identification by condition monitoring and allow time for remedial action before full functional failure. For other failure modes, however, there might be little or no practical or economic way of identifying potential failures.[91]

The risk that assets will fail during service is substantially determined by the length of the inspection cycle. This is because, assuming inspection effectiveness remains constant, the average number of degradation failures in the system will be proportional to the length of the inspection cycle.[92]

Any reduction in the length of the inspection cycle will reduce risk, even if the effectiveness of inspection does not improve. Increasing the inspection cycle from three years to five years will cause a 66 per cent increase in random failures in the system by the time of inspections. Professor Hastings explained that with time network components degrade and that in the short to medium term it should be assumed that defects accumulate at a constant rate. Over three years, for example, the average number of defects in the system will be three times as high as for a one-year period (assuming no inspections during that time). Those results follow from the mathematical modelling supported by reliability-centered maintenance, or RCM, theory.[93]

The likelihood of detecting degradation failures also increases if the effectiveness of the inspection methodology improves, thereby reducing the risk of in-service failure.[94]

A 1997 RCM study of Powercor's network produced results consistent with Professor Hastings' conclusions. Powercor calculated it could reduce the frequency of inspections and maintain the existing level of 'acceptable risk' of in-service failures by increasing the assumed effectiveness of its inspections from 50 to 65 per cent. The study shows that reducing the number of degradation and in-service failures is demonstrably achievable by shortening the inspection cycle. A return to a three-year inspection cycle (even if inspection effectiveness does not improve) would result in a very substantial—about 70 per cent—reduction in the number of in-service failures.[95]

The 1997 RCM study also showed that a substantial improvement in the effectiveness of asset inspection significantly reduces the risk of in-service asset failure. Powercor's analysis shows that, if the improvements in effectiveness foreshadowed in 1997 had been made without extending the inspection cycle, the projected number of in-service failures each year would have reduced from 500 to 84.[96]

Energy Safe Victoria continued to approve five-year inspection cycles on the basis that there had been 'no obvious increase in failures' and that trends in in-service failures remained relatively consistent and 'at a relatively low level'.[97]

Although either one of these two factors alone will considerably reduce the risk of in-service failure, the distribution businesses made a deliberate choice to offset improvements in one (the inspection effectiveness) with relaxation of the other (the inspection cycle). In practice, they have forgone an opportunity to improve safety in order to reduce costs.

It is not satisfactory that the distribution businesses can decide that a specific level of bushfire risk is 'acceptable' and rely on the benefit of improved processes and technology to maintain that risk level (instead of reducing it) in order to decrease their operating costs or increase their profits. Distribution businesses should take all reasonable opportunities to reduce bushfire risk. In particular, they should not trade improvements achievable by shortening the inspection cycle against those arising from improved inspection methods.

No inspection regime will detect all failures during inspections, and improvements in processes and equipment will always be limited by the effectiveness of inspections.

Although it is evident that Powercor did improve the effectiveness of its inspection regime at the time it moved to a longer inspection cycle (as demonstrated by the absence of obvious increases in failure rates), even then it could assume that each inspection was only 65 per cent effective, meaning it assumed that about one-third of defects would still be missed by the improved inspection process. The report of the 1997 study observed, 'The cyclic program intervals are generally too long to be fully effective but significant risk reduction is provided by the reports which should be made'. The very same observation was made in a follow-up study in 2003, after the introduction of the five-year cycle.98

Additionally, the rates of failure of some important network components are climbing as those components age. Increasing failure rates warrant increased opportunities for detection.

It is appropriate that the inspection cycle is responsive to differentiated risk. It is also important, however, to avoid complicating the inspection process with too many varying intervals. The Commission considers that a suitable balance would be achieved if a shorter inspection cycle were adopted in all areas of high bushfire risk, in keeping with the previous standard of a three-year interval, while directing specific programs at assets that are at high risk for other reasons.99The Commission also considers that the State should press the Australian Energy Regulator to allow distribution businesses an adjustment to their price determination on the basis that a move to a shorter inspection cycle is a material change in obligations and necessitates additional expenditure.

RECOMMENDATION 28

The State (through Energy Safe Victoria) require distribution businesses to change their asset inspection standards and procedures to require that all SWER lines and all 22-kilovolt feeders in areas of high bushfire risk are inspected at least every three years."

While the VBRC Report characterises a move to shorter inspection cycles as a material change in obligations, in truth this appears to be a recommendation designed to remedy a decision made by the Victorian networks to reduce costs by adopting longer inspection cycles.

This highlights an important point in relation to a comparison of regulatory obligations in Victoria and Queensland. It is clear that regulatory obligations in Victoria have become more prescriptive in recent years than those in Queensland. This does not mean they are more burdensome or more costly to comply with.

A comparison of vegetation management obligations is a good case in point. As the AER has noted, the Queensland Electricity Safety Regulation 2013 requires Queensland DNSPs to ensure that trees and other vegetation are prevented from coming into contact with their electric lines where it is likely to cause injury or damage to property. In Victoria, vegetation management obligations are more prescriptive, setting minimum clearance spaces for the power lines that are stricter in areas of higher bushfire risk.[11]

The AER's finding that the Victorian obligation is more burdensome (and therefore more costly to comply with) is only tenable if it proceeds on the assumption that the Victorian laws require DNSPs in that jurisdiction to do *more than is necessary* to ensure that trees and other vegetation are

[11] Preliminary Determination, page 7-204

prevented from coming into contact with electric lines where it is likely to cause injury or damage to property.

We do not believe this view is tenable. As noted by Huegin, the major change in compliance costs, recognised by the AER in 2010, resulted from the removal in the 2010 ELCC of various exemptions that had previously existed. However, the fundamental obligation under the ELCC was, and is comparable to what is required of a Queensland DNSP. Indeed the AER, in its Preliminary Determination, that the vegetation management obligations imposed on Ergon Energy were more burdensome than those in Victoria, because Queensland DNSPs did not share this responsibility with other bodies (e.g. local councils).[12]

The AER has failed to take into account differences in opex v capex

The VBRC is equally critical of the prudency and effectiveness of various other pre-2009 Victorian NSP practices that have led to changes in regulations to ensure there is no doubt about the standard required by those businesses and to seek to avoid a tragic repeat of the impacts of the 2009 Black Saturday events. As previously indicated to the AER, it is unclear how these sorts of issues have been addressed by the approach the AER has taken to benchmarking operational costs and finding that the comparison firms are generating similar (or better) lower cost safety outcomes than Ergon Energy.

As mentioned earlier, it is clear that safety performance outputs by NEM DNSPs represent a complex combination of operating and capital expenditure inputs over time, including asset replacement costs. However, in considering the AER's benchmarking results it is unclear how the AER has allowed for this in assessing the relative performance and cost of maintaining safety of each DNSP. In fact, it seems to Ergon Energy that the AER's analysis has completely (and inappropriately) discounted the impact of capital expenditure on its benchmarking of NEM DNSP safety performance in the Preliminary Determination.

A comparison between Ergon Energy's and AusNet's asset renewal programmes reinforces the important contribution to safety performance made by capital expenditure

To help understand the impact of the above-mentioned significant gap in the AER's analysis, Ergon Energy undertook a review of Ausnet's latest safety strategies in this area.

Ausnet has developed an Enhanced Network Safety Strategy (ENSS) as a result of drivers of its Electrical Safety management Scheme (ESMS), its Bushfire Mitigation management Scheme and Work Health and Safety Management systems (HSEQ). Ergon Energy's October Proposal and its Revised Proposal and Submission contain details of the various safety plans and strategies proposed and historically undertaken by the company, and these appear to be broadly similar in approach to the approach outlined in the Ausnet ENSS.

In undertaking this analysis, including of the various asset renewal programmes proposed by both Ergon Energy and AusNet in the 2016-2020 period it is apparent to Ergon Energy that both companies are proposing similar safety driven capital expenditure initiatives to address similar risks and issues.

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[12] Preliminary Determination, page 7-225 to 7-227

The main difference in the approach between the two companies in relation to bushfire risk seems to be that in articulating the need for the relevant expenditure, in addition to applicable safety and engineering drivers, AusNet is also able to draw on more prescriptive legislative obligations and VBRC directives to support the same type of expenditure Ergon Energy has incurred or is proposing. Ergon Energy is mainly supporting the business need for these safety driven investments and long-held practices more generally based on NER requirements, the existence of appropriate safety drivers and prudent and good electrical engineering practices.

Below is a comparison of the various asset renewal programmes contained in the ENSS against the approach adopted by Ergon Energy in relation to the same sort of safety issues.

In reviewing these programmes, Ergon Energy notes that the AER's consultants EMCa have previously accepted that Ergon Energy's capex unit rate replacement costs are generally at benchmark levels. In many cases, our average unit rate costs appear to be similar to, if not below, many of the capex costs of the comparison firms.

In some cases, volume replacement rates proposed by Ergon Energy for similar types of assets appear to be lower than those proposed by AusNet. It is not clear at all to Ergon Energy how the AER has allowed for the impact of these differing capital expenditure programmes (as well as those across all other DNSPs) on its assessment of safety-related operating cost expenditure being incurred by the comparison firms relative to Ergon Energy's safety-related operating costs.

We outline below other observations relating to the asset management practices of AusNet and Ergon Energy.

Pre-emptive replacement of neutral screened (NS) service cables

Ausnet has identified that some 16,000 NS Service cables are to be replaced as a result of a high contribution to known faults. Ergon Energy observes this is part of a longer term strategy to remove these assets which are considered to be at end of life. Ergon Energy has also recently proposed to replace 3126 Neutral Screened services due to a systemic insulation degradation issue which are exhibiting end of life symptoms. Both Ausnet and Ergon Energy propose replacements driven by safety drivers. Ergon Energy supports Ausnet's approach.

Crossarm replacements

Ausnet has proposed to replace 17,000 HV crossarms and 29,000 LV crossarms over the next regulatory period – replacing some 46,000 wooden crossarms with steel equivalents in high risk bushfire areas. Ausnet has some 383,000 power poles and presented statistics suggesting that crossarms failures introduce approximately 200 potential fire start situations per annum, and that crossarm failures are the actual cause of fires around 13% of the time.

At Ergon Energy, Dangerous Electrical Events arising from crossarm/pole top issues and failures average around 160 events per annum. Ergon Energy has a population of some 980,000 power poles and expects to replace 45,200 crossarms, based upon forecasts of actual failures, condition monitoring and failure analysis. This suggests Ergon Energy's replacement rate per 1000 poles is around 40% that required by Ausnet. With any large population of low value individual assets, a compromise occurs between the routine costs related to necessary inspections to ensure safety and the replacement cost of those assets.

Replacement strategies aimed at mitigating public safety risk situations, such as exposure to fallen energised conductor, and bushfire initiations, particularly for large volume low value individual assets, will generally be more prudent that extensive condition monitoring.

Given that more than 90% of Ausnet's network (by route length) is rural and that 80% is located in designated high bushfire risk areas, Ergon Energy considers that Ausnet's approach to replace crossarms with steel equivalents appears sound. Ergon Energy's service area does not encompass such a high proportion of high risk bushfire area, and Ergon Energy continues to employ timber and composite fibre crossarms as the most prudent and cost effective replacement options.

EDO Targeted Fuse Replacement

Ausnet proposes to replace 9500 EDO fuse disconnectors. Ausnet, like Ergon Energy, has observed that EDO fuses are a source of bushfire ignition. Like Ausnet, Ergon Energy has observed that with these assets types, candling and fuse hang-up become significant root causes of fire ignition, and has also proposed plans to replace 1,587 EDO Fuses in high bushfire risk areas.

Given the risk presented by EDO fuse failures, Ergon Energy considers that Ausnet's replacement approach is prudent and appropriate.

Conductor Replacement

Ausnet has identified that conductor failures have been a significant cause of major bushfires. They have observed that their replacement rate is sufficient to arrest and hold steady the rate of actual failures; however are finding that the rate of reported damage is increasing. Ausnet have had targeted programs of conductor replacement progressing for some time, and are focusing upon Copper (Cu) and galvanised steel (SC/GZ) asset classes. Ausnet proposes to replace 2,060 kilometres of conductor during the 2016-2020 regulatory period – around 4.5% of its 44,800 circuit kilometres of overhead and underground lines.

Ergon Energy has focused upon replacement of the smaller diameter Cu conductor which has figured prominently in conductor failure records. Ergon Energy has imposed live working bans on the smaller Cu conductor due to the safety risks of failure, and observes this appears to be a similar outcome for Ausnet. Ergon Energy is proposing to replace some 1,207 kilometres of conductor in the 2015-2020 regulatory period (less than 1% of its 160,000 circuit kilometres).

Ergon Energy notes the risks to public safety and instances of fatalities caused by failures of LV or aged copper conductor in Queensland and Western Australia and considers that Ausnet's proposal for replacement appears prudent.

Vibration Dampers and Armour Rods

In 2011, the ESV has issued a directive to Ausnet to plan for the fitting of distribution armour rods and vibration dampers. The program commenced and stage 1 of the program was to be completed by 2015. Stage 2 is now intended to be addressed in the 2016-2020 regulatory period.

Ergon Energy considers this program to be a prudent exercise. Ergon Energy has employed armour rods and vibration dampers throughout its network for many years and firmly believes this has contributed to life extension and overall longevity of its conductor assets. There will, of course be reduced benefit for Ausnet when applied to already aged assets as the annealing and embrittlement is a cumulative deterioration effect, however there remains significant potential to slow the ongoing deterioration impacts.

There has been a cost over the years for Ergon Energy to design, install, inspect, maintain and repair these assets. The use of vibration dampers and armour rods is considered a basic and essential element of engineering design that promotes asset safety and longevity. This extra expense has impacted Ergon Energy's RAB and opex expenses. In turn, this has influenced trending results for partial performance indicators and even MTFP benchmarking. Ergon Energy observes that what are now recently mandated requirements in Victoria have been considered good engineering and operating practice in Queensland for many years.

LV Spacers

Ausnet has LV Spacers installed on its assets since 1983 and intends only routine maintenance and replacement as a result.

Ergon Energy installed LV Spacers in areas most likely to suffer cyclonic winds and storms. It has observed the spacers are particularly effective under high wind conditions and found that during the 2010-2015 regulatory period, LV spacers considerably reduce LV mains conductor failure rates. Particularly after severe storms, this has significantly improved public safety from fallen energised power lines. It was also observed they contributed to the longevity of even the small Cu conductor. Ergon Energy has now proposed to install LV spacers in other major areas to mitigate such risks so far as is reasonably practical.

Clearances

Ausnet submitted a plan to the ESV to survey 10,242 spans to identify circuit clearances. This was later updated to 14,905 spans and with an expectation that some 400-500 spans (3%) yet to be identified that will require some form of augmentation to ensure adequate and safe clearances exist.

In addition, Ausnet has identified that some 1,210 conductor and service cable clearances are below current design standards.

Ergon Energy has employed a somewhat subjective test for span clearances for many years and recently introduced the use of LiDAR and associated processing to improve the situation. Ergon Energy's entire network has been evaluated for span, circuit and conductor clearances and has identified as a high risk almost 15,000 separate spans (~1.5%) require some form of correction (conductor retensioning, pole straightening, inter-poling etc.). This inspection will be done annually, as the LiDAR is employed to identify vegetation issues.

Ergon Energy is in no doubt that correction of such issues is a significant exercise, and notes that low conductor clearance increases the risk of public contact and shock. In Queensland, there is a statutory imperative to fix these issues. In Victoria, it appears there is a risk assessment strategy employed to identify priority and management approach. Ergon Energy considers that Ausnet's approach appears prudent.

SWER Earths

Ausnet has presented that a number of SWER earthing systems exceed the Upper Specification Limit. This limit appears to be typically set at 30 or 40 ohms. Ausnet has proposed a program to progressively remediate around 318 non-compliant earths each year during the 2016-2020 regulatory period.

Ergon Energy has a routine SWER earth testing program in place. It is currently governed by a Code of Practice standard that sets the Upper Specification Limit at 20v. Ergon Energy has recently proposed a program for the 2015-2020 regulatory period with a final exercise to achieve compliance to the new level and a change in the USL to 30v and has been working actively to monitor and achieve improved compliance rates against applicable requirements over time.

Ergon Energy notes that Ausnet also appears to be actively managing earthing system assets to achieve compliance, and considers this approach to be prudent.

Poles

Ausnet proposes replacing some 15,000 poles of a population of 383,000 during the 2016-2020 regulatory period. This equates to a reliability level of the order of 96%. Ausnet has budgeted $170M ($2014 direct) for this purpose, or around $11.3K per pole.

Ergon Energy forecasts to replace around 5400 poles in some 980,000 poles for the regulatory period 2015-2020. Ergon Energy's pole reliability is the order of 99.4%. Ergon Energy's cost to replace a pole is $3001 ($2014 direct).

Major Asset Class Replacements

Ausnet has proposed to replace 70 of the oldest 22kV oil circuit breakers; 12 of the oldest 66kV oil circuit breakers. Ausnet has indicated its risk evaluations and replacement decisions are based upon risk and condition. Their documented approach appears to be chiefly aged related.

Ausnet has proposed to replace 11 of the oldest transformers. Ausnet has indicated its risk evaluations and replacement decisions are based upon risk and condition. Their documented approach also appears to be chiefly aged related.

Ausnet operates 53 zone substations. Its replacement allowance for this defined work is $57.6M ($2014 direct)

Ergon Energy operates some 370 substations and almost 700 zone transformers. Ergon Energy has established CBRM analysis to identify those deteriorated assets near end of life and that present highest risk for service delivery.

Ergon Energy has proposed to replace 163 circuit breakers, chiefly problematic 66kV oil circuit breakers and 11kV oil circuit breakers. In addition, it expects that 22 (lower risk) circuit breakers are likely to fail in service during the 2015-2020 regulatory period.

Ergon Energy has proposed to replace 25 zone substation transformers. In addition, up to 55 (lower risk) transformers are likely to fail in service during the 2015-2020 regulatory period.

Ergon Energy observes that its replacement rates appear to be substantially lower than Ausnet's, although Ergon Energy's approach is derived from a combined condition and risk assessment. In addition, Ergon Energy's direct unit rate replacement allowances for these assets appear to be almost half of Ausnet's unit replacement rates. Even after overhead allocations, Ausnet costs appear to be of the order of 40% higher that Ergon Energy's cost. The significant difference is likely to be due to overall volumetric quantities and different safety and design criterion.

Treatment of Overheads

From the data provided, Ausnet allow for an overhead rate of 15%. Ergon Energy employs 48%. Significantly, however, Ausnet's direct costs appear to be much higher that Ergon Energy's direct costs. For example,

Pole Replacement

	Overhead	Direct Cost	Actual Cost
Ausnet	15%	$11.3k	$12.99K
Ergon Energy	48%	$3.0K	$4,44K

This example demonstrates that overhead allocation comparisons between NSPs are somewhat moot. Actual costs and expenses must be considered when making comparisons.

Concluding Remarks on Safety

Ergon Energy customers' consistent feedback to the company is that they do not want compromised safety. Recently, through the Bushfire Royal Commission in Victoria, and the following ESV requirements, it is clear that Victorian customers have the same sorts of expectations.

The AER has undertaken benchmarking analysis which, in the AER's view, indicates that:

- Victorian DNSPs have been safer than Ergon Energy;
- Victorian DNSPs have been more efficient than Ergon Energy in their expenditure on safety and bushfire risk mitigation; and
- there has been an increase in the cost of complying with regulatory obligations relating to safety and bushfire risk mitigation in Victoria following the VBRC.

In fact, the evidence before the AER shows that that none of these findings are accurate. The level of performance revealed by the AER's analysis does not reflect the necessary balance between prudency and efficiency which is required by the expenditure criteria in the NER. Taken as a whole, the material before the AER seems to show that the historical levels of operating expenditure incurred in Victoria (which included recurrent expenditure for safety and/or bushfire mitigation) over time were not consistent with the levels of what a benchmark DNSP would have efficiently and prudently spent to meet the expenditure objectives.

The regulatory changes in Victoria (the bulk of which were not a direct response to the VBRC) imposed regulatory obligations in Victorian DNSPs that were more prescriptive, not more burdensome.

Many elements of what are now recently mandated requirements in Victoria have been considered good engineering and operating practice in Queensland for many years. Ergon Energy also notes the AER's intent to drive all NSPs towards efficient performance by employing benchmarking techniques.

However, the current approach adopted by the AER fails to adequately assess the combined impacts of capital and operational expenditure on safety outcomes and also fails to adequately account for the impacts of major jurisdictional safety issues (including OHS harmonisation and Bushfire Risk Management) on the overall efficient and prudent costs of each NSP. The inappropriate overemphasis placed by the AER in its benchmarking on effectively equating lowest cost outcomes with efficiency and prudency may in fact send signals that drive NSPs towards asset management and operating practices that unnecessarily increase risk and are not necessarily good engineering practice or safe long term operation.

In its 2014 Report, ESV also highlighted the competing pressures the regulatory framework and desires of the community, industry, governments to address the impacts of growing electricity prices place on effective risk management and safety across aging distribution networks:

"Observations and commentary in this, ESV's fourth annual safety performance report, are set against a backdrop of an increasing expectation on MECs to better manage risk, deliver returns to shareholders, as well as provide a more efficient and reliable service to the community – all in the face of increased weather volatility and extremes.

The reduction in electricity consumption in recent years has only heightened the natural tensions and pressure on MECs and the economic regulator to ensure balanced outcomes are achieved. These will be matters for consideration by industry, government and regulators as they approach the next five-year price determination to be conducted by the AER over the coming year into 2015.

The saw-toothed pattern of investment that was identified last year persists. This is where investment is lower immediately after a regulatory price determination. This may reflect, in part, the features of the five-year cost-of-service pricing regime and the adequacy of incentives to take a longer-term and more consistent view to managing long-life assets, including developing the resource and skills base for capital programs as well as making the necessary investment in higher-risk new technologies. …

Ultimately, the primary responsibility for addressing the competing priorities of shareholders, reliability, service and safety still lies with the MECs. ESV observes however that the pressure to take greater risk, especially with an ageing network, means that the current approaches both to the administration and design of economic regulation may not be sustainable in the longer term."

Ergon Energy therefore considers that the AER's analysis of bushfire risk mitigation costs in Victoria, compared to other jurisdictions, highlights the flaws in the AER's use of benchmarking, combined with increasingly detailed and complex operating environment factor adjustments, to determine forecast opex allowances. A sensible comparison of prudency and efficiency between jurisdictions is very nearly impossible.

More specifically, if the AER is determined to persist with its use of benchmarking to determine forecast opex allowances, Ergon Energy considers that the analysis outlined above and set out in the attached reports must lead to the removal of the OEF adjustment between Queensland and Victoria for bushfire risks.

Professional Australia also submitted on the need for the AER to take into account the long term safety and reliability of the network when making decisions on efficient expenditure:

> "While Professionals Australia supports efforts to maximise efficiency within energy networks and reduce cost burdens on consumers, these efforts must take into account the long-term provision of safe and reliable networks.
>
> We call on the AER to protect the long-term interests of the community, rather than respond to short-term political pressure around electricity prices."[13]

Professionals Australia provides a timely reminder that consequences of an unreliable and unsafe network are severe:

[13] Ibid, p2.

“A tragic and recent reminder of the risks and dangers associated with electricity assets came as recently as 4 February 2015 when two people were killed and several others injured when a transformer exploded in the Galleria shopping centre in Perth. This incident has resulted in regulator changes and new processes, however these have come too late to prevent the loss of lives. The proposed revenue cuts will hinder the ability of distributions businesses to address safety issues in a proactive manner, causing further deterioration of networks and placing more lives at risk.”[14]

[14] Ibid, p7.

Metering

Call out fees

In the regulatory control period 2010-15, Ergon Energy applied the relevant 'Wasted Truck Visit' charge in circumstances where we attended a customer's premises and were unable to perform the job due to no fault of our own (e.g. due to a locked gate). This included situations where we attended a customer's premises to perform a final meter read. The 'Wasted Truck Visit' charges allowed Ergon Energy to recover at least the efficient costs we incurred in providing the service, in accordance with section 7A of the NEL.

In its Framework and Approach Paper for the regulatory control period 2015-20, the AER decided that "distributors are able to charge customers for a wasted truck visit under our classification of the related alternative control service".[15] Accordingly, Ergon Energy considers that we are able to charge a call out fee for final meter reads which reflects the opportunity cost of the fleet and labour resources used.

The AER has not explicitly approved a call out fee for final meter reads in 2015-16. Ergon Energy therefore intends to write to the AER to seek approval, in accordance with section 8.2 of our 2015-16 Pricing Proposal. If approved, Ergon Energy expects the AER's Substitute Determination will recognise the application of the call out fee(s) during the regulatory control period 2015-20.

Finally, Ergon Energy notes that we have proposed call out fees for our new fee based services and quoted service for the installation and provision of Type 5 or 6 meters in our revised Regulatory Proposal. In the event the AER maintains its current upfront metering charge structure, Ergon Energy believes the AER should introduce a call out fee. This is consistent with the approach to call out fees for other Direct Control Services.

[15] AER (2014), *Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014, p49.