QCOSS

Queensland Council of Social Service

Understanding the long term interests of electricity customers

Submission to the AER's Queensland electricity distribution determination 2015-2020

30 January 2015

About QCOSS

The Queensland Council of Social Service (QCOSS) is the state-wide peak body for individuals and organisations working in the social and community service sector.

For more than 50 years, QCOSS has been a leading force for social change to build social and economic wellbeing for all. With almost 600 members, QCOSS supports a strong community service sector.

QCOSS, together with our members, continues to play a crucial lobbying and advocacy role in a broad number of areas including:

- sector capacity building and support;
- homelessness and housing issues;
- early intervention and prevention;
- cost of living pressures including low income energy concessions and improved consumer protections in the electricity, gas and water markets;
- energy efficiency support for culturally and linguistically diverse people; and
- early childhood support for Aboriginal and Torres Strait Islander and culturally and linguistically diverse peoples.

QCOSS is part of the national network of Councils of Social Service lending support and gaining essential insight to national and other state issues.

QCOSS is supported by the vice-regal patronage of His Excellency the Honourable Paul de Jersey AC, Governor of Queensland.

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QCOSS Queensland Council of Social Service

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1.1 Introduction

Electricity differs from many other regulated industries as it is an essential service that is needed by households on a daily basis. Electricity is essential for lighting, hot water, food preparation, washing and cleaning, communications, and heating and cooling. Having access to these things supports people to participate in employment, education and social interaction. It is therefore critical that electricity is affordable and accessible to all Queenslanders.

QCOSS is making this submission in order to provide a voice for low-income and disadvantaged households in the Australian Energy Regulator's (AER) Queensland distribution determination for the 2015-2020 Regulatory Control Period (RCP). The households which QCOSS represents are increasingly struggling to pay their electricity bills in the context of rising electricity prices and growing unaffordability which has largely been driven by significant increases in network costs over recent years. For this reason, it is QCOSS's priority to ensure that the decisions made by the AER on the future revenue allowances for Energex and Ergon Energy (Ergon) do not allow high electricity prices to persist resulting in worse outcomes for low income and vulnerable Queenslanders.

In providing this submission, we note the complexity of the technical issues being considered and proposed as part of this review. QCOSS has had the benefit of a consultant, Mr Luke Berry from Engineroom Consulting, to provide technical advice on all aspects of the AER's Better Regulation reform program as well as the regulatory proposals submitted by Ergon and Energex.

QCOSS's submission is structured as follows:

Chapter 1: Overview of Submission details the context around energy affordability, the economic regulatory framework, and sets out QCOSS's response to the Ergon Energy (Ergon) and Energex's Regulatory Proposals (RPs). This chapter also sets out QCOSS's recommendations.

Chapter 2: Consumer Engagement assesses how effective Ergon and Energex have been in engaging with consumers and their representatives, how they have identified consumer issues and concerns, and how these have been reflected in their RPs.

Chapter 3: Capital Expenditure (capex) details QCOSS's views on whether the capex proposals provided by Ergon and Energex are prudent and efficient as required by the National Electricity Rules (NER).

Chapter 4: Operating Expenditure (opex) details QCOSS's views on whether the opex proposals are prudent and efficient, as required by the NER.

Chapter 5: Regulated rate of return (ROR) assesses whether the RORs proposed by Ergon and Energex are commensurate with the NER's requirement for efficient financing of a benchmark efficient entity with the same level of risk.

Chapter 6: Other Issues sets out a number of priority issues for consumers which QCOSS wants to highlight to the AER, however resources and time has permitted QCOSS from undertaking a full assessment. These include:

- Demand Management (DM)

- Metering Services
- Incentive Schemes

1.1.1 Acknowledgements

This submission was part funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy and research for the benefit of consumers of electricity and natural gas. The views expressed in this submission do not necessarily reflect those of the Consumer Advocacy Panel or the Australian Energy Market Commission. QCOSS would like to thank the Panel for making funds available for this important advocacy project in Queensland.

QCOSS would like to acknowledge and sincerely thank all who participated in the development of this submission. Thank you to the following Queensland consumer and community representatives who participated in our workshop/meetings to share their views and discuss the merits and implications of the regulatory proposals for Queensland consumers:

- Queensland Consumers Association
- Council on the Ageing Queensland
- Chamber of Commerce and Industry Queensland
- Regional Development Australia Far North Queensland and Torres Strait
- All members of the QCOSS Essential Services Consultative Group

Special thanks to Mr Luke Berry of Engineroom Consulting for his technical advice and assistance in drafting this submission. Thanks also to the Consumer Challenge Panel members who provided guidance to Queensland consumer groups on technical aspects.

Finally, acknowledgement and thanks to the staff of the AER, Energex and Ergon who organised and participated in the information sessions and workshops as part of the consumer engagement. These were productive exercises which benefited QCOSS in the preparation of this submission.

1.1.2 Energy affordability

QCOSS's interest in this consultation is driven by our vision for a Queensland free of poverty and disadvantage, and our concern about the impact of high electricity prices on low income and vulnerable households across the state. Electricity prices have increased by 86 per cent over the past five years[1] and this has been largely driven by network costs.

Of particular concern to us are the increasing number of households who have lost access to electricity or experienced significant hardship as a result of these price increases, as demonstrated in Queensland by the increasing rates of residential electricity disconnection for non-payment, increased uptake of emergency assistance schemes and greater participation in hardship programs offered by electricity retailers. A record high of 25,305 Queensland households had their electricity disconnected for not paying a bill in 2013-14 and this figure is tracking to be even higher in 2014-15 with over 7,000 disconnected in the first quarter alone.[2]

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[1] QCOSS (2014) *Regional Cost of Living Report*.
[2] Queensland Competition Authority (2014) *Small Customers Disconnections, Hardships and Complaints*

Another 33,636 households successfully sought assistance from their retailer's hardship program in 2013-14 to assist them in meeting their rising electricity costs.

Many Queenslanders are suffering significant detriment and there is evidence emerging that larger numbers are resorting to emergency relief and community sector support services to cope with the financial pressure created largely by these electricity price increases. Much of this is attributable to large network price rises due to the expenditure of network businesses over previous RCPs. QCOSS has reason to believe that the impact of electricity prices is spreading beyond the concern of low income and disadvantaged households, affecting a broader group of consumers who may not have struggled before. This is evidenced by recent research which suggests that that 70 per cent of Australians are often or occasionally worried about being able to pay their electricity bill.[3]

With prices already at peak levels, and likely to remain unaffordable for many on fixed incomes for many years ahead, the need for real reductions in electricity prices over the next regulatory period is critical to ensure all Queenslanders can maintain access to this essential service in the future. This is the fundamental purpose for QCOSS in providing this submission for consideration by the AER.

1.1.3 Economic regulatory context

QCOSS notes the AER must have strong regard for the National Electricity Objective which is '…*to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to* –

a) *Price, quality, safety, reliability and security of supply of electricity; and*
b) *The reliability, safety and security of the national electricity system.*'[4]

Despite this, during the 2010-2015 RCP, the Queensland distributors were awarded many billions of dollars of additional capital expenditure than was required to meet their obligations to serve the long term interests of consumers. Unfortunately for consumers, these costs are now locked into the regulated asset base which will result in consumers paying higher prices in future years as a result.

QCOSS has therefore welcomed the AER's Better Regulation Program which has sought to establish guidelines to address these issues for the 2015-2020 RCP and give the AER greater power to scrutinise and question the proposals put forward by the distributors. We have also welcomed the increased focus on consumer consultation as a result of new requirements arising from the Better Regulation Program. We have participated as fully as possible in these engagement activities. We look forward to seeing the outcomes of these regulatory improvements in terms of tangible impacts for consumers on the ground.

We support the AER in applying a higher level of scrutiny on the regulatory proposals provided by the distributors. We must also acknowledge that, even with the AER's greater level of scrutiny and improvements in consumer engagement, there remains a high level of asymmetry of information and an imbalance between resources for consumers and distributors in this process. Resources for consumers to participate in this consultation process are extremely limited when compared to the significant resources available to the distribution businesses. Therefore, QCOSS

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[3] EY Report: Customer Voice Getting Louder - http://www.ey.com/Publication/vwLUAssets/EY-CX-series-Utilities-Wave3/$FILE/EY-CX-series-Utilities-Wave3.pdf
[4] National Electricity (South Australia) Act 1997 – 19.12.2013, Schedule-National Electricity Law, Part 1, 7, p.38.

and other consumer groups encourage the AER to consider all consumer submissions, regardless of how big or small, as a significant and important contribution of the consumer 'voice' into what is a largely inaccessible process for the vast majority of consumers.

In short, consumers are largely relying on the AER to 'get it right' in assessing the distributors' proposals in circumstances where the distributors themselves continue to have strong incentives to 'gold plate' and over state their expenditure proposals.

1.2 QCOSS's overall response to the Regulatory Proposals

In the main, both Energex and Ergon's RPs are forecasting some reductions in capex, opex and the WACC for the next RCP (2015-2020). However, these reductions are not significant enough to translate into a lower revenue requirements and hence there is no price relief for the end consumer.

It is disappointing that both Energex and Ergon are proposing increased revenue allowances over the next RCP.

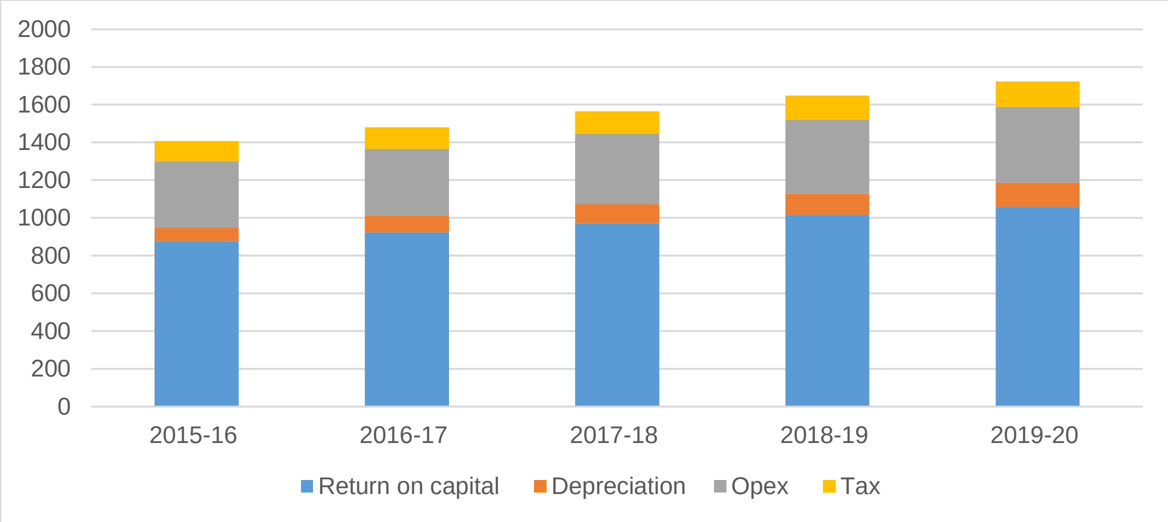
Energex[5] is seeking an increase in its revenue allowance from $7.4 billion ($7.1 billion actual revenue) in the current RCP to $9.8 billion in the 2015-2020 RCP. This includes the solar bonus scheme payments but excludes metering services in the latter RCP. This is a nominal increase of 32 per cent over the 2010-2015 allowance and about a 38 per cent increase over actual revenue recovered. Should the solar bonus payments be excluded (as per the election promise of the current Queensland Government) then Energex would be seeking $8.4 billion, which would amount to about 13 per cent increase over the 2010-2015 allowance.

Ergon[6] comparison of revenue requirement is presented in 2014-2015 dollars (real terms) in its overview document. Ergon was allowed $7.1 billion for the 2010-2015 RCP and it is now seeking $7.6 billion for the next RCP. This relates to about a 7 per cent increase in real terms. It is understood that Ergon's revenue for the next RCP excludes metering services however it is not clear from its Overview document if the solar bonus scheme payments are included or not in 2015-2020 revenue figure. From the graphic set out in page 30 in the Overview document it would appear that the solar bonus scheme payments are not included in the above revenue figures.

QCOSS's view is that these revenue increases are being driven by increases to the Regulatory Asset Base (RAB) (or in other words the stock of assets which the distributors' capital charges are based on). These capital charges are depreciation (or asset consumption) and the rate of return (weighted average cost of capital or WACC) which the distributors are allowed to earn for investing in the assets. Chart 1.1 and Chart 1.2 shows that these two capital charges are increasingly accounting for a greater share of revenue for both Energex and Ergon over the next RCP.

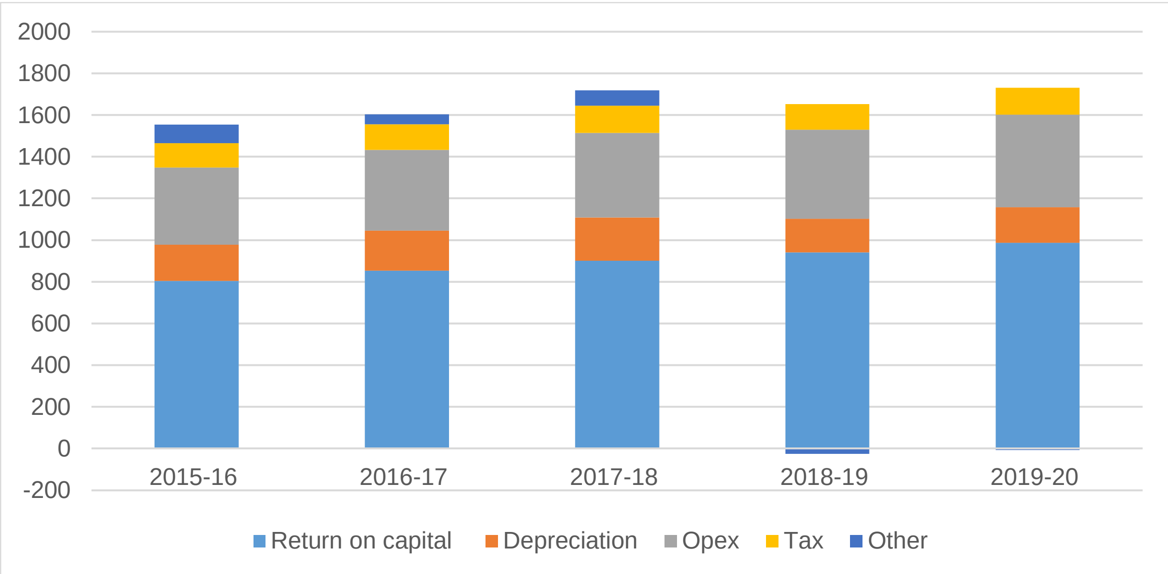
[5] Energex 2014, *Our Five Year Plan – Regulatory Proposal Summary 2015-2020*, p7
[6] Ergon 2014, *Overview Regulatory Proposal*, notes to chart on P29.

Chart 1.1 Energex – composition of annual revenue requirement 2015-2020



Source: Compiled by Engineroom Consulting

Chart 1.2 Ergon - composition of annual revenue requirement 2015-2020



Source: Compiled by Engineroom Consulting

Both Distributors' RABs are forecast to rise significantly over the next RCP, as evident in Table 1.1. Ergon's RAB is forecast to increase by 27 per cent and Energex's by 20 per cent. Further, it must be pointed out that these RABs in 2019-2020 do not include the metering RABs which are estimated to be in the order of $61 billion for Ergon and $400 billion for Energex.

Table 1.1 Growth in the regulated asset bases of Energex and Ergon

	Basis	2009-10	2014-15	2019-20
Energex	$m nominal at close of FY	7,867.3	11,844.0	14,255.2
Energex - growth from prior period			51%	20%
Ergon	$m nominal at close of FY	7,160.95	10,095.83	12,867.00
Ergon - growth from prior period			41%	27%

Source: Ergon RP, Table 3, p.20 and Table 4, p.21; Energex RP, Table 12.1, p. 148 and Table 12.2, p. 150. The 2019-2020 values do not include metering assets.

It is not surprising, given these forecast increase in revenues, as set out in Table 1.3, that the indicative network prices increases are just less than inflation, and hence are barely declining in real terms. The current government's election commitment for the 2015 Queensland State Election is to remove the cost of the Solar Bonus Scheme feed-in tariff (FIT) from network prices. If this policy is implemented, there would be a large once-off reduction in prices in 2015-16, and as shown in Table 1.2, then prices increases would stabilise and slightly decline in real terms.

Ergon residential customers benefit from the Queensland Government's Uniform Tariff Policy which sets their tariff prices at the same level as in Energex's area. Accordingly there is only one set of tariff prices for residential customers whether those customers are located in Energex's or Ergon's distribution area.

Table 1.2 Energex Indicative Tariffs (8400 Residential Flat) not including feed-in tariff

	2015-16	2016-17	2017-18	2018-19	2019-20
c/kWh	13.53	13.57	13.38	13.18	13.00
Change from prior year	-9.7%	0.3%	-1.4%	-1.5%	-1.4%

Source: Energex summary of RP, p.5
Note: Metering costs not included

Table 1.3 Energex Indicative Tariffs (8400 Residential Flat) including feed-in tariff

Including FiT	2015-16	2016-17	2017-18	2018-19	2019-20
c/kWh	15.32	15.66	15.74	15.80	15.88
Change from prior year	2.2%	2.3%	0.5%	0.4%	0.5%

Source: Energex summary of RP, p.5
Note: Metering costs not included

The main outcome of the Queensland Distributors' RPs is that the network prices will stabilise at the current very high prices. This is especially concerning as network prices make up the largest component on households bills. The very large RABs mean that, going forward, all electricity consumers will be locked into the current very high price regime. This will be the case unless the AER's revenue determination results in significant reductions in the main 'building block' components of the cost build up, including capex, opex and the WACC.

QCOSS's view is that further reductions can be justified and this submission sets out the case for significantly lower revenue requirement (lower capex, opex and WACC) for Energex and Ergon in the next RCP. Specifically this submission concludes that the AER should not accept the RPs based that:

- overall demand is falling and peak demand is clearly showing signs of weakening;
- reliability standards have reduced significantly in the 2010-2015 RCP;
- increasing low utilisation of assets and shortening of average asset lives indicates over investment in assets in the 2010-2015 RCP;
- the cost of debt has eased considerably in financial markets since the last RCP;
- the cost of equity is lower given the low risk environment of the Queensland Distributors;
- recent major reviews of both Energex and Ergon have identified opportunities for significant improvements in efficiencies; and
- the AER in its own benchmarking analysis has identified that Energex and Ergon are performing poorly against a number of other Australian electricity utilities.

1.3 Summary of submission

1.3.1 Consumer engagement

Overall, QCOSS acknowledges that the consumer engagement in preparation for the 2015-2020 RCP represents a marked improvement on the consumer engagement previously undertaken by Energex and Ergon for the 2010-2015 RCP. It is clear to QCOSS that both distributors have attempted to undertake engagement with consumers in the lead up to submitting their RPs to the AER. Certainly both distributors employed significant resources to make issues transparent and understandable for a range of consumer representatives, including QCOSS, through multiple information sessions and working group meetings. This was especially important and useful given the highly technical nature of the regulatory process.

Despite this, it cannot be said that the views and concerns of QCOSS and other consumer representatives heavily engaged in these processes have been reflected in the RPs submitted to the AER. QCOSS's view is that both Energex and Ergon focused more heavily on the results of market research activities to incorporate the view of consumers into their decisions, as opposed to incorporating feedback provided by QCOSS and other consumer representatives. While both distributors undertook a significant number of information sessions and working group meetings, these did not result in the proposals reflecting the views/feedback from participants. Both distributors commenced their detailed engagement to late and Energex openly acknowledged that its workshops were essentially information sessions. Ergon, to its credit, did attempt to set up a framework for seeking feedback from consumer representatives on some specific issues with the intent of reflecting this in their RP. However, it was difficult for consumer groups to provide definitive positions at the time without full information about the price implications for consumers and the necessary technical knowledge required to scrutinise the issues in an informed manner.

We acknowledge that the requirement in the NER for networks to consult with consumers about their RPs is relatively new and that it is a learning curve for both distributors and consumers. As such, in this submission QCOSS has made a number of recommendations (including for the AER) on how consumer engagement can be improved going forward.

1.3.2 Capital expenditure (capex)

It is noted that both distributors are proposing lower capex programs than during the 2010-2015 RCP. Energex is seeking a capex allowance of $3.2 billion which is down from $4.7 billion in the 20105-2015 RCP. Ergon's is also seeking a smaller allowance of $3.6 billion which is down from $4.1 billion. There is also a marked difference between the patterns of capex between the two distributors.

While the overall capex levels are down from the levels in the 2010-2015 RCP, different classes of capex are still increasing, most notably Energex's huge replacement capex. This is of concern for consumers, as every increase in capex is rolled into the RABs. It is difficult to understand why there is a need for more capex and especially repex, particularly given that: (1) demand is falling and there is declining growth in peak demand; (2) recent independent reviews have significantly reduced reliability standards and identified a wide-ranging set of recommendations to improve opex and capex efficiency; (3) system utilisation is falling; (4) average age of assets is shortening; and (5) analysis of Energex and Ergon's performance against industry benchmarks indicates that they are relatively inefficient against a range of capital and asset productivity measures.

In view of these trends, QCOSS asserts that the AER cannot allow transitionary arrangements for the Queensland Distributors to achieve greater efficiencies, and recommends that the AER carefully assess the prudency and efficiency of augex and repex including the extent to which the Distributors have considered non-network options.

1.3.3 Operating expenditure (opex)

Overall both distributors are not seeking major increases in opex. Energex's proposal for the 2015-20 RCP is less than previous RCPs, about 5 per cent less than in 2010-15. As the AER points out in its Issues Paper, Energex is suggesting that the decrease is as a result of efficiencies achieved in network management, contract management and overheads. Ergon is also seeking less opex overall from 2010-15 to 2015-2020 RCP. Ergon is forecast to overtake Energex in terms of opex for the first time in the 2015-2020 RCP. It is noted that Ergon's proposed opex annual forecasts are trending up towards the latter part of the RCP.

However, both distributors operate young, under-utilised networks and the residual lives of Energex and Ergon assets are increasing rapidly. As a result, just as with capex, they should not require as much opex as they would if they operated older networks. Consequently, QCOSS is concerned that the distributors' opex proposals are overstated and would ask that the AER in its assessments of prudency and efficiency of opex to have especially close consideration for the following issues:

- the Distributors' relative poor performance against industry benchmarks;
- that the findings of the IRP are reflected in the RPs' opex forecasts;
- that there are inefficiencies in the base year's opex expenditure and further adjustments may be needed; and
- to seek out further efficiencies in some specific items of opex expenditure, notably, inspections and planned maintenance; assumptions on wages growth; network costs; vegetation management; debt raising costs; and self-insurance costs.

Finally, QCOSS asserts that the AER does not provide for any transitionary arrangements for the Distributors to achieve greater efficiencies.

1.3.4 The regulated rate of return

The WACCs proposed by Energex and Ergon are 7.75 per cent and 8.02 per cent respectively (noting that they are placeholder WACCs and may be subject to change). These are lower than the WACC allowed in the 2010-15 period which was 9.72 per cent. However, the proposed WACCs are higher than in the 2010-2015 RCP when measured as a margin to the risk-free rate. This measure is the margin allowed to the Distributors for investment risk. This measure for Ergon at a 4.3 per cent margin to the risk-free rate and for Energex is a 4.2 per cent margin to the risk-free rate. These are both higher than the current margin allowed in the 2010-2015 RCP (3.9 per cent) and the margin recently allowed by the AER in its NSW draft determinations (3.6 per cent).

QCOSS has been advised by Engineroom Consulting on the AER's and the RP's consideration of the regulated rate of return. Following this advice, QCOSS considers that Energex and Ergon's proposed WACCs are significantly in excess of the efficient financing costs of an efficient benchmark entity, and if adopted, would result in prices to consumers that are significantly higher than required to finance a benchmark efficient firm. QCOSS presents a case in this Chapter why the WACCs are not justified and that the AER should not accept them. QCOSS notes also that the proposed WACCs are higher than the WACC of 7.15 per cent put forward for consultation by the AER in its recent draft distribution determination for NSW.

QCOSS's advice is that electricity distribution is a relatively low risk business relative to the overall market (which is dominated by private sector companies who face significant competitive pressures both domestically and/or internationally). Market conditions are arguably less risky than at the onset of the previous RCP when the Global Financial Crisis had resulted in high cost of debt and a poor economic outlook. Furthermore, electricity networks are monopoly businesses, with low financial risk as this is spread across millions of customers, with little alternatives of supply, and consequently is characterised by relatively high cash flow certainty. The regulatory framework which allows for a revenue cap is close to a guaranteed income for the next five years. Further, under the AER's new approach to setting the cost of debt, the business risk is reduced in comparison to previous years as the cost of debt is updated annually.

The proposed WACCs also compare unfavourably with recent rates set in the United Kingdom (UK) and New Zealand (NZ). In the UK, Ofgem is proposing a rate of 4.8 per cent (nominal vanilla) in the electricity determination currently underway.[7] In NZ, the Commerce Commission set a nominal vanilla rate of 7.19 per cent based on the risk-free rate prevailing in NZ at 1 September 2014, on an equity base of 56 per cent of the RAB. The risk-free rate was 4.09 per cent, resulting in a margin to the risk-free rate of 3.1 per cent.

In their proposals, Energex and Ergon have departed in a number of areas from the AER's rate of return guideline issued in December 2013. This was developed as part of the AER's Better Regulation Reform Program which involved major consultation with consumers and Distributors. Essentially the Distributors are still disputing key areas and have departed from the Guideline in the following:

- The credit rating used for calculating the cost of debt is proposed to be BBB rather than BBB+ as in the guideline
- Debt should enter the RAB weighted in according with its timing (i.e. more weight in years with high capex)
- The Sharpe-Lintner Capital Asset Pricing Model (the SL CAPM) should apply, but estimate the parameter values within the range generated by the SL CAPM having regard to the strength and weaknesses of all relevant evidence

[7] Bruce Mountain presentation to AER public form, 9 December 2014.

- Estimate the BBB debt margin based on the RBA's 10 year BBB yields (as the RBA currently only publishes this data at the end of the month). This data source does not comply with the minimum averaging period under the AER's Guideline, which is 10 business days
- Gamma value of 0.25 rather than 0.5 (noting the AER moved from its own guidelines which proposed a gamma of 0.5 to use a gamma of 0.4 in the NSW draft determination)
- In view of the way in which the regulatory arrangements reduce business risk QCOSS considers that the return on investment should approximate that on a debt security rather than on a business exposed to normal market risk.

Table 1.4 summarises the key points of departure in terms of their impact on parameters/inputs to the WACC. The implication of these departures to the AER's guideline is that the proposed WACCs are higher and if they were accepted then more revenue would be recovered by this capital charge that what the AER considered to be appropriate to finance a benchmark efficient entity. This is most concerning to consumer groups such as QCOSS, which following technical advice from Engineroom Consulting, is of the view that there is further scope for the AER to revise the WACC parameters and inputs. QCOSS proposes the following values in Table 1.5 below for the WACC and these would result in a lower WACC and one more appropriate given the current economic and risk outlook to finance an efficient benchmark entity.

Engineroom's technical advice is set out Chapter 5 and in Appendix 1 and this includes its advice on further issues that the AER is requested to consider in its draft decision of the appropriate WACC. These include the overall rate of return and the appropriateness of selecting the midpoint of the range of estimates; that the AER take into consideration the benchmark efficient entity's parent in deciding on credit rating and other parameters; and consistency amongst WACC parameters to ensure that they align with each other.

Table 1.4 Summary of AER rate of return guideline compared with Energex and Ergon proposals

Parameter	AER Guideline	Energex RP	Ergon RP
Gamma	0.5	0.25	0.25
Risk-free rate	TBD	3.63	3.63
Credit rating	BBB+	BBB	BBB
Equity Beta	0.7	0.91	0.82 or 0.91 (depending on method used)
Market risk premium (%) (i.e. Rm-Rf)	5 to 7.5%	7.57	7.57
Equity risk premium (%)	not specified	4.2	4.3
Overall WACC (%)	**TBD**	**7.75**	**8.02**

Source: Energex RP, pp.163, 165. Ergon RP, Appendix C

Table 1.5 QCOSS proposed WACC parameters and inputs

Parameter	Recommendation
Model	SL CAPM modified for the observed upward bias in returns available to low beta stocks
Credit rating	A-
Equity beta	0.5 to 0.55
MRP	6.0%
Observation window for cost of debt	20 business days as close as possible prior to the start of each new financial year
Approach to trailing average	Equal yearly weighting
Gamma	0.5

Finally, QCOSS does not consider that the proposed WACCs reflect stakeholders' concerns and input as the distributors only informed the consumers groups of their proposed WACCs just prior to the regulatory proposals being submitted. They did not take into account consumers' concerns about departures from the AER's Guidelines nor did they explain how these variations were in consumers' long-term interests.

1.3.5 Other issues

Given time and resource constraints it has not been possible for QCOSS to review comprehensively all of the Distributors' RPs however there are a number of key issues of particular interest to residential customers. QCOSS has provided some comment on demand management (DM) proposals; metering services; and the four incentive schemes.

1.3.5.1 Demand Management

QCOSS supports the continued investment in Demand Management (DM) by the Distributors in principle. QCOSS's view is that the AER will assess the cost effectiveness of the DM proposals (and assess to what extent the benefits to consumers (by preventing future augmentations to the network) outweigh the costs associated with DM). In addition, the AER must take into account that there are direct benefits of broad based DM programs in term of reduced affordability for customers which should be taken into account in assessing the overall net economic benefit. Further, to support the Distributors' DM proposals is consistent with the AERs regulatory objectives for the network businesses to provide 'efficient and prudent non-network alternatives'.[8]

QCOSS is especially concerned if the AER reduces funding for a more broad-based DM program in the next RCP, given its draft decision in NSW.[9] The AER has expressed the view that the Regulatory Investment Test for Distribution (RIT-D) can drive demand management and other non-network solutions where those solutions are the most cost-effective. QCOSS is not confident that the RIT-D on its own is likely to result in the uptake of demand management initiatives and other non-network alternatives.

Over time, as the uptake of peak demand tariffs and advanced meters increase it may well be the case the effectiveness of such DM programs may reduce. However, it remains to be seem how quickly this uptake will happen, particularly in Queensland. In the meantime, DM programs are effective in supporting people to manage electricity demand and hence their bills. At this stage it is not the case that

[8] Productivity Commission, 2013, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra.
[9] AER, November 2014, Draft Decision for Ausgrid

new pricing methodologies, such as demand and time of use pricing, and smart metering technology are substitutes to DM.

It is noted that a number of other consumer groups have made substantive comments on DM, namely the Queensland Consumers' Federation (QCF) and the Total Environment Centre (TEC). QCOSS supports their submissions and in particular the TEC recommendation calling for more guidance from the AER on how it considers DM proposals.

1.3.5.2 Metering services

As part of their RPs, Energex and Ergon have submitted indicative prices and building blocks for type 6 metering services.[10] Both distributors are proposing a building block cost build-up approach.[11] QCOSS is concerned that there are wide variations between the two sets of building blocks and other relevant estimates such as: (1) exit fees where Energex's fee is much higher than Ergon's, (2) return on capital with Ergon proposing much lower return on capital; and (3) depreciation where Ergon is proposing much higher allowance and consequently much higher opex than Energex.[12] These discrepancies seem very hard to explain in practice and may suggest some level of arbitrariness in approach by one or both of the distributors.

In undertaking its assessment the AER will also have to assess the methodology and assumptions used by both Distributors for estimating the opening value of the metering RAB and the RAB for standard control services. As the economic regulator, AER should provide guidance to the Distributors on how they value their metering RAB to ensure consistent valuation approaches.

1.3.5.3 Incentive schemes

Overall, QCOSS does not consider there is adequate evidence that the identified incentive schemes drive more efficient behaviour by Energex or Ergon and that in fact they increase the rewards to gaming because Distributors may overstating capex and opex requirements. QCOSS also has concerns about the complexity of the incentive arrangements and considers that incentives, if they apply at all, should be very modest and should only be in areas where there is a clear and demonstrable link between reduced spending and efficiency.

1.4 Recommendations

Recommendation 2.1
QCOSS recommends that the AER assess the appropriateness of Ergon using customers' feedback from its market research findings in verifying expenditure and how Ergon have reflected feedback from its Working Group of consumer representatives.

Recommendation 2.2
QCOSS recommends that the AER assess the appropriateness of Energex using customers' feedback from its market research findings in verifying expenditure and how Energex have reflected feedback from its Information Sessions with consumer representatives.

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[10] Energex RP, chapter 25; Ergon RP, pp. 47-51 and supporting document 05.03.01 – Default Metering Services Summary.
[11] Energex RP, pp.269-270; Ergon RP pp. 50-51.
[12] Comparing Energex RP, p. 276, Table 25.9 with Ergon RP, p. 50, Table 24.

Recommendation 2.3
QCOSS recommends that the AER review the resourcing of the CCP with consideration for expanding their role to further assist in addressing the significant information and expertise asymmetry in the consumer engagement processes undertaken by the Distributors.

Recommendation 3.1
QCOSS recommends that the AER give close consideration to system utilisation and the age of assets in assessing the appropriateness of the capex proposals provided by Ergon and Energex.

Recommendation 3.2
QCOSS recommends that the AER does not accept the demand forecasts provided by Ergon and Energex without comprehensive scrutiny into the basis for those forecasts, in light of previously misforecasts and notable changes in energy use, technologies, future tariffs and trends over the next RCP.

Recommendation 3.3
QCOSS recommends that the AER's decision on the allowed capex to the Distributors reflect the impact of reduced reliability standards.

Recommendation 3.4
QCOSS recommends that the AER use benchmarking to critically examine the capex proposals, and in particular, the need for the Energex's extensive replacement program.

Recommendation 3.5
QCOSS recommends that the AER does not allow extra time for Queensland distributors to adjust to efficient and prudent practice in relation to capex.

Recommendation 3.6
QCOSS recommends that the AER scrutinise major augex and repex projects to ensure all projects need to occur in 2015-2020 period and that all non-network options (including demand management) have been investigated and dismissed in arriving at the capital solution.

Recommendation 3.7
QCOSS recommends that the AER should 'ground-truth' its capex benchmarking by doing a ''bottom up" analysis of sample planned augex and repex projects, to determine whether networks have adequately considered non-network options.

Recommendation 4.1
QCOSS recommends that the AER does not accept the opex proposals of the Distributors in light of the AER's own industry benchmarking and the findings and recommendations of the IRP and ENCAP reviews.

Recommendation 4.2
QCOSS recommends that the AER apply its benchmarking and other tools to determine an efficient base cost for 2012/13 on which to apply the proposed 'step and trend' changes to this base cost.

Recommendation 4.3
QCOSS recommends that the AER consider referencing the operational practice of the Queensland Distributors with that of other distributors to see what practices they have in relation to inspection and preventative maintenance.

Recommendation 4.4
QCOSS recommends investigating further the proposed wage growth forecasts over the regulatory period for consistency with short and medium term trends in wage and economic conditions in Queensland and in particular in regional Queensland.

Recommendation 4.5
QCOSS recommends that the AER conducts a thorough examination of the prudency and efficiency of the proposed expenditure outlined in the above subsections 4.4.4 to 4.4.7.

Recommendation 4.6
QCOSS recommends that the AER does not allow extra time for Queensland distributors to adjust to efficient and prudent practice in relation to opex.

Recommendation 5.1
QCOSS recommends to the AER, that it adopts the parameters and inputs set out in Table 5.3 in calculating the range of values of the WACC, for the reasons outlined in Sections 5.3 to 5.12 of this submission.

Recommendation 5.2
QCOSS recommends that the AER select a WACC at or below the midpoint range.

Recommendation 6.1
QCOSS recommends that the AER approve funding for the ongoing management and improvement of Energex's Load Control System, hot water load control, pool pump load control and PeakSmart air-conditioning.

Recommendation 6.2
QCOSS recommends that Ergon Energy also undertake the PeakSmart air-conditioning program for its distribution area based on the approach in the Energex proposal.

Recommendation 6.3
QCOSS recommends that Ergon and Energex place a stronger focus on targeted consumer programs towards low income and vulnerable high energy use households and particularly customers with high and inflexible consumption such as those with energy intensive medical conditions.

Recommendation 6.4
QCOSS recommends that the AER does not solely rely on the RIT-D to drive demand management and other non-network solutions.

Recommendation 6.5
QCOSS recommends that the AER accept the DM proposals submitted by Energex and Ergon as QCOSS believes this is consistent with the long term interests of consumers.

Recommendation 6.5
QCOSS recommends that the AER develop a guideline on how non-network options, including DM initiatives, will be considered in its assessment.

Recommendation 6.6
QCOSS recommends that the AER review the methodology and assumptions used by both Distributors for estimating the opening value of the metering RAB and the RAB for standard control services, and that the AER provide guidance to the Distributors on how they value their metering RAB to ensure consistent valuation approaches.

Recommendation 6.7
QCOSS recommends that the AER review the methodology and assumptions used for forecasting the number of total and replacement meters over the next RCP.

Recommendation 6.8
QCOSS recommends that the AER review the methodology and assumptions used by both Distributors to calculate their depreciation allowances and if necessary provide guidance on the appropriate methodology.

Recommendation 6.9
QCOSS recommends that the AER explore the extent to which different methodologies have led to differences in the exit fee. If this is the case then guidance by the AER should be provided on appropriate exit fee methodology.

Recommendation 6.10
QCOSS recommends that the AER check the relevant calculations from the Distributors in relation to the incentives, and closely monitor the effectiveness of the schemes in delivering outcomes in the long term interests of consumers.

Recommendation 6.11
QCOSS recommends that the AER check the relevant calculations from the Distributors in relation to the incentives, and closely monitor the effectiveness of the schemes in delivering outcomes in the long term interests of consumers.

2 Consumer engagement

2.1 Context

QCOSS regards consumer engagement as a key element in the economic regulatory framework for electricity. Electricity networks are essentially monopolies that do not have that direct pricing interface[13] with residential and small business customers that they serve. Hence they may lack the immediate and direct feedback from consumers in business decision making and price setting. For this reason, QCOSS has welcomed the emphasis placed on consumer engagement by the AER in its Better Regulation Program and in particular that it will take into account the extent and quality of the distributors' consumer engagement in assessing the regulatory proposals. We note that the AER will also assess the extent to which the distributors' expenditure proposals reflect consumer concerns. This consumer engagement by the distributors and the subsequent assessment by the AER must not be tokenistic.

Consequently, we welcome the AER's emphasis on engagement between distributors and consumers which:[14]

- equips consumers to participate in consultation;
- makes issues tangible to consumers;
- enables distributors to obtain a representative cross-section of views; and
- encourages distributors to consider and respond to consumer views.

2.2 Overview of consumer engagement

Overall, QCOSS acknowledges that the consumer engagement in preparation for the 2015-2020 RCP represents a marked improvement on the consumer engagement previously undertaken by Energex and Ergon for the 2010-2015 RCP. On the whole, it is clear to QCOSS that both Distributors have attempted to undertake additional engagement with consumers in the lead up to submitting their RPs to the AER. Certainly both Distributors employed significant resources to make issues transparent and understandable for a range of consumer representatives, including QCOSS, through multiple information sessions and working group meetings. This was especially important and useful given the highly technical nature of the regulatory process. These processes meant that a wide spectrum of consumers were better equipped to participate in the consultation process, to review the RPs, and prepare submissions to the AER.

Despite this, it cannot be said that the views and concerns of QCOSS and other consumer representatives heavily engaged in these processes have been reflected in the RPs submitted to the AER. QCOSS's view is that both Energex and Ergon focused more heavily on the results of market research activities to incorporate the view of consumers into their decisions, as opposed to incorporating feedback provided by QCOSS and other consumer representatives. While both distributors undertook a significant number of information sessions and working group meetings, these did not result in the proposals reflecting the views/feedback from participants.

We acknowledge that the requirement in the NER for networks to consult with consumers about their regulatory proposals is relatively new and that it is a learning

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13 Ergon Energy is an exception as it does have a retail function.

14 AER, Issues Paper – Qld electricity distribution regulatory proposals 2015-20, December 2014, p. 37.

curve for both distributors and consumers. We therefore would like to contribute our view of the effectiveness of the consultation undertaken and make a number of recommendations on how it might be improved going forward.

2.3 Distributors' consumer engagement

There were two different types of consumer engagement employed by the Distributors in Queensland:

- Market research, large household consumer surveys, focus groups and interviews; and
- Consumer engagement with consumer groups and representatives. This comprised mainly of workshops and information sessions with organisations representing consumers.

QCOSS also has the benefit of consumer engagement with Ergon via membership of its Customer Council. Regular updates on the regulatory process were provided to Council members.

QCOSS's approach to its assessment of the consumer engagement is to firstly, assess the quantity and format of the distributors' consumer engagement, and then secondly, to provide some comments on how effective the engagement was. QCOSS uses the criteria as set out in the AER's Consumer Engagement Guideline as reported above.

2.3.1 Ergon Energy

Ergon commenced consumer engagement in July 2013 and engagement was conducted over four distinct phases. These were:[15]

- **Phase 1**: Invite Stakeholders to be involved and build on engagement (July 2013)
- **Phase 2**: Undertake Customer Research (August 2013). This involved, in Ergon's words, "*a sophisticated service/cost trade-off research study …. which allowed customer views across different segments and geographical areas to be actively considered in the development of the final proposal*".
- **Phase 3**: Validate Ergon's service commitments and its service commitments and direction of investment plans (April to August 2014) - "*This engagement activity was undertaken to validate the direction of the proposal, supported by the release of our refreshed service commitments, as well as our research findings and a range of other updates*".
- **Phase 4**: Present Ergon's RPs (September to November 2014). Ergon stated that this "*Advanced presentation of the Regulatory Proposal was undertaken, allowing customers and other stakeholders to review and assess the key building blocks of our expenditure and the potential price impacts. This engagement is continuing. We are also encouraging participation in the AER's engagement activities through the final stages of the process*".

QCOSS has been aware of all four phases and has been involved in three of the phases (1, 3, and 4). QCOSS (and its consultant Engineroom Consulting) participated in the Customer Council Working Group specifically set up for the regulatory process

[15] Ergon Energy (2014). Supporting Documentation: Informing Our Plans, Our Engagement Program, p. 7.

and comprising of customer council members. During Phase 4, Ergon expanded this group to include extra stakeholders including a member of the AER's Consumer Challenge Panel.

The magnitude of Ergon's engagement is significant as well as the type and depth of consultation. The Working Group, for example, conducted detailed information sessions from April 2014. The stated aim of this group was to "*validate the service commitments and direction of investment plans*". In total there were five (5) sessions which covered all the components of the building block costs as well as an introductory session on the Regulatory Framework.

Several senior staff of Ergon were involved in the Working Group Customer Council's Information Sessions including a session with the Chief Executive Officer who provided the overall strategic direction of Ergon and made himself available for questions and answers.

In addition, Ergon devoted a lot of resources to consumer engagement including doing the "service/cost" trade off surveys. A combination of qualitative and quantitative research was conducted. The methodology used trade-off analysis to assess customers' willingness to pay for a number of electricity supply and service elements. Engagement included focus groups, in-depth interviews and online surveys with both residential and business customers.

How effective was Ergon's consumer engagement?

QCOSS's view is that Ergon did attempt to extend engagement beyond information sessions and to actively engage customers in their decision making. Ergon's consumer engagement was relatively strategic and focussed on improving the understanding of consumers in relation to the drivers for network operation and investment. This is evident in how Ergon structured its workshop/information sessions as well as the inclusion of an independent consultant to facilitate the workshops. Importantly Phase 3 was designed to assist consumer groups come up to speed on technical issues prior to when the details of the RP would be presented. Also during Phase 3, Ergon attempted 'to workshop' through a number of key issues where it had to take specific positions and/or where there will be changes. Ergon sought feedback from the Working Group on the following specific issues:

- Metering charges - Ergon presented a number of options on how revenues and prices will be determined for metering services and requested feedback from the Working Group;
- Carry forward of revenue under-recoveries - Ergon presented its approach to the specifics of how the carry over adjustment will be calculated and entered into its pricing model; and
- Recovery of the Solar FIT in prices - Ergon sought the Working Group feedback on how best to manage the recovery of the FIT in prices by presenting four potential options for achieving a smoothed price for customers

The Working Group Customer Council was effective in improving and building up the capacity of the consumers' knowledge and ability to review the RPs and ultimately make submissions to the AER. Importantly it allowed different consumer groups and stakeholders the opportunity to meet and share experiences who also have a strong interest in the provision of Ergon Energy's distribution services. Specifically, Ergon Energy consumer engagement was effective in:

- promoting better understanding the regulatory framework under which Ergon Energy provides its distribution services;
- clarifying how the regulation of distribution services, and the development of distribution prices, fits into the build-up of retail electricity prices that are charged to end customers;
- understanding Ergon Energy's considerations in developing its RP, including how it addresses the Rules' requirements and responds to the AER's Better Regulation Reform Program; and
- discussing issues (mentioned above) Ergon Energy identified as being important to the next regulatory period, particularly where they are either new or where Ergon Energy considers a change in approach is required from what has applied in the current RCP.

While this information was very useful and important in understanding some of the decisions that Ergon took, QCOSS's view is that the Working Group Customer Council was not able to validate Ergon's service commitments or provide direction to investment plans which was the objective of Phase 3. On the whole the interface was passive and mainly informational in nature. Many members of the group including QCOSS were not in an informed position at that stage to provide definitive positions on the issues presented. Furthermore, it was difficult to comment on particular options as the group were not given the full information including implications of those options on customer bills. Such key information was provided during Phase 4 once the RPs had been developed and the details were presented.

While Ergon did provide information on its capex and opex forecasts it delayed providing information on the WACC and its parameters as requested by consumer representatives. Ergon did allow a member of the AER's Consumer Challenge Panel to participate in Phase 4 of their consumer engagement, which was of benefit to the other consumer groups and demonstrated a marked difference to the passive engagement that had characterised the previous sessions.

Ergon did make an attempt to demonstrate how it considered and responded to customer issues and concerns. They have set this out in their consumer engagement report[16] and have relied on their market research "Customer Insights" results to represent customers' views. However QCOSS is concerned with some of the inferences which Ergon has drawn from its customer research. For example, on page 16[17], it infers that the Customer Insights informed:

> *Ergon Energy's corporate strategic goal, set in 2011, to limit increases to average network charges to less than the CPI. This goal has provided the umbrella framework for developing the expenditure forecasts for the entire Regulatory Proposal. It has driven an organisation-wide focus on prudency, efficiency and effectiveness*.

And then furthermore in its RP, Ergon states:[18]

> *Our customers appreciate the best possible price is not the lowest possible price. We are seeking sustainable outcomes, which address affordability concerns now without sacrificing service or affordability in the future.*

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[16] Ibid,
[17] Ibid,
[18] Ergon Energy (2014 Regulatory Proposal, p. 16.

This suggests that customers are satisfied if prices do not go above CPI. Our view is that Ergon's goal should be to seek out the lowest possible price consistent with its regulatory obligations around reliability and safety. The prices are unaffordable now for low income and vulnerable people who are struggling to manage their bills. It would be very interesting if the AER sought information on the breakdown of this response for the different socio-economic groups that are listed on page five of the consumer engagement report.[19]

It is also stated that this goal drove its "expenditure plans" for the RPs and led to them seeking out prudency and efficiency. Again this is disconcerting given that, although Ergon did use a "stated preference" type survey, it would not be possible for Ergon to be confident people were making informed trade-offs based on plausible outcomes. In particular, respondents are likely to have assumed given prices or given service quality levels in responding to the choices in the surveys. Yet the impression given is that this survey was a factor in informing (and possibly justifying) investment plans and setting the overall goal which directed expenditure.

QCOSS also notes that the information sessions and workshops conducted by Ergon were all held in Brisbane[20]. While many of the groups attending, such as QCOSS, represent consumers throughout Queensland, no video facilities were made available in regional centres. As evident during the AER Public Forums (where video conferencing facilities were made available), there was good participation and interest from regionally based groups. QCOSS has raised this issue with Ergon and going forward the latter will be making video facilities available in its regional offices (depending on the interest) for its future workshops and consumer engagement on its Future Tariff Reform.

In conclusion, Ergon's approach to consumer engagement has merit in that it recognised there are a broad spectrum of customers who have different levels of knowledge and abilities to engage. Ergon has a good understanding of its customers and produced an informative consumer engagement report. It therefore provided a mix of engagement methods which included the establishment of the Working Group of consumer groups to allow engagement to evolve and deepen over time. It would have been more effective if this group had been established earlier so that there was plenty time to bring all members up to speed before the technical detail of the RPs was finalised. The scope of the attendees could also have been extended to allow regionally based representatives. When the key results in the RPs were ready for consultation, it would then have been very effective to bring in more of the CCP members for Queensland.

Ergon is to be commended for continuing to engage with stakeholders on the RP process and conducted an information session on their regulatory proposal prior to stakeholders putting in their submissions to the AER on 30 January 2015. Also Ergon is workshopping the design of its future tariffs as part of its consumer engagement for the preparation of its Tariff Structure Statement. This would indicate that it is seeking input from consumer groups in the design of the tariff structure. It has also recently called for submissions on its tariff structure which will informed its consultation paper (draft Tariff Structure Statement) which is due in May 2015. This means that there is a greater likelihood that consumer groups concerns may input into and influence the design outcomes.

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[19] Ergon Energy (2014). Supporting Documentation: Informing Our Plans, Our Engagement Program, p. 5.

[20] It is acknowledged that Ergon did hold a Cairns based information session in October 2014 where it provided an Overview of its Regulatory Proposal to stakeholders.

Recommendation 2.1 ***QCOSS recommends that the AER assess the appropriateness of Ergon using customers' feedback from its market research findings in verifying expenditure and how Ergon have reflected feedback from its Working Group of consumer representatives.***

2.3.2 Energex

Energex commenced consumer engagement[21] in January 2013. Very broadly the engagement was in two programs:

- "Connecting with you" included planning and preliminary consultation and market research; and
- "Consumer Engagement Strategy" included a mix of general and detailed information sessions on the different components of the regulatory proposal

QCOSS was involved in the second stage and was invited to attend the information sessions. QCOSS or its consultant, Engineroom Consulting, attended all of the Energex sessions. They commenced in April 2014 with a number of general public sessions for business and residential consumers. Energex responded well to consumer groups' requests for more detailed sessions when feedback was provided, by QCOSS and others, that the initial information sessions were too light handed and did not provide sufficient detail.

Energex's consumer research and engagement was extensive and included:

- research with 6,700 residential, small and large business customers, customer representative organisations and retailers (surveys, focus groups and interviews);
- workshops commencing in April 2014 – business and residential workshops (held 3) and fact sheets developed;
- eight (5) in-depth information sessions (August to October 2014):
  - expenditure (capital and operating expenditure);
  - revenue and prices (rate of return, revenue, indicative prices);
  - your network and services (demand and energy forecasting, metering strategy, re-visit indicative pricing and broader classification of services);
  - demand management; and
  - overview.

How effective was Energex's consumer engagement?

QCOSS's view is that the detailed information sessions were effective in building the capacity of consumers and consumer representatives to participate in the regulatory process. They were attended by a cross-section of customers including large and small business, local government, irrigators, large users and small residential customers' representatives. As a result of the process, QCOSS is more informed and in a stronger position to make a submission to the AER. Importantly, Energex presented detailed information on key issues which included proposed capex, opex, WACC and indicative prices for different tariffs before the regulatory proposal's

[21] Energex (2014), Please check out the following webpage for more details: https://www.energex.com.au/about-us/corporate-responsibility/connecting-with-you/our-research-programs/customer-engagement-research-program

deadline. The quality of their presentation and the information was good and easy to understand.

However, Energex made it clear from the onset that the purpose of the sessions was to provide information and not to influence or validate their positions as the RPswere well advanced by June 2014 when the detailed sessions commenced. Unfortunately, the detailed workshops and information sessions commenced too late for any meaningful opportunities to influence and develop policies. This consumer engagement was only ever intended to be passive and one-way. There was no attempt to use Energex's Consumer Engagement Strategy to inform its expenditure plans. However, Energex has used its "Connecting with you" market research program which engaged with a large number of customers identified a number of high level issues and views which Energex uses, in part, to justify expenditure decisions, for example in Chapter 9 of its Regulatory Proposal: Forecasting Capital Expenditure:[22]

> *Customers have indicated, through research, that a reduction in capex is appropriate as large network investment driven by growth is no longer required. There was broad support for capex reductions provided network performance is maintained and future reliability standards are not at risk. Customers supported Energex's plans to invest in poor performing feeders to address lower than average reliability standards. Maintenance of reliable supply is considered important to customers. Customers were advised of the trade-offs between capex and opex, and supported analysis and delivery of cost effective non-network solutions to defer capex.*

While these are valid customers' views, they are high level and strategic in nature. To what extent they can reasonably be used to inform complex expenditure decisions is questionable. It is not clear to what extent the comments and feedback from customers was fully informed. The customer surveys were generally framed as a choice between lower spending and lower reliability. Customer surveys in these circumstances can easily subtly "lead" respondents in the direction of a particular answer. As in the case with Ergon, QCOSS would question how credible market research results are and especially whether consumers can make informed views on detailed questions on hypothetical reliability/price trade-offs when all the input choices are not clear.

In conclusion, it is QCOSS's view that Energex's consumer engagement has been effective in preparing consumer representatives to prepare better informed submissions to the AER. However, Energex's expenditure plans do not reflect consumers' views or concerns, as:

- justification for complex expenditures decisions cannot be based on inferences from high level market research; and
- consumer groups were not given the opportunity to influence/input into the RP as Energex, from the onset, clearly stated that the information sessions were about providing information and were not about influencing/validating positions.

Going forward, Energex is to be commended for its consumer engagement program on its network tariff reform process, "Your Network, Your Choices". This commenced in November 2014 where the objective of consumer engagement is stated as:[23]

[22] Energex RP, p. 108.
[23] Energex, (2014), Please check out the webpage for more details: https://www.energex.com.au/about-us/corporate-responsibility/connecting-with-you/your-network-your-choices

… you can help us shape the future of the prices you pay. We want you to be a part of the change in how we charge for the use of the network. Get involved and shape the future

Energex is consulting with consumers and consumer groups on its future tariffs as part of its Tariff Structure Statement under the new AEMC Rule.[24] Similar to Ergon's approach, Energex is holding a series of workshops where the design of future tariffs is discussed with Energex staff and other consumer groups, and consumers can put in submissions prior to the consultation paper release in May 2015. Consumer groups will be expecting to see that their views/concerns will be addressed in the Tariff Structure Statements. If distributors do not adopt the positions put forward by consumers it is important that they acknowledge them and clearly state the reasons for not adopting them.

Recommendation 2.2

QCOSS recommends that the AER assess the appropriateness of Energex using customers' feedback in terms of its market research findings in verifying expenditure and how Energex has reflected feedback from its Information Sessions with consumer representatives.

2.4 Recommendations for the AER

It is acknowledged that the consumer engagement for the AER revenue determination is the start of an on-going journey for both distributors and consumers and it is important going forward to identify how things can be done better.

The current consumer engagement process is not a level playing field. Consumer groups (often made up of volunteers) do not have the time or resources to absorb all the information/data provided. Most consumer groups are working in a range of different areas or portfolios unrelated to energy and do not have the technical knowledge or the time to get across the significant volume of complex and technical information provided. On the other hand, distributors are well resourced to complete their RPs as they are allowed to recover their expenditure on regulatory processes. Consequently, for many consumer groups, the information sessions were only ever going to be passive, with one way information flow going from distributors to consumer groups.

In principle, the AER's CCP has been an excellent initiative to strengthen engagement on the consumers' side. The AER hosted CCP fora were excellent and the Queensland CCP members are to be commended in making available excellent information and support to consumers groups in these sessions.

QCOSS's view is that there is an opportunity for greater contribution from CCP members in addition to the AER hosted forums. QCOSS was fortunate to have secured funding from the Consumer Advocacy Panel to hire Engineroom Consulting to assist with the submission however many other consumer groups do not have dedicated technical support. QCOSS sees an opportunity for CCP members to work as "technical intermediaries" in the consumer engagement undertaken by Distributors to add an extra layer of scrutiny and questioning from a more informed source. The nature of the tasks involved would need to be determined, however it

[24] AEMC (Nov 2014) Distribution Network Pricing Arrangements, Final Determination

could involve attendance at Distributors' information sessions prior to the submission of their RPs.

Recommendation 2.3

QCOSS recommends that the AER review the resourcing of the CCP with consideration for expanding their role to further assist in addressing the significant information and expertise asymmetry in the consumer engagement processes undertaken by the Distributors.

3 Capital expenditure forecasts

3.1 Context

Capital expenditure (capex) is typically categorised as:

- augmentation expenditure (augex), that the increase of the network through new facilities or expansion of existing facilities;
- replacement expenditure (repex) to replace deteriorating assets;
- new connections and customer initiated works; and
- non-network capital expenditure, which is expenditure on long-lived assets such as IT systems, cars, and buildings.[25]

Capex is typically driven by factors including (but not limited to):

- demand and peak demand growth, particularly at a localised level;
- reliability and other regulatory obligations; and
- age and condition-based factors necessitating replacement of the network.

The NER rules relating to the assessment of forecast capital expenditure (capex) are contained in clause 6.5.7 of the NER. In relation to the assessment of capex, this clause provides that the capex forecast is required to meet expected demand and comply with applicable regulatory obligations.[26] The capex must reasonably reflect the capital expenditure criteria, which are defined as the *efficient* and *prudent* capex costs based on a realistic expectation of demand forecast and cost inputs.[27] In deciding whether the capex forecasts are reasonable, the AER must have regard to matters including:[28]

- *the most recent [AER] annual benchmarking report;*
- *the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding RCPs;*
- *the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;*
- *the relative prices of operating and capital inputs and substitution possibilities between operating and capital expenditure; and*
- *the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.*

There is an additional provision in relation to the evaluation of contingent projects, which are projects that may or may not proceed depending on specific developments.

The capex proposals should be framed to meet expected demand and reliability obligations.

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[25] Ergon has two additional categories of capex: (i) reliability-related and quality of supply capex; and (ii) other capex.
[26] NER clause 6.5.7(a).
[27] NER clause 6.5.7(c).
[28] NER clause 6.5.7(e).

The capex rules require the AER to assess capex proposals in terms of their efficiency, prudency, and whether they assume realistic demand forecasts (known as the capital expenditure criteria).[29] In assessing proposals, the AER is to have regard to factors including industry benchmarking, historical capex, consumer concerns, substitution of opex, and non-network ways of meeting demand (such as demand management and local generation).[30] The industry benchmarking is a new requirement introduced as part of the Better Regulation Program.

3.2 Overview of Energex and Ergon's capex proposals

Energex's and Ergon capex programs are set out below in Table 3.1.

Table 3.1 Energex and Ergon capex proposals for 2015-2020 RCP (2014-15$)

	Basis	2010-2015 actual	**2015-16**	2016-17	2017-18	2018-19	2019-20	Total 2015-2020
Ergon	$m	4,188*	769	753	691	677	663	3,555
Energex	$m	4,700*	670	688	629	613	638	3,239

Source: Ergon RP, Table 41, p.87 and p. 93; Energex RP, p.4 and Table 9.1, p.104
Note: Energex 2010-2015 actual capex only specified to two significant figures.
Note: Ergon 2010-2015 actual figure includes $354m in standard service customer contributions and $71m in alternative control customer contributions, leaving a net figure of $3,764m

It is noted that both distributors are proposing lower capex programs than during the 2010-2015 regulatory period. This is to be welcomed. However it has come too late to stop a major increase in the size of the RAB which drives well over half the regulated revenues. The growth in Energex's and Ergon's RABs are set out in Table 3.2 below. This table shows the extent of the increase of the RAB during the current regulatory period and the continuing rapid increase in the RAB in the forthcoming regulatory period. The actual increase in the RAB would be greater except that the 2019-2020 RAB does not include metering assets, which in the case of Energex and Ergon respectively, are estimated to be $417 million and $61.60 million as at the end of 2014-15.[31]

Table 3.2 Growth in the regulated asset bases of Energex and Ergon

	Basis	2009-10	2014-15	2019-20
Energex	$m nominal at close of FY	7,867.3	11,844.0	14,255.2
Energex - growth from prior period			51%	20%
Ergon	$m nominal at close of FY	7,160.95	10,095.83	12,867.00
Ergon - growth from prior period			41%	27%

Source: Ergon RP, Table 3, p.20 and Table 4, p.21; Energex RP, Table 12.1, p. 148 and Table 12.2, p. 150. The 2019-2020 values do not include metering assets.

QCOSS notes there is a marked discrepancy between the patterns of capex between the two distributors.

[29] NER clause 6.5.7(c)
[30] NER cl 6.5.7(e).
[31] Energex RP, Table 12.1, p. 148, and Ergon RP, Table 25, p. 50 Values are in nominal dollars

Energex's proposed capex is set out in Table 3.3 below. This table compares Energex's proposed capex with its historical capex from the 2010-2015 RCP. There is a marked reduction in augex, a very strong increase in repex, and a halving in the numbers of connections and customer initiated works and the non-system capex budgets. It should be noted that the historical figures are nominal while the 2015-2020 proposed figures are 2014-15 dollars.

Table 3.3 Comparison of Energex capex in the 2010-15 RCP to 2015-2020 RCP

$m	2010-2015 (Nominal)	2015-2020 (2014-15$)
Asset replacement	1,147.2	1,773.0
Augmentation	1,930.6	726.0
Connections and customer initiated works	883.8	472.6
Non-system	459.2	268
Total	**4,420.7**	**3,239.6**

Source: Energex RP Summary, p. 10, Energex RP, p. 105, Table 9.2

Table 3.4 compares Ergon's capex for the 2015-2020, 2010-2015 and 2005-2010 RCPs. Repex remains roughly level for the 2015-2020 RCP after a steep rise last period. Augex fell significantly in the 2010-2015 RCP and is proposed to remain roughly the same in the coming period. Customer connection and initiated works capex costs are consistently high compared to Energex but have fallen from the 2005-2010 RCP. Other system capex is down to the same as the first period after a steep rise in the 2010-2015 RCP. Non-system capex in the coming period is proposed to decline from the first and second periods.

Interestingly, there is a huge rise in alternative control customer contributions (likely to be mainly metering), while customer contributions for standard control services has fallen by 50 per cent. Ergon has an additional category of reliability and quality of supply capex and other capex. Gross capex declined from the first period to the second period by around 5 per cent and then by around 2 per cent to the third period.

Table 3.4 Comparison of Ergon capex in the 2010-15 RCP to 2015-2020 RCP

$'000 (real 2014-15)	2005-2010	2010-2015	2015-2020
Asset Renewal	805,979	1,255,262	1,358,064
Corporation Initiated Augmentation	1,175,088	808,880	790,490
Customer Connection Initiated Capital Works	1,523,766	1,045,886	1,188,935
Reliability and Quality of Supply	60,017	159,534	17,528
Other System	150,653	259,042	148,872
Non-System	708,526	659,731	603,341
Gross capital expenditure	**4,424,028**	**4,188,335**	**4,107,231**
less Alternative Control Services customer contributions	*0*	*(70,841)*	*(551,940)*
Standard Control Services gross capital expenditure	**4,424,028**	**4,117,494**	**3,555,291**
less Standard Control Services customer contributions	(356,080)	*(353,553)*	*(158,260)*
Standard Control Services net capital expenditure	**4,067,948**	**3,763,940**	**3,397,031**

Source: Ergon RP, pp. 90, 92-93.

3.3 Evaluation of Energex and Ergon's capex proposals

While the overall capex levels are down from the levels in the 2010-2015 RCP, different classes of capex are still increasing and QCOSS is very concerned with the size of the capex programs for a number of reasons.

- They will result in significant growth in the RAB, regulated revenue and ultimately the prices which consumers pay. These capital programs are locking in a regime of high prices for many years which many people are struggling to afford.
- Their forecasting risk is with the consumers who have to pay for any significant over estimation for many years. This was evident in the last RCP where Energex was awarded $6.245 billion in capex and spent $4.420 billion (both nominal dollars)[32] and Ergon was awarded $4.989 billion ($2009-10 dollars) but spent $4.188 billion ($3.764 billion after customer contributions).[33]
- Given the growing complexity of the energy sector with solar and other disruptive technologies it is important to take account of factors that, while they may not apply to a significant degree now, are likely to apply during the upcoming RCP.
- Any 'underspend' could be retained in part by the distributors under the CESS as a reward for 'outperformance'. It is important that any such incentive is not the result of inaccurate estimation or a 'margin for prudency' by the regulator when assessing distributor proposals.

Increasing capex means the RABs are still growing strongly. This is difficult to understand when demand is falling and there is declining growth in peak demand (with Energex experiencing actual falls in peak demand). This means that assets will increasingly become underutilised and average ages are shorter. It is also difficult to understand when recent reviews such as: the 2011 ENCAP[34] review have significantly reduced reliability standards: and the Independent Review Panel (IRP) review came up with a wide-ranging set of recommendations to improve opex and capex efficiency and estimated costs savings in the order of $5.0 billion to occur in both the 2010-2015 and 2015-2020 RCPs (see the opex chapter for more details).

QCOSS questions the size of the proposed capex programs given the trends in demand and peak demand, age and condition-based factors, and reliability obligations .Analysis of Energex and Ergon's performance against industry benchmarks indicates they are inefficient in their capex and asset policies. In view of these trends, QCOSS asserts that the AER cannot allow transitionary arrangements.

QCOSS is not in position to fully evaluate the prudency and efficiency of Energex's and Ergon's capex proposals, particularly in light of opex substitution, non-network alternatives, and upwards and downwards directions in underlying input costs such as employee and contractor costs. Clearly the AER is better placed to employ resources to carry out such assessments noting that the distributors themselves have strong incentives to inflate their proposals when putting forward proposals to the regulator. In this chapter QCOSS highlights a number of issues to the AER to take into account in its assessment of augmentation, replacement and other capex.

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[32] Energex RP Summary, p.10. Note that Energex's actual capex spend for 2014-15 of $828m is a forecast.

[33] AER, *Final Decision - Queensland distribution determination 2010–11 to 2014–15*, p.141 and Ergon RP, p.93.

[34] Electricity Networks Capital Program review 2011 was initiated by the Queensland Government.

3.4 Capex drivers

3.4.1 Utilisation of assets and average asset age

It is QCOSS' view that the large capex program in the 2010-2015 RCP has led to a major reduction in the average utilisation of the network and in the average age of the network, right at a time when peak demand and total demand growth are declining. For the coming regulatory period, the distributors expect average and peak demand to grow slowly over the coming regulatory period, with Energex expecting 1.1 per cent growth per year and Ergon expecting 1.3 to 1.5 per cent growth per year in peak demand.[35] The expectation from this set of circumstances would for the distributors to only have a low requirement to invest capital in the next RCP.[36]

QCOSS, to illustrate its views, uses data for Energex[37] from the AER RIN[38] and CCP has assessed the amount of assets used and found that these are growing rapidly, and this has been exacerbated by decline in demand and slowing of peak demand since 2010.

For example, Table 3.5 shows that the residual life of Energex's assets has climbed markedly in the period 2006 to 2013 for many of its key assets including overhead less than 33kV, overhead 33kV and above and zone substations and transformers. None of the asset categories has declined in residual life.

Table 3.5 Energex residual life by asset category (in years)

Asset category	2006	2013
Overhead network assets less than 33kV (wires and poles)	16.3	27.3
Underground network assets less than 33kV (cables)	44.7	45.9
Distribution substations including transformers	25.6	30.4
Overhead network assets 33kV and above (wires and towers / poles etc.)	24.5	37.4
Underground network assets 33kV and above (cables, ducts etc.)	21.0	32.7
Zone substations and transformers	28.3	37.1
Meters	0.0	0.0
"Other" assets with long lives	12.6	19.0
"Other" assets with short lives	4.3	5.1

Source: Energex RIN 2014, RAB tab, Table 4.4.2 Asset Lives – estimated residual service life.

Chart 3.1 shows the direction of annual demand in GWh on the Energex network. There is a clear downward trend for residential from a peak around 2010.

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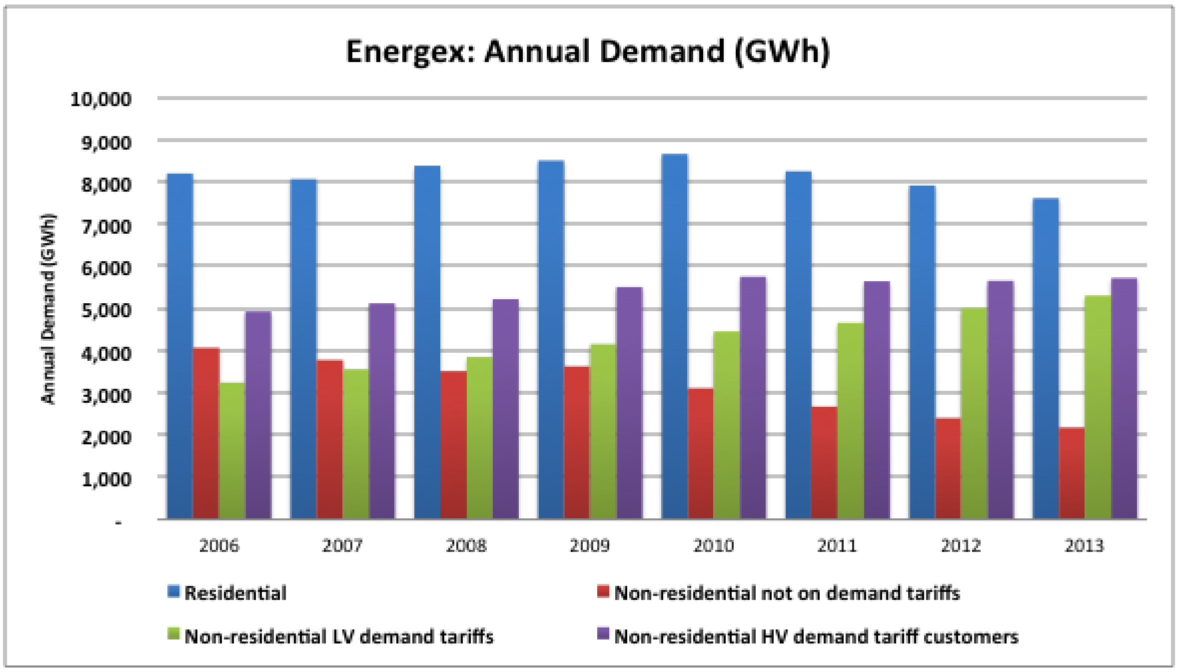
[35] Energex RP, p. 96, Figure 8.4; Ergon RP Overview, p. 10.
[36] The above analysis only provides information on Energex as Ergon's RIN does not provide longitudinal sufficient information to do a similar analysis. QCOSS is confident that Ergon's trend information would be similar to Energex's given its patterns of capital expenditure, demand and peak demand growth, and customer numbers. Certainly, it is clear that Ergon's peak demand is currently trending flat or slightly down: Ergon RP, p. 97, figure 16. QCOSS wishes to express its concern at the lack of information in Ergon's RIN and the inconsistency in the format of the RINs which makes comparison of performance very difficult.
[37] QCOSS has not looked at Ergon's utilisation and average age of assets. It is expected that the AER will undertake such analysis.
[38] Regulatory information Notice

Chart 3.1 Energex annual demand (GWh)



Source: Bev Hughson presentation to Queensland energy users, 8 August 2014, slide 7.

Table 3.6 below shows peak demand on Energex's system from 2006 to 2013 at a zone substation level. For non-coincident maximum demand there are falls from 2011 onwards following a peak in 2010. For coincident maximum annual maximum demand, there is a similar pattern of falls from 2011 onwards after a peak in 2010.

Table 3.6 Annual system maximum demand characteristics at the zone substation level – MW measure

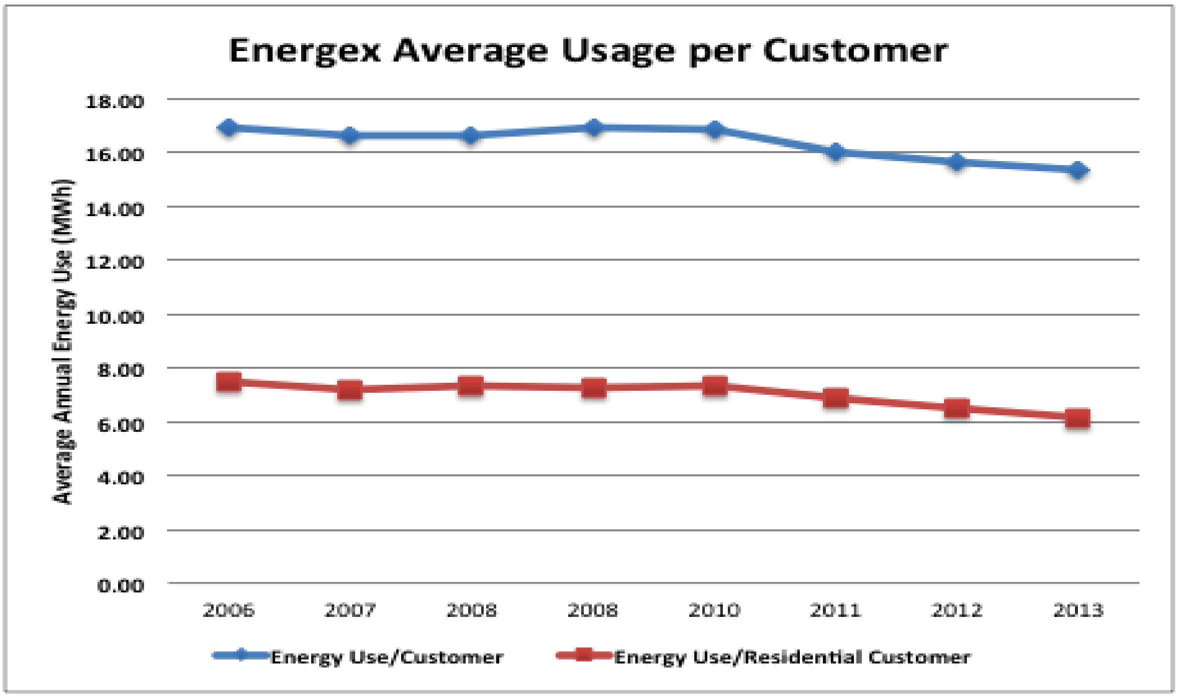
	2006	2007	2008	2009	2010	2011	2012	2013
Non-coincident Summated Raw System Annual Maximum Demand	4670	4824	4894	5160	5257	5090	5008	5029
Coincident Raw System Annual Maximum Demand	4021	4192	3923	4435	4580	4554	4335	4307

Source: Energex RIN 2014, Operational Data tab, Table 5.3.1

Charts 3.2, 3.3 and 3.4 also confirm the trend downwards since 2010 for Energex's network in terms of use per customer and system utilisation of the network. In particular,

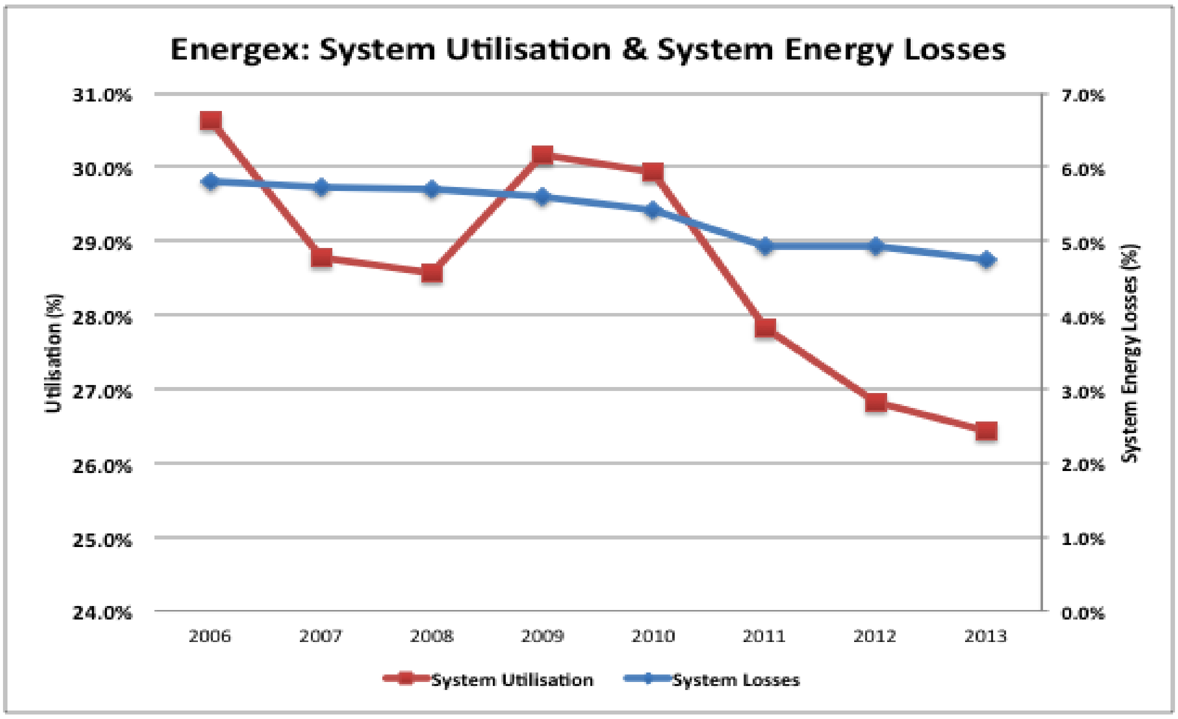
Chart 3.4 uses a MVA measure to depict the downward trend in peak demand since 2010. MVA peak demand is the key demand-related driver for capex.

Chart 3.2 Energex average use per customer



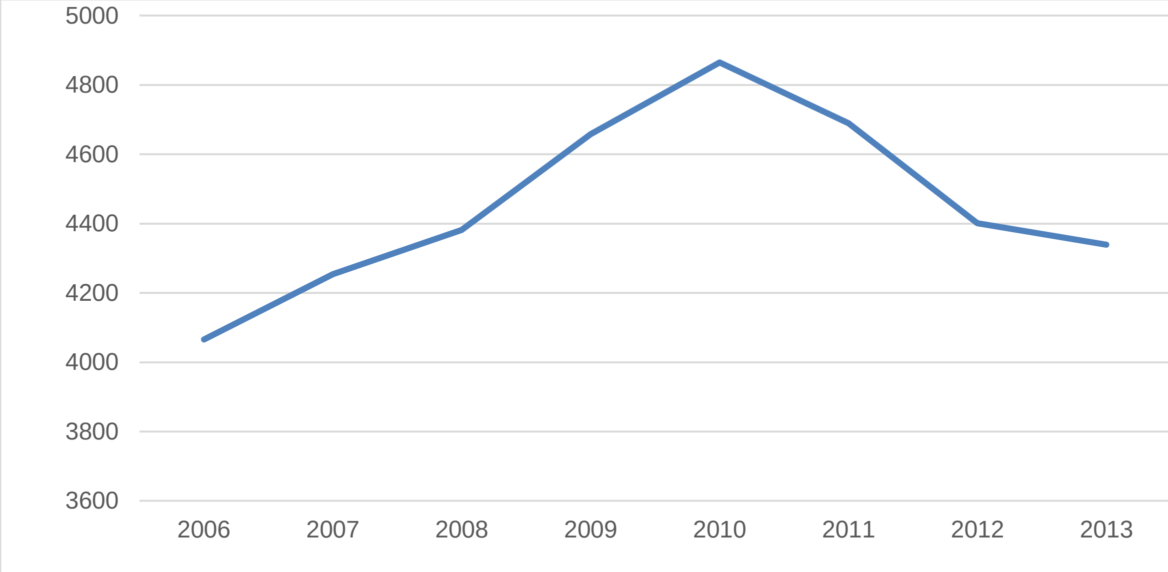
Source: Bev Hughson presentation to Queensland energy users, 8 August 2014, slide 8

Chart 3.3 Energex system utilisation



Source: Bev Hughson presentation to Queensland energy users, 8 August 2014, slide 10.

Chart 3.4 Trend in coincident raw system annual maximum demand – MVA measure



Source: Energex RIN, Operational data tab, Table 5.3.1 Annual system maximum demand characteristics at the zone substation level – MW measure

For Energex, we have extracted and analysed the network in terms of the growth in assets, customer numbers, peak demand (in MVA), and the amount of energy delivered at on-peak and off-peak times. This information is presented in Table 3.7 below. Table 3.7 also illustrates key metrics such as the amount of assets used to deliver peak demand (asset/peak), the amount of assets used per customer (asset/customer), and the amount of delivered energy per asset (delivered energy/asset).

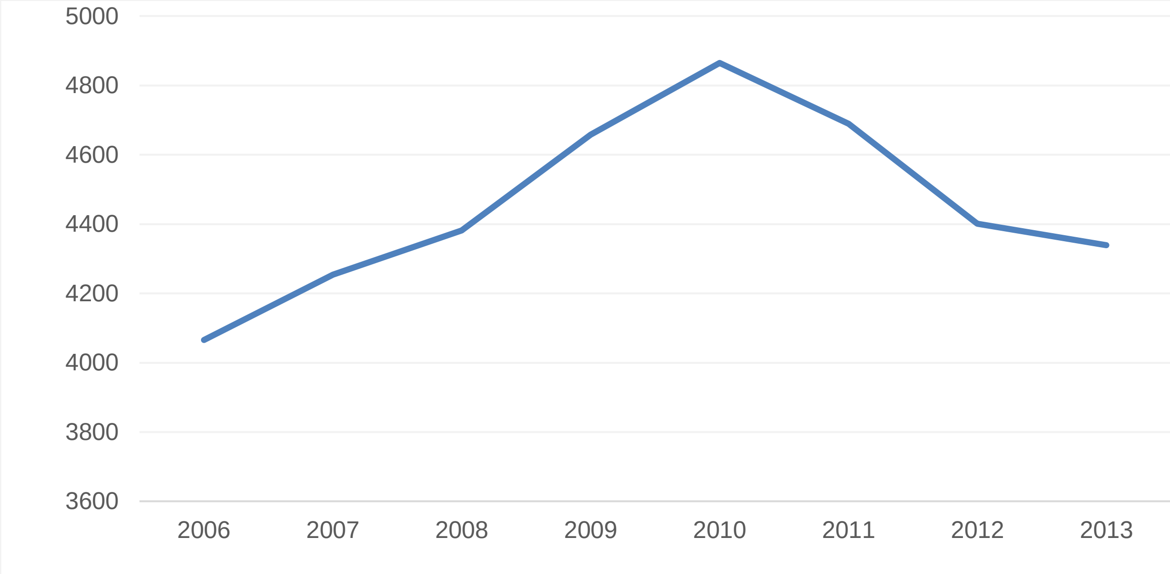
Table 3.7 Key delivery information and metrics for Energex network 2006-2013

	units	2006	2007	2008	2009	2010	2011	2012	2013
Assets $m	$,000	4,077	4,478	4,881	5,369	6,151	6,789	7,346	7,963
Customer numbers	number	1212064	1236101	1263763	1287436	1307554	1326564	1343865	1359712
Energy delivered	GWh	20618	20707	21155	21994	22193	21454	21210	21055
Peak demand	MVA	4066	4254	4381	4658	4865	4689	4401	4339
On-peak deliveries	GWh	10939	10899	11062	11611	11630	11192	10896	10557
Off-peak deliveries	GWh	10704	10796	10905	11329	11465	11105	11001	10909
Asset/customer	$/cust	3364	3623	3863	4171	4705	5118	5467	5857
Asset/peak	$m/MVA	1002959	1052826	1114181	1152633	1264646	1447947	1669245	1835317
Delivered energy/asset	kWh/$	5.056	4.623	4.334	4.096	3.607	3.160	2.887	2.644

Source: Energex RIN, RAB and Operational data tabs, Table 4.1, Closing value for asset value, Table 5.1 Energy delivery, Total energy delivered, Table 5.2.1 Distribution customer numbers by customer type or class, Table 5.3.3, Coincident Raw System Annual Maximum Demand, Table 5.1.2 Energy - received from TNSP and other DNSPs by time of receipt, Energy into DNSP network at On-peak times Energy into DNSP network at Off-peak times

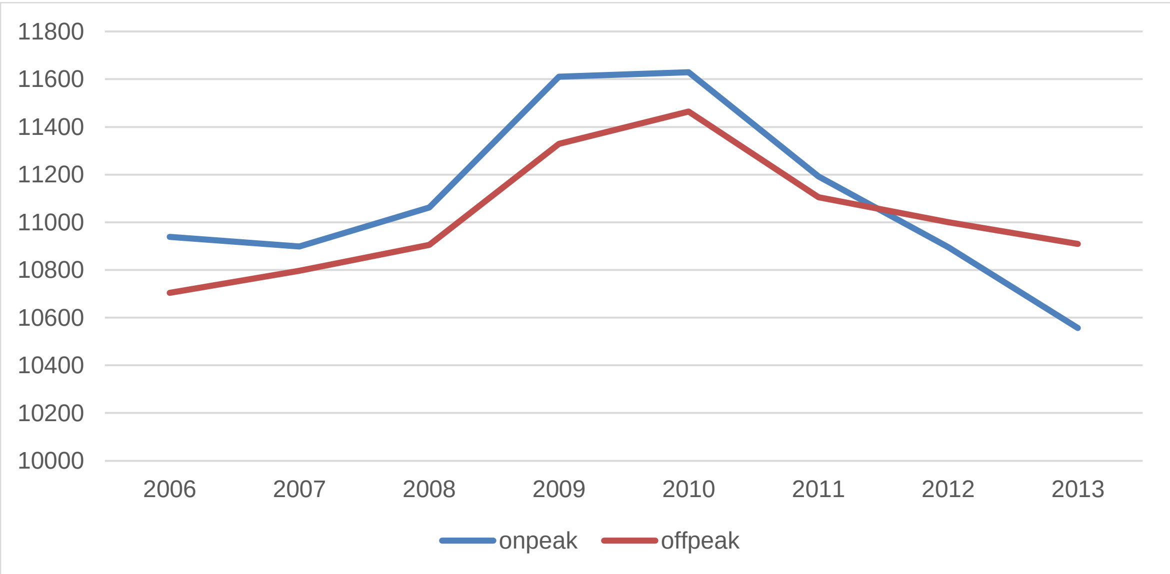
The key metrics from Table 3.7 are illustrated in Charts 3.5 to 3.9 below.

Chart 3.5 Energex peak MVA 2006-2013



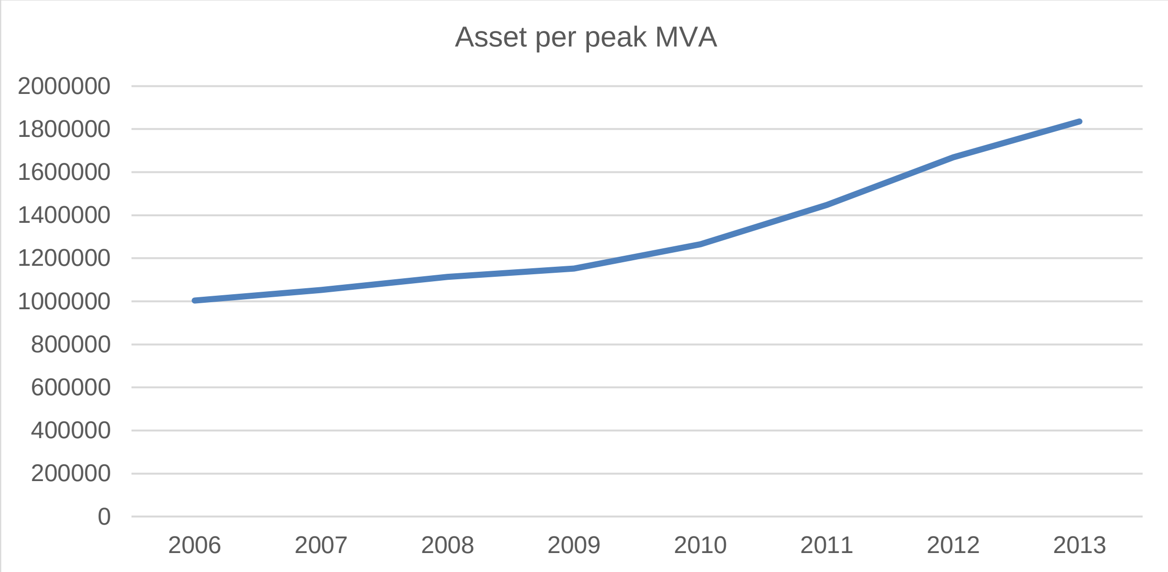
Source: Table 3.7 analysis

Chart 3.6 Energex on-peak and off-peak deliveries 2006-2013



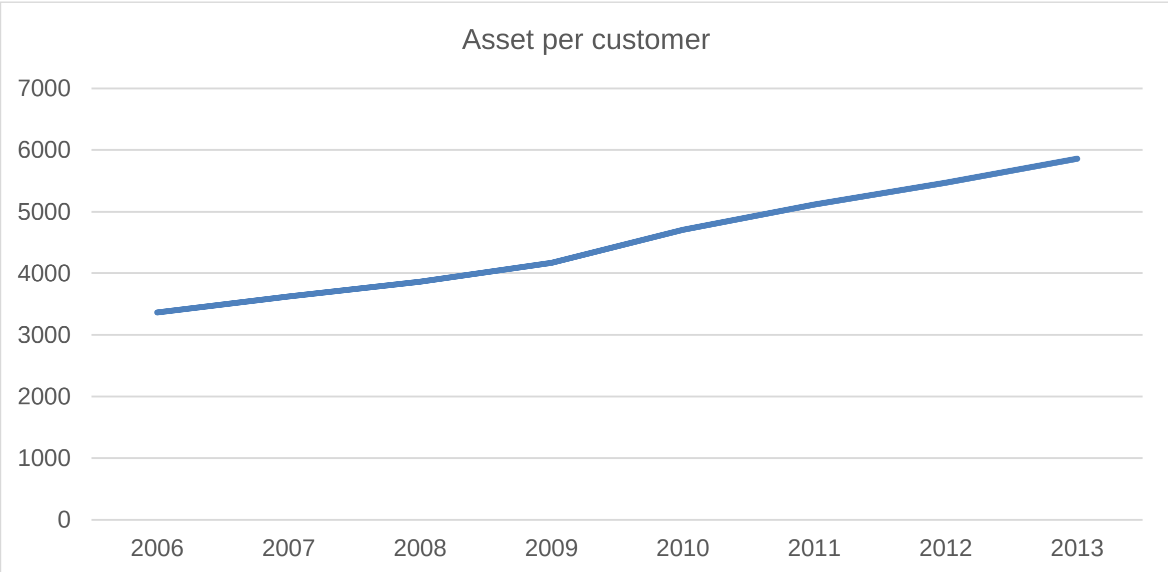
Source: Table 3.7 analysis

Chart 3.7 Growth in assets used to deliver peak MVA – Energex network – 2006-2013



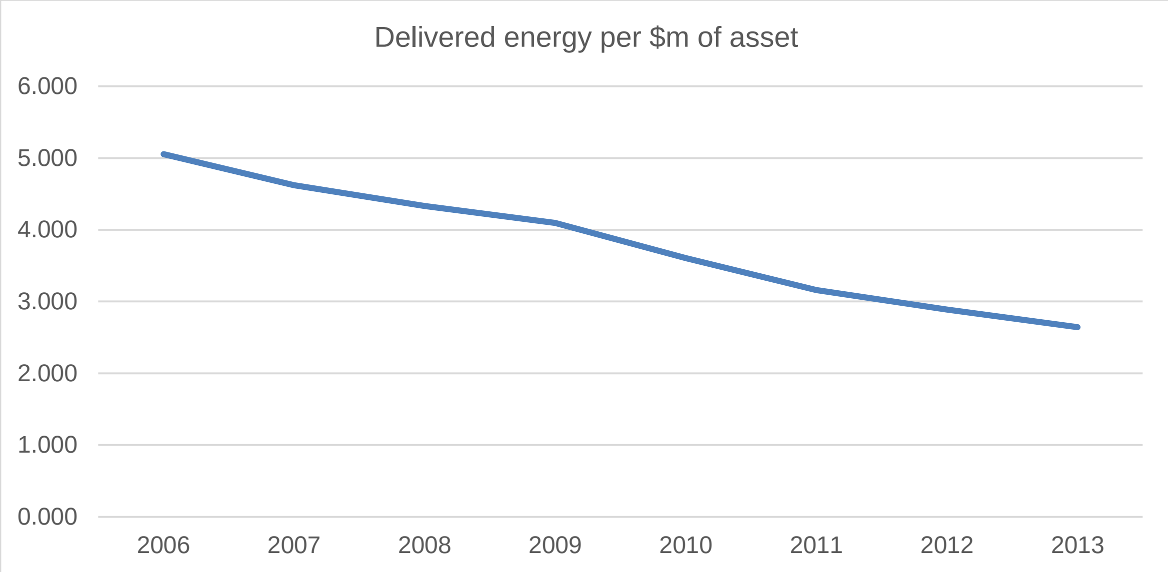
Source: Table 3.7 analysis

Chart 3.8 Growth in assets per customer – Energex network – 2006-2013



Source: Table 3.7 analysis

Chart 3.9 Delivered energy per $m of assets – Energex network – 2006-2013



Source: Table 3.7 analysis

Chart 3.5 shows that peak demand on Energex's network rose until 2010 and has declined since then.

Chart 3.6 shows that demand on Energex's network is slowly migrating from peak to off-peak times.

Charts 3.7 and 3.8 show that assets used to deliver peak demand and assets per customer grew rapidly between 2006 and 2013. Chart 3.9 shows that the delivered energy per $million of assets declined rapidly and consistently over the period from 2006 to 2013.

Recommendation 3.1 ***QCOSS recommends that the AER give close consideration to system utilisation and the age of assets in assessing the appropriateness of the capex proposals provided by Ergon and Energex.***

3.4.2 Trends in demand and peak demand

Much of the capex proposed by the distributors relating to augex, connections and customer initiated work and some repex is driven by demand forecasts. Therefore, the accuracy and validity of the Queensland distributors' demand and localised peak demand forecasts are highly relevant to their capex forecasts.

As part of their capex proposals, Energex and Ergon are proposing that demand will grow gradually over the next RCP. This is set out in the regulatory proposals.

Energex has forecasted a rise in peak demand of 1.1 per cent per annum over the coming RCP. This appears high compared to the trend over the last five years where peak demand has reduced by 0.5 per cent per year.[39] Similarly, Ergon has forecast growth of 2.2 per cent in peak demand, despite the trend over the last five years of peak demand reducing by 0.1 per cent per year.[40] It is QCOSS's view that these

[39] AER Issues paper (Dec 2014) : Qld electricity distribution regulatory proposals 2015-16 to 2019-20,
[40] Ibid

forecasts diverge significantly from recent historical trends (as evident above in Charts 3.1, 3.4, 3.5 and Table 3.6 analysis for Energex) and do not reflect reasonable expectations about the future of peak demand in Queensland.

We note that Energex and Ergon have traditionally significantly overstated demand and peak demand in their forecasts. For example, during the 2010-2015 RCP, Energex's peak demand forecasts for summer (the peak season) were significantly above actual demand, consistently each year, as can be seen from Table 3.8 below:

Table 3.8 Energex summer peak demand forecasts compared with actual

Energex Summer Peak Demand Forecasts					
	2010-11	**2011-12**	**2012-13**	**2013-14**	**2014-15**
Demand- forecast (MW)	4,931	5,089	5,328	5,555	5,733
Demand - actual (MW)	4,875	4,881	4,590	4,372	4,356
Actual as a percentage of forecast	99	96	86	79	76

Source: Energex RP, table 3.2, p.35

Given demand generally peaks in summer in Queensland[41], especially in north Queensland, these misforecasts drove serious over-allocation of augex (and understatement of tariffs) during the 2010-2015 RCP.

QCOSS would wish to comment on Ergon's forecasts for the 2010-15 RCP but this information is not available or not accessible in their RPor RIN. Ergon in many cases has provided information only in graph format (for example, their peak demand graph[42]), which makes analysis impossible. This lack of transparency suggests further scrutiny by the AER is required to ensure demand forecasts are reasonable and reflect up-to-date information on factors that influence trends in demand.

Similar to their forecasts for the current regulatory period, QCOSS considers that the distributors' demand and peak demand forecasts for the coming regulatory period are likely to be significantly overstated.

Part of the reason for this is the very high rise in prices since around 2000. The Productivity Commission charted the rise of residential electricity retail prices in Brisbane from 1980 to 2012. Prices roughly doubled between 1980 and 2000 in a period of relatively high inflation – see Chart 3.10 below. However, between 2000 and 2012, prices have gone up almost 200 per cent in Brisbane despite a period of low inflation. Prices in Brisbane have continued to go up steeply since 2012, with a jump of about 50 per cent in residential electricity prices in the last three years. The Productivity Commission has compiled an annual growth rate graph showing the rise relative to inflation – see Chart 3.11 below.

These price trends have driven a reduction in peak demand in recent times and are likely to continue to do so.

The Productivity Commission in 2012 noted that: *The ESAA (2012) estimates that consumption per customer fell by around 2.5 per cent in both 2010-11 and 2009-10.*

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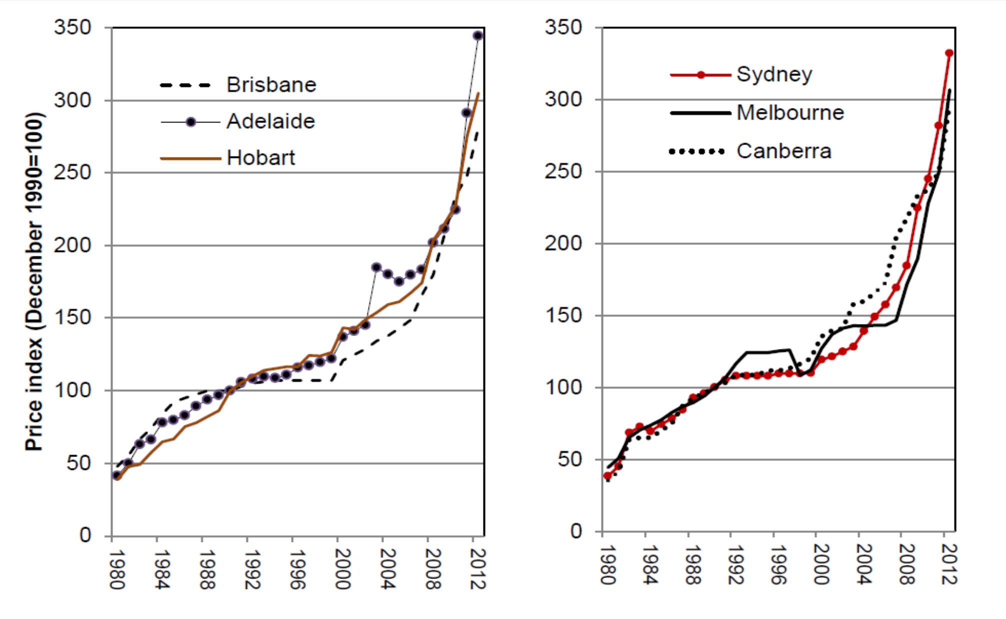
[41] While this is true as a general statement, it may not necessarily be true in relation to peak demand at a substation level.
[42] Ergon RP, p. 97, figure 16.

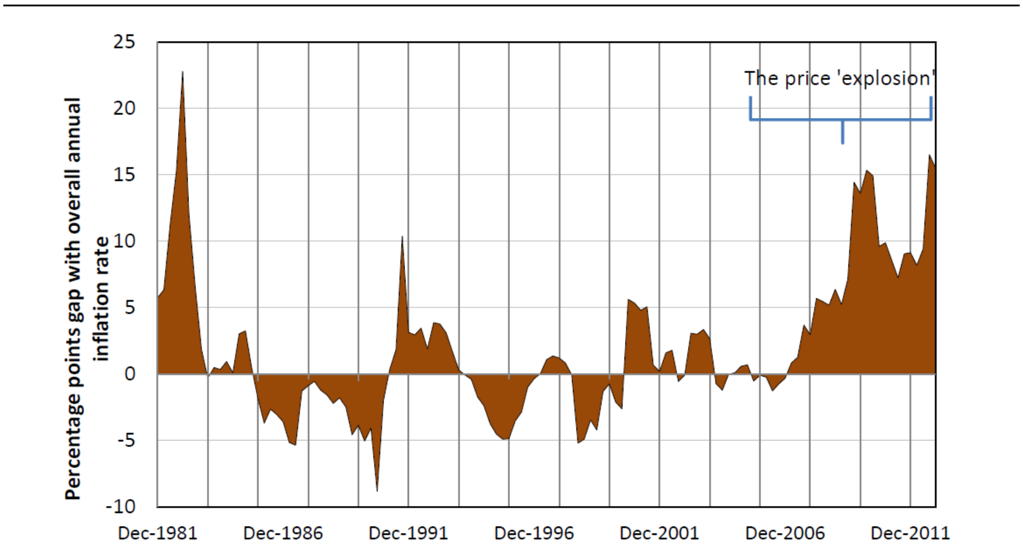
Indeed, even total consumption fell in these two years despite rising population and household formation. [43]

Chart 3.10 Relative residential electricity price rises by NEM jurisdiction



Data source: ABS (2012e).

Chart 3.11 Price rises relative to inflation (Source Productivity Commission)



Data source: Figure 2.8.

[43] Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, at pp. 98-99

As a consequence of the very steep price rises in the past 10 years, QCOSS considers that consumers are in the middle of a significant medium term to long-term shift to reduced electricity use through responses such as:

- simple reduction in use as a response to price rises;
- greater energy efficiency, including purchase of appliances such as more energy efficiency lighting, fridges; and
- solar generation and other forms of local generation

The point is that due to the higher medium term elasticity of electricity prices, these responses are starting to take effect now. As the Commission noted about the elasticity of electricity demand, it is unsurprisingly higher in the medium term:[44]

> *Demand is not very responsive to prices in the short run, with a 10 per cent increase in prices likely to reduce electricity demand by somewhere between 2 and 4 per cent. The reduction is significantly greater — somewhere between 5 and 7 per cent — over the long run (Fan and Hyndman 2010, p. 8; Langmore and Duffy 2004). It is higher again for peak periods (PC technical paper). Consequently, some of the recent falls in electricity demand may reflect the impacts of the large price increases described in [this report].*

As the Queensland distributor proposals would maintain price levels at current levels, then the medium term response to the very large increase in tariff levels is likely to continue. To the extent that demand falls and the revenue cap adjusts prices upward, the trend towards lower use may increase.

QCOSS does not expect economic activity to be a key driver for increased peak demand in the next RCP. First, as the Public Interest Advocacy Centre (PIAC) notes in its submission to the NSW Draft Determination, the role of economic growth in driving increased electricity use is becoming progressively weaker over time.[45] Second, at present, the Queensland and national economies are currently relatively subdued with a weak to moderate outlook, as noted by the Reserve Bank of Australia in its December 2014 interest rate decision press release:[46]

> *In Australia, most data are consistent with moderate growth in the economy. Resources sector investment spending is starting to decline significantly, while some other areas of private demand are seeing expansion, at varying rates. Public spending is scheduled to be subdued. Overall, the Bank still expects growth to be a little below trend for the next several quarters.*

Accordingly, QCOSS expects that current price levels and the weak to moderate economic conditions in Queensland are unlikely to drive an increase in demand or peak demand, and are more consistent with a continuation of the current trend of falling demand and peak demand.

In addition to these trends towards lower use and lower peak demand, QCOSS notes that there are significant reforms underway to manage demand and increase

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[44] Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, at p. 102.
[45] PIAC, Submission to the NSW Electricity Determination, p.40, and in particular figure 8.
[46] RBA, press release 2014-21, 2 December 2014, at http://www.rba.gov.au/media-releases/2014/mr-14-21.html, accessed 18 January 2015.

energy productivity by reducing peak demand and taking pressure off networks. Council of Australian Governments (COAG) recently identified energy productivity and improving energy use decisions as a key reform focus in its December 2014 communique:[47]

> *The Council recognises that the development of new energy services, technologies (such as efficient equipment and buildings) and recent reforms (including cost reflective pricing and competitive metering) increasingly provide strong opportunities to progress Australia's energy productivity. It considers a concerted national focus on energy productivity can drive higher economic output, reduce energy bills for households and business, increase national competitiveness, reduce carbon emissions and improve sustainability.*
>
> *To further these opportunities, the Council will develop a new policy framework for energy productivity. This policy framework will seek to ensure that energy consumers (large and small) understand and can effectively manage and reduce their energy bills and are maximising the value of their energy to support a growing, competitive and sustainable economy. It will coordinate nationally across both energy efficiency and energy market reform, seeking to improve market and regulatory efficiency. The framework will build on current energy efficiency initiatives and market reforms underway and consider if additional measures are needed to engage and empower consumers in choosing new services (such as trusted decision tools and access to data), measures to support or reduce barriers to competition and innovation in new services, and to improve minimum efficiency standards in buildings and appliances.*

In particular, there are well-progressed proposals being considered to reform network tariffs in order to shift the burden of prices to users that consume at peak times. These proposals to increase the cost of peak use should shift use towards off-peak times as well as drive innovation in storage (particularly but not only of solar-generated electricity), resulting in lower peak demand in the future compared to at present. The introduction of more information and better decision-making tools under COAG's reform gaze should accelerate this trend.

In addition, the distributors' demand management strategies, such as peak-smart tariffs for air conditioners, hot water and pool pump demand on off-peak tariffs, are also likely to moderate growth in peak demand. These demand management strategies are noticeably better developed in Queensland than other NEM jurisdictions, with off-peak and super-off-peak tariffs (tariffs 33 and 31 respectively) and management of loads by ripple meters.

Energex's and Ergon's demand management strategies could continue to be more developed to manage load at critical peak times for substations. For substations with significant residential load this is typically around 5:30pm to 8:30pm in the evening.

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[47] COAG Energy Council, Meeting Communique, Adelaide, 11 December 2014, accessed at https://scer.govspace.gov.au/files/2014/05/COAG-Energy-Council-Communique-11-Dec-2014-FINAL2.pdf on 18 January 2015.

At these times, the stack of load at a disaggregated level contains significant lighting, hot water, and air conditioning load,[48] all of which can be moved to off-peak times through expansion of existing strategies.

Moreover, while storage solutions may not (yet) be cost-effective to cover all load, they may be cost-effective to manage peak demand. For example, where a substation is approaching peak constraints, limited storage equal only to the forecast shortfall in capacity for that substation (rather than storage equal to the substation's full capacity) could be installed at major users drawing on that substation. This storage may be able to defer augmentation of that substation for a considerable period.

Other demand management strategies could be applied as well. For example, in Western Australia, Independent Market Operator (IMO) notes that "the Individual Reserve Capacity Requirement (IRCR) mechanism, which allocates the cost of Capacity Credits to Market Customers, provides an incentive for customers to reduce their demand during system peak demand intervals" while the "new Balancing market in the WEM brought improvements in market transparency that assist these customers in predicting peak demand periods".[49] IMO found that evidence of better management of energy usage during peak intervals by some large commercial and industry customers.[50]

In summary, QCOSS considers that the drivers of peak demand (and demand generally) are pointing mostly to a decline in peak demand over the next regulatory period. QCOSS does not expect that peak demand is likely to grow significantly or be a significant driver of capex. Moreover, there are a range of demand management strategies available to manage peak and the implementation of these strategies is likely to be hastened by network tariff reform.

QCOSS notes the arguments by Energex and Ergon that in fact it is spatial peak demand rather than aggregate peak demand which drives capex, and that growth in demand and peak demand at a substation level is likely to drive increases in investment at a substation level for selected substations.[51] QCOSS considers some further analysis would need to be done at a substation level to evaluate the forecast distribution of peak demand. The Distributors' claim requires careful evaluation of where peak demand is likely to grow, and whether the relevant substations and lines have spare capacity to cater to that peak growth; and/or operational policies could manage these peaks without further investment. Such policies could include demand management or operating assets beyond their nameplate capacity for short durations, as occurs on most networks. A question arises whether these operational policies are optimal compared with those of other networks.

Recommendation 3.2

QCOSS recommends that the AER does not accept the demand forecasts provided by Ergon and Energex without comprehensive scrutiny into the basis for those forecasts, in light of previously misforecasts and notable changes in energy use, technologies, future tariffs and trends over the next RCP.

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48 AGL, Working Paper No.45 – Demand Tariffs, p. 7, figure 5.
49 IMO, Electricity Statement of Opportunities – June 2013, p.5.
50 While it is recognised that the WEM operates under different rules, the WA example provides evidence of demand management solutions that can be found by setting the right incentives.
51 For example, Ergon RP Overview, p. 10, where it argues 45 per cent of substations will have sustained (1 to 3.5 per cent) or significant growth (greater than 4 per cent).

3.4.3 Reliability standards

Queensland suffered from a range of challenging weather-related events during the 2010-2015 RCP including widespread floods across Queensland (including the Brisbane floods in 2011 and 2012) and serious cyclones including Cyclone Yasi in 2011 and Cyclone Oswald in 2013. Cyclone Oswald came down the Queensland coastline and damaged north, central and southern Queensland coastal areas with very high winds.[52] However, despite these natural disasters and other challenging weather-related events, reliability improved for both Energex and Ergon in the 2010-2015 RCP.

Reliability is typically measured in terms of:

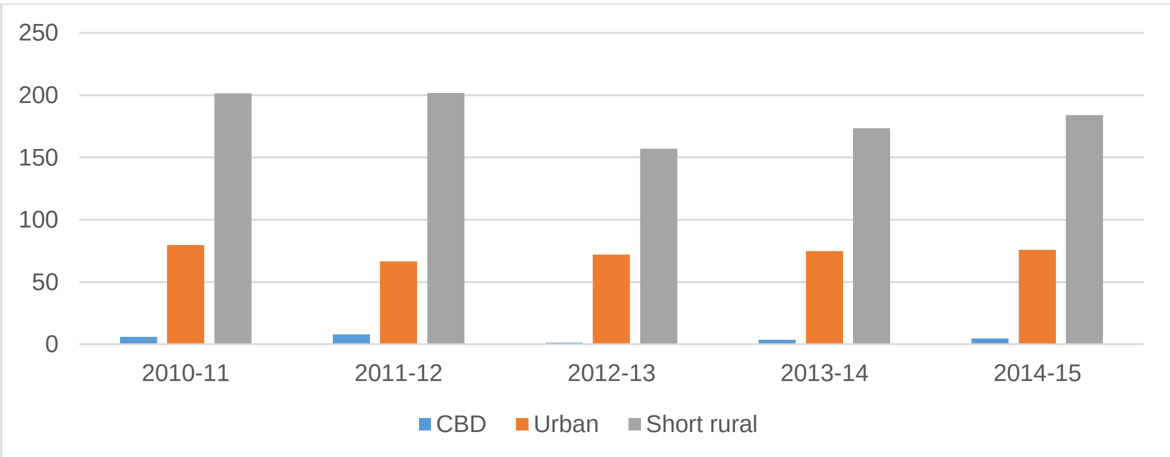
- SAIDI (average minutes off supply per year); and
- SAIFI (average number of interruptions per year).

Energex's reliability performance and trends are charted in Table 3.8 and Chart 3.12 below.

Table 3.8 Energex reliability outcomes during current regulatory period

SAIDI (mins)	2010-11	2011-12	2012-13	2013-14	2014-15	MSS
CBD	6.05	8.16	1.41	3.56	4.59	15
Urban	79.75	66.65	71.92	74.86	75.77	102
Short rural	201.58	201.81	156.94	173.39	184.02	216

Chart 3.12 Energex reliability outcomes during current regulatory period



[52] It is noted that certain events may be excluded as major events from reliability performance figures.

Ergon's performance is illustrated in Table 3.9 and Chart 3.13 below.

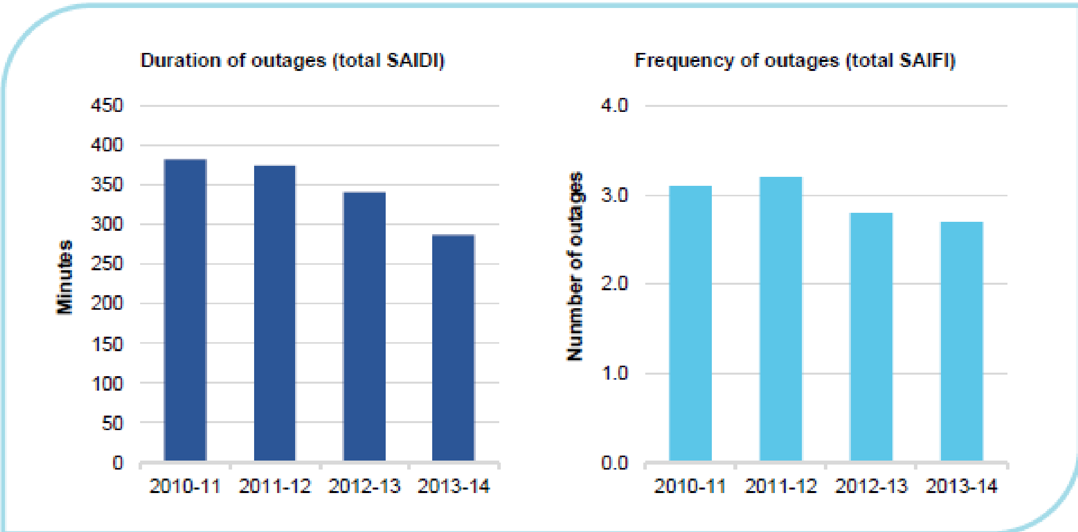
Table 3.9 Ergon reliability performance 2010-2015

Parameter	2010-11	2011-12	2012-13	2013-14	MSS
Minutes off supply (SAIDI)					
Urban	148.88	136.28	135.12	118.49	146
Short rural	425.74	391.95	341.44	291.91	406
Long rural	827.35	1041.58	951.53	798.42	916
Interruptions (SAIFI)					
Urban	1.628	1.413	1.493	1.394	1.92
Short rural	3.532	3.549	2.977	2.767	3.80
Long rural	5.266	7.019	6.246	6.118	7.10

Source: Ergon RP, Table 46, p.99.
Note 1: MSS applies from July 2014.

Chart 3.13 Ergon reliability outcomes during current regulatory period

Figure 9: SAIDI and SAIFI, 2010-11 to 2013-14



Note: SAIDI means average annual minutes off supply. SAIFI means average annual number of interruptions

In 2011, the Queensland Government undertook the Electricity Network Capital Program (ENCAP) review. The ENCAP review found significant scope for savings in implementation of the reliability standards, with savings in capex by the two distributors estimated at around $15.4billion in the 2010-15 RCP alone. ENCAP found that reliability standards contributed to overinvestment in networks. They found that Queensland's standards, which required networks to be designed to an 'N-1' standard (where system requirements can continue to be met even following the failure of the single largest network component) had resulted in more reliable electricity supply but at a high cost, which has been reflected in electricity prices.

The further IRP review recommended reductions in standards, which were accepted by the Queensland Government. In 2014, the Queensland Government, increasingly concerned about rapid increases in electricity prices, moved to adjust reliability standards. It is QCOSS's view that the decision to reduce reliability standards could be interpreted as a response to widespread customer feedback on the trade-off between reliability and prices.

Under the new standards applying from 1 July 2014: [53]

- The N-1 requirement for distribution was removed;
- The performance of the distributors continues to be measured against minimum service standards (MSS); and
- The distributors now have to take a more 'economic' approach to building new infrastructure for reliability purposes, meaning they have to consider or trade-off the costs of network reliability improvement against the value that customers place on reliability.

As different customer classes place different valuations on reliability (with commercial and industrial customers typically placing a far higher value on reliability than residential customers), this implies a differential approach to determining investment in different parts of the network depending on whether they serve C&I, residential, or other types of customers.

Analysing the impact of the changes, the Queensland Department of Energy and Water Supply notes that:[54]

> *…the average impacts are expected to be relatively minor. For example in Energex's network area, forecasts indicate only an additional 13 minutes of supply interruptions for urban customers in 2020 (83 minutes vs. 69 minutes if current standards were kept), increasing to an additional 36 minutes in 2030 (around 105 minutes vs. 69 minutes if current standards were kept).*

As noted, under the new standards, Energex and Ergon are required to meet minimum service standards (MSS). The MSS specify annual SAIDI and SAIFI targets for each of the distributors. If a distributor exceeds the same MSS limit (i.e. SAIDI limit or SAIFI limit) for three financial years in a row, this is considered a 'systemic failure' and represents a contravention of the conditions of the entity's Distribution Authority. Extraordinary events are excluded.

As can be seen in Table 3.10 and Table 3.11 below, at 2013-14 levels of performance, Energex and Ergon are comfortably meeting their MSS obligations.

Table 3.10 Energex reliability performance in 2013-14 against MSS

Energex	2013-14 SAIDI performance	MSS- SAIDI	2013-14 SAIFI performance	MSS- SAIFI
CBD feeders	3.560	15	0.058	0.150
Urban feeders	74.864	102	0.804	1.220
Short rural feeders	173.392	216	1.556	2.420

Source: DEWS, *Performance against minimum service standards (MSS) by Energex and Ergon Energy for the 2013-14 financial year*

[53] Queensland Department of Energy and Water Supply website, https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards/facts, accessed 17 January 2015.

[54] : As different customer classes place different valuations on reliability (with commercial and industrial (C&I)customers typically placing a far higher value on reliability than residential customers), this implies a differential approach to determining investment in different parts of the network depending on whether they serve C&I, residential, or other types of customers.

Table 3.11 Ergon reliability performance in 2013-14 against MSS

Ergon	2013-14 SAIDI performance	MSS- SAIDI	2013-14 SAIFI performance	MSS- SAIFI
Urban feeders	118.49	146	1.394	1.92
Short rural feeders	291.91	406	2.767	3.80
Long rural feeders	798.42	916	6.118	7.10

Source: DEWS, Performance against minimum service standards (MSS) by Energex and Ergon Energy for the 2013-14 financial year

QCOSS considers that the MSS represent a reasonable standard for Energex and Ergon to aim for in terms of reliability, noting that the standards provide considerable flexibility in that only have to be met *once* in every three continuous years for the distributor to avoid breaching its regulatory obligations. The MSS standards do not have to be met every year as a matter of regulatory obligation.

This would suggest that under the new reliability standards that have applied from July 2014, reduced reliability standards would be expected to be a strong ***downward*** driver on capital spending in the next RCP.

The magnitude of the savings in capex from the more relaxed reliability standards are hard to estimate precisely. However, it is noted that Productivity Commission in 2012 estimated that NSW distributors could save $1.1 billion in the short term and likely much more in the longer term.[55]

Recommendation 3.3

QCOSS recommends that the AER's decision on the allowed capex to the distributors reflect the impact of reduced reliability standards.

3.4.4 Performance against industry benchmarks

Energex's and Ergon's capex proposals can be evaluated against industry performance benchmarks. Evaluation against industry best practice rather than internal benchmarks is important as the regulatory injunction under the capital expenditure criteria in clause 6.5.7 of the NER is to evaluate expenditure against that of an efficient and prudent operator rather than against a distributor's internal practice.

The AER published its first benchmarking report for NEM distributors - *Electricity distribution network service providers' Annual benchmarking report* - in November 2014. QCOSS welcomes the release of this report and the value it offers to consumers in terms of improved transparency and information with which to assess the expenditure claims put forward by distributors.

To measure capital efficiency, the AER applied an asset cost per customer adjusted for customer density over the 2009-2013 period to assess the capital efficiency of NEM distributors.[56] Asset cost is defined as the sum of charges for the use of

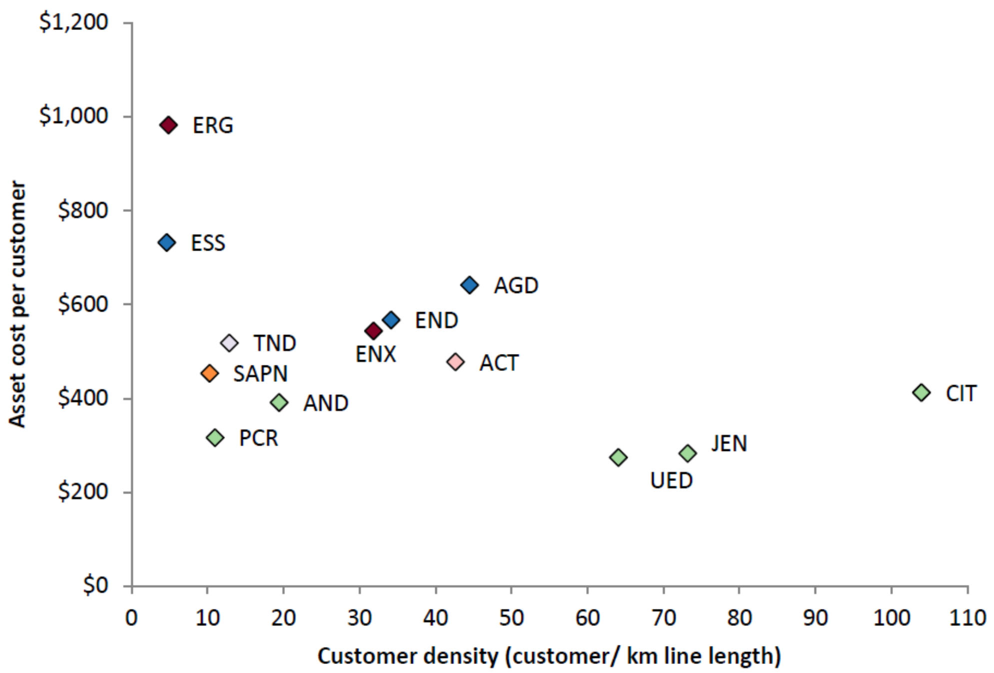
[55] Productivity Commission 2013, *Electricity Network Regulatory Frameworks*, Report No. 62, at p. 2.
[56] AER, *Electricity distribution network service providers' Annual benchmarking report*, November 2014, p. 25.

capital, namely depreciation and return on investment (rate of return or WACC) for the given period.

Chart 3.14 shows the performance of Energex and Ergon on this measure.[57] The results show that the Queensland and NSW distributors (marked in maroon) performed poorly compared with the Victorian and South Australian distributors, i.e. they applied a high amount of assets to deliver services after allowing for the relative customer density of their two networks. This is confirmed by the measure of State-wide Multi-factor Productivity (MTFP) in the AER's benchmarking report.[58]

Chart 3.14 Performance of NEM distributors against asset cost

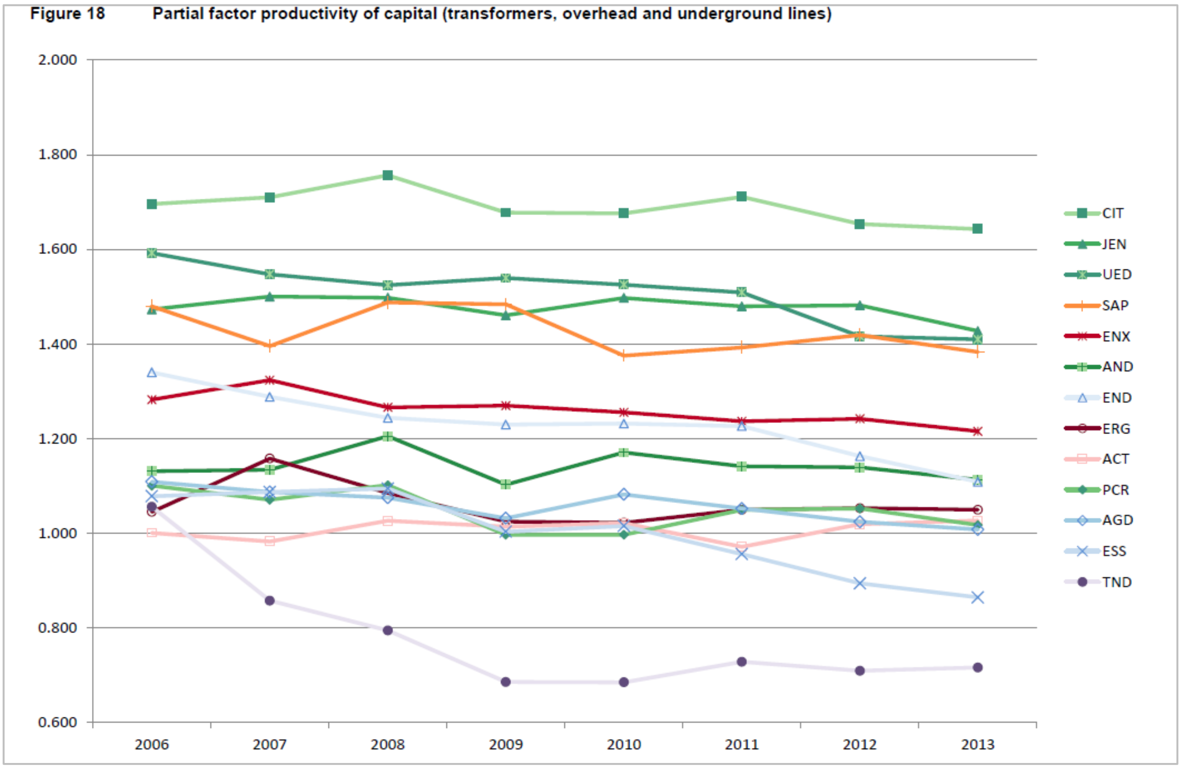
Figure 13 Asset cost per customer compared to customer density (average 2009–2013)



As illustrated in Chart 3.15 Energex and Ergon also perform poorly against best practice in respect of the partial factor productivity (PCFP) of transformers, overhead and underground lines. Again, Energex is in the middle of the pack while Ergon is near the bottom. Energex's relative performance is about 1200/1650 or 72 per cent of the leader, while Ergon's is about 1050/1650 or 64 per cent of the leader.

[57] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, p. 26.
[58] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, figure 17, p. 32.

Chart 3.15 NEM distributor performance on partial capital factor productivity of transformers, overhead, and underground lines



The AER's benchmark of total costs (totex), which combine the asset cost and operating cost of delivering services, shows a very similar picture of the performance of the two Queensland distributors against the Victorian and South Australian counterparts.

This level of performance is significant given that the capital expenditure criteria require capex proposals to be assessed, as noted earlier, against efficient and prudent practice, rather than requiring the regulator to assess whether internal measures of efficiency in delivery are improving.

The benchmarking report also assessed Energex and Ergon on multilateral total factor productivity (MTFP), which is a combination of capital and operating factors.

MTFP is formally defined as:[59]

> *This MTFP analysis compares the outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability, and circuit line length) against the inputs (opex and capital). In this analysis capital input is split into five distinct components – overhead distribution lines, overhead subtransmission lines, underground distribution cables, underground subtransmission cables, and transformers and other.*

This definition of MTFP makes it clear that the outcomes are adjusted for operating differences among networks.

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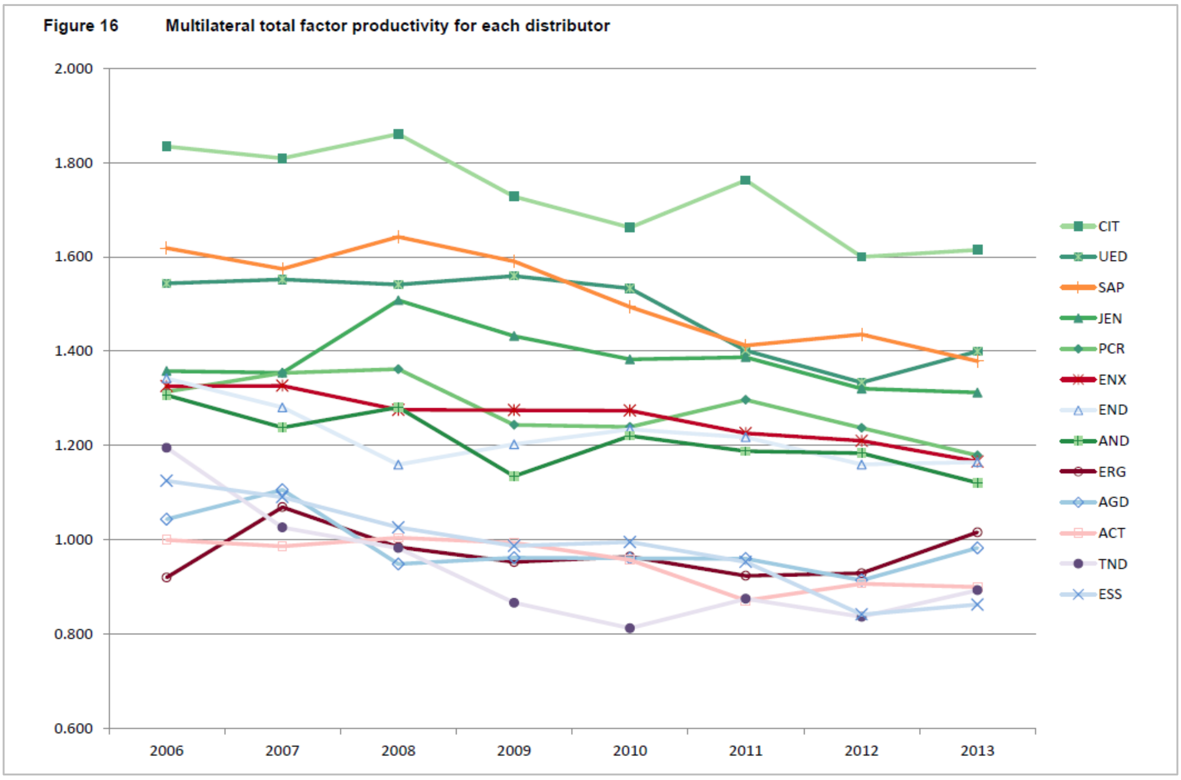
[59] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, p. 28.

The MTFP assessment for the 2006-2013 period for NEM distributors is displayed in Chart 3.16.

Most of the distributors trended downwards, perhaps due to rising labour costs and increased asset costs following large capex programs. The graphs of partial factor productivity of capital and opex (figures 18 and 19 in the AER's benchmarking report) would suggest that the declines in MTFP over this period are more attributable to opex factors than capital factors, with partial capital performance relatively flat while opex productivity factors decline significantly.[60] Energex's performance is around the middle of the pack, finishing around 1200. It is ranked sixth out of 13 distributors but well below the top end of the range set by Citipower (1600). In simple arithmetic terms Energex is 1200/1600 or 75 per cent as efficient as the most efficient distributor. Ergon managed to lift its performance over the 2006 to 2013 period, perhaps the only distributor to do so. This lifted it from clear last place (13th) to ninth by the end of the period. Nonetheless, its performance was around 1000, or around 62.5 per cent of the most efficient distributor.

Chart 3.16 MTFP outcomes for NEM distributors for the period 2006-13



QCOSS would argue that on the basis of these benchmarks, Energex and especially Ergon have some way to go in terms of their capital (and opex) productivity performance in terms of efficient practice as represented by other Australian distributors such as Citipower.

[60] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, pp. 33-34.

Recommendation 3.4

QCOSS recommends that the AER use benchmarking to critically examine the capex proposals, and in particular, the need for the Energex's extensive replacement program.

3.5 Extra time to transition to efficient and prudent practice

It may be argued that the distributors need time to adjust their performance towards best practice however QCOSS would ask the AER to consider that:

- This is arguably not legally permissible under the NER. The NER provides for proposals to be assessed against external measures of efficiency and prudency with only efficient and prudent expenditure to be approved. The rules clearly do not contemplate a transition period as they say nothing about the permissible period of transition or the angle of the glide path to best practice;
- Allowing time for transition to best performance weakens incentives to achieve best performance. For example, if the inefficiency is due to higher than efficient wages, providing time for transition weakens the bargaining position of management apropos labour; and
- Allowing time for transition arbitrarily penalises users in distribution areas where networks are inefficient for the duration of the transition period;
- Most fundamentally, allowing time to transition undermines the incentive properties of the regulatory arrangements. It provides an additional allowance for inefficiency for a period of time, and may even, depending on the length of the transition period, allow for some of the improvements towards efficiency to be captured in incentive arrangements such as the CESS and EBSS.

QCOSS supports the draft decision by the AER in the NSW Electricity Determination.[61]

Recommendation 3.5

QCOSS recommends that the AER does not allow extra time for Queensland distributors to adjust to efficient and prudent practice in relation to capex

3.6 Prudent and efficient assessment of capex

As already referred to above, QCOSS is not in a position to assess the prudency and efficiency of capital projects. Given the trends in the drivers of capex and the benchmarking analysis, it is expected that the AER will scrutinise major augex projects to ensure all projects need to occur in 2015-2020 period and assess to what extent there may be scope to defer some of the proposed augex projects, particularly those commencing towards the back of the RCP. It will be important also to ensure that all non-network capital options (including DM) have been carefully investigated and dismissed before deciding on the capital option.

QCOSS is especially concerned about the proposals relating to replacement capital. There is a significant disjunction between Energex's and Ergon's repex budgets - there is not an automatic expectation that they would align but the patterns of growth. Repex is driven by the age and condition of assets and decisions on like-for-like replacement of assets. It is difficult to understand the justification for the large

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[61] AER, AER Draft Decision - Ausgrid 2015-19 – Overview, pp. 11-12.

repex proposals given the decline in average asset age for Energex and Ergon as evident in above charts. By its nature, repex should be relatively stable over time however Energex is now proposing a significant pole replacement program while at the same time operating far in excess of jurisdictional safety requirements.

QCOSS would ask the AER to challenge whether all assets coming to the end of their life need to be replaced. Replacements may be able to be deferred through e.g. corrective maintenance, acceptance of risk of failure, or the fact that assets may not be needed given weak or declining demand and peak forecasts. Further it is expected that non-network options should also be assessed in decision on repex as well as augex.

The AER must investigate whether or not repex is keeping corrective maintenance and opex costs down, QCOSS believes Energex (and Ergon to a lesser extent) should identify where the savings are in those areas stemming from its major repex program for the 2015-2020 period.

Other investigations which the AER may consider include:

Energex and Ergon practices for operating beyond nameplate capacity should be compared with other networks – especially the more efficient SA and Victorian networks. This may yield savings from deferral of capex.

Similarly, Energex and Ergon practices for condition-based maintenance or automatic replacement at a set age should be compared with other networks' asset management practices to see if they could provide savings.

Investments in non-system capex should be justified on the basis that they generate savings elsewhere. For example, new IT dispatch systems could be expected to yield opex savings through more efficient dispatch systems and greater labour productivity. QCOSS believes Energex and Ergon should demonstrate these savings through their business cases.

Recommendation 3.6

QCOSS recommends that the AER scrutinise major augex and repex projects to ensure all projects need to occur in 2015-2020 period and that all non-network options (including demand management) have been investigated and dismissed in arriving at the capital solution.

Recommendation 3.7

QCOSS recommends that the AER should 'ground-truth' its capex benchmarking by doing a ''bottom up" analysis of sample planned augex and repex projects, to determine whether networks have adequately considered non-network options.

4 Operating expenditure

4.1 Context

Opex is recurring expenditure that the distribution businesses need to operate on a day-today basis. It tends to be more stable over time than capex but could be expected to reduce over time with improvements in operating practice, the quality, age, and condition of installed equipment and technology, and increase over time as distribution networks grow in geographic size.[62]

There may be trade-offs between opex and capex. For example networks may decide to install more costly but reliable equipment (increased capex) which needs less maintenance (reduced opex). These trade-offs may result in reductions in opex.

Clause 6.5.6 of the NER sets out the provisions in relation to the determination of opex. Clause 6.5.6(a) provides that forecast opex should be sufficient to meet expected demand for regulated services and comply with all applicable regulatory obligations. Clause 6.5.6(c) sets out the operating expenditure criteria, which are that the forecast expenditure reflects:

- *the efficient costs of achieving the operating expenditure objectives; and*
- *the costs that a prudent operator would require to achieve the operating expenditure objectives; and*
- *a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*

In considering the operating expenditure criteria, the AER must have regard to matters including:[63]

- *the most recent [AER] annual benchmarking report;*
- *the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
- *the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;*
- *the relative prices of operating and capital inputs and substitution possibilities between operating and capital expenditure;*
- *the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.*

> *(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);*
> *(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.*

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[62] An increase in the RAB may not drive an increase in opex as the increase in the RAB may reflect only that depreciated assets have been replaced by new assets. On the other hand, an increase in the geographic size of the network might, other factors being equal, increase opex.
[63] NER clause 6.5.6(e).

4.2 Overview of Energex and Ergon's opex proposals

Energex and Ergon's high level opex proposals are set out in Table 4.1. They exclude any costs associated with the feed-in tariff or metering costs (given both these sets of costs are not included in forward estimates).

As evident in Charts 4.1 and 4.2 both distributors' opex has been trending up over the three RCPS with particular spikes in certain years. Energex has a relatively flat opex profile with a small rise from 2005-2010 to 2010-15 and then a fall from 2010-2015 to 2015-2020. Ergon's profile has been trending up over the three RCPs and has overtaken Energex in terms of opex for the first time in their 2015-2020 forecasts.

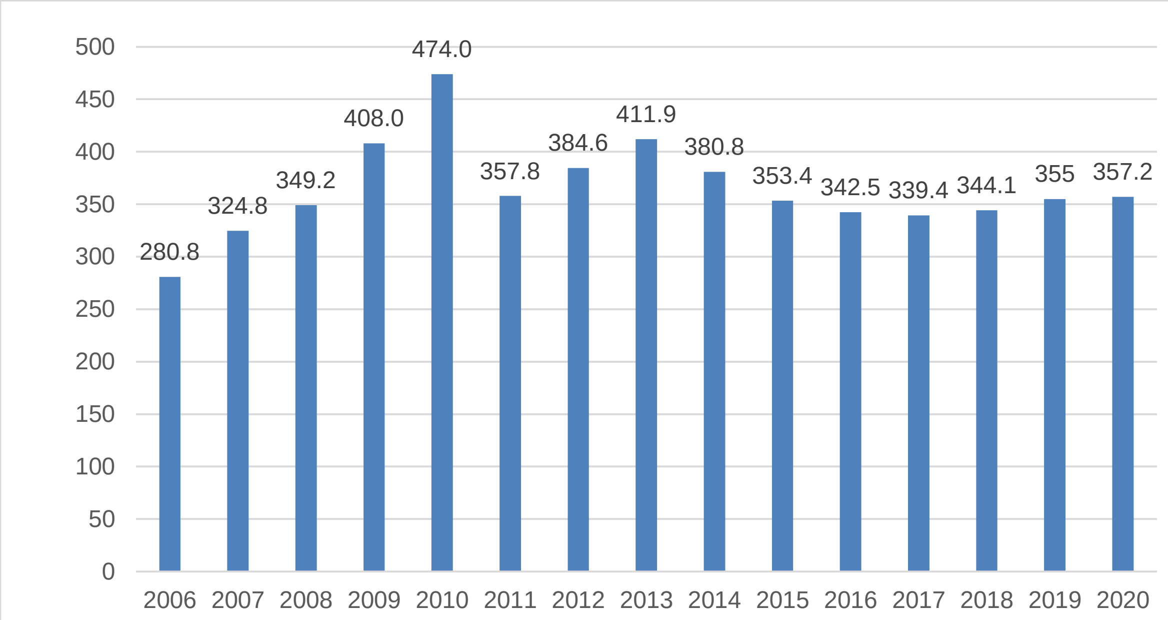
Table 4.1 Ergon and Energex opex actuals for 2005-15 and forecasts for 2015-2020

	Basis	2005-2010	2010-2015	2015-16	2016-17	2017-18	2018-19	2019-20	2015-2020
Energex	$m 2014-15	**1,837**	**1,889**	343	339	344	355	357	**1,738**
Ergon	$m 2014-15	**1,634**	**1,865**	350	356	364	373	379	**1,821**

Source: Energex RP, Table 10.1, p.124; Ergon RP, p. 64, Tables 34, p. 67, Table 36, p. 68, Table 37; Note: Does not include metering costs or feed-in-tariff costs. Energex opex in 2010-15 adjusted to exclude network billing and other energy market services (taken to be meter reading costs) and adjusted from nominal to real 2014-15$ using RBA data table G1, series GCPIAC. Energex meter reading costs for 2005-2010 unavailable so estimated as $15m per year real 2014-15$. Ergon meter reading costs excluded for 2005-10 and 2010-2015.

The opex trend for Energex is shown in Chart 4.1 below.

Chart 4.1 Energex opex trend 2005-2020 in $m (2014-15$ real)



Source: Energex, *Regulatory Proposal for the period July 2010 – June 2015*, July 2009, p. 120, and Energex, Energex 2015-20 RP Overview, p.32
Note: 2006 to 2015 expenditures are in nominal terms adjusted for CPI using RBA data table G1, series GCPIAC and assuming 2014-15 inflation is 2.5 per cent. 2015-2020 expenditures are in 2014-15 dollars.
Note: 2009, 2010, and 2015 expenditures are estimates given the data are from regulatory proposals submitted prior to the end of the regulatory periods. All other expenditures from 2006 to 2015 are actual.
Note: Metering costs removed as noted in Table 4.1 above

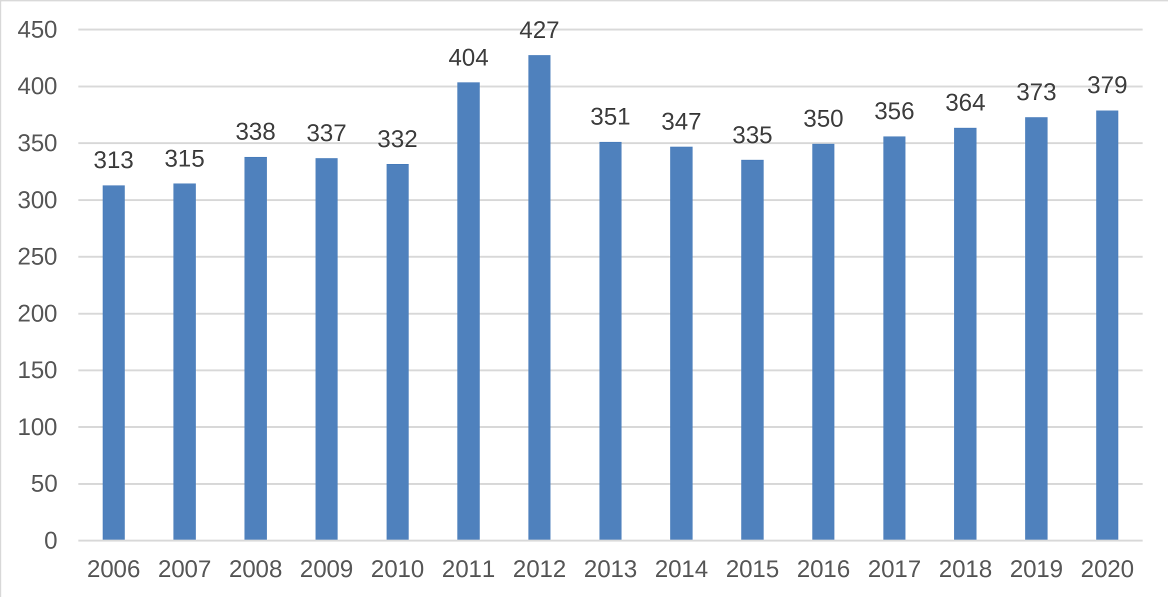
The trend chart data has been adjusted by CPI for the years in which opex is stated in nominal terms, namely the 2005 to 2014 financial years inclusive.[64] The 2015 and forward years are in 2014-15 constant dollars. QCOSS has excluded historical meter reading costs[65] to ensure a consistent basis for comparison of opex trends.

The chart depicts a steep climb in opex costs during the 2005-2010 regulatory control period, followed by flatter spending patterns during 2010-2015 RCP. The opex forecasts in the 2015-2020 period are relatively constant and slightly lower than during the 2010-2015 period. Energex notes that it overspent its allowance in 2010-2015 by $130.5 million "*due to the emergency response for ex-tropical cyclone Oswald in 2013 and the 2011 Queensland flood-event, as well as costs associated with changing our organisational structure*".[66] The opex does not include costs associated with the solar feed-in tariff.[67]

[64] CPI has been applied to the financial years ending 2006 to 2014 inclusive using RBA Historical series, table G1, series GCPIAC and assumed 2014-15 inflation of 2.5 per cent.
[65] As explained in the notes to Table 4.1 above.
[66] Energex RP Overview, p. 32.
[67] Energex RP Overview, p. 31.

Ergon's opex trend is depicted in Chart 4.2 below.

Chart 4.2 Ergon opex trend 2005-2020 in $m (2014-15$ real)



Source: Ergon RP, pp. 66-68. Meter reading costs excluded

Ergon has excluded the costs of the feed-in tariff for comparison purposes given it is not expected to form part of 2015-2020 expenditures (discussed further below).[68] QCOSS has excluded historical meter reading costs to ensure a consistent basis for comparison of opex trends.

The trend in Ergon's opex is of slowly rising costs in real terms, with a significant spike in the 2011 and 2012 financial years. This may be the result of Cyclone Yasi, which occurred in January/February 2011. Ergon state that it had a significant effect on their operating costs.[69] However, it is also relevant to note that Energex's opex did not spike following the natural disasters that affected it, namely the Brisbane floods (2011) or Cyclone Oswald (2013).

4.3 Evaluation of Energex and Ergon's opex proposals

As already stated in the Chapter 3 on capex, consumers are not in a strong position to analyse the opex proposals by the distributors for prudency and efficiency. Consumers are weakly resourced and subject to information asymmetry. At the same time, the distributors have strong incentives to overstate their opex requirements. This means that consumers rely heavily on the analysis of the AER to accurately review the regulatory proposals.[70].

As identified in the capex chapter, both distributors operate young, lightly utilised network with residual lives of Energex and Ergon assets are increasing rapidly. As a result, they should not require as much opex as they would if they operated older networks. Consequently, QCOSS is concerned that the distributors' opex proposals

[68] Ergon RP, p. 67. The current Queenslad Government has proposed to fund the feed-in tariff if it is re-elected at the State election on 31 January 2015.
[69] Ergon RP, p. 69.
[70] QCOSS comments in the Incentive chapter on our view that the assumed incentives in the regulatory framework for distributors to reveal efficient costs over time are weak and are countered by other incentives.

are overstated and would ask that the AER especially address the following concerns:

- the Distributors' performance against industry benchmarks;
- that the findings of the Independent Review Panel (IRP) and its potential efficiencies are reflected in the opex forecasts;
- that there are inefficiencies in the base year's opex expenditure and further adjustments may be needed; and
- that there are inefficiencies in some specific items of opex expenditure.

4.3.1 Performance against industry benchmarks

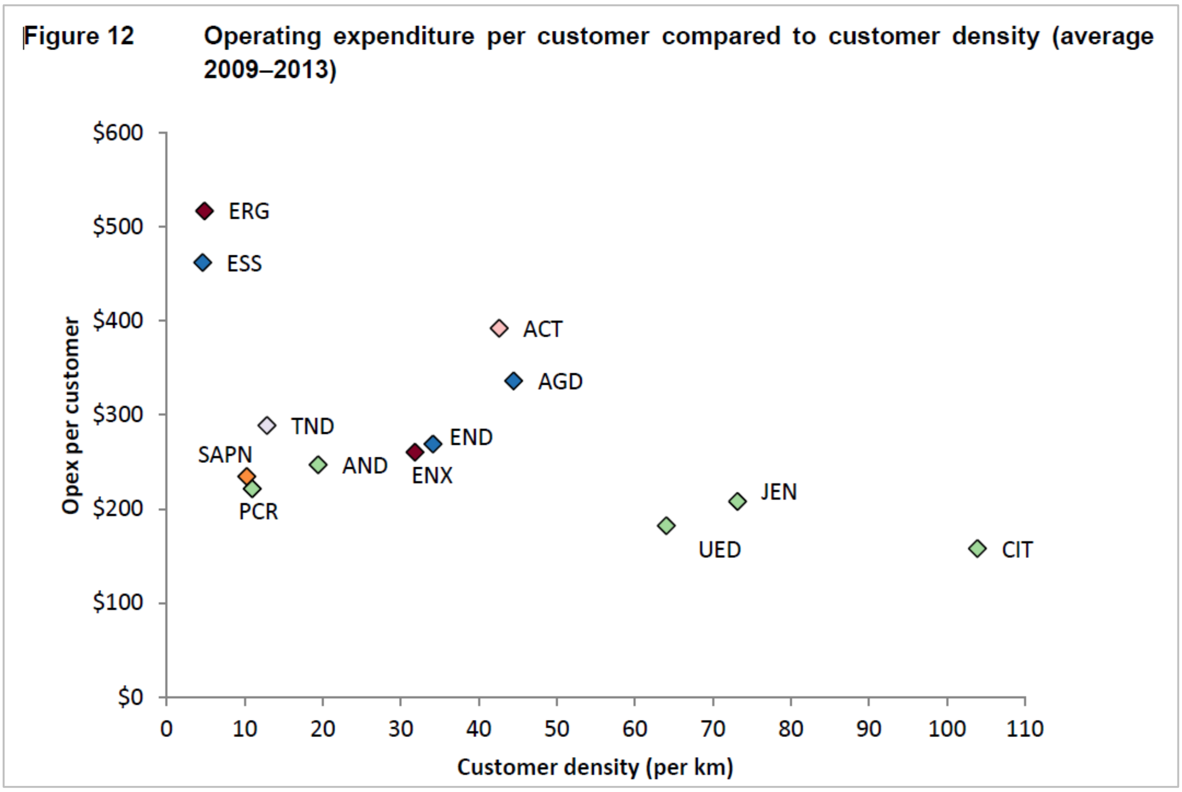
Consistent with the operating expenditure criteria in clause 6.5.6(c), Energex's and Ergon's opex proposals should be evaluated against industry best practice. QCOSS considers industry benchmarking a critical component in assessing distributor efficiency and welcomes its inclusion in the AER assessment framework. Benchmarking distributor performance against its own internal benchmarks does not show whether the distributor is performing efficiently or prudently.

The AER's benchmarking report provides two measures of opex efficiency: (i) the opex per customer adjusted for customer density; and (ii) the partial factor productivity of opex). In addition, it provides some total measures of total factor productivity, specifically MTFP and totex, which incorporate opex and capex efficiency measures.[71]

Chart 4.3 illustrates the opex performance of the NEM distributors adjusted for customer density factors for the 2009-2013 period.

[71] QCOSS's analyses of Energex's and Ergon's performance against MTFP and totex measures is contained in the capex chapter of this submission. It is noted Energex's and Ergon's performance against the MTFP and totex measures is consistent with their performance against the partial opex measures discussed in this chapter.

Chart 4.3 Operating expenditure partial benchmark[72]



The chart illustrates the opex expended by Energex and Ergon compared with customer density for the period 2009-2013. It shows that Energex and Ergon spend considerably more than the Victorian and South Australian distributors to deliver electricity distribution services even after adjusting for relative customer density. Energex's and Ergon's opex performance was significantly below best practice. This indicates that Queensland consumers pay more than efficient and prudent costs for electricity distribution services.

While the Queensland distributors may point to special factors explaining their performance, such as customer density or subtropical weather conditions, the comparisons have been adjusted for customer density and other distributors face their own weather and climate-related challenges such as higher bushfire risk and other risks specific to their geographical area.

The AER also charted partial factor productivity of opex for Energex and Ergon (Chart 4.4), which more clearly illustrates the gap between their performance and best practice.

[72] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, figure 17, p. 24.

Chart 4.4 NEM distributor partial factor productivity of opex[73]

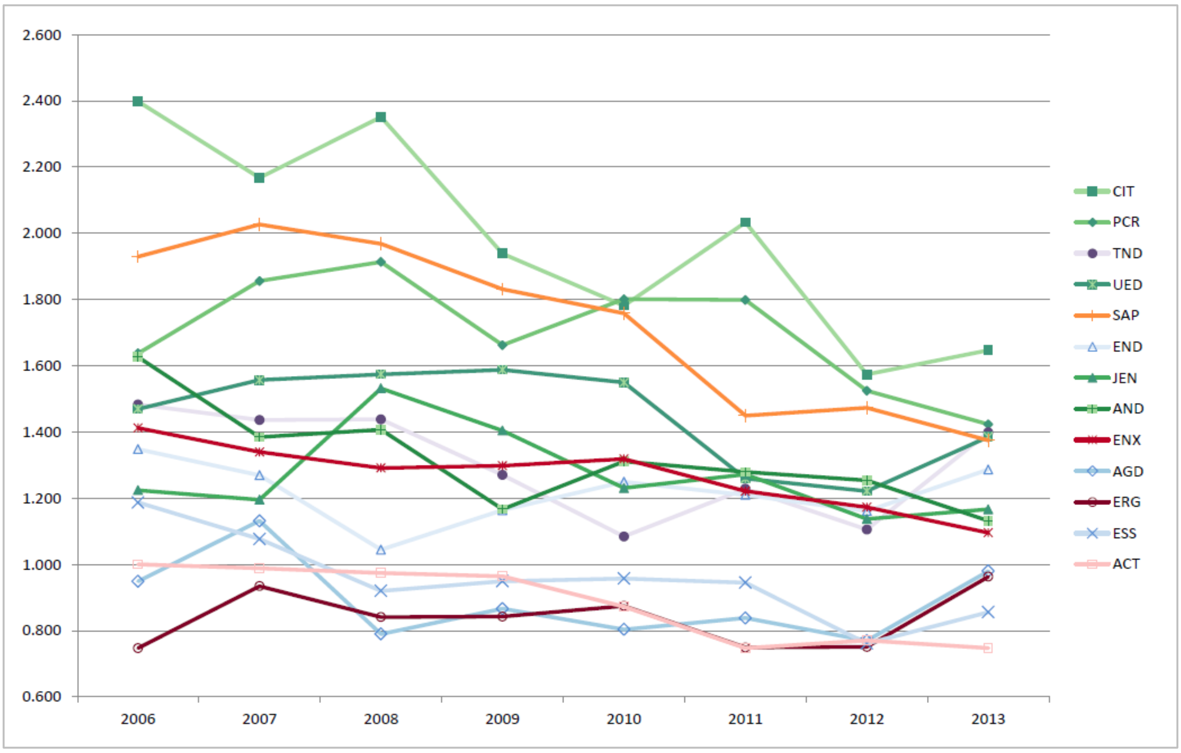


Chart 4.4 shows the significant decline in opex performance over the period 2006-2013 of the electricity distributors in general. Energex and Ergon are ranked ninth and eleventh at the end of the review period, with some compression in scores over that period between the best and worst scores. At the end of the period, Energex is about 1100/1650 or 67 per cent of efficient practice while Ergon is about 1000/1650 or about 60 per cent of efficient practice.

The AER Benchmark report also provided some total measures of total factor productivity, specifically MTFP and totex, which include measures of opex (and capex) efficiency. The MTFP and totex performance of Energex and Ergon (discussed in capex chapter of this submission) were consistent with the above opex performance.

The findings of the AER's benchmarking are consistent with the findings of the Productivity Commission in its review conducted in 2013.[74]

While industry benchmarks are not a sole measure of efficient performance they do offer an indication of the relative efficiency of the network businesses, particularly when viewed in conjunction with the other arguments outlined in this chapter.

4.3.2 Independent Review Panel (IRP) review

The Queensland Government ordered a review of network costs for Energex and Ergon, which was conducted by an IRP consisting of experienced energy industry managers (Tony Bellas, Matt Rennie, and Alec Faulkner). The task of the review was to "develop options to address the impact of the development of the electricity

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[73] AER, Electricity distribution network service providers' Annual benchmarking report, November 2014, figure 17, p. 34.
[74] Productivity Commission, *Electricity Network Regulatory Frameworks – Report No. 62*, April 2013, particularly chapter 6.

network in Queensland on electricity prices". The Terms of Reference directed the IRP to make specific recommendations on matters including:[75]

> *… the efficiency of current network capital and operational expenditure within the GOC network businesses (Ergon Energy, Energex, and Powerlink) and innovative options to:*
>
> - *Address peak demand increases;*
> - *Improve efficiency of capital and operating expenditure;*
> - *Plan for (and respond to changes in) economic growth;*
> - *Deliver savings in corporate and overhead costs including IT;*
> - *Incorporate the value to customers of network security and reliability in network planning and the setting of performance standards; and*
> - *Improve demand forecasting.*

The IRP handed down its final report in 2013.[76] The IRP recommended a set of reforms for regulation of the electricity networks in Queensland of which the recommendations are summarised in Table 4.2 below. The Queensland Government agreed or agreed in principle to all of the relevant recommendations.[77] The distributors have implemented many of the findings of the review.

Table 4.2 Summary of IRP recommendations on network costs

IRP Recommendations
• *Remove the N-1 reliability standards and replace them with outcomes-based standards.* • *Continuation of implementation of efficiency programs.* • *Reassess ICT expenditure and focus it on core activities.* • *Implement an integrated operating model for planning and partnering positions within the distributors.* • *Progress Ergon's ROAMES (geospatial) project.* • *Ergon to consider contracting out of modular substation supply.* • *Ergon to sell land holdings for forests.* • *Reduce expenditure on consultancies.* • *Implement an effective scheduling tool.* • *Implement a common set of output-based performance measures at depot level to measure and report labour efficiency.* • *Consider local service agent models for small Ergon depots.* • *Reduce overtime to benchmark levels and review gross pay to base pay ratios.*

[75] IRP, Independent Review Panel on Network Costs – Interim Report: Summary Findings and Draft Recommendations, 15November2012, p. ii.

[76] Independent Review Panel on Network Costs (IRP), *Electricity Network Costs Review - Final Report*, at https://www.dews.qld.gov.au/__data/assets/pdf_file/0010/78544/irp-final-report.pdf, accessed 19 January 2015.

[77] Queensland Government, Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform, at https://www.dews.qld.gov.au/__data/assets/pdf_file/0007/78568/queensland-government-response-to-idc-report.pdf, accessed 19 January 2015.

- *Seek amendments to regulatory provisions around road access and other matters.*
- *Improve workforce flexibility and harmonise fatigue management policies.*
- *Create a common holding company for Energex and Ergon with single Board and CEO.*
- *Improve network planning.*
- *Only implement demand management projects where they have been subject to rigorous commercial assessment.*

The IRP estimated these reforms would save $3.6 billion in opex and capex in the 2010-2015 RCP, and a further $1.4 billion in indirect opex and capex costs in the subsequent RCP alone.[78]

These recommendations demonstrate some basic inefficiencies in Energex's and Ergon's operational practices. These inefficiencies were not identified and removed from the distributors' costs under any previous reviews of regulatory proposals. QCOSS asks that the AER also recommends that the DBs implement these efficiencies and that the resulting, adjusted opex budgets for the two distributors serve as the base year (proposed by both distributors to be 2012-13) in the base-step-trend approach (perhaps with further adjustments to reflect other available efficiencies).

Further, the IRP review followed the earlier ENCAP review which took place in 2011. As already mentioned in the capex chapter 3, the ENCAP review found significant scope for savings in implementation of the reliability standards, with savings in capex by the two distributors estimated at around $15.4billion in the 2010-15 RCP alone. Much of these savings were estimated to come in customer and corporate initiated works.[79] It is important that the AER make an appropriate base year adjustment for efficiencies arising out of the earlier ENCAP recommendations.

Furthermore, it is understood that as part of their efficiency drives following the ENCAP and IRP reviews, Energex has cut its workforce by 20 per cent while Ergon has cut its workforce by 17.5 per cent.[80] The savings from these measures are likely to only start to be flowing through now given the cuts occurred towards the back end of the current regulatory period and the distributors had to make provision for the cost of the redundancies from their opex budgets.[81] The AER is encouraged to analyse the savings from these cuts to assess whether the savings have been fully

[78] IRP, Independent Review Panel on Network Costs – Interim Report: Summary Findings and Draft Recommendations, 15November2012, pp. v-vi.

[79] ENCAP Review, Electricity Network Capital Program Review 2011 - Detailed report of the independent panel, 2011, accessed at https://www.business.qld.gov.au/__data/assets/pdf_file/0018/9117/ENCAP_Review_Final_Report_3_new.pdf, 22 January 2015, at p. 13*: ENERGEX identified $870 million in capital savings over the current regulatory control period. The Panel has accepted ENERGEX's proposal in relation to variations to the security standards totalling $255 million and the flat-lining of MSS targets totalling $40 million. ENERGEX has identified $550 million in savings related to customer and corporate initiated works that may also flow through. Ergon Energy identified $709 million in capital savings over the current regulatory control period. The Panel has accepted Ergon Energy's proposal in relation to variations to the security standards totalling $250 million. The remainder of Ergon Energy's savings relate to customer and corporate initiated works.*

[80] Pers Comms, Energex Information Session, 22 October 2014 and Ergon, RP Overview, P14

[81] Energex noted the cost of changes in organisational structure as part of its opex overspend in the 2010-15 regulatory control period.

passed on. With lower capex and opex forecasts going forwards, the workforce (encompassing both employees and contractors) could be expected to fall.

In August 2014, the Queensland Minister for Energy and Water Supply ordered the Queensland Competition Authority (QCA) to review the reasonableness of the distributors' capex and opex proposals and their implications for customer prices.[82] The QCA investigated the draft RPprior to submission to the AER and handed its findings to the Minister on 10 October 2014.[83] While QCOSS has not had access to the findings of the QCA review, we note that the AER may find value in the findings of the review, if there are to be made available.

4.3.3 Base year

Under the AER Guideline, the AER proposes to apply a base-step-trend (BST) approach to assessing opex, where base year opex is adjusted for upward and downward steps in the operating environment and for trends in drivers such as demand.[84] Both distributors, as noted, propose to use the 2012-13 year as the base year. As the AER notes, this assumes that the base year is considered efficient. However, QCOSS does not consider that the 2012-13 year represents efficient and prudent practice in terms of the opex criteria. For example, the distributors would have incurred many of their restructuring costs associated with reducing their workforces. As once-off costs, they should be removed from the base year in forecasting efficient opex requirements. Clearly, also, the costs associated with meeting the higher N-1 regulatory obligations should also be removed.

When viewed historically, the opex allowances for Energex and Ergon during the 2010-2015 RCP were an aberration. QCOSS considers that the opex allowances in 2011-2015 were significantly above efficient levels. In this regard, the savings identified by the IRP since the 2010 decision demonstrate the efficiencies available compared to the opex levels set in the 2010-15 decision. The opex levels set in the 2010-2015 RCP should not be the norm for comparison purposes, nor should they set an expectation for the efficient levels of opex going forward.

Recommendation 4.1

QCOSS recommends that the AER scrutinise the opex proposals of the Distributors in light of the AER's own industry benchmarking and the findings and recommendations of the IRP and ENCAP reviews.

Recommendation 4.2

QCOSS recommends that the AER apply its benchmarking and other tools to determine an efficient base cost for 2012/13 on which to apply the proposed 'step and trend' changes to this base cost.

4.4 Specific opex categories

4.4.1 Inspections and planned maintenance

Energex and Ergon's inspection and preventative maintenance cycles should be compared with those of other networks. In particular, QCOSS has some concerns

[82] Minister for Energy and Water Supply, Terms of Reference, 19 August 2014.
[83] This was the due date for submission of the QCA's final report to the Minister. QCOSS is not specifically aware of the actual date of submission of the report.
[84] AER (Nov 2013), Expenditure Forecast Assessment Guideline: Explanatory Statement, p11

about specific planned maintenance that has been proposed by Energex. In the 2015-2020 RCP, even as the overall proposed opex budget falls, Energex is forecasting significant rises in planned maintenance (up from $329.5m to $397.2m), debt raising costs, and self-insurance.[85] The scale of the rise in planned maintenance appears surprising given the direction of overall capex spending and the young age of the network.

QCOSS has concerns about these proposed expenditure and raises the following questions:

- Is there evidence of over-servicing?
- How do Energex and Ergon adjust inspection and preventative maintenance cycles in light of condition assessments, especially longer-term feedback from condition assessments on asset life?
- What are failure rates for selected asset classes such as wooden poles? Are these failures rates low at present which might suggest that replacement of poles may be occurring too early?

Recommendation 4.3

QCOSS recommends that the AER consider referencing the operational practice of the Queensland Distributors with that of other distributors to see what practices they have in relation to inspection and preventative maintenance.

4.4.2 Wages growth

Energex and Ergon's proposals assume an increase in salaries by around 3 per cent per annum as per their collective bargaining outcome.[86] However, salaries in the broader economy are currently growing below inflation. QCOSS expects that salaries at the distributors were artificially elevated by the boom conditions that applied pre-2007 and again during 2010-12. In other words, in the last RCP, wage growth would have been historically high due to the large capex programs and general economic pressures including competition from mining which shares many of the skill sets required by the distributors as well as located in same geographical area as Ergon.

With the global financial climate and the current economic climate, it could be expected that real wages would decline rather than increase. Accordingly, salary-related opex should not be granted on the basis of the collective bargaining arrangements as these arrangements are out of step with the broader economic conditions and do not represent efficient and prudent outcomes. This should be able to be verified by reference to a range of external data such as salaries for comparable roles in other industries, and the general direction of wages. RBA commentary in August 2014 on wage growth suggests that wage growth in the general economy has been subdued and will continue to be subdued for the medium term.[87] The analysis by PIAC in its submission to the NSW Electricity Determination

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[85] Energex RP, comparing table 10.2 at p.125 (2010-15 opex) with Table 10.5, p. 138 (proposed 2015-2020 opex).

[86] Personal Communication Energex Information Session on 22 October 2014.

[87] The RBA found that:

> Wage growth has remained low, with the wage price index increasing by 2.6 per cent over the year to March, which was around 1 percentage point below its decade average growth rate. … The increase in spare capacity in the labour market over the past two years or so, as indicated by the increase in the unemployment rate and various measures of underemployment, has contributed to the significant reduction in wage

supports the view that wage increases in the general economy are likely to be below inflation in the short to medium term.[88]

Recommendation 4.4
QCOSS recommends investigating further the proposed wage growth forecasts over the regulatory period for consistency with short and medium term trends in wage and economic conditions in Queensland and in particular in regional Queensland.

4.4.3 Feed-in tariff

The Queensland Government is proposing that the cost of the feed-in tariff to cover electricity generated from solar panels and injected into the distribution system be funded from consolidated revenue rather than from the distributors' opex.[89] The implementation of this policy may depend on the result of the Queensland State election, which is to be held on January 31, 2015. It is noted that the opex forecasts appear to assume that these feed-in tariff costs will not be part of forward opex. QCOSS believes it would be useful to consumers for opex forecasts to be shown with regard to these costs, until such time as a policy to remove them from opex has been confirmed and is in place.

4.4.4 Ergon's network operating costs and other costs

Ergon is forecasting: (i) a small rise in network operating costs after a big jump in these costs between the 2005-2010 RCP and the 2010-2015 RCP; and (ii) a very large rise in 'other operating costs' (about 100 per cent) in the 2015-2020 RCP after a large rise (about 50 per cent) in such costs in the 2010-2015 RCP.[90] There is little reason for network costs to rise as they are projected to. In terms of 'Other Costs', QCOSS considers that classifying a large proportion of opex as 'other' makes it particularly non-transparent, subject to assessment generally, or subject to assessment across RCPs, and is therefore not desirable.

4.4.5 Ergon's vegetation management

It is noted that Energex was able to achieve significant savings in vegetation management costs during the 2010-2015 RCP and is forecasting lower vegetation management costs going forwards ($371.1m in 2010-2015 compared to $327.4m in 2015-2020). QCOSS would suggest the AER might question whether equivalent savings are also available to Ergon.

> growth over this period. …. Business surveys indicate that wage growth remained subdued in the June quarter, while expectations for the September quarter suggest that wages will continue to grow at a relatively slow pace. …
>
> The pace of wage growth remains subdued across the economy, although it appears to be stabilising in many industries. …
>
> Low wage growth has contributed to an extended period of low growth of unit labour costs. The national accounts measure of unit labour costs has been little changed over the past two years, with average earnings and labour productivity having grown at around the same pace.

See RBA, *Statement on Monetary Policy – August 2014*, at http+://www.rba.gov.au/publications/smp/2014/aug/html/index.html, accessed on 20 January 2015.

[88] PIAC, Submission to NSW Draft Determination, pp. 62-63, and in particular Figure 17.

[89] LNP *Strong Choices: Electricity Price Relief.* Can be found at this link: http://qld.lnp.org.au/wp-content/uploads/2015/01/SE15_Policy_ElectricityPriceRelief_Document.pdf

[90] Ergon RP, pp.66-68.

4.4.6 Debt raising costs

Energex is forecasting significant rises in debt raising costs and while it is understood that the changes to the debt arrangements would drive some increases in costs, the extent of such increases should be limited to the changes were made to bring assumed practice into alignment with actual existing practices.

4.4.7 Self–insurance costs

Energex is forecasting significant rises in self-insurance and the arguments for the increase in these costs compared to the 2010-15 RCP do not seem compelling.

Recommendation 4.5

QCOSS recommends that the AER conducts a thorough examination of the prudency and efficiency of the proposed expenditure outlined in the above subsections 4.4.4 to 4.4.7.

4.5 Adjustment to opex categories

To the extent that the regulator finds that the opex forecasts are not efficient or prudent, QCOSS would not propose any transitional arrangements to preserve higher than efficient opex for a period of time. QCOSS discussed its reasons for this position in the capex chapter.

Recommendation 4.6

QCOSS recommends that the AER does not allow extra time for Queensland distributors to adjust to efficient and prudent practice in relation to opex.

5 The regulated rate of return[91]

5.1 Regulatory framework

The AER must set an allowed rate of return or weighted average cost of capital (WACC) for standard control services. Standard control services are essentially the service of distributing electricity from the junction of the transmission-distribution system to users.

The regulated rate of return is the main driver for over half of the revenue requirements for distributors. For Energex and Ergon the return on capital component ranges between 53 and 61 per cent of their total annual revenue requirement for the next RCP.

The rate of return is set as a weighted average return on debt and equity for the efficient financing costs of a benchmark efficient firm with a similar degree of risk to that of the regulated firm (NER 6.5.2.(c)). This inevitably involves examining a range of parameters within the return on equity and on debt.

In setting the WACC, the AER must operate under the National Electricity Objective in the NEL, which provides that:[92]

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

The AER is also bound by the revenue and pricing principles in the NEL, which provide in part that:[93]

> *(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.*
>
> *(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.*

The rate of return provisions as in clause 6.5.2 of the NER provides that the "*allowed rate of return objective is that the rate of return for a Distribution Network Service*

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[91] We would like to acknowledge PIAC's submission to the NSW Electricity Determination 2014-19 in preparing this chapter.
[92] Section 7*, National Electricity (South Australia) Act 1996* (and other state and Federal uniform legislation)
[93] Section 7A, National Electricity (South Australia) Act 1996

Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider". The provisions relating to the setting of debt reinforce the notion that the return should be set on the basis of a benchmark efficient firm.[94]

The allowed rate of return is set as a blend of the return on equity and debt. NER clause 6.5.2(e)(3) notes that in setting parameters for these returns, the regulator should have regard to "*any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt". The provisions relating to the setting of debt again reinforce this principle that the regulator should have regard to "The interrelationship between the return on equity and the return on debt*".[95]

Clause 6.5.3 of the NER provides that the corporate tax rate will be set in accordance with a formula that adjusts the multiple of the efficient taxable income by expected statutory income tax by 1 minus gamma, where gamma is the value of imputation credits.

5.2 Overview of Energex and Ergon regulatory proposed WACCs

Table 5.1 presents Energex and Ergon's proposed WACCs compared with the WACC set under the 2010-2015 RCP.

Table 5.1 Actual and proposed WACCs for Ergon and Energex

	2010-2015 – actual	2015-2020 - proposed
Ergon (%)	**9.72**	**8.02**
Energex (%)	**9.72**	**7.75**

Source: Ergon overview p.29, Ergon RP, Table 52, p.121 and Table 52, p.124; Energex overview p.32, Energex RP, pp. 6-7
Ergon assumptions: a return on debt of 6.36 per cent, a return on equity of 10.5 per cent, and a gearing ratio of 60 per cent.
Energex assumptions: a return on debt of 5.91 per cent, a return on equity of 10.5 per cent, and a gearing ratio of 60 per cent.

These WACC proposals are acknowledged to be 'placeholder' WACCs subject to possible changes in prevailing market rates, and in particular the risk-free rate.[96]

Following technical advice from Engineroom Consulting (please see Appendix 1 for more details) QCOSS considers that Energex and Ergon's proposed WACCs are significantly in excess of the efficient financing costs of an efficient benchmark entity, and if adopted, would result in prices to consumers that are significantly higher than required to finance such an efficient benchmark entity.

Engineroom Consulting considers that electricity distribution is a relatively low risk business relative to the overall market (which is dominated by private sector companies who face significant competitive pressures both domestically and/or internationally). It is a monopoly business, with low financial risk as this is spread across millions of customers, with little alternatives of supply, and consequently is characterised by relatively high cash flow certainty. The regulatory framework which allows for a revenue cap is close to a guaranteed income for the next five years.

[94] NER 6.5.2(j).
[95] NER clause 6.5.2(k)(2).
[96] The placeholder nature of the WACC proposals is discussed, for example, at Ergon RP, p.121.

Further, under the AER's new approach to setting the cost of debt, the business risk is reduced in comparison to historically as the cost of debt is updated annually. The AER notes that, "*Overall, we expect our new approach to estimating the return on debt and equity to decrease the volatility of service providers' cash flows*."[97] In view of the way in which the regulatory arrangements reduce business risk Engineroom considers that the return on investment should approximate that on a debt security rather than on a business exposed to normal market risk. The revenue cap delivers certainty in respect of revenues while costs are relatively predictable and there are arrangements to protect against cost blowouts such as pass-through arrangements.

QCOSS does not consider that the proposed WACCs reflect stakeholders' concerns and input as the distributors only informed the consumers groups of their proposed WACCs just prior to the regulatory proposals being submitted. They did not take into account consumers' concerns about departures from the AER's Guidelines nor did they explain how these variations were in consumers' long-term interests.

The WACCs proposed by Energex and Ergon are higher than in the 2010-2015 RCP when measured as a margin to the risk-free rate, with Ergon at a 4.3 per cent margin to the risk-free rate and Energex at a 4.2 per cent margin to the risk-free rate. The current margin in the 2010-2015 RCP is 3.9 per cent. The margin recently allowed by the AER in its NSW draft determinations is 3.6 per cent.

The proposed WACCs are higher than the WACC of 7.15 per cent put forward for consultation for NSW electricity distributors in the AER's review Draft Determination.

The proposed WACCs compares unfavourably with recent rates set in the UK and New Zealand (NZ). In the UK, Ofgem is proposing a rate of 4.8 per cent (nominal vanilla) in the electricity determination currently underway.[98] In NZ, the Commerce Commission set a nominal vanilla rate of 7.19 per cent based on the risk-free rate prevailing in NZ at 1 September 2014, on an equity base of 56 per cent of the RAB. The risk-free rate was 4.09 per cent, resulting in a margin to the risk-free rate of 3.1 per cent.

In their proposals, Energex and Ergon have departed in a number of areas from the AER's rate of return guideline issued in December 2013.

The departures for both Queensland distributors are:

- the credit rating used for calculating the cost of debt is proposed to be BBB rather than BBB+
- debt should enter the regulated asset base weighted in according with its timing (i.e. more weight in years with high capex).
- the Sharpe-Lintner Capital Asset Pricing Model (the SL CAPM) should apply, but estimate the parameter values within the range generated by the SL CAPM having regard to the strength and weaknesses of all relevant evidence
- estimate the BBB debt margin based on the RBA's 10 year BBB yields (as the RBA currently only publishes this data at the end of the month). This data source does not comply with the minimum averaging period under the AER's Guideline, which is 10 business days

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[97] AER, Rate of Return Guideline Explanatory Statement, p. 39.
[98] Bruce Mountain presentation to AER public form, 9 December 2014.

- gamma value of 0.25 rather than 0.5 (noting the AER moved from its own guidelines which proposed a gamma of 0.5 to use a gamma of 0.4 in the NSW draft determination).

Table 5.2 summarises the key points of departure in terms of their impact on inputs to the WACC.

Table 5.2 Summary of AER Rate of Return Guideline compared with Energex and Ergon proposals

Parameter	AER Guideline	Energex RP	Ergon RP
Gamma	0.5	0.25	0.25
Risk-free rate	TBD	3.63	3.63
Credit rating	BBB+	BBB	BBB
Equity Beta	0.7	0.91	0.82 or 0.91 (depending on method used)
Market risk premium (%) (i.e. Rm-Rf)	5 to 7.5%	7.57	7.57
Equity risk premium (%)	not specified	4.2	4.3
Overall WACC (%)	**TBD**	**7.75**	**8.02**

Source: Energex RP, pp.163, 165.

Following technical advice from Engineroom Consulting, QCOSS proposes the values set out in Table 5.3 below for the WACC parameters and inputs. Engineroom's technical advice is set out in Appendix 1 and this includes its advice on further issues that the AER should consider as part of assessing the appropriate WACC. These include: the appropriateness of selecting a rate above the midpoint for the overall rate of return, benchmark efficient entity, and consistency amongst WACC parameters.

Table 5.3 QCOSS proposed WACC parameters and inputs

Parameter	Recommendation
Model	SL CAPM modified for the observed upward bias in returns available to low beta stocks
Credit rating	A-
Equity beta	0.5 to 0.55
MRP	6.0%
Observation window for cost of debt	20 business days as close as possible prior to the start of each new financial year
Approach to trailing average	Equal yearly weighting
Gamma	0.5

Recommendation 5.1

QCOSS recommends to the AER, that it adopts the parameters and inputs set out in Table 5.3 in calculating the range of values of the WACC, for the reasons outlined in Sections 5.3 to 5.12 of this submission.

5.3 Overall rate of return

The AER sets out a range of factors in the Rate of Return Guideline for assisting in determining the overall rate of return as well as the equity beta, market risk premium, risk-free rate, and return on equity.[99]

Apart from the risk free rate, these parameters are not directly observable and have to be estimated. There are a number of different methods used to do this and this results in a range rather than one definitive "rate of return". In considering where to set the rate of return (as well as input parameters such as the equity beta), regulators have often considered that as a matter of prudency they should set the allowed rate of return above and possibly well above its midpoint estimate. Advice to QCOSS indicates that the AER should set the rate of return at or below the midpoint of the range of values. Further details are set out in Appendix 1 and the main reasons are:

- investors have different risk preferences and some will continue to invest with lower rates of return;
- the New Zealand Courts in the *Wellington Airport* case and the Australian Competition Tribunal in the Telstra case favour a midpoint estimate;
- the risks of underinvestment from setting the WACC too low in the next RCP are small due to the significant level of over-investment in the 2010-2015 RCP (discussed further in the capex chapter);
- Ergon and Energex have not made a compelling case why the WACC should be above its midpoint estimate, especially given the sharp falls in the utilisation rate of assets, the sharp rise in the amount of assets used to supply each KVA of peak demand, the increase in the assets per customer, and the increase in the amount of assets used to deliver each KVA of demand. The onus is on Ergon and Energex to demonstrate this case in a compelling way before the regulator should award a WACC above the midpoint estimate;
- the inherent bias in selecting a value for rate of return above the midpoint is compounded when values above the midpoint are also selected for the estimated WACC inputs such as the equity beta;
- there is empirical evidence from market studies such as Black, Black, Jensen, and Scholes (1972), and Frazzini, Kabiller, and Pedersen (2013) that supports the view that the market rewards low beta stocks over high beta stocks, which would justify setting a WACC below the mid-point estimate (discussed further below).

Further, analysing the legal directive in the NEO and the NER, it is arguably not permissible for the regulator to set the WACC (or inputs to the WACC such as the equity beta) above a benchmark efficient level given:

- The NEO aims to promote investment only to the extent that it is efficient; and
- NER clause 6.5.2(c) provides for the rate of return to be set commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk.

Engineroom is not specifically aware if the AER has legal advice to support setting a WACC above the midpoint or most likely estimate. Ultimately, it is a question for the regulator to determine if it is consistent with the NEO and NER or conceptually

[99] AER Rate of Return Guideline, p. 14.

sensible to select a value above the midpoint, particularly in the absence of compelling evidence to justify doing so.

Recommendation 5.2 ***QCOSS recommends that the AER select a WACC at or below the midpoint range.***

5.4 Benchmark efficient entity

Engineroom questions the definition of the benchmark efficient firm as a “pure play, regulated energy network business operating within Australia” without a parent organisation.[100] Engineroom considers that the benefits of having a parent should be taken into consideration as a material factor given such parentage reflects unanimous corporate practice, is considered by rating agencies in assigning credit ratings (which reflect in turn on the cost of both equity and debt), confers benefits, and is measurable.

5.5 Consistency among WACC parameters

The policy intent and the relevant NER provisions highlight that the WACC parameters must be considered in a holistic way rather than as a set of independent drivers which simply ‘come together’ to provide a value for the rate of return after separate determination. In particular, the policy intent of clarifying that *inter-linked matters must be considered* highlights that the overall responsibility of the AER and the Tribunal is to ensure that the overall WACC meets the NER. Clause 6.5.2(e)(3) in this regard provides for the regulator to have regard to “any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.”

Advice to QCOSS suggests that the Guideline is inconsistent with the NER and policy framework in the sense that it focusses on setting values for each of the WACC parameters and does not look at the inconsistency in the values assigned to those parameters. Specially, there is a lack of consistency between the assumed Standard and Poor’s debt credit rating of BBB+ and the equity beta of 0.7 and the equity to debt ratio of 40:60. For example, a Standard and Poor’s rating of BBB+ is not far above junk bond status and it describes BBB (which Ergon and Energex are proposing in place of BBB+) as:[101]

> *An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.*

A credit rating of BBB+ is considered lower medium grade. This credit rating is not consistent with a firm with:

- an equity beta of 0.7 (which is, relative to the market, considered low risk);
- high cash flow certainty of a revenue cap;

[100] AER, Rate of Return Explanatory Statement, pp. 36-47.
[101] Standard and Poor’s website, at https://www.globalcreditportal.com/ratingsdirect/renderArticle.do?articleId=1331219&SctArtId=257653&from=CM&nsl_code=LIME&sourceObjectId=5435305&sourceRevId=7&fee_ind=N&exp_date=20240818-02:07:33, Accessed 6 January 2015.

- the ability to engage in annual revisions of the debt allowance; and
- a relatively conservative gearing ratio of 60 per cent.

This would suggest that either the credit rating of BBB+ or the equity beta or both are wrong. Advice to QCOSS considers the credit rating of BBB+ is irreconcilable with the other values and inputs in the AER Rate of Return Guideline. A more compatible credit rating would be likely to be A-, the middle of the medium upper grade.

5.6 Selecting the most appropriate model for determining the cost of capital

While Engineroom and QCOSS broadly agree with the AER's view in the Rate of Return Guideline that the S-L CAPM is transparent, well supported by theory, and well-understood, it is concerned along with other consumer groups (for example, PIAC's submission to the NSW Draft Determination) that the AER's new approach in practice increases the complexity and uncertainty of selecting the appropriate value for the cost of equity. This approach allows for the use of multiple models and approaches (specifically, the following four - SL CAPM, Black CAPM, DGM, Wright approach) in determining various parameters or the overall return. The approach encourages "cherry picking' by permitting the distributors to choose whichever model delivers the highest rate of return at the time of a given RCP. Advice to QCOSS suggests that the approach of using a range of models together (e.g. using the Black CAPM to pick the point estimate for the equity beta within the range estimated by the SL CAPM) is flawed because:

- the models have conflicting conceptual bases and assumptions and are not compatible with each other
- distributors can vary the weight that they put on the models from one RCP to the next. This approach is clearly evident in the relatively arbitrary weighting placed by SFG on the outputs of different models in estimating WACC parameters such as the equity beta.

The historical approach under the SL CAPM was reasonably predictable and transparent. This reduced opportunities for distributors to cherry-pick outcomes, which was a central concern expressed by policy-makers and stakeholders.

Despite the above comments advice to QCOSS suggests that there are some concerns about the operation of the SL CAPM in relation to low beta stocks and proposes a downwards adjustment to the SL CAPM to cater to the upwards bias in the SL CAPM for low beta stocks. The downwards adjustment should be based on market observations of the Sharpe outperformance of low beta stocks. The AER would need to decide whether to rely on Australian stock performance only or refer more broadly to international observations.

5.7 Equity beta

The equity beta for a firm or industry adjusts the market risk premium calculated for the market as a whole for the relative risk of the firm or industry.

The distributors themselves acknowledge that electricity utilities face a much more stable business environment than the market as a whole given their monopoly status, the relatively less elastic demand for their services, and their cash flow predictability. This is evidenced, as noted by PIAC by the way in which distributors present themselves to investors, that is:[102]

- being regulated monopolies with high barriers to entry; and
- providing stable long-term regulated cash flows.

In addition, the revenue cap arrangements essentially guarantee the level of revenue that the distributors will earn.

The coming regulatory period is even less risky compared to the 2010-2015 RCP. This is because the AER has issued guidelines around a range of issues which provide certainty to investors and owners of the regulated assets. Additionally, the cost of debt will be updated annually, reducing exposure to the cost of debt prevailing at any given time. Under the revenue cap to be applied, energy usage risk will be borne by consumers. The AER has also identified that its approach to setting the return on equity is likely to "promote a more stable return on equity over time".[103]

During the Better Regulation program, the AER commissioned two studies on the types of risk that should be considered in determining the equity beta – by McKenzie and Partington, and Frontier Economics.[104] These studies suggested that the equity beta for the Australian regulated networks was well below one, reflecting the very low risks of the regulated network businesses compared to the market as a whole. For example, McKenzie and Partington talk about the generally acknowledged "low default risk in regulated utilities". Prior to the Better Regulation program, the AER commissioned Professor Olan Henry to review the equity beta and update his earlier 2009 paper to the regulator. However, Professor Olan had not completed his 2014 report when the AER was require to finalise its rate of return guideline. His study included multiple analyses of Australian utility data returns.[105] Based on these studies, the AER concluded that the equity beta, supported by extensive empirical analysis, fell within the range 0.4 and 0.7.

The AER Guideline set the beta at the top of this range, that is, at 0.7. Professor Olan's 2014 work suggested that the best value for beta was between 0.5 and 0.6 (representing the median of the various analyses).

The distributors in their regulatory proposals have argued for a beta of 0.91, specifically relying on a report by SFG Consulting.[106] The sample which SFG uses to determine this value is significantly weighted to US stocks which are subject to very different operating and market conditions. The SFG also applies a range of approaches and then applies an arbitrary weighting to the different approaches to arrive at this value. The weighting applied to the value from the SL CAPM model is the lowest of the weightings.

Following advice from Engineroom, QCOSS agrees with the criticisms of the SFG study by PIAC that:[107]

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[102] Extract from SP AusNet, 2014, Full Year 2014 Results for the financial period ended 31 March 2014, 5. Similar statements are made to investors by other regulated utilities.
[103] AER Rate of Return Guideline – Explanatory Statement, p. 38.
[104] Frontier Economics, 2013, Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia, a report prepared for the AER, and McKenzie M and G Partington, 2013, Report to the AER: Risk, Asset Pricing Models and WACC.
[105] O T Henry, 2009, Estimating Beta.
[106] Energex RP at p.165; Ergon RP, p.123.
[107] PIAC submission to NSW Draft Determination, pp.78-79.

- the SFG study found the median of the Australian values was significantly below 0.7
- the US data set displayed a very different distribution and higher set of values
- the SFG study provided little or no explanation for its strong weighting towards the US entities and data
- if overseas data is to be used, then why not use UK, NZ, or other comparable data?

Overall, advice to QCOSS suggests that the equity beta should be a value between 0.5 and 0.6 which it considers represents the most appropriate outcome of the empirical studies and is consistent with the McKenzie and Partington and Frontier reports that the risks of the regulated network businesses are significantly less than the risks in the market as a whole. Specifically, it is consistent with Henry 2014's estimate of the mean value of beta while being well above the median value of beta.

It is noted that while the distributors are advocating for the equity beta to include overseas data, at the same time the distributors do not suggest incorporating overseas bond rates into analysis of the cost of debt even though the Queensland distributors borrow in international markets through the QTC as part of their capital management strategies.

5.8 Market risk premium

In the CAPM model, the market risk premium (MRP) represents the return on the market above the risk-free rate that investors expect to earn on the market portfolio of all risky assets.

In the Rate of Return Guideline, the AER proposes to:

> *…estimate the range for the MRP with regard to theoretical and empirical evidence – including historical excess returns, dividend growth model estimates, survey evidence and conditioning variables. The AER will also have regard to the recent decisions among Australian regulators.*

Engineroom's contends that the DGM model should not be used to determine the MRP because of the identified upward bias in its application. Given the DGM model incorporates analyst forecasts, its use sits oddly with the AER's decision not to use information from trading multiples, asset sales, or brokers' WACC estimates in determination of the rate of return.[108]

MRP should be stable, and should be based on very long term factors observation of investors' minimum requirements for an excess return on stocks compared to risk-free assets. This provides investors with regulatory certainty and reduces the incentives for gaming or for arbitrary gain or windfall loss for a purchasing investor compared to a selling investor if the regulator changes its position on MRP subsequent to the sale of a regulated asset.

The MRP should be estimated by regression of a series of market data over an historical period of more than 50 years). This approach is reasonable, stable,

[108] AER Rate of Return Guideline, p. 14.

predictable, and transparent given that the forward cost of equity is not directly observable.

Advice to QCOSS notes that most of the survey evidence and regulator estimates support a value of 6.0. This evidence and regulator estimates were set out in Economic Insight's paper for the NZ Commerce Commission.[109]

5.9 Selection of the risk free rate for debt and equity

The AER's Guideline proposes that the cost of debt be calculated on the basis of the 10-year commercial bond yield for a firm with an average credit rating of BBB+. The AER's Guideline proposes the introduction of a trailing average approach with annual updating, reducing the exposure of both networks and consumers to significant movements in interest rates during the regulatory period and between regulatory periods.

Advice to QCOSS submits that the use of a 5 year BBB+ rate is more appropriate than a 10 year rate because:

- it reflects realistic debt setting period in capital markets in Australia and the length of the RCP. A period of 5 years is consistent with giving the distributor an ex ante efficient return on capital matched to the prospective period;
- the QCA and the NZ Commerce Commission use a 5 year period;
- there is far more data for 5 year rates, which simply reflects the much more liquid market for 5 year borrowing than 10 year borrowing.
- in practice, the distributors' borrowing practices are much more likely to be calibrated to internal treasury borrowing which are much likely to be short term and not reflect anything like the 40 to 50 year life of electricity distribution assets;
- a 5 year rate is more consistent with the move to annual adjustment of the cost of debt.

5.10 Selection of the observation window for the risk-free rate

The AER Guideline proposes to use 10-year Commonwealth government securities based on the 'prevailing' yield averaged over a short observation window close to the date of the determination.

QCOSS and Engineroom agree with the AER's approach in relation to the observation window. This approach aligns with the view that the WACC and in particular the cost of debt is forward-looking. It is consistent with the AER's previous approach and also with the new approach of weighting debt on a year-by-year or trailing basis.

However, we do not agree with the distributors selecting a longer observation period as it may give weight to historical debt costs that no longer apply. As debt costs have been coming down significantly in recent times, it also tends to suggest that distributors advocating for an observation window reaching significantly into the past are seeking to game the outcome.

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[109] Economic Insights, *Regulatory Precedents for Setting the WACC within a Range* (Report prepared for New Zealand Commerce Commission), June 2014.

The approach of using a short observation window close to the start of the RCP (with similar timescales for observation windows in subsequent years) was accepted by the Australian Competition Tribunal as reasonable in the *APA GasNet* case.[110]

5.11 Application of the trailing average

Engineroom has advised QCOSS to support the AER's approach in the rate of return guideline of attaching equal weights to each year when calculating the cost of debt.[111] It is further advised that using equal weights for each of the years rather than weighting by actual capex or the approved capex under the PTRM is commensurate with setting a cost of debt that equates with the efficient financing costs of a benchmark efficient entity.[112] Consequently, QCOSS does not support the distributors' proposals that the debt weighting be aligned with the capex spending profile. Its reasons are set out in Appendix 1.

5.12 Imputation credits ('gamma')

Under the Australian taxation system, when domestic investors receive dividends they are provided with a franking credit which can be used to offset other tax payable by them. The franking credit reflects tax paid by the company. The presence of franking credit reduces the returns required by domestic investors to invest in a stock. Therefore, the distributors' tax costs should be adjusted down to reflect the value of the franking credit.

Under the NER, the nominal vanilla WACC is not adjusted for the value of franking credits. Instead, franking credits are incorporated as an adjustment to the regulatory allowance for tax costs.

This tax adjustment, known as gamma, is generally accepted to be the product of the rate at which profits are distributed as dividends (the distribution rate or dividend payout rate) (F) and the rate at which they can be used by investors (the utilisation rate or theta).

A high gamma value means that the distributor will receive a relatively lower regulatory allowance for tax costs and, therefore, a lower revenue allowance to pay for these costs. This will present as a lower regulated cost of service. A low gamma means the opposite.

The value of gamma has been a highly contested area and includes rulings from the Australian Competition Tribunal which ordered the AER to accept Energex's and Ergon's proposal for a gamma of 0.25.[113]

The AER responded to the Tribunal decision by re-evaluating the conceptual basis for estimating the value of gamma and undertook analysis using taxation statistics and other measures. In the Guideline, it proposed a gamma of 0.5. Energex and Ergon have now rejected the AER's approach in their regulatory proposals and

[110] Australian Competition Tribunal, Application by APA GasNet Australia (Operations) Pty Limited (No 2) (2013) ACompT 8, 18 September 2013.
[111] AER Rate of Return Guideline, p. 19. The AER applied this approach in the NSW Draft Determination, e.g. AER Ausgrid Draft Determination at p. 81.
[112] As per NER clause 6.5.2(c).
[113] Australian Competition Tribunal, Application be Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011).

continue to propose a gamma of 0.25, based largely on a consulting report by SFG Consulting.

At dispute is the conceptual framework for determining gamma. This is a difficult issue since, as the Tribunal recognised in 2011, as there is no generally agreed methodology to assess theta, one of the key inputs to gamma.

It is worth noting that in the NSW Draft Determination, the AER selected a value of 0.4, based primarily on the equity ownership approach, which was supported by its consultants Handley, and Lally, and which suggested a range of 0.4 to 0.5.[114] The QCA recently set a gamma of about 0.47 in its regulatory decisions.

QCOSS ‘s advice is that a more even-handed and consistent approach would be the value of 0.5 as per the AER Guideline.

[114] AER, Draft Decision - Ausgrid 2014-19, pp. 46-47. Referring to J. Handley, Report prepared for the Australian Energy Regulator: *Advice on the value of imputation credits*, 29 September 2014; and M. Lally, *The estimation of gamma*, 23 November 2013, p. 4.

6 Other issues

QCOSS has also made a number of comments on three specific areas which it considered as especially relevant in understanding the long term interests of electricity consumers. These are: demand management; metering services; and incentives schemes.

6.1 Demand management

6.1.1 Context

Demand management encompasses initiatives to defer network expansion by reducing demand on the network at peak times. QCOSS agrees with Energex's view that "demand management coupled with effective supply side management is necessary for sustainable business operations, capital investment and optimal economic efficiencies for distribution services to customers".[115] Demand management can take a number of forms, including load control via air-conditioner, pool pump and hot water load control.

Demand management (DM) is a critical element of controlling network capex. Even at a time when peak demand is falling in aggregate, some substations and feeders are experiencing increases in peak demand.

QCOSS's view is that the proposals from both distributors support the national electricity objective in relation to the long term interests of consumers, and for the AER to not accept these proposals would be inconsistent with the NEO.

6.1.2 Overview comments on demand management

Electricity distributors are large infrastructure businesses with long term planning horizons. This, combined with the regulatory environment they work within, can result in a lack of flexibility and responsiveness to emerging issues. This is particularly the case in demand management where technology advancements, commercial interests and consumer behavioural change can result in rapid change to electricity demands within relatively short periods of time. Therefore electricity distributors need to be strategic and mitigate future demand constraints.

Energex

Energex's approach to DM in Queensland has traditionally been through direct load control and off-peak pricing strategies. Significant customers, and consequently load, continue to subscribe to these products and shift their demand away from peak times. Although the ability of DNSPs to recruit new customers to Tariff 31 and Tariff 33 has been eroded at certain points in the previous regulatory period, because of narrow gaps between these Tariffs and the Standard regulated tariff - Tariff 11, these tariffs are still valuable, effective and worthy of support. In particular an increased focus on the recruitment of new households to off-peak tariffs with direct load control will benefit the Queensland network.

However Energex has successfully introduced an alternate and very effective strategy to decrease peak demand through Peak-Smart air-conditioning. This strategy creates significant cost efficiencies by leveraging off of private sector corporate interests in its implementation. It also locks in network pricing benefits (and consequently customer benefits) into the long term by increasing the load under

[115] Energex RP, p. 80.

direct load control indefinitely without linking the customer to a reduced tariff. QCOSS commends this program and strongly supports its continuation.

> ***Recommendation 6.1***
>
> ***QCOSS recommends that the AER approve funding for the ongoing management and improvement of Energex's Load Control System, hot water load control, pool pump load control and PeakSmart air-conditioning.***

Ergon Energy

As the regional and remote distributor, it is acknowledged that Ergon Energy faces unique challenges in the NEM. QCOSS acknowledges that Ergon Energy has created a DM strategy specifically targeted towards regional areas of concern and support this approach in principle. Ergon's Demand Management approach includes a five-year program where the largest share of demand reductions planned are from programs that target network constraint and risk locations, rather than broad-based programs. Some of these are new programs while others are a continuation from the 2010-2015 regulatory period. There is also a shift to delivering Demand Management via market enablement. This involves initiatives such as: A Demand Response Incentive Map (which will inform the market about the location, timing, economic value and metrics around different programs to encourage participation and support); and continued market engagement via the establishment and operation of a list of preferred suppliers, for products and services that can support demand management products or services, through the Trade Ally Network.

Other Ergon initiatives consider: future network needs, manage risks within the network and provide opportunities for improving asset utilisation as well as a continuation of the DMIA to enable Ergon to explore new technologies and develop its capability and capacity in the demand management area.

As demonstrated in their RPs, climate is a major driver of peak demand in Queensland and the penetration of air-conditioning is increasing. Hot weather events have the potential to create significant reliability of supply issues for the Queensland network and PeakSmart air-conditioning is an effective DM program to address this.

> ***Recommendation 6.2***
>
> ***QCOSS recommends that Ergon Energy also undertake the PeakSmart air-conditioning program for its distribution area based on the approach in the Energex proposal.***

> ***Recommendation 6.3***
>
> ***QCOSS recommends that Ergon and Energex place a stronger focus on targeted consumer programs towards low income and vulnerable high energy use households and particularly customers with high and inflexible consumption such as those with energy intensive medical conditions.***

6.1.3 Use of the RIT-D to drive non-network solutions

The AER has expressed the view that the RIT-D test can drive demand management and other non-network solutions where those solutions are the most cost-effective. QCOSS is not confident that the RIT-D test on its own is likely to result in the uptake of demand management initiatives and other non-network alternatives by the Distributors. This is because:

- Demand management and demand responses need to be coordinated across a wide range of users to be effective in deferring a network solution. This cannot generally be done in the relevant timeframe in which the network has to choose between a network and a non-network solution.
- It is very difficult in the RIT-D test to compare the reliability outcomes from network versus non-network solutions, making it easy for distributors to favour network solutions in practice where they wish to pursue network solutions.
- Demand management initiatives often require longer-term cultural change by users through significant user education and acceptance (for example user acceptance of distributor control of air-conditioning). This requires a long-term commitment to non-network solutions by distributors and users working together rather than specific choices around particular network versus non-network solutions. For example, the effort to increase the uptake of controlled hot water load does not fit within a RIT-D business case framework as it is more diffused across the network and longer–term than contemplated by the RIT-D.
- RIT-D decisions are made by distributors. Distributors may favour network solutions as they have a preference for building network (as recognised by the IRP)[116] and because network solutions may present lower operational and revenue risk[117].

Recommendation 6.4
QCOSS recommends that the AER does not solely rely on the RIT-D to drive demand management and other non-network solutions.

6.1.4 Concluding comments on Demand Management

QCOSS supports the continued investment in DM by the distributors in principle and supports both Distributors broad and targeted approaches. The Queensland distributors have historically taken a proactive approach to DM. Both businesses have strong track records of previous performance in this area.[118] The measures put in place during the 2010-2015 RCP have resulted in a changing culture of awareness on electricity demand and use in Queensland and constitute the only significant (in terms of scope of impact) DM programs in operation in Queensland.

QCOSS considers there is a need for both broad-based and targeted initiatives. Broad-based programs increase general customer awareness about peak demand, peak times and encourages behavioural change for large population groups. This

[116] Independent Review Panel on Network Costs, *Electricity Network Costs Review - Final Report*, p. v.

[117] For example, when Powerlink experienced problems with interruptions between Central and Northern Queensland in the early 2000s, in the short term it was required to make large unanticipated payments under network support agreements to local generators to prevent curtailment of supply. These payments exposed Powerlink to considerable risk because of their size and uncertainty. A network solution represented a lower risk to Powerlink's revenues.

[118] Dunstan, C., Ghiotto, N., Ross, K., 2011, Report of the 2010 survey of Electricity Network Demand Management in Australia. Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, UTS.

benefit is difficult to measure and has not been quantified in the regulatory proposals but the value of this should not be underestimated.

QCOSS's view is that the AER will assess to the cost effectiveness of the DM proposals (and assess to what extent the benefits to consumers (by preventing future augmentations to the network) outweigh the costs associated with DM). In addition, the AER must take into account in that there are direct benefits of broad based DM program in term of reduced affordability for customers which should be taken into account in assessing the overall net economic benefit. QCOSS's experience in the community sector suggests that there are flow-on benefits to consumers from Energex and Ergon's DM programs. For example, with the off-peak pricing and load control programs consumers spread some of their peak load which has benefits for reducing peak demand. This not only results in reduced augmentation but also consumers are better able to manage their use and hence their bills. Further, to support the Distributors' DM Proposals is consistent with the AERs regulatory objectives for the network businesses to provide 'efficient and prudent non-network alternatives'.[119]

QCOSS is especially concerned if the AER reduces funding for a more broad-based DM program in the next RCP, given its draft decisions in NSW.[120] QCOSS is not confident that the RIT-D test on its own is likely to result in the uptake of demand management initiatives and other non-network alternatives by the distributors. Moreover, over time, as the uptake of peak demand tariffs and advanced meters increase it may well be the case that the effectiveness of such DM programs may reduce. However, it remains to be seem how quickly this uptake will happen. In the meantime, DM programs are effective in supporting people to manage electricity demand and hence their bills. At this stage new pricing methodologies, such as time of use pricing, and smart metering technology are not a substitute to DM.

Given time and resource constraints it has not been possible for QCOSS to review comprehensively the DM proposals. We note that other consumer groups are likely to undertake more comprehensive assessments and in the main we would be supportive of their assessments, particularly the Queensland Consumers' Federation and the Total Environment Centre. We broadly support the latter's views on seeking more guidance on DM from the AER. There is a need for more guidance on how the AER will assess the DM proposals. This would be separate to the DMEGIS and could include guidance on how expenditure factor 10 (consideration of non network options) in clause 6.5.7(e)(10) of the NER and more broadly expenditure on DM will be considered by the AER in regulatory determinations. The guideline would provide guidance on both DM and Capex plans in the regulatory determination process.

Recommendation 6.5

QCOSS recommends that the AER accept the DM proposals submitted by Energex and Ergon as QCOSS believes this is consistent with the long term interests of consumers.

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[119] Productivity Commission, 2013, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra.
[120] AER, November 2014, Draft Decision for Ausgrid

Recommendation 6.6

QCOSS recommends that the AER develop a guideline on how non-network options, including DM initiatives, will be considered in its assessment.

6.2 Metering services

6.2.1 Context

Type 6 metering services cover manually read accumulation meters which are the most common type of meter for households and other small users. Currently, type 6 metering services are part of standard control services, essentially electricity distribution services, which are regulated under a revenue cap arrangement shared amongst all customers. The AER proposed in its Framework and Approach Paper to transfer type 6 metering services from a standard control service to an alternative control service.[121] As an alternative control service, type 6 metering would no longer be part of a bundled charge for standard control services, but customers would instead pay a cost reflective charge based on the meter installed. Under clause 6.2.6 of the NER, distributors have to propose the control mechanism for alternative control services, including indicative prices and the building blocks used to determine those prices.

The Australian Energy Market Commission (AEMC) released a consultation paper in April 2014 seeking stakeholder comment on making metering more competitive as part of encouraging a move to smart metering that support peak demand-based pricing. The AEMC expects to publish a Draft Rule Determination by end of February 2015, with a Final Rule and Rule Determination to be published later in 2015.

6.2.2 Overview of Energex's and Ergon's type 6 metering proposals

As part of their regulatory proposals, Energex and Ergon have submitted indicative prices and building blocks for type 6 metering services.[122] Both distributors are proposing a building block cost build-up approach.[123]

There are wide variations between the two sets of building blocks and other relevant estimates such as exit fees, with Ergon proposing much lower return on capital, much higher depreciation, much higher opex, and much higher tax allowance than Energex.[124] These discrepancies seem very hard to explain in practice and suggest some level of arbitrariness in approach by one or both of the distributors.

Energex values its type 6 metering RAB at around $436 million as at July 2015 based on its stock of around 2.2 million meters.[125] Ergon values its type 6 metering RAB as 61.6 million on its stock of around 1.3 million meters.[126] The difference in these values is very hard to understand or reconcile. This is discussed further below.

Energex estimates its exit fee at between $290 to $324 over the course of the 2015-2020 RCP,[127] while Ergon estimates its exit fee (Ergon identify it as the customer

[121] AER, Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015, April 2014, p. 22.
[122] Energex RP, chapter 25; Ergon RP, pp. 47-51 and supporting document 05.03.01 – Default Metering Services Summary.
[123] Energex RP, pp.269-270; Ergon RP pp. 50-51.
[124] Comparing Energex RP, p. 276, Table 25.9 with Ergon RP, p. 50, Table 24.
[125] Energex RP, pp. 274-275, Table 25.7, and p. 268, Table 25.1.
[126] Ergon RP, p. 50, Table 25.
[127] Energex RP, p. 280, Table 25.13

transfer fee used in Table 26 of Ergon's regulatory proposal) at between $137 and $166 over the same period.[128] Energex's exit fee is double despite having a much greater level of customer density, which could be expected to make it less costly to access and replace meters.

Ergon Energy is proposing a very large expansion in metering capex, an increase in the order of 47 per cent, in order to increase its planned meter replacement program from 12,433 in the current RCP to 124,720 in the 2015-20 period. Ergon is forecasting 377,698 meter installations in total over the five year period for a net increase of over 130,000 meters, which is equal to 30 per cent of the estimated stock of meters at the end of 2015-16.[129] Ergon argues that the volume of meter replacements in the 2010-15 RCP slowed due to the significant uptake of solar meters, uncertainty around the future policy and regulatory framework, and the need to run an asset data program to identify the location of BAZ meters due to their age and poor legacy records.

It is noted that Ergon's proposed revenue requirement is much higher than that of Essential Energy in NSW, despite the latter having a higher number of customers and a distribution area reasonably similar in terms of customer density.[130]

6.2.3 Evaluation of Energex and Ergon capex proposals

6.2.3.1 Meter valuation

Ergon calculates the value of its metering assets based on optimised depreciated replacement cost basis (ODRC). The ODRC was estimated by multiplying the number of regulated Type 5 and 6 assets by their 'modern equivalent" asset price, and reducing this value by depreciation assuming straight line depreciation and standard asset lifetimes.[131] By contrast, Energex is using depreciated value.[132]

Energex's approach could be expected to lead to a lower value per meter as it is essentially depreciating the book value of actual meters as opposed to a modern equivalent which is what Ergon is doing. However, Energex is valuing its meters at $200 each, while Ergon is valuing its meters at $48.

It seems difficult to account for the 400 per cent variation in average value per meter.

QCOSS is concerned at this wide differences in valuations. While we will not speculate on possible causes (and indeed this may well be a calculation error), this is very concerning given the RAB value drives both capital charges (return on and return of capital) which together make up the majority of the revenue requirement. Further, it also calls into question how the Distributors are valuing the RABs which supply standard control services. QCOSS considers that the AER should investigate the different methodologies used to determine the metering RAB values and apply an appropriate and consistent methodology.

QCOSS has also identified a possible discrepancy in how the opening value of metering RAB for both distributors have been calculated. Specifically, Energex

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[128] Ergon RP, p. 51, Table 26.
[129] Ergon RP, p. 50, Table 25.
[130] The AER Benchmarking report provides information on the customer numbers and densities for Ergon and Essential: AER, Electricity distribution network service providers, Annual benchmarking report November 2014 at Figure 4, p. 12 and Figure 8, p. 19.
[131] Ergon RP, Attachment 05.03.01 Default Metering Services Summary, pp. 26-27.
[132] "For the purposes of establishing the MAB, Energex has employed actual depreciation of Type 6 metering assets in the RF": Energex RP, p. 274.

values its type 6 metering RAB at $435.94 million on 1 July 2015 (in nominal dollars) according to Table 25.7[133] but only deducts $417.5 million from the RAB for standard control services as at 30 June 2015 according to Table 12.1.[134] The difference is about $18.44 million and it would appear that Energex's opening RAB for standard control services should be adjusted downwards by this amount. .

Ergon values its type 6 metering RAB at $61.6 million on 1 July 2015 in nominal dollars according to Table 25[135] but only deducts $54.29 million from its RAB for standard control services on 30 June 2015 on Table 3.[136]

Recommendation 6.7

QCOSS recommends that the AER review the methodology and assumptions used by both Distributors for estimating the opening value of the metering RAB and the RAB for standard control services, and that the AER provide guidance to the Distributors on how they value their metering RAB to ensure consistent valuation approaches.

6.2.3.2 Forecast demand for installations

To propose such a large increase in meter installation and other capex, the distributors must be assuming that no material competition in metering services will occur over the 2015-20 RCP.[137] Even allowing for this the forecasts of new meter installations seem very high.

For example, Energex is forecasting 546,528 meter additions to its current total stock of 2,183,022 meters,[138] which is an increase of more than 25 per cent. Of this number, it is forecasting 200,000 replacements or over 10 per cent of the current total stock. This seems very high when one considers that the standard life of current type 6 meters of 25 years.[139]

The AEMC has not published its draft determination on the future metering arrangements as discussed above. However current indications are that the new arrangements will operate from 1 July 2017. This is within the next RCP and it is likely that some level of competition in metering services will emerge, especially in South east Queensland where there is already retail competition.[140] These forecasts seem especially excessive assuming some level of competition in metering installation services.

Recommendation 6.8

QCOSS recommends that the AER review the methodology and assumptions used for forecasting the number of total and replacement meters over the next RCP.

[133] Energex RP, Table 25.7, pp. 274-275.
[134] Energex RP, Table 12.1, p. 148.
[135] Ergon RP, Table 25, p. 50.
[136] Ergon RP, Table 3, p. 20.
[137] For example, Energex RP, p. 273, section 25.6.2, where it discusses forecast demand.
[138] Energex RP, p. 268, Table 25.1 and p. 273, Table 25.3.
[139] Ergon RP, Attachment 05.03.01 Default Metering Services Summary, p. 13.
[140] It is also understood that the Queensland Government is examining ways to promote retail competition in Ergon's distribution area through changes to subsidy arrangements for Ergon network charges.

6.2.4 Depreciation

Ergon is proposing a very large increase in the depreciation allowance over the next RCP. This results in the proposed depreciation allowance making up around 43 per cent of the revenue requirement for metering services.[141]

Ergon has depreciated its opening alternative control services default metering RAB over a shorter five year accelerated period compared to seven years for Essential Energy. Ergon states that its more aggressive depreciation approach will assist in minimising stranding asset risk and improve metering price outcomes for customers in the longer term.[142]

Energex on the other hand, is forecasting depreciation based on a straight line approach based on an assumed 15 year remaining life.[143]

While QCOSS recognises that smart meters may render existing accumulation meters obsolete prior to the end of their standard life, QCOSS considers Energex's approach much more reasonable. Furthermore, competition in metering services is likely to emerge in Southeast Queensland at a faster rate than in regional Queensland.

Recommendation 6.9

QCOSS recommends that the AER review the methodology and assumptions used by both Distributors to calculate their depreciation allowances and if necessary provide guidance on the appropriate methodology.

6.2.5 Metering opex

Ergon Energy is proposing to spend $169.5 million in metering opex during 2015-2020.[144] This is much higher than that of Energex, which is proposing to spend only $92.3 million (both real 2014-15$).[145] Ergon's proposed opex seems very high in comparison to Energex's given that it is forecast to have 40 per cent less meters as at the start of 2015-16.[146] While Ergon has a much larger geographic area over which to read meters, it reads meters less frequently and sometimes as rarely as once a year, and requires some consumers, even consumers that are not particularly remote, to do self-reads.

6.2.5.1 Exit fee

As noted above, Energex estimates its exit fee at between $290 to $324 over the course of the 2015-2020 RCP.[147] Ergon estimate their exit fee (assuming it is the customer transfer fee used in Table 26 of Ergon's regulatory proposal) to range from $137 to $166.[148] These exit fees compare with Essential Energy's exit fee of $117.[149]

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141 Ergon RP, p. 50, Table 24.
142 Ergon RP, Attachment 05.03.01 Default Metering Services Summary, p. 36.
143 Energex RP, p. 275, Table 25.8.
144 Ergon RP, Attachment 05.03.01 Default Metering Services Summary, p. 3.
145 Energex RP, p. 274, Table 25.3.
146 Energex has 2.183 million meters at present while Ergon forecasts it will have 1.280 million in 2015-16: Energex RP, p. 268, table 25.1 and Ergon RP, p. 50, Table 25.
147 Energex RP, p. 280, Table 25.13
148 Ergon RP, p. 51, Table 26.
149 Ergon RP, Attachment 05.03.01 Default Metering Services Summary, p. 37.

QCOSS is concerned with the very wide discrepancy between the three exit fees presented above and would request that more details are provided by the Distributors as to the exit fee methodology and assumptions.

Recommendation 6.10

QCOSS recommends that the AER explore the extent to which different methodologies have led to differences in the exit fee. If this is the case then guidance by the AER should be provided on appropriate exit fee methodology.

6.2.6 Improvements in capex and opex programs from installation of smart meters

If smart meters are installed in significant numbers over the period 2015-2020 there will be significant benefits to the distributors. These include lower meter reading costs, lower costs of network operation (e.g. faster fault location, smart grid operation), and savings in capex (particularly in conjunction with demand-based network tariffs). These have been evident in New Zealand and in Victoria where a number of cost-benefit analyses of smart meters identify benefits to distributors from smart meter installation.

QCOSS considers that the AER should take account of these benefits to adjust the distributors' general opex and capex programs in line with reasonable assumptions of the roll-out of advanced meters. It is not clear if Energex and Ergon have adjusted their budgets to take these savings into account and hence they both may have over forecasted their *general* capex and opex budgets[150]. It is important that the AER investigates this especially as both distributors are assuming they will be installing large numbers of new meters.

6.3 Incentive schemes

6.3.1 Context

The chapter comments on the specific incentive arrangements in the regulatory framework, which include the:[151]

- efficiency benefit sharing scheme (EBSS), designed to improve opex decisions;
- capital efficiency sharing scheme (CESS), designed to improve capex decisions;
- service target performance incentive scheme (STPIS), designed to provide incentives in relation to service quality; and
- demand management and embedded generation connection incentive scheme (DMEGCIS), designed to improve decisions to implement demand management.

The NER sets out the scope of these incentive schemes, and considerations in implementing them.

[150] That is their capex and opex budgets relating to the provision of standard control services.
[151] In addition, the regulatory framework itself contains incentives

6.3.1.1 QCOSS position on incentive schemes

Overall, QCOSS does not consider there is adequate evidence that the identified incentive schemes drive more efficient behaviour by Energex or Ergon.

The basic premise of the incentive schemes is that the distributor will have an incentive over the RCP to seek out expenditure savings in order to retain the excess as a reward. This then leads to the distributors revealing their efficient cost of operation.

QCOSS would question this premise because:

Firstly, rather than spending less than the regulatory allowance, distributors may instead choose to live a 'quiet' life.[152] The Productivity Commission 2013 review found some evidence to support the view that distributors, particularly publicly-owned distributors, are electing to take this course.[153] Ausgrid has publicly identified that it has paid its workforce wages that were higher than efficient levels due to inflexibility in arrangements with unions representing their workforce.[154]

Secondly, there are so many changes between regulatory periods which affect efficient spending levels that the spending in one regulatory period may well not be a guide to efficient spending levels in the following regulatory period. The changes in the reliability obligations applying to Energex and Ergon provide a case in point. It is very difficult to provide a proper adjustment for such changes.

QCOSS considers that benchmarking and other techniques such as efficiency quotients be employed to identify the efficient level of expenditure rather than assume that the incentive schemes will drive the distributors to reveal their efficient costs of operation.

QCOSS also has concerns about the complexity of the incentive arrangements. For example, it is noted that Energex and Ergon are both claiming EBSS payments even though Energex overspent its allowance and Ergon only marginally underspent its allowance.[155] Energex is claiming around $37.8m and Ergon is claiming $153.87m (both nominal dollars).[156] There are adjustments for exceptional events, changes in the scope of standard control services (for example, removal of metering for type 6 meters), and arguments about the nature of accounting treatments (e.g. treatment of unallocated overheads or inspection costs for service lines).

QCOSS considers that incentives, if they apply at all, should be very modest and should only be in areas where there is a clear and demonstrable link between reduced spending and efficiency.

Where the AER sets up incentive arrangements, QCOSS considers that setting easy targets will not incentivise a move to best practice. Targets should be set at or near

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[152] Living a quiet life may manifest in overpaying the workforce to keep peace with the unions or in maintaining service quality levels above efficient levels by goldplating the network.
[153] Productivity Commission, Electricity Network Regulatory Frameworks, Report No. 62, 2013, pp. 257 – 260.
[154] Vince Graham, *Selling off Electricity Networks will give NSW cheaper power bills*, newspaper article in The Australian, 20 August 2014, p. 12.
[155] For example, Energex's actual expenditure was 1857.2m compared to an allowance of 1726.8m for the 2010-15 period: Energex RP Overview, p. 32.
[156] Energex RP, pp. 190; Ergon RP, p. 26.

best practice to ensure distributors do not earn incentives for moving to existing best practice but only for exceeding existing best practice.

6.3.2 Evaluation of Energex and Ergon proposals

6.3.2.1 Efficiency Benefit Sharing Scheme (EBSS)

The EBSS is designed to provide a continuous incentive for DNSPs to drive efficiencies in its opex, through positive and negative carryovers to reward or penalise for efficiency gains and losses respectively. It provides that distributors keep any efficiency gains (or bear any efficiency losses) for five years after the year in which they are incurred. The AER published version 2 of the EBSS in November 2013, and proposes in the F&A paper to apply version 2 to Energex and Ergon in the forthcoming RCP.[157]

In version 2 of the EBSS, the AER proposes a number of adjustments to forecast or actual opex when calculating the carryover amounts, including accounting for:

- approved pass through amounts or opex for contingent projects
- capitalised opex that has been excluded from the RAB
- categories of opex that are not forecast using a single year revealed cost approach
- inflation.

Energex is broadly proposing to accept the EBSS version 2, "with the exception of categories of opex that are not forecast using a revealed cost approach or reclassified in the subsequent RCP".[158] Ergon also proposes to accept the application of the EBSS in the 2015-2020 RCP. However, Ergon notes that it did not apply for a pass-through of opex costs associated with major weather events such as Cyclone Yasi during the 2010-2015 RCP and expresses concern that it does not do so in future RCPs this may be reflected in a lower EBSS payment.[159]

In terms of the carryover from the current RCP to the upcoming RCP, Energex is proposing that opex associated with meter reading continue in the EBSS opex targets. QCOSS opposes this as the opex targets should not include opex related to activities that are not likely to continue as standard control services in the 2015-2020 RCP. This is because it may reward the distributors for saving opex in relation to an activity that they are not required to perform.

Energex reduced its opex for the purposes of calculating the EBSS by $16.8m for unanticipated inspection of service lines, even though it actually spent $26 million on this activity. This means that under Energex's proposal, consumers would bear the costs of the difference ($9.2million) as an EBSS reward during the 2015-2020 RCP.

Energex says that the costs were unanticipated because of a manufacturing defect. Energex has only deducted from the opex target that it must beat the accounting provision of 16.8million rather than the full cost of the inspections. As Energex could have conducted better inspection processes or contracted for the manufacturer to make good any defects it should bear the full cost of the inspections rather than users bearing $9.2 million of these costs as an EBSS reward for Energex.

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[157] AER, Framework and Approach Paper, Energex and Ergon Energy 2015–2020, p. 14.
[158] Energex RP, p. 191.
[159] Ergon RP, p. 29.

Ergon's RP does not provide sufficient detail for a similar analysis by users of whether its EBSS claims are justified. As Ergon's claim is for $154.87million, this is highly concerning.

6.3.2.2 Capital Efficiency Sharing Scheme (CESS)

The CESS was introduced as part of the better regulation reforms. NER clause 6.4A provides that the objective of the CESS is that the only capital expenditure included in the RAB must reasonably reflects the "capital expenditure criteria". Clause 6.4A also provides for the publication of a guideline on the implementation of the CESS.

The NER clauses 6.5.8A and 6A.6.5A of the NER provide that any CESS must be consistent with the capital expenditure incentive objective. In addition, in developing any CESS the AER must take into account the following capital expenditure sharing scheme principles.

- Distributors should be rewarded or penalised for improvements or declines in capex efficiency.
- Rewards and penalties should be commensurate with efficiencies or inefficiencies, but rewards and penalties do not have to be symmetric.
- Interaction of the CESS with any other schemes for efficient opex or capex.
- The capital expenditure objectives and, if relevant, the operating expenditure objectives.

The AER published a Capital Expenditure Incentive Guideline in November 2013.[160] The CESS detailed in the guideline provides a mechanism that rewards distributors for capex efficiency gains and penalises them for capex efficiency losses. Under the Capital Expenditure Incentive Guideline, the AER has proposed a CESS with a symmetric reward and penalty of 30 per cent on cumulative underspends or overspends over the RCP. Under its F&A paper, the AER proposes to apply the CESS to the Queensland distributors in the 2015-2020 RCP.[161] Both distributors agree with this proposal. Energex does not propose any modifications,[162] while Ergon notes its concern about:

- customer Connection Initiated Capital Works expenditure being above or below the expected AER allowances and
- the impact of a decision by the distributor not to apply for pass throughs for events that may meet the threshold but generate capital costs that could contribution to over-expenditure of allowances.[163]

A particular problem with an incentive scheme related to capex is that, unlike for opex, past capex spending patterns provide very little guide to future capex spending requirements. This is because capex spending is:

- discontinuous (as networks age or assets deteriorate there may be some periods where little spending is required and others were significant spending is required),
- lumpy (spending has to occur in large lumps and may result in over-building for a period of time until growth in demand soaks up excess capacity. Spending may take account of demand growth over five or ten year windows); and

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[160] AER, Capital Expenditure Incentive Guideline, 2013.
[161] AER, Framework and Approach Paper, Energex and Ergon Energy 2015–2020, p. 14.
[162] Energex RP, p. 192.
[163] Ergon RP, p. 29, and Ergon RP, *03.01.03 – Application of Incentive Schemes*, pp. 6-10.

- based on highly uncertain demand and peak demand forecasts.[164]

This means that forecasting capex is problematic and thus underspends may just as easily not represent 'efficiencies'.

During the current regulatory period, QCOSS considers that the capex allowance for the distributors was vastly in excess of their requirements. For example, Energex was awarded $6.2458 billion but actually only spent $4.4207 billion (both nominal dollars).[165] Only a small part of this excess allowance could be attributed to changes in the regulatory obligations in July 2014 as they only cover the final year of the 2010-15 RCP and the distributors may have already committed part of the capex for that year under prior, multi-year capex spending programs. Arguably, most of the excess was simply a regulatory error, either around the efficient requirements or misforecasts of demand and peak demand growth, or both.

The key issue in the design of the CESS will be to avoid any errors in the capex allowance, or to ensure that errors are controlled in some way so that distributors do not benefit from underspending that can be attributed to error or changes in regulatory obligations rather than efficiency. For example, with reference to the regulatory obligations for reliability which were adjusted down in July 2014, how would the AER have accounted for this if a CESS had been in place during the 2010-2015 RCP? Would the distributors have been able to retain any savings or would the capex spending allowance have been reduced for the purposes of calculating the incentive payment to carry through to the 2015-2020 RCP? These are the difficult CESS design and implementation issues that the regulator must consider in its assessment of the CESS for the 2015-2020 RCP.

In view of the complexity and potential for error under the CESS, QCOSS would argue for as small a CESS incentive as possible, or ideally no incentive arrangement at all. QCOSS says this even noting that not having a CESS may incentivise the distributors to substitute capex for opex in order to increase rewards under the EBSS.

If a CESS is introduced, then it will be imperative to set the capex forecast for 2015-2020 against efficient and prudent expenditure consistent with best practice rather than improvement on existing practice. Otherwise the Queensland distributors may be rewarded for improving on current inefficient practice compared to SA and Victorian networks. Setting targets consistent with the distributors' current inefficient capex practices would reward them for reducing their level of inefficiency.

6.3.2.3 Service Target Performance Incentive Scheme (STPIS)

The STPIS is designed to reward improvements and penalise reductions in service quality. The rewards or penalties are applied by adjusting the amount of allowed revenue in a year in accordance with the mechanism set out in the distribution determination. The distributors currently receive a maximum reward or penalty of plus or minus two per cent of their annual revenue requirement.[166]

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[164] To give an idea of these uncertainties, even if peak demand could be forecast accurately at an aggregate level, it might not be enough as arguably it has to be forecast accurately at a substation level.
[165] Energex RP Summary, p. 10.
[166] AER, Framework and Approach Paper, Energex and Ergon Energy 2015–2020, p. 14.

NER Clause 6.6.2 provides for the matters to be considered in implementing a STPIS. These include, in particular, a focus on reliability performance.

The AER proposes to apply the STPIS in the upcoming RCP with the same maximum reward or penalty of plus or minus 2 per cent of annual revenue.[167]

Energex and Ergon broadly agree with the AER's proposed approach that the STPIS remain at plus or minus two per cent in the 2015-2020 RCP.168 Energex proposes to adjust the reliability of supply performance targets to correct for performance that exceeded the revenue at risk upper limit and also in view of the downward adjustment in regulatory obligations (following the IRP's recommendations) for a downward adjustment in performance targets.

QCOSS considers that, at present, there is little or no evidence to suggest that Queensland users in aggregate want an improvement in reliability or other service standards in Queensland. This is not to exclude the possibility that those being supplied by the worst performing feeders may want some improvement in reliability. The prevailing evidence from the IRP is that reliability is currently above the levels that customers are willing to pay for at prevailing tariffs. Relevantly, the IRP found that reliability standards are too high and that this is feeding into prices that were:

- well above the point where users were willing to pay for them; and
- causing financial hardship and energy poverty for a significant number of users.[169]

The IRP recommended reductions in regulatory obligations, even while it recognised that the reductions would, over the medium term, *lower* the level of reliability.[170] The Government estimated that the changes would result in reduced reliability levels but that these would be acceptable given the cost savings.[171] The IRP recommended and the State government accepted setting minimum service standards (MSS) as a backstop to a freefall in reliability standards.[172] The findings from the distributors' market research was consistent with the IRP's recommendations.[173]

QCOSS notes that clause 6.6.2(3)(i) provides that the regulator must take into account that any "*benefits [under the STPIS] to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme*" and "*the willingness of the customer or end user to pay for improved performance in the delivery of services*". These provisions clearly contemplate that a STPIS should

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[167] AER, Framework and Approach Paper, Energex and Ergon Energy 2015–2020, p. 14.
[168] Energex RP, p. 193; Ergon RP, 03.01.03 – Application of Incentive Schemes, p. 5.
[169] Independent Review Panel on Network Costs, *Electricity Network Costs Review Final Report*, p. vii. Of course, if prices were lower for a given service quality level, then users might make different choices about whether they would be prepared to pay more for improvements in service quality. However, as the Queensland distributors are offering proposals for the 2015-2020 regulatory control period which essentially maintain current real pricing, QCOSS would expect that users would not support increases in service quality that were accompanied with higher prices.
[170] Independent Review Panel on Network Costs, *Electricity Network Costs Review Final Report*, pp. 39-47.
[171] Department of Energy and Water Supply, Ch*anges to electricity network reliability standards facts*, at https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards/facts, accessed 27 January 2015. The changes in reliability standards were estimated to add 13 minutes to SAIDI for urban customers in 2020 and 30 minutes to SAIDI for rural customers in 2020.
[172] Independent Review Panel on Network Costs, Electricity Network Costs Review Final Report, pp. 42-43 and Department of Energy and Water Supply, Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform, p. 4.
[173] For example, Energex RP, p. 47.

not be applied where users are not willing to pay for the improvements (at prevailing prices) or would not benefit sufficiently to justify rewarding the distributors for improving service quality. A further issue is the extent to which users may wish to see a *reduction* in service standards where this is accompanied by a *reduction* in price levels. The STPIS *could* be re-engineered as a penalty scheme for not *reducing* reliability levels back towards the maximum service levels users are prepared to accept for a given price. As this might be outside the expected implementation of the STPIS, QCOSS is not pursuing this position. The better way to manage down service standards over time where they are above the level that users are willing to pay for is through adjustments in the capex and opex allowances.

As noted above, Energex is proposing to adjust downward the performance targets under the STPIS in recognition of the lower regulatory obligations reflected in lower opex and capex forecasts for the distributors. The problem with this approach is that it will take a number of years for the reduced regulatory obligations to actually result in lower reliability outcomes. The performance outcome from reduced capex and opex lags by a number of years because near-term performance is the outcome of historical spending and associated targets. The Department of Energy and Water Supply recognised the slow drop off in performance following a cut in reliability obligations and spending in their fact sheet on the impact of reduced reliability standards on reliability. The fact sheet forecast that the reduced reliability standards and associated spending programs would result in only a small fall in reliability by 2020 (13 minutes SAIDI for urban feeders) with a larger fall by 2030 (44 minutes SAIDI for urban feeders).[174] QCOSS proposes that the STPIS targets should be around the same as at present for 2015-2016 and thereafter fall gradually so that they reflect the declines in reliability forecast by the Department of Energy and Water Supply by 2020.[175]

6.3.2.4 Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS)

There are insufficient details in Energex's and Ergon's proposals for QCOSS to provide comment.

Recommendation 6.11 ***QCOSS recommends that the AER check the relevant calculations from the Distributors in relation to the incentives, and closely monitor the effectiveness of the schemes in delivering outcomes in the long term interests of consumers.***

[174] Department of Energy and Water Supply, Ch*anges to electricity network reliability standards facts*, at https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards/facts, accessed 27 January 2015.
[175] In other words, the 2015-16 target should be the same as at present, while the 2019-2020 target for say urban feeders should reflect a 13 minutes SAIDI reduction, with the targets between 2015-16 and 2019-2020 to reflect interim targets.

Appendix 1: Technical advice on the regulated rate of return: Engineroom Consulting

1.1 Overall rate of return

The AER sets out a range of factors in the Rate of Return Guideline for assisting in determining the overall rate of return as well as the equity beta, market risk premium, risk-free rate, and return on equity.[176]

Apart from the risk free rate, these parameters are not directly observable and have to be estimated. There are a number of different methods used to do this and this results in a range rather than one definitive "rate of return".

In considering where to set the rate of return (as well as input parameters such as the equity beta), regulators, as a matter of prudency, have set the allowed rate of return above and possibly well above its midpoint estimate or central tendency. The conceptual basis for doing this was recently restated by Frontier Economics in a paper for Transpower NZ.[177] The paper argued that if the allowed rate of return is set too low, the result will be underinvestment by the regulated entity, while if it is set too high, then the result will be under-use of regulated services by users.[178] The paper argued that, given the cost of interruptions to reliability, the costs of under-investment (i.e. lower than optimal investment) were significantly greater than the costs of over-investment (i.e. lower than optimal use).[179]

However, the High Court in *Wellington International Airport & Ors v Commerce Commission* [2013] NZHC 3289 recognised limits to this position when it reviewed the Commission's practice of setting the allowed rate of return at the 75th percentile of the range of estimates. The Frontier paper states that:[180]

> *… the Court commented that neither the Commission nor its advisers had provided evidence required to justify its practice of setting the allowed rate of return by reference to the 75th percentile of the WACC range. The court noted that in 2007 the Australian Competition Tribunal (ACT) had refused an adjustment to the allowed WACC for Telstra to recognise the asymmetric costs of error. [Telstra Corporation Ltd (No 3) [2007] ACompT 3] The Court questioned how using a 75th percentile WACC estimate could be consistent with sub-section 52A(1)(d) of the Commerce Act and suggested a 75th percentile WACC estimate was "unlikely to be necessary to promote incentives to invest and innovate" (para [1479]).*

176 AER Rate of Return Guideline, p. 14.

177 Frontier Economics, Evidence in support of setting allowed rates of return above the midpoint of the WACC range - A Report Prepared For Transpower New Zealand Ltd, March 2014.

178 Frontier Economics, Evidence in support of setting allowed rates of return above the midpoint of the WACC range - A Report Prepared For Transpower New Zealand Ltd, March 2014, particularly at pp. 7-18.

179 Others have argued that setting the WACC too high is self-correcting as new competitors enter the market – For example Telstra in Telstra Corporation Ltd (No 3) [2007] ACompT 3 at para 441. However this argument is weak in relation to a natural or near natural monopoly: Telstra Corporation Ltd (No 3) at para 445.

180 Frontier Economics, Evidence in support of setting allowed rates of return above the midpoint of the WACC range - A Report Prepared For Transpower New Zealand Ltd, March 2014, p. 1.

Following the case, the Commerce Commission has decided its allowed rate of return from the 75th to the 67th percentile, noting the Court's view that:[181]

> *... the use of the 75th percentile was not supported by sufficient evidence, and might be at odds with the Part 4 objective to limit the ability of regulated suppliers to earn excessive profits.*

The Wellington International Airport cited the Telstra case, which was decided by the Australian Competition Tribunal.

In the Telstra case, Telstra advocated for a WACC above the midpoint estimate. The Tribunal found that:

- The assumption that a WACC that was too low would deter investors may not be correct given the different risk preferences of different investors. More generally, setting the WACC too low would more likely lead to a limited reduction in investment rather than a cessation.
- The midpoint estimate was likely to represent the appropriate WACC;
- The onus lay on the regulated entity to demonstrate that the midpoint estimate did not represent an appropriate WACC; and
- The evidence that needed to be provided by the entity had to be compelling.

The Tribunal in the Telstra case said:

> *452 Telstra assumed that setting a WACC that was too low would deter investors. However, different investors will inevitably have different attitudes to risk. Setting the WACC below the true value may deter some investors and therefore result in less investment taking place in the short run, but it will not be likely to cause all investors to cease providing funds. Of course, the service provider might be forced to cut back on maintenance or service quality if it perceived the return on these investments to be too low, but no evidence was advanced by Telstra that consumers' valuations of different levels of quality was asymmetric. It is possible, at least in theory, that consumers might value lower quality, or less innovation, that might follow from less than efficient levels of investment no differently than they value the surplus lost from greater-than-efficient quality, or wasteful innovation, that could arise from too much investment.*
>
> *468 ….we regard an estimate of the true WACC value, if it has been arrived at through a statistically-unbiased estimating process, as representing a figure that, on average, in the long-run probabilistic sense in which all such estimates should be considered, would yield the true expected value of the variable in question. To add an amount artificially to such an estimate would in this correct statistical sense result in too high an estimate of the true average of the variable in question, in this case the WACC. …*

181 Commerce Commission NZ, Media Release - Commerce Commission reduces the margin that it applies to regulated businesses' cost of capital, 31 October 2014.

> *470 …. In the absence of compelling economic and statistical evidence, we do not consider that it is reasonable to account for such errors using a single (and arbitrary) error calculation. In our opinion, the reasonable approach would be to consider the error involved in estimating each of the individual component parameters and from this derive a reasonable estimate of the range in which the true overall WACC value would be accepted to lie.*
>
> *472 … a more robust demonstration in terms of empirical justification and acceptability both commercially and in terms of rigorous academic support would be necessary.*

Engineroom considers that a key point from this analysis is that the cost of a WACC below the appropriate level is likely to be mild. Rather than reduction in investment like a sheer cliff, the reduction was likely to be at the margin from investors with the highest risk attitude. This response was likely be similar to the response from consumers if the WACC and resulting prices were too high – not an absolute cessation of use but a small reduction in use compared to the optimal situation.

The Tribunal's approach also suggests that any distribution of allowable WACCs is likely to be normally distributed and as such any adjustment from the midpoint should be small. The Tribunal noted that an adjustment of one standard deviation as put by Telstra was well outside the 95 per cent confidence interval.[182]

The Wellington and Telstra cases reflect the reasonable limits of the argument for favouring over-investment to under-use of the network. At a point, that favouritism moves away from the overall objective of setting a benchmark efficient WACC.

In fact, analysing the legal directive in the NEO and the NER, it is arguably not permissible for the regulator to set the WACC (or inputs to the WACC such as the equity beta) above a benchmark efficient level given:

- The NEO aims to promote investment only to the extent that it is efficient; and
- NER clause 6.5.2(c) provides for the rate of return to be set commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk.

The only argument to support a rate of return above the midpoint in light of the requirements in the NEO and the NER might be to cater to uncertainty in the measurement of the midpoint estimate, but this argument fails to recognise that the midpoint estimate itself incorporates the uncertainty in the range of estimates.

ENGINEROOM is not specifically aware if the AER has legal advice on whether if it identifies a midpoint or most likely estimate for the appropriate rate of return, whether it can reasonably set a rate of return higher than this point. Ultimately, it is a question for the regulator to determine if it is consistent with the NEO and NER or conceptually sensible to select a value above the midpoint, particularly in the absence of compelling evidence.

The view that parameters should be set at their midpoint has a significant bearing also on the selection of input parameters to the WACC, such as the point estimate for the equity beta and the value for the market risk premium. In relation to these inputs, selecting a value above the midpoint is questionable for the above reasons

[182] Telstra Corporation Ltd (No 3) [2007] ACompT 3, at paras 458-468.

as well as it distorts the estimate of the WACC. In other words, if each of the input parameters are set at the top end of their range, then the resulting range of WACC values will be well above its reasonable range and the selection of a midpoint within the resulting WACC range of values will be well above a reasonable value.

To the extent that the Telstra case could be argued as authority for the proposition that it is permissible to select a point other than the midpoint value within a range, then it could be construed as putting the onus on the regulated entity to make a compelling case for a higher value.

Certainly, ENGINEROOM's view is that Energex and Ergon have not, as required by the Telstra case, made a **compelling** case to adjust the allowed rate of return above a midpoint range.

In fact, there is a **compelling** case for selecting a value in the WACC range that is below the midpoint estimate.[183]

As postulated earlier, a rate over a reasonable rate of return might result in under-utilisation of the network, as well as a cycle of rising unit costs and falling demand. Looking at recent outcomes, this is exactly what can be observed. We have presented evidence in the capex chapter of the submission of this trend to over-investment, including:

- The sharp fall in the utilisation rate of assets;
- The sharp increase in the assets used to meet each KVA of peak demand;
- The sharp increase in the assets per customer; and
- The sharp fall in the delivered energy per $m of assets.

This evidence is supplemented by the observation that chapter 6 of the NER historically embedded a favouritism for over-investment, particularly in the setting of the equity beta at 1.0 for transmission networks and the NSW/ACT distributors, which is unarguably over its real value and above the value proposed by the distributors themselves. The value of 0.8 used by the AER to set the equity beta more recently is also above the value that the AER considers appropriate.[184] All else being equal, this artificial uplift in the equity beta compared to its best value in the range 0.4 to 0.7 would induce over-investment.[185] Moreover, the pronounced reduction in usage of electricity network since 2010 after more than 50 years of constant expansion in use is consistent with a pattern of over-investment driving usage below optimal levels.

The NEL at section 7A(6)-(7) direct the regulator to this consideration where they provide that the regulator should have regard for the potential both for under and over-investment by the regulated entity and for under or over-use by users. The rules as drafted provide for an even-handed or agnostic assessment of the impacts of under-use against under-investment and towards ensuring against future under-use (under-investment) depending on the balance of risks prevailing at the time of the regulatory decision. This is reinforced by the requirement in the NEO in section 7 to focus on the sustainable long-term interests of consumers. It is not in the interests of users (or distributors) for distributors to have a rate of return over a reasonable level leading to over-investment in the short term and lower use in the

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183 Compare Telstra Corporation Ltd (No 3) [2007] ACompT 3, at for example, paras 429-432 and 469-472.

184 Compare AER, Appendices to Explanatory Statement, Rate of Return Guidelines, pp. 75-76.

185 This assumes distribution networks have not become significantly *less* risky since the equity beta was set at 1.0 or 0.8, but there is no real evidence to support that view.

longer term. This is because network businesses critically rely on economies of scale to bring down the unit costs of transportation services on their networks. The Frontier paper presented an argument that the specifics of use of networks are such that under-investment will be costly due to the high cost of unserved energy. This ignores the high cost to networks of under-utilisation, given the very high returns to economies of scale.[186]

In circumstances of historical over-investment, the downside risks from under-investment are low, while the downside risks from continuation of parameters that encourage over-investment are high. In these circumstances, ENGINEROOM argues that, to the extent the regulator considers it has the discretion to set a WACC away from its central estimate, then it should select a WACC below the midpoint range. This would correct for the observed historical over-investment in the network, which has been driving under-utilisation of the network.

1.2 Benchmark efficient entity

ENGINEROOM would question the definition of the benchmark efficient firm as a “pure play, regulated energy network business operating within Australia” without a parent organisation.[187]

ENGINEROOM considers that the definition of a benchmark efficient firm should take account of its corporate parentage. In the Explanatory Statement to the Rate of Return Guideline, the AER identified that having a parent organisation is an advantage to regulated entities:[188]

> *Today all regulated energy entities in Australia have parent ownership. Furthermore, there is evidence that credit rating agencies consider the parent ownership in assessing ratings. Parent ownership presents a different risk profile to an assumption of no parent ownership. An example of this is where the parent is able to influence negotiations to secure good terms, which results in a material decrease in the network entity’s refinancing risk. Frontier identified that efficiencies may be available to the parent via scale economies associated with largely fixed issuance costs, access to markets with minimum issuance size requirements, pooling of risk across subsidiaries achieving internal diversification, lowering default risk and so borrowing costs*. (footnotes omitted)

ENGINEROOM considers that the benefits of having a parent should be taken into consideration as a material factor given it reflects unanimous corporate practice, is considered by rating agencies in assigning credit ratings (which reflect in turn on the cost of both equity and debt), confers benefits, and should be measurable.

1.5 Consistency among WACC parameters

The Better Regulation program provided the AER with more flexibility to address the setting of the WACC by providing more flexibility to the AER to exercise its discretion in the long-term interests of consumers when assessing the WACC, subject to the

[186] While a revenue cap may guarantee revenues for a period even in the face of falling usage, in the longer term such a situation is clearly not viable. The NEL and NEO focus on the long term.
[187] AER, Rate of Return Explanatory Statement, pp. 36-47.
[188] AER, Rate of Return Explanatory Statement, pp. 35-36.

National Electricity Objective, the rate of return objective in the NER and the revenue and pricing principles in the National Electricity Law (NEL).

The Australian Competition Tribunal's processes were reformed to highlight that its decisions had to take a holistic approach to decisions on aspects of the WACC in order to prevent distributors selectively contesting certain WACC parameters while not contesting another parameters which might be generous to the distributor. The December 2013 reforms were designed to show that the Tribunal must take into account the broader impact of its decisions on consumers' long-term interests.[189] SCER's policy intent behind the reforms included:[190]

> *clearly link the intent of the original decision and review processes, to ensure a common focus on outcomes that are in the long term interests of consumers - consistent with the National Electricity Objective (NEO) and the National Gas Objective (NGO) and the revenue and pricing principles;*
>
> *[and]*
>
> *clarify the matters that may be raised by parties to a review, including allowing raising of inter-linked matters to the extent they are relevant to whether a materially preferable decision exists;*

This is reinforced by the NER, which adopts identical wording in providing that the AER in setting the WACC must have regard to any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.[191]

These policy objectives and the NER provisions highlight that the WACC parameters must be considered in a holistic way rather than as a set of independent drivers which simply 'come together' to provide a value for the rate of return after separate determination. In particular, the policy intent of clarifying that *inter-linked matters must be considered* highlights that the overall responsibility of the AER and the Tribunal is to ensure that the overall WACC meets the NER. Clause 6.5.2(e)(3) in this regard provides for the regulator to have regard to "any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt."

The Guideline is inconsistent with the NER and policy framework in the sense that it focusses on setting values for each of the WACC parameters and does not look at the inconsistency in the values assigned to those parameters.

Specifically:

- The implied risk levels associated with the different parameter values and inputs are inconsistent with each other; and
- The overall WACC as a product of the upper end of the range of a number of parameters lies outside the range of 'plausible' WACC values.

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[189] The NEL was amended in December 2013, following an extensive and rather critical review of the operation of the Tribunal, and its decisions which reflected a narrow focus on legal issues rather than the overall NEO.
[190] EMRWG Bulletin #21,http://www.scer.gov.au/workstreams/energy-market-reform/limited-merits-review/
[191] NER clause 6.5.2(e).

The AER Rate of Return Guideline proposes a set of values and inputs for WACC parameters. These were largely confirmed in the NSW Draft Determination 2014-19.[192] The values are set out in Table 1 below.

Table 1: AER WACC parameters

Parameter	AER proposed position
Rf	Yield on CGS 10 year term 20 business day averaging period as close as possible to the start of the RCP
Equity beta	Range of 0.4 to 0.7 Point estimate of 0.7 based on observations from overseas networks and the Black CAPM Value of 0.7 used in the NSW Draft Determination
MRP	Not specified but a value of 6.5 per cent used in the NSW Draft Determination
Debt to equity	Not specified but value of 60 per cent debt to 40 per cent equity used in the NSW Draft Determination. The AER has typically applied an equity to debt ratio of 40:60, meaning that it assumes the asset base is 40 per cent equity and 60 per cent debt.
Re	the outcome of the Re formula should be rounded to the nearest 0.25 per cent
Rd	Trailing average of 10 years with equal weights per year and automatic updating BBB+ credit rating 10 year tenor Set based on 10 or more consecutive business days up to a maximum of 12 months and fixed in advance of the RCP
Gamma	Payout ratio of 0.7 Utilisation rate of 0.7 Derived gamma of 0.5

Note: this is not intended to be a comprehensive summary of all of the AER's proposed positions in the Rate of Return Guideline.

ENGINEROOM view is that there is a lack of consistency between the assumed Standard and Poor's debt credit rating of BBB+ and the equity beta of 0.7 and the equity to debt ratio of 40:60. For example, a Standard and Poor's rating of BBB+ is not far above junk bond status and it describes BBB as:[193]

> *An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.*

A credit rating of BBB+ is considered lower medium grade. This credit rating is not consistent with a firm with:

- An equity beta of 0.7 (which is, relative to the market, considered low risk),
- High cash flow certainty of a revenue cap,
- The ability to engage in annual revisions of the debt allowance, and a

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[192] AER Rate of Return Guideline, December 2013, and AER, Draft decision: Ausgrid distribution determination 2015–16 to 2018–19 - Overview, November 2014

[193] Standard and Poor's website, at https://www.globalcreditportal.com/ratingsdirect/renderArticle.do?articleId=1331219&SctArtId=257653&from=CM&nsl_code=LIME&sourceObjectId=5435305&sourceRevId=7&fee_ind=N&exp_date=20240818-02:07:33, Accessed 6 January 2015.

- Relatively conservative gearing ratio of 60 per cent.

This would suggest that either the credit rating of BBB+ or the equity beta or both are wrong. ENGINEROOM considers the credit rating of BBB+ is irreconcilable with the other values and inputs in the AER Rate of Return Guideline. A more compatible credit rating would be likely to be A-, the middle of the medium upper grade.

1.6 Selecting the most appropriate model for determining the cost of capital

The Better Regulation program led to a debate about the most appropriate model for determining the cost of capital.

The AER Rate of Return guideline selected:

- the Sharpe-Linter capital asset pricing model (SL CAPM) as the foundation model;
- the Black CAPM to assist in the selection of the equity beta;
- the dividend growth model (DGM) to assist in the selection of the market risk premium (MRP);[194]
- the AER also proposed to use the Wright approach to inform the return on equity; and
- a range of market information and other regulators' estimates to further inform the MRP or return on equity.[195]

While ENGINEROOM broadly agrees with the AER's view in the Rate of Return Guideline that the S-L CAPM is transparent, well supported by theory, and well-understood, it is concerned that the AER's new approach in practice increases the complexity and uncertainty of selecting the appropriate value for the cost of equity. Moreover, the approach leads to "cherry picking' of different models where the distributors will choose models that provide them with the highest rate of return for a given RCP. This approach allows for the use of multiple models and approaches (specifically, the following four - SL CAPM, Black CAPM, DGM, Wright approach) in determining various parameters or the overall return. ENGINEROOM is concerned that the mix of models opens up opportunities for such gaming because:

- these models have different conceptual bases or assumptions to the SL CAPM and may not be compatible with it
- the use of a number of different model increases the opportunities for gaming as distributors can vary the weight that they put on the models from one RCP to another
- the use of other models also requires that the models are reasonably consistent with the SL model in their input terms and assumptions.

To demonstrate this point further, consider that the Wright approach[196] effectively adjusts the rate of return in a counter-cyclical way to the current economic cycle. This arguably embeds gaming, by stabilising returns on equity over the economic cycle, as it inflates returns on equity at times of low returns and deflates returns at times of high returns. At present, the distributors having come from a time of high returns on equity towards low returns will favour the Wright approach in this RCP. McKenzie and Partington and Lally cast doubt on the Wright approach, and in

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[194] AER, Rate of Return Guideline, p.13.
[195] AER, Rate of Return Guideline, p.14.
[196] The Wright approach assumes a (relatively) constant return on the market. This leads to an assumed higher rate of return in weak markets and a lower rate of return in strong markets.

particular its assumption of a perfectly negative correlation between the risk-free rate and the market risk premium, while CEPA did not find evidence that supported the Wright approach.[197]

ENGINEROOM does consider that the historical approach under the Sharpe-Lintner model was reasonably predictable and transparent. This reduced opportunities for distributors to cherry-pick outcomes, which was a central concern expressed by policy-makers and stakeholders. For example, PIAC noted in its submission to the NSW Draft Determination that the distributors had engaged in cherry-picking:[198]

> *There was clear evidence of changing approaches by the networks depending on the outcomes of each approach at the time of the determination. For example, in the past, DNSPs and the AER have proposed various sources of data to obtain a 10-year bond rate, such as Bloomberg extrapolated, CB Spectrum, the average of both, a weighted average of both and so on. Generally, the combination that provides the highest or near highest outcome at that particular time is the one that appears to be pursued most vigorously by the proponents.*
>
> *…a different combination of weightings of modelled outcomes might be applied with the aim of achieving on higher cost of equity. In fact, the Tribunal said as much with respect to an appeal by a NSP, APA GasNet. APA GasNet challenged the AER's decision not to use the results of the DGM in determining the cost of equity/MRP. In rejecting APA GasNet's appeal, the Tribunal noted that the DGM had on occasion produced very low estimates ('just above 2 per cent'),176 and expressed its doubt whether the networks would be prepared to use the DGM on those occasions, or only when the outcome was a much higher figure and better suited to the networks' 'end purpose'. (footnotes omitted)*

1.6.1 SL CAPM bias against low beta stocks

Despite the above comments ENGINEROOM has some concerns about the operation of the SL CAPM in relation to low beta stocks.

The SL CAPM model used by the AER assumes that the equity beta measures the systemic risk of that stock compared to the market average and thus accounts for the return for a given stock. In other words, the AER model assumes that a stock with a low equity beta should require a lower return than the stock market average while a high equity beta stock should require a higher return than the stock market average.

However, evidence suggests that low-beta stocks in fact perform better over time on a risk-adjusted basis than high-beta stocks. For example, a number of papers identify Warren Buffett's successful investment strategy as built on favouring low-beta stocks and leveraging to invest in them.[199] These papers build on earlier work in this area such as Black (1972) and Black, Jensen, and Scholes (1972). For example, Black, Jensen, and Scholes find that:

[197] AER Rate of Return Guideline, Explanatory Statement, pp. 24-26.
[198] PIAC, *Submission to NSW Draft Determination*, footnote 160, pp.73-74, and p. 77.
[199] Frazzini, A. and L. H. Pedersen (2013), Betting Against Beta, Journal of Financial Economics 111 (2014), 1-25; and Frazzini, Andrea, David Kabiller, Lasse H. Pedersen, Buffett's Alpha, NBER Working Paper No. 19681, November 2013.

> *…work done by Miller and Scholes suggests that the alphas on individual assets depend in a systematic way on their betas: that high-beta assets tend to have negative alphas, and that low-beta stocks tend to have positive alphas.*[200]

Black, Jensen, and Scholes test the returns on low beta stocks against high beta stocks and find that:

> *The tests indicate that the expected excess returns on high beta assets are lower than (1) suggests and that the expected excess returns on low-beta assets are higher than (1) suggests. In other words, that high-beta stocks have negative alphas and low-beta stocks have positive alphas.*[201]

Frazzini, Kabiller, and Pedersen (2013) apply a range of additional tests against a broad range of market data to determine whether low-beta stocks consistently outperform expectations, or in the parlance of their paper have a Sharpe ratio above 0. They confirm the earlier hypothesis of Black, Jensen, and Scholes. In another paper, Frazzini and Pedersen (2013) find that "A betting-against-beta (BAB) factor, which is long leveraged low beta assets and short high-beta assets, produces significant positive risk-adjusted returns".[202]

On any measure, electricity distribution activities have an equity beta significantly lower than the market average of 1.0, with the AER's work indicating that the equity beta of electricity distribution lies in the range 0.4 to 0.7. The above findings would suggest that the returns for low-beta stocks such as Energex and Ergon should be adjusted to reflect the excess returns enjoyed by low beta stocks over high beta stocks. This view also strongly militates against the use of the Black CAPM to set parameters in the WACC, as the Black CAPM sets a higher reward than the SL CAPM (discussed further below).

ENGINEROOM support retention of the SL CAPM model for determining the cost of capital but propose a downwards adjustment to the SL CAPM to cater to the upwards bias in the SL CAPM for low beta stocks. The downwards adjustment should be based on market observations of the Sharpe outperformance of low beta stocks. The AER would need to decide whether to rely on Australian stock performance only or refer more broadly to international observations.

1.7 Equity beta

1.7.1 Introduction

The equity beta for a firm or industry adjusts the market risk premium calculated for the market as a whole for the relative risk of the firm or industry.

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[200] Black, F., M.C. Jensen, and M. Scholes (1972), *The Capital Asset Pricing Model: Some Empirical Tests*. In Michael C. Jensen (ed.), Studies in the Theory of Capital Markets, New York, pp. 79-121, republished at http://fi.qu.edu.az/~faliyev/ibdia/capm.pdf, p. 3. The page numbering is taken from the weblink version.

[201] Black, F., M.C. Jensen, and M. Scholes (1972), *The Capital Asset Pricing Model: Some Empirical Tests*. In Michael C. Jensen (ed.), Studies in the Theory of Capital Markets, New York, pp. 79-121, republished at http://fi.qu.edu.az/~faliyev/ibdia/capm.pdf, p. 4. The page numbering is taken from the weblink version.

[202] The paper finds that this outcome is partly but not fully explained by leverage.

The distributors themselves acknowledge that electricity utilities face a much more stable business environment than the market as a whole given their monopoly status, the relatively less elastic demand for their services, and their cash flow predictability. This is evidenced, as noted by PIAC by the way in which distributors present themselves to investors, that is:[203]

- Being regulated monopolies with high barriers to entry;
- Providing stable long-term regulated cash flows; and
- In addition, the revenue cap arrangements essentially guarantee the level of revenue that the distributors will earn.

The coming regulatory period is even less risky compared to the 2010-2015 RCP. This is because the AER has issued guidelines around a range of issues which provide certainty to investors and owners of the regulated assets. Additionally, the cost of debt will be updated annually, reducing exposure to the cost of debt prevailing at any given time. Under the revenue cap to be applied, energy usage risk will be borne by consumers. The AER has also identified that its approach to setting the return on equity is likely to "promote a more stable return on equity over time".[204]

During the Better Regulation program, the AER commissioned two studies on the types of risk that should be considered in determining the equity beta – by McKenzie and Partington, and Frontier Economics.[205] These studies suggested that the equity beta for the Australian regulated networks was well below one, reflecting the very low risks of the regulated network businesses compared to the market as a whole. For example, McKenzie and Partington talk about the generally acknowledged "low default risk in regulated utilities". Prior to the Better Regulation program, the AER commissioned Professor Olan Henry to review the equity beta and update his earlier 2009 paper to the regulator. However, Professor Olan had not completed his 2014 report when the AER was require to finalise its rate of return guideline. His study included multiple analyses of Australian utility data returns.[206] Based on these studies, the AER concluded that the equity beta, supported by extensive empirical analysis, fell within the range 0.4 and 0.7.

The AER Guideline set the beta at the top of this range, that is, at 0.7. Professor Olan's work suggested that the best value for beta was between 0.5 and 0.6 (representing the median of the various analyses).

The distributors in their regulatory proposals have argued for a beta of 0.91, specifically relying on a report by SFG Consulting.[207] The sample which SFG uses to determine this value is significantly weighted to US stocks which are subject to very different operating and market conditions. The SFG also applies a range of approaches and then applies an arbitrary weighting to the different approaches to arrive at this value. The weighting applied to the value from the SL CAPM model is the lowest of the weightings.

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[203] Extract from SP AusNet, 2014, Full Year 2014 Results for the financial period ended 31 March 2014, 5. Similar statements are made to investors by other regulated utilities.
[204] AER Rate of Return Guideline – Explanatory Statement, p. 38.
[205] Frontier Economics, 2013, Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia, a report prepared for the AER, and McKenzie M and G Partington, 2013, Report to the AER: Risk, Asset Pricing Models and WACC.
[206] O T Henry, 2009, Estimating Beta.
[207] Energex RP at p.165; Ergon RP, p.123.

We consider the criticisms of the SFG study by PIAC that:[208]

- The SFG study found the median of the Australian values was significantly below 0.7.
- The US data set displayed a very different distribution and higher set of values
- The SFG study provided little or no explanation for its strong weighting towards the US entities and data.
- If overseas data was to be used, then why was UK, NZ, or other comparable data not used?

ENGINEROOM considers that the equity beta should be a value between 0.5 and 0.6 which it considers represents the most appropriate outcome of the empirical studies and is consistent with the McKenzie and Partington and Frontier reports that the risks of the regulated network businesses are significantly less than the risks in the market as a whole.

It is noted that while the distributors are advocating for the equity beta to include overseas data, at the same time the distributors do not suggest incorporating overseas bond rates into analysis of the cost of debt even though the Queensland Distributors borrow in international markets through the QTC as part of their capital management strategies.

1.7.2 Range of betas

The AER compiled a list of equity betas based on studies before it. Subsequent to the AER's work, Henry produced a 2014 report updating his 2009 study. Professor Henry's 2014 report found:[209]

> *… the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate of β lies in the range of 0.3 to 0.8. …within the range of 0.3 to 0.8 the average OLS [ordinary least squares) estimates for the individual firms reported in Table 2 is 0.5223 while the median estimate is 0.3285.*

Recent and well-respected studies in relation to Australian firms are presented in Table 2 below.

Table 2: Selected observations of equity betas

Study	Range	Average	Median	Source
Henry 2014 Table 2	0.3 - 0.8	0.5223	0.3285	Henry 2014, p. 63
ERA 2013 Monthly	0.07 - 0.97	0.46	0.43	AER EM, pp.55-56
ERA 2013 Weekly	0.22 - 1.34	0.5	0.43	AER EM, pp.55-56
SFG 2013 – Australian firms only – equal weight indices	0.27 - 1.13	0.55	Not specified	SFG June 2013, pp. 12-15

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[208] PIAC submission to NSW Draft Determination, pp.78-79.
[209] Ibid, 63. It is interesting to see that SFG and CEG consider that the study supports a higher equity beta, See for example, SFG, 2014, Equity Beta, 27-28. However, this is not what Professor Henry concludes from his study as cited above.

In its 2013 study, SFG also compiled equity betas for 56 US firms. It is interesting to note the consistent wide discrepancy between the Australian and US beta observations over a wide range of timescales and data samples, especially in terms of their central tendency but also in their range.[210] This would suggest that the US and Australian data are not comparable, as the difference must be explicable in terms of differing tax, regulatory, corporate structure, market, or other factors. This lends weight to the view that overseas data should not be considered in determining equity beta.

The AER has argued for a range of 0.4 to 0.7 for the equity beta. Arguably the Henry 2014 report supports a lower range with an average of 0.5223 and a median of 0.3285. The median value in that study in particular lies outside the bottom end of the AER's range, while the mean average is in the lower half of the AER's range. The median value has the advantage of excluding the effects of outliers. At the very least, it would be expected that the AER should set a range which incorporates the median observation of the Henry study. To account for this we would recommend a range of 0.2 to 0.7, noting that the bottom half of the observations lie between 0.2 and 0.4.

1.7.3 Selecting the point estimate for the equity beta

ENGINEROOM considers there needs to a more transparent debate about where the equity beta is set in the relevant range of estimated equity betas. The debate could be similar to the debate that has occurred in NZ around setting the WACC within a range. The debate should involve analysis of the distribution of observations and how to select the equity beta within a range. The international evidence from NZ and the UK reviewed by Economic Insights in relation to the selection of WACC within a range of plausible estimates was unequivocal that the very top end of the range is very rarely selected by the regulator.[211] While a responding report from Frontier Economics may have had some valid criticisms of the approach taken by Economic Insights, Frontier's analysis pointing to a number of estimates higher in the range in the UK conveniently ignored the fact that UK ranges are much narrower than NZ ranges and that, provided with a narrower range of uncertainty the regulator may have been more willing to select a value more towards the top end of the range.[212] In other words, if the UK regulators identify a much tighter range, then they may be more willing to select a value at the top end of the range.

Such a debate would illuminate some critical issues such as:

(i) The implicit assumptions in the selection of a value within the range. As discussed earlier, one prevalent assumption that is often made is that the cost of under-investment is higher than the cost of over-investment. However, that assumption needs to be proved and may not hold true in a number of circumstances. In fact, a contrary position may be true justifying the selection of a lower value. For example, do the assumed conditions for deciding that the cost of under-investment outweigh the costs of over-investment actually hold at present in Australia? Or in fact

[210] SFG, Regression-based estimates of risk parameters for the benchmark firm, June 2013, pp.12-15.

[211] Economic Insights, Regulatory Precedents for Setting the WACC within a Range, 16 June 2014, pp. v- viii.

[212] For example, see Figure 1 in Frontier's report at page 7: Frontier Economics, Regulatory Precedents for setting the WACC within a range, July 2014.

are the conditions of weak demand supportive of the view that the costs of over-investment may outweigh the costs of under-investment at the present time.

(ii) Is it reasonably to adjust for outliers or examine the reason that they are outliers? Outliers may distort the range. Is it more appropriate to examine the central tendency of the group than define a range? Is there an even distribution of values or are there two distinct populations? For example Henry's (2014) report appeared to find two distinct populations of equity betas.[213] This is an important debate as equity betas can be quite unstable in terms of ranges if measured on a weekly versus monthly basis but may tend to have the same central tendency across both timescales.

(iii) How representative is the range? For example, in Australia the list of publicly traded pure energy plays is weighted towards gas companies, since gas have traditionally been delivered by private players while electricity has traditionally been delivered by public entities. Gas arguably is riskier than electricity which could bias the equity beta towards a higher value.

(iv) Is the range normally distributed such that selecting a value at the top or bottom end of the range is statistically 'extreme'? This was the position taken by the Tribunal in the Telstra case, and in NZ, although not necessarily in the UK.

After applying the SL CAPM and drawing on the analysis in Henry 2009 and subsequent studies including SFG 2013, the AER identifies the equity beta should be in the range 0.4 to 0.7. The AER then turns to the question of what value it should select within that range.

Discussing the use of foreign data to determine the equity beta, the AER state:[214]

> *The use of a foreign proxy is a suboptimal outcome. It should only be used where there is evidence that this will produce more reliable estimates of the domestic equity beta than the Australian estimates themselves. We consider service providers and their consultants have not established reasonable basis to conclude that US data should be used in place of Australian data.*

The AER further notes:[215]

> *If the systematic risk of the market portfolio in Australia is higher than that of other countries, then international comparators may produce upwardly biased estimates when used in Australian context.*

The AER states that its choice of equity beta at the top end of the range has been is selected by reference to the Black CAPM and to international observations of equity betas. Nonetheless, with respect, it is difficult fully to understand in practice the way

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[213] Henry, Olan T., Estimating Beta: An Update, 2014, Table 2, p. 17.
[214] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.60.
[215] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.60.

in which the AER used international observations and the Black CAPM to select the value of 0.7.

The Black CAPM modifies the SL CAPM by using a zero beta rate in the CAPM formula instead of a risk-free rate. This is said to address one of the weaknesses in the SL CAPM which is the assumption in the SL CAPM that investors can borrow or lend limitlessly at the risk-free rate.[216] The Black CAPM instead assumes "that investors can access unlimited short selling of stocks, with the proceeds immediately available for investment".

The AER notes that "[e]ither of these assumptions might correctly be criticised as being unrealistic, and it is not clear whether the replacement assumption is preferable".[217]

The problem with the Black CAPM is however, that it then requires not only the determination of an unobservable equity beta, but also an unobservable zero equity beta.

In relation to the Black CAPM, the AER notes that it produces a flatter curve with a higher y-axis incept than the SL CAPM since the zero beta is above the risk-free rate. This is said to provide higher returns to low beta stocks and lower returns for high beta stocks.[218]

Examining the international data, the AER states:[219]

> *Although we have concerns with the equity beta estimates derived from international comparators, we have considered the US empirical estimates as well as other international estimates before us. They range from 0.5 to 1.3. Recognising the inherent uncertainty caused by the inability to quantify differences between the US and Australia, we consider the analysis of overseas energy networks support the choice of a point estimate in the upper end of our range.*

The AER also states that "…our proposed point estimate of 0.7 is not inconsistent with our consultants' [McKenzie and Partington's] advice".[220] However, it is difficult to see that this is the case. In fact, McKenzie and Partington state a preference for a beta 'among the lowest possible'.[221]

ENGINEROOM considers that the Black CAPM should not be used to select a point value for the equity beta because:

- there are difficulties in its implementation, and its results suffer from poor credibility;
- it introduces an additional unobservable factor that has to be estimated (the zero equity beta);
- it provides little guidance on the point estimate of the SL CAPM model;

216 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.68.
217 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.68.
218 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.72.
219 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.64.
220 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.76.
221 AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.76.

- there is no logical consistency between the SL CAPM model and the Black CAPM model, meaning that using one model to adjust the results of another does not make sense;
- in practice, low beta stocks are arguably over-rewarded for risk compared to high beta stocks, which is the reverse of the assumption made in the Black CAPM model; and
- it has not been used by a regulator elsewhere in the world. The McKenzie and Partington report notes that: … to the best of our knowledge, there has not been a regulatory body that has relied on the Black CAPM to estimate the cost of equity. [222]

McKenzie and Partington's report for the AER provides a good high-level set of reasons for rejecting the use of the Black CAPM model to help to determine the equity beta.[223]

> *A problem with the Black CAPM is that the assumption made about the proceeds of short selling does not accord with how the stock lending markets work... In the real world, short sellers are required to post collateral when lending stock in the form of cash and/or equity. As this key assumption to the Black model does not hold, the efficiency of the market portfolio is again lost. As noted by Markowitz (2005, p.19), these departures of efficiency can be considerable and the market portfolio can have almost maximum variance among portfolios with the same expected value. In this case, there is no representative investor and expected returns are not linear functions of risk.*
>
> *The near universal practice in measuring the risk premium/excess returns is to benchmark using the risk free rate as proxied by the yield on a government security. The widespread nature of this approach suggests that there are good reasons to prefer the risk free rate as the benchmark. As we subsequently demonstrate there are indeed good reasons to prefer the risk free rate. Using the yield on a government security as a proxy for the risk free rate is generally accepted. The measurement of the yield is relatively simple and transparent. The input variables can be readily observed and error in the measurement of the resulting yield is little or nothing. In contrast, there is no generally accepted empirical measurement of the zero beta return in the Black CAPM. This is because the empirical measurement of the zero beta return is neither simple, nor transparent. There are many possible zero beta portfolios that might be used and the return on these portfolios is not directly observed, but has to be estimated. In the estimation process for the zero beta return, there are also inputs that cannot be observed and they too have to be estimated. The resulting estimate of the zero beta return is sensitive to the choices made in regard to the input variables and methods of estimation. As a result the measurement error can be large and the result ambiguous.*

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[222] McKenzie and Partington, DGM final report - rate of return guideline, December 2013, p.26.
[223] McKenzie and Partington, DGM final report - rate of return guideline, December 2013, pp. 25 -26.

Many of these shortcomings have been recognised by the AER in its commentary on the Black CAPM in the Appendices to the Rate of Return Guideline.[224]

> *The Black CAPM requires the estimation of three parameters — the return on the market portfolio, the return on the zero beta portfolio, and the equity beta. 45 The estimation of the return on the market and zero beta portfolios, however, is complex. Moreover, estimates of the return on equity from the Black CAPM are highly sensitive to these inputs.*
>
> *NERA's report demonstrates that the estimation of parameters for the Black CAPM is not sufficiently robust such that the model could be implemented in accordance with good practice. Further, the sensitivity of the model to estimates of both the zero beta and market returns (especially given the difficulties in robustly estimating these parameters) represents a fundamental limitation of the model. Given the abovementioned limitations, it is informative to also consider the use of the model by regulators and academics. To our knowledge, the Black CAPM is not used by other regulators (either domestically or internationally), academics or market practitioners to estimate the return on equity.*

If, as the AER finds, it is not easy or practical to implement the Black CAPM then it is difficult to see how it could provide guidance on the selection of an equity beta selected using a different model such as the SL CAPM model. The AER indeed notes this in its discussion of the use of the Black CAPM.[225]

> *Relative to the Sharpe–Lintner CAPM, the theory of the Black CAPM points to the selection of a higher estimate for this parameter. However, while the direction is known, the magnitude is much more difficult to ascertain.*

The point is that if the Black CAPM cannot describe logically where the point estimate should be set in the range offered by the SL CAPM as it offers no insight into the appropriate magnitude of any shift from one point in the range from 0.4 to 0.7 to another.

More broadly, if, as the AER observes, the Black CAPM is capable of practical implementation, then it is not capable of acting as a check on the values arising from implementation of an alternative model.

The AER Appendices to the Rate of Return Guideline explain why the AER has rejected the Black CAPM as a foundation or co-foundation model. They did so because it produces a range of values for the equity beta that do not seem credible. In this regard, the AER reviews the application of the Black CAPM in the NERA report submitted by the ENA[226] and finds:

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[224] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, pp. 16-17.
[225] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.72.
[226] NERA, *Estimates of the zero-beta premium: A report for the Energy Networks Association*, June 2013.

> *The NERA report submitted by the ENA Illustrates how difficult it is [using the Black CAPM] to obtain a reliable empirical estimate of the return on the zero-beta portfolio."*[227]
>
> *The fact that "The headline result is that the zero beta premium is around 12 per cent …. Estimates of this magnitude appear implausible. Such a zero beta premium is approximately double the market risk premium of six per cent under a standard approach"*[228]
>
> *The "zero beta return estimates [produced by the application of the Black CAPM] imply there is a negative price for systematic risk. That is, as a share takes on more systematic risk exposure, the expected return declines. Greater systematic risk means less reward."*[229]

We pose the question, if the Black CAPM cannot produce credible results, then how can it be appropriate to use it as a check on the application of the SL CAPM?

Finally, as noted, the Black CAPM provides higher returns on low beta stocks and lower returns on high beta stocks.

This is a concern for two reasons. The first reason is that it would indicate further conflict and incompatibility between the SL CAPM and the Black CAPM, suggesting that the Black CAPM should not be used to identify the point estimate for the equity beta in the range limited by the SL CAPM.

The second reason is more fundamental. This is that market evidence suggests that returns on low beta stocks are higher **in risk-related terms** than on high beta stocks. This issue was discussed above in relation to the use of different models for determining the rate of return on capital. That runs contrary to the assumption in the Black CAPM, and specifically in the assumption in the Black CAPM that the zero beta rate is higher than the risk-free rate.

ENGINEROOM's preference in selecting the point estimate for the equity beta is to place little or no weight on:

- The US data due to its lack of observed consistency with Australian data observations;
- The Black CAPM, for the reasons stated above.

ENGINEROOM considers that consistency among the WACC parameters and the observed mean and median of equity betas in Henry 2014 would lead to an equity beta in the range 0.5 to 0.55. Such a range is well above the median observation found in Henry 2014 and encompasses the mean observation in Henry 2014. ENGINEROOM would strongly advocate against selecting an equity beta above the midpoint estimate in the range of equity betas because it is contrary to observed market evidence presented in Black, Jensen, and Scholes (1972) and Frazzini and Pedersen (2013).

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[227] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.69.
[228] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.70.
[229] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.70.

1.8 Market risk premium

In the CAPM model, the market risk premium (MRP) represents the return on the market above the risk-free rate that investors expect to earn on the market portfolio of all risky assets.

In the Rate of Return Guideline, the AER proposes to:

> *…estimate the range for the MRP with regard to theoretical and empirical evidence – including historical excess returns, dividend growth model estimates, survey evidence and conditioning variables. The AER will also have regard to the recent decisions among Australian regulators.*

ENGINEROOM contends that the DGM model should not be used to determine the MRP. McKenzie and Partington identify clear limitations on the value of the DGM model, particularly in a two stage process:[230]

> *… we are of the view that the dividend growth model (DGM) might be used as a reasonableness check in regulatory determinations. However, it is important to note that there are substantial limitations to the basic form of this model. To that end, an alternative specification of the DGM may prove useful, subject to the caveat that any extension of the model is going to require additional assumptions to be made and there will be considerable uncertainty around what the correct assumptions are. As such, any results must be interpreted carefully, keeping in mind the sensitivity of the results to the assumptions made.*
>
> *We caution that current applications of the DGM, including the two stage model, are quite likely to result in upward biased estimates of the cost of equity. We explore the three main reasons for this upward bias.*
>
> *The first is the common practice of modelling the growth path of dividends using analysts' forecasts. A well-established literature finds clear evidence that analysts' forecasts are overly optimistic with respect to target prices, earnings and dividends. Further, analyst forecasts are also not as forward looking as we might expect and react slowly to new information.*
>
> *The second reason for this bias is linked to the growing importance of non-dividend forms of cash flows between the company and its shareholders. Specifically, it is share issues and the rise in prominence of share repurchases and dividend reinvestment plans that complicate matters and may lead to a biased result.*
>
> *The third reason for upward bias is the common use of the GDP growth rate as a proxy for the expected long run growth rate for dividends. We note that empirically, there is a lack of evidence to support this assumed relationship and that negative correlations between GDP growth and stock returns are commonplace. Putting this aside and assuming that the*

[230] McKenzie and Partington, DGM final report - rate of return guideline, December 2013 p.4.

> *GDP growth rate is used to proxy for the long run dividend growth rate it should be adjusted downwards. This adjustment is required to account for the additional capital that investors must supply to support the growth in GDP.*
>
> *We also note that there is a tendency for dividend growth rate forecasts to be persistently positive and decidedly optimistic. This is possible in the short run for both individual firms and the market, but it is clearly not possible that all short-runs have above average growth rates.*
>
> *We survey evidence on long run dividend growth rates for Australia and the average of the estimates that we consider is 3.73% (3.78% excluding the most extreme values). By way of contrast, the AER estimate is higher than these values at 4.6%.*

ENGINEROOM consider that the DGM model should not be used because of the identified upward bias in its application. Given the DGM model incorporates analyst forecasts, its use sits oddly with the AER's decision not to use information from trading multiples, asset sales, or brokers' WACC estimates in determination of the rate of return.[231]

ENGINEROOM considers that the MRP should be stable, and should be based on very long term factors observation of investors' minimum requirements for an excess return on stocks compared to risk-free assets. This provides investors with regulatory certainty and reduces the incentives for gaming or for arbitrary gain or windfall loss for a purchasing investor compared to a selling investor if the regulator changes its position on MRP subsequent to the sale of a regulated asset.

ENGINEROOM considers the MRP should be estimated by regression of a series of market data over an historical period of more than 50 years). This approach is reasonable, stable, predictable, and transparent given that the forward cost of equity is not directly observable.

An issue is the degree of weighting towards prevailing market conditions. While the MRP is a forward-looking estimate, investors are likely to invest based on perceptions of historical returns and are likely to look through short-term market conditions when making investment decisions, particularly in relation to assets such as energy networks with long-lived asset lives and stable cash flows. The predictability of the cash flows of these assets in particular is likely to encourage investors to maintain a constant attitude towards excess return requirements.

ENGINEROOM notes that most of the survey evidence and regulator estimates support a value of 6.0. This evidence and regulator estimates were set out in Economic Insight's paper for the NZ Commerce Commission.[232]

1.9 Selection of the risk free rate for debt and equity

The AER's Guideline proposes that the cost of debt be calculated on the basis of the 10-year commercial bond yield for a firm with an average credit rating of BBB+. The AER's Guideline proposes the introduction of a trailing average approach with

[231] AER Rate of Return Guideline, p. 14.

[232] Economic Insights, *Regulatory Precedents for Setting the WACC within a Range* (Report prepared for New Zealand Commerce Commission), June 2014.

annual updating, reducing the exposure of both networks and consumers to significant movements in interest rates during the regulatory period and between regulatory periods.

ENGINEROOM submits that the use of a 5 year BBB+ rate is more appropriate than a 10 year rate as it reflects realistic debt setting period in capital markets in Australia and the length of the RCP. A period of 5 years is consistent with giving the distributor an ex ante efficient return on capital matched to the prospective period.

The QCA and the NZ Commerce Commission use a 5 year period.

The use of a 5 year period obviates many of the difficulties that apply in setting a 10 year rate. This is because there is far more data for 5 year rates, which simply reflects the much more liquid market for 5 year borrowing than 10 year borrowing. A 10 year borrowing period can correctly be described as artificial and non-reflective of market practice.

A major reason stated by the AER for preferring a 10 year period (at least in relation to the risk-free rate for the cost of equity) is the long-lived nature of the assets.[233] However, in practice, the distributors' borrowing practices are much more likely to be calibrated to internal treasury, borrowing, and financing practices rather than to the life of the assets. First, this is because there are simply no commercial borrowing arrangements in Australia which reflect anything like the 40 to 50 year life of electricity distribution assets, and so a significantly shorter term and multiple refinancings must occur irrespective of the borrowing term chosen. Second, the cash flows of distributors are sufficiently predictable to support a range of financing strategies rather than simply one of matching as far as possible the tenor of the borrowing period to the life of the asset. Since a key risk is the regulatory reset outcome, and one which is externally and less controllable, it arguably makes sense to align borrowing with the regulatory period of 5 years.

Moreover, a 5 year rate is more consistent with the move to annual adjustment of the cost of debt.

1.10 Selection of the observation window for the risk-free rate

The AER Guideline proposes to use 10-year Commonwealth government securities based on the 'prevailing' yield averaged over a short observation window close to the date of the determination.

ENGINEROOM agrees with the AER's approach in relation to the observation window. This approach aligns with the view that the WACC and in particular the cost of debt is forward-looking. It is consistent with the AER's previous approach and also with the new approach of weighting debt on a year-by-year or trailing basis.

It is not appropriate to select a longer debt window as it may give weight to historical debt costs that no longer apply. As debt costs have been coming down significantly in recent times, it also tends to suggest that distributors advocating for an observation window reaching significantly into the past are seeking to game the outcome.

The approach of using a short observation window close to the start of the RCP(with similar timescales for observation windows in subsequent years) was accepted by

[233] AER Rate of Return Explanatory Statement,

the Australian Competition Tribunal as reasonable in APA GasNet Australia (Operations) Pty Limited (No 2) (2013).[234]

1.11 Application of the trailing average

ENGINEROOM support the AER's approach in the rate of return guideline of attaching equal weights to each year when calculating the cost of debt.[235] ENGINEROOM considers that using equal weights for each of the years rather than weighting by actual capex or the approved capex under the PTRM is most commensurate with setting a cost of debt that equates with the efficient financing costs of a benchmark efficient entity.[236]

The distributors are proposing that the debt weighting be aligned with the capex spending profile. For example, Energex argues that the:[237]

> *… method used to average the return on debt estimates under the trailing average approach should be based on the benchmark borrowing profile reflecting the approved capex in the PTRM. This better meets the Rule requirements by more closely aligning the return on debt with the return on debt of a benchmark efficient entity.*

Ergon argues that a "simple average could still result in a material mismatch between the actual and allowed return on debt given the lumpy nature of an energy NSP's capital expenditure profile". However, any approach including an alignment of the cost of debt with the approved capex in the PTRM could result in a material mismatch. In practice it is unlikely that the distributors' actual spending profile will match its approved capex profile, or that it necessarily reflects the only choice of a benchmark efficient spending profile. The regulator quite rightly stands back from dictating the actual capex spending profile of the distributor which may be considered to be doing if it weights the cost of debt with the approved capex in the PTRM.

Moreover, this ignores that borrowing practices are driven by a range of considerations other than actual capital spending profiles. A significant driver for the borrowing profile is the distributor's risk management. For example, a distributor may decide to hedge an equal debt burden each year as a risk management strategy irrespective of actual capital spending. A decision to hedge in this way would protect the borrowing entity from too large an exposure at any given time. In fact, it was arguably this preference to align the approach under the NER with market practices towards a more even spread of debt refinancing periods that motivated the change from the previous practice where the entire debt was assumed to be refinanced at the start of the RCP. We consider that most likely an efficiently financed business would, in practice, actively manage the debt portfolio and use treasury tools to manage risk and take advantage of movements in interest rates. As noted by PIAC, most private sector utilities report they have significantly reduced their costs of debt

[234] Australian Competition Tribunal, Application by APA GasNet Australia (Operations) Pty Limited (No 2) (2013) ACompT 8, 18 September 2013.
[235] AER Rate of Return Guideline, p. 19. The AER applied this approach in the NSW Draft Determination, e.g. AER Ausgrid Draft Determination at p. 81.
[236] As per NER clause 6.5.2(c).
[237] Energex RP, p. 153. Also see Ergon RP, pp. 123-124.

in the last few years through refinancing and restructuring their debt and by better management of their debt portfolio.[238]

A concern is that the distributors' proposals raise another way to game the regulatory framework. The exact form of such games may be difficult for the regulator to predict ex ante. The types of possible games that could be played would depend on the rules set by the regulator around the timing of debt. For example of a game might arise where the cost of debt is determined by the time of commissioning of a project, especially where that project is multi-year project (as many if not most significant capex projects would be). One possible game a distributor might play would be to seek to shift the timing of the commissioning of a project back from June to July (or forward from July to June) to take advantage of a year of higher debt or forecast debt. This would advantage the distributor in circumstances where the debt had been effectively or mainly incurred in a year other than the year of commissioning where the prevailing cost of debt was lower.

1.12 Imputation credits ('gamma')

Under the Australian taxation system, when domestic investors receive dividends they are provided with a franking credit which can be used to offset other tax payable by them. The franking credit reflects tax paid by the company paying the dividend to them. For example, fully franked dividends come with a franking credit equal to 30 per cent of the grossed up (i.e. pre-tax) value of the dividend. Franking credits cannot be claimed by foreign investors and so are of no value to them.

The presence of franking credit reduces the returns required by domestic investors to invest in a stock. Therefore, the distributors' tax costs should be adjusted down to reflect the value of the franking credit.

Under the NER, the nominal vanilla WACC is not adjusted for the value of franking credits. Instead, franking credits are incorporated as an adjustment to the regulatory allowance for tax costs.

This tax adjustment, known as gamma, is generally accepted to be the product of the rate at which profits are distributed as dividends (the distribution rate or dividend payout rate) (F) and the rate at which they can be used by investors (the utilisation rate or theta).

A high gamma value means that the distributor will receive a relatively lower regulatory allowance for tax costs and, therefore, a lower revenue allowance to pay for these costs. This will present as a lower regulated cost of service. A low gamma means the opposite.

Energex and Ergon and the AER have accepted the value of the payout ratio of 0.7 based on ATO data.[239]

However, the distributors propose a theta value of 0.35.[240]

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[238] For example, SP AusNet recently successfully issued 15-year bonds on the Norwegian market. SP AusNet states, 'The issue was competitively priced and will add to our funding diversity both in terms of maturity and sources of debt'. SP AusNet, ASX & SGX-ST Media Release, 16 June 2014.

[239] Ergon RP, p.148, Energex RP, p.178

[240] Ergon RP, p.148, Energex RP, p.178, AER Rate of Return Guideline, pp. 23-24.

In 2011 Energex and Ergon contested the AER's assessment of gamma to the Australian Competition Tribunal. The Tribunal ordered the AER to accept Energex's and Ergon's proposal for a gamma of 0.25 based on a theta of 0.35.[241]

Energex and Ergon consider the Tribunal's decision to be directive that the gamma should be set at 0.25. However, as noted by PIAC in its submission to the AER NSW Electricity Determination:

> *The Tribunal considered that 0.25 was the preferable figure at the time, based on the evidence in front of it. However, the Tribunal also urged the AER to undertake a more thorough examination of the possible approaches to the assessment of theta. ENGINEROOM argues that this suggests the Tribunal was by no means indicating that its directions were 'permanent'.*
>
> *…The Tribunal's statements were heavily qualified throughout its analysis of the value of gamma by its concern about the lack of a sound conceptual base for the assessment of gamma and its constituent components in the regulatory context. The Tribunal encouraged the AER to investigate a wider range of approaches and, importantly, to better establish the conceptual framework in which the regulatory value of gamma is determined.*

The AER responded to the Tribunal decision by re-evaluating the conceptual basis for estimating the value of gamma and undertook analysis using taxation statistics and other measures. In the Guideline, it proposed a gamma of 0.5 based on a theta of 0.7 and a distribution payout ratio of 0.7.

The AER has investigated various approaches to estimating the value of theta and have provided an extensive assessment of the various approaches in the Explanatory Statement to the Rate of Return Guideline.

Energex and Ergon have rejected the AER's approach and continue to propose a gamma of 0.25, based largely on a consulting report by SFG Consulting.

For example, Ergon's RPcites the SFG report as providing:[242]

> *SFG clearly demonstrates that the relevant task is to establish a market-based value of theta. This also invalidates the equity ownership, tax statistics and 'conceptual goalposts' approach that have been referred to by the AER.*
>
> *Ergon Energy concurs with this view. The gamma parameter is intended to reflect the value that investors place on franking credits in establishing the rate of return they require from the efficient benchmark firm. This has to be a market value.*

At dispute is the conceptual framework for determining gamma. This is a difficult issue since, as the Tribunal recognised in 2011, as there is no generally agreed methodology to assess theta, one of the key inputs to gamma.

[241] Australian Competition Tribunal, Application be Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011).
[242] Ergon RP, p. 149.

IN the NSW Draft Determination, the AER selected a value of 0.4, based primarily on the equity ownership approach, which was supported by its consultants Handley, and Lally, and which suggested a range of 0.4 to 0.5.[243] The QCA recently set a gamma of about 0.47 in its regulatory decisions.

The value is at the lower end of the range suggested by the equity ownership approach. ENGINEROOM considers a more even-handed and consistent approach would be the value of 0.5 in the AER Guidelines.

[243] AER, Draft Decision - Ausgrid 2014-19, pp. 46-47. Referring to J. Handley, Report prepared for the Australian Energy Regulator: *Advice on the value of imputation credits*, 29 September 2014; and M. Lally, *The estimation of gamma*, 23 November 2013, p. 4.

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Wellington International Airport & Ors v Commerce Commission [2013] NZHC 3289