Submission to the AER on its Preliminary Determination

Corporation Initiated Augmentation

Summary

This document sets out Ergon Energy's response to the Australian Energy Regulator (AER) on Augmentation Expenditure.

Ergon Energy accepts the AER's Preliminary Determination in relation to:

- The Network Reliability forecast expenditure as it is consistent with our proposed approach in our Regulatory Proposal.
- The Quality of Supply forecast expenditure as it is consistent with the approach proposed in our initial Regulatory Proposal.

However, we challenge the AER's decision:

- In the areas of reduced expenditure forecast for Subtransmission and Distribution Augmentation, Other System-Enabling Capex and Unexplained Capex.
- Specifically, Ergon Energy maintains that the proposed level of Subtransmission augmentation expenditure remains at the same level as in our October regulatory proposal, that the level of Distribution augmentation expenditure be reduced by 4.5% compared to the October regulatory proposal, that the level of Other System enabling expenditure remains unchanged and that the Unexplained Capex from the October be restored following the explanation provided in this submission.
- Ergon Energy recommends that the AER accept this revised proposal for Corporation Initiated Augmentation.

Outcomes

In light of the above, Ergon Energy has proposed a reduction of 4.5% or $15.3 million to the distribution augmentation program and that the overall Corporation Initiated Augmentation for the 2015-2020 regulatory control period should now be $644.8 million (direct cost 2014/15 real $).

It should be noted that the dollars presented in this document are in 2014/15 real $ and are in reference to the direct costs and cost escalations that applied in Ergon Energy's Draft Proposal.

Cost escalations have changed for Ergon Energy's Revised Proposal forecasts, and for these please refer to the following documents that have been updated for our revised proposal:

- 07.00.02 Forecast Expenditure Summary Corporation Initiated Augmentation
- 07.00.04 Forecast Expenditure Summary Other System and Enabling Technologies
- 07.00.05 Forecast Expenditure Summary Reliability and Quality of Supply

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Introduction

On 30 April 2015, the Australian Energy Regulator (AER) released its Preliminary Determination on Ergon Energy's Regulatory Proposal for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.

This document details our response to the AER's Preliminary Determination and stakeholder comments on Augmentation Expenditure. We have made revisions to our Regulatory Proposal and its supporting documents to reflect these positions, where necessary.

Ergon Energy has structured this document in the following manner:

- Section 1 summarises the AER's Preliminary Determination in relation to Augmentation Expenditure.
- Section 2 outlines issues raised by stakeholders since the lodgement of our initial Regulatory Proposal, both through our own consultation process and the AER's.
- Section 3 provides our response to technical issues raised and the positions adopted by the AER's consultant, Energy Market Consulting associates (EMCa)
- Section 4 provides our response to the positions adopted by the AER
- Section 5 details the revisions to our initial regulatory proposal documentation which have been updated due to new or updated information, or changes in methodology.
- Section 6 introduces new documents that are being provided to support the revised regulatory proposal

1. AER's Preliminary Determination

Attachment 6 of the AER's Preliminary Determination details its positions on Augmentation Expenditure. The following sections summarise these positions and the AER's rationale.

The AER stated

> We do not accept Ergon Energy's proposed augex allowance. Our substitute augex allowance is 15.5 per cent lower than Ergon Energy's proposal. We have reduced Ergon Energy's proposed augex to reinforce the sub-transmission and distribution segments of Ergon Energy's network, and its other system-enabling capex proposal. This reduction reflects the removal of systemic bias present within Ergon Energy's forecast which overstate its proposed augex. These biases have been quantified through a detailed engineering review performed by our consultant, Energy Market Consulting Associations (EMCa). The AER was not satisfied that Ergon Energy proposed total forecast capex reasonably reflected the capex criteria[1].

The AER advised it employed a number of techniques in reviewing total expenditure.[2] These included:

- Economic Benchmarking
- Trend analysis
- Expenditure Category Analysis
- Predictive Modelling
- Technical Review

The AER advised that its review of augmentation expenditure[3] was undertaken in four parts:

- Consideration of the proposed forecast in context of past expenditure, demand and current network utilisation
- Governance processes and forecasting methodologies
- Findings of a technical review conducted by EMCa of sample projects
- The remainder of the augex forecast not considered by EMCa i.e. Other system-enabling capex and the unexplained capex

The AER stated

> *Our preliminary decision to include $558.1 million ($2014−15) for augex in our alternative estimate is based on:*

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[1] AER Preliminary Decision Attachment 6, section 6.1, page 8
[2] AER Preliminary Decision Attachment 6, Appendix A page 34
[3] AER Preliminary Decision Attachment 6, B.2 page 6-41, 6-42

- *removing the impact of the identified overestimation bias evident in the Ergon Energy's forecast of distribution and sub-transmission capex by adopting the mid-point of the range established through the technical review of a sample of projects undertaken by EMCa*
- *removing the impact of the identified overestimation bias evident in the Ergon Energy forecast of other system-enabling capex by adopting the upper range established by EMCa for the distribution and sub-transmission forecasts*
- *removing the unexplained capex forecast from Ergon Energy's forecast.*

> *This amount should provide Ergon Energy with a reasonable opportunity to recover at least the efficient costs to augment its network to meet forecast demand, and network reliability, quality and security requirements.*[4]

Ergon Energy challenges some aspects of these outcomes, as detailed in Section 1.2 and 4

1.1. Economic Benchmarking

The AER states that[5]:

> The NER sets out that we must have regard to our annual benchmarking report. This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of Ergon Energy's proposal in a broader context. However, in our capex assessment we have not relied on our high level benchmarking metrics set out below other than to gain a high level insight into Ergon Energy's proposal. We have not used this analysis deterministically in our capex assessment

Ergon Energy has drafted this revised proposal in the same manner by utilising the benchmarking to obtain a broad understanding of the overall program. However the detail of each program has been developed to provide a prudent and efficient outcome based on achieving mandated standards at the lowest cost.

1.2. Trend Analysis

The AER advised

> *We have reviewed the trends in maximum demand and network utilisation as these are the key drivers of augmentation. This provides an initial sense of whether Ergon Energy's augex forecast is reasonably required to meet forecast demand and alleviate forecast capacity constraints.*[6]
>
> *A number of parties have made submissions noting that there is little justification for Ergon Energy's proposed augex allowance given the excess capacity present within Ergon Energy's network.*[7]

[4] AER Preliminary Decision Attachment 6, B.2, page 6-42, 6-43
[5] AER Preliminary Decision Attachment 6, Page 6-25, 6-26
[6] AER Preliminary Decision Attachment 6, B.2.1 page 6-44

As part of the detailed network analysis and as a pre-cursor to the submission Ergon Energy recognised and accounted for observed trends in augex for the period 2005-2015. It should be noted that Ergon Energy reviews its augmentation expenditure on an annual basis and in doing so responds to changes in network demand as well as changes to external requirements such as security of supply standards and specific areas of network performance.

The level of augmentation expenditure is revised to a level appropriate for the demand forecast, network capacity, network constraints and security criteria that exists at the time of the annual review. This has been demonstrated during the 2010-2015 regulatory control period where the level of augex expenditure was reduced to a level below that of the AER determination in response to changing circumstances in each of these areas. This ensures that “excess capacity” is not introduced in a scenario where the rate of demand growth has slowed. A full range of options to address identified constraints are considered in order to minimise any resulting augmentation expenditure including network and non-network alternatives, demand management and operational response.

Our proposal for the 2015-2020 regulatory control period provides clear evidence of Ergon Energy’s declining level of augmentation expenditure which would be expected in the present circumstances, as well as the continued focus by Ergon Energy on non-network alternatives and operational responses to network contingencies in order to minimise the cost of maintaining performance at required levels. As observed by the AER certain areas of the network will reach levels of utilisation that will require augmentation during the 2015-2020 regulatory control period and these are the areas that have been addressed in the Ergon Energy augex proposal.

1.3. Expenditure Category Analysis

The AER has employed this approach to

> *compare expenditure across service providers, and over time, for various levels of capex:*
>
> - *overall costs within each category of capex*
> - *unit costs, across a range of activities*
> - *volumes, across a range of activities*
> - *asset lives, across a range of asset classes which we have used in assessing repex.*
>
> *Using standardised reporting templates, we have collected data on … augex, …. for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by distributors, and how these factors may change over time.* [8]

Ergon Energy disagrees with the AER that they have collected standardised category data. Ergon Energy asserts that a considerable volume of data has been estimated or omitted or interpreted differently by the different service providers that have provided the data and consequently there has been no “standard” way in which this has been complied. While the intent is reasonable, Ergon Energy asserts that the level of standardisation is insufficient to achieve the intended result.

1.4. Predictive Modelling

The AER employed a predictive model known as the augex model. The AER stated

[7] AER Preliminary Decision Attachment 6, B.2.1 page 6-44

[8] AER Preliminary Decision Attachment 6, Appendix A.3 page 36

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation. The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period. In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast. However, we have not relied heavily on the augex model for this reset. This is because Ergon experienced negative demand growth and positive growth in augex in some network segments during the 2010−15 regulatory control period. This resulted in the model being unable to produce reliable benchmark results from the previous period. Therefore, for this decision we have only had regard to trends in utilisation rates in a qualitative sense. [9]

Ergon Energy notes that the augex model has produced a predicted level of augmentation expenditure which is higher than our proposed level of expenditure on augmentation during the 2015-2020 regulatory control period. Even so, Ergon Energy believes that caution should be used when drawing on the results from the augex model given the different network configurations, operating environments and non-standard techniques for data collection and presentation by various distributors, especially during periods when there are changing levels of demand as well as changing standards for network security. Ergon Energy asserts that any use of incorrect assumptions may lead to inappropriate decisions regarding augex forecasting and result in funding allowances that are incompatible with the level forecast demand growth, consequent network constraints and network performance requirements.

1.5. Technical Review

The AER employed Energy Market Consulting Associates (EMCa) to perform a (limited) technical review of Ergon Energy's augex forecasts and proposals.

In summary, the AER has stated that EMCa found that

- *The augex is not always adequately linked to a prudent needs-driven analysis, including efficient timing of expenditure and connection of new load*
- *The augex is not always adequately supported by cost-benefit analysis, robust options analysis and appropriately-applied risk assessment, and*
- *the augex includes some estimates that have led to a higher level of expenditure than may required*[10]

EMCa concluded that

- our sub-transmission proposal was overestimated by 0 to 5 per cent. Consequently, the AER applied a 2.5 per cent reduction to our sub-transmission augmentation forecast.
- our distribution proposal was overestimated by 10 to 20 per cent. Consequently, the AER applied a 15 per cent reduction to our distribution augmentation forecast.

Ergon Energy challenges all of these findings, as discussed in Section 3 and Section 4.

[9] AER Preliminary Decision Attachment 6, Appendix A.4 page 37

[10] AER Preliminary Decision Attachment 6, Appendix B.2.3 page 6-51

2. Stakeholder comments

Stakeholders have raised a number of concerns in relation to Ergon Energy's capex proposal since the lodgement of our initial Regulatory Proposal on 31 October 2014. This section outlines these concerns.

2.1. AER consultation

The AER stated

> *A number of parties have made submissions noting that there is little justification for Ergon Energy's proposed augex allowance given the excess capacity present within Ergon Energy's network. In particular:*
>
> - *AGL encouraged the AER to confirm that any augmentation of existing capacity is founded on realistic maximum demand forecasts as the network's forecast of peak demand appear aggressive.*
> - *The Energy Users Association of Australia (EUAA) submits that Ergon Energy's augex appears high considering the Queensland jurisdiction has relaxed its security and reliability standards following the 2011 ENCAP review.*
> - *The CCP submitted that Ergon Energy's augex proposal has not taken into account significant levels of excess capacity and declines in network utilisation. It stated that the AER needs to ensure that Ergon Energy's excess capacity is more efficiently utilised ahead of any additional augmentation investment.* [11]

These concerns are recognised by Ergon Energy and are addressed collectively by detailed responses below.

2.1.1. AGL

Within this section, Ergon Energy will address concerns by AGL that were highlighted in the AER draft determination.

Ergon Energy has completely revised our demand forecasting process during the 2010-2015 regulatory control period. In developing the 2015-2020 augex proposal Ergon Energy has used a robust demand forecasting methodology in which top down and bottom up forecasting processes are developed independently and reconciled to ensure system level forecasts and spatial level forecasts remain consistent. Ergon Energy has used demand forecasts associated with the low economic outlook to develop the augex program for the 2015-2020 regulatory control period. The AER has stated in its preliminary determination that *"…we are satisfied that on current forecasts, the augex forecast is based on a realistic expectation of demand."*[12]

2.1.2. Energy Users Association of Australia (EUAA)

Within this section, Ergon Energy will address concerns by Energy Users Association of Australia (EUAA) that were highlighted in the AER draft determination.

The Ergon Energy regulatory proposal shows that Ergon Energy significantly reduced augmentation expenditure during the 2010-2015 regulatory control period from the level that was approved by the

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[11] AER Preliminary Decision Attachment 6, Appendix B.2.1 page 6-46
[12] AER Preliminary Decision Attachment 6, Appendix B.2.2 page 6-48

AER in response to reducing demand growth and security of supply standards. In the regulatory submission for the 2015-2020 regulatory control period Ergon Energy has demonstrated a declining level of expenditure when compared to the 2010-2015 regulatory control period and consistent with lower security of supply standards and lower level levels of load growth. Ergon Energy has used load growth consistent with the low economic growth scenario to develop the augmentation plan.

2.1.3. Consumer Challenge Panel CCP2

Within this section, Ergon Energy will address concerns by the Consumer Challenge Panel (CCP) that were highlighted in the AER draft determination.

The Ergon Energy augmentation program is based on the forecast load growth in specific sections of the network and not on the system level demand forecasts. A top down and bottom up demand forecasting process is utilised to ensure system level forecasts and spatial level forecasts remain consistent. Network augmentation planning is performed on the loading in the relevant section of the network where the load occurs. There are areas of the network where load is increasing as a result of additional network connections and if those sections of the network are subject to a constraint as a result of this localised change in demand, augmentation will need to be performed to ensure the quality and reliability of supply is maintained at mandated levels. The capabilities of the network as well as the relevant network security of supply and technical standards are used to identify constraints in the network that may need to be addressed by the augex program. Marginal increases in demand can result in augmentation being required depending on how close to a limit specific sections of the network are operating. Some augmentation may still be required in the absence of increasing demand. For example: The addition of PV generation to the network has resulted in augmentation being required to ensure voltage levels remain within statutory limits even if there has been no additional growth in customer demand.

3. Our Response to the EMCa technical review

In its Preliminary Determination, the AER has advised that it employed EMCa as a consultant to advise about specific elements of Ergon Energy's proposal.[13]

In its report to the AER[14], EMCa were asked to consider a number of specific matters as part of their assessment. This section discusses their findings and conclusions.

3.2. Demand Forecasting

Ergon Energy does not agree with some of the AER's consultants (EMCa) comments in relation to Demand Forecasting. Consequently Ergon Energy does not agree with any conclusions drawn by the AER as a result of these comments.

In the report to the AER EMCa stated

> *We found that Ergon increased the spatial forecasts by around 1% to 2% to account for its top down econometric model based forecast…..*[15].

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[13] AER Preliminary Decision Attachment 6, page 23

[14] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Regulatory Proposal 2015−20*, April 2015, paragraph

[15] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Regulatory Proposal 2015−20*, April 2015, paragraph 200

This is an incorrect interpretation of the reconciliation process. The reconciliation of the top-down to bottom-up values varies from year to year, so an overall effect can't be generalised like this. The 1% to 2% only applies to this specific forecast and the level of reconciliation will vary up or down with every new forecast to specifically ensure the top-down and bottom-up forecasts are consistent. In The 2010-2015 determination the AER specifically noted that the top down and bottom up demand forecasts need to be reconciled and this process is consistent with that requirement. The adjustment is certainly not always an upwards adjustment and is not designed to artificially influence the level of augmentation expenditure in any way.

Ergon Energy emphasises that the reconciliation adjustment is part of the approved forecasting methodology to provide consistency between top-down and bottom up forecasts and complies with recommendations made by the AER to Ergon Energy in the determination for the 2010-2015 regulatory control period. It is not a subjective decision made to influence the outcome. The actual amount of trim may vary above and below zero depending on the specific forecast to comply with the documented forecasting methodology.

3.3. Demand Management

We note the AER's comment that ....*EMCa note that more capex will likely be deferred than is currently forecast*[16]*…* and later that *We are therefore considering whether it is appropriate to estimate the amount of capex that may be efficiently deferred through the use of demand management initiatives and explicitly reduce the capex forecast by this amount*[17].

It is emphasised that Ergon Energy's revised Demand Management proposal does not have any funding allocated for projects contained within the existing capex proposal, but is focused on the risk of constraints/projects that have already been removed from this program as well as the continuation of existing demand management activities. Ergon Energy will instead investigate efficient capex/opex trade-offs during the regulatory control period as part of our normal planning process. This planning process was reviewed and confirmed by EMCa in their technical review paper.[18] This capex/opex trade-off will be performed at a project level as more detailed information and conditions are known, rather than attempting a program level estimation at this point in time. This approach will ensure the most efficient and prudent final outcome.

3.4. Subtransmission

The AER reflected the comments by their consultant EMCa in the area of subtransmission in their determination and consequently the response to the EMCa technical review of subtransmission is addressed in section 4.4.1. of this document.

3.5. Distribution

3.5.1. Risk review of distribution augmentation

Ergon Energy notes the comment regarding the application of network risk assessment by the EMCa which states that

[16] AER Preliminary Decision Attachment 6, page 51
[17] AER Preliminary Decision Attachment 6, page 112
[18] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Regulatory Proposal 2015−20*, April 2015, paragraph 141

We note that $95.9M of the DNAP of expenditure has an 'end of period project risk' of 36 by the end of the RCP. We understand that Ergon would define this risk as 'intolerable'. This outcome casts some doubt on the applications of the network risk assessment process, since many of these projects and programs would reflect an intolerable risk assessment[19].

Ergon Energy believes that the risk score of 36 is an appropriate assessment of the level of risk that would be experienced across an entire program when considering the individual elements that make up that program as detailed below.

The following paragraphs highlight the risk assessment process, how a risk score is assigned to a network constraint and the criteria for inclusion of a project in the augmentation program based on the risk score assigned.

The Ergon Energy Security Criteria for 'Urban' feeders is 75% of maximum utilisation under normal 50PoE load conditions. Under the distribution augmentation specified program, an 'Urban' feeder project is included in the works schedule when risk assessed at '24' or above reflecting an adjacent group of feeders exceeding the 85% utilisation threshold under normal 50PoE load conditions to prevent:

- Feeder exit cable failures during a 10PoE demand (which could exceed 50PoE demands by up to 15%);
- Backbone overhead statutory clearance breaches during a 10PoE demand;
- Operational complexities when managing an Urban feeder distribution network under contingency conditions;
- Loss during demand management response equipment (e.g. AFLC) failure or wide area loss of PV support; or
- Capacity risk to plant exposed to environmental condition changes (e.g. high thermal resistivity due to dry out of soils).

In this context, a risk score of '36' across a full program view is considered an 'Intolerable' risk for 'Urban' feeders exceeding 100% maximum utilisation under normal 50PoE load conditions.

The Ergon Energy 'Urban' feeder Voltage Design Criteria of 3.5% maximum HV voltage drop under 10PoE load conditions is to ensure compliance with the Queensland Electricity Regulations statutory voltage requirement of 240v +/- 6%. Under the distribution augmentation specified program, an 'Urban' voltage project is risk assessed at '30' reflecting an additional 3.0% HV voltage drop from this standard under normal 50PoE load conditions. The risk level of '30' considers the balance of risk exposure between the current requirement to meet the statutory voltage limits defined in the Queensland Electricity Regulations, and managing Unspecified distribution augmentation expenditure.

A risk score of '36' reflects an additional HV voltage drop of 5.5% beyond the previous scenario (i.e. total voltage drop of 9.0%) which is considered an 'Intolerable' risk for an 'Urban' feeder and program of feeders across the wider Ergon Energy distribution network. This is considered an appropriate assessment of risk as it prevents systemic non-compliance with the current Queensland Electricity Regulations (240v +/- 6%) and National Electricity Rules (Nominal Voltage + / - 10%) under normal 50PoE load conditions.

To risk assess distribution augmentation projects, Ergon Energy has applied Ergon Energy's *Network Risk Assessment Guidelines* document. This document was supplied to the AER as per the

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[19] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Regulatory Proposal 2015−20*, April 2015, paragraph 262

information provided in response to the AER information request AER Ergon 031(4). Ergon Energy's network risk assessment methodology follows the process stages as defined in '*AS/NZS ISO 31000:2009 Risk Management - Principles and Guidelines'*.

Projects have only been created and entered into the program if a risk score at year end exceeds 24. Risk scores of ≥24 are considered as a high (risk score 24-30) and intolerable (risk score 30-36) risks. Moderate and low risk projects were excluded from the distribution augmentation specified program. Hence because "Low" risks have been completely excluded from the augex program and only "High" and "Intolerable" risks have been included, Ergon Energy does not agree with the statement by EMCa that "…*Ergon's risk management has elements that are likely to have led to a degree of engineering conservatism and therefore to a degree of upwards bias in its forecast.*[20]".

3.6. Our consultation

3.6.1. Impacts on Reliability - Augmentation

Ergon Energy employed consulting firm Jacobs Group (Australia) Pty. Ltd (Jacobs) to quantify impacts on reliability performance likely to occur as a result of implementation of the AER's Preliminary Determination. The report, *EXP09.02 AER Preliminary Decision Response – Reliability Impact Assessment* is included in Ergon Energy's response documents.

The Jacob's assessment modelled the impact of the reduced expenditure allowed for in the AER Preliminary Decision on Ergon Energy's ability to discharge its Minimum Service Standards (MSS) obligations under the Ergon Energy Distribution Authority and its revenue outcomes under the AER Service Target Performance Incentive Scheme (STPIS). The modelling demonstrated that the reduction in expenditure resulted in increased frequency and average duration of supply interruption events over the Regulatory Control Period 2015/16 to 2019/20. The review highlighted that the improvements in reliability of supply established through investment in the current Regulatory Control Period will be eroded over the next Regulatory Control Period to the point where Ergon Energy will be at considerable risk of non-compliance across a number of MSS performance indices over the next two Regulatory Control Periods.

Based on the Jacob's report, it is expected that:

- MSS regulatory limits for SAIDI will be exceeded by:
  - Urban feeders – by 2019/20 and annually thereafter
  - Long Rural feeders – by 2018/19 and annually thereafter
- MSS regulatory limits for SAIFI are unlikely to be exceeded during the 2015-2020 regulatory period.

Exceedance of the same MSS limit (i.e. SAIDI limit) three financial years in a row is considered a "systemic failure" and constitutes a breach of Ergon Energy's distribution authority.[21] In effect, it is projected that implementation of the AER's preliminary determination will result in Ergon Energy being in breach of its distribution authority at or near the end of the 2015-2020 regulatory period or in the first year of the 2020-2025 regulatory period.

The Jacob's report, also found that Ergon Energy's reliability of supply performance will degrade to a consistently STPIS penalty environment by the end of the 2015-2020 Regulatory Control Period.

[20] EMCa Report to AER, page iv
[21] Distribution Authority – No. D01/99 Ergon Energy Corporation Limited Section 9

4. Our response to the AER's Preliminary Determination

The following sections detail our response to the AER's Preliminary Determination and stakeholder concerns.

4.1. Forecasting Methodology

The AER stated

> *Our assessment of Ergon Energy's forecasting methodology is informed by the findings and recommendations from engineering consultants EMCa. These findings suggest that the framework and methodology applied by Ergon Energy is consistent with industry standards and that the top-down assessment process applied by Ergon.*
>
> *Energy delivered material reductions in its initial bottom-up forecast. However, the application of the top-down assessment to meet a price path objective may result in an overstated augex forecast.*[22]

Ergon Energy has a focus of developing the subtransmission augmentation program to meet mandated levels of performance at a level of expenditure that is prudent and efficient. When network constraints are identified business cases consider a range of internal and external non-network, network, demand management and operational solutions (as well as combinations of each) in order to resolve the constraint. Options are then subject to net present value analysis to determine the appropriate response based on costs, benefits and timing to determine the solution that offers the least level of overall expenditure. The Regulatory Test for Distribution (RIT-D) ensures that at the subtransmission level this process is conducted in a public manner with opportunities for any interested parties to make comment or offer possible solutions. For this reason there is confidence that the top-down assessment of the program has not resulted in an overstated augex forecast but has delivered material reductions in the initial bottom-up forecast as observed by the AER.

4.2. Demand Forecasting

Ergon Energy notes that the AER has found that "…the augex forecast is based on a realistic expectation of demand"[23] but will consider the outcomes of the AEMO connection point demand forecast when making the final determination. Given the timing of the AEMO forecast (July, 2015) Ergon Energy will not have an opportunity to account for, examine or explain any differences between the AEMO connection point forecast and the demand forecast made by Ergon Energy prior to having to make this submission. We will however comment on three aspects of this:

1. This will be the first time that AEMO have performed a connection point forecast in Queensland and consequently there is no history on which to determine if the process they will be using is robust and will provide a sufficient level of accuracy. AEMO may need to observe feedback on their process following this first release of the information;
2. Ergon Energy has been provided with a draft version of the AEMO forecast which in fact shows demand growth during the 2015-2020 regulatory control period to be slightly higher than that forecast at transmission connection points by Ergon Energy; and

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[22] AER Preliminary Decision Attachment 6, Appendix B.2.2 page 6-47, 6-48
[23] AER Preliminary Decision Attachment 6, Appendix B.2.1 page 6-48

3. Demand growth at transmission connection points will not be exactly the same as for individual zone substations which are located lower in the network hierarchy.

4.3. Cost Estimation

In Attachment 6 – Capital Expenditure - Section B.2.3 Driver and Project Analysis the AER stated

> *However, EMCa also identified systemic issues of overestimation across the sample of projects which they consider means that Ergon Energy's total forecast augex for 2015–20 is overestimated. In particular, EMCa found that:*
>
> > *the augex is not always adequately linked to a prudent needs-driven analysis, including efficient timing of expenditure and connection of new load*
> >
> > *the augex is not always adequately supported by cost-benefit analysis, robust options analysis and appropriately-applied risk assessment, and*
> >
> > *the augex includes some estimates that have led to a higher level of expenditure than may be required.*

Ergon Energy does not accept that the scope of some augmentation projects leads to systemic overestimation in total project costings. Projects are scoped to meet expected levels of expenditure at the time the planning reports are completed. Items like the undergrounding referred to in section B.2.2 may require more or less of the total length of lines to be constructed underground depending on the outcomes of community consultations conducted during the project. Over the entire augmentation program it is expected that these variations will balance to meet a level of expenditure that is both prudent and efficient. It should also be noted that in general there is increasing community pressure to extend the amount of underground feeders in urban and semi-urban areas rather than the reverse.

4.4. Driver and project analysis

4.4.1. Subtransmission augmentation program

The AER stated

> EMCa concluded that there are opportunities for Ergon Energy to optimise its sub-transmission programs, including project deferral, greater tolerance of risk and the timing of capex. Based on these findings, EMCa considered that Ergon Energy's sub-transmission proposal is overestimated by 0 to 5 per cent.
>
> In light of these findings, we [AER] have applied a 2.5 per cent reduction to the sub-transmission forecast (which is the mid-point of EMCa's recommended range). As set out previously, we

> consider that the mid-point is reasonable in the absence of evidence pointing towards to the top or bottom of the range.[24]

Ergon Energy believes it has provided well justified and prudent submission to the AER for subtransmission augmentation expenditure. Ergon Energy restates our position that the level of subtransmission expenditure is prudent and will result in acceptable levels of network performance that aligns with the metrics required by our distribution licence conditions.

Ergon Energy believes the subtransmission augmentation program in our proposal has been developed to optimally reflect the timing of when constraints on the network will occur and to ensure the lowest overall cost option (non-network or network) has been selected to resolve those constraints. The range of options considered is broad and will ensure both internal and external (market based) solutions are compared to achieve the best overall solution as required by the Regulatory Investment Test for Distribution requirements of the NER.

The change from deterministic to probabilistic planning during the 2010-2015 regulatory control period has been reflected in the development of options for augmentation as well as consideration of the appropriate mix of non-network and network based solutions, including demand management and operational responses to meet the requirements of the security of supply criteria which is defined within our distribution licence conditions.

4.4.2. Distribution augmentation program

The AER stated

> EMCa concludes that there are opportunities for Ergon Energy to optimise its distribution programs, including project deferral, greater tolerance of risk and the timing of capex.115 Based on its findings, EMCa considered that Ergon Energy's distribution proposal is overestimated by 10 to 20 per cent. In light of these findings, we have applied a 15 per cent reduction to the distribution[25] forecast (which is the mid-point of EMCa's recommended range). As set out previously, we consider that the mid-point is reasonable in the absence of evidence pointing towards to the top or bottom of the range.[26]

Ergon Energy challenges the AER on their 15% reduction to the distribution augmentation forecast. Our revised proposal is $327M (2014-15 direct dollars) which represents a $15.3 million or 4.5% reduction in expenditure below that of the original proposal submitted in October 2014 of $342M.

The reduction is based a revision of the specified (modelled) distribution augmentation projects since the original submission based on updated demand forecasts and network constraints which has reduced the scope and volume of some of the proposed projects.

[24] AER Preliminary Decision Attachment 6, Appendix B.2.3 page 6-54
[25] AER Preliminary Decision Attachment 6, page 6-56 – mistakenly written as sub-transmission
[26] AER Preliminary Decision Attachment 6, Appendix B.2.3 page 6-54, 6-55

Table 1 summarises the expenditure allowance for each program of distribution augmentation based on the re-submitted scenario which includes the draft proposal (October 2014) cost escalations:

Table 1 Distribution Augmentation program – Revised Proposal

DNAP Investment Programs	Total by Program 2014/15 Real $ M, based on draft proposal cost escalations)
Works in Progress (WIP)	45.9 (no reduction)
Unspecified / reactive / un-modelled (UNMOD)	89.9 (no reduction)
Specified / modelled (MOD)	136.7 (10.1% reduction)
Photovoltaic (PV / IES)	45.1 (no reduction)
Distribution transformer augmentation (DTF)	9.3 (no reduction)
Total DNAP	**327** (4.5% reduction)

Refer to *07.00.02 Forecast Expenditure Summary Corporation Initiated Augmentation* for the revised proposal forecast which is based on updated cost escalations.

Ergon Energy's decision for the resubmission of the distribution augmentation program is based on:

a) Reviewing the contents of the document - *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015*-2020 - Energy Market Consulting associates and Strata Energy Consulting
b) Reviewing the contents of the document - *Preliminary Decision – Ergon Energy determination 2015-16 to 2019-20 Attachment 6 – Capital expenditure – Australian Energy Regulator*
c) Post-submission analysis of the distribution network completed using an updated distribution network demand forecast
d) Further review of risk assessments for all the studied options

Specified (modelled) Distribution Augmentation

With specific consideration of post-submission works described above and the EMCa and AER's findings in relation to risk assessment and demand growth, Ergon Energy believes that an adjustment in the order of 10.1% (from $152 million to $136.7 million in 2014-15 direct dollars) is an appropriate revised proposal estimate for this sub-category.

This 10.1% reduction includes the removal of 54 specified projects including all projects with starting year risk scores of 12 (ALARP) and all except nine projects with risk scores of 18. These projects were assessed in detail during the re-prioritisation revision. Feeders associated with the 54 removed specified projects supply >30,000 customers, including 384 priority customers of which 93 are in the life support category.

In addition, taking into account that the subtransmission augmentation, reliability and quality of supply budgets have been reduced compared to the previous regulatory control period, coupled with introduction of the new safety net criteria, specified distribution augmentation is the key program addressing identified network limitations, mitigating reliability and power quality issues and supporting safety net responses.

Unspecified Distribution Augmentation

Ergon Energy's unspecified program is one of the key investment sub-categories supporting frequent un-modelled problems on distribution HV and LV networks. Historic expenditure (approx. $143 million) of all unspecified related works in the last five years was the baseline for this submission. It should be noted that:

1. The Unspecified submission of $89.9 million (2014-15 direct dollars) is already significantly (37%) below historic levels of unspecified expenditure;
2. There is no evidence based on historical trends (both customer complaints and historic expenditure) to suggest that Ergon Energy's Unspecified expenditure requirements will decrease in future years. In fact, if anything, trend analysis indicates an increasing requirement;
3. Customer side increased visibility of network performance will place further pressure on Ergon Energy's Unspecified program;
4. As Ergon Energy's capex does not have a specific low voltage (LV) augmentation investment category, the unspecified program provides support for any necessary reinforcement of the LV networks in the future.

Ergon Energy believes that the 37% reduction of historic unspecified expenditure in combination with development of pro-active control mechanisms eliminates concerns highlighted in the EMCa's report under clause 7(iii) about revised demand outlook[27].

Ergon Energy is also aware that reduction of the specified program by 10.1% will place some additional pressure on the unspecified sub-category. This will become evident through an increase in customer related complaints in areas such as power quality. Additionally, as noted in point (3) above, with both Ergon Energy and its customers becoming more aware of voltage levels following the introduction of smart meters, IES and other new technologies, this risk will be further exacerbated.

Distribution - Impact of Solar Systems Installations

The AER argued that

> *Ergon Energy proposed network augmentation to manage voltage fluctuations in the network, resulting from solar systems installations.[104] EMCa found that this capex has not been justified with a business case demonstrating an economic basis for the projects.[105] While EMCa agrees with Ergon Energy that voltage control is a potentially costly issue associated with growth in inverter energy system connections, these costs need to be articulated in the form of a detailed business case. Additionally, EMCa considers that Ergon Energy's analysis should take into account how the uptake of solar installations will reduce augmentation requirements on the LV network over the 2015–20 regulatory control period.*[28]

Ergon Energy challenges the reduction in the forecast expenditure for photovoltaic augmentation. We have provided sufficiently detailed technical and economic analysis, including assumptions, methodology and evidence of the impacts and associated network augmentation to manage voltage fluctuations in the network, resulting from solar system installations. The extensive supporting document "Distribution Network Impacts of Photovoltaic Connections to 2020" which totalled 390

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[27] EMCa Report to AER, page ii

[28] AER Preliminary Decision Attachment 6, page 6-55

pages, and three associated parent business cases detail and support this expenditure. Ergon Energy also specifically draws the AER's attention to Section 11 and Annex JJ of the supporting document which provide the results of 1400 customer meter probe reads that were undertaken to validate the modelled results and have confirmed the correlation between Solar PV capacity and overvoltage issues.

Whilst Ergon Energy proposed a program in line with the low uptake scenario, since providing its submission to the AER, uptake of Solar PV has been tracking slightly above the low uptake scenario of PV, with 108,834 of customer PV equating to 395MW as of April 2015. Most up-to-date advice however now also shows a high likelihood that forecast uptake of PV will far exceed that of the low uptake scenario, with AEMO, as an independent body, forecasting 3,988 to 4,738 GWh per annum of Solar PV generation in Queensland by 2020. This equates to 228,929 to 271,968 customers with Solar PV being connected within Ergon Energy territory by 2020 – comparable to the Ergon Energy High uptake scenario[29].

Since the submission there has also been a change of Queensland government, with a key election promise of the now incumbent government being to achieve 1 million rooftops with Solar PV by 2020[30], which would equate to approximately 350,000 customers with Solar PV within Ergon Energy territory. This outcome will be far in exceedance of the Ergon Energy High uptake scenario. This policy not only makes the business case to perform works to address voltage issues on the network more compelling, but also drastically increases the volume of expenditure required, which is anticipated to be in excess of $137 million CAPEX (high-case inclusive of overheads), representing an increase of over $76 million of what was requested in original submission to AER for an anticipated low uptake scenario.

In addition to the potential for the higher uptake, when calculating the costs of required expenditure for 2015/20 regulatory control period in relation to Solar PV, allowances do not account for the requirement for Ergon Energy's connection policy to comply with the AER's Connection Charge Guidelines for Electricity Retail Customers and include a shared network augmentation charge threshold below which retail customers will not be required to make a capital contribution towards the cost of shared network augmentation, insofar as it involves more than an extension. While Ergon Energy has proposed a lower threshold of 80A on main grid and 10kVA on SWER (compared to 100A in the AER guideline) the reality is that this will remove Ergon Energy's ability to have customer's pay for the augmentation to the shared network that is required to mitigate voltage rise above statutory limits directly attributed to the connection of their Solar PV. This in turn will result in greater uptake of Solar PV and an increase in the average size of Solar PV connections, due to a connection of up to 19.2 kVA (80A) being able to connect without financially contributing to the augmentation required on the shared network to accommodate the connection. Under a *Low uptake* scenario – as used in the Ergon Energy submission to the AER – this would increase the required capital expenditure by $81 million up to $142 million (inclusive of overheads). Removal of this connection policy threshold for shared network contribution from applying to generation, and/or allowing the requirement for non-export as a reasonable technical requirement to impose by a DNSP

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[29] *AEMO National Electricity Forecasting Report December 2014 Update Queensland.* http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/planning/NEFR/2014/2014%20Updates/2014%20NEFR%20Update%20NEM.ashx

[30] *Australian Labour Party - A Solar Future: Power Queensland's renewable energy industries.* http://solar.org.au/wp-content/uploads/2015/01/A-Solar-Future-released-23-January-2015.pdf

where there is a voltage rise issue, is critical to avoid this expected significant increase in expenditure.

Ergon Energy would also like to highlight to the AER, the information provided in response to the AER information request AER Ergon 002 on 18 December, question 2(b) regarding the proactive approach Ergon Energy has and continues to take to reduce the proliferation of Solar PV causing network voltage issues without the need for network expenditure. A key part of Ergon Energy's strategy is customer enablement and facilitating "Choice and Control" and with an increasing number of Queenslanders choosing to install solar systems, Ergon Energy must be able to respond. Significant work has already occurred in ensuring that Ergon Energy's approach is as prudent and efficient as possible, to enable customers while minimising impacts on prices. Even where funding has been sought for network augmentation, Ergon Energy has already investigated and recommended the use of non-traditional solutions such as STATCOMS, in order to minimise cost. It is also important to note that no specific LV augmentation program of works has been included in the Ergon Energy Distribution Network Augmentation Plans (DNAPs) to address the issues associated with the uptake of Solar PV, but rather this has been pulled out to be completely covered by this Solar PV business case and associated comprehensive supporting document.

With respect to the AER's comments on the impact of Solar PV on reducing augmentation requirements on the LV network, unfortunately this is not the case. Low voltage expenditure is attributed predominantly to either voltage issues or to evening peak load caused by air-conditioning, neither of which Solar PV has any impact on reducing. In addition, Ergon Energy highlighted in Section 8.2 of the supporting document that no consideration has been made for expenditure required to address impacts at a Medium Voltage network level due to Solar PV attributed reverse power flow from the Low Voltage networks, with approximately 44.6% of Medium Voltage feeders forecast to be affected by 2020, and any costs associated with remedying this not currently included in our submission due to the current uncertainty in forecasting the expenditure associated with this requirement.

Overall Ergon Energy has taken a prudent approach to both forecasting and addressing solar related network issues and is very concerned by the potential customer impact of a reduction in funding in this area. Based on the information that has been provided we cannot see grounds for the 50% reduction that has been applied and as such encourage the AER to review in detail the information that has already been submitted in this regard, in order to reconsider its decision.

Distribution Transformer Upgrade Program

Ergon Energy has taken a prudent approach to both forecasting and addressing Distribution Transformer (DTF) Upgrades. Ergon Energy manages more than 90,000 distribution transformers. The DTF Program is utilised to proactively replace overloaded distribution transformers exceeding their emergency ratings, not normal cyclic capacities as in the past. Basically, this means that typical outdoor transformers supplying residential loads can be loaded up to 145% of their nameplate capacity before being scheduled for replacement with the next standard size transformer. This change was adopted for economic reasons but equally increases the level of risk on the distribution network.

The DTF Program includes the upgrade of 787 units (less than 1% of total population) exceeding Emergency Cyclic Capacity (ECC). With only $9.3 million (in 2014/15 direct dollars) this funding is well below historic levels (by approximately 50%) and only allows a reactive approach as major potential issues are identified.

Risk exposure of the re-submitted distribution augmentation program

From an engineering perspective, the distribution augmentation program reductions comprise an increase in Ergon Energy's risk levels. Ergon Energy has endeavoured to optimise programs as much as possible to manage network and customer risks while producing a prudent and efficient augmentation program. Reductions have been made to the best of Ergon Energy's abilities to ensure distribution feeders will not exceed their rated thermal capacities, thereby minimising safety impacts to the public and staff.

A brief summary of the nine major increased risks identified at the proposed level of expenditure during the 2015-2020 regulatory control period is outlined below.

1. Safety concerns

Increased feeder utilisation may result in overhead line clearance breaches and consequent safety risks for people, equipment and property. Reduced reliability causes safety risks for Ergon Energy's priority and life support system customers.

2. Reduced reliability

Increased number and duration of outages caused by reduced specified and unspecified program funding, as well as increased feeder utilisation.

3. Increased voltage and power quality (PQ) issues

Voltage variations outside of statutory limitations due to reduced unspecified and PV program funding, as well as increased feeder utilisation.

4. Increased Distribution Transformer failures and bushfires

There is a higher likelihood of distribution transformer failures causing outages and bushfires due to reduced Distribution Transformer program funding and increased feeder utilisation.

5. Failure to meet customer commitments

Reduction in distribution augmentation program funding places 7 of the 8 Ergon Energy commitments to customers at increased risk of not being met:

- Being always safe
- Maintaining/improving reliability
- Restoration of supply after storms
- Guaranteed service levels
- Market enablement/customer choice of supply
- Easy connection to the network and
- Reduction of network charges.

6. Increased number of customer complaints

Distribution augmentation program reductions causing increased and unresolved voltage issues will drive greater numbers of customer complaints.

7. Regulatory penalties, fines & claims

Breaches of the statutory voltage limits and planning criteria may incur fines under legislation or non-compliance with the Ergon Energy distribution authority. Outages, faults, equipment failure and dangerous events have the potential to increase the compensation claims payable by Ergon Energy.

4.4.3. Power Quality

The AER stated

> Ergon Energy proposes $6.5 million ($2014−15) to extend the network monitoring of power quality to approximately 67 per cent of the network feeders. This is a continuation of an existing network monitoring program.[118] The proposed capex is significantly less than the actual capex incurred by Ergon Energy for power quality in the 2010−15 regulatory control period.
>
> Based on EMCa's findings, and our comparison of the forecast against historic expenditure, we accept that the proposed power quality forecast of $6.5 million reasonably reflects a prudent and efficient amount.

Ergon Energy agrees with the AER that the proposed power quality amount reasonably reflects a prudent and efficient forecast.

4.4.4. Network Reliability

The AER stated

> As Ergon Energy has generally proposed reliability capex to meet its regulatory obligations, we have allowed this capex as it is consistent with the capex criteria. We have also had regard to the technical review conducted by our consultants EMCa of whether the capex is the prudent and efficient expenditure amount for maintaining reliability and meeting the reliability obligations. EMCa found that there are no systemic issues with Ergon Energy's forecast and, on balance, it was satisfied that the $5.5 million ($2014−15) capex proposed for meeting reliability is prudent and efficient.[133]
>
> Based on these findings, we are satisfied that Ergon Energy has shown that the proposed capex meets the capex criteria in that it is for meeting obligations under the Distribution Authority and for maintaining reliability. We will accept the $5.5 million ($2014−15) Ergon Energy proposed for reliability capex and will include this expenditure in our alternative capex estimate.

Ergon Energy agrees with the AER that the proposed network reliability amount meets the capex criteria in that it is for meeting obligations under the Distribution Authority and for maintaining reliability.

4.4.5. Other system-enabling capex

The AER stated

We do not accept Ergon Energy's forecast for other system enabling capex. We have instead included an amount of $82.4 million ($2014−15) in our alternative estimate, a reduction of 15 per cent.

The AER also noted the following

We are satisfied there is a need to address some of the issues raised by Ergon Energy to justify the other system enabling projects. However, it is unclear whether the forecast capex reflects the efficient amount a prudent operator would spend to address these issues. In particular, based on the supporting information provided by Ergon Energy in its regulatory proposal, there are a number of systematic issues with Ergon Energy's approach to developing the forecast programs of work:

- *The benefits to consumers and Ergon Energy have generally not been quantified and assessed against the costs of the programs…..*
- *There is insufficient risk assessment and it is not evident that the proposed volume of work has not been optimised for risk….*
- *There is insufficient exploration of alternative options and solutions, and the cost/benefit of these options to achieve the desired outcomes……*

Our analysis above identified that Ergon Energy's forecasts for sub-transmission and distribution capex were over-estimated by 5 to 15 per cent based on systemic biases in Ergon Energy's forecasting process. These systemic biases were:

- *the capex has not been adequately linked to a prudent needs-driven analysis*
- *the capex has not been adequately supported by cost-benefit analysis, robust options analysis and appropriately-applied risk assessment, and*
- *the capex includes estimates that have led to a higher level of expenditure than may be required.*

We consider these biases are systemic to Ergon Energy's capex forecasting approach and are therefore also present within Ergon Energy's forecasting of other systems enabling capex. Accordingly, we have reduced Ergon Energy's proposed capex forecast for other system enabling technologies by 15 per cent to $82.4 million ($2014−15). This is at the upper end of the range of the expected over-estimation within Ergon Energy's sub-transmission and distribution forecasts.

For sub-transmission and distribution, we adopted a mid-point of the range found by EMCa in its sample review. While there was no evidence pointing towards the upper or lower bounds of the range, there was some evidence that Ergon Energy followed robust methodologies to estimate augex (including prudent deferral of some projects). However, as we are not satisfied based on the evidence (as discussed above) that Ergon Energy has generally applied prudent forecasting techniques in developing its other system-enabling capex proposal, we consider that the upper

> *end of the range more reasonably reflects the expected over-estimation within Ergon Energy's forecast of other system-enabling capex*

Ergon Energy does not believe there is a systematic bias of 15% in this category. The responses below highlight the justifications associated with this statement.

Business Case Development and Justification

EMCa did not review the Other Systems Capex category, and as such the systematic biases that were claimed to be evident in subtransmission and distribution are not material to the way the costing model is applied to Other System Enabling Capex. For the specified projects in this category, there has been applied a robust estimating process that was reviewed by Parson's Brinkerhoff and Sinclair Knight Mertz. For each business case costing, was qualified for each component in detail and the quality of its source determined. This was detailed in the following two documents (that formed part of the submission) – *07.09.01 Network Capital Expenditure Forecast Model Summary and 07.00.09 Capital Expenditure Forecast Unit Cost Methodologies 2015-20.*

For the projects listed by the AER (Integrated Network Operations Centre, Alternative Data Acquisition Service and Distribution Management System), the Ergon Energy business case tool contains a minimum of 3 alternatives for each project - Do Nothing, Option A and Option B. Each option is explored in depth and financial and risk calculated for each. An option comparison summary is supplied as part of each business case which summarises the financial (NPV) and risk for each option. However the detail associated with Do Nothing (Business as usual) and the non-preferred options (e.g. Option B, C etc.) were not included in the summary report given to the AER. However that information is available in the Business Case if required by the AER.

For technology investments, Ergon Energy has focused the business cases on the most prudent and efficient solution to meet the business need. Customer drivers were determined and validated prior to the development of the business cases.

The document titled *07.00.04 Forecast Expenditure Summary Other System and Enabling Technologies 2015-2020* was provided to the AER to support Ergon Energy's Regulatory Proposal. In Section 4.1 of this document it described that the technology investments in Operational Technology (including Distribution Management System, Integrated Network Operations Centre and Alternative Data Acquisition Service) are focused around providing the customer more choice in how they obtain and manage their power as well as allowing Ergon Energy to improve utilisation and spend less on augmentation of the network. These customer drivers were taken from the detailed customer surveys completed as part of the AER preparation. As such they are not quantified in business cases but simply stated as a requirement to achieve. Therefore, business cases and strategy documents associated with the Distribution Management System, Integrated Network Operations Centre and Alternative Data Acquisition Service focus on delivering the most prudent and efficient solution rather than attempting to justify the customer drivers.

Safety Implications of an across the board 15% reduction

A number of the programs in Other Systems Enabling Capex relate to the safety of the network, the public and the environment. Specifically these programs are AC System Upgrades, LV Spreaders and Fuses and Transformer Bunding.

The AER has not specifically commented upon the LV Spreaders and Fuses program and it also appears that EMCa have not provided comment on this proposed program either. However a 15% reduction has occurred without an understanding of the safety implications.

Substation AC systems are an essential component necessary to operation of a substation. The systems provide services such as lighting, pumping, general 240v and 415v ac power supply. Most substations are designed today with embedded ac systems. In the past some of Ergon Energy's legacy organisations designed the source of the ac systems to be external to the substation, and others to provide power supply directly to customers.

As fault levels have generally risen over the years, these historical designs have resulted in steadily increasing step and touch potentials for those customers fed from these supplies, or for staff in substations fed from external supplies.

In *07.04.02 Engineering Report AC Systems*, Ergon Energy documented safety issues arising from these step and touch potentials and the legislative driver requiring Ergon Energy to undertake mitigation measures So Far as Reasonably Practical (SFAIRP).

Ergon Energy questions whether the AER has considered the need for resolving this safety issue, or the background provided in the submission document. As such, the AER has not met its obligations to achieve the NEO [National Electricity Objective]. Ergon Energy contends that the AER should review its decision in regards to funding reductions related to resolving this long term public and staff safety issue.

In EMCa's review of Ergon Energy's Proposed Augmentation and Replacement Expenditure they stated[31]:

> *For the Distribution overhead conductors, Ergon proposed a combination of targeted programs for connector, splice replacement, feeder re-conductoring and installation of LV spreaders in addition to the management of defects identified from inspection.*

EMCa also noted that[32]

> *For LV switchgear, defects are managed as a part of the defect refurbishment program. LV transformer fuses are being installed to mitigate LV clashing as part of the LV fuse and spreaders program.*

Ergon Energy included a program for application of LV Spreaders and Fuses under the Other Systems and Enabling Technologies category, recognising that its proposal is to increase the volumes of these assets beyond current network asset quantities.

Ergon Energy contends that the intent of this program is clearly to mitigate safety risks arising from low voltage conductor failures, resulting in live wires on the ground. Ergon Energy documented several serious public safety incidents that have arisen out of grounded live wires. As documented in its submission, Ergon Energy is bound by the Queensland Electrical Safety Act and is required SFAIRP to undertake mitigation measures unless the cost is grossly disproportionate.

Ergon Energy questions whether the AER has considered the need for resolving this safety issue. Ergon Energy is concerned that by assigning an arbitrary reduction of 15% for this funding, the AER has not met its obligations to achieve the National Electricity Objective.

Finally, Ergon Energy takes its environmental responsibilities seriously. The purpose of transformer bunding is to prevent a low probability high consequence event of significant loss of oil event

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[31] EMCa report to AER: Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020 Final version 8.3, 20/04/2015, page 72

[32] EMCa report to AER: Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020 Final version 8.3, 20/04/2015, page 77

occurring. Under this scenario, typically thousands of litres of oil may be released into the surrounding environment.

In Ergon Energy's submission document *07.04.01 Engineering Report Zone Substation Bunding Upgrade Program*, Ergon Energy described the technology available to manage oil releases of the volumes contemplated under transformer failure scenarios. Ergon Energy also documented legal advice (In Annex C of the submission proposal document) that discusses Ergon Energy's potential liability arising out of an absence of bunding at substations. In essence, Ergon Energy's legal obligations include a need to:

- Ensure compliance generally with the general environmental duty; and
- Avoiding committing offences of unlawful environmental harm.

It is an offence under s440ZG of the EP Act to unlawfully deposit a prescribed water containment (including transformer oil) in a place in a way so that it could be reasonably expected to wash or otherwise move into waters, a roadside gutter or a storm water drain. If done accidently, the penalty maximum is $165,000.

Ergon Energy reviewed its substation bunding arrangements. It identified sites where bunding did not exist and therefore represented a possible environmental hazard. The sites were assigned a risk level based upon proximity to potable water storage, water courses, drains and the ocean and the potential that released oil would be transferred into those water systems.

In its submission, Ergon Energy proposed that high risk sites would be treated with appropriate bund to prevent this environmentally catastrophic circumstance. Typically, these sites are upstream of rivers, water supply dams, providing potential for oil release into the Great Barrier Reef or contaminating the water supply for entire communities.

The AER has commented that insufficient justification has been provided to demonstrate why bunding is the most cost effective solution. Bunding is intended to prevent low probability high consequence oil release into the environment. Ergon Energy acknowledges the AER's comment and advises that the only alternatives not presented in the submission document would be removal of the potential containments completely either by:

- removal of 50 large substation power transformers, at a cost of the order of $75 million ($2014 - 15, direct cost). This would not eliminate the low probability high consequence scenarios and the high risk rating of the situation, hence would not change the risk situation and hence would be imprudent.
- removal/transfer the entire 43 substations to alternate locations. The cost for this is conservatively estimated at $800 million ($2014 - 15, direct cost) and would present a grossly disproportionate response and hence be imprudent.

These alternatives have costs that are so far and above the presented alternatives as to be considered nonsensical and hence not included in the submission documents.

Ergon Energy asserts that the AER should re-evaluate its preliminary determination and approve separate funding provision for installation of bunds at high risk locations.

4.4.6. Unexplained capex

The AER stated Ergon Energy's total proposed augex forecast is $660 million ($2014−15). Based on our review of Ergon Energy's supporting documentation, we can account for $627 million through the individual forecasts for sub-transmission, distribution, reliability, power quality, and other system-enabling capex (as set out in Table B.3). The remaining $33 million ($2014−15) is not accounted for within Ergon Energy's regulatory proposal and its supporting documentation. Furthermore, it was not identified by EMCa in its technical review.

We cannot be satisfied that this additional $33 million ($2014−15) is prudent and efficient without supporting evidence of the underlying driver of the capex and how it can be calculated. On this basis, we have not included it in our alternative estimate.

As per the AER's invitation in the Preliminary Determination, Ergon Energy offers a detailed explanation to account for of the $33.1 million of unexplained augmentation capital expenditure. Ergon Energy understands that the AER sourced the direct cost forecasts, provided in "Table B.1 Ergon Energy's proposed augex ($2014-15, million, excluding overheads)" from the relevant Forecast Expenditure Summary documents of Ergon Energy's proposal.

The "unexplained" capex being $33.1 million is due to different escalation methodologies applied to re-state forecast expenditure in $2014-15 in:

- the Forecast Expenditure Summary documentation
- the reset RIN

The difference is due to the reset RIN forecasts which include full labour, materials and CPI cost escalation, while the expenditure stated in the Forecast Expenditure Summary documentation only includes escalation for CPI.

Related to the issue of escalation, the AER was dissatisfied with Ergon Energy's forecast real cost escalation and substituted an alternative estimate across all capital expenditure categories. This reduction proposed by the AER includes the identified $33.1 million of "unexplained" capital expenditure from Augmentation. While the justification of the non-CPI (material and labour) real cost escalation will be discussed in other parts of Ergon Energy's Revised Submission. The removal of $33.1 million from the Augmentation Expenditure Forecast (in isolation) effectively results in this amount being deducted twice from Ergon Energy's total submission.

This is detailed further in the *Submission to the AER on its Preliminary Determination - Ergon Energy Reset RIN Response to Material Issues* document.

5. List of Changes

Table 2 sets out the changes we have made to our supporting documents in response to the AER's Preliminary Determination.

Table 2: Revisions to our supporting documents in relation to augmentation expenditure

Document	Section/Table	Revision
07.00.02 Forecast Expenditure Summary Corporation Initiated Augmentation	Section 1.1	• Removal of advice concerning consideration of costs as unescalated
	Section 2.1 Table 1	• Update Corporation Initiated Augmentation capital expenditure direct costs to $2014-15 and revised estimate of 2014-15 year expenditure
	Table 2	• Update Corporation Initiated Augmentation capital expenditure total costs to $2014-15 and revised estimate of 2014-15 year expenditure
	Section 4.2 Table 7	• Updated Actual vs Forecast CIA
	Section 6 Table 9	• Updated DNAP expenditure category tools to $2014-15$
	Section 7 Table 10	• Additional information with revised expenditure • Updated Demand Reduction Targets moved to $2014-15
	Section 8.1 Table 11	• Updated CIA Capital Expenditure Forecast (direct) to $2014-15
	Table 14	• Updated Augex Model Output Projected costs (direct) to $2014-15
	Table 15	• Updated Comparison of Augex to Proposed (direct) to $2014-15
	Section 8.2.1	• Additional information with revised expenditure included for Sub-transmission Augmentation
	Table 12	• Updated Expenditure Categories to $2014-15
	Figure 19	• Updated 19 Sub-Transmission Expenditure Profile
	Section 8.2.2	• Additional information with revised expenditure included for Distribution Augmentation
	Section 8.2.3	• Revised and updated information for Impact of High Penetration of Photovoltaic (PV) Systems on Distribution Networks

Document	Section/Table	Revision
07.00.04 Forecast Expenditure Summary Other System and Enabling Technologies	Section 2.1 Table 1 Table 2	• Forecast Direct cost SCS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure • Forecast Direct cost ACS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure
	Section 2.2 Table 3 Table 4	• Forecast Total cost SCS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure • Forecast Total cost ACS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure
	Section 3 Table 5	• Current period Direct cost expenditure updated to $14-15
	Sections 4-6 Table 6 - 8	• Forecast Direct cost expenditure updated to $14-15
07.00.05 Forecast Expenditure Summary Network Reliability and Quality of Supply	Section 2.1 Table 1	• Updated forecast Direct Expenditure information to $14-15 SCS. • Forecast Direct cost SCS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure
	Section 2.2 Table 2	• Updated forecast Total Expenditure information to $14-15 (SCS) • Forecast Total SCS expenditure updated to $14-15 and revised estimate of 2014-15 year expenditure
	Section 4.2 Table 3 Table 4	• Updated 2014-15 year Direct cost expenditure estimate and variance • Updated 2014-15 year Total cost expenditure estimate and variance
	Section 4.3.2 Table 6	• Updated to include estimated Quality of Supply complaints for 2014-15
	Section 6.1.1 Table 7 Table 8	• Updated forecast Direct cost SCS expenditure to $14-15 • Updated forecast Total cost SCS expenditure to $14-15
	Section 6.2.1 Table 10 Table 11	• Updated forecast Direct cost SCS expenditure to $14-15 • Updated forecast Total cost SCS expenditure to $14-15
07.02.02 Distribution Network Augmentation Plan	DNAPList	• Reduction in the DNAP Modelled/ Specified capex forecast (Direct cost, 2012/13 Real $); • Combining the data in the five worksheets titled: "RegionalDNAPList", "Combined Project costs (0B)", "Inputs Dist Augmentation V3", "Inputs Dist Aug Specified V4-1" and "DAD_Extract_20140709" into a single worksheet titled: "DNAPList". This streamlining of the number of worksheets has meant duplicated information has been removed.

Document	Section/Table	Revision
07.02.11 Demand Management Overview	Various	• All position titles in the document to reflect position titles present organisation structure. • Program expenditure to reflect revised program forecast • Demand management targets to reflect the revised forecast program • Safety-net impacts and the application of safety-net expenditure • Broad based programs and the application method • Forward forecasts and the impacts of a high growth scenario • Cost benefit analysis and details of program impacts

6. Supporting documents

The following documents support our response to the AER on augmentation expenditure.

Name
Network Risk Assessment Guideline
Submission to the AER on its Preliminary Determination - Ergon Energy Reset RIN Response to Material Issues
Attachment A - EECL Reset RIN Revision to Template 2.2 Repex (this is an attachment to the *Ergon Energy Reset RIN Response to Material Issues* document)
EXP09.02 Jacobs – Reliability Impact Assessment
Submission to the AER on its Preliminary Determination – Demand Management

Definitions, acronyms, and abbreviations

ECC	Emergency Cyclic Capacity
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
EMCa	Energy Market Consulting associates
EUAA	The Energy Users Association of Australia
ALARP	As Low As Reasonably Practical
Capex	Capital expenditure
CPI	Consumer Price Index
CCP	Consumer Challenge Panel
DNAP	Distribution Network Augmentation Plan
DNSP	Distribution Network Service Provider
DTF	Distribution Transformer
ENA	Energy Networks Association
ENCAP	Electricity Network Capital Program
Ergon Energy	Ergon Energy Corporation Limited
HV	High Voltage
IRP	Independent Review Panel on Network Costs
LV	Low Voltage
MSS	Minimum Service Standards
NEM	National Electricity Market
NSP	Network Service Provider
NER	National Electricity Rules
Opex	Operating expenditure
PoE	Probability of Exceedance
PV	Photovoltaic
QCA	Queensland Competition Authority
RIN	Regulatory Information Notice
RIT-D	Regulatory Test for Distribution
SFAIRP	So Far as Reasonably Practical
STPIS	Service Target Performance Inventive Scheme
SWER	Single Wire Earth Return