Consumer
Challenge
Panel

CCP14

# Response to the Energy Queensland (Energex and Ergon Energy) 2020-25 Draft Plan and Early Engagement

Submitted to the AER and Energy Queensland, September 2018

*CCP14 has reviewed the EQ 2020-25 Draft Plan. We can confirm that we have made relevant checks to ensure that to the best of our knowledge, the document does not contain any confidential material or material that is commercial in confidence. This document can be published on the AER website.*

# 1. Overall assessment of EQ's Draft Plan

Energy Queensland (EQ) is the parent organisation for the two Queensland Electricity Distributors - Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon).

As a 100% State Government Owned Corporation operating under the *Government Owned Corporations Act 1993* (GOC Act), the influence of government initiatives in regard to the price of energy and regional support is observable in the Draft Plan. This is seen particularly in the importance of the efficiency savings stemming from the Government's decision in 2016 to merge Energex and Ergon to form EQ. That affordability is the key issue is well recognised.

We believe that the Draft Plan is a quality document, with sufficient narrative for the reader to understand the key objectives and intent inherent in the 2020-25 plans, with sufficient depth in quantitative information to allow effective and informed comment and questioning by an informed consumer advocate or other interested stakeholder.

Based on the latest AER data (2015/16), Energex is around the middle of the pack and Ergon is at or near the bottom in terms of the productivity of the 13 DNSPs. While the merger savings would have improved Energex and Ergons absolute position, many other DNSPs, especially in NSW, have also undergone significant transformations in recent years to improve their efficiency and productivity. We recognise the challenges of operating and maintaining a regional electricity distributor with a wide variety of climates. However Ergon did enjoy significant funding for network security in recent regulatory periods and consumers are looking for the benefit of those past investments in reductions in the proposed capex and opex plans for Ergon.

The Draft Plan presents indicative data suggesting that Energex and Ergon are efficient. We look forward to more substantive information being provided in the January 2019 submission and the AER's review of this data as well as in the opex productivity review recently announced by the AER.

The Draft Plan shows that Energex retail customers will receive a nominal 8% fall in the network component of their bill in 2020-21, the first year of the new regulatory period. The corresponding reduction for Ergon residential customers is also 8% because of the way in which the Uniform Tariff Policy (UTP) is applied in setting retail prices in regional Queensland. Without the UTP the fall in the network component would be only 1%. Energex business customers get a similar 7% fall in the network component of their bill in 2020-21. However, business customers connected to Ergon Energy's network which are not supplied by Ergon Energy Retail do not benefit from the UTP and hence will see no change in their prices in 2020-21 even with the fall in WACC.

While the efforts by EQ to improve efficiency and productivity, particularly in Energex, are acknowledged, these price falls are more driven by a lower WACC than they are by EQ efficiency measures. The fall is WACC is outside of EQ's control – a combination of lower interest rates and a lower equity return in the AER's Draft Guideline issued in June.

Changes within EQ's control eg lower capex and opex, contribute only around half of the price fall for Energex customers and only around a third of the price change for Ergon customers – with the rest due to WACC changes. The price for business customers connected to the Ergon network but not Ergon Retail customers would have gone up by in 2020-21 were it not for the fall in WACC.

While CCP14 welcomes the proposed productivity improvement, our key question is – why could they have not been greater? The price changes would have been quite different had interest rates been increasing. Once capex gets into the RAB it stays there for its asset life and the inevitable interest rate cycles. Affordability is influenced not just by today's WACC, but the WACC over the life of the asset.

EQ has shown a genuine desire to continue substantive consumer engagement in the lead-up to it making its submission and we look forward to this. We look forward to this further engagement leading to a submission in January 2019 that is capable of being accepted by stakeholders.

The approach taken in this submission is to:

- Comment on issues raised so far in the Draft Plan and consumer engagement
- Indicate areas where we look to further information/clarification being provided by EQ either at the Customer Council and RP-TSS Working Group Forum on 7th November 2018 or in the January 2019 submission.

Mark Grenning (Chair), Louise Benjamin and Mike Swanston - CCP14

## 2. The purpose of this response to the EQ Draft Plan

The role of the CCP has expanded recently to provide a focus on the early engagement stage prior to a network's formal submission of its proposal to the AER. We view this as an important step in the maturing landscape of community engagement related to a regulatory reset. It provides a great opportunity where key issues can be aired and considered by a network business with the view of presenting a regulatory proposal that is 'capable of being accepted'.

Issues raised in this submission are intended to be considered by:

- the AER, to assist in the identification of key issues and the engagement with EQ in the lead-up to, and after, the regulatory proposal is submitted
- EQ, to identify areas of community concern and opportunities to improve their draft proposal, assisting in its acceptance by customers and community groups, and
- other community groups and stakeholders in the EQ reset engagement process, to assist in clarifying matters against which the level of engagement and 'listening' for proposal can be measured.

Section 3 provides an overview of the key issues we see in the Draft Plan. Section 4 discusses the AER data on Energex and Ergon efficiency. Section 5 highlights key issues - particularly where more information would assist consumers in understanding the EQ proposal. Section 6 focuses on capex. Section 7 on opex. Section 8 reviews EQ's consumer engagement activities. Section 9 comments on the Network Tariff Summary.

## 3. Overview of EQ Draft Plan

The Draft Plan together with the information provided in the lead-up information sessions ('deep dives'), provides a sound basis for consumers to get a good understanding of EQ's proposal. This section provides an overview of the key points we consider as being of most interest to consumers.

1. In contrast to the current period, peak demand over the 2020-25 period is forecast to be relatively flat with an annual 0.4% growth for both Energex and Ergon.

Total energy is forecast to increase slightly driven by a forecast 117,000 (0.8%) increase in Energex and 60,000 ( 0.8%) in Ergon customer numbers by 2025. We look forward to reviewing the demand forecasts in the January 2019 submission to understand trends in the following format.

| MW | Actual | | 2020-25 | | | |
|---|---|---|---|---|---|---|
| | Energex | Ergon | 50% POE | | 10% POE | |
| | | | Energex | Ergon | Energex | Ergon |
| 2015-16 | xx | xx | | | | |
| 2016-17 | xx | xx | | | | |
| 2017-18 | xx | xx | | | | |
| 2018-19 | xx | xx | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2019-20 | xx | xx | | | | |
| Forecast peak | | | xx | xx | xx | xx |

2. Improved reliability and exceeded Minimum Service Standards (MSS)

Both Energex and Ergon are currently meeting their network performance targets by some margin. This applies for both Minimum Service Standards (MSS) and Service Target Performance Incentive Scheme (STPIS) targets [1]. Customer engagement indicated 83% of survey respondents were satisfied with the overall reliability or quality of their power supply.

The State Government is yet to provide EQ with the MSS for the next regulatory period.

3. Comment on forecast revenue vs AER allowances

We look forward to information being provided in a form that allows the following comparison.

| $2020 | 2015-20 | | 2020-25 | |
|---|---|---|---|---|
| | Allowance | Forecast | Forecast | % change |
| Energex | | | | |
| Total | ?? | ?? | $6,691m | -8.4% |
| Revenue per customer (av) | ?? | $935 | $774 | - 17% |
| Ergon | | | | |
| Total | ?? | ?? | $6,880m | ?? |
| Revenue per customer (av) | ?? | $1,723 | $1,548 | -10% |

4. The largest price falls in network charges are to Energex customers and Ergon customers that are the beneficiaries of the Uniform Tariff Policy. Business customers connected to the Ergon network but which are not Ergon Retail customers receive no benefit, even with the fall in WACC.

**Table 1 Forecast reduction in distribution network charges between 2019-20 to 2020-21[4]**

| | Average Residential Customer | | Average Business Customer | |
|---|---|---|---|---|
| | Real | Nominal | Real | Nominal |
| Energex | 10% ↓ | 8% ↓ | 9% ↓ | 7% ↓ |
| Ergon Energy | 3% ↓ | 1% ↓ | 2% ↓ | 0% ↓ |

*Figure 1 - Forecast reduction in distribution network charges 19-20 to 20-21 (Source: Draft Proposal Table 1)*

The table shows the Energex and Ergon reductions in year 1 (P0) and reflects the strong feedback from consumers to have the largest fall in year one followed by CPI increases in years 2-5 rather than smoothed reducing price paths over the full 5 years. Application of the Uniform Tariff Policy

[1] EQ Draft Plan, page 24

will change the 1% nominal reduction for residential customers to the same 8% as Energex residential customers.

5. The price falls in 2020-21 are substantially driven by a fall in WACC (lower interest rates and lower equity return in the AER's Draft Rate of Return Guideline) rather than actions by EQ to reduce its capex and opex. For Energex over a half of the price fall is driven by a lower WACC. For Ergon is it around two-thirds.
6. The price falls in 2020-21 assume continuation of the Queensland Government payment of the costs of the Solar Bonus Scheme.

   In 2015-17 the Queensland Government payed EQ a $771m Electricity Affordability grant to remove the costs of the Solar Bonus Scheme from electricity retail prices from 2017-18 to 2019-20, the last year of the current regulatory period. In 2018-19 this is estimated to cost $284.2m[2].
7. Energex is forecasting a variance in the current period capital investment of an under expenditure against the AER allowance of $380m or -12%. This includes:
   a. a 20% reduction in asset replacement (Repex)
   b. a 16% reduction in the aggregate of IT and capitalised overheads, and
   c. only property (24% or $21.8m) and Connections (4%, $20m) were overspent in the period.
8. Against this capital underspend in the current period, Energex is proposing a further 16% ($460m) reduction in capital investment in 2020-25. The treatment of IT makes a clear assessment of the trend of IT expenditure and capitalised overheads difficult. CCP14 proposes that EQ arrange another specialised deep-dive workshop to further explain these costs so that they can be properly considered by consumer groups.
9. Ergon is forecasting a variance in the current period capital investment of an under expenditure against the AER allowance of $495m or -15%. The Ergon result comprised mainly underspends in network augmentation (-46%, $261m) and IT / Overheads of 19% ($214m) The Ergon result was tempered by an increase in asset replacement investment in Ergon by 13% or $103m.
10. Against this capital underspend in the current period, Ergon is proposing a further 10% ($278m) reduction in capital investment in 2020-25.
11. Total ($2020) RAB is down very slightly for Energex and constant for Ergon. RAB per customer is down 7-8% for both reflecting increasing customer numbers and better (but still relatively low) asset utilisation levels.
12. For Energex opex is forecast to be $1.79b, a 4% decrease from the current period's forecast. There are no step changes and offsetting productivity improvements in works delivery (3%) and overheads (2.8%) to partially offset the forecast rise in real labour costs.
13. For Ergon, opex is forecast to be $1.79b, an 8.29% decline on forecast costs in the current period. Again, there are no step changes and offsetting productivity improvements in works delivery (3%) and overheads (3.4%) to partially offset the forecast rise in real labour costs.
14. Both Energex and Ergon propose the introduction of the Lifestyle tariff on an opt out basis. The tariff includes a seasonal time of use component, which can be smoothed over the year by customers choosing a higher usage band. The tariff also includes a top up charge which applies to the highest daily exceedance of the customer's nominated usage band during the summer peak

[2] See p. 163 https://budget.qld.gov.au/files/BP2-2018-19-Appendix%20A.pdf

window months (currently November to March inclusive). An extensive education and trial program known as TEDI will support the introduction of the tariff to manage customer impacts through education and the provision of information tools to customers.

## 4. How efficient are Ergon and Energex?

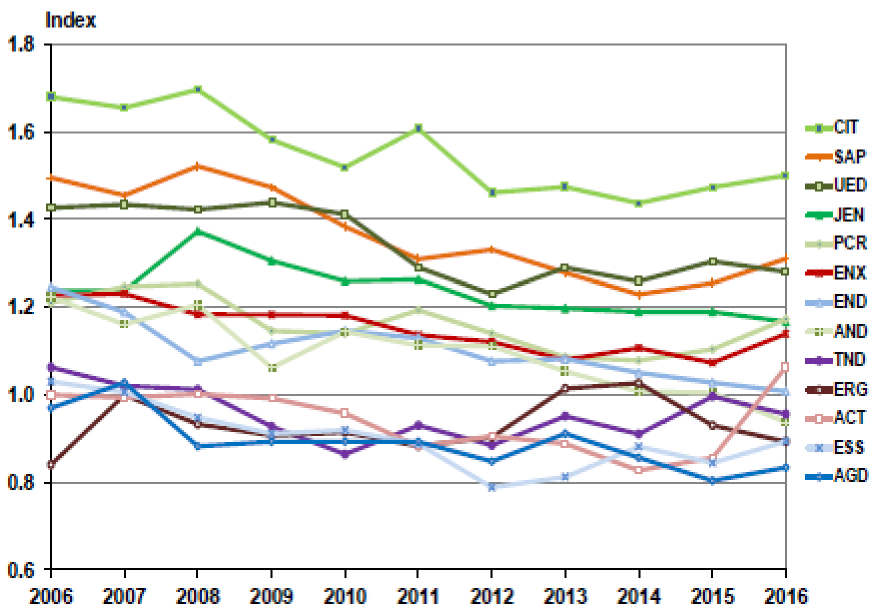
In short, not very, particularly Ergon. Based on the most recent 2017 AER 2017 DNSP Benchmarking report[3], Energex was around the middle of the pack and Ergon the second worst for 2015/16 out of 13 DNSPs for multilateral total factor productivity (MTFP).

| | 2016 Rank | MTFP Score |
|---|---|---|
| Citipower | 1 | 1.50 |
| SAPN | 2 | 1.31 |
| Energex | 6 | 1.14 |
| Ergon | 12 | 0.89 |

The next figure shows that over the 10 year period from 2006 for which data is available[4]:

- the relative positions of Energex and Ergon have remained similar to those in 2015/16
- generally overall DNSP productivity fell in the period 2006 to ~2012-2014, with some rise in recent years, though in many cases it is still generally significantly below the rate in 2006

Figure 15 MTFP by individual DNSP, 2006–16

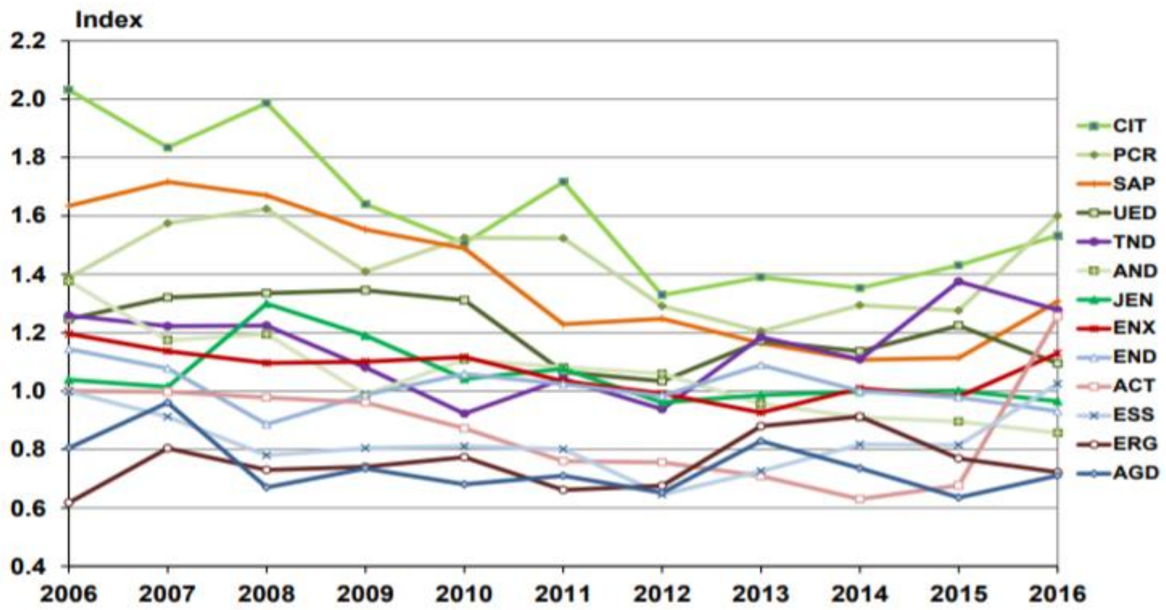



[3] See AER "Annual Benchmarking Report Electricity Distribution Network Service Providers" November 2017 p. 8 https://www.aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf

[4] Ibid p. 32

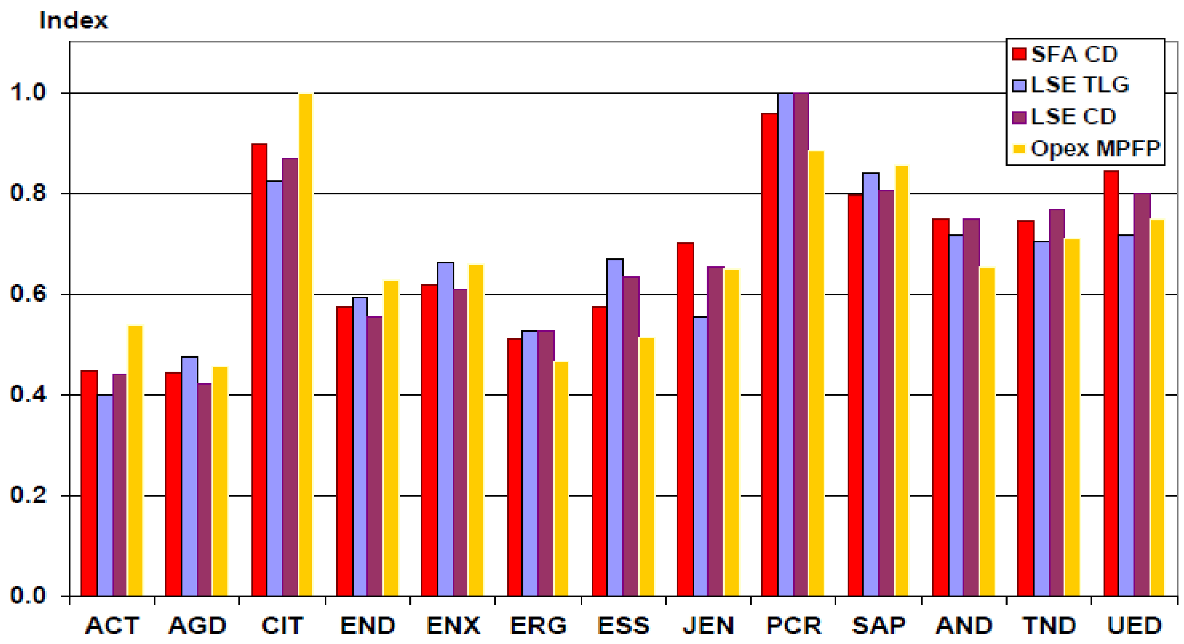
Energex and Ergon are in similar relative positions for opex productivity with similar trends over time. Whether the MPFP benchmarking data[5] is used:

Figure 17 Opex multilateral partial factor productivity (MPFP), 2006–16




or the comparison including the three econometric models incorporating overseas data (MPFP is only Australian data) that the AER uses[6]:

Figure 18 DNSP opex cost efficiency scores, (2006–16 average)




[5] See AER op cit p. 37

[6] See AER op cit p. 39

Energex is around the middle and Ergon is in the bottom 2-3 DNSPs.

More recent data is expected to show further improvement in MTFP and MPFP scores across many networks. In NSW DNSPs, for example, this will be driven by the major redundancy programme that has been underway in recent years[7]. The Draft Plan provides indicative data for both Energex and Ergon that argues for both (p. 58 and 86) that:

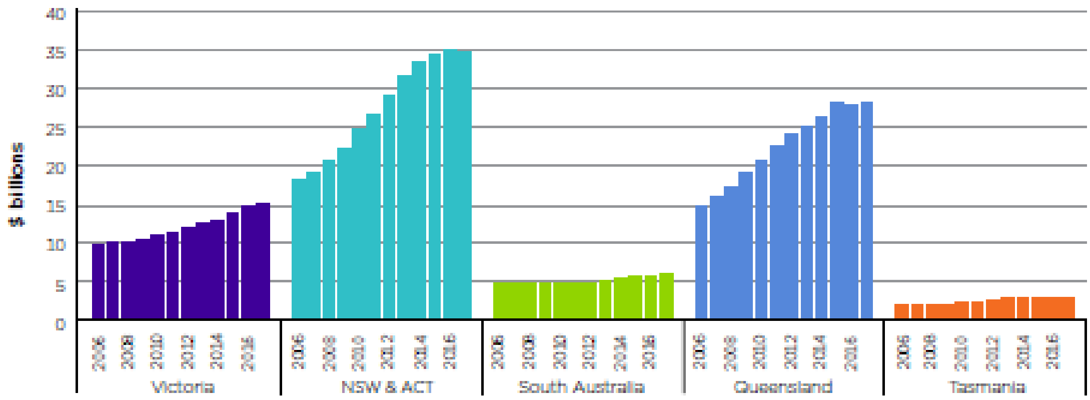
> "Overall opex appears comparable to our peers once our operating environment is considered using both the AER current and draft Sapere-Mertz approaches."

We look forward to more comprehensive data being provided in the submission to substantiate the conclusions made in the Draft Plan.

A major cause of this poor productivity for Energex and Ergon was over-investment in assets and then the associated operating costs of those assets. The recent ACCC Electricity Report highlighted the growth of these assets in Queensland, concluding that[8]:

> "…driven primarily by excessive reliability standards and a regulatory regime tilted in favour of network owners at the expense of electricity users (see figure D). This has enabled networks to recoup billions of dollars of extra revenue from consumers."

Figure D: Regulatory asset base from 2006 to 2017, by NEM region, real $2016–17




A good indicator of the impact of this over-investment is asset utilisation levels[9]:

| | 2006 | 2017 |
|---|---|---|
| Energex | 50% | 43% |
| Ergon | 71% | 53% |
| Average of all DNSPs | 57% | 47% |

[7] Ibid p. 10

[8] ACCC "Restoring electricity affordability and Australia's competitive advantage - Retail Electricity Pricing Inquiry—Final Report" June 2018 p.ix
https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf

[9] AER RIN Data

Under the regulatory framework, once an asset is included in the regulated asset base RAB), it stays there until it is fully depreciated. Unless of course the owner voluntarily writes down the value of the asset base which was the recommendation in the ACCC report[10]. This has been rejected by the Queensland Government.

So this leaves consumers to focus on new capex to ensure that only essential capex gets into the RAB, and opex, to ensure it is at the efficient level to meet the network's licence conditions on reliability, security and safety. As the Draft Plan notes (p.19):

> "Our stakeholders want us to:
>
> - explain the sources of savings, including: merger, efficiency, productivity, innovation, and trade-offs between alternatives
> - show what efficiencies and customer benefits have been achieved and what are planned – e.g. from ICT rationalisation and transformation."

# 5. Key issues in the EQ Draft Plan and engagement to date

## 5.1 More information is required on the pass-through of the merger savings to consumers

A range of information has been provided during consumer engagement on the level and impact of the so-called "merger savings". Overall, we find the information provided somewhat confusing. If we understand the merger savings fact sheet[11] correctly then:

- The originally announced savings in the 2015/16 MYFER were $562m over the current reset period to 30th June 2020
- The latest estimate of these savings for this period  is $595m
- When "other" savings are added the "merger savings" total savings for the current period are $735m which will be seen in a reduction of $595m in the actual recovery for a combined Energex and Ergon vs AER allowances for the 2015-20 period with the breakdown shown in this figure:

[10] ACCC op cot p. xviii Recommendation 11

[11] file:///C:/Users/mark/Downloads/Fact_Sheet_-_Ergon_Energy_and_Energex_-_Savings_Against_the_2015-20_AER_Allowance_(June_2018).pdf


- These savings will be allocated 58% to Energex and 42% to Ergon
- Merger savings are expected to continue into the next 2020-25 regulatory period.

However, we are still confused by what appears to be inconsistent representation of the savings from different sources and we look forward to this being clarified. The Treasurer's media release in December 2015[12] announcing the merger savings said:

> "Along with a number of other efficiency measures across Queensland's electricity network and generation businesses, this merger will save around $680 million over the 2019-20 period"

  - What is the difference between the $680m number and the numbers presented in the fact sheet, particularly the $562m number? Is the $562m relating to the impact on the regulated parts of EQ?
  - Presume "…over the 2019-20 period" is a mistake and it should have been "…over the period 2015-16 to 2019-20"?

We look forward to clarification on:

- What "$" are the numbers presented in? it can be confusing - p. 17 says the $735m was nominal as is the $562m; presumably the $680m number announced in 2015/16 was nominal as well?
- Were all the savings directed at the regulated parts of EQ's business? How much occurred in the unregulated parts of EQ's business?
- What was the relative contribution of capex (lower depreciation/return of capital) vs opex? What were the reductions by capex/opex category?

The fact sheet says:

> "In addition to savings enabled specifically by the merger, Energex and Ergon Energy … also achieved reductions prior to the completion of the merger transaction. Energy Queensland expects to achieve total savings against the regulatory allowances for the current five year period (net of implementation costs) of approximately $735 million across the two businesses."

What does "prior to the completion of the merger transaction" mean? Does it mean that there were savings already found prior to the MYFER announcement? Were there any other savings identified

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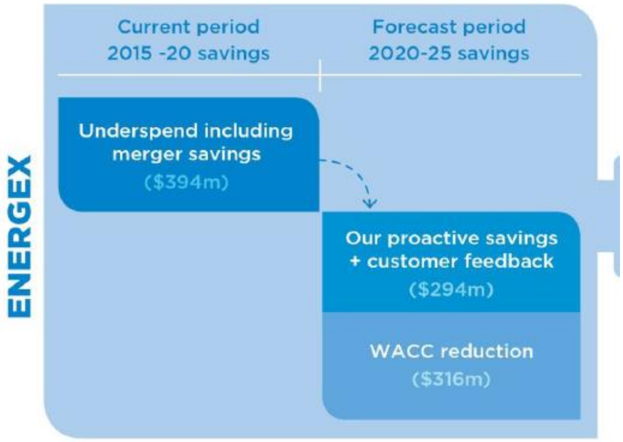
[12] http://statements.qld.gov.au/Statement/2015/12/15/electricity-company-mergers-save-680-million-and-drive-regional-jobs

subsequent to the MYFER announcement that were in addition to those identified as part of the MYFER announcement?

The presentation of the impact on Energex on p.4 of the Draft Plan:




We look forward to clarification on:

- The $394m referred to as "Underspend including merger savings" is 58% (the Energex share set out in the fact sheet) of the $680m number, not 58% of the $735m number
- Does the 58%/42% allocation apply in 2020-25 as well as 2015-20?
- What is actual impact on total revenue collected? The fact sheet says:

  "The savings achieved through the merger have flowed predominantly to capital expenditure, whereas the associated restructuring costs have reduced the profit of the organisation.

  Savings in capital expenditure will flow into the next regulatory period (2020-2025) when the regulatory asset base will be lower than it otherwise would have been and network prices will be set based on this lower cost base. It is also expected that adjustments will be made under various regulatory incentive schemes."

  - But the figure shown above suggests that the $206m "Restructuring and redundancy cost" is clawed back as additional revenue rather than a reduction in profit. If it was a reduction in profit then the "Total net totex savings to AER allowance" would be $206m higher
  - Will consumers receive the total benefit of the capex/opex reductions in the current period in the next period or only receive 70% because of the application of CESS and EBSS?
- The Draft Plan says (p.34):

  > "We forecast underspending the AER's total capex and opex (totex) allowance by $394m in the current regulatory period for Energex and $503m for Ergon (real $2020)."

  How does this reconcile to nominal amount of $735m – see footnote 12?
- What is the contribution of merger savings in the 2020-25 reset period given:

  "We expect savings from the merger to continue to be sustained throughout the next regulatory period. In addition to benefits to customers relating to savings in the current regulatory period, EQL will be incorporating a commitment to achieve further savings in indirect expenditure into its regulatory proposals."
- It would be helpful to build up a table something like the following for both Energex and Ergon:

| | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|
| AER Allowance | xx | xx | xx | xx |
| Actual/forecast revenue | xx | xx | xx | xx |
| Reduction<br>- Due to reduced capex<br>- Due to reduced opex<br>- Total | <br>xx<br>Xx<br>xx | <br>xx<br>xx<br>xx | <br>xx<br>xx<br>xx | <br>xx<br>xx<br>xx |

## 5.2 More information is required on the impact of merger savings on unit costs of doing work, including vegetation and overheads.

We look forward to more comments on this issue.

## 5.3 Total RAB is falling very slightly for Energex and is static for Ergon.

The table summarises RAB trends:

| $2020 | 30th June 2015 | 30th June 2020 | | 30th June 2025 |
|---|---|---|---|---|
| | | AER final decision | Draft Plan | Draft Plan |
| Energex | | | | |
| Total ($m) | $12,248m | $13,170m | $12,919m | $12,755 |
| % change on forecast for 30 June 2020 | | | | -1.3% |
| Per customer ($) | $8,7667 | $8,713 | $8,547 | $7,831 |
| % change on forecast for 30 June 2020 | | | | -8.4% |
| Ergon | | | | |
| Total ($m) | $10,824 | $11,806 | $11,690 | $11,701 |
| % change on forecast for 30 June 2020 | | | | 0 |
| Per customer ($) | $14,862 | $15,090 | $14,941 | $13,889 |

| | | | | |
|---|---|---|---|---|
| % change on forecast for 30 June 2020 | | | | -7% |

Trends in RAB are a key issue for consumers. Given the generally long life of most network assets, once capex gets into the RAB consumers will continue to pay for it for its entire asset life, irrespective of whether it is fully utilised. While WACC levels are relatively low today driven by historically low interest rates, consumers are aware that prices can increase dramatically in the future when the interest rate cycle changes. This is why there is the focus on ensuring only the most necessary capex is included in the 2020-25 period.

We look forward to seeing data on forecast asset utilisation for the 2020-25 period to see the level of improvement on the current rates of around 43% for Energex and 53% for Ergon.

### 5.4 We await more detail on demand forecasts

EQ is developing revised demand forecasts incorporating the impact of their proposed tariff changes.

### 5.5 The commitment to apply the forthcoming binding AER Rate of Return Guideline is welcome as is the approach used by EQ to show the impact of the change in WACC on their proposal

The commitment to the 2018 Rate of Return (WACC Guideline) is expected by all customers in all current resets.

We note that EQ has calculated the WACC in its Draft Plan in accordance with the AER's recently published 2018 Draft Rate of Return Guideline and we welcome the commitment in the Draft Plan (p.44) that the outcomes from the final 2018 binding WACC Guideline will be incorporated into the Regulatory Proposal.

We also commend EQ for being transparent about the relative contributions in the revenue changes in 2020-25 from 2015-20 between:

- factors outside of EQ's control e.g. lower equity return in the AER's Draft Rate of Return Guideline form June and lower interest rates,
- and those within EQ's control eg lower capex and opex - separating out the initial EQ proposal from the further reductions due to the deep dive consumer engagement process.

The table shows that the contribution of a lower WACC to the reduction in forecast revenue is ~ 55% for Energex and ~70% for Ergon:

| | Energex | Ergon |
|---|---|---|
| WACC contribution | 4.4% | 3.2% |
| EQ contribution | 4.0% | 1.4% |
| Total | 8.4% | 4.6% |

The following figures show the relative contribution from customer feedback for Energex (p.44):


and Ergon (p.72):

Figure 52 Impact of WACC and customer feedback on revenue reductions


### 5.6 The role of the various incentive schemes is unclear

The data from the capex workshop shows that over one-third of the reduction in capex in 2020-25 over forecast 2015-20 is due to a steep decline in expenditure in demand-driven augmentation and connection costs, similar to that seen in other states and jurisdictions as a result of external factors such as falling demand growth, improved appliance efficiency and a response by customers to higher energy prices.

We look forward to further data to better understand the impact of the opex and capex reductions in the current period on CESS and EBSS and revenue in the 2020-25 period

### 5.7 The issue of DER growth in Qld and the transition to a Distribution System Operator (DSO) remains an area of interest for customers. We seek further clarity regarding of EQ's investment plans in future network technology, with a specific focus on the costs and engagement of all consumers.

We acknowledge the challenges brought on by the rapid development of distributed energy resources (DER) sponsored in part by various Government initiatives and not entirely consistent with the efficient development and operation of the distribution network. The is particularly the case in South Australia where very strong Government subsidies will have a potentially much more significant impact during the 2020-25 regulatory period than it will for EQ. The Peak Smart and other controlled load initiatives that the Queensland distributors have put in place have assisted EQ in managing the increasing pressures from DER.

At the request of the AER, CCP14 provided specific advice to the AER on 29 June 2018[13] regarding a customer-focussed and transparent investment planning process to ensure it's plans were most likely

[13] See https://www.aer.gov.au/system/files/Subpanel%2014-%20Response%20to%20SA%20Power%20Networks%20approach%20to%20the%20challenges%20of%20the%20high%20penetration%20of%20embedded%20generation%20as%20part%20of%20their%202020-25%20Regulatory%20Proposal%20early%20enagegement%20-%2029%20June%202018.pdf. SAPN responded

to be understood and supported by their customers. That advice focussed on investment in capex proposals for DER monitoring and curtailing. CCP14 has also raised our concerns about the development of DSO style capability as a response to manage the impact of DER on the network.

We will be particularly interested in how EQ addresses the impact of DER and the state renewable energy policy in their proposal and responds to the concerns raised in our advice to the AER on SAPN.

### 5.8 Further evidence that capital expenditure items are well supported by data or the sentiment of the community through informed and balanced advice will assist

The section on "Customer insights and our actions" discusses a range of insights gained from a range of customer engagement activities:

- Strong (83%) support for current reliability
- 79% concerned or highly concerned about affordability
- Customer want significant reductions in network charges in 2020-25
- They want those reductions front-ended

We look forward to EQ providing more details on specific consumer feedback on the proposed capex programme.

## 6. Summary of the Draft Plan – Capital

CCP14 has a number of overarching principles to support capital investment, being:

1) a demonstrated commitment to a reduction in the RAB, with a goal for the capital investment to be less than the depreciation
2) ensure investments in non-network assets, in particular IT, provide demonstrable benefit to consumers
3) ensure investment leading to improved or changed performance or services has clear and informed consumer support
4) identify under-expenditure in the current period that is not efficiently carried forward
5) aggressively continue to pursue efficiencies, cost reductions and productivity improvements
6) changes in design or risk approach that leads to reduced cost (e.g. overhead lines in lieu of underground)
7) use of new technology leading to clear cost reductions or expenditure deferral
8) network performance agreements with customers enhancing non-network options
9) a staged approach to asset replacement
10) a focus on the reduction in capitalised overheads, and

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on 2nd August 2018 See https://www.aer.gov.au/system/files/SAPN%20response%20to%20CCP14%20advice%20to%20AER.pdf

11) per-unit efficiencies for assets such as vehicles, buildings and mobile technology.

## 6.1 Energex Limited

Energex is proposing a significant reduction in capital investment in 2020-25 of -16% (-$460m) when compared to its forecast expenditure in the current 2015-20 period. This reduction is one of the largest reduction we have seen in the latest round of regulatory proposals, and the only case where reductions have been proposed in all categories other than IT.

The major areas of planned reduction are:

- Replacement of assets – 24% (-$250m)
- Augmentation -34% (-$144m)
- Property -28% ($34m)

*Customer connections*

Energex is expecting to connect 117,000 new customers in 2020-25, at a slightly lower cost than in the current period. Energex is forecasting a gross capital requirement of $485m to do this, down by 7%. On early consideration, this approach seems reasonable, and is generally consistent with the proposals from Ausgrid, where similar high-density development is occurring.

It is interesting to note that Endeavour Energy in Western & Southern Sydney is planning to connect a similar number of new customers in the period (120,000), yet at a significantly higher total cost and with a significantly different ratio of capital contributions to total cost. One explanation for this change may be the greater proportion of high-density multi-story development in South-east Queensland. In the future, CCP14 strongly recommends the AER consider a broader study of the cost of connections and the capital contribution policies across distributors.

*Network Reliability*

Given ,as noted above that both Energex and Ergon are meeting their MSS and STIPIS targets, we do not expect to see any increase in investment for the improvement of network reliability, except should Energex or Ergon make a specific issue of worst performing feeders. This is not evident to date.

*Augmentation*

Energex is intending to reduce its investment in network capacity and reliability by 34% or $144.5M. This is a significant decrease, but not unlike that of similar utilities that have been subject to increased network reliability standards in recent periods.

*Replacement Capital*

Energex is intending to reduce its investment in asset replacement by 24% or $204.5M. This is also a significant decrease. Unlike that of similar utilities, this is a continuing downward trend from the previous period, not seeking to increase the rate of investment.

We recognise the tools and expertise the AER has in assessing this type of capital requirement, and defer to the AER in this area. More broadly though, we recognise that the trend, along with stable network performance, suggests:

- a reasonable expectation that the proposal is sustainable, and
- an assumption that the underspend this period is efficient.

*Capitalised Overheads*

No comment until the clarity as to the IT transfers in the current period are resolved.

*Non-network capital*

It is noted that the proposed expenditure on Fleet & Equipment and Property is significantly less (-11% and -28% respectively) than the current period.

### 6.2 Ergon Energy Limited

Ergon is proposing a significant reduction in capital investment in 2020-25 of -10% (-$278M) when compared to its forecast expenditure in the current 2015-20 period.

The major changes are:

- Replacement of assets decreases marginally by 4% (-$36m)
- Augmentation falls by 22%
- Connections down by 15%
- Property down by 24%
- Fleet and equipment increase marginally by $1.74M (+1%)

*Customer connections*

Ergon is expecting to connect 60,000 new customers in 2020-25, at a slightly lower cost than in the current period. Ergon is forecasting a gross capital requirement of $305M to do this, down significantly by 22%.

*Network Reliability*

Similar comment as for Energex.

*Augmentation*

Ergon is intending to reduce its investment in network capacity and reliability by 15% or $44M. This decrease is not as marked as we have seen elsewhere. It is seen as acceptable due to Ergon's current low growth rate.

*Replacement Capital*

Ergon is intending to reduce its investment in asset replacement marginally by 4% or $36m. This is not a significant decrease, but is consistent with the narrative presented by Ergon regarding previous expenditure and operating practices.

We recognise the tools and expertise the AER has in assessing this type of capital requirement, and defer to the AER in this area. More broadly though, we recognise that the trend, along with stable network performance, suggests:

- a reasonable expectation that the proposal is sustainable and
- an assumption that the underspend this period is efficient.

*Capitalised Overheads*

No comment until the clarity as to the IT transfers in the current period are resolved.

*Non-network capital*

It is noted that the proposed expenditure on Fleet & Equipment is stable, and investment in Property is significantly less (-24%) than the current period.

### 6.3 Information Technology

It is difficult to ascertain neither any change to IT investment nor any reduction in corporate overheads. This is because in prior years, IT costs were allocated to Energex and Ergon from Sparq Services, their joint-owned ICT service provider. We acknowledge that investment in IT is a significant component in what is largely a data-driven organisation.

The high-level analysis in this Draft Plan considered Capitalised Overheads and IT costs as a 'bundle'. We expect to see historical overhead and IT costs provided by EQ shortly, in time for meaningful analysis and comment prior to the finalisation of the regulatory proposal.

We note the aggregated IT spend for Energex and Ergon is[14]:

- allowed 2015-20 - $451m
- forecast 2015-20 - $367m, and
- proposed 2020-25 - $46m

Overall, the planned expenditure on IT is significant and the alternatives and benefits of such expenditure have not been not well articulated.

We have previously advised EQ to run a workshop to better explain the IT priorities and requirements prior to finalising their regulatory proposal. This is critical given the short asset lives and the impact of depreciation on price.

There is a significant under-expenditure of IT resources across Energex and Ergon in the current period. Whilst a proportion of these savings are likely to be attributed to real efficiencies and genuine deferral options by the distributors, the significant increase proposed in 2020-25 of $94m (+25%) suggests close examination of the reasons and 'efficiency' of the increased investment is necessary.

We note a comment made in the engagement workshops where EQ advised of plans for a significant simultaneous change to many of the IT systems in the next regulatory period. Other than the cost / benefit of such an undertaking, this raises a number of concerns:

- Experience has shown that few organisations have the capability to absorb such a significant change in IT systems efficiently and without a high level of disruption to business processes. We suggest the AER take a particular interest in the annual performance measures and risks within the EQ distributors in respect to service levels and the impact on schemes such as EBSS and CESS.
- The impact on the productivity of the companies should be considered in the light of labour cost agreements and delivery of savings. We note comments in the workshops that EQ is placing a high expectation on the proposed IT program to underpin many of the cost reductions in the capital works programme.
- The amalgamation of the IT systems was an objective of the previous service provider, Sparq Services. It will be important to understand if funding was made available in previous periods for similar work that may not have been delivered, and what impact this may have on the efficiency sharing schemes.

[14] Draft Plan Figure 33, p51

- The cost of amalgamating IT services for the two distributors may be considered a merger cost, and 'netted off' the quoted saving of the merger in the presentation of business benefits in the proposal.

When EQ makes more detailed information available on IT, we would be seeking:

- Demonstration by EQ that the expenditure is as low as it possibly can be, and that maximum value is extracted from the assets. For customers, such an approach is seen as critical.
- Reassurance that EQ are not seeking to invest in 'the best available' solution, and are considering 'compromise' or less elegant, but also less expensive, approaches to the IT challenges and service objectives.
- Engagement with customers on scaled options, such as articulating the costs and risks of the deferment of investment, alternative solutions or the real impact to consumers. The counterfactual positions were largely along the lines of 'an inability to maintain acceptable business performance'. We encourage EQ to reconsider the discussion to reflect more practical and realistic examples of changes to risk and business performance should the IT funding vary by, say 10, 15 or 20%.

It is reasonable to expect that many IT investments are targeted largely at business efficiency, and therefore could be largely 'self-funded' by the distributor as the return of the investment is a lower cost of running the business. We ask: "should customers pay for facilities that assist the business to operate more efficiently, or is that a return on the investment of shareholder funds?"

# 7. Summary of the Draft Plan – Opex

## 7.1 Introduction

As noted above, over time Energex is around the middle and Ergon at or near the bottom in relative opex efficiency for all 13 DNSPs.

Recognising this position and the focus on affordability, it is good to see the commitment that EQ has shown to propose some productivity improvement in opex expenditure. EQ is following the recent lead of TasNetworks distribution and Essential in proposing opex productivity improvements.

Consumers have long argued that the AER assumption of zero productivity improvement is not consistent with a regulatory regime designed to reflect what would occur in a workably competitive market.

Also as noted above, the Draft Plan provides indicative evidence that both Energex and Ergon opex “appears comparable to our peers”. We look forward to more comprehensive data being provided in the January 2019 submission to substantiate the conclusions made in the Draft Plan.

We welcome the recent AER announcement of a review of opex productivity growth factors. We note that the outcome of the AER review will apply to EQ.

## 7.2 Energex Limited

We look forward to receiving the data to enable completion of the following table:

| $2020m | 2010-15 | 2015-20 | 2020-25 |
|---|---|---|---|
| Energex submission (original/revised) | | ?? | |
| AER Final Decision Allowance | ?? | ?? | |
| Actual/forecast | ?? | ?? | |
| Draft Plan | | | $1,794.16 |
| % change over 2015-20 forecast | | | -4% |

There is some confusion in the numbers in the Draft Plan eg for 2020/21 Figure 39 p.57 says $362m; Table 9 p. 59 has a range of numbers, none of which is $362m.

Applying the base-step-tend AER approach, Energex proposes 2018/19 as the Base Year. It’s “indicative” analysis, using a range of category analysis benchmarking measures for 2017 and adjustment for OEF factors, concludes that the forecast opex in the Base Year is efficient when compared with other DNSPs.

We look forward to EQ providing a more comprehensive analysis to support these conclusions in their submission and then the AER’s assessment of this analysis. Given the improvement in some other previously poorly performing networks in recent years, it will be interesting to see how Energex and Ergon are positioned in both a relative and absolute sense.

We welcome:

- No step changes
- The 3% reduction over the regulatory period reflecting improved works delivery that reduces the real annual labour costs escalator from 0.85% to 0.26% Zero real increase in materials costs

- 2.8% annual productivity increase reflected in reduced overheads which have been imposed on the forecasted costs to reflect the management commitments to reductions in overheads and improvements in program delivery.

However, there is still a real increase in labour costs. Consumers expect that any increase in real labour costs will be at least fully offset by productivity improvements. This is not the case for Energex. We do not believe that consumers should bear the cost of a network's failure to obtain productivity improvements to offset wage rises.  It should be borne by the network's shareholders.

### 7.3 Ergon Energy Limited

We look forward to receiving the data to enable completion of the following table:

| $2020m | 2010-15 | 2015-20 | 2020-25 |
|---|---|---|---|
| Ergon submission (original/revised) | | ?? | |
| AER Final Decision Allowance | ?? | ?? | |
| Actual/forecast | ?? | ?? | |
| Draft Plan | | | $1,789.98 |
| % change over 2015-20 forecast | | | % |

While we welcome the proposed:

- No step changes
- The 3% reduction over the regulatory period reflecting improved works delivery that reduces the real annual labour cost increase from 0.85%  to 0.26% (what does this mean and how is it calculated?)
- Zero real increase in materials costs
- 3.4% annual productivity increase reflected in reduced overheads which have been imposed on the forecasted costs to reflect the management commitments to reductions in overheads and improvements in program delivery.

we remain to be convinced that this is the best that Ergon can do. Given the poor cost performance in the past, a greater rate of change is required to justify the claim that the Draft Plan properly reflects the affordability concerns. While those customers that benefit from the Uniform Tariff Policy do see a reduction, further reductions in opex are required to bring any benefit to those consumers not cover by the UTP.

# 8. Consumer and stakeholder engagement

CCP14 has had many opportunities to observe EQ's engagement including:

- Participation in Regulatory Proposal – Tariff Structure Statement Customer Working Group sessions
- Participation in Community Leader Forums
- Participation in specialist groups such as the Agricultural Forum
- Participation in in tariffs webinars, and
- Observation of the collection of qualitative residential and business customer research.

CCP14 commends EQ for their engagement approach. We had some concerns that EQ's engagement 'started in earnest' later than its peers, and the quality of some engagement activities has been patchy with unclear information and overstated narratives in areas such as IT. The latter stages of engagement leading to the production of the Draft Plan however have been effective, well-attended and engaging. We also note that the sessions have been very well attended and supported by the CEO and senior executive team.

This style of early engagement is consistent with comments made by Paula Conboy to the ENA conference in July 2017 when the AER first discussed AER 2.0. CCP14 believes that there are 4 aspects to a successful early engagement strategy:

1. the first is 'no surprises' so that stakeholders understand what will be in EQ's proposal prior to it being lodged.
2. The second is for stakeholders to give feedback to EQ about its proposals and for EQ to respond to that feedback by making changes to its proposal.
3. Ideally the draft revenue proposal that will be lodged by EQ in 2019 would be largely capable of acceptance in that it would be supported by stakeholders and EQ's customers as being in their long-term interests.
4. The AER would adopt a more top down triaged approach to a draft revenue proposal that had stakeholder support as being in the LTIC.

The positive aspects of EQ's early engagement are that issues of concern to customers have been highlighted early. Capex examples include a strategy for investment in the network of the future and the ongoing IT investment. Opex examples are labour efficiency. There has also been a significant focus on EQ's merger synergies and whether any merger costs remain in the draft proposal.

We are very supportive of the way EQ has made this Draft Plan available to energy consumers and other stakeholders in the state.

The EQ 2020-2025 Draft Plan is a significant milestone in the engagement process.

Stakeholders including the AER's technical advisory team, have made a very large investment in early engagement with EQ. EQ's engagement involved a lot of time from its executives with detailed slide packs and information fact sheets. Customer advocates and other stakeholders, including CCP14, have limited resources and attending multiple deep dive sessions is resource intensive. The result is that EQ is now fully aware of the issues that its stakeholders have with its Draft Plan.

The challenge for EQ is to now move to collaborating with stakeholders in a flexible way about their concerns. EQ has set out the feedback from its customers about the need to keep prices at an affordable level and the price reduction has been welcomed by stakeholders. Part of the feedback is to show that EQ has avoided or deferred any unnecessary expenditure. This means EQ needs to justify to its customers that the Draft Proposal:

- does not contain one single dollar more investment than is necessary
- delivers benefits that are in consumers interest, and
- is equitable between its different customer groups.

Key to the success of the engagement is that this Draft Plan is seen not as a summary of the eventual regulatory proposal, but as a lightning rod for conversation, comment and feedback. Critical is the way EQ draw out, receive and consider feedback, and listen to the sentiment, questions and emotion presented in the feedback to the Draft Plan. It is now time for the 'hard conversations' to assist EQ to understand the issues as seen by the energy consumer and ensure that their regulatory proposal demonstrates 'listening and responding' to the issues raised.

CCP14 believes that EQ has an opportunity to work with its stakeholders in a collaborative way between now and January 2019 to further amend the draft proposal and show that EQ has incorporated the feedback of its customers into its Draft Plan.

Over the next few months, CCP14 will keenly watch the way EQ considers the feedback from the range of stakeholders, interacts with its Working Group and Community Leader Forums and takes this excellent opportunity to incorporate the advice from those groups by modifying, adapting and improving their proposal to best reflect the needs, thinking and suggestions from the community.

EQ has not embraced the establishment of an informed and engaged Consumer Panel in the way that other distributors, notably SAPN and Ausnet Services, have done. We have observed informed and active conversation in some areas, such as Public Lighting, however such an active engagement specifically on matters of the regulatory reset is not advanced. We encourage EQ to consider investing in a dedicated Customer Panel, which could then provide continuity of customer engagement between and across regulatory resets.

EQ has a wide community engagement framework in place that covers the full range of community interactions across Queensland, including retail and billing issues relevant to Ergon Retail. In addition, investments in information gathering such as the Queensland Household Energy Survey are powerful in understanding consumer trends.

We look forward to those expansive engagement channels being adapted and integrated more effectively into future regulatory resets.

# 9. Pricing: DM and Tariff Structure Statement

Both Energex and Ergon observe on page 9 in their Network Tariff summaries that their tariff plans for 2020-25 seek to respond to three concerns raised by its customers during engagement:

1. Customers support tariff reform and greater cost reflectivity, but remain concerned about customer impacts and transition
2. Customers expect us to demonstrate competitiveness of network supply where customers have a choice (e.g. off grid, edge-of-grid solar/diesel), and
3. Customers expect us to ensure equity of access to electricity.

Whilst CCP14 agrees that EQ has heard these concerns from some stakeholders and the need for a gradual transition to full cost reflective pricing, CCP also agrees with Energex and Ergon's summary about the need for change[15]:

> "This means our current network tariffs, which were developed at a time when these advances in technology and customer expectations had not yet emerged, no longer suit the changing needs of our customers and of our network. In particular, the current tariffs (largely developed in the early 1990s) include cross subsidises which can lead to inefficient use of the network. We therefore need to review our existing tariff suite and introduce new network tariffs that are better suited to this new environment and are sufficiently flexible to accommodate future changes in customers' expectations, market developments and new technologies."

CCP has contributed to the development of Pricing Directions Principles which is at Attachment A2. These principles have been prepared in conjunction with ECA, PIAC and TEC and endorsed by those organisations as well as the AER TSS team and most recently by the ACCC in its Final Report in the Retail Electricity Pricing Inquiry.

The purpose of cost reflective tariffs is to send a signal to retailers (and ideally to the end customers) of the impact (cost) of their use of energy on the distribution network to try to bring about behavioural change, which will in turn defer investment. We recognise that each network has different issues to manage and hence different signals need to be sent through tariffs and DM strategies.

The ACCC concludes in its Final report that the progress of cost reflective tariffs has been too slow. The ACCC notes[16]:

> "The above factors mean that there is a risk that, if left unchecked, the incentives under current tariff structures will result in higher network charges for all customers as networks are required to undertake potentially avoidable investment. These networks costs may also need to be recovered over a smaller volume of total electricity consumption due to incentives on customers to minimise their consumption (including through the installation of solar PV systems). These additional costs will be borne disproportionately by those customers unable to access new technology or services to manage and reduce their electricity supply.

[15] Energex and Ergon Network Tariff Summary p. 7
[16] ACCC op cit p. 180

> In the short term, adoption of cost reflective pricing should lead to a fairer distribution, rather than a reduction, in overall electricity costs. This will include some customers paying more than under current tariffs. However, there are inherent inequities in current pricing structures as well, with some customers already paying more than they should because of the cross-subsidies in current tariffs. Cost reflective pricing would mean that existing cross-subsidies in favour of high peak usage customers are unwound. As such, more cost reflective tariff structures should lead to fairer outcomes, as those paying more will be doing so because of the demands they place on the network."

The key change proposed by EQ for both Energex and Ergon is the introduction of the Lifestyle tariff, which includes a seasonal time of use component, which can be smoothed over the year by customers choosing a higher usage band. The proposed summer peak window period of November to March inclusive is long and for residential customers Energex is proposing a daily Summer Peak Window from 4 pm to 9 pm November to March. For small business customers, the Summer Peak Window is week days from 10 am to 8 pm November to March inclusive. Larger business Summer Peak Windows follow the same format as small business however for Energex customers will finish slightly earlier at 6 pm.

In the stakeholder engagement that CCP observed about tariffs, stakeholders were generally supportive of the Lifestyle tariff and the need to remove inequity from current tariffs. However consumers expressed concerns about the length of the summer peak window period and the length of the windows. Other concerns focussed on the inclusion of public holiday and special days in the trigger for extra payments.

We welcome Energex and Ergon's commitment on page 14 of the Network tariff Summary to review the window. As noted above and in the attached Pricing Principles, CCP supports demand being used as the basis for calculating tariffs. We welcome Energex and Ergon's commitment on page 14 of their respective Network tariff Summaries to review the window.

EQ has also responded to concerns from its customers about its proposed assignment policy. The current drafts represent a change from mandatory assignment to opt out. The change as we understand it stems from concerns raised by customers and customer advocates, including QCOSS and COTA, about the need for education and complementary initiatives to help protect vulnerable customers who may not be able to shift their load. One option EQ could consider would be to limit the ability to opt out from the tariff to a customer's choice only and not permit retailers to opt out on a customer's behalf without their consent.

In this way EQ could maximise the transition to cost reflective tariffs and still maintain an opt out approach.

A key feature of EQ's tariff policy is its education and trials program known as TEDI. CCP14 is impressed with the potential of this leading program. We agree that empowering customers with greater information through tools can empower customers to respond to tariffs by changing their behaviour where possible. As Energex and Ergon note these tools will also enable EQ to support localised Demand management (DM) initiatives. CCP14 believes that Energex and Ergon can do more to integrate DM strategies into its pricing strategies and tariff plans to show that it is striving to defer investment as discussed above.

We have also observed engagement between EQ and representatives of Ergon's agricultural customers, particularly around the need for additional tariff reform. This engagement has been triggered by the transition from legacy tariffs and stakeholders expressed concern about the impact of the tariffs on the competitiveness of these business customers.

CCP14 welcomes the recent progress in EQ responding to these concerns through discussions about proposed food and fibre tariffs for these customers.

CCP looks forward to working with EQ, ECA and others on the customer impacts of the proposed Lifestyle tariff and the upcoming trials with retailers.

**ATTACHMENTS FOR REFERENCE**

## A1 - CAPEX – Points for discussion

| Table 6 Energex capex trends Real $2020 $M | 2010-2015 Actuals | 2015-2020 Allowance | 2015-2020 Forecast | 2020-2025 Forecast | change -> current forecast to proposal | | variance in current period | |
|---|---|---|---|---|---|---|---|---|
| **Replacement** | $882.71 | $1,083.99 | $869.76 | $665.11 | -$204.65 | -24% | -$214.23 | -20% |
| **Connections** | $751.52 | $501.96 | $521.76 | $485.49 | -$36.27 | -7% | $19.80 | 4% |
| **Augmentation (incl Reliability)** | $1,561.47 | $445.19 | $423.71 | $279.21 | -$144.50 | -34% | -$21.48 | -5% |
| **Escalation** | | | | $9.37 | $9.37 | | | |
| **Capitalised Overheads** | $1,381.43 | $926.87 | $783.16 | $517.19 | -$265.97 | -34% | -$143.71 | -16% |
| **Total System** | $4,577.13 | $2,958.01 | $2,598.39 | $1,956.38 | -$642.01 | -25% | -$359.62 | -12% |
| **ICT** | $0.00 | $9.61 | $7.96 | $234.46 | $226.50 | 2845% | -$1.65 | -17% |
| **Fleet & Equipment** | $214.27 | $163.34 | $122.30 | $109.37 | -$12.93 | -11% | -$41.04 | -25% |
| **Property** | $242.71 | $92.56 | $114.34 | $82.86 | -$31.48 | -28% | $21.78 | 24% |
| **Total Non-network** | $456.98 | $265.51 | $244.60 | $426.69 | $182.09 | 74% | -$20.91 | -8% |
| **Total Capex** | $5,034.11 | $3,223.52 | $2,842.99 | $2,383.07 | -$459.92 | -16% | -$380.53 | -12% |
| Totals may not add due to rounding. Note: due to changes in treatment capitalised overheads and ICT cannot be compared over periods on a like-for- | | | | | | | | |
| Overheads + ICT | $1,381.43 | $936.48 | $791.12 | $751.65 | -$39.47 | -5% | -$145.36 | -16% |

| Table 12 Ergon capex trends Real $2020 $M | 2010-2015 Actuals | 2015-2020 Allowance | 2015-2020 Forecast | 2020-2025 Forecast | change -> current forecast to proposal | | variance in current period | |
|---|---|---|---|---|---|---|---|---|
| **Replacement** | $932.38 | $812.83 | $916.01 | $880.00 | -$36.01 | -4% | $103.18 | 13% |
| **Connections** | $679.29 | $447.75 | $392.08 | $305.90 | -$86.18 | -22% | -$55.67 | -12% |
| **Augmentation (incl Reliability)** | $908.10 | $562.47 | $301.61 | $257.12 | -$44.49 | -15% | -$260.86 | -46% |
| **Escalation** | | | | $10.66 | $10.66 | | | |
| **Capitalised Overheads** | $1,404.14 | $1,069.07 | $865.92 | $572.95 | -$292.97 | -34% | -$203.15 | -19% |
| **Total System** | $3,923.94 | $2,892.12 | $2,475.62 | $2,026.63 | -$448.99 | -18% | -$416.50 | -14% |
| **ICT** | $0.00 | $28.13 | $17.68 | $226.18 | $208.50 | 1179% | -$10.45 | -37% |
| **Fleet & Equipment** | $229.06 | $174.69 | $159.80 | $161.54 | $1.74 | 1% | -$14.89 | -9% |
| **Property** | $299.41 | $218.65 | $165.14 | $125.46 | -$39.68 | -24% | -$53.51 | -24% |
| **Total Non-network** | $528.47 | $421.47 | $342.61 | $513.18 | $170.57 | 50% | -$78.86 | -19% |
| **Total Capex** | $4,452.41 | $3,313.59 | $2,818.23 | $2,539.81 | -$278.42 | -10% | -$495.36 | -15% |
| Totals may not add due to rounding. Note: due to changes in treatment capitalised overheads and ICT cannot be compared over periods on a like-for- | | | | | | | | |
| Overheads + ICT | $1,404.14 | $1,097.20 | $883.60 | $799.13 | -$84.47 | -10% | -$213.60 | -19% |

# A2 - Pricing Directions: A Stakeholder Perspective

### Objective of tariffs and related instruments

The objective is to develop a pricing strategy comprising tariffs and other supporting incentives and measures that:

- Promote more efficient, lower cost means of meeting consumers' demand for energy services
- Reflect consumers' preferences, such as enhancing customers' control over their bills and encourage tariff transparency and consumer agency/empowerment.

Many utilities have the aim of 'putting the customer at the centre', as successful competitive businesses do. These objectives support, and provide a test, for that objective.

Note: by supporting 'incentives and measures' we mean programs such as:

- locationally specific tariffs and payments to consumers and purchases of demand reduction from intermediaries, such as retailers or other energy service providers, that encourage reduction in peak loads at critical parts of the network
- alliances with retailers and other energy service providers to roll-out innovative end-user technologies that promote more flexible and efficient provision of energy services
- information programs and other 'nudges' designed to inform consumers and encourage consumers to manage loads in their and the network's interest.

### Key features of the pricing strategy and TSS

Key features of a successful pricing strategy are that:

- it uses customer-facing language
- is adaptable to new information and changing technologies and demand patterns
- is adaptable to the different circumstances of each network
- is integrated with Demand Management strategy, programs, and incentives
- engages with the retailers and other energy service providers

Central to this is the understanding that consumers do not want electricity per se; they want the services that can be provided by using electricity: power (to produce things and for communication and entertainment), heating, and comfort.

#### *Customer-facing language*

The primary audiences for the TSS may well be the AER, retailers and energy service providers, and some large consumers. It may only be read by a small number of other consumers, but the objective should still be to express it in terms that the final consumer can understand. However even more important will be the clarity of the accompanying consumer information package (paper and electronic) that should communicate the tariffs, what the tariffs hope to achieve, and the opportunities for customers to reduce their cost of using the network in simple terms. For example, 'costs you can control' may be a better way of expressing 'variable charges'.

#### *Adaptability*

Circumstances can change significantly, quickly, and in directions not anticipated. For example, in the lead-up to the review of the pricing principles by the AEMC, peak demand had been rising quickly putting pressure on existing networks and investment requirements. By the end of the AEMC review the problem was one of stagnant or declining demand and the implications of this for the fixed component of network bills. This is a practical example of changes occurring in a short term that can lead to significant differences in pricing strategies. It is expected that the pace of change in the technology for supply and use of energy to provide the services consumers need will accelerate. Our knowledge of how we can best provide the right signals to consumers is also expanding and changing. It is increasingly understood that it is not all about the price, but understanding what signal (price and non-price or informational) and how consumers respond to different signals. This is leading to innovations in customer-facing signals in various fields that are moving beyond traditional pricing models. While NSPs may innovate in pricing the responses of customers and retailers and other intermediaries may be uncertain. Hence, there may be a need to adapt strategies to their responses.

The key implications are that:

- the 'end-point' for pricing should not be seen as fixed. It is important to have a vision of where prices are headed, but this end-point cannot be fixed. IT will need to adapt to changing circumstances, new information, and responses of others.
- mid-point reviews of the TSS are desirable to build in adaptability in pricing strategies
- changing end-points may well mean that prices are in 'constant transition.

*Network Specific*

Different networks may face different problems that will result in different transition paths and end-points, especially in regard to the balance between fixed and controllable costs, the nature of the demand charge, and the choices between demand and capacity charges. There may be differences in the metering/technology infrastructure, particularly the roll-out of smart meters, that affect the feasible tariff options. Another key factor will be customer composition and demand growth. A network which has broadly-based growth in customers and demand may well move towards a broadly based tariff with a strong demand/capacity signal. Other networks may face stagnant or falling demand on average with only a few pockets of growth. This will lead to different choices and perhaps greater reliance on specific options (tariff and non-tariff) in those locations where growth is driving expected costs. Networks with a larger proportion of remote or difficult to serve customers may face greater risk of 'customer exit' from the grid. The key question here is whether the marginal costs of supplying those customers from the grid is greater than or less than the cost of self-supply. If it is, the network may try to design tariffs to discourage inefficient exit that would leave other customers having to pay more.

*Role of Retailers*

Except for some very large customers, the tariffs the customers see are the tariffs charged by the retailer which recover generation costs and the retailers own-costs as well as the network charges. At present customers mostly do not see the network charges directly and retail charges do not necessarily simply pass-on the network charges in the form and structure that they see them. The signals sent by networks may not only be 'washed out'; they may be substantially changed by the retailer. This is not necessarily a problem as long as the retailers see the cost reflective charges, bear the associated risks, and work with customers in whatever manner in response to the signals provided by the network charges. However, it is important that networks work with retailers and other service providers to ensure that:

1. there is a good understanding of the cost drivers the network is facing and points of current or potential congestion; and
2. opportunities to work together to maximise efficient use of distributed resources in areas of constraint are explored.

This may raise questions of the nature of the relationship between networks and retailers and other energy service providers and what forms of strategic alliances are acceptable where the network has no direct interest in retailing.

One option may be to require retailers to offer at least one pricing option that passes through the network tariffs as set by the DNSP.

### Expectation for 'end point' of network pricing strategy and tariff design[17]

1. As peak demand is a more prominent cost driver for networks than energy consumption the objective is to signal these costs to retailers and customers in a way that customers can respond to and reduce future costs. Just and equitable demand or capacity-based tariffs are the most direct way of signalling these costs but a highly targeted volumetric rates may also achieve this objective. These tariffs would be the standard tariff. The demand or capacity component is equal to or greater than the LRMC averaged across the network.
    - Demand /capacity better signals cost drivers than volumetric charges
    - Consumers need to be aware of and be able to respond to peak demand signals

    The design and implementation of the tariff would have regard to the impacts on consumers.
2. Priority should be on the transition to demand/capacity tariffs. TOU tariffs today are highly averaged and hence poorly targeted on the key periods of high demand, and often have too little difference between the peak and off-peak rates to achieve the objectives. However, there may be a role for a volumetric tariff that is much more closely targeted on the key periods of high demand.
3. Under demand tariffs a key issue is what demand, what peak? Should it be the local or a broader, a coincident peak or the customer's peak demand? How often should peak demand be measured – a few nominated peak days or monthly or annual? There may not be a single 'correct' answer. It requires a balance between a relatively stable, easier to understand measure of demand and other measures of demand that can better measure the impact on future investment needs. Hence the choices made may depend on the importance of the demand signal in terms of the opportunities to defer investment, the nature of the customers and their capacity to respond, and whether it is the standard tariff or a more dynamic, locational-specific tariff. Decisions on the measurement of demand used should be supported by analysis at the sub-station level and may vary between DNSPs due to the differences in composition and location of customers. There may be areas with significantly different requirements – such as areas with high levels of tourism or specific activities like skiing. Optional locational tariffs may be the best means of responding to these circumstances, based on the outcome of research to reveal use profiles for each area.
4. Residual costs recovered by charges that are 'less distorting'[18] such as fixed charges but increases in fixed charges should be tempered by:

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[17] As we understand it at this stage. New technologies, information and new thinking will see a continual evolution in ways we perhaps may not be able to envisage at present.

[18] It is likely that usage charges based on LRMC will not yield sufficient revenue to cover all the allowed costs of the NSP. If so, economic efficiency is enhanced if the remaining revenues are raised through charges that have as little impact on behaviour as possible.

- Recognition consumers prefer variable to fixed charges[19] – consumers want to do the right thing and be rewarded for it
- Consideration of consumer impacts
- Consideration of environmental costs in setting variable charges (i.e. in an energy charge or the demand or capacity charge)[20]. This supports the achievement of policy objectives of reducing carbon emissions; is consistent with NEO, which is an economic objective, and the economically efficient utilisation of network assets; and reduces the long-term costs to consumers given the carbon reduction objectives. It also helps a) reconcile efficient tariffs with consumer preferences for greater control over the bill and to be rewarded for 'doing the right thing' as they see it and reducing usage b) reduce the impacts – and the often perceived inequity - of high fixed charges. Ongoing research provides the opportunity to test this perception.

5. The standard tariff is unlikely to be location specific (see point 3 above). It will be highly averaged but is aimed at encouraging some demand response consistent with overall objective.
6. Application of the standard tariffs should be mandatory for new customers or connections where a new meter with different capabilities has been installed initially then expanding to all customers, recognising that this may impact on transitional arrangements and support. If mandatory application is not achievable in the short term, opt-out approaches should be adopted, but preferably not to a tariff with a single energy rate. Tariffs be set to tilt people towards not opting out, and supported by information programs and other incentives.
7. Innovative, dynamic local tariffs (e.g. critical peak rebates but all options should be 'on the table') aimed at reducing demand at/when it will make the biggest difference to capex requirements by promoting efficient distributed resources. These innovative tariffs are most likely to be optional and will require partnerships with retailers and energy service providers.
    - Where dynamic pricing is offered consumers may prefer rebate programs (with high 'normal' charges) than very large peak charges
8. Tariffs should not look beyond the meter
    - What customers pay in network charges should reflect their load profile not what energy-related equipment (e.g. Electric Vehicles s or PV panels) they have
    - But the networks/retailers/ESCOs may want to know what equipment consumers have so they can work with consumers to optimise my energy services.
9. As the economics of renewable energy continues to improve and renewable energy capacity increases, two-way flows will become a more important feature of the energy system and will introduce new challenges in pricing. To the extent that two-way flows have a different impact on network costs, this should be reflected in the pricing (including network support payments) for those flows. The objective should be to price access to the distribution networks in a manner that:
    - Provides signals for renewable capacity to locate in areas and be operated in a manner that benefits the network where possible
    - Fairly reflects the costs imposed on the distribution network as well as the benefits that it may provide.

[19] Fixed charges refer to per customer charges that do not vary with past or current demand or consumption. A capacity charge set based on demand in previous periods is not, under this definition, a fixed charge even though within the year it may not vary from month-to-month.

[20]

10. At the retail level, or in partnership with retailers and ESCOs, innovative incentives and nudges – information programs, rebates rather than prices, special 'bonuses' etc may be more effective than standard incremental price changes. The learnings from behavioural economics on how people respond to signals can be important in developing tariff strategies.

Note: (1)-(5) sets up the standard tariff, which will probably help a bit, but the action/benefits are really in the locational specific pricing and incentives at (7).

## Framing the Pricing Strategy

### *Scope of the pricing strategy*

In considering the scope of the pricing strategy it is important to remember:

1. It is not just about traditional tariffs and structures
2. There must be an integration between pricing and incentives for demand management and distributed resources.
3. The strategy should reflect customer preferences.

The tariff structures in the TSS should not be a mechanical application of the LRMC pricing rule. Behavioural responses are not all about prices. Innovation in pricing and other instruments may well come from extensions of the learnings from behavioural economics into tariffs rather than econometric studies.

Demand management incentives that are likely to be location specific should be seen as an integral part of the tariff strategy. Locational signals that best reflect ex-ante costs may be provided by demand management incentives as well as, or instead of, standard tariffs. This may have implications for how networks approach and structure the development of tariffs and demand management incentives so that they are not developed in isolation. In assessing whether the tariff strategy meets the requirements of the network pricing principles the AER should asses the total tariff package including the demand management incentives.

Consultation by networks with their customers have highlighted that:

- Many customers have proactively sought to improve their energy efficiency
- They have done this not just to reduce their own bill but because they see it as doing the 'right thing' to benefit the environment
- Even though there is an element of 'green altruism' that consider that they should be able to benefit from reducing their consumption.

These preferences should be considered in determining the balance between fixed and variable costs and how sunk costs should be recovered.

### *What are the relevant costs?*

Two issues in estimating the relevant costs are:

1. What is the cost basis - market costs (i.e. what the utilities pay) or economic costs (i.e. resource costs including environmental costs)? Principles of economic efficiency support inclusion of estimates of environmental costs where these are not priced into the market costs. To not do so will encourage overuse of resources with adverse consequences for the community.
2. What should be the basis of the estimation of LRMC. The principles allow for the use of either the Average Incremental Cost or Turvey (Perturbation) methods. The AIC approach is simpler,

is more widely used in the DNSPs, but is less time or location specific than the Turvey method. In contrast, the Turvey method can provide a stronger locational signal and is more sensitive to the timing of new investment requirements. Hence, while the AIC may be preferred in estimating variable rates for the standard tariffs, the Turvey method may be more appropriate for locational price signals.

*Customer impacts*

Where significant tariff changes are proposed the DNSP should provide well-founded, comprehensive modelling of the impact of the changes on various users (classified by tariff class, usage patterns, and socio-demographic characteristics). Best practice impact modelling would link consumption data to household socio-demographic data and undertake microsimulation modelling that examines impacts pre- and post- expected behavioural responses.