QCOSS

Queensland Council
of Social Service

Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020

July 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
- 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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Table of Contents

1. Introduction

The AER released its Preliminary Decision on the regulated revenues for standard and alternative control services provided by Energex and Ergon on 30 April 2015.

QCOSS is concerned that the AER preliminary decision does not reflect the long-term interests of Queensland consumers using electricity distribution and metering services.

Distribution tariffs were already at record levels due to the excessive capex and opex and WACC settings in the 2010-2015 regulatory control period (RCP). The Preliminary Decision leaves distribution tariffs, and thus retail tariffs, at what can only be considered artificially high levels. These high tariffs are significantly impacting on people and business activity.

The AER's final decision provides an opportunity for a more rigorous assessment of the distributors' revenue requirements for 2015-2020.

We believe there is a strong case for the AER to further reduce the significant opex and capex allowances for Ergon and Energex in its final decision because:

- Reliability standards were relaxed in Queensland in July 2014;[1]
- The excessive spending in the last RCP resulted in significant excess capacity and a lower forward need for capex and preventative opex;
- Forward demand and peak demand is weak;
- The excess capex awarded in the preliminary decision does not take account of any possible future stranding of the network investment which may result from technological changes in battery, metering, and PV technology; and
- The preliminary decision does not place significant discipline on the distributors to move towards efficient provision of distribution or metering services.

The Preliminary Decision confirms the concerns of users, expressed by the Inter Departmental Committee (IDC), that "there is also a concern that the underlying regulatory framework has not provided the right incentives for efficient capital expenditure".[2] Acceptance of the AER Preliminary Decision risks user groups becoming disenchanted with, and disengaging from, the AER's consultation processes.

QCOSS considers that it is critical that the AER and the Queensland Government, as owner of the distribution assets, listen to and engage with consumers and apply strict disciplines in operating and capital allowances as well as in the WACC settings.

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[1] See https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards

[2] IDC 2013, *Report to Government: Interdepartmental Committee on Electricity Sector Reform*, May, p.7.

2. Overall views on capex and opex allowances

It is well documented by the Independent Review Panel (IRP) on Network Costs that the excessive capex and opex awarded in the 2010-2015 RCP resulted in lax capital and operating controls by the distributors. For example, the IDC was particularly concerned about the IRP's reports of a noticeable cultural disregard for cost within the distribution network businesses.[3] The IRC, IDP and earlier Electricity Network Cost Review (ENCAP) reviews demonstrated that the 2010-2015 RCP revenue allowances were a mistake based on overly optimistic demand forecasts and over-generous allowances and should not serve as a comparison point for setting future allowances. Rather the AER should have regard to revenue allowances in the 2000-2005 and the 2005-2010 RCPs as a more valid point of comparison for setting revenues for the 2015-2020 RCP.

The danger is that the excessive capex and opex awarded in the AER preliminary decision will result in a continuation of undisciplined expenditure and lack of cost-control, at the expense of consumers.

Moreover, the capital allowances set the RAB on an unsustainable path, locking in a requirement for future high returns on capital for the current and future regulatory control periods. The return on the RAB is already unsustainable at around 60 per cent of total revenue requirements, meaning that even with future reductions in capital spending to reasonable levels, the consequences of excessive capex allowances will not be unwound for the life of the underlying assets, perhaps 50 years.

QCOSS is very disappointed at the low level of reduction in Energex's and Ergon's capex and opex allowance in the AER's preliminary decision. For example:

- The AER did not adjust Energex's opex proposal and has only applied a 10 per cent reduction to Ergon's opex proposal;
- In relation to capex, the AER adjusted Energex's augmentation and customer connections capex by 25 per cent and Ergon's augmentation by 10 per cent.
- While more significant reductions were made to repex proposals, this was based on proposals far above historical levels.
- The AER made only modest reductions to capitalised overheads for both distributors (8.5 per cent for Energex and 5 per cent for Ergon); and
- non-network capex (no reduction for Energex and a 17 per cent reduction for Ergon).

[3] IDC 2013, *Report to Government: Interdepartmental Committee on Electricity Sector Reform*, May, p.49.

QCOSS contends that the AER Final Decision must take much greater account of a number of factors which its Preliminary Decision did not adequately address. QCOSS calls for the capex and opex allowances for both businesses be reduced compared with the position in the Preliminary Decision in light of:

- Changes in reliability standards
- Weak forward demand and peak demand
- Failure to address ongoing inefficiencies
- Excessive capital expenditure allowances based on benchmarking comparisons
- Inefficiencies in capitalised overheads
- Excessive allowances for customer connection capex
- Excessive opex based on benchmarking comparisons
- Insufficient evidence to support a case for parametric insurance.

2.1 Changes in reliability standards

There have been significant changes in reliability standards. The ENCAP adjusted reliability standards after its review:[4]

> *…found that more cost effective alternatives exist to achieve acceptable reliability levels than the duplication of major assets (i.e. N - 1).*

The IRC found that this:[5]

> *…. more outcome-focussed approach, which still included some specified levels of redundancy, was adopted, resulting in identified capital expenditure savings of approximately $505 million over the remainder of the 2010-15 regulatory period.*

These savings which cover only part of the 2010-2015 RCP indicate the very considerable capex savings from even a partial relaxation of the reliability standards.

The IRC review recommended a further relaxation in reliability standards to a standard set by the distributors themselves to meet their global minimum service standards, which involve devolving "responsibility for determining the security standards necessary to deliver reliable supply to the Boards of the DNSPs".[6]

QCOSS submits that the Boards' positions on reliability should be driven, as in other markets by customers' expectations and willingness to pay.

[4] Independent Review Panel on Network Costs (IRC), *Electricity Network Costs Review Final Report*, p.42.

[5] Independent Review Panel on Network Costs (IRC), *Electricity Network Costs Review Final Report*, p.42.

[6] Independent Review Panel on Network Costs (IRC), *Electricity Network Costs Review Final Report*, p.42.

Reviewing user group submissions to the AER, it is very clear that users have expressed a clear preference for lower prices without raising reliability concerns. On Ergon's regulatory proposal, for example, user groups[7] repeatedly criticised the path of high prices over recent years and did not raise concerns about reliability. The direction of the submissions from user groups on Energex's regulatory proposal was just as clear. The State Government's relaxation of reliability standards supports this direction, which reflects community preferences.

The Queensland Government accepted the IRC recommendations from July 2014.[8] This provides much more flexibility for distributors to defer augex as reliability is delivered to meet customer needs. The savings from the IRC should be considerably more than the $505m savings already from the ENCAP review, because the period in question (2015-2020) is the whole of the RCP, and because the IRC standard is lower, and because the savings in the 2010-15 were reduced by the requirement to complete existing committed projects.

However, the change in the reliability standard has not been adequately factored into Energex's and Ergon's augex proposals as the distributors have continued to ignore customer preferences and continue to build network in excess of customer willingness to pay. Neither distributor has provided convincing evidence of customer willingness to pay to the level implicit in their regulatory proposals. This view is reinforced by the observation that Energex and Ergon reliability has improved considerably over the period from 2006 to 2014, as disclosed in the distributors RINs.

QCOSS calls on the AER to comprehensively address in its Final Decision the issue of "over servicing" and whether or not the amount of capex and opex allowed is over stating the volume of work required given that they are more than meeting reliability standards.

2.2 Weak forward demand and peak demand

There is a strong incentive in the regulatory framework for DNSPs to over-estimate demand, as has occurred in previous regulatory periods. High demand forecast estimates support higher capex and supporting opex, and higher returns on the assumed capital investment during the RCP. The distributors and the AER must make every effort to ensure that demand

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[7] see the submissions by a wide and diverse range of user groups embodied in the Alliance of Electricity Consumers, Bundaberg Regional Irrigators Group, CCIQ, COTA, Cummings Economics, EUAA, National Irrigators Council, FNQ Regional Organisation of Councils, Townsville Enterprise, UDIA, Australians in Retirement, Canegrowers, QRC, QCOSS, Qld Consumers Association, RDA FNQ&TS, Central Highlands Cotton Growers and Irrigators Association, Cotton Australia, Darling Downs Cotton Growers Inc., and the Qld Farmers Federation

[8] See https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards.

forecasts are robust and credible as the over-forecasting risk is borne by the consumers for the five years of the RCP.

Given that maximum demand has been declining for a number of years Ergon's forecasts are not credible. Consumer groups at a number of meetings with Ergon repeatedly raised the following issues and it is disappointing that they are continuing to produce what appears to be inflated forecasts.

For example, Ergon's maximum demand peaked in 2008-09. The maximum demand in the 2010-2015 RCP was 2,441 MW, or 3.4 per cent lower than the 2008-09 peak.[9] However, Ergon is now forecasting a 2015-16 maximum demand to be 2,537 MW and for it to grow to 2,685 MW by 2019-2020 (all figures 50 per cent probability of exceedance).[10] That would represent a growth of 4 per cent from the peak in 2015-16 even though maximum demand has not risen past its 2008-09 levels.

There is a strong onus on Ergon to justify the in its forecasts of maximum demand. Ergon forecast 3,330 MW maximum demand in 2010 for the 2014-15 year while actual demand was only 2,500 MW. While Ergon has argued it has improved its demand forecasting methodologies since 2010 its current methodologies do not align with AEMO's methodology.

AEMO relies primarily on Gross State Product (GSP) while Ergon seeks to also include a range of other (more subjective) factors such as "Ergon Energy's knowledge and understanding of its customer base and its assessment of future growth in the communities supplied from each zone substation".[11] These factors cannot be independently verified and should not be taken into account by the AER.

The maximum system demand forecasts also take no account of the likely outcome of proposed tariff reform to be implemented by 2017 which aims to flatten demand by providing stronger incentives to move demand to off-peak times. (Ergon has already introduced a voluntary demand tariff.) This is important as Ergon's demand forecasts in 2010 erred by not taking sufficient account of the price impacts of tariffs on demand. AEMO has sought to improve its forecasting in recent years by increasing its focus on the price-elasticity of demand.

Further it would appear that Ergon has not made any allowance for the impact of future disruptive technologies such as batteries which are already on the market in Australia.

AEMO released its most recent maximum demand forecasts in June 2015. AEMO's forecasts do not support Ergon's forecasts for maximum system demand. The AEMO 2015 demand forecasts indicate that most growth is at the industrial level due to growth in LNG and that *"[e]xcluding LNG, operational consumption would not be expected to return to this level until*

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[9] Ergon RP, p.97.

[10] Cited at AER Preliminary Decision, 6-117.

[11] Cited at AER Preliminary Decision, 6-117.

2028–29, driven by recovery in both industrial and residential/commercial consumption".[12] AEMO continues to forecast a fall in per capita consumption in the residential sector from 6.5 MW to 6.2 MW, continuing a trend from 7.9 MW in 2009-10.[13] AEMO expects that after accounting for population growth, demand for the combined residential/commercial sector is only likely to grow at 0.5 per cent per year.[14]

In relation to maximum demand, AEMO's view is that the:[15]

> 10*% POE maximum demand is forecast to increase at an annual average rate of 2.8% over the short term (2014–15 to 2017–18). This is primarily driven by increased LNG demand*.

AEMO does not disaggregate LNG demand from other demand in relation to the forecast of maximum demand.

If most of the growth in demand in Ergon's area is coming from growth in LNG demand, which is concentrated in a small number of specific locations, it is not reasonable for Ergon to forecast growth in maximum demand across its network above the direction of historical trends. AEMO is forecasting only 0.5 per cent growth per annum for combined residential and commercial demand over 2015-2020. In other words, in areas of Ergon's network where growth is driven by residential and commercial load, there is unlikely to be significant growth in maximum demand during 2015-2020.

LNG demand and maximum demand is likely to be met to a large extent by the transmission network and is likely to be located in specific regions. This does not support a significant augex program by Ergon.

Similarly, Energex's forecasts of maximum demand do not seem consistent with historical trends. For example, figure 8-7 in Energex's RP shows maximum demand moving sideways and upwards despite a significant downward trend since 2011-12.[16] The growth in demand around LNG is also not a factor in Energex's distribution area. The continued subdued economic and population growth in Queensland do not support Energex's forecasts of maximum demand.

The report by Frontier in Appendix 15 of Energex's RP criticises aspects of Energex's forecasting methodology, particularly in relation to forecasts of peak or maximum demand:[17]

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[12] AEMO 2015, *Detailed Summary of 2015 Electricity Forecasts, 2015 National Electricity Forecasting Report*, June, p.22.
[13] AEMO 2015, *Detailed Summary of 2015 Electricity Forecasts, 2015 National Electricity Forecasting Report*, June, p.26.

[14] AEMO 2015, *Detailed Summary of 2015 Electricity Forecasts, 2015 National Electricity Forecasting Report*, June, p.26.

[15] AEMO 2015, *Detailed Summary of 2015 Electricity Forecasts, 2015 National Electricity Forecasting Report*, June, p.33.

Energex RP, p.100.

[17] Energex RP, Appendix 15, pp.3-4.

> *The peak system demand model has also been developed in a professional manner, but it is not quite as well documented [as forecasts of total demand]. The files provided contain sufficient information to reproduce some but not all of Energex's forecasts. Most notably, no information is provided on how the forecasts for the low and high economic scenarios are obtained. In addition, although the number of and types of diagnostic and validation tests conducted is satisfactory; in most cases, there is insufficient detail on the results of the tests to make an independent assessment of the test outcomes.*
>
> *With respect to model specification our main concern is that the economic drivers only appear in the model as interactions with the temperature variables. This makes it hard to assess the impact of the economic drivers on peak demand, and it could lead to biased estimates of the coefficients.*
>
> *Finally, there is no discussion on how the projections of the economic drivers obtained from external sources have been validated. We have been assured that Energex will address the above issues in the future development of the peak system demand model.*
>
> *Subject to the above provisos, it is our view that Energex's peak system demand forecasting model meets AER's criteria for good forecasting methodology.*

QCOSS considers Energex and Ergon demand forecasts do not support significant augmentation of the existing network in the 2015-2020 RCP.

2.3 Failure to address on-going inefficiencies

The 2013 IRP and IDC, and the 2011 ENCAP reviews found significant inefficiencies in Energex and Ergon practices during the 2010-2015 RCP. These inefficiencies were not identified when the AER did its regulatory review in 2009 and hence were not taken into account by the AER in setting the 2010-2015 revenue allowances.

More importantly, Deloitte's report for the AER for this Determination found that "*the service providers have not yet addressed a number of IRP recommendations*" and found that:[18]

Deloitte's key findings include:

- both service providers (but Ergon Energy in particular) have high total labour costs compared to more efficient peers, which is a result of having too many employees rather than the cost per employee
- certain EBA provisions, while not necessarily unique to Energex and Ergon Energy, limit their ability to quickly adjust their workforces flexibly and utilise them productively. This is amplified by the large proportion of employees engaged under EBAs. Examples include:
  - no forced redundancies

[18] AER Preliminary Decision, 7-25.

  - contractors are unable to perform certain tasks, such as switching (unique to QLD)
  - certain tasks cannot be performed by a single person (unique to Ergon Energy)
  - minimum apprentice numbers
  - restrictions on outsourcing.
- Energex and Ergon Energy have not implemented the IRP's recommendation that they market test the ICT services that SPARQ (a joint venture owned by the two distributors) provides, resulting in significant inefficiencies
- Ergon Energy has not yet implemented a LSA model for its regional depots, despite the IRP's recommendation (based on Powercor's success with this model) to do so. Deloitte considers Ergon Energy could realise efficiencies if it implemented an LSA model.

These inefficiencies are represented in Energex’s and Ergon’s regulatory proposals and demonstrate on-going inefficiencies in Energex and Ergon’s opex and capex which should be removed from their allowances. The distributors have not removed these inefficiencies in their latest regulatory proposals.

Even though Energex’s proposal shows a reduction in capex and opex compared with the current RCP, Energex’s proposed capex and opex is well above longer term historical levels. The benchmarking work by Economic Insights shows that both distributors are operating well below efficient practice.

The AER should be aiming to remove these inefficiencies in the allowances provided to the distributors.

2.4 Capex benchmarking outcomes

A range of capex benchmarks including both the Economic Insights work for the AER and other capex benchmarks indicate that the distributors’ proposed capex and consequent RABs are excessive.

A real concern is that this over-investment is likely to lead to partial stranding of network investment, particularly given emerging new and disruptive technological options for electricity supply. This is a significant risk for consumers as distributors may seek compensation if the network is stranded on the basis that the stranding occurred as part of a legislative obligation to serve.

The distributors need to engage much more closely with users to understand their needs and to ensure their services and more particularly their future investment plans remain relevant in terms of prices and service quality.

In addition to the Economic Insight benchmarking work, QCOSS refers to benchmarks of capital efficiency including:

- Asset age trends;
- System utilisation trends;

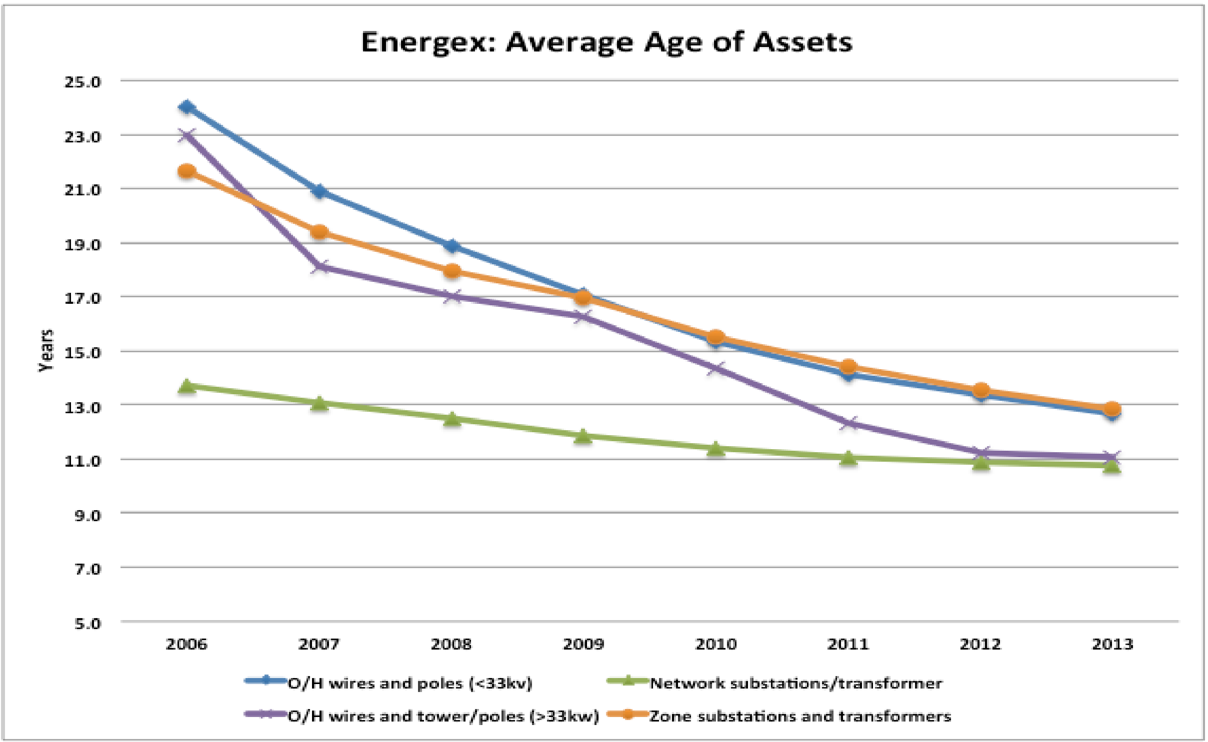
- Growth in the regulated asset base (RAB);
- Growth in RAB per customer, RAB per connection, and RAB per unit of peak demand; and
- Replacement capital (repex) trends.

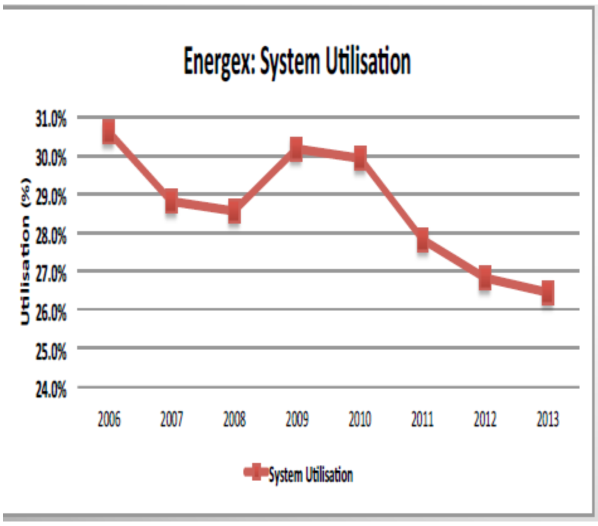
The graphs below set out disturbing trends in the growth of the RABs for the two Queensland distributors. These graphs show that, increasingly, the Queensland networks are young, lightly utilised, and that the RABs for both Queensland distributors are growing rapidly despite low or negative growth in total demand and maximum demand. They show that the ratio of RAB to peak demand is rising rapidly, reflecting the increase in the RAB while maximum demand has remained steady or fallen slightly.

The second last figure shows that the RAB is rising very rapidly relative to the number of connections. The final figure demonstrates the rapid escalation in repex over the period 2006 to 2020 (the period from 2015 to 2020 represents proposed repex). While the AER preliminary decision reduced the distributors' repex allowances, the resulting repex allowance is still well above historical levels from 2006 to 2010 (or earlier). This is implausible given repex should be relatively steady over time, as the AER acknowledged in its Issues Paper for this regulatory review.

These RAB and repex trends indicate that the distributors have engaged in a major and excessive expansion of the RAB despite little or negative growth in total demand and maximum demand. The AER's preliminary capex allowances would worsen these trends and QCOSS calls on the AER to understand and interrogate the drivers for repex and augex better in addition to using benchmarking. For example, it is noted that one reason for Repex is the replacement of obsolete assets. This reasoning needs to be investigated by the AER and to understand if this is prudent and efficient given the emerging disruptive assets and the implications that may have for stranding of assets even relatively new ones. With respect to augex one of the main drivers is reliability rather than new growth. Again this needs to be investigated given the excess capacity in much of Energex's network.

QCOSS calls on the AER to understand and interrogate the drivers for repex and augex better in addition to using benchmarking to arrive at the prudent and efficient allowances.


Energex: Average Age of Assets
Years
25.0
23.0
21.0
19.0
17.0
15.0
13.0
11.0
9.0
7.0
5.0
2006
2007
2008
2009
2010
2011
2012
2013
O/H wires and poles (<33kv)
Network substations/transformer
O/H wires and tower/poles (>33kw)
Zone substations and transformers


Energex: System Utilisation
Utilisation (%)
31.0%
30.0%
29.0%
28.0%
27.0%
26.0%
25.0%
24.0%
2006
2007
2008
2009
2010
2011
2012
2013
System Utilisation

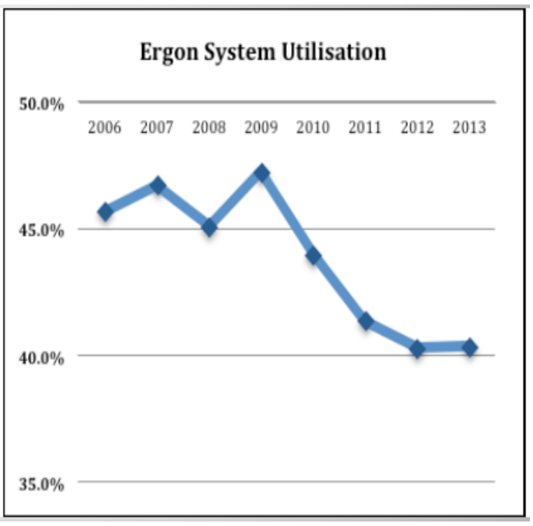
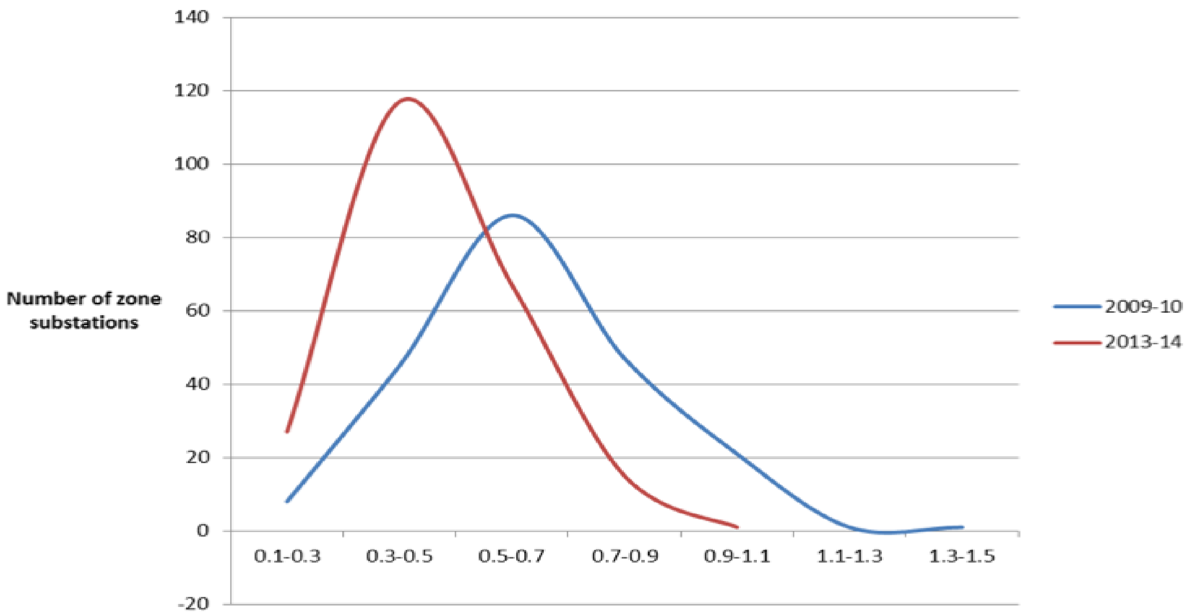
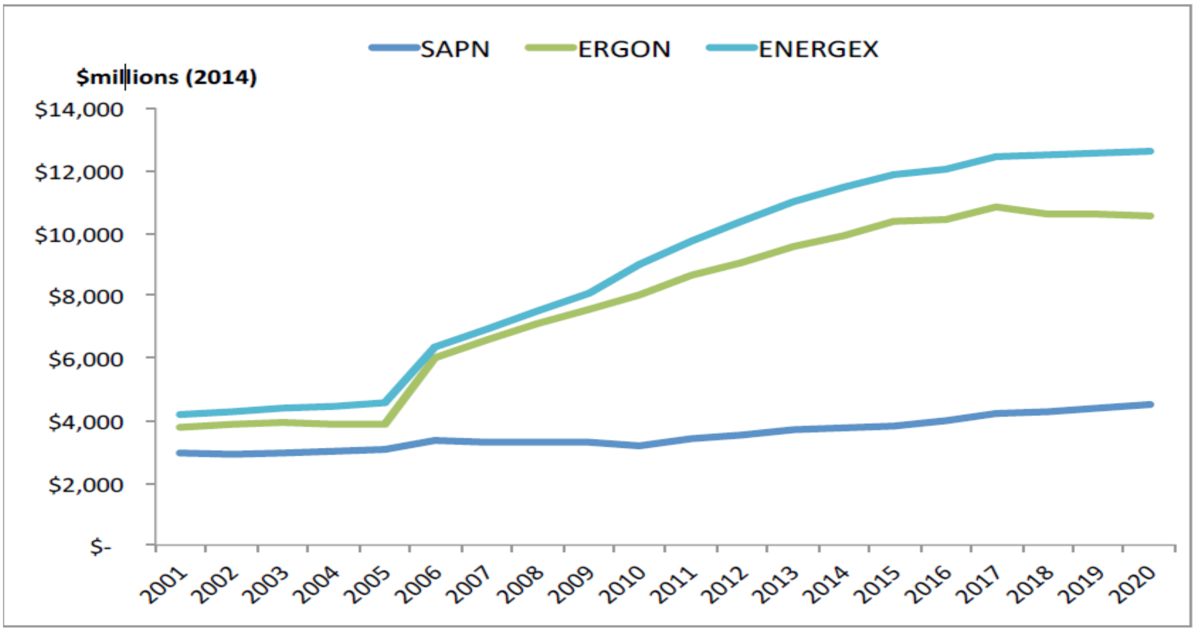
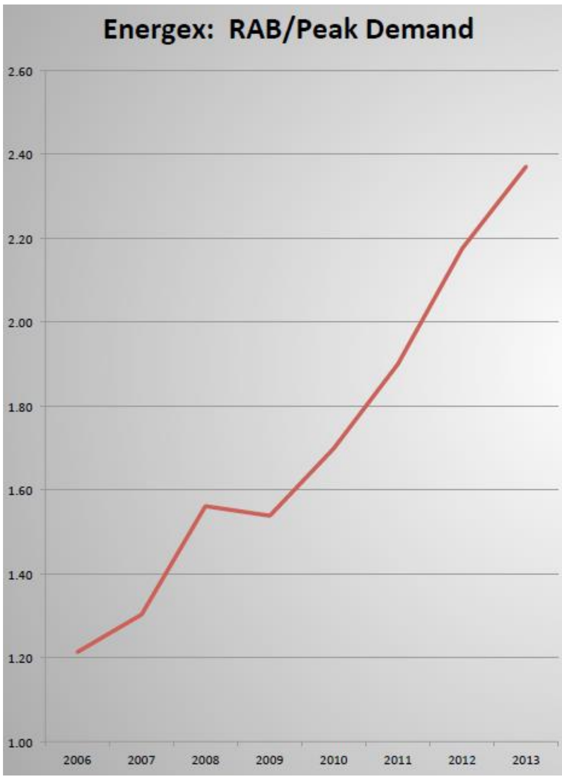
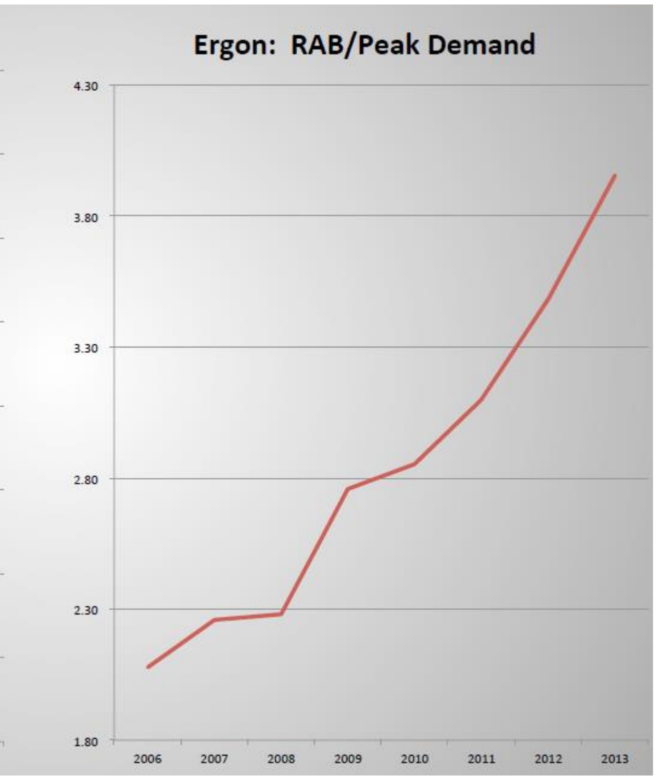

Ergon System Utilisation
50.0%
45.0%
40.0%
35.0%
2006
2007
2008
2009
2010
2011
2012
2013

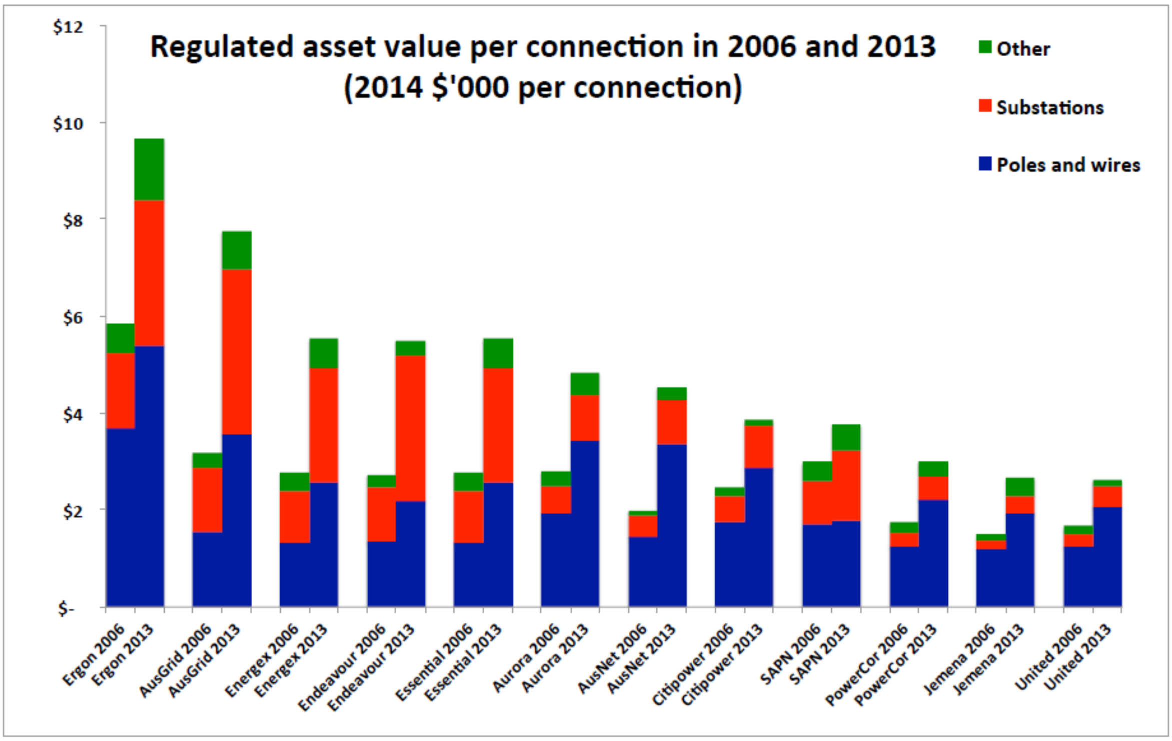
Figure B-2 Zone substation utilisation 2009–10 and 2013–14

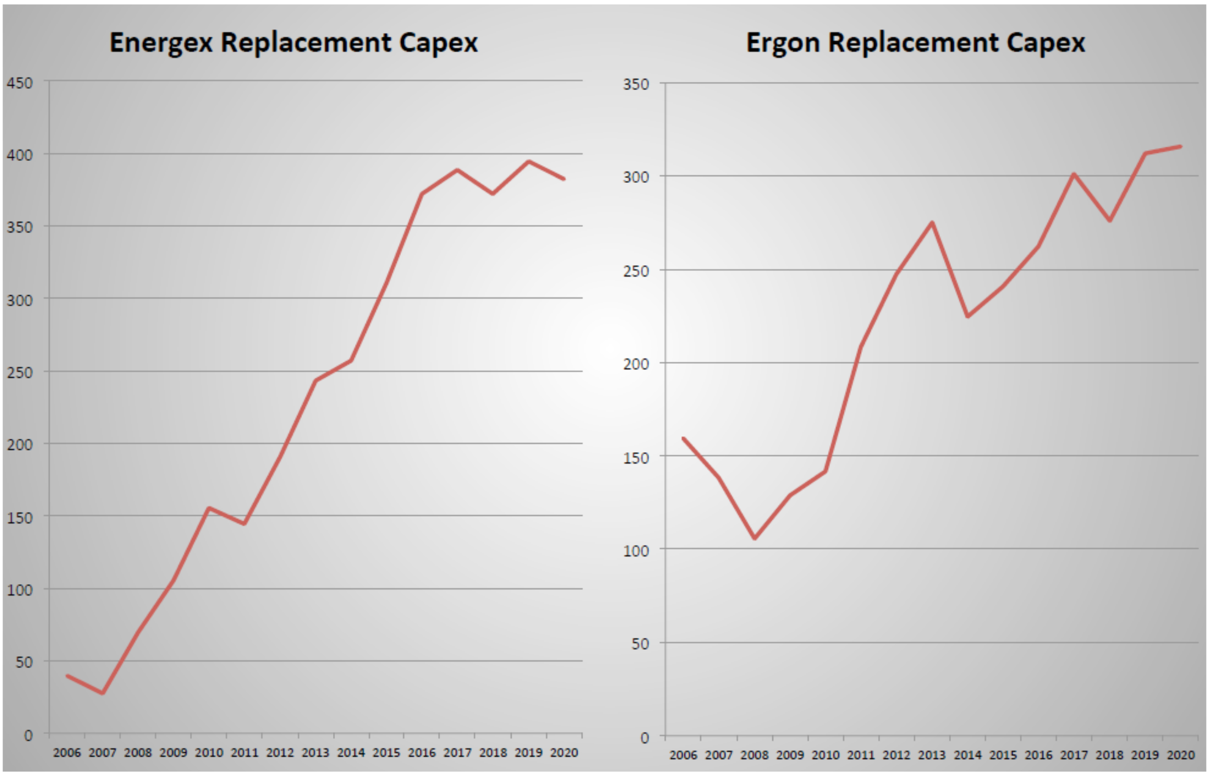





Energex: RAB/Peak Demand
2.60
2.40
2.20
2.00
1.80
1.60
1.40
1.20
1.00
2006
2007
2008
2009
2010
2011
2012
2013


Ergon: RAB/Peak Demand
4.30
3.80
3.30
2.80
2.30
1.80
2006
2007
2008
2009
2010
2011
2012
2013


Regulated asset value per connection in 2006 and 2013
(2014 $'000 per connection)
Other
Substations
Poles and wires
$12
$10
$8
$6
$4
$2
$-
Ergon 2006
Ergon 2013
AusGrid 2006
AusGrid 2013
Energex 2006
Energex 2013
Endeavour 2006
Endeavour 2013
Essential 2006
Essential 2013
Aurora 2006
Aurora 2013
AusNet 2006
AusNet 2013
Citipower 2006
Citipower 2013
SAPN 2006
SAPN 2013
PowerCor 2006
PowerCor 2013
Jemena 2006
Jemena 2013
United 2006
United 2013



2.5 Capitalised overheads

Capitalised overheads represent allocation of costs expended in support of the construction of capital items, for example IT costs.

For the 2015-2020 RCP, Energex proposed $900m in capitalised overheads, while Ergon proposed $1,017m. The AER Preliminary Decision approved $824m for Energex and 962m for Ergon. The AER preliminary decision applied only very modest reductions in the capitalised overheads proposed by the distributors (8.5 per cent for Energex and 5 per cent for Ergon).

QCOSS considers the level of capitalised overhead approved in the Preliminary Decision is excessive.

The IRP noted that the two distributors' capitalised overheads placed them among the least efficient in the NEM. A major element of the capitalised overheads incurred by the two distributors is SPARQ Solutions. SPARQ, which is jointly owned by the distributors, provides Information and Communications Technology (ICT) services to Energex and Ergon Energy. ICT expenditure accounts for around 35 per cent of the distributors' capitalised overheads.

The IRP recommended market-testing SPARQ's costs against external providers, particularly given it is owned by the distributors. In its information guidelines and ring-fencing guidelines, the AER typically insists on close examination of the costs of related party transactions to ensure regulated entities do not seek to transfer profits via related party transactions to non-regulated entities by inflating the costs of the related party services. Deloitte noted that the distributors had not implemented this recommendation.

QCOSS contends that the rate of capitalised overheads, especially for the costs of SPARQ, need to be thoroughly market-tested before they can be accepted by the AER.

2.6 Customer connection capex

Ergon proposed $279.5m of customer connections capex (or CCIW) in its regulatory proposal, net of customer contributions. The AER accepted Ergon's proposal without adjustment.[19]

Ergon states that:[20]

> *We forecast **Customer Connection Initiated Capital Works** using average historical costs and an econometric model that forecasts volumes using the following State macroeconomic variables: final demand; private investment – dwelling; and private investment – non-dwelling. These variables historically demonstrated the greatest causality and correlation to customer connection outcomes. This aligns with the approach that the AER applied to forecast this capital expenditure for the current regulatory control period.*

However, Ergon does not add that the capex that the AER allowed for the current RCP (2010-2015) was significantly in excess of that required by Ergon for CCIW.

In 2010 the AER criticised Ergon's approach, saying that dwelling house growth had little causality with industrial and commercial growth in CCIW.[21] In the 2010-2015 RCP, Ergon used a similar method as it is seeking to use this time to forecast CCIW of $1,694.99m.[22] The adjusted the forecast CCIW downwards by $402.3m.

Ergon spent $1,045m during the 2010-2015 RCP although this included $353m of customer contributions[23], resulting in a net Ergon CCIW spend in the current RCP of only $692m, well below the AER's lower allowance. This would suggest that it is unwise to rely on Ergon's CCIW forecasting methodology.

Ergon's CCIW is likely to be most similar to Essential Energy, given similar patterns of low density rural networks and high capex allowances during the current regulatory control period.

In its regulatory proposal Essential proposed CCIW net of customer contributions of $29.1m (with customer contributions of 353.9m).[24] This is almost ten times less than Ergon's regulatory proposal.

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[19] AER Preliminary decision, 6-64 to 6-66.

[20] Ergon RP, p. 110.

[21] AER 2010 Final Decision, pp.111-113.

[22] AER 2010 Final Decision, p.141. The dollars are $2009-2010.

[23] Ergon 2015 RP, p.93. These dollars are $2014-15.

[24] Essential RP, p. 114.

Essential gave the following reason for its low forecast for CCIW:[25]

> *As a result of the significant program of work during the 2009-14 regulatory control period and the low forecast growth over the 2014-19 regulatory control period, growth expenditure is forecast to be lower. The forecast growth expenditure is $521 million, or 41 per cent, below our growth expenditure in the 2009-14 regulatory control period.*

These reasons are likely to apply with equal force to Ergon. The disparity between Ergon and Essential is unaccounted for and not plausible.

2.7 Opex benchmarking outcomes

The AER's preliminary decision proposes to compare Energex and Ergon's opex forecasts with the bottom ranked distributor in the top quartile (which happens to be the fifth most efficient distributor in the NEM) and then to make further adjustments for operating environment factors. The AER applied environmental adjustments of 17.1 per cent for Energex and 24.4 per cent for Ergon.[26]

QCOSS contends that the AER should compare Energex and Ergon's opex and capex forecasts with a point closer to the efficiency frontier for distributors disclosed in Economic Insights benchmarking work for the AER.

Since the initial benchmarking has already accounted for the major variations in operating environments such as the density of the network the AER should not make adjustments for operating environment factors. Additional adjustments are likely to over-account for differences in network operating environments.

QCOSS considers there is simply no logical basis or clear rationale for selecting the fifth best performing distributor as the point of comparison. The fifth best distributor is clearly significantly below an efficient level (as indeed the most efficient observed distributor may be). The fifth best performing distributor exhibits a range of inefficiencies in capital and operating practices, while the NEO points to setting revenue to recoup the costs of efficient provision of services.

QCOSS agrees generally with the criticisms expressed in PIAC's challenge to the AER's final decision in NSW of the application of AER's benchmarking approach. The case for adjustments for operating environment factors has not been made for a range of such factors.

The national electricity objective in section 7 of the NEL is "to promote *efficient investment* in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity …". This supports a

[25] Essential RP, p. 114.

[26] AER 7-27

view that the AER should seek to compare performance with the most efficient operator rather than the fifth most efficient operator.

In a cohort of only 13 distributors, the fifth most efficient operator is AusNet, which was assessed by Economic Insights to have an average opex efficiency score over the 2006 to 2013 period of 66.5% of Citipower, the most efficient operator. It needs to be borne in mind that Citipower's performance does not represent the efficiency frontier, but only the leading Australian distributor's performance.

Applying a point of comparison that is not closer to the efficiency frontier is inconsistent with the AER's objective under the NEO and is likely to postpone a move towards greater efficiency and prolong higher tariffs for distribution services at significant cost to economic activity and hardship to low income users.

It is also important for opex comparisons and benchmarking to have regard to a longer trend period than the 2010-2015 RCP or indeed 2006 to 2013. Assessed on longer term trends, opex has risen from around $140m per year for both distributors in 2001-02.[27]

The AER should have regard to a longer period of time in determining suitable base opex requirements.

2.8 Ergon's proposal for parametric insurance

Ergon proposed $60.3 million in parametric insurance to cover the cost of cyclones. The AER preliminary decision was that:[28]

> *Given the cost of the insurance, the expected payout and the size of Ergon Energy's asset base, we consider Ergon Energy has not provided us with sufficient evidence to convince us that it is more efficient for it to purchase parametric insurance than to continue to self insure. Given the nature of the proposed insurance product, we are also concerned that consumers may pay to transfer cyclone and storm risk to a third party but may still bear costs associated with the cyclones.*

QCOSS supports the AER's preliminary decision in this area. We consider that the cost of cyclone insurance is unlikely to be efficient given Ergon's much greater knowledge of the cost of damage to its network than an insurer's, meaning that the insurance premium may be in excess of Ergon's private estimation of the cost of damage.

[27] Independent Review Panel on Network Costs (IRC), *Electricity Network Costs Review Final Report*, p.vii.

[28] AER, 7-30.

Ergon also has control of network resilience through its capex program and the insurance may reduce its incentives to design its network to prevailing conditions.

Alternatively if Ergon is provided with capex for resilient construction of the network it will receive double compensation for potential cyclone damage (especially as Ergon is not required under the revenue cap arrangements to actually obtain insurance). Finally, it is open to Ergon to apply for cost pass-throughs associated with cyclone damage above a cost threshold, which provides a significant measure of protection for Ergon against major cyclone damage.

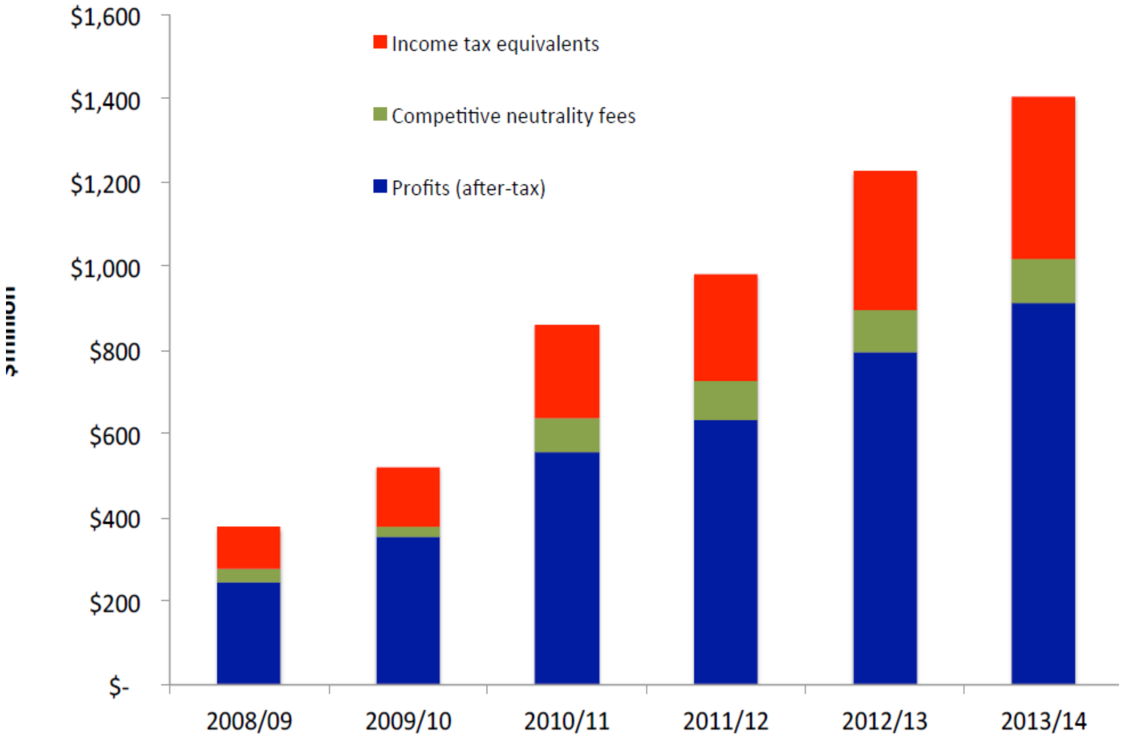
3. WACC

In addition to QCOSS's concern about the Preliminary Decision on opex and capex, QCOSS considers that the final decision provides an opportunity to reduce the WACC. The WACC parameters in the Preliminary Decision are too conservative and are not consistent with the low prevailing cost of capital at present and the low risk of distribution activities.

QCOSS notes that Energex's and Ergon's profitability has been growing at rapid and arguably unsustainable levels in recent times. This reflects excessive capital allowances that have not had to be spent in the current RCP (retained in the form of returns on elevated RABs and associated depreciation of unbuilt assets), excessive opex allowances, and excessive rates of return through overly conservative WACC parameters.

For example, the rapid growth in Ergon's profitability is illustrated below.[29]

[29] Hugh Grant CCP presentation to Queensland Preliminary Decision Conference May 2015, slide 16.



While it is understood that the AER does not regulate profitability as distinct from revenue, the very rapid rise in profitability reflects elevated allowances in capex, opex, and the rate of return.

QCOSS continues to contend that the AER parameters are too conservative in a range of areas, namely market risk premium, gamma, term for debt, and equity beta. QCOSS raised arguments on the values of these parameters in its earlier submission in January 2015. The AER did not accept these values in its Preliminary Decision and we urge the AER to reconsider these for the Final Decision. In this submission QCOSS continues to recommend the point value selected for the equity beta of 0.7.

QCOSS contended in its earlier submission to the AER for an equity beta:[30]

> *…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*

The AER notes that the best available evidence pointed to an estimate of the equity beta around 0.5. For example, the AER noted "*We also consider Henry's 2014 results indicate a best empirical estimate of approximately 0.5 for the benchmark efficient entity. This is because most of the estimates are clustered around 0.5, as shown in figure 3-27*".[31] Figure 3-27 shows a tight

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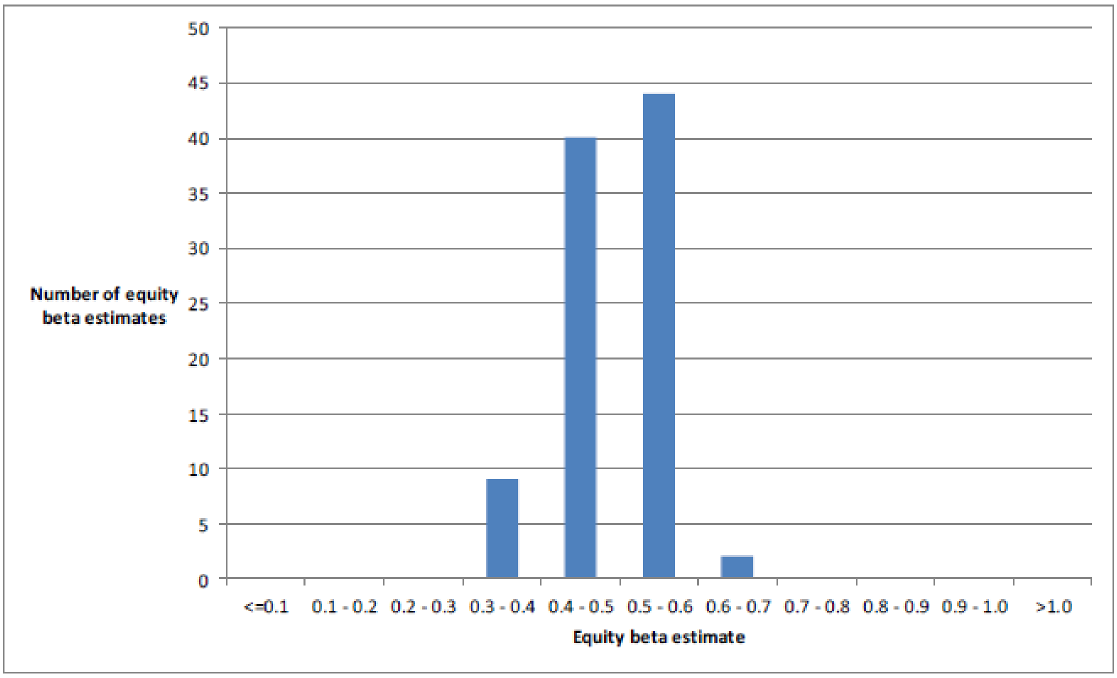
[30] QCOSS, Submission in response to Queensland Regulatory Proposals, p.78.

[31] AER, 3-370.

grouping of the observed equity betas around a value of 0.5.[32] Figure 3-27 also shows very few values in the range 0.6 to 0.7, while far more in the other three ranges.

Figure 3-27 Equity beta estimates from Henry's 2014 report (average of individual firm estimates and fixed weight portfolio estimates)



Source: AER analysis; Henry, *Estimating β: An update*, April 2014.

Nonetheless, in its Preliminary Decision, the AER selected a point value for the equity beta of 0.7 based on:[33]

- Empirical estimates of international energy networks;
- The theoretical principles underpinning the Black CAPM;
- The importance of providing stakeholders with certainty and predictability in our rate of return decisions; and
- The observation that "*a point estimate of 0.7 is consistent with [its] sources of information and is a modest step down from [the AER's] previous regulatory determinations*".

The first reason – using observations from international (especially US) energy networks – is not a strong reason and is disputed by QCOSS. The AER itself pointed to the weakness of relying on these observations in forming the appropriate range, including that many of these businesses are vertically integrated and conduct activities that are much more risky than distribution activities, and are subject to different forms of regulation to Australia. These observations are salient to whether overseas equity betas should be used to

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[32] AER, 3-370.

[33] AER, 3-388 to 3-389.

select a point value for the equity beta. The AER has not adjusted the observed values for the impact of vertical integration or other factors.

Neither does the second reason – the theoretical underpinnings of the Black CAPM –provide strong grounds to select a value above 0.5. QCOSS argued in its earlier January 2015 submission that the Black CAPM should not be used in setting the point value of the equity beta.

QCOSS argued that:[34]

- *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;*
- *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.*

QCOSS also argued that, "*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*".[35] This is because as the AER observed, "[r]elative 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". [36]

QCOSS also mentioned that the Black CAPM has not been observed to work in practice in providing sensible values for the equity beta. The AER itself observed that the Black CAPM does not produce credible results for the equity beta.[37]

Finally, there is little to support the central contention of the Black CAPM for higher returns on low beta stocks and lower returns on high beta stocks. Studies such as Black, Jensen, and Scholes (1972) and Frazzini and

[34] QCOSS, p.111-112.

[35] QCOSS, p.113.

[36] QCOSS, p.113.

[37] AER, Appendices to AER Rate of Return Guideline Explanatory Statement, p.70, discussed at QCOSS, p.113-114.

Pedersen (2013) discussed in QCOSS's submission would suggest the opposite.[38]

The third reason – providing certainty and predictability – overweights the value of certainty against setting the best value on the equity beta consistent with the observed evidence. QCOSS considers that the AER needs compelling grounds to justify moving from the central tendency of the values in Figure 3-27 of around 0.5. This is especially true given the significant divergence of the selected value from the central tendency of the observed equity betas.[39]

QCOSS also disagrees with the reasoning by the AER of using 0.7 on the basis that it is only a modest step from previous values used, which have been around 1.0. The value of 1.0 was higher than the values observed by Olan or indeed by SFG. We would argue that using a value of 0.7 because it is a smaller variation from previous values tends to commit the AER to varying by only small steps rather than setting the equity beta at the level best justified by the evidence.

QCOSS argues that the best available evidence should be the basis for selection of the equity beta. Using the best available evidence would suggest an equity beta around 0.5.

The four reasons given by the AER to select a value of 0.7 rely on the application of variable regulatory discretion over time and are therefore arguably non-transparent. Relying on the best observed evidence is ultimately more predictable and gives users greater confidence in the regulatory approach. Using the best available evidence would suggest an equity beta around 0.5.

4. Metering

4.1 Metering asset base

QCOSS has particular concerns about metering given the AEMC's Rule Change to expand competition in metering services and the future market-led rollout of smart meters in Queensland. We strongly believe the AER should more closely scrutinise metering in the DNSP proposals (particularly Energex). There is little consistency of approach either in the approaches proposed by distributors or in the regulatory decisions reached by the AER. These inconsistencies can be observed in relation to:

- Valuation of the metering asset base (MAB);
- Capex allowances; and
- Opex allowances.

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[38] QCOSS, p.114.

[39] Compare QCOSS submission to the Qld regulatory proposals at p.109-110.

For example, there are no agreed rules for valuation of the metering asset base (MAB) and distributors have taken divergent approaches. Distributors were required to value their existing metering asset base (MAB) for type 5 and 6 meters as part of the round of electricity distribution regulatory determinations in NSW, South Australia, and Queensland. The distributors' valuation methodologies for the MAB have varied among:[40]

- Depreciated actual cost or DAC (e.g. Energex);
- Optimised depreciated replacement cost or ODRC (e.g. Ergon); and
- RAB carve-out (e.g. Essential).

The valuations proposed by distributors and the valuations set by the regulator are inconsistent, as can be seen from table 1.

Table 1: Average meter values

	Ergon*	Essential	SAPN*	Endeavour	Energex*	Ausgrid	Average
Average meter value proposed by distributors	48	81	101	20	200	111	93
Average meter value set by AER	47	65	101	14	206	114	91

Source: AER regulatory decisions
* Preliminary decisions

It can be observed that:

- Energex's average meter value is almost twice as much as any other distributor. In fact, Energex's MAB as set by the regulator in the preliminary decision of $448.8m is almost as high as the total MAB for all the NSW and SA distributors combined ($465.9m).[41]
- The variation in average meter value (comparing the values set by the regulator) is a factor of almost 15.[42]
- The only distributor to receive a significant reduction in the value of their MAB was Endeavour, which had proposed by far the lowest average value for its MAB.

These inconsistencies are implausible given the valuations relate to meters using similar technologies. It could be argued that one MAB was significantly older than another or that one MAB contained significantly more interval meters than another. However it is noted that Energex's MAB contains a high proportion of old meters.[43]

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[40] Energex regulatory proposal 2014, p. 274; Ergon Regulatory Proposal 2014, *05.03.01 Default Metering Services Summary*, p. 37; Ausgrid Regulatory Proposal *Attachment 8.21 - Energeia review of Ausgrid's metering tariffs*, p. 44

[41] The NSW MABs are in $2013-14 while the SA and Qld MABs are in $2014-15.

[42] Energex meters at an average value of $206 per meter compared to Endeavour meters at an average value of $14 per meter.

[43] Energex provides information that 298,163 of its meters or almost 14% of its meters are 35 years of age or older: AER, *Energex determination 2015–20, Attachment 16 – Alternative control services*, p. 16-45, table 16.16.

It may be sensible to apply a consistent valuation methodology for the MAB and QCOSS accepts this is not straightforward One approach to valuation would be DAC, given that the MAB is intended to have a finite life (until depreciation of the existing asset base with few new assets being added to the MAB). The valuation under an ODRC methodology is likely to approximate the valuation under a DAC methodology. The ODRC measures the cost of replicating system assets in the most efficient way possible, from an engineering perspective, given their service capability and the age of the existing assets. However, there is no sensible modern proxy for valuation of the existing meters apart from the existing meters themselves. The step change in functionalities between the existing accumulation and interval meter asset base and the new smart meter asset base means that smart meters are not a suitable comparator for valuing the existing meter stock. The RAB carve-out method, where metering assets are carved out of the RAB and assigned a transfer value that is then deducted from the RAB, is not in itself a distinct valuation methodology – all that it achieves is a consistent valuation of the assets previously part of the RAB.

A key issue in setting the MAB is whether the AER has the power to examine and determine the MAB. In the context of the large variation in Energex's and Ergon's MAB, the AER argued that:[44]

> *There are various reasons why the MABs of Energex and Ergon Energy can differ. For example, the amount of past capex and depreciation differs across both service providers. We do not currently have powers to review past capex on meters. This means a key driver behind Energex's relatively higher opening MAB cannot be reviewed as part of our regulatory processes.*

The AER must ensure that the MABs of Ergon and Energex contain only metering assets and especially that there are no additional assets comprising services such as for the LV network.. This would distort the distributors MABs. The MABs should be consistent in the range of assets they comprise, and should only include metering assets.

QCOSS considers that the AER has the power to make an appropriate allocation for the MAB compared to the RAB net of the MAB. Any other position would be equivalent to distributors having a free hand to set their MAB at any level up to the RAB that they wish.

4.2 Metering capex allowances

QCOSS also contends that Ergon's proposed metering capex is excessive compared to its MAB and compared to the number of meters given:

- Customers will pay for new or customer-initiated meters up front in the future; and

[44] AER, *Energex determination 2015–20, Attachment 16 – Alternative control services*, pp. 16-37 to 16-38.

- The meter base of type 5 and 6 meters could be expected fall as smart meters are introduced.

Table 2 below shows that new capex approved by the regulator in NSW, South Australia, and Queensland is high as a proportion of the MAB. The new capex ranges from a low of 7 per cent for Energex to a high of 85 per cent of the existing MAB for Ergon. As Energex's MAB and to a lesser extent Ausgrid's MAB are unusually high as discussed earlier, this may have the effect of making the capex spending as a percentage appear unusually low. Accordingly, the new capex programs have also been expressed as a percentage of the average MAB value, that is as a levelised capex/MAB, which may be a fairer way of comparing relative capex among distributors. On the levelised capex/MAB measure, capital expenditure ranges between a low of 12 per cent for Endeavour and a high of 55 per cent for Ausgrid.

Table 2: New capital spending on accumulation and interval meters by distributors

	Ergon	Essential	SAPN	Endeavour	Energex	Ausgrid
Capex accepted by regulator	51.3	46.6	10.6	14.6	29.4	117.8
Capex/MAB (%)	85	49	12	78	7	44
Levelised capex/MAB (%)	44	35	14	12	15	55

Source: Distributor Regulatory Proposals, 2014 and AER decisions. $2014-15

The proposed capex program by Ergon is notable as it is $51.3m compared to an approved MAB of $60.7m (or 85 per cent of the MAB).[45]

It seems infeasible that Ergon should expect to continue to spend strongly on expansion of its MAB. It also means that, contrary to conventional wisdom in this area:

- Depending on depreciation profiles, MABs may well continue to expand rather than shrink over time, particularly over the course of the next regulatory control period in some distribution areas in NSW and Queensland;
- Over time rising MABs may drive the residual costs higher, with implications for users who have switched to smart meters. These users may find that their annual residual capital cost associated with paying off their old accumulation meter rises from year to year, and thus their initial private cost-benefit analysis of the net benefits of switching to a smart meter is wrong;
- Exit costs are unlikely to be clear and transparent as recommended by the AEMC in their Power of Choice review, reasonable, or less than three times the annual metering charge; and

[45] AER 2014, *Ergon Preliminary decision 2015–20: Attachment 16 – Alternative control services*, p. 16-23. Expressed in $2014-15.

- It may be difficult for new entrants to compete with distributors in the provision of new meters given distributors have large forward capex budgets for provision and installation of new meters.

These are all highly undesirable policy outcomes.

4.3 Operating expenditure on existing meters

Table 3 below sets out: (i) the approved operating expenditure for each of the distributors; (ii) the approved opex as a percentage of the MAB; and (iii) a levelised opex as a percentage of an average MAB.

Table 3: Approved operating expenditure to maintain existing metering asset base

	Ergon	Essential	SAPN	Endeavour	Energex	Ausgrid
Forecast opex approved by AER	118.6	124.7	34.9	71.7	78.6	111.0
Opex/MAB (%)	195	132	41	381	18	42
Levelised opex/MAB (%)	102	93	46	58	40	52

Source: Distributor Regulatory Proposals, 2014. $2014-15

As with the MAB and proposed capital spending, there are big variations in proposed opex. While it could be expected that rural-based distributor opex costs would be higher than urban-based distributor opex, the unusual aspect of the opex proposals is that the components vary considerably among the distributors.

4.4 Recognition of opex and capex savings from the installation of smart meters

One of the benefits of the introduction of smart meters identified in the draft rule is the saving in opex and capex to the distributors. These savings come in a number of forms, including savings in meter reading, connection and disconnection costs, quicker fault detection, and capital and operating expenditure savings arising from shifting demand from peak to shoulder or off-peak times. As noted earlier, a substantial portion of the benefits identified in the NERA 2008 cost-benefit analysis accrued to distributors.[46]

The AER has not recognised in its Preliminary Decision any capex or opex savings arising from installation of smart meters. Thus consumers do not receive any benefit, at least for the next regulatory control period, from the savings arising to distributors from the installation of smart meters.

4.5 Exit arrangements

Exit arrangements relate to the arrangements for covering the residual costs of existing meters when switching to a new meter.

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[46] $2.1 to $2.9b out of total net benefits of $4.5 to $6.7b, or roughly half the total net benefits.

The distributors have proposed an arrangement where a user exiting from an existing meter to a smart meter would pay an upfront exit fee to cover the residual cost of the existing meter.

The AER has proposed that instead of exit fees, users replacing meters would continue to pay residual capital costs (although not operating costs). It is understood that users would continue to pay the residual capital cost until the MAB depreciates to zero. The AER's Preliminary Decision proposes that existing users continue to pay an annual charge covering the capital costs of the meter they have exited from rather than an upfront exit fee. However, in essence it provides for a similar approach in that the residual fee is based on the average meter cost under the MAB. Thus the suitability of the AER's approach depends on whether the MAB is appropriately valued, as the MAB drives the calculation of the residual fee paid by users migrating to smart meters.

As noted above, the valuation of the MAB has been problematic as a wide variety of valuation methodologies and values have been proposed to the AER.

This is another compelling reason not to accept the opening MAB and attempt to provide a prudent and efficient opening MAB which can be rolled forward with confidence.

Given the significant approved capex inflows to the MABs for the next regulatory control periods in some distribution areas in NSW and Queensland (although not in South Australia where the capex proposal is more modest) exit costs may rise over the course of the regulatory control period. This may cause confusion for consumers, change the terms of their private cost-benefit equation, and move the exit arrangements and costs away from those recommended by the AEMC in its 2012 Power of Choice report.