QCOSS
Queensland Council of Social Service

Draft proposal for the 2020-25 regulatory period

QCOSS submission

October 2018

QCOSS Queensland Council of Social Service

About QCOSS

The Queensland Council of Social Service (QCOSS) is the state-wide peak body representing the interests of individuals experiencing or at risk of experiencing poverty and disadvantage, 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 members across the state, 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:

- place-based activities
- citizen-let policy development
- cost-of-living advocacy
- sector capacity and capability building.

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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ISBN –

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Glossary

AEMO	Australian Energy Markets Operator
AER	Australian Energy Regulator
AUGEX	Augmentation Expenditure
CAPEX	Capital Expenditure
CESS	Capital expenditure sharing scheme
DER	Distributed energy resources
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency benefit sharing scheme
ENA	Energy Networks Association
EQ	Energy Queensland
MSS	Minimum Service Standards
NER	National Electricity Rules
RAB	Regulatory Asset Base
REPEX	Replacement Expenditure
STPIS	Service Target Performance Incentive Scheme
WACC	Weighted Average Cost of Capital (the rate of return)

Introduction

QCOSS thanks Energy Queensland (EQ) for the opportunity to comment on its draft Regulatory Proposal for the Energex and Ergon distribution networks. It is understood that a final Regulatory Proposal will be submitted to the Australian Energy Regulator (AER) by 31 January 2019 by EQ. Following a consultation process the AER will then make a revenue determination in April 2020, for the period 1 July 2020 to 30 June 2025.

The revenue determination will form a critical element in the tariffs paid by Queensland households and businesses from 2020-25. The distribution component makes up about a third of the typical household bill. It will also establish principles for the development of the future grid. This will likely include greater distributed energy resources and new patterns of consumption, pricing, and trading of energy generation.

QCOSS welcomes the price prediction of 10 per cent fall in nominal distribution tariffs, "tariffs", in the first year of the 2020-2025 regulatory period for households in the Energex network (as set out in EQ's document, *Our Draft Plans 2020-2025* (draft Plan) on 5 September 2018). It is noted that this proposed decrease in tariffs will also apply in the Ergon Distribution area to small residential customers because of the application of the Uniform Tariff Policy (UTP).

The falls for other customers are more muted, with small business customers in the Ergon network receiving no nominal tariff reduction. At present, most of the fall in tariffs for Energex and Ergon household customers is due to factors beyond the control of EQ, such as changes in the cost of debt and equity. QCOSS acknowledges that EQ has found some reduced costs in areas within its control, however considers the significant legacy of over investment and the subdued demand and peak demand forecasts for the next regulatory period, provide opportunities to deliver more significant tariff reductions.

In this submission QCOSS puts forwards a number of recommendations about how EQ will be able to achieve this within the context of:

- The price directions for distribution tariffs;
- The use of the grid during the 2020-25 regulatory period, including changes arising from new technologies, and changes in how customers are likely to use the grid; and
- The potential for more savings in capital and operating expenditure, and from incentive arrangements that can be addressed in EQ's Final Regulatory Proposal.

Summary of issues, opportunities and recommendations

QCOSS welcomes the forecasted fall in distribution tariffs by EQ in its draft Plan – of 10 per cent on 1 July 2020. However, contends that there are three main factors which impact on and put upward pressures on these price forecasts over the next regulatory period. That is why every effort must be made as part of this revenue determination to find cost savings and put downward pressure on distribution prices. These factors include the cost of debt which is at a historical low rate; the accuracy of demand forecasts; and the exclusion of the costs of the solar bonus scheme.

The EQ Regulatory Proposal 2020-2025 is being developed at a challenging time for EQ. Distribution tariffs are at a historical high, however customers use of the energy grid is changing rapidly, and the demand and cost implications of this are less predictable. QCOSS's view is that one of the main drivers keeping distribution tariffs relatively high is excess historical capital expenditure (capex) as identified in the Australian Consumer and

Competition Commission's (ACCC) pricing report and the Grattan Institute Report.[i] The over-investment takes the form of stranded assets, over-capacity in assets such as substations and transformers, and brought-forward expenditure. The central point of the analysis on this issue by bodies such as the Grattan Institute and the ACCC is that there is a critical need for EQ to ration future capex and look to non-network alternatives to avoid the risk of stranding network assets. Poor decision making about capital investment in the past has produced adverse outcomes for consumers.

Going forward, EQ has to be nimble in assessing and responding to changes which could impact on capex requirements. EQ's capex spending needs to be restrained as far as possible through the effective use of:

- Demand management and demand response;
- Assessment of the impact of cost-reflective tariffs on demand;
- Changes in network use arising from new technologies such as greater distributed energy resources, including solar and batteries; and
- Emerging demand for peer-to-peer trading and electric vehicle charging.

Issues and opportunities to further reduce costs	**QCOSS recommendations**
Insufficient transparency and information on price directions, including that EQ haven't undertaken a sensitivity analysis around key price risk factors.	Recommendation One That EQ provide greater transparency and information on price directions in its final Regulatory Proposal and in the Deep Dive consultation in November 2018.
Insufficient priority given to demand management, and insufficient information about how the incentive for demand management innovation allowance will be spent and the expected benefits from this spend.	Recommendation Two That EQ provide more detail on its proposed demand management arrangements and on the estimated savings in augex and repex.
Insufficient detail about how much EQ expects to spend during 2020-2025 to manage grid stability in response to generation from solar panels and batteries.	Recommendation Three That EQ provides information in its final Regulatory Proposal to explain how much it expects to spend during 2020-2025 to manage grid stability in response to generation from solar panels and batteries.
Connection policy in relation to distributed energy resources seems arbitrary and may stifle efficient non-network investment.	Recommendation Four That EQ reviews its connection policy for distributed energy resources (DER) and that it consults with consumer groups to achieve this.
Disconnect between reliability standards, investment decisions and customer expectations.	Recommendation Five That EQ in conjunction with the Queensland Government and in consultation with stakeholder groups investigate how to increase transparency around reliability standards, provide greater certainty for EQ, and provide a direct link between the

	standards that customers want and the standards that customers get.
Uncertainty about the way customers want to use the grid in the future and, from a consumer perspective, that the grid will be able to meet their needs.	Recommendation Six That EQ in consultation with stakeholder groups investigate and undertake scenario analysis of how customers will use the grid in the short, medium and long term. This should include but not be limited to electric vehicles and peer to peer trading.
Inadequate transparency on capex decisions to give customers more assurance of capital efficiency from investment decisions.	Recommendation Seven That EQ improve monitoring and transparency on capital efficiency, including against metrics such as RAB per customer and capacity per customer.
The need for significant increase in ICT expenditure has not beenn adequately explained or demonstrated	Recommendation Eight That EQ provide sufficient information in its final Regulatory Proposal to enable the Australian Energy Regulator (AER) and stakeholders to make informed assessment as to the justification for the size of the ICT expenditure.
Inefficiencies from misaligned accounting principles used between Energex and Ergon.	Recommendation Nine That EQ provide a common accounting position to allow the AER and other stakeholders to compare the capex and opex performance of Energex and Ergon against other distribution networks within the National Energy Market (NEM). QCOSS recommends that EQ use the WARL method to calculate regulatory depreciation for both Energex and Ergon assets.
Uncertainty over the future of current policy of attributing ICT through unit rates to capital projects.	Recommendation Ten That EQ continue its current policy of attributing ICT through unit rates to capital projects.
Lack of transparency around projects that are funded but don't go ahead and potential for windfall gains.	Recommendation Eleven That EQ, in its final Regulatory Proposal, identify projects that are re-proposed in the 2020-25 regulatory period which have been funded in earlier regulatory periods.
Lack of information about opex trends and how this impacts on efficiencies.	Recommendation Twelve

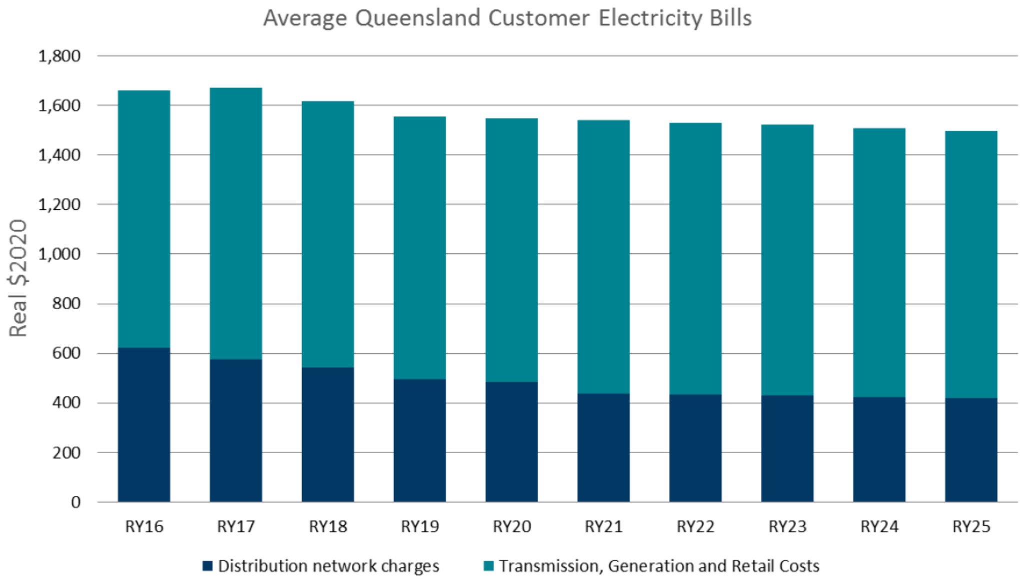
	That EQ address the below questions in its final proposal. • What operating efficiencies do smart meters provide for EQ, for example in more rapid fault detection? • What benefits does the proposed ICT spending provide in terms of reduced opex?
Lack of information in EQ's draft Regulatory Proposal across a number of asset categories about typical maintenance costs for young assets compared to older assets	Recommendation Thirteen That EQ provide information in its final Regulatory Proposal across a number of asset categories about typical maintenance costs for young assets compared to older assets.
It is unclear how efficiency gains from vegetation management are being recovered and passed on to consumers.	Recommendation Fourteen That EQ seek to recoup some of the benefits of vegetation management from third parties and pass them through as savings to electricity customers.

We look forward to further discussion on these recommendations in the November 2018 Deep Dive and for responses in the Final Regulatory Proposal.

Price directions

EQ has forecast price falls for the coming 2020-25 regulatory period of 10 per cent in nominal terms in 2020-21 (8% real). Figure 5 in the draft regulatory proposal (reproduced below) indicates further small falls in real prices over the following four years to 2024-25.

Figure 5 Indicative distribution network proportion of Queensland electricity bills[5]



The forecast price falls are welcome. However, it is noted that the trend of price falls is decreasing, with the fall in the coming 2020-25 period lower than during the current regulatory period. In the past four years of the current regulatory period, price falls for distribution services have averaged seven per cent per year.[ii]

QCOSS contends that there are three main factors which may impact on and put upward pressures on these price forecasts over the next regulatory period. That is why every effort must be made as part of this revenue determination to find cost savings and put downward pressure on distribution prices.

Cost of debt

QCOSS notes that the forecast price falls for 2020-2025 are heavily dependent on reductions in the weighted average cost of capital (WACC) or rate of return. Analysis of the causes of the price fall indicates that factors beyond the control of EQ account for much of the change in prices:

- For Energex, around 55% of the 8.4% reduction in revenue in 2020-21 is due to changes in Weighted Average Cost of Capital (WACC) parameters;
- For Ergon around 70% of the 4.6% reduction in revenue in 2020-21 is due to changes in WACC parameters.

The AER has published a draft rate of return paper containing a proposed draft WACC. EQ has indicated that it will accept the WACC proposed in the AER's final rate of return paper, which is due to be published around December 2018. Although the WACC will be binding, the cost of debt component is allowed to vary in line with the trailing average methodology. The cost of debt may increase over the regulatory period given it is at historically low levels. If the cost of debt varies from forecast, then these forecast distribution tariff falls may not be fully realised.

Forecasting Demand

The forecast price falls are also very sensitive in a revenue cap system on the accuracy of forecasting of electricity demand, which has shown a tendency over the past 10 years to vary from the previous stable and steady upward trajectory of the previous 40-50 years. Present forecasting models have better data to predict the impact of solar panel installation and some forms of current energy efficiency but have relatively little data to judge the future impact of batteries and new energy efficiency measures. If demand falls more than expected, then prices will rise above forecasts to recoup the fixed revenues set under the revenue cap.

Solar Bonus Scheme

Another factor affecting distribution tariffs is whether the Queensland Government will continue to fund the cost of the solar bonus scheme. The Government has only committed to do this until July 2020. The prices represented in the EQ's *Our Draft Plans 2020-2025* assume that this policy will continue to 2028 when the scheme is finished.

Recommendation One:

QCOSS requests greater transparency and information on price directions by EQ in its final Regulatory Proposal and in the deep dive in November 2018.

QCOSS requests EQ conduct sensitively analysis to provide a clearer picture of the impacts on network prices of movements in key risk factors. QCOSS is looking to understand the impact on network prices of:

- including the solar bonus scheme in tariffs from 2020-21;
- the cost of debt varies up or down by 1 per cent; and/or
- where annual demand forecasts vary up or down 1 or 5 per cent.

The context for future use of the grid

The energy grid of the future will look very different to the one of today and this is challenging for energy distributors. QCOSS considers that the grid of the future is changing more rapidly than envisaged in the draft Plan. The implication going forward will be that the future changes to the use of the grid will provide additional revenue opportunities, as well as potentially increased costs including the increased likelihood of stranding risks for parts of the network.

Going forwards, for this next regulatory period and beyond EQ has to be nimble in assessing and responding to changes which could impact on capital expenditure (capex) requirements. EQ's capex spending needs to be restrained as far as possible through the effective use of:

- demand management, demand response and distributed energy resources (DER)
- options,
- assessment of the impact of cost-reflective tariffs on demand,
- future customer preferences for reliability, and

This submission looks at these issues in turn and puts forward a number of recommendations for its consideration on the future use of the grid.

Distributed energy resources and demand management

It is important that final electricity prices are constrained as much as possible, so that they are not, above the cost of distributed energy resources (DER) options for users.[iii] As the price of solar comes down with the development of lower cost batteries and next generation solar cells, such as thin film solar cells, this challenge will become more acute. The solution is to impose strict prudency and efficiency requirements on new capital spending to avoid distribution network costs contributing to grid based supply becoming more expensive than alternatives such as a package of low cost solar and batteries over the next 5-10 years. Given grid options involve investment in long-life assets which may last 40-50 years, this requires discipline over the longer term, as investment decisions made in 2020-25 must compete on cost terms with alternatives over the full 40-50 years of their asset life (rather than just over the 2020-25 regulatory period).

A disciplined approach to capital investments will be critical to the affordability of grid supply over the next 10-20 years. Many or most capex decisions in the 2020-25 regulatory period will need to continue to be assessed against emerging non-network alternatives.

Demand Management

Demand management is a process of shifting demand from peak to off-peak times to avoid having to expand the network.

The AER has introduced a demand management innovation allowance (DMIA) to support research on new forms of demand management. More recently, it has published a demand management incentive scheme (DMIS) aimed at providing incentives for distributors to undertake efficient expenditure on non-network options relating to demand management, such as direct load control of air-conditioning.

In its draft proposal, EQ have proposed a demand management plan covering issues such as coordinating network and customer resources, the transition to provision of demand management by third parties, and connection of DER to the grid. However, there is insufficient information in the draft Plan to judge whether the demand management plan is likely to be adequate.

QCOSS notes that the budget for demand management proposed by EQ during the deep dive sessions seemed relatively small, especially as EQ pointed to large savings in past regulatory periods from demand management.

Recommendation Two:

That EQ provide more detail on its proposed demand management arrangements and on the estimated savings in augex and repex.

Distributed Energy Resources

A significant volume of solar panels has been installed and connected to the EQ distribution network at both a residential rooftop level and commercial scale. At present there are significant uncertainties around the impact of solar generation on network stability and reliability. In particular, there is little transparency over the impact of increasing solar on the network.

The change in voltage levels from 240 volts to 230 volts is expected to have changed the level of intervention required to manage the stability of the distribution network. However, the level of change and the impact of solar in particular areas of the network are unclear. Also unclear is the impact that batteries may have when installed across the network, particularly in conjunction with solar panels.

We note that in June 2018 the Energy Networks Association (ENA) and Australian Energy Markets Operator (AEMO) have agreed to collaborate on the Open Energy Networks Program for ways to manage distributed energy resources.

This program proposes ways to improve the electricity system “to ensure household solar and storage work in harmony and deliver the most value for all customers”.[iv] The consultation paper released by the ENA and AEMO talks about passive DER (solar supply into the grid) and active DER (batteries and ‘sophisticated home energy management systems that can adjust electricity usage in response to price signals or dispatch signals’). This passive and active DER must be better coordinated to manage voltage to manage voltage quality to prevent fuses blowing or appliances burning out. Earlier ENA work noted that better coordination could save $1.4 billion in avoided network investment or $414 per household bill.[v]

We are anticipating that the Open Energy Networks program can improve management of passive and active DER across the EQ network to achieve some of the identified benefits.

Recommendation Three:

That EQ provides information in its final Regulatory Proposal to explain how much it expects to spend during 2020-2025 to manage grid stability in response to generation from solar panels and batteries.

Connection policy for DER

It is understood that Ergon has a policy of not permitting connection at a local level of more than 10 kW installed capacity or permitting more than 5 kW maximum export load. It is not clear that the basis of this policy is and what is rationale for this connections policy?

It is understood that this policy is imposing significant costs on connection of new DER including geothermal generation and may be the most significant hurdle to some new small-scale generation of this type. This runs the risk of stifling efficient non-network investment and going forward it is important the EQ re-considers how best to implement this policy.

For example, rather than imposing this as a blanket policy, EQ could consider applying a policy that removes barriers to the connection and export of renewables. The new policy should take account of the specific location of the proposed connection/export (e.g. including factors such as the amount of redundancy in the grid at the point of connection) and the cost of any measures to ameliorate any grid stability issues (e.g. grid measures or requiring connection of a user-funded battery subject to Ergon control). If any element of such a policy would require changes to State Government or National Energy Rules (NER) laws or regulations, this could be flagged for a cooperative process of rule-change between EQ and advocates for DER.

Recommendation Four:

That EQ reviews its connection policy for DER and that it consults with consumer groups to achieve this.

RIT-D

At present, the RIT-D is used to determine whether network or non-network alternatives are chosen to meet demand in a region. We understand that there are challenges in comparing DER with grid supply in terms of reliability. We understand the AER is working towards making this process more transparent with its current review.

For the RIT-D test to work as a discipline on network investment, there needs to be a clearer basis for comparing the reliability outcomes of network and non-network alternatives.

To achieve this, networks need to work more closely with potential DER providers, DM aggregators, and demand response providers and give them advance notice of constrained areas of the network. More broadly, networks need to provide adequate advance notice of future network challenges for parties that wish to provide DER in order to give the most efficient investment outcomes. While networks provide a range of planning information in documents such as the distributed annual planning report (DAPR), this information may not be in a financial form suitable for non-network proponents to start to plan their options.

A further issue is that the RIT-D consultation processes provide a relatively short period for non-network alternatives to organize and plan non-network alternatives. This time period may be insufficient to bring out some non-network alternatives.

Future customer preferences for reliability

As reliability is a major driver of both capital and operating expenditure,[vi] QCOSS considers that customers should be at the heart of setting reliability standards. Customers are the parties that use electricity and therefore are the only one that can set a value on reliability.

At present the Queensland Government sets minimum service standards and the AER sets a service target performance incentive scheme (STPIS) that rewards reliability performance compared to specific targets and penalises failure to meet this target.

Reliability standards arguably represent a major cross-subsidy within networks because much higher standards are set in CBD and inner urban areas, where wealthier users live, than in outer urban, rural, or remote areas.[vii]

So the debate across the most appropriate reliability standards involves not only questions around the total level of spending on reliability but also how it should be recovered, and from which users.

We understand that the Queensland Government sets the standards and that EQ provide advice on the cost of setting particular standards. We appreciate that EQ needs to be involved in setting standards as it has access to the best data about its networks on the marginal costs of meeting particular reliability levels in different parts of the network. However, customers should be consulted in the setting of reliability standards too. EQ should publish information on the marginal costs of providing particular levels of reliability in the CBD, urban, short rural, and long rural feeder categories. This information should be published in an on-going way by EQ.

QCOSS would welcome collaboration with EQ to assist in developing a governance mechanism for customers to become more central in setting reliability standards. This governance mechanism should operate not only every five years when there is a new RESET but an on-going way, as reliability standards sought by customers are likely to change over time.[viii]

Recommendation Five:

That EQ in conjunction with the Queensland Government and in consultation with stakeholder groups investigate how to increase transparency around reliability standards, provide greater certainty for EQ, and provide a direct link between the standards that customers want and the standards that customers get.

Changes in how customers use the grid

EQ has anticipated that customer use of the grid will change over time, with increasing solar and batteries connected to the grid, as well as increasing demand response and smart grid technologies (e.g. smart meters, home demand management).

Drawing from its past experience EQ is preparing for these changes across upcoming and later regulatory periods as follows:

- 2015-20: enhanced customer experience
- 2020-25: customer led transformation
- 2025-30: empowered communities and customers.

While it is clear that more efficient solar panels, batteries, DER, electric cars, smart management, energy efficiency investments, cost-reflective tariffs, peak-shifting, and data-based services are emerging and will continue to emerge, it is difficult to predict the rate of uptake of these developments.

Given the unpredictable rate of change, it is likely that some of these developments proposed by EQ for 2025-2030 may be expected by customers in the 2020-25 regulatory period. The rapid take up of solar panels from around 2010 caught networks and regulators by surprise, reducing overall demand,[ix] putting traditional volumetric pricing systems under pressure, leading to a cost explosion in the solar bonus scheme through the 44 cent feed-in tariff, and arguably creating a range of cross-subsidies within and across tariff classes. We note that the draft Plan states that these issues will be addressed in the next regulatory period 2025-2030. The EQ Final Regulatory Proposal 2020-2025 should set out a plan to cater to more rapid, and some unexpected, changes in customer demand through quicker take up of these technological developments.

It is likely that some of these developments will emerge more quickly than anticipated, leading to potential disruption of some aspect of traditional grid delivery of electricity in either a positive or negative way. Positive in this sense means leading to more grid flows, while negative means lower grid flows and this could result in higher prices. Under the current revenue cap arrangements, lower flows on the grid would lead to higher prices.

As investments in the grid involve long-life assets, these investments must be able to 'defend' themselves against non-grid alternatives over their whole life, rather than just over the next five year regulatory period.

Table 1 sets out several future developments and their impact on demand and on peak demand.

Table 1: Future developments and their potential impacts on grid demand (both positive and negative)

Development	Impact
Solar panels, other renewables such as geothermal, pumped hydro, or hydrogen	Reduce demand for grid supply. May reduce peak demand where renewables are capable of being scheduled e.g. geothermal, pumped hydro
Batteries	Reduce demand for grid supply, move demand to off-peak times
Electric cars	Increase demand for grid supply, or could contribute to diverting it to off-peak times given car batteries could serve as batteries for the house
Smart grid management	Demand response and demand management and moving of supply to off-peak times will contribute to reductions in peak demand (e.g. automated moving of demand such as dishwashers and washing machines to off-peak times) and overall demand (e.g. switching off appliances not in use)
Energy efficiency	Reduce demand for grid supply
Cost-reflective tariffs	Reduce peak demand
Data services	Assist with peak shifting and avoidance of coincident peaks, reduces need for grid
Peer-to-peer trading	Ambiguous, but may reduce prices and therefore increase demand

Table 1 shows that many of the developments are likely to put downward pressure on peak or overall demand both in a total sense and at most points of the distribution network. This sharpens the need for EQ to be careful when spending capital in order to avoid the risk of stranding some of its expenditure.

Electric vehicles

The impact of electric vehicles (EVs) on the grid is uncertain. EVs could lead to higher flows as car-owners opt for such cars because of their low whole-of-life costs. EVs could also serve as batteries to shave peaks.

Current barriers to EVs such as uncertainty about their range (considered a major factor in a country such as Australia where people can travel long distances), the time taken to charge a car, and the number of charging stations. These barriers are likely to be reasonably transitory as solutions such as longer battery lives, fast charge stations, and increased scale and investment in charging stations emerge.

Networks need to be at the forefront of making positive changes to support EVs into the network, and they need to be doing so now rather than later.

Development of peer-to-peer trading

Peer-to-peer trading involves DER providers connected to the distribution system selling excess generation to users connected to the distribution system. This form of trading seems to create positive value for the direct participants as it bypasses the need for additional transmission or remote generation investment and maximises the value of installed DER. From the distribution network's perspective, it also creates a value stream to the extent that it involves some form of payment to the network for transporting the electricity from the DER provider to the user.

EQ should start to determine arrangements for peer-to-peer trading. At present, some commentators see that DER providers should be able to feed electricity into the grid at a given or agreed price and that purchasers of that electricity should be able to use it at their premises at that price. This does not recognize any value for the transport of the electricity from the generator to the user. For networks to earn value from the transport function, they need to participate in helping to establish and provide a price for the transport function. This price could be based on short run or long run marginal cost, or some other value such as one based on whether the flows constrain the network. However, if networks resist supporting and developing peer-to-peer trading (or are slow to support it), then they will slow the development of these markets.

Recommendation Six:

That EQ in consultation with stakeholder groups investigate and undertake scenario analysis of how customers will use the grid in the short, medium and long term. This should include but not be limited to electric vehicles and peer to peer trading.

Potential for reductions in capital costs

Capital costs

Capital costs make up the majority of the regulatory costs and therefore QCOSS welcomes EQ's signal to apply the WACC parameters in the AER's draft and final rate of return guideline. This accounted for around 68 per cent of EQ's revenue across the return on assets and depreciation. As already mentioned above one of the main drivers keeping distribution tariffs relatively high is the excess historical capex identified in the ACCC pricing report and the Grattan Institute Report. Therefore, this submission now looks at the criticality of reduction capital costs and sets out a number of recommendations.

Excess historical capex

The Grattan Institute[x] argued that networks in NSW and Queensland invested excessively in assets that are not needed by customers. The investments were in response to prevailing regulatory incentives, public ownership, lower demand growth than anticipated, and excessive reliability standards. Jumps in capex in Queensland following the introduction of prescriptive reliability standards contributed significantly.

The ACCC[xi] also argued that Queensland and NSW networks had rapidly run up the investment in their networks ahead of growth in peak demand. The ACCC argued this was "driven primarily by excessive reliability standards and a regulatory regime tilted in favour of network owners at the expense of electricity users".[xii]

Essentially, both the Grattan Institute and the ACCC argue that there has been a major 'bring-forward' in capex from around 2005 to present. The Grattan report notes that investment in NSW and Queensland grew far more than Victoria or South Australia. This suggests that the investment was relatively excessive to that in the other two States.[xiii]

The over-investment takes the form of stranded assets, over-capacity in assets such as substations and transformers, and brought-forward expenditure.

The Grattan Institute analysis of the over-investment is based on metrics such as growth in the RAB compared to growth in customer numbers, energy, or maximum demand, and RAB per customer.

It argued that Energex should write down its regulated asset base (RAB) by between $1.7 and $3.9 billion, and Ergon by $2.4 billion. This over-investment took the form of stranded assets, over-capacity in assets such as substations and transformers, and brought-forward expenditure.

The Grattan Institute's main policy prescription for avoiding future over-investment is to move to cost-reflective tariffs, price caps rather than revenue caps, and, without being specific, managing the transition to a dynamic grid where investment is no more than required compared to adopting non-grid solutions.

The Grattan Institute argued that RABs should grow in line with usage. Usage could be measured in terms of maximum localized demand.

The truth of this analysis by the Grattan Institute and ACCC can be supported or otherwise by an analysis of current capacity compared to historical capacity and broader metrics such as capex, opex, and multifactor productivity benchmarking. EQ could measure capex against metrics such as capacity and maximum demand, and look at all alternatives when investing capital in order to avoid the risk of stranding network assets.

EQ has access to longitudinal data to verify or otherwise the claims made in the Grattan Institute and ACCC reports. Capital expenditure 2020-2025

To the extent that there has been significant historical over-investment in capacity, this can be expected to be reflected in significantly lower future capital spending across the capital budget.

EQ are forecasting low growth in peak demand of 0.4 per cent for both Energex and Ergon, with about 30 substations across both networks having annual growth rates in peak demand above 2 per cent (out of around 675 substations in total, or about 4.4 per cent).

Augex

This low rate of growth in peak demand should be expected to result in low augex and as evident in Table 2 there is some reduction in forecast augex for the current and 2020-25 regulatory periods.

Table 2: Forecast augex for 2015-20 and 2020-25 ($m)

	Energex	Ergon
2015-20 (forecast actual)	423	301
2020-25 (forecast)	279	257

To provide some confidence around this expectation, QCOSS requests that EQ provide information in its Final Regulatory Proposal on the level of spare capacity in the 30 substations as this will allow for greater transparency on the likelihood that such substations might need to be expanded.

For these substations in particular, there may be low-cost options to manage the growth in demand,[xiv] such as batteries, local demand management, or increased demand response. Further, in its recent short submission to the Round Three consultation on the EQ's Tariff Structure Statement (TSS), QCOSS has encouraged EQ to support the active management of peak demand and congestion by demand management including assessing the potential of the extensive existing take-up of load control tariffs, solar sponge tariffs and capacity peak rebates.

Augex also covers spending relating to reliability. In terms of reliability, Energex and Ergon are performing above the Queensland Minimum Service Standards (MSS) and the STPIS[xv] targets set by the AER across all twenty-four targets.[xvi] This is arguably consistent with the view in the Grattan report that unduly high historical reliability standards drove excessive capex in the period from around 2005.

In any event, it is expected that augex would be less than in previous regulatory periods given

- the low forecast growth in peak demand - less than 4.4 per cent of substations are expected to experience growth above 2 per cent, and some of these substations potentially have the capacity to carry this rate of growth across the 2020-25 regulatory period;
- the high prevailing reliability levels against the MSS and the STPIS targets; and
- the high historical levels of augex identified by the Grattan Institute and the ACCC, which should provide for respite in augex spending as spare capacities and Regulatory Asset Base (RAB) per customer rebalance.

QCOSS would be looking for EQ to place a strict critical focus on its level of augex for the 2020-25 regulatory period to assess whether it is justified. QCOSS is keen that EQ compare their augex with what other networks are proposing to spend over their coming regulatory period.

REPEX

QCOSS notes that forecast repex is expected to decline relative to forecast actual expenditure in 2015-20, as noted in Table 3 below.

Table 3: Forecast repex in 2015-20 and 2020-25 ($m)

	Energex	Ergon
2015-20 (forecast actual)	869.76	916.01
2020-25 forecast	665.11	880.00

This is a welcome trend.

QCOSS considers that since the start of the last regulatory period, the RIT-D now applies to both augex and repex. This places the focus squarely on ensuring that retiring assets are not replaced with like assets without testing if there are non-network alternatives or cheaper, perhaps lower capacity, network alternatives. It will be important for EQ to demonstrate in its Final Regulatory Proposal that its repex budget has been set after considering feasible lower cost options.

Noting the finding above in the Grattan Institute report that spare capacity has grown considerably within distribution networks in Queensland and NSW, there may be significant opportunities for assets to be replaced with lower capacity, less costly assets when they are replaced.

CAPEX

The 2015-20 forecasts and 2020-25 capex requests are summarized in Table 4 below.

Table 4: Forecast capex for 2015-20 and 2020-25 ($m)

	Energex	Ergon
2015-20 (forecast)	2,842	2,818
2020-25 (forecast)	2,383	2,539

EQ is proposing to spend $4.922 billion across the two networks in 2020-25 compared with $5.66 billion (forecast actual) in the current regulatory period. This is a reduction in real terms of 13 per cent. The issue is whether this reduction is sufficient given the arguable bring-forward in capex that occurred across the period from 2005 to the present.

QCOSS notes that EQ has committed to constrain Ergon's capex repex budget by an average $50 million per year, overhead costs by 10 per cent, and program of works delivery (understood to be unit rates) by 3 per cent.

However, the question remains whether this is likely to bring capex efficiency measures such as the RAB per customer metrics and capacity per customer metrics significantly back towards reasonable levels.

It will be imperative in the 2020-25 regulatory period to be very strict with the governance of capex approval processes to ensure no more investment is spent that required. The capex spending needs to be restrained as far as possible through the effective use of demand management, demand response and DER options. At present, the comparison of these alternatives is not adequately transparent, particularly in relation to technical issues such as grid stability and system security issues. It is recommended that there needs to be greater transparency and accountability around how non-network alternatives are compared with network alternatives, especially on non-cost issues such as reliability of supply.

Recommendation Seven:

That EQ improve monitoring and transparency on capital efficiency, including against metrics such as RAB per customer and capacity per customer.[xvii]

Potential for reductions in other costs

ICT budget

EQ has proposed an ICT budget around $461million ($234 million for Energex and $226 million for Ergon) for the 20202-5 regulatory period. This compares with an allowed budget of $451 million against estimated actual spending of $367 million in the 2015-2020 regulatory period. In the draft Plan, EQ has listed 18 systems for replacement over the 2020-25 regulatory period from geospatial systems to security systems.

Energex and Ergon jointly set up SPARQ in 2004 as a shared ICT provider for Energex and Ergon. As a result, it could be expected that the consolidation of Energex and Ergon in 2015 would not require significant further IT system integrations.

Given ICT depreciates quickly (say within 10 years or so) it has a significant impact on prices. EQ is proposing to spend considerably more in 2020-25 than in the current regulatory period on ICT (up from $367 million to $461 million in 2020 dollars).

The justification and transparency for the size of the ICT budget is not clear in the draft Regulatory Proposal. It is noted that EQ will be conducting another deep dive on ICT expenditure in November 2018. QCOSS is requesting that in determining its ICT budget across the two networks, EQ answers the following questions:

- What specific operating efficiencies are likely to arise from the ICT spending?
- What would happen if 10 per cent was removed from the ICT budget?
- What ICT work has been carried over from the current and previous regulatory periods? It is noted that EQ was allowed around $451 million this regulatory period but only spent $367 million. How can customer advocates be confident that the proposed budget of $461 million does not include spending on ICT budget items that were proposed in the current regulatory period but were deferred to the 2020-25 regulatory period?

Recommendation Eight:

That EQ provide sufficient information in its final Regulatory Proposal to enable the AER and stakeholders to make informed assessment as to the justification for the size of the ICT expenditure.

Unit rates

Unit rates are a unit of measurement of the costs of inputs such as materials and labor needed to build capital items. They include all direct costs and sometimes include indirect costs such as head office costs.

EQ is forecasting an improvement in the program of works of around 3 per cent which is welcome. Such improvements are likely to be due to efficiencies in unit rates due to technological improvements offered by the ICT investment which make capital works more efficient. Other areas where there is potential for improved efficiencies in unit rates is via improvements in work practices in the delivery of capital works.

It would be helpful for EQ's final Regulatory Proposal to provide more transparency on the contribution of the ICT spending to more efficient delivery of the capital works program. Further in its final Regulatory Proposal, EQ should discuss how it plans to reform work practices to improve capital delivery programs and address how it plans to return any labour rates above market rates back to market-comparable levels over time.

Savings arising from changes in accounting treatment

Accounting standards

EQ has differing accounting standards between its two networks, for example around depreciation. It is understood that EQ's accounting standards differ from those of other networks, for example around how labour costs or ICT costs are attributed to capital works programs.

While this may be allowed under the rules, it makes it difficult for stakeholders like QCOSS to understand or benchmark or compare Energex's or Ergon's capex or opex performance against other networks. There should be some way to state Energex's and Ergon's capex and opex performance on common terms against the performance of other networks. This point of comparison should be capable of independent replication.

Regulatory depreciation

EQ is proposing for Energex to move from accounting for asset classes using the weighted average remaining life (WARL) method to the year-on-year tracking method. Ergon is currently using the year-on-year tracking (YOYT) method. The WARL method operates within each asset class to weight existing assets and their remaining life with new assets to arrive at an average remaining life for that asset class. Under the YOYT method, the regulatory depreciation for each individual asset is calculated and summed to give the regulatory depreciation expense for each financial year of the regulatory period.

QCOSS considers that it is less costly and simpler to use the WARL method and both networks should move to using this method. QCOSS notes that EQ estimates that the price impact of Energex moving from the WARL method to the YOYT method is to uplift distribution tariffs by one per cent, which is a significant impact. QCOSS notes that the WARL method was the AER's preferred method for the 2016-2020 NSW and ACT electricity distribution regulatory determination.

QCOSS is concerned by the additional cost to Energex in implementing the change in accounting policy moving to the YOYT method.

At another time, the YOYT method might result in lower electricity tariffs, which begs the question whether networks might seek to be gaming tariffs by choosing the method that maximises tariffs in the short-term. At this time, the YOYT method increases regulatory depreciation, and represents a break from the previous accounting policy. The issue is whether a change in an existing accounting arrangement is fair to users, when user prices had previously been set under another accounting policy.

Electricity prices are having a major impact on customers, with significant rates of disconnection and loss of amenity through users suffering through minimizing their use (e.g. elderly users not using air-conditioning even when they are hot). Factors such as accounting changes should not be resulting in significant uplifts in electricity tariffs (one per cent being highly significant).

Recommendation Nine:

That EQ provide a common accounting position to allow the AER and other stakeholders to compare the capex and opex performance of Energex and Ergon against other distribution networks within the NEM.

QCOSS recommends that EQ use the WARL method to calculate regulatory depreciation for both Energex and Ergon assets.

Accounting treatment of ICT

Accounting arrangements between capex and opex and treatment of assets for the purposes of depreciation therefore have a major impact on distribution tariffs and final prices for users.

QCOSS welcomes the adjustments that EQ made to accounting policies for property leases and its decision to extend the rate of depreciation on ICT from 5 to 10 years.

However, QCOSS notes that previously, a significant portion of ICT was attributed through unit rates to assets and therefore was depreciated over the life of the underlying assets, eg, 40 years. This means that identifying ICT as its own asset class and depreciating it over 10 years reduces unit rates while significantly bringing forward the rate of depreciation on ICT assets from 40 years to 10 years. This has an uplift on distribution tariffs during the 2020-25 regulatory period compared to the previous policy. This would appear to be about 0.1 per cent.

QCOSS sees no reason to treat ICT differently to other inputs to capital projects. While ICT assets themselves have a shorter life than the assets that they contribute to, such as the construction of transformers with an asset life of 40 years, this is not considered particularly relevant. The other inputs to capital projects include indirect labor expenses, which essentially have no depreciable life at all.

Recommendation Ten:

That EQ continue its current policy of attributing ICT through unit rates to capital projects.

Project carry-overs

On occasion, networks will propose capital expenditure in a particular regulatory period on a project which is not spent in that period. This could be because the project is no longer necessary or can be deferred (e.g. because demand does not rise as anticipated), or because the project is delayed in part or in full due to some reason (e.g. labour backlogs, higher priorities, large capex budgets, management issues).

In these circumstances, the capital project may be proposed again in the upcoming regulatory period. Under the current arrangements, this can result in a double reward for the network.

The network receives an assumed rate of return and regulatory depreciation on the asset during the first regulatory period.

At the end of the first regulatory period, unspent capex is removed from the asset base. Under the CESS, the network receives a bonus equal to part of the saving in the capex budget. However, if other projects are overspent, the saving might not represent a genuine saving due to efficient delivery of capital projects.

At the start of the second regulatory period, if the project is again proposed and accepted by the regulator, the network incorporates it into the RAB and earns a return on it and regulatory depreciation from the time during the regulatory period that it is scheduled to be built.

This provides networks with incentives to defer capex, especially towards the end of regulatory period. The picture is complicated further by the fact that the AER stands back from specific projects and only approves a total capital budget, and then includes capital at the end of the regulatory period in the RAB if the distributor has underspent the total capital budget. The overall and arguably undeserved reward to the distributor from doing so is equal to the revenue earned on the project during the first regulatory period, when in fact the project was not required or not delivered. The reward is labelled ‘undeserved’ not in any pejorative sense but in the sense that it is not the result of efficiencies in the delivery of capital projects but from a mistake by the distributor or regulator in allowing the project in the first regulatory period.

EQ should clearly justify any capex projects that are carried over from the 2015-20 regulatory period to the 2020-25 regulatory period. The AER should consider adjusting the CESS to remove any reward that arises from the carry-over of a capital project and consider adjusting also for the quantum of any undeserved reward arising from the project being included in the first regulatory period.

Recommendation Eleven:

That EQ, in its final Regulatory Proposal, identify projects that are re-proposed in the 2020-25 regulatory period which have been funded in earlier regulatory periods. QCOSS encourages EQ to provide more detail on its proposed demand management arrangements and on the estimated savings in augex and repex.

Operating expenditure generally

EQ estimates that operating expenditure will be around $1,794 million for Energex and $1,789 million for Ergon in the 2020-25 regulatory period. EQ's draft proposal does not include specifically how much was spent by Energex or Ergon on opex during 2015-2020 or during the base year. This makes it difficult to determine trends in opex.

Some of the questions that arise include:

- What operating efficiencies do smart meters provide for EQ, for example in more rapid fault detection?
- What benefits does the proposed ICT spending provide in terms of reduced opex?

Recommendation Twelve:

QCOSS recommends that EQ address these questions in its final proposal.

Network age

QCOSS notes the considerable investment by EQ since 2005 in the network, particularly compared to the pre-2005 value of the network. This means that a considerable portion of the network could be relatively young. QCOSS understands that the average age of network assets has decreased through this recent capital investment.

QCOSS believes that the younger age of the network could be expected to result in savings in maintenance to EQ. This is on the basis that younger assets typically require less maintenance. QCOSS looks to engage with EQ and the AER through the final proposal and regulatory determination to understand whether and how much the younger age of the network might provide savings in maintenance to EQ.

Recommendation Thirteen:

That EQ provide information in its final Regulatory Proposal across a number of asset categories about typical maintenance costs for young assets compared to older assets.

Benchmarking

EQ has provided summary benchmarking data as part of its draft proposal on its opex program.

QCOSS will be looking at the AER's opex benchmarking assessment to provide its views on Energex's and Ergon's proposed opex budgets. QCOSS will be hoping that the proposed budgets drive both Energex and Ergon considerably closer to the frontier of efficiency as determined by the benchmarking analysis.

Where Energex and Ergon are not moving towards the efficiency frontier, then QCOSS will be reccommending to the AER that there should be close scrutiny on the factors hindering the move towards the frontier.

Vegetation management

From information provided during the deep dives, EQ reports that it expects to reduce the cost of vegetation management from around $40 million per year for each network to around $30 million per year. This will occur through introduction of new technologies (e.g. LIDIR), reduction in the frequency of aerial inspections, and recent negotiations of vegetation management contracts with contractors.

QCOSS welcomes this saving.

QCOSS notes that responsibility for vegetation management varies from jurisdiction to jurisdiction and that in Queensland, some of the benefits of vegetation management paid for by EQ are enjoyed by third parties such as Local Councils, pay TV providers, and telecommunications companies.

Recommendation Fourteen:

That EQ seek to recoup some of the benefits of vegetation management from the third parties and pass them through as savings to electricity customers. QCOSS recommends that EQ provide information in its final Regulatory Proposal across a number of asset categories about typical maintenance costs for young assets compared to older assets.

Insurance

EQ proposes to self-insure for the 2020-25 regulatory period.

QCOSS considers that it is a matter for EQ to determine whether to self-insure or not based on the likelihood and extent of possible damage to the network, and the costs of insurance. It would seem as a large and sophisticated party with deep understanding of the risks that its network faces, EQ should be well-placed to judge these factors and make the best choice about whether to self-insure or seek external insurance.

An issue is whether EQ should be able to claim any of the costs of self-insurance through the revenue determination. QCOSS contends that since EQ is able to recover a return on any assets destroyed by natural events and is able to pass-through the costs of reconstruction (once such costs reach a threshold), there is no case to be able to recover the costs of self-insurance through the revenue determination. QCOSS will be raising this issue with the AER but would be looking to EQ - if it seeks to recover the costs of self-insurance through the regulatory determination - to present the reasons why in its final Regulatory Proposal.

Labour productivity

It is important that any potential policy reasons for workforce decisions and resulting impacts on prices are transparent**.** This is important as it has implications for how such decisions are funded, that is, from reduced dividends to government (as owner) rather than in (higher) prices to customers.

QCOSS anticipates that the AER will investigate the prudency and efficiency of workforce decisions such as wage rises under the Enterprise Bargaining Agreement (EBA) and ensure that they have been justified on the basis of improvements in productivity. For example, The *SAPN case* found that an enterprise agreement (EA):[xviii]

> *… must satisfy the prudency and efficiency tests under the opex and capex criteria. The mere negotiation of an EA, albeit in good faith and at arm's length, is not itself an adequate foundation for discharging the opex and capex criteria. As earlier*

> *explained, the nature of an EA leaves itself open to considerable management discretion on terms, even if they may arise from employee demands. It would be important, for example, to demonstrate productivity and other improvements, consistent with wage conditions in the industry.*

The EBA negotiated by EQ with its workers should be considered no differently to an EA in this regard. We will be encouraging the AER to look into the prudency and efficiency of workforce decisions and their implications for wages levels in comparison with market levels and productivity gains.

Finally, a further point we would like to make with respect to labour force issues relates to the how the AER determines efficient wages. The AER has generally determined efficient wages based on a wage price index (WPI) approach. The problem with this approach is that it assumes that historical wages reflect efficient and productive levels and ignores any inefficiencies that might have been ‘baked-in’ to wages at an earlier time. We would consider the WPI approach may be a good way to assess the direction of recent wage rises. But not whether the starting points for wages were appropriate. Therefore, we will be raising this issue with the AER and recommending that it supplements the WPI approach with an assessment of wages for comparable or near comparable work to those of EQ at the start of the 2020-2025 regulatory period and consistent with the EBA time period.

Savings from incentive schemes

The EQ draft Regulatory Proposal states that the underspend in the current (2015-2020) regulatory period is $394 million. The draft proposal identifies that these savings result from underspend including savings of $394 million from the consolidation of Energex and Ergon.

These savings are anticipated to have largely been made in the base year of 2018-19, with forecast merger savings to come in 2019-20 of just $10 million (Energex -$2 million and Ergon -$8 million).

The Queensland Government forecast savings from the merger of $680 million when it announced the consolidation of Energex and Ergon in 2015.[xix] QCOSS requests information on the variation between the Queensland Government forecast of savings and the result reported in the draft Regulatory Proposal.

A key question that arises is whether any savings should be retained through the EBSS and CESS. The draft Regulatory Proposal provides that EQ “support the AER continuing to apply these to us in the next regulatory control period as long as they continue to be in the customer interest and will come back to customers with further information”.

An argument against their retention is that these savings did not come from internal management effort to reduce costs or improve efficiency but rather represent a once-off windfall from external policy changes of the Queensland Government.

EBSS/CESS

The AER states that it proposes to apply the CESS and will decide whether or not to apply the EBSS in its determination.[xx] The AER decided to apply the EBSS in the 2015-20 regulatory period.

QCOSS consider that the incentive properties of the EBSS and CESS work best when the two schemes work together and when any savings are clearly attributable to internal management decisions that reduced costs or increased efficiency or productivity.

QCOSS will be asking the AER to examine the extent to which any savings should be retained through the EBSS/CESS to be examined to assess whether they resulted from factors other than internal management efficiencies. Such factors could include:

- Arguably excessive capex or opex allowances made for the 2015-2020 regulatory period. Some of these excess allowances may have come from high peak demand forecasts, demand forecasts, or new connection forecasts;
- Capex that has been deferred from 2015-20 to 2020-25;
- Inefficiencies in capex and opex compared to industry benchmarks, and in particular any costs in excess of efficient levels while EQ is transitioning towards an efficient level of costs;
- Savings from changes in Government policy and specifically the Government's announcement in December 2015 that it would merge Energex and Ergon.

Above, in the section on project carry-overs, QCOSS argued that the AER should closely examine any apparent saving in capex that arose from an approved capital project being carried over from one regulatory period to another. The reward under the CESS should be primarily aimed at rewarding projects that are delivered under budget or where a lower cost option (either a network or a non-network option) was implemented.

STPIS

The STPIS aims to reward (or penalize) reliability performance above (below) targets specified by the AER. The Grattan Institute and the ACCC pointed to over-investment in the RAB due to a range of factors including spending in response to historically higher levels of reliability. This is likely to have resulted in reliability levels above those demanded by customers for the given price levels.[xxi]

Indeed, examining Energex's and Ergon's performance against both the STPIS and the MSS set by the Queensland Government, both networks out-performed the STPIS and MSS targets across all of the 24 sub-targets in 2017-18.

This would suggest that the STPIS or external regulation may be either incentivizing or requiring EQ to provide reliability in excess of levels that customers want. QCOSS will raise this issue with the AER and in particular will also suggest that either the AER should reduce the incentive payments under the STPIS to reduce EQ's incentives to lift reliability given customers arguably do not want higher reliability (or do not want it at current prices).

Bibliography

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AER 2018, *Final Framework and Approach: Energex and Ergon Energy Regulatory control period commencing 1 July 2020*, July

ENA and AEMO 2018, *Open Energy Networks*, June

Grattan Institute 2018, *Down to the Wire: A sustainable electricity network for Australia*, March.

SA Power Networks [2016] ACompT11

Endnotes

[i] See Grattan Institute 2018, *Down to the Wire: A sustainable electricity network for Australia*, March and ACCC 2018, *Retail Electricity Pricing Inquiry—Final Report*, June.

[ii] That is the four years from 2015-16 to2018-19

[iii] Noting that EQ only controls the DUOS element of final prices.

[iv] ENA website

[v] ENA and AEMO 2018, *Open Energy Networks*, June.

[vi] As identified in the Grattan Institute report and, in Queensland, by the Independent Review Panel in 2013.

[vii] At the same time, it is noted that low customer density in some rural and remote areas may create cross-subsidies in favour of those areas, even allowing for the fact that they may be served by SWER lines.

[viii] Future technologies could change customers' preferred reliability standards. For example, after large numbers of customers adopt EVs they may be able to 'ride through' short interruptions (say under 5 minutes) without noticeable effect, as the house switches over automatically to an islanded state supplied by the car's battery. This could mean customer stop valuing grid investments that avoid short interruptions.

[ix] In conjunction with other factors

[x] Grattan Institute 2018, *Down to the Wire: A sustainable electricity network for Australia*, March.

[xi] ACCC 2018, *Retail Electricity Pricing Inquiry—Final Report*, June.

[xii] ACCC 2018, p. ix

[xiii] Absent a significant difference in growth patterns or the rate of asset replacement among the four States.

[xiv] Assuming there is insufficient spare capacity during 2020-25 to cope with the forecast expansion in demand.

[xv] Service Target Performance Incentive Scheme

[xvi] For 2017-18

[xvii] Measured, for example, in substation capacity, transformer capacity, or line length per customer. The measures would ideally not be limited solely to line length per customer.

[xviii] Application by SA Power Networks [2016] ACompT11 at paragraph 550. The SAPN case clarifies the extent of the earlier *Ausgrid* case on this point at paragraphs 498 to 544.

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

[xx] AER 2018, *Final Framework and Approach: Energex and Ergon Energy Regulatory control period commencing 1 July 2020*, July.

[xxi] That is, the price levels that resulted from the higher RAB and opex budgets that resulted from the spending.