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Dear Mr Khoe

SUBMISSION ON THE ECONOMIC REGULATION OF NETWORK SERVICE PROVIDERS CONSULTATION PAPER

Ergon Energy Corporation Limited (Ergon Energy) welcomes the opportunity to provide a submission to the Australian Energy Market Commission (AEMC) on its *Economic Regulation of Network Service Providers (NSPs) Consultation Paper*.

Ergon Energy is generally unsupportive of the Rule change requests put forward by the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (the Committee). On the whole, Ergon Energy considers that the existing Rules provide a sound economic regulatory framework and should be allowed to operate as originally intended. Having said this, Ergon Energy recognises that the AER has proposed a number of improvements and refinements which are worth pursuing through the Rule change amendment process.

Ergon Energy is a member of the Energy Networks Association (ENA), the peak national body for Australia's energy networks. The ENA has prepared a comprehensive submission addressing each of the questions posed by the AEMC in the two Consultation Papers published on 20 October 2011 and 3 November 2011. Ergon Energy is fully supportive of the arguments contained in their submission. In addition to the issues raised by the ENA, Ergon Energy provides further comments on a number of areas of concern.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact Jenny Doyle, Manager Regulatory Affairs – Policy and Regulation, on (07) 4092 9813.

Yours sincerely

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Encl: Ergon Energy's submission.

Ergon Energy Corporation Limited

Economic Regulation of Network Service Providers

Consultation Paper

Australian Energy Market Commission

8 December 2011

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Consultation Paper
Australian Energy Market Commission
8 December 2011

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TABLE OF CONTENTS

1. INTRODUCTION 3

2. KEY ISSUES 5

2.1 Drivers of rising electricity prices 5

2.2 Capital and operating expenditure approval framework 6

2.2.1 The evidentiary burden is on the AER 7
2.2.2 Requirement to accept a forecast if it ‘reasonably reflects’ 7
2.2.3 Line-by-line assessments and other assessment techniques 9

2.3 AER discretion and merits review 10

2.3.1 Gamma 11
2.3.2 Non-system property capex 11
2.3.3 Labour cost escalators 11
2.3.4 Other costs 11

2.4 Equitable treatment for government-owned NSPs 12

3. SPECIFIC COMMENTS 13

3.1 Forecasting required expenditure 13

3.2 Incentives to spend within expenditure forecasts 13

3.3 Contingent projects, capex re-openers and pass through events 13

3.4 Treatment of shared assets 14

3.5 Determination of the rate of return 14

3.5.1 Current arrangements 14
3.5.2 Benchmark for government-owned NSPs 15
3.5.3 Excessive profits 15
3.5.4 Debt risk premium 15

3.6 Submissions received during a determination process 15

3.7 Timeframe for the conduction of WACC Reviews 16

1. INTRODUCTION

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider (DNSP) in Queensland, welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) on its *Economic Regulation of Network Service Providers (NSPs) Consultation Paper*.

Ergon Energy is generally unsupportive of the Rule change requests put forward by the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (the Committee). Of particular concern is that the AER is proposing significant amendments to the National Electricity Rules (the Rules) when the current regulatory regime has only been in place for three years. The AEMC extensively consulted with stakeholders on these issues at the time of establishing Chapter 6A in 2006. The framework aimed to encourage investment in the energy sector and sought to provide certainty to investors to make long-lived investments. We recognise that incremental changes to the Rules are important to improve the flexibility and resilience of energy markets, but changes to the fundamental design of the framework are not appropriate at this time.

Ergon Energy does not believe the AER Rule change package demonstrates any systematic failures in the Rules in the proposed areas of change, or that these perceived deficiencies are significant contributors to rising electricity prices. It is important to understand that the consolidated Rule change request is not the solution to the problem of rising electricity prices. As acknowledged by the AER, there are many drivers of rising electricity prices, and one practical solution to this is to enhance customers' understanding of peak demand and how their behaviour impacts on it (for further discussion, see Section 2.1).

Ergon Energy is a member of the Energy Networks Association (ENA), the peak national body for Australia's energy networks. The ENA has prepared a comprehensive submission addressing each of the questions posed by the AEMC in the two Consultation Papers published on 20 October 2011 and 3 November 2011. Ergon Energy is fully supportive of the arguments contained in their submission. In addition to the issues raised by the ENA, Ergon Energy provides further comments on a number of areas of concern.

Additionally, Ergon Energy acknowledges that the Queensland Treasury Corporation (QTC) has prepared a detailed submission on the technical aspects of the consolidated Rule change request in relation to the debt risk premium and the regulated cost of debt. As the expert in this regard, Ergon Energy refers the AEMC to QTC's submission. However, Ergon Energy notes that:

- It supports the current use of a ten year risk-free interest rate and debt risk premium for the purpose of calculating the regulated cost of debt for all NSPs;
- The regulated cost of debt allowance for government-owned NSPs should continue to include compensation for a ten year debt risk premium. The level of network charges should not differ due to the ownership status of the NSPs;
- Claims of over-compensation cannot be made by analysing the cost of debt without having regard for the cost of equity. The increasing reliance on shorter-term debt since the start of the global financial crisis (GFC) has led to an increase in refinancing risk. The impact of this risk on the equity providers must also be considered;
- Ergon Energy supports consideration of whether a less prescriptive definition for the debt risk premium is appropriate to allow the AER to draw upon a sufficient range of data sources. The Rules should provide some guidance as to how the debt risk premium is to be estimated, rather than giving complete discretion to the AER. Further discussion of this issue prior to the next Weighted Average Cost of Capital (WACC) review would be useful; and
- Calculating the regulated cost of debt according to a longer term moving average may have some merit, although the risk-free interest rate and debt risk premium should correspond to a ten year term. The current method of fixing the cost of debt over a short time interval every five years creates significant market signalling and re-pricing risks for NSPs with large debt portfolios.

This submission provides additional information in relation to the debt management strategies used by Ergon Energy to manage interest rate risk within the current regulatory framework. In particular, we present information in response to the claims made by the Committee that government-owned NSPs have no control over their borrowings and do not respond to incentives to reduce the actual cost of debt.

Ergon Energy has structured this submission into the following sections:

- Section 2 details our key issues relating to the consolidated Rule change request; and
- Section 3 outlines our specific comments on various aspects of the consolidated Rule change request.

On the whole, Ergon Energy considers that the existing Rules provide a sound economic regulatory framework and should be allowed to operate as originally intended. Having said this, Ergon Energy recognises that the AER has proposed a number of improvements and refinements which are worth pursuing through the Rule change amendment process.

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

2. KEY ISSUES

This section discusses Ergon Energy's key issues in response to the amendments to the Rules proposed by the AER and the Committee. Ergon Energy believes these key issues require further development and consideration by the AEMC.

2.1 Drivers of rising electricity prices

It is important that the AEMC understand that the proposed Rule changes by the AER and the Committee are not the solution to the problem of rising electricity prices. As acknowledged by the AER, there are numerous drivers for the recent price rises including:

- increased investment to replace ageing assets and to meet increased peak demand;
- growing customer connections;
- higher reliability standards; and
- increases in labour and material costs.[1]

As a DNSP, we are acutely aware of how important a high quality, reliable and affordable supply of electricity is to the continued economic growth, prosperity and lifestyle of Queenslanders. For this reason, we invest heavily in developing affordable alternatives to address growing peak demand. Over the 2010–2015 regulatory control period, Ergon Energy plans to invest almost $70 million in developing these solutions. We consider that through enhancing customers' understanding of peak demand and how their behaviour impacts on it, we can help alleviate electricity price pressures. An important mechanism to achieve this will be through practical applications arising from the *Power of Choice – giving consumers options in the way they use electricity* review.

It is also important to recognise the impact social policies have on electricity prices, including the strong push towards investing in renewable energy (e.g. solar photovoltaic (PV) systems) and the provision of safety net tariffs. The Commonwealth Government and state and territory governments have introduced a myriad of policies and programs to stimulate the growth in renewable energy. Of particular note are the Commonwealth Government's Small-scale Renewable Energy Scheme (SRES) and state-based Feed-in Tariff (FiT) schemes such as the Queensland Government's Solar Bonus Scheme. These schemes are financed by all electricity customers. Further, those customers accessing a FiT scheme are internalising the benefits they gain from producing the energy by limiting their future exposure to other policies like the price on carbon. As stated by the Commonwealth Government Minister for Resources and Energy, Martin Ferguson MP:

> *Premium Feed-in Tariffs create an additional burden on electricity consumers, particularly those that cannot afford to install renewable energy systems but pay higher electricity prices to cross-subsidise those that can afford such systems.*[2]

We acknowledge that recent adjustments to a range of policies and programs may have benefits for consumers into the future.

As indicated above, another important consideration for electricity prices is the operation of regulated electricity price markets through the application of safety net tariffs. The Queensland Government has in place a Uniform Tariff Policy (UTP) which allows customers of the same class to access uniform retail tariffs and pay the same Notified Price for their electricity supply, regardless of their geographical location. The UTP subsidies customers in Ergon Energy's distribution area through a Community Service Obligation (CSO) payment which funds the difference between actual costs incurred by Ergon Energy Queensland Pty Ltd (Ergon Energy's retail business) and the amount of revenue recovered from its customers at Notified Prices. As actual costs of supplying electricity in regional Queensland are higher than the Notified Prices, this means that customers in regional Queensland do not see the true cost to supply electricity to their premises. This means that customers may not have an incentive to consider the

[1] AER (2011), *Rule change proposal – Economic regulation of transmission and distribution network service providers*, September 2011, p6

[2] Ferguson, M. (2011), *House of Representatives – Questions in writing*, 8 February 2011, Question 43

economic costs of their decisions (for example, the location of their business or their contribution to peak demand).

Ergon Energy acknowledges that the Queensland Government has directed the Queensland Competition Authority to develop a new retail pricing framework and tariff structure based on cost-reflective tariff structures which will commence from 1 July 2012.

2.2 Capital and operating expenditure approval framework

In our submission to the AEMC's Issues Paper entitled *Review of the Electricity Transmission Revenue and Pricing Rule*, Ergon Energy argued that the Rules should not seek to impose unnecessary prescription but rather should establish high level principles and provide the AER with discretion in undertaking its functions. The right balance between prescription and discretion needed to be attained and we believe that the existing Rules generally accomplish this. Ergon Energy believes that the AER can achieve most of what it wants and needs to, but there are some instances where it is not fully exercising this power.

The current propose-respond model enables DNSPs to submit a preferred approach consistent with the Rules based on their individual commercial and operating issues. The AER then assesses this submitted information and is able to reject the proposal, including in instances where the parameter values for capex and opex do not reasonably reflect:

- The efficient costs of achieving the expenditure objectives; and
- The costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve those objectives.[3]

The AER has argued that the current drafting of the Rules:

- Allows NSPs to propose the highest possible forecast and places the evidentiary burden on the AER to prove the forecast is not prudent and efficient, resulting in systematically inflated expenditure forecasts being included in the AER's determinations;
- Only allows the AER to amend a proposed forecast 'to the extent necessary' to make it fall within the range that 'reasonably reflects' the required expenditure (i.e. the AER can only amend forecasts to bring them back to the top of the range); and
- Requires the AER to form any substitute on the initial regulatory proposal on the basis of a line-by-line assessment of the expenditure forecasts, thus restricting the AER from using benchmarking and assessing matters such as the deliverability of expenditure.

An examination of the evidence from the AER's Final Distribution Determination for Ergon Energy does not support the AER's arguments that its analysis has been restricted in the manner it claims. As discussed in the following sections, the AER has:

- Placed the evidentiary burden on Ergon Energy to demonstrate that our forecast for customer service costs was prudent and efficient;
- Downwardly revised the total expenditure forecasts initially proposed by Ergon Energy in our regulatory proposal to ensure they reasonably reflected the expenditure criteria, and, for particular expenditure categories, has adopted a midpoint of a potential range of forecasts or has not considered a potential range at all; and
- Made top level (not 'line by line') adjustments to our expenditure allowances and used other assessment techniques such as benchmarking and the deliverability of our proposed property program and program of works.

Ergon Energy therefore considers that the Rules as currently drafted strike an appropriate balance between prescription and discretion. The existing framework allows the AER to assess expenditure proposals and make adjustments as appropriate in order to ensure prudent and efficient expenditure. In

[3] Clause 6.5.6(c) and 6.5.7(c)

making this assessment, the AER may have regard to a range of factors, and is not limited to what is contained in the regulatory proposal. The AER has also used its information gathering powers under the National Electricity Law (NEL) to collect any relevant cost information not voluntarily provided by NSPs.[4]

The AER's Rule change request seeks a significant expansion of this discretion by allowing the AER to *determine* rather than accept/substitute forecasts and have regard to any factors it considers relevant, which may or may not include the regulatory proposal. Ergon Energy believes this is unwarranted and heightens the risk of regulatory error. It is likely to lead to forecasts which significantly depart from actual expenditure needs when it is Ergon Energy, not the AER, who best understands the future expenditure needs of the business. Ergon Energy considers that the AER must be required to start from the regulatory proposal and make minimal adjustments to ensure prudent and efficient expenditure.

2.2.1 The evidentiary burden is on the AER

Ergon Energy considers that the evidentiary burden is not on the AER to prove that a forecast is prudent and efficient. During the 2010–15 Distribution Determination process for Ergon Energy, the evidentiary burden was on us to "*provide sufficient evidence to support its (our) claims that the forecasts only relate to correctly classified opex…*" for our customer service costs.[5] Ergon Energy provided updated and corrected spreadsheets to the AER during the Draft Decision process. The AER's consultant, Parsons Brinckerhoff Australia Pty Limited (PB), was unable to find evidence that the forecasts included costs that should have been classified as Alternative Control Services (ACS), but recommended adjustments regardless.[6] The AER considered that the operating expenditure (opex) forecasts needed to be unambiguously related to either Standard Control Services (SCS) or ACS. Since the AER considered that we did not sufficiently demonstrate that the customer service opex forecast related solely to SCS, the AER found that our proposed forecast was unsubstantiated.[7] This led to a proposed reduction of $50 million to the customer service opex forecasts during the Draft Decision, and a final reduction of $33 million in the Final Distribution Determination.[8] Therefore, because Ergon Energy failed to meet the burden of proof, the AER was able to reject our forecasts.

2.2.2 Requirement to accept a forecast if it 'reasonably reflects'

Ergon Energy does not believe that the AER has been restricted by the Rules to accept total expenditure forecasts which are upwardly biased nor has it been limited to bring forecasts back to the top of the reasonable range. Indeed, in its Final Distribution Determination for Queensland DNSPs, the AER rejected both the total capital expenditure (capex) forecasts and the total opex forecasts proposed by Ergon Energy in its regulatory proposals. The AER then substituted its own forecast of the total capex (opex) it considered reasonably reflected the capex (opex) expenditure criteria, having regard to the capex (opex) factors outlined in the Rules.[9] As illustrated by Table 1, this led to a 17 per cent reduction in Ergon Energy's capex allowance, and a 10 per cent reduction in opex allowance.

Table 1: Difference between Ergon Energy's proposed forecast and the AER's substituted expenditure forecast

	Capex			Opex		
	Proposed [(a)] ($m, 2009-10)	*Substituted ($m, 2009-10)*	*% change*	*Proposed ($m, 2009-10)*	*Substituted ($m, 2009-10)*	*% change*
Ergon Energy	6032.9	4988.9	-17 [(b)]	1992.6	1801.2	-10 [(b)]

Source: AER (2010), *Final Decision – Queensland Distribution Determination 2010–11 to 2014–15*, May 2010.

Notes:
(a) Refers to the amounts proposed in the initial regulatory proposals.

[4] Division 4 of Part 3 of the NEL allows the AER to issue regulatory information notices requiring the submission of such information as the AER considers necessary for it to perform or exercise its functions or powers under the NEL or the Rules.
[5] AER (2010), *Final Decision – Queensland Distribution Determination 2010–11 to 2014–15*, May 2010, p178
[6] AER (2009), *Draft Decision – Queensland Draft Distribution Determination 2010-11 to 2014-15,* 25 November 2009, p163
[7] Ibid 5, p180
[8] Ibid 5, pp177 and 180
[9] See clauses 6.5.6(e) for opex and 6.5.7(e) for capex

(b) The Australian Competition Tribunal's decision later increased Ergon Energy's capex to $5112.9 million and opex to $1813.2 million, translating into a 15 per cent reduction and 9 per cent reduction on the initial proposal respectively.

Evidence also shows that in making adjustments to particular expenditure categories for Ergon Energy, the AER generally did not include any discussion of potential ranges. Where potential ranges were discussed, the AER adopted the midpoint rather than the upper bound. For example:

- In determining an appropriate estimate of the proportion of Corporation Initiated Augmentation (CIA) capex, the AER considered that it was a reasonable approach to take the midpoint of the possible range of values as an appropriate estimate due to the lack of available information.[10] In its Draft Decision,[11] the AER reduced the CIA growth capex forecast by $526 million based on advice from PB as result of deferring this expenditure for 18 months. This was based on PB's reliance on MMA's advice that Ergon Energy's demand forecast was about one to two years ahead of MMA's demand forecast.[12,13] In the Final Distribution Determination, the AER readjusted the reduction in forecast to $500 million.[14] This demonstrates that the AER has not been restricted to bringing expenditure forecasts back to the top of the range.

- The AER did not contemplate a range at all in assessing our Customer Initiated Capital Works (CICW) growth capex forecast. PB did a full substitution using its own methodology for forecasting CICW work as PB was of the view that the forecast was not sufficiently substantiated.[15] In its Draft Decision, the AER reduced the CICW growth capex forecast by $318 million.[16] When the correct input data was used, the PB model resulted in an even higher adjustment to Ergon Energy's CICW growth capex forecast, leading to a reduction of $402 million in the Final Distribution Determination.[17] This illustrates that the AER is not constrained in substituting data from its own models.

- The AER also did not contemplate a range when assessing our proposed preventative maintenance opex, but rather did a full substitution. The AER reduced our proposed forecast by $23 million based on the findings of PB.[18] The adjustments reflect a change from Ergon Energy's four year inspection cycle to a four and a half year inspection cycle, a reduction in coincident visual inspections and the incorporation of a capex/opex trade-off as a result of the increased capex in both replacement and growth capex.[19]

- The AER reduced Ergon Energy's proposed property capex by $191 million to reflect a 'business as usual' approach in its Draft Decision on the basis that Ergon Energy was unable to provide business case documentation for the high value property projects.[20] This meant the AER was unable to assess the prudency and efficiency of the forecasts. PB substituted a 'business as usual' forecast which meant there was no allowance for any property capex beyond refurbishment of existing assets at recent historical levels. That is, there was no provision for replacement or new building assets as the recent historical spend levels were just small capitalised refurbishment items while a whole of business property strategy was being developed.

  It was later readjusted to a reduction of $148 million to reflect PB's analysis of the major property capex and exclusion of the two largest property projects.[21] PB accepted the business cases but substituted its own methodology for ranking the major property projects. In all cases none of the projects should have proceeded based on this methodology but PB recommended only excluding the two largest projects. This demonstrates that the AER is able to exercise a lot of discretion in the way it approaches the analysis and the way it then chooses its reasons for including or excluding individual projects. Ergon Energy appealed this decision at merits review and the

[10] Ibid 5, p110
[11] Ibid 6, pp106-107
[12] Ibid 5, p109
[13] PB (2009), *Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015*, October 2009, pp36-37
[14] Ibid 5, p111
[15] Ibid 13, p39
[16] Ibid 6, p107
[17] Ibid 5, p113
[18] Ibid 5, p165
[19] Ibid 5, pp157-165
[20] Ibid 6, p107
[21] Ibid 5, pp126-132

Australian Competition Tribunal (the Tribunal) found that the AER erred in applying different criteria in its assessment of the major property projects (see also Section 2.3.2). If the AER had been consistent then the Tribunal would likely have accepted the AER's adjustments, resulting in a capex allowance below 'business as usual' and below the lower bound of a reasonable range. This demonstrates that the AER could go below a reasonable range based on a limited examination of 'business as usual' and the drivers for the 'business as usual' expenditure.

Finally, the Tribunal has noted that:

> *Simply because there is a range of forecasts and a DNSP's forecast falls within the range does not meant it must be accepted when…the AER has sound reason for rejecting the forecast.*
>
> *…the Rules does not require the AER to identify a range of forecasts and determine whether a DNSP's figure falls within that range. Nor is there anything in the legislation…that requires the AER to accept a figure advanced by a DNSP simply because it may be within a range of figures that the DNSP may point to as reasonable.*[22]

This means the AER has the power to achieve regulatory outcomes that are not overly distorted by the strategic behaviour of NSPs.

2.2.3 Line-by-line assessments and other assessment techniques

While Ergon Energy agrees with the AER that a 'line-by-line' assessment of the regulatory proposal may not be sufficient to assess prudency and efficiency and that other tools may be required, we do not support the AER's contention that it is being driven to undertake a 'line-by-line' assessment of a DNSP's regulatory proposal. Evidence from our 2010–15 Distribution Determination process shows that the AER has, in practice, used other assessment techniques:

- In determining the appropriate forecast of Ergon Energy's CIA capex, the AER assumed what portion of CIA was sensitive to the demand forecast, and then adopted a top-down adjustment approach. The AER considered it to be a reasonable alternative where a detailed bottom-up was not feasible.[23]
- The AER had regard to benchmark capex and opex expenditure that would be incurred by an efficient DNSP over the regulatory control period in coming to its conclusions on Ergon Energy's forecast capex and opex allowances.[24] The AER used capex ratio analysis and reviewed unit cost information to assess capex, and used opex ratio analysis and regression analysis to assess opex.[25] The AER stated in its Final Distribution Determination that "*the outcomes of the benchmarking undertaken by the AER have… directly impacted on the adjustments made to the opex and capex forecasts proposed by the DNSPs*".[26] Further, the AER has suggested that it will be able to use benchmarking to a greater degree once further data over a longer time period is available and more robust benchmarking techniques are developed. This indicates that the AER's statements around the limitations on benchmarking are in relation to the availability of information rather than restrictions in the Rules.
- The AER explicitly assessed deliverability of expenditure as part of the Ergon Energy's Distribution Determination process for our property program. PB reviewed information provided in relation to the deliverability of Ergon Energy's property program and found that the delivery of the property program to be reasonable and achievable.[27] PB noted that deferred implementation of the largest capex project, Townsville, from 2010–11 to 2012–13 and the removal of the Data

[22] Australian Competition Tribunal (2010), *Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11*, 24 December 2010, para 69
[23] Ibid 5, pp 110-111
[24] Ibid 5, p207
[25] Ibid 5, Appendix G, pp414–427
[26] Ibid 5, p421
[27] PB (2010), *Review of Ergon Energy's revised regulatory proposal for the period July 2010 to June 2015,* May 2010, p62

Centre building reduced the magnitude of the property program over the first two years and assisted in smoothing the schedule of major property works.[28] This was restated in the AER's Final Distribution Determination[29] and the AER found that Ergon Energy had "*demonstrated that its property program had been prioritised and based on a delivery timetable that appears reasonable and prudent*".[30]

- PB also explicitly assessed the deliverability of Ergon Energy's proposed program of works in its October 2009 Review of our regulatory proposal. PB recognised that Ergon Energy should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the 2010–15 regulatory control period.[31] The AER's Draft Decision specifically states that the AER reviewed the deliverability of the forecast capex program[32] and that 'it was satisfied that the deliverability of the forecast capex program will not be constrained by resource availability'.[33] Further, the AER noted that the deliverability is consistent with the capex objectives and reasonably reflects the capex criteria.[34]
- In its Draft Decision, the AER applied a reduction of $119 million to the asset replacement capex forecast as PB was of the view that the volume forecasts underpinning the forecasts were not demonstrated to be prudent.[35] Ergon Energy provided forecasts for 26 different equipment types of which four were examined by PB. PB concluded that of the four examined the basis for the volume forecasts for three were unable to be substantiated and the fourth appeared to be a 'business as usual' approach.[36] PB then applied a volume growth rate based on data from 2001–02 to 2004–05 and applied it to the current level to generate a 'business as usual' forecast for all equipment types.[37,38] This demonstrates that the AER applied a sampling approach and was not constrained by a 'line-by- line' examination.

Finally, Ergon Energy does not agree that a line-by-line approach undermines incentives for efficiency. Upon establishing an expenditure allowance, Ergon Energy is not confined to spending each component or line item that makes up that allowance. We are able to seek out efficiencies and alter this spending mix accordingly and face strong incentives to do so. Therefore, the way in which the expenditure allowance is determined has no impact on efficiency incentives.

2.3 AER discretion and merits review

Under the current regulatory framework, the ability of the AER to reject NSPs' proposals means that it is essential for NSPs to have access to merits review. A merits review is a review of the merits of a decision or challenge to a finding of fact. Generally speaking, merits review tribunals will stand in the shoes of the original decision maker and exercise the powers of the decision maker. Merits review enables NSPs to protect their interests in circumstances where they believe that their proposed parameter values have been unreasonably rejected. The presence of such a review process also encourages NSPs to ensure that their proposals are within the reasonable range. Otherwise, an 'unreasonable' proposal would not be supported on appeal to the Tribunal.

While we note that the merits review process is external to this Rule change request, it is important to consider the outcomes of previous applications to the Tribunal as this highlights instances where the AER has made errors. In light of the AER's proposal to determine forecast expenditure, the merits review process becomes even more important.

[28] Ibid 27
[29] Ibid 5, p127
[30] Ibid 5, p130
[31] Ibid 13, p154
[32] Ibid 6, pxxi
[33] Ibid 6, p127
[34] Ibid 6, p127
[35] Ibid 6, pxxiii
[36] Ibid 13, pp44–53
[37] Ibid 6, p111
[38] Ibid 13, pp54-55

Some examples of the outcomes of previous applications to the Tribunal are outlined below.

2.3.1 Gamma

Ergon Energy, ENERGEX and ETSA Utilities appealed the AER's decision to set gamma, the value of franking credits to shareholders used to calculate the company tax allowance component, at 0.65. The value of gamma is defined as a product of the imputation credit distribution ratio (F) and the utilisation rate (theta).

The AER acknowledged during the proceedings that it had made errors in various parts of its decision on gamma and that:

- There was no empirical data that was capable of supporting an estimated distribution ratio higher than 0.7 (the AER had proposed a ratio of 1.0); and
- It was open for the Tribunal to adopt a substitute distribution ratio of 0.7.

The Tribunal also found that the report relied upon by the AER to determine theta was not the best dividend drop-off study available for the purpose of estimating gamma and decided that theta should be 0.35 rather than 0.65.

Based on the above, the Tribunal determined gamma to be 0.25.

2.3.2 Non-system property capex

Ergon Energy appealed the AER's decision to exclude non-system property capex proposals for sites at Townsville and Rockhampton on the grounds that they were not prudent and efficient. The AER accepted that it should have arrived at a substitute value for this by allowing the cost of the 'business-as-usual' proposal. Further, in a submission to the Tribunal, the AER acknowledged that it had "*no information before it to suggest that Ergon Energy's estimate of the scope and costs…was inaccurate or unreasonable. Accordingly, the AER considers that it is reasonably open to the Tribunal to accept Ergon Energy's cost estimates…*".[39] The Tribunal found that Ergon Energy's original estimates for the sites were appropriate and that the AER had erred in applying different criteria in its assessment of the major property projects.

2.3.3 Labour cost escalators

Ergon Energy appealed the AER's decision to apply a real cost escalator of 0.21 per cent to Ergon Energy's internal labour costs for the first year of the regulatory control period, 2010–11. The Tribunal found that the AER made an error of fact and the exercise of the AER's discretion was incorrect having regard to all the circumstances. The Tribunal accepted the nominal figure of 4.5 per cent derived from Ergon Energy's Union Collective Agreement should be used for calculating its real internal labour rate escalator and that in converting to real terms, an inflation rate of 2.13 per cent inflation rate should be applied. This led to a real increment of 1.33 per cent for 2010–11 instead of the 0.21 per cent proposed by the AER.

2.3.4 Other costs

The Tribunal found that the AER made an error of fact in its finding that Ergon Energy's costs would not be efficiently incurred in delivering Quoted Services. This error did not arise because the AER acted unreasonably or improperly exercised its discretion. Rather, it made an error in findings of fact. The AER also made another error of fact by asserting that Ergon Energy did not provide any information that supported our contentions. While the Tribunal found that Ergon Energy failed to provide adequate information in relation to 'other costs', there was sufficient information provided to necessitate at least a further enquiry by the AER. The Tribunal decided to allow Ergon Energy to recover other one off costs incurred in supplying Quoted Services.

[39] Australian Competition Tribunal (2011), *Application by Ergon Energy Corporation Limited (Non-system Property Capex) (No 8) [2011] ACompT 2,* 10 February 2011, para 2

2.4 Equitable treatment for government-owned NSPs

Ergon Energy disagrees with the Committee's proposal that the return on debt for government-owned NSPs should be determined on a different basis to privately owned NSPs. Ergon Energy is actively involved in managing its interest rate risk and determining the duration and debt maturity profile of its Client Specific Debt Pool (CSP) (for further discussion, see Section 3.5.1).

Ergon Energy notes that the Committee does not provide any reason as to why electricity prices should differ across jurisdictions simply as a result of the ownership of the relevant assets, nor does it recognise the adverse consequences for resource allocation that may result. Their proposal would give rise to circumstances where NSPs operating in different geographic regions set prices that are differentiated by ownership rather than by reference to the underlying economic costs of providing those services. This is inconsistent with the National Electricity Objective and could lead to an artificial incentive for over-investment by customers in the lower price regions, along with under-investment in demand side initiatives, undermining the principles of allocative and dynamic efficiency.

3. SPECIFIC COMMENTS

This section outlines Ergon Energy's specific comments on various aspects of the consolidated Rule change request.

3.1 Forecasting required expenditure

As discussed in Section 2.2 above, Ergon Energy is not supportive of the AER's proposed move towards a 'consider-decide' framework. However, if such a model is adopted, it is vital that the proposed clauses 6.5.6(c) and 6.5.7(c) recognise the circumstances relevant to the specific DNSP. This requirement currently exists under clauses 6.5.6(c)(2) and 6.5.7(c)(2) of the Rules. From a Queensland perspective, it is important for the AER to consider Queensland topography and the high incidence of severe weather events when performing the benchmarking process due to the extent of our network and associated costs.

We also believe that the AER should be restricted from selecting which capex and opex factors it will have regard to. Under clauses 6.5.6(d) and 6.5.7(d) of the proposed Rules "the AER may, as it considers appropriate, have regard to the following…". This should be amended so that the AER must consider and advise its position with respect to all the listed factors for the relevant DNSP.

3.2 Incentives to spend within expenditure forecasts

Ergon Energy agrees that the capex incentive framework can be improved. However, the introduction of a mechanism whereby 40 per cent of any capex overspend during the regulatory control period should be funded by the NSP is not appropriate. This mechanism may lead to a stronger incentive for NSPs to over-forecast and could have a detrimental impact on reliability of supply and service levels. It will also not provide a consistent incentive across the regulatory control period. That is, an NSP will still face an incentive to defer any overspend to the end of the period to minimise the extent of unrecoverable financing costs.

Clause 6.5.8(b) of the Rules currently provides the AER with the power to introduce a capex incentive scheme via the Efficiency Benefit Sharing Scheme (EBSS). If a capex incentive scheme is introduced, we suggest that this is a more appropriate avenue to do so and welcome the opportunity to consult with the AER and other relevant parties to develop it.

Such a scheme will need to be supported by standard performance measures. Specific target performance levels will also need to be initially established with respect to the current performance of individual NSPs given the significant differences in the operating environments faced by NSPs within the National Electricity Market.

Above all, incentive regimes should focus on what is valuable to customers and not just on minimising the cost of service. In doing so, the creation of a capex incentive scheme should have regard to maximising the value of the service that is provided to customers.

3.3 Contingent projects, capex re-openers and pass through events

In principle, Ergon Energy supports the proposed contingent project process. However, we note that this process will be more difficult for a DNSP to implement than for a TNSP due to the large number of projects and significant changes over a regulatory control period that DNSPs face. This process needs to be carefully considered by the AEMC and stakeholders to ensure its useful application.

We also support a re-opening of the revenue cap for unforeseen capex. However, the materiality threshold of 5 per cent of the Regulatory Asset Base (RAB) is too high to be of any practical use to DNSPs. If this is applied to DNSPs, where capex projects are generally on a smaller scale than TNSPs, it would likely never be used. Based on Ergon Energy's opening RAB as at 1 July 2010 of around

$7.1 billion,[40] a non-forecast capex project of at least $355 million would be required to trigger a re-opening.

3.4 Treatment of shared assets

Ergon Energy agrees with the AER's proposal to extend the use of assets in the RAB for provision of services other than non-standard control services. Nonetheless, we disagree with the extent of the changes to the Rules as proposed by the AER and suggest that a more appropriate mechanism to address this issue is through a minor change to the Rules and an adjustment to the Ring-fencing Guidelines.[41] Prescribing a mechanism in the Rules is inflexible and fails to take account of jurisdiction-specific issues, changing market conditions and the differing operating environments of NSPs.

If a sharing mechanism is adopted, it must:

- Provide meaningful incentives to DNSPs to engage in profitable activities that utilise shared SCS assets;
- Ensure benefits are only shared with SCS customers when a commercial benefit has been achieved;
- Recognise the associated risks that regulated and unregulated businesses bear; and
- Be subject to a materiality threshold to ensure that DNSPs can efficiently provide these services.

3.5 Determination of the rate of return

In Ergon Energy's view interest rate risk cannot be considered in isolation from refinancing risk. The two risks must be considered together. Similarly, the regulated cost of debt should not be considered without also considering the actual cost of equity. Ergon Energy therefore recommends a balanced view should be taken when considering these risks and the determination of the regulated WACC.

3.5.1 Current arrangements

Ergon Energy actively manages its interest rate risk. The Ergon Energy Board (the Board) has responsibility for all decision-making related to the duration and maturity profile of the debt instruments held in its CSP with QTC,[42] including the liability management parameters. The Board also determines the debt refinancing and hedging strategies which apply at each regulatory reset (in consultation with QTC) and the management of associated risks such as inflation risk, which is implicit in the nominal cost of debt used in the regulated WACC.

Ergon Energy manages its debt in line with the regulatory framework and with reference to the AER's methodology for the calculation of the regulated cost of debt. Ergon Energy is accountable for managing its overall capital structure, including the debt on its balance sheet, and actively responds to regulatory incentives to minimise its debt costs and reduce the impact of adverse interest rate changes on net profit. The Board delegates some authority to QTC. However, the range is narrow and QTC is obligated to comply with this range when executing any transactions.

The actual weighted average cost of debt paid by Ergon Energy for the 2010–11 financial year was 7.14 per cent,[43] which includes a competitive neutrality fee (CNF) component. The CNF has been fixed for five years in alignment with the current regulatory control period and in accordance with the Code's requirements. Under the Code, Ergon Energy has the option of fixed or variable CNF costs. The CNF is expressed as a margin to the QTC State government guaranteed yield curve, not the Commonwealth Government yield curve.

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[40] Ibid 5, p323

[41] Clause 6.17 of the Rules

[42] The Queensland Code of Practice for Government-Owned Corporations' Financial Arrangements (the Code) requires Ergon Energy to source all of its borrowings through QTC. Ergon Energy makes quarterly debt service payments to QTC in relation to its CSP and CNF payments to Queensland Treasury

[43] Ergon Energy (2011), *Annual Financial Statements for the year ended 30 June 2011*, p47

Ergon Energy's actual debt costs are expected to increase over the remainder of the current regulatory control period as Forward Starting Loans (hedged future borrowings) settle and are incorporated into the CSP book interest rate.

Based on the above, Ergon Energy disagrees with the Committee's claims that government-owned NSPs have no control over the debt on their balance sheet and are therefore unable to respond to regulatory incentives to minimise their debt costs.

3.5.2 Benchmark for government-owned NSPs

Ergon Energy is not aware of how the current fixed rate borrowings made within the CSP could be re-structured to deliver an actual cost of debt that matches the cost produced by the Committee's proposed benchmark. The proposed benchmark is also based on the incorrect assumption that embedded debt costs are irrelevant for government-owned NSPs. As such, Ergon Energy does not consider the Committee's proposed benchmark to be appropriate.

3.5.3 Excessive profits

There is no evidence of excessive profits for Ergon Energy:

- Ergon Energy's return on average assets before revaluations were 8.0 per cent in 2011 and 5.7 per cent in 2010, and including revaluations the figures were 13.8 per cent in 2011 and 6.6 per cent in 2010; and
- Ergon Energy's return on average equity was 10.8 per cent in 2011 and 6.4 per cent in 2010.

With the exception of the 2011 result, which includes a large revaluation of property, plant and equipment, the return on assets earned by Ergon Energy is below the WACC allowed in the Final Distribution Determination of 9.72 per cent.

As indicated above, Ergon Energy's weighted average cost of debt for the 2010–11 financial year was 7.14 per cent.

3.5.4 Debt risk premium

While Ergon Energy agrees that the definition of the debt risk premium could be improved, we do not support the AER's proposal to completely remove the definition of the debt risk premium from the Rules. Nor do we support the AER's proposal to increase the scope of the WACC review to allow the AER to determine the methodology for setting the debt risk premium. The AER's proposal for broad regulatory discretion is a significant departure from current practice.

Ergon Energy also does not support the AER's implied proposal to set the regulated cost of debt based on the actual funding practices of the NSPs. This is a circular argument as Ergon Energy's current funding practices are based on the AER's methodology for calculating the regulated cost of debt.

3.6 Submissions received during a determination process

Under the AER's proposed Rule change request, DNSPs will only be afforded one opportunity to review and respond to the AER's assessment of their regulatory proposals (i.e. via the Revised Regulatory Proposal). On the other hand, the AER will be able review regulatory proposals at two different stages. Ergon Energy asserts that this is not equitable and reduces the number of opportunities for DNSPs to respond to new information and alert the AER to any errors that it may have made.

In the past, third parties have introduced new information during the consultation round on the AER's Draft Decision for Queensland DNSPs and our revised regulatory proposal. In February 2010, nine submissions were received from stakeholders.[44] While the arguments put forward in these submissions

[44] Cement Australia Pty Ltd, ENERGEX, EnergyAustralia, Energy Users Association of Australia (2), Maryborough Sugar Factory, Queensland Council of Social Service, Queensland Minister for Energy and the Total Environment Centre

did not hold sufficient weight in the AER's Final Distribution Determination, it is nevertheless important to provide DNSPs with the opportunity to respond where appropriate.

Further, a DNSP may not wish to (and is not required to) lodge a Revised Regulatory Proposal. In such circumstances, it is important that the DNSP be afforded the opportunity to respond to the AER's Draft Decision as a matter of procedural fairness and to maintain the robustness of the regulatory decision-making process.

Other circumstances may also arise after the lodgement of the Revised Regulatory Proposal which may require the DNSP to further respond. For example, a DNSP may not be able to collect all evidence (including expert evidence) required to respond to the AER's Draft Decision in time for inclusion with the Revised Regulatory Proposal due to the timing in the Rules. In Queensland, the six week period to respond to the Draft Decision coincides with the Christmas/New Year period when key staff and consultants may have limited availability to review and respond to any new information.[45] These circumstances are not sufficiently covered by the AER's proposal and could be detrimental to Ergon Energy if the Revised Regulatory Proposal is the only opportunity afforded to us to respond.

Consequently, Ergon Energy agrees with the ENA's suggestion to introduce a process of submissions and cross-submissions on the draft decision and Revised Regulatory Proposal. This process allows third parties to comment on any further submissions made by the NSP and provides the NSP with an opportunity to respond to any submissions made by third parties on its Revised Regulatory Proposal. A further two week consultation period should be allowed after submissions on the Revised Regulatory Proposal close to allow for cross-submissions.

3.7 Timeframe for the conduction of WACC Reviews

Ergon Energy supports the AER's proposal to extend timeframes where appropriate. However, any extension should take into consideration the timeframe for lodging regulatory proposals. This will provide impacted businesses with sufficient lead time to review, assess and seek expert analysis on the AER's decision.

The AEMC has previously acknowledged this issue by providing ETSA Utilities, Ergon Energy and ENERGEX with a one-off one month extension to submit their regulatory proposals for the 2010–15 regulatory control period following the AER being granted an extension to complete its first WACC Review by 1 May 2009 rather than 31 March 2009. The revised due date for the impacted DNSPs' regulatory proposals was 1 July 2009.[46]

[45] The AER's Draft Decision was published on 30 November 2009 and the Revised Regulatory Proposal was due on 14 January 2010.
[46] AEMC (2009), *WACC Reviews: Extension of Time*, Rule Determination, 26 March 2009, Sydney