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14 June 2019

Warwick Anderson
General Manager
Networks Finance and Reporting
Australian Energy Regulator
GPO Box 3131
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By email: EnergyQueensland2020@aer.gov.au
cc: warwick.anderson@aer.gov.au

Dear Mr Anderson

Response to QLD electricity distribution determinations – Energex and Ergon Energy 2020-25

CANEGROWERS welcomes the opportunity to provide comment on the Regulatory and Tariff Structure Statements proposed by Energy Queensland for the 2020-25 regulatory period.

Representing around 75 per cent of Australia's sugarcane growers, CANEGROWERS is the peak body for the sugarcane industry in Australia. The Queensland sugar industry relies heavily on irrigation. The cost of the electricity used in that task is threatening the international competitiveness of farmers in our industry and in other agricultural industries across the state.

CANEGROWERS is a founding member of Queensland Farmers' Federation (QFF) and endorses the points raised in the QFF submission to the AER.

CANEGROWERS seeks network distribution determinations from the AER for Energy Queensland's Ergon Energy and Energex networks for the 2020-25 regulatory period that rigorously apply the national electricity rules (NER). The gaming of these rules, must be stopped if electricity price gouging endorsed by regulation is to be reined in.

CANEGROWERS concern is that the cost escalations contained Energy Queensland's regulatory and tariff proposals are not reflective of the true costs of prudently and efficiently delivering electricity to consumers and should be rejected by the AER.

Revenues and tariffs

We engaged the Sapere Research Group (Sapere) to review Energy Queensland's proposals and provide expert advice in relation to those proposals. Sapere's report is attached.

Sapere found Energy Queensland's tariff proposals:

- **are not cost reflective;**
- **are inconsistent with the principles contained in Chapter 6 of the NER; and**
- **do not meet any of the three limbs of the proposed AER compliance assessment approach.**

They conclude that if the long run marginal cost (LRMC) revenue requirement was motivated by the objective of reducing customer impacts from LRMC pricing (principle 6.18.5(h)), the LRMC component of the proposed tariff structures would be below seven (7) per cent of the total revenue requirement.

Further, the absence of a clear methodology for converting an estimate of unit LRMC (the LRIC methodology) into an estimate of the LRMC component of the total revenue requirement to be recovered from regulated tariff structures suggests, the proposed tariff structures are not compliant with the efficiency principles of the NER, in particular the LRMC pricing principle (6.18.5(f)).

Delays and incomplete proposal

CANEGROWERS is concerned about the extreme delay in Energy Queensland preparing and submitting what turned out to be incomplete regulatory proposals and tariff structure statements for its Ergon Energy and Energex networks and delays in EQ responding to requests for additional information to evaluate proposals. These delays have reduced the time available to conduct a full and complete assessment of the tariff proposals and their likely impact at a consumer/retail price level. This is an unacceptable situation.

Bill impact

In our submission to the Queensland Competition Authority's (QCA) recent determination of retail electricity prices in regional Queensland, CANEGROWERS presented evidence that the network costs borne by irrigators are too high. This reflected the pricing structures employed by networks and the fact that irrigators on non-congested parts of the network are required to bear the costs of network upgrades that are not needed and are unlikely to ever be delivered. In its final determination, QCA acknowledged the CANEGROWERS concerns and noting that it 'must set prices based on the network tariffs levied by distributors' wrote 'concerns regarding network prices should be directed to the AER as part of the AER's distribution pricing determination process' (QCA Retail Price Determination 2019-20, p72).

Despite CANEGROWERS raising these concerns and in full knowledge that the AER review of the network tariffs for both Egon Energy and Energex networks was underway, QCA elected to change its characterisation of irrigation tariffs (T62, T65 and T66) from transitional to obsolete. Energy Queensland has not provided a detailed analysis of the likely bill impact of its network tariff proposals in the 2020-25 regulatory period. Nonetheless, when forced to make the forced transition to the so-called cost reflective tariffs irrigators will face immediate and significant bill increases. Results obtained through Ergon Energy's agricultural tariff trial show that the electricity bills doubled for many irrigators who trialled T24 as an alternative to the traditional irrigation tariffs.

Separately, Sapare estimated the annual bill impact of the proposed default demand tariff for a user with a 'typical irrigator' load profile relative to that of a user with a 'typical small business' load profile, where the total annual volume is the same. They identified the prospect of irrigators incurring significant penalties despite irrigators making a negligible contribution to demand during periods of the highest network utilisation, compared with the average demand profile. The penalties of up to 33 per cent, depending on assumptions about whether the day or night loadings are applied.

Similar results are obtained for Ergon's larger customers if required to switch from T62 to a so-called cost reflective tariff (**attachment**). In the example, using Energy Queensland's on-line energy analysis facility, a customer with annual projected energy use of 48,583kWh and monthly demand in the range of 150kW to 331kW would pay an additional $156,116 per year if moved to T46.

For small and large businesses alike, the additional bill shock likely to arise from Energy Queensland's proposed tariff structures will not be offset by any concomitant increase in sales revenues.

Regulatory Constraints

In its July 2018 report 'Restoring electricity affordability & Australia's competitive advantage', the ACCC recommended that the Queensland government take immediate steps to remedy past over investment in the network capacity Energy Queensland's network businesses by a voluntary write down of the net asset bases of those businesses. According to the ACCC, this would 'enhance economic efficiency by reducing current distorting price signals.'

Despite the consistency of the Sapere results with the ACCC recommendations and CANEGROWERS raising concerns about the fact that existing network tariffs overstate the true cost of delivering electricity across the Ergon Energy network, QCA a captive arm of the Queensland government made it very clear that the regulation of network tariffs is an issue for the AER. Until the issues with Energy Queensland's network tariffs are resolved and those tariffs are truly reflective of the prudent and efficient cost of delivering electricity, the international competitiveness of irrigated agriculture across regional Queensland will be impaired.

CANEGROWERS is concerned that Energy Queensland's regulatory proposal overstates the administrative, operational ad capital costs associated with delivering electricity across Queensland. Simply put, the underlying cost structure on which the TSS proposal is based is too high. The adverse impact of this higher cost base is made worse for irrigators by a tariff structure design that does not take account of the fact that irrigators, operating on unconstrained parts of the network, are no contributing to the need for network upgrades or augmentation.

During the reset for the current (1995 to 2000) regulatory period, AER made it clear that its regulatory role was restricted to ensuring network proposals complied with the rules and that it has limited ability to constrain the distribution network service providers revenue requests and tariff proposals where those requests complied with the rules. During the course of this review CANEGROWERS, with the assistance of Sapere, has consistently demonstrated the flaws in Energy Queensland's approach.

CANEGROWERS calls on the AER to <u>reject</u> the Energy Queensland regulatory proposal and tariff structure statement and <u>require</u> it to:

- **reduce the revenue request for both the Ergon Energy and Energex networks; and**
- **develop network tariffs suitable for food and fibre production and other users that are on non-congested parts of the network and are not imposing capital costs associated with network expansion and augmentation.**

Conclusion

CANEGROWERS has identified a number of flaws in Energy Queensland's regulatory proposal and tariff structure statement 2020-25 rendering it not capable of regulatory acceptance.

CANEGROWERS is calling for the AER to approve a sharply lower revenue requirement and tariff structure that reflects the prudent and efficient costs of users on non-congested parts of Energy Queensland's networks.

An AER network price determination for Ergon Energy and Energex that accepts CANEGROWERS recommendations and reduces electricity prices by one-third will be an important first step in restoring the international competitiveness of Queensland's energy intensive industries.

Yours faithfully

[redacted]

Dan Galligan
Chief Executive

Attachment

Tariff comparisons – Ergon

Eligible tariffs

Tariff 62 Farming business time of use declining block (transitional)

Current tariff

This tariff is for farmers who use electricity at night and on weekends for irrigation, pumping, watering stock, heating piggeries, lighting hatcheries, dairy refrigeration or similar. It offers a cheaper rate after the first 10,000 kWh per month and for electricity supplied between 9pm and 7am. Not available in conjunction with Tariffs 20, 21 or 22. All costs and savings are GST inclusive. This tariff will end on 30 June 2020. Peak period: 7am-9pm weekdays.

Annual projected energy cost

$12,003

SWITCH TO THIS TARIFF DETAILS

Tariff 45 Large business monthly demand

This tariff has a charge for the total amount of electricity used, plus a demand charge and a daily supply charge. All costs and savings are GST inclusive. Demand threshold: 120 kW.

Annual projected energy cost

$103,148

SWITCH TO THIS TARIFF DETAILS

Tariff 44 Large business monthly demand

This tariff has a charge for the total amount of electricity used, plus a demand charge and a daily supply charge. All costs and savings are GST inclusive. Demand threshold: 30 kW.

Annual projected energy cost

$115,032

SWITCH TO THIS TARIFF DETAILS

Tariff 46 Large business monthly demand

This tariff has a charge for the total amount of electricity used, plus a demand charge and a daily supply charge. All costs and savings are GST inclusive. Demand threshold: 400 kW.

Annual projected energy cost

$168,119

SWITCH TO THIS TARIFF DETAILS

Source: Energy Queensland / Ergon Energy: https://www.ergon.com.au/retail/business/account-options/energy-analysis-for-consolidated-accounts/register-for-energy-analysis

CANEGROWERS

QLD electricity distribution determinations - Energex and Ergon Energy 2020-2025: Submission to Australian Energy Regulator's Issues Paper on distribution

Simon Orme, Dr. James Swansson

June 2019

sapere® research group

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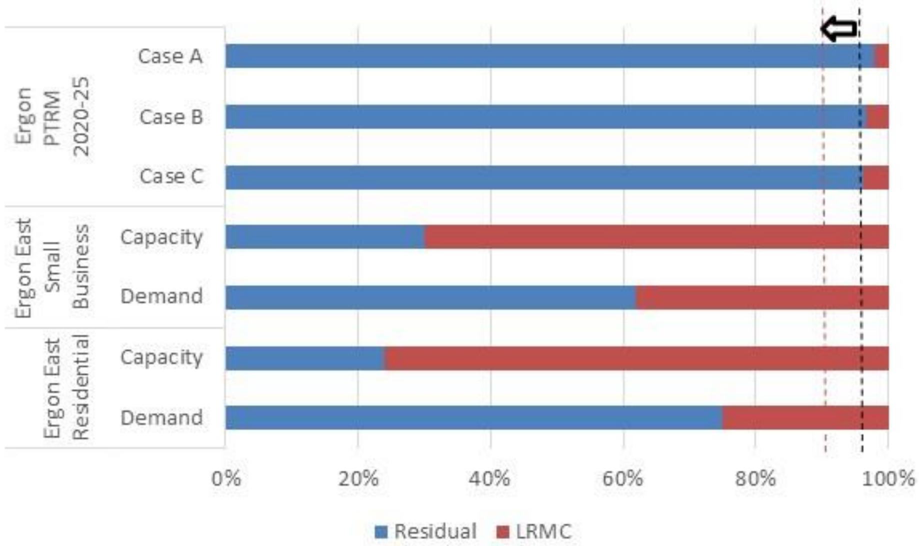
The authors have been retained by CANEGROWERS to provide expert advice to assist CANEGROWERS prepare a submission on Tariff Structure Statements (TSS) in response to the Australian Energy Regulator's (AER) Issues Paper; QLD electricity distribution determinations; Energex and Ergon Energy, 2025-25, dated March 2019. This topic is addressed in chapter eight (8) of the AER's Issues Paper. While proposals for Ergon are the focus of this report, due to the Queensland government's uniform tariff policy we have also reviewed briefly Energex proposed tariff structures against its Long Run Marginal Cost (LRMC).

Do proposed time of use tariffs reflect Long Run Marginal Cost (LRMC)?

Figure 1 compares the LRMC component of Ergon revenue requirement, derived from the post-tax revenue model submitted by Energy Queensland to the AER, with the LRMC component of the aggregate Ergon East Residential and Small Business tariff revenue, as advised by Energy Queensland (see Table 4).

Figure 1 LRMC revenue requirement versus residential and small business tariff LRMC revenue forecast



This shows that the LRMC component of both capacity and demand tariff revenues, for both residential and small business customer classes, substantially exceeds the LRMC revenue requirement for the period to 2025. On the one hand, the LRMC revenue requirement is no more than seven (7) per cent of total revenue, while the LRMC component of the capacity tariff is between 70 and 76 per cent of forecast tariff revenue and the LRMC component of the demand tariff is between 25 and 38 per cent of tariff revenue.

The discrepancies between LRMC revenues from each tariff and the LRMC revenue requirement for each tariff do not appear to be motivated by the objective of reducing customer impacts from LRMC pricing (6.18.5(h)). If they were, the LRMC components of the proposed tariff structures would be below seven (7) per cent of the total revenue requirement.

Consequently, the proposed tariff structures are not compliant with the efficiency principles in Chapter 6 of the Rules, and in particular the LRMC pricing principle (6.18.5(f)). This appears to reflect the absence of a clear methodology for converting an estimate of unit LRMC (the LRIC methodology) into an estimate of the LRMC component of the total revenue requirement to recovered from regulated tariff structures. It follows that the proposed tariff structures do not meet any of the three limbs of the proposed AER compliance assessment approach.

We are not suggesting that the LRMC component of any individual customer bill should not exceed seven (7) per cent. Where the incremental LRMC revenue requirement can be ascribed to a subset of a customer class – where a demand profile is much higher than the average for the customer class during periods of greatest utilisation of the network – then the efficient LRMC component should be a substantial portion of the total bill.

We have also reviewed the LRMC revenue requirement for Energex (see section 4.3 below). This is broadly similar to Ergon – the LRMC revenue requirement for small residential and business customer classes is unlikely to exceed seven (7) per cent of the total revenue requirement. As for Ergon, the revenue tables in the input sheet to the PTRM have not been populated for Energex and it is therefore not possible to derive estimates of the LRMC proportion of customer bills from publicly available information.

Table 1 estimates the annual bill impact of the proposed default Demand Tariff on an irrigator load profile relative to a "typical" small business load profile, where the total annual volume is the same (see the load profiles in Figure 5).

Table 1 Estimate of load profile impact on cost, default Demand Tariff 2020-21 rates

Small business load profile[1]	Estimated annual bill	Bill penalty
"Typical" load (NSLP) (night)	~$6,300	
Pump load (night)	~$8,400	33%
Pump load (day)	~$7,000	10%

Table 1 indicates the prospect of significant penalties for irrigation loads that make a negligible contribution to demand during periods of the highest utilisation of the network,

1 For simplicity, it has been assumed that the typical NSLP based profile has incurred the higher night period demand charge, where the irrigation load is considered in a 24 hour mode facing the night period demand charge and daytime mode facing the day period demand charge.

compared with the average demand profile. **The penalties are between 10 and 33 per cent**, depending on assumptions about whether the day or night loadings are applied.

If the demand tariff structure were cost reflective, both pumped load profiles in this example would result in lower annual bills and the savings would create an incentive to switching to a time of use tariff along with the associated interval metering. This is a further demonstration that the proposed demand tariff is not consistent with the pricing principles as it incorporates an LRMC component for a demand profile that only uses infra-marginal capacity.

LRMC revenue recoveries substantially exceed the incremental LRMC revenue requirement and hence the proposed demand and capacity tariffs do not effectively signal the cost of providing network services. The large discrepancy in the LRMC component of the demand and capacity tariffs is further evidence the tariff design is not cost-reflective. Moreover, the proposed demand tariff results in a higher bill for lower cost profiles which is the very opposite of what a cost reflective tariff should do.

Our previous reports examined in detail why there is an economic cost to the State from tariff structures that apply LRMC pricing to infra-marginal demand. Marginal pricing of marginal demand reduces or avoids triggering a requirement for new investment in future. Marginal pricing of infra-marginal demand signals to consumers to avoid demand where there is little or no marginal cost, or to increase investments to by-pass of network services. There is no avoided network cost. Under these conditions, network pricing reform does not mean lower customer bills over the longer term.

We agree that time of use and demand tariffs can be designed to be cost reflective. Our analysis shows that the LRMC component of cost reflective tariffs should be less than seven (7) per cent. This could be further refined if the revenue forecast input sheets in Ergon's PTRM were populated by Energy Queensland. These input sheets have been requested but have not been made available to us.

The analysis of the bill impact of the proposed demand tariff structure on high and low-cost profiles (relative to periods of greatest utilisation of the network) demonstrates that low cost profiles end up paying a bill penalty. Accordingly, the demand tariff is not suitable as a default tariff for customers with interval meters.

The extent LRMC should play a role in guiding the design of tariffs in Queensland is set out in the rules and hence appears outside the scope of the present consultation process.

We have no objection to the move away from the average incremental cost (AIC) method of deriving LRMC, as this in part appears to be an acknowledgement that the underpinning of the LRMC component in tariff structures approved by the AER in 2016 are inconsistent with the Rules. The long run incremental cost (LRIC) approach is in principle a sound method and we do not dispute the derivation of the unit cost estimate for a notional network augmentation.

The LRMC model does not yield the LRMC component of the revenue requirement, either for either of Energy Queensland's networks (Ergon or Energex) as a whole, or for a particular customer class. This is because there is no volume component or reconciliation back to the demand and CAPEX forecast in the PTRM. Moreover, there is no method or process for allocating the LRMC component of the aggregate revenue requirement to specific customer classes. On its own, therefore, LRMC model does not provide the LRMC to be reflected in the LRMC component of cost reflective tariff structures applied to a customer class.

In its assessment of compliance, we **recommend that the AER as a matter of course consider the LRMC component of the total revenue requirement**. It should also consider the allocation of the total LRMC related revenue requirement between customer classes. We recommend that, in order to undertake a full and proper compliance assessment, the AER requires Energy Queensland and other DNSPs to complete the revenue input sheet to the PTRM for each of their network businesses.

1. Introduction

The authors have been retained by CANEGROWERS to provide expert advice to assist CANEGROWERS prepare a submission on Tariff Structure Statements (TSS) in response to the AER Issues Paper; QLD electricity distribution determinations; Energex and Ergon Energy, 2025-25, dated March 2019. This topic is addressed in chapter eight (8) of the AER's Issues Paper. While proposals for Ergon are the focus of this report, due to the Queensland government's uniform tariff policy we have also reviewed briefly Energex proposed tariff structures against its LRMC.

The AER stated that the TSS submitted by the QLD distributors on 31 January 2019 were either unclear or subject to further consultation. The Issues Paper set out a set of key issues the AER suggested needed to be addressed in this consultation.

We encourage the QLD distributors, when formulating their preferred position on each of these issues, to take into account the recent AER decisions on TSS proposals in other jurisdictions. The key insights from these decisions are:

1. *The AER will not approve the flat tariff as the default network tariff for new residential and small business customers. In other words the default network tariff must have a cost reflective structure.*
2. *The AER considers that Time of Use and demand tariffs can be designed to be cost reflective.*
3. *The AER believes that it is in the interests of customers for the distributor to also offer alternative cost reflective tariffs on an opt-in basis.*
4. *To achieve an acceptable speed of transition to cost reflective pricing, the AER requires the distributor to re-assign existing customers with a smart meter to a cost reflective tariff as long as there are sufficient safeguard measures and transitional arrangements in place.*

The AER also states that:

> *We are seeking the views of stakeholders on the extent that long run marginal cost should play a direct role in guiding the design of tariffs in QLD? How should this occur? We also wish to receive feedback from stakeholders on the QLD distributor's proposed change in LRMC methodology. Do you think that this change is appropriate? Is it preferred to current industry practice of using the Average Incremental Cost (AIC) methodology?*

In this report we focus on the extent that the long run marginal cost (LRMC), forecast to be recovered from the LRMC component of proposed tariffs, corresponds to LRMC. This report builds on a series of reports and submissions we have prepared for CANEGROWERS pointing out that the tariff structures Energy Queensland has proposed for its Ergon and Energex networks are not LRMC based and therefore not consistent with the relevant national electricity rules and specifically the distribution pricing principles. Full references to these reports are provided in Chapter 8.

The structure of the remainder of this report is as follows.

Chapter 2 briefly summarises the relevant pricing rules which in combination represent the relevant benchmark for the AER's assessment of Energy Queensland (EQ) tariff structure proposals. This is neatly encapsulated in a helpful email from AER staff.

Chapter 3 summarises EQ's updated tariff proposals, focusing on the two new 'cost reflective' tariffs – demand tariff and capacity tariff for small residential and small business customers. This establishes the proportion of revenue for cost reflective tariffs that Energy Queensland proposes to be LRMC based.

Chapter 4 analyses Ergon's populated PTRM model to derive an estimate of the proportion of the total revenue requirement that is LRMC. This percentage LRMC cost can then be compared with LRMC percentage revenue from Chapter 3.

Chapter 5 sets out relevant context that provides a cross check on the estimate of LRMC derived from the PTRM – the extent of future network congestion in Queensland. It also recaps the relevant findings of the ACCC's Electricity Retail Price Review.

Chapter 6 considers whether a demand or capacity tariff reflects LRMC for an individual irrigator customer.

Chapter 7 draws the analysis together to set out conclusions in relation to some of the AER's consultation questions as well as Energy Queensland's Tariff Strategy Principles.

2. Network pricing reform

This section recaps network pricing reform and the current rules framework. In 2014 network pricing reform was initiated by amendments to the National Electricity Rules (NER) changing the framework in which network tariffs are developed to achieve network pricing objective (NPO) in the National Electricity Rules (6.18.5(a)):

> *"the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer."*

The AEMC in its Final Decision on the new network pricing rules states that:

> *Cost reflectivity in relation to network tariffs has three key components:*
>
> *(i) Sending efficient signals about future network costs.*
>
> *(ii) Allowing a DNSP to recover its regulated revenue so that it can recover its efficient costs of building and maintaining the existing network.*
>
> *(iii) Each consumer should pay for the costs caused by its use of the network.*
>
> *Taken together, these three components of cost reflectivity should result in an outcome where the network prices that each consumer faces reflect the costs that particular consumer causes through its use of the network.*

The first round of network pricing reform in Queensland was implemented through Tariff Structure Statements for the period 2017-2020. In its final decision on the Queensland TSS, dated February 2017, the AER approved the Energex and Ergon revised TSS submitted on 4 October 2016. The AER approved Ergon Energy's suite of demand, time of use and inclining block tariffs for small and medium size business customers as it was satisfied these contribute to compliance with the distribution pricing principles.[2]

Relevant rules

Under 6.18.5 (f) Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

> (1) the costs and benefits associated with calculating, implementing and applying that method as proposed;
>
> (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff <u>at times of greatest utilisation of the relevant part of the *distribution network*</u>; and

[2] See page 57 of the Queensland – Tariff structure statement 2017-10 – final decision.

(3) the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network*.

Under 6.18.5(g) The revenue expected to be recovered from each tariff must:

(1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff;

(2) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and

(3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).

(h) A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to:

(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*);

(2) the extent to which *retail customers* can choose the tariff to which they are assigned; and

(3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.

(i) The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:

(1) the type and nature of those *retail customers*; and

(2) the information provided to, and the consultation undertaken with, those *retail customers*.

(j) A tariff must comply with the Rules and all *applicable regulatory instruments*.

In email correspondence dated 30 May 2019 with the authors, AER staff stated that[3]:

> *From an AER staff perspective, our compliance assessment approach will involve the following three elements:*

[3] Correspondence from Robert Telford, Senior Advisor Network Pricing, Australian Energy Regulator to Simon Orme, 30 May 2019

(1) the appropriateness of the proposed methodology for estimating LRMC.

(2) the robustness of the LRMC modelling undertaken in accordance with this proposed methodology.

(3) whether the proposed application of the LRMC estimate to tariffs both in terms of tariff structure and tariff levels is compliant with the efficiency principles in Chapter 6 of the Rules, noting that a departure from LRMC-based pricing could be justified where necessary to satisfy the customer impact principle in the Rules.

3. EQ updated tariff proposals

3.1 May updates

Following further consultation following the AER's Issues Paper, in early May 2019 EQ published a set of tariff structure statement update documents:

1. Energy Queensland – Overview – Tariff Structure Statement 2020-25 update (2 May 2019)
2. Energy Queensland – Network Tariff Structure Statement 2020 -25 Update (2 May 2019)
3. Energy Queensland - Residential and Small Customer Impacts – Tariff Structure Statement 2020-25 Update (2 May 2019)
4. Energy Queensland – Tariffs and Tariff Assignment Arrangements – Tariff Structure Statement 2020-25 Update (2 May 2019).

Energy Queensland stated that its May tariff structure proposals are underpinned by the following proposed Tariff Strategy Principles:

- *Effectively signal to customers the cost of providing network services.*
- *Signal an efficient adoption of Distributed Energy Resource (DER) technologies, and encourage appropriate optimised use of that technology.*
- *Are as simple as possible in their structure, and resources and information are provided to improve understanding for customers and retailers.*
- *Are underpinned by data-driven decision making.*
- *Are underpinned by genuine stakeholder engagement.*
- *Have consideration for customer impacts in the pace and magnitude of change.*
- *Are flexible, innovative, and cognisant of the decisions made by other DNSPs.*

A key feature of May update is a repackaging of some of the proposed cost-reflective tariffs:

- Cessation of the Seasonal TOU Energy tariff;
- Replacement of the and Seasonal TOU Demand tariff, featuring one TOU window and summer peak rates, with a new Demand tariff (the default for those residences and small businesses with interval meters) with two TOU windows (day/night) and no seasonal variability. Replacement of the Seasonal TOU Demand tariff, featuring one TOU window and summer peak rates, with a new Demand tariff (the default for those residences and small businesses with interval meters) with two TOU windows (day/night) and no seasonal variability.
- Replacement of the optional "Package" tariffs with the optional Capacity tariff that offers five levels of demand "allowance" paid for in the fixed charge with additional charges for excess demand in two TOU windows (day/night) and no seasonal variability.

The Small Business Demand Tariff is the default small business tariff (less than 100MWh per year) for those with a digital meter after 1 July 2020. Relative to the existing Seasonal Time of Use Demand (STOUD) tariff it is both simpler in that it is non-seasonal and more complex in that the TOU peak window is split into two windows, day and night, with higher demand charges for the night interval. The demand charge is based on the maximum monthly half-hourly demand recorded with day/night window. The indicative rates for 2020-21 are given in Table 2 below.

Table 2 Ergon Small Business Demand Tariffs, indicative rates 2020-21[4]

Fixed Charge $/month	Demand Day $/kW/month	Demand Night $/kW/month	Volume Charge Flat $/kWh
	10-am – 4pm weekdays	4pm – 9pm weekdays	All volume
0.41	1.715	3.429	0.055

The Small Business Capacity Tariff, like the predecessor 'Package' tariffs, intends to provide consumers simplicity and stability in a demand-based tariff by providing the main component in a capacity allowance "pre-paid" through the fixed charge, so that if the consumer selects an appropriate level tariff behaves like the familiar "fixed plus flat" tariff. There is some leeway in that consumers can exceed their capacity level on 3 separate days per month during the day or night window with no consequence. Consumers who exceed their capacity allowance on more than 3 separate days will pay demand charges similarly to the demand tariff, that is based on highest day and night kW measurements in excess of the selected capacity level. The indicative rates for 2020-21 are given in Table 3 below.

Note this tariff is not clearly specified, including the capacity allowance levels and the detail of the excessive demand charge calculation. Energy Queensland states:

> *It is anticipated that demand charges for additional capacity use will apply infrequently if the selected capacity level is at least equal to 80% of the customer's maximum annual demand and Energex and Ergon Energy would assist retailers and customers in selecting the appropriate capacity level.*[5]

Based on a "typical" small residential or business customer (represented by NSLP in Figure 5 below), on this basis of these excess charges are likely to be incurred for the months December to March, so that this is a *de facto* seasonal tariff.

4 Energy Queensland, Tariffs and Tariff Assignment Arrangements - Tariff Structure Statement 2020-25 Update - 2 May 2019; Energy Queensland - Network Tariff Charges - Tariff Structure Statement 2020-25 Update - 2 May 2019

5 Energy Queensland - Overview - Tariff Structure Statement 2020-25 Update - 2 May 2019

Table 3 Ergon Small Business Capacity Tariff, indicative rates 2020-21[6]

Band	Fixed Charge $/mth	Capacity Day $/kW/ month	Capacity allowance* kW/month	Capacity Night $/kW/month	Capacity allowance* kW/month	Volume Charge Flat $/kWh
		10-am – 4pm every day		4pm – 9pm every day		All volume
1	14.467	2.893	5	5.787	2.5	0.032
2	26.04	2.893	9	5.787	4.5	0.032
3	40.507	2.893	14	5.787	7	0.032
4	57.867	2.893	20	5.787	10	0.032
5	86.801	2.893	30	5.787	15	0.032

1. The "demand allowance" has been estimated by dividing the monthly fixed charge by the capacity charge

3.2 Additional information supplied by Energy Queensland on request

In response to a request from CANEGROWERS to Energy Queensland, on 31 May Energy Queensland also provided a percentage breakdown of revenue for residential and small business tariff for Ergon East at the distribution level for nominal 2020-21 (see Appendix 1). [7] The purpose of this request was to identify the outcome or impact of Energy Queensland's tariff proposals. This information is typically provided in the revenue forecast tables within the PTRM input sheet of the PTRM. The January PTRM did not include any revenue forecast tables and this remained the case after the updated tariff proposals were released in May 2019.

We understand Energy Queensland's revenue forecasts have been derived by applying the proposed tariff structure and rates, multiplied by forecast sales volumes, to estimate the composition of revenues from Ergon East residential and small customer energy sales. This information is reproduced in Table 4 below.

6 Energy Queensland, Tariffs and Tariff Assignment Arrangements - Tariff Structure Statement 2020-25 Update - 2 May 2019; Energy Queensland - Network Tariff Charges - Tariff Structure Statement 2020-25 Update - 2 May 2019

7 Correspondence from Karen Stafford, General Manager Legal, Regulation and Pricing, Energy Queensland Limited to Warren Males, Head – Economics for CANEGROWERS and others, 31 May 2019

Table 4 Energy Queensland advice on revenue composition for residential and small business tariffs

	Ergon East Residential		Ergon East Small Business	
Tariff	**Demand**	**Capacity**	**Demand**	**Capacity**
Fixed Revenue	44%	0%	10%	0%
Demand Revenue	25%	76%	38%	70%
Volume Revenue	31%	24%	52%	30%

1. "For both the Demand and Capacity Tariffs, the Demand Revenue is based on LRMC with the remaining revenue then allocated across both fixed and volume."

For simplicity, we removed information on revenue from the basic tariff (e.g. for customers without interval meters – the bulk of customers by a large margin). This information was broken into fixed revenue and volume revenue but the LRMC and non-LRMC components were not differentiated.

In Table 5 below, we simplify the revenue forecasts for the relevant tariffs further by splitting forecast revenues into LRMC based revenue and residual revenue.

Table 5 Tariff revenue relative to rules

	Ergon East Residential		Ergon East Small Business	
	Demand	**Capacity**	**Demand**	**Capacity**
LRMC based revenue (6.18.5(f))	25%	76%	38%	70%
Residual revenue (6.18.5 (g))	75%	24%	62%	30%

Source: Sapere summary of EQ advice

This indicates that the LRMC component of the residential capacity tariff constitutes around three times the LRMC component of the demand tariff. This also indicates the proposed business demand tariff has a much larger LRMC component (38%) compared with the residential demand tariff (25%).

4. Estimating LRMC

4.1 Methods for estimating LRMC

In its current proposals, Energy Queensland has moved to a new method for estimating LRMC – long run incremental cost or LRIC. This replaced the previous Average Incremental Cost (AIC) method.

In both cases, the output from these models is an average or typical unit rate ($/kVA/annum). There is no volume component or reconciliation back to the demand and CAPEX forecast in the PTRM. The LRMC model outputs do not include the LRMC component of the total revenue requirement for the network as a whole, or its allocation to specific customer classes (retail customers).

4.2 The Post-Tax Revenue Model calculates incremental LRMC

The proportion of revenue associated with future capital expenditure (Capex) has been investigated in Ergon Energy's *Post-Tax Revenue Model for Standard Control Services* (PTRM).[8] This was submitted in January 2019 as part of Ergon Energy's regulatory proposal for the AER's Determination for the 2020-25 period.[9] The PTRM for the period 2025 to 2030 has not been populated by Energy Queensland. If it were, then LRMC could be considered for the next decade.

The PTRM is among other things a model for converting incremental LRMC for a given period into an increment to the annual revenue requirement for each year within that same period. The PTRM typically draws on the revenue requirement for the last year of the current revenue control period (in this case 2019-20) and forecasts this for two future revenue control periods or a decade (in this case to 2030).

The PTRM uses inputs for current capacity, the demand forecast and CAPEX, regarding both the unit rates for different types of new network capacity (e.g. transformers and feeders), as well as inputs on the volume of new assets and the capitalised labour required for installing new capacity. From these two kinds of inputs, the PTRM calculates the change in the total revenue requirement associated with incremental capacity.

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8 Ergon Energy - 8.004 - PTRM - SCS - January 2019, https://www.aer.gov.au/system/files/Ergon%20Energy%20-%208.004%20-%20PTRM%20-%20SCS%20-%20January%202019.xlsm

9 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/proposal#step-63380 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/proposal - step-63380

The change in the revenue requirement associated with increasing capacity by a certain increment, for example in response to rising peak demand or change in reliability regulations, represents a measure of the incremental LRMC. To be very clear, the resulting incremental increase in the revenue requirement represents incremental LRMC not incremental Short Run Marginal Cost (SRMC).

It is possible and indeed likely that the total incremental LRMC for one five year period differs from the total incremental LRMC for the preceding or following five year period. But this does not justify increasing the LRMC revenue requirement in one five year period in case the LRMC revenue requirement in a succeeding five year period could turn out to be higher. That is equivalent to pre-empting the following price or revenue reset.

It is also true that incremental LRMC varies from year to year within a regulatory period. The year to year variance is dealt with by the smoothing mechanism or x factor.

There is no requirement to over-recover incremental LRMC in one revenue control period. The total incremental LRMC in one revenue control period is of course recovered over multiple revenue control periods. For example, the cost of an asset with a 50 year economic life would be recovered over 10 revenue control periods. This is achieved by rolling forward the Regulatory Asset Base from one revenue control period to the next, in accordance with relevant guidance in the Rules and from the AER.

In our first piece of advice on Ergon's tariff structure proposals, dated March 2016, we noted there was no reconciliation to Ergon's PTRM for 2015-2020. We suggested this would be necessary to check LRMC revenue proposals against the LRMC component of the total revenue requirement. Ideally, this would be broken down into revenue proposals per customer segment, as provided for in the revenue tables in the revenue input sheets to the PTRM. This was challenging for the previous TSS round because the TSS period did not correspond to the PTRM period.

4.3 Our analysis of Ergon's PTRM

From the current PTRM, we have reviewed forward LRMC to derive an estimate of the LRMC component of the revenue requirement for 2020-25. Our methodology has been simply to measure the variation in the (unsmoothed) revenue "Building Block Components" for the period provided on the "Revenue summary" worksheet[10] when we vary the "Forecast Capital Expenditure – As Incurred" on the PTRM input worksheet.[11] This employs the pre-existing relationships (such as varying Opex for changes in Capex) embedded in formulae in the PTRM template by the AER. We note that only the first 5 years of the PTRM are populated.

The one assumption we have employed is to attempt to map between the asset types listed in the PTRM and asset investment purposes as related to network augmentation (or not). For

10 See rows 28 to 36, Revenue summary worksheet

11 See rows 39 to 71, PTRM input worksheet

this we have employed the *Capex Forecast Model - Standard Control Services*[12] submitted in January 2019 as part of Ergon Energy's regulatory proposal, to understand the proportions of Capex allocated to "Asset Replacement", "Augmentation", "Connections & Customer-Initiated Works" and "Non-System" categories.[13] First of all, we do not vary the "Non-System" categories (e.g. IT systems, motor vehicles, buildings). Then we identify the proportion of system Capex by category, as shown in Table 6.

The proportions in Table 6 are combined into an annual factor that is to be excluded from system Capex categories entered into the PTRM input worksheet. We consider three cases as listed in Table 7 below: Case A excluding augmentation (Augex) and half of replacement Capex (Repex); Case B excluding both Augex and Repex; and Case C excluding all system Capex.

Table 6 Proportion of Ergon Energy forecast SCS Capex by investment purpose

	2020-21	2021-22	2022-23	2023-24	2024-25
Asset Replacement	67%	66%	70%	74%	76%
Augmentation	19%	20%	18%	13%	11%
Connections & Customer-Initiated Works	14%	14%	13%	13%	13%

Table 7 Designation of proportion of category CAPEX as LRMC

	Augmentation	Asset Replacement	Connections & Customer-Initiated Works	Non-system
Case A	100%	50%	0%	0%
Case B	100%	100%	0%	0%
Case C	100%	100%	100%	0%

12 Ergon Energy - 7.154 - Forecast Capex Model(s) and Methodology - January 2019 https://www.aer.gov.au/system/files/Ergon%20Energy%20-%207.154%20-%20Forecast%20Capex%20Model%28s%29%20and%20Methodology%20-%20January%202019.xlsb

13 See capex Summary worksheet. Note values are in $ real 2018 values compared to $ real 2019-20 values in PTRM. We have not attempted to reconcile the two submissions to the AER.

4.4 LRMC component of Ergon and Energex revenue requirements

Table 8 shows the result quantifying the LRMC component of Ergon revenue requirement for the 2020-25 period using the *Post-Tax Revenue Model* – this component is less than four (4) per cent of the revenue requirement even in the most extreme case.

Table 8 Identifying the LRMC component of the total revenue requirement

	Case A	Case B	Case C
Period Revenue Requirement ($m)	$6,083	$6,083	$6,083
Requirement excluding augmentation ($m)	$5,960	$5,880	$5,848
LRMC component ($m)	$123	$203	$234
LRMC component (%)	2.0%	3.3%	3.9%

Of these three cases, we suggest that a point between Case B and Case A would correspond to forward looking LRMC for the entire Ergon customer base. Case C is clearly too high as it includes connection costs that should not be cross-subsidised by other customers via regulated tariffs.

We are not suggesting that the LRMC component of residential and business tariffs would be no greater than 3.3 per cent. We recognise that small residential and business customers may contribute disproportionately to total LRMC. For example, in earlier reports we showed that the Net System Load Profile was significantly "peakier" than Ergon's aggregate system load profile.

We suggest that Ergon's PTRM shows the LRMC component of residential and small business revenue requirements can be no more than seven (7) per cent. This would be the case if virtually all the LRMC revenue requirement were recovered from these two customer classes (or retail customers). The revenue requirement for these two customer classes is most likely much less than this since some of the LRMC revenue requirement would be in response to marginal demand from larger industrial and commercial customers. As the revenue forecast component of the PTRM has not been populated by Energy Queensland, however, it is not possible to explore this matter further using publicly available information.

Table 9 compares the outcome of the same procedure applied to PTRM submitted to AER by Energex for its 2020-25 determination.[14] Table 9 indicates outcomes that are slightly lower than Ergon for each case. Hence a similar conclusion can be drawn for the Energex network.

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[14] Energex - 8.003 - PTRM - SCS - January 2019 https://www.aer.gov.au/system/files/Energex%20-%208.003%20-%20PTRM%20-%20SCS%20-%20January%202019.xlsm

Table 9 Comparing Energex and Ergon LRMC component of the total revenue requirement

	Case A	Case B	Case C
Ergon LRMC component (%)	2.0%	3.3%	3.9%
Energex LRMC component (%)	1.8%	2.8%	3.4%

5. Current and forecast surplus capacity

5.1 ACCC finding on QLD surplus capacity

The ACCC recommended in its July 2018 final report *Restoring electricity affordability & Australia's competitive advantage* that Energy Queensland assets should be written down as this would 'enhance economic efficiency by reducing current distorting price signals.'

Recommendation 11

The governments of Queensland, NSW and Tasmania should take immediate steps to remedy the past over-investment of their network businesses in order to improve affordability of the network. With appropriate assistance from the Australian Government, this can be done:

- in Queensland, Tasmania and for Essential Energy in NSW, through a voluntary government write-down of the regulatory asset base
- in NSW, where the assets have since been fully or partially privatised, through the use of rebates on network charges (paid to the distribution company to be passed on to consumers) that offset the impact of over-investment in those states.

Such write-downs would enhance economic efficiency by reducing current distorting price signals. The amount of the write-downs and rebates should be made by reference to the estimates of over-investment by the Grattan Institute, and should result in at least $100 a year in savings for average residential customers in those states.

This reflected its finding that there had been over-investment in capacity in the past. The ACCC's July report referred to evidence from the Grattan Institute suggesting that nearly half of Ergon's RAB growth may have been in excess of the capacity required to meet maximum firm demand under a once in a decade demand event.

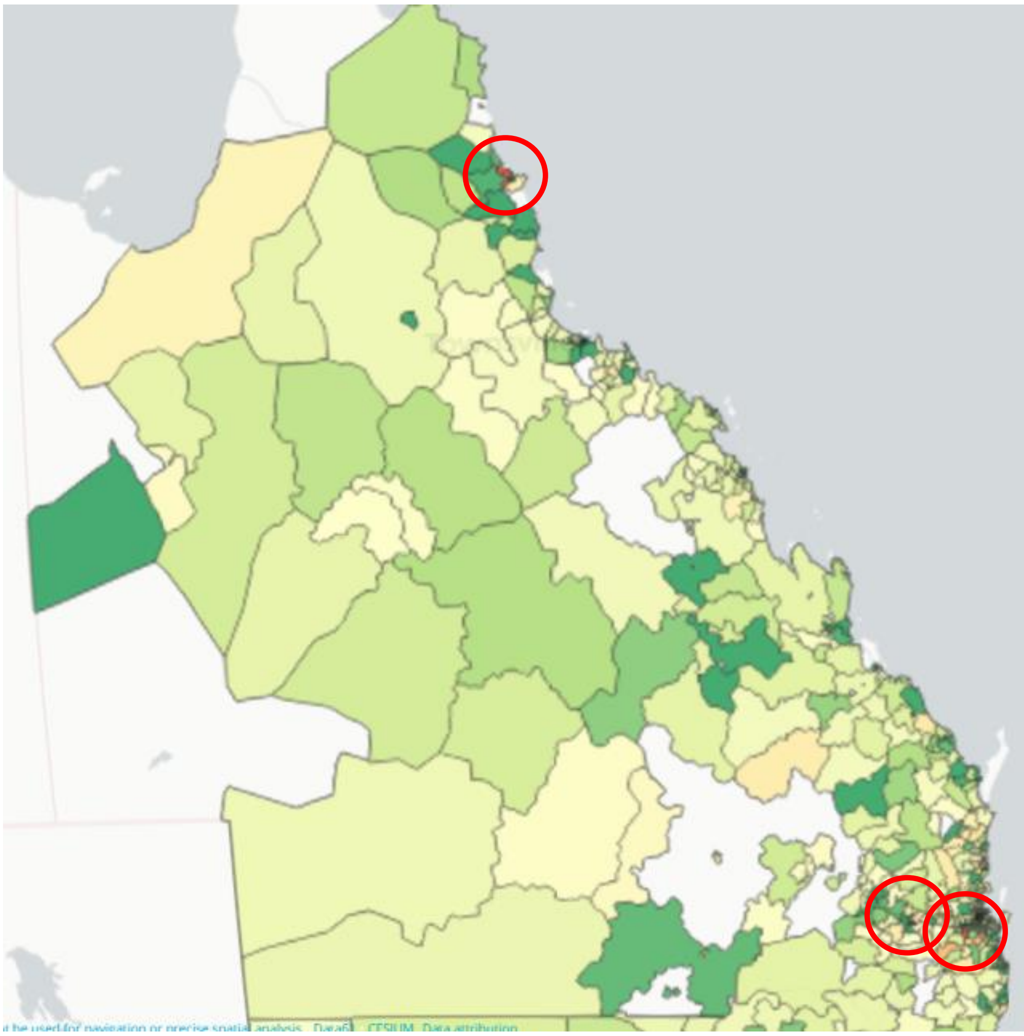
Network	Excess growth	As percentage of RAB growth
Energex	$1673–3935m	26% to 61%
Ergon Energy	$2442m	48%
Powerlink	$885m	24%

5.2 ARENA data on forecast surplus capacity

Publicly available forward data on network deferral value forecast to 2025 or thereabouts, provided by the Australian Renewable Energy Agency (ARENA), also demonstrates forward LRMC for Ergon and Energex is substantially lower than assumed in the 2016 TSS approved by the AER. The following figures give examples of the data on future network congestion available from the ARENA data to mid-2026, based on publicly available data derived from the most recent DAPR for the two networks.

These examples demonstrate that there is no system wide network congestion for the foreseeable future for either of the two Queensland networks. The significance of this, as we have repeatedly stated before (such as our October 2018 report), is that the LRMC includes calculating the benefit of this 'spare' capacity in terms of how long before rising levels of demand draw this capacity into use and allow the trigger for further network augmentation. **Put more simply, the nominal LRMC value from a model like long run incremental cost or LRIC may be the same but the deferral into the future means its net present value will be lower.**

Figure 2 Available distribution capacity in mid-2026[15]



Source: Australian Renewable Energy Mapping Infrastructure https://www.nationalmap.gov.au/renewables/

1. This is a map of 'firm substation capacity' (determined by the local reliability criteria), minus the forecast peak demand at the Zone Substation level.

The ARENA data appears consistent with Distribution Annual Planning Report (DAPR) forecasts prepared by Ergon and Energex. It shows that in all of Queensland there are just

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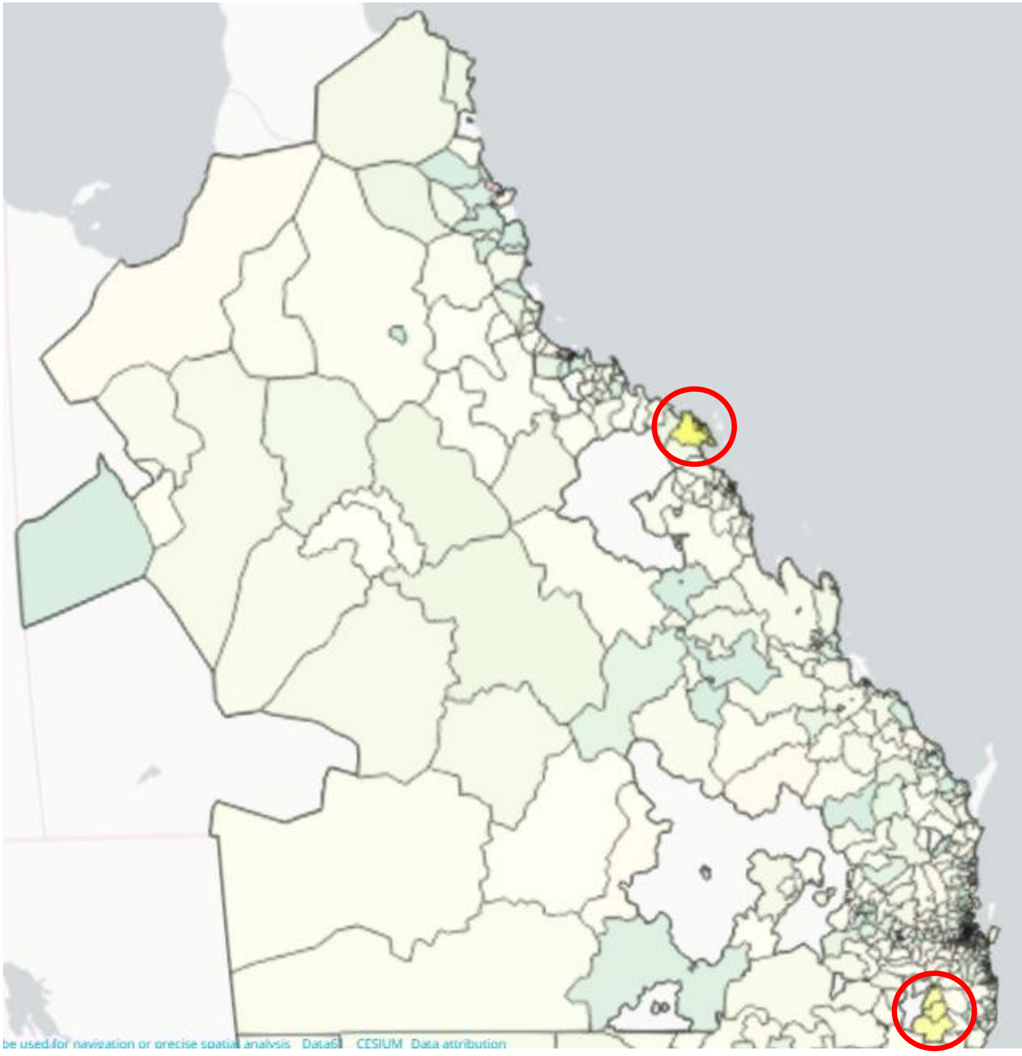
15 The web interface is possibly ambiguous regarding the final forecast period, with one part referring to 2015 and another to 2026.

four (4) major network elements (ZS) where the estimated deferral value within the forecast period is significant.

Where there is potential for future local congestion giving rise to a possible requirement for augmentation, Ergon's DAPR reveals this relates to new connections, not increases in maximum demand from existing connections. This is evident for example with respect to the growth in the Prosperine area highlighted. These areas do not, for example, correspond with an increase in irrigation demand for electricity or an increase in the irrigation load creating a need for network augmentation.

Figure 3 Annual Deferral Value

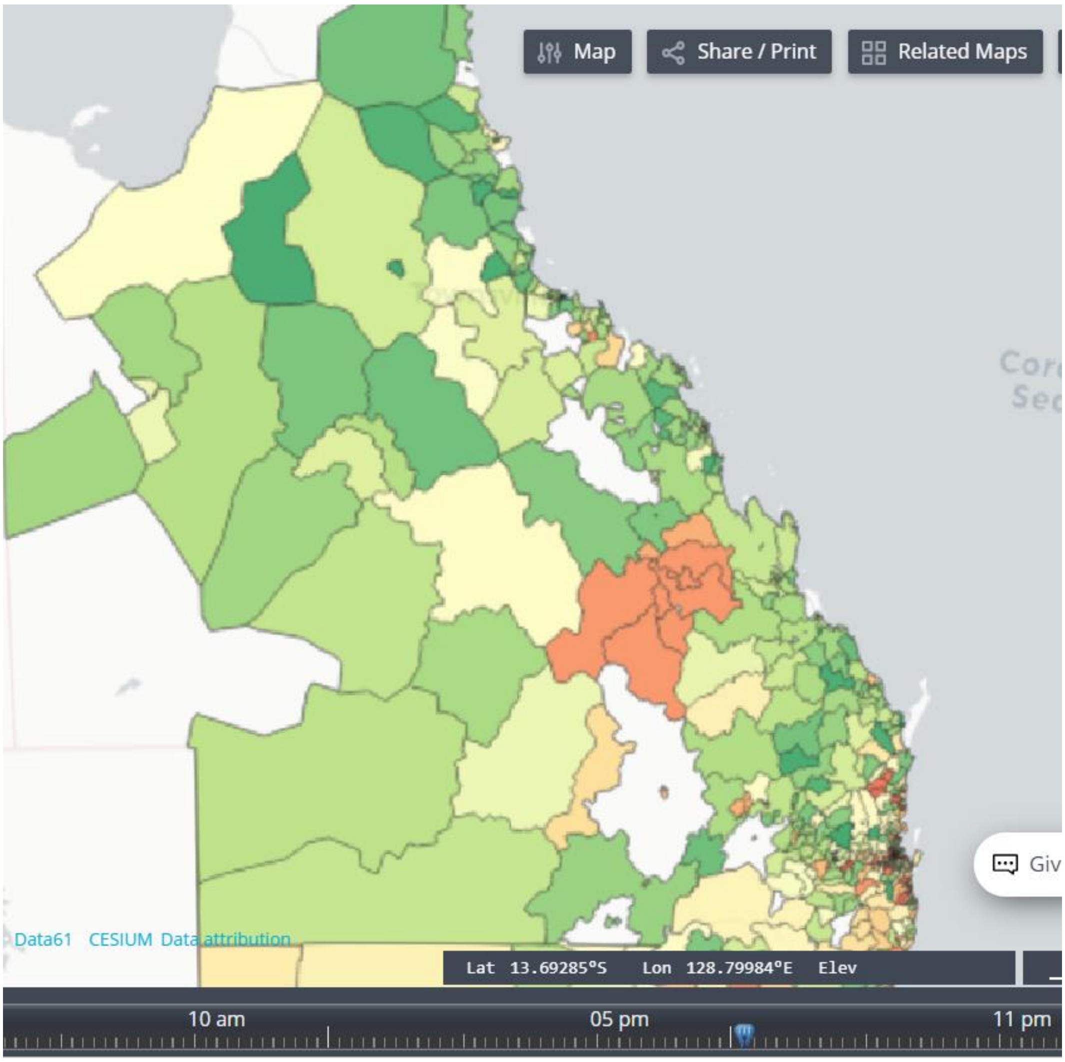


Source: Australian Renewable Energy Mapping Infrastructure https://www.nationalmap.gov.au/renewables/

2. Annual Deferral Value shows the effective cost of addressing upcoming network constraints through the preferred network solution.

The distribution pricing principles do not imply any associated costs should be recovered through peak tariffs and an LRMC component in flat tariffs for existing retail customers. This would represent a cross subsidy and breach the AEMC's three components of cost-reflectivity.[16] Instead, augmentation costs arising from new connections would more efficiently and fairly be recovered from network connections charges or capital contributions funded by new retail customers.

Figure 4 Peak Day Available Capacity Peak day available capacity by time of day



Source: Australian Renewable Energy Mapping Infrastructure
https://www.nationalmap.gov.au/renewables/

3. This map layer shows the available capacity (as a % of asset capacity) for each hour of the peak day in the lowest level of the network each area with potentially deferrable investment. A value > 0% represents spare capacity, while a value < 0% represents an exceedance.

16 See page 19 of the AEMC's Rule Determination, National Electricity Amendment (Distribution network Pricing Arrangements) Rule, 2014.

6. Case study- LRMC charges on inframarginal demand

In our October 2018 report, we tested the impact of Energy Queensland's tariff proposals on two customer demand profiles. This section reconsiders these cases in light of the May updated tariff structure proposals.

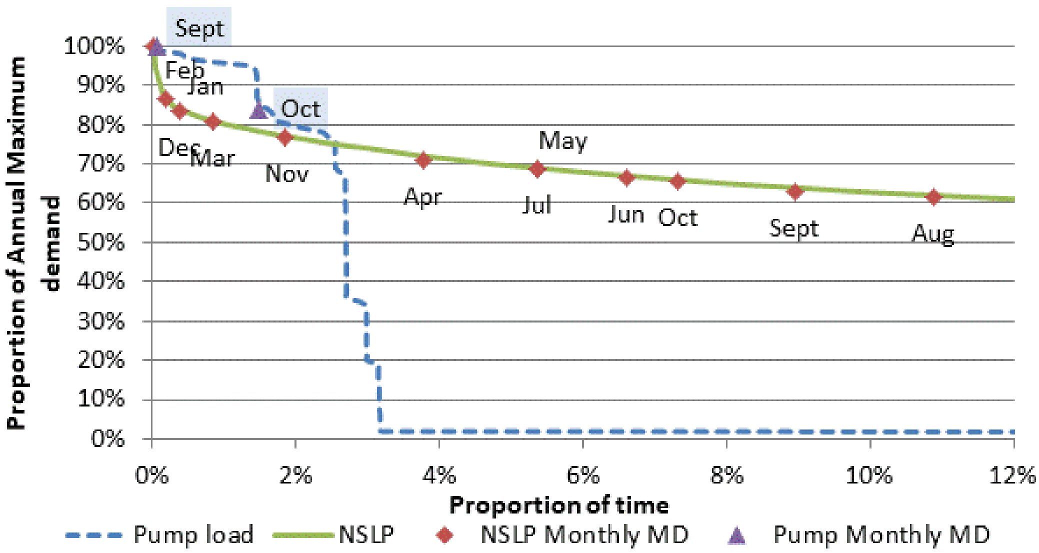
6.1 Two customer demand profiles compared

Small residential and business customers are known as Standard Asset Customers (SAC). SACs share connections to the network and do not require dedicated connection assets (whether shallow or deep), as may be the case for large customers. The "relevant part of the distribution network" for SACs is the shared standard assets, and the relevant "times of greatest utilisation of the relevant part of the distribution network" are collective peaks in maximum demand from SAC customers.

Under both the proposed demand and tariff structures, the pumped load would be subjected to LRMC related charges. **There is no causal connection between the LRMC revenue requirement and the demand profile of the pumped load, because the maximum demand for the pumped load does not contribute to the requirement for future capital expenditure that underpins LRMC.**

Figure 5 below shows the highest 12 per cent of the annual load duration curves for two Ergon small customers, one represented by the net system load profile and one irrigator.

Figure 5 Irrelevance of monthly demand metrics to incremental change in demand



The load duration curve for any customer or group of customers indicates the proportion of time (the x axis) that demand (the y axis) exceeds a given threshold. It provides an accurate visualisation of a customer's demand during times of greatest network utilisation, and hence the derivation of cost reflective tariff rates.

Ergon's small customer base, in aggregate and as a "typical" customer, is represented by the net system load profile (NSLP), providing ½ hourly interval data on coincident demand, where interval metering data is not available. The NSLP is the key driver of the total network load duration curve. Hence total network costs are driven by the capacity necessary to deliver energy during these few hours of "greatest utilisation" of the network.

The small customer demand load duration curve – the green line in Figure 5 – is notable for being very "peaky". Demand above 80 per cent of maximum demand occurs for only about one (1) per cent or 90 hours of the year, and within 10 per cent of peak for less than a day's worth of ½ hour periods.

Figure 5 also indicates the maximum demand in each month, highlighting the 90 hours of maximum consumer demand, or the periods of greatest utilisation of the network, occur in the months between December and March. Every other month of the year the maximum network demand does not approach 80 per cent of annual maximum demand.

Applying this to Energy Queensland's proposed Capacity Tariff (see section 3.1) at the recommended capacity level equal to at least 80% of the customer's maximum annual demand, it is likely that consumers will incur excessive demand charges in these months between December and March. Like the earlier "Package" tariffs, this smooths customers' bills across the year relative to the Demand Tariff, while still providing some incentive to reduce demand during the periods of greatest utilisation of the network.

The "typical" customer profile is contrasted with the load duration curve for an irrigator (blue dashed line), applying half hourly interval data provided by Ergon at the customer's request. The irrigator load is negligible during periods of greatest utilisation of the network, with maximum demand is in September, when maximum demand by the NSLP is around two thirds of the NSLP maximum demand.

Table 10 provides an estimate of the annual network costs for a small business customer based on the difference between the two profiles in Figure 5, using the indicative Demand Tariff rates in Table 2. For simplicity, it has been assumed that the peak demand ½ hour period in each month for the typical (NSLP) profile has incurred the higher night period demand charge. For the irrigation load Table 10 assumes both 24 hour irrigation facing the night period demand charge and daytime irrigation facing the day period demand charge.

Table 10 Estimate of load profile impact on annual bills, default Demand Tariff 2020-21 rates

Small business load profiles	Estimated annual bill (demand tariff)	Penalty
"Typical" load (NSLP) (night)	~$6,300	
Pump load (night)	~$8,400	33%
Pump load (day)	~$7,000	10%

Table 10 indicates the prospect of significant penalties for irrigation loads that make a negligible contribution to demand during periods of the highest utilisation of the network, compared with the average demand profile. The penalties are between 10 and 33 per cent, depending on assumptions about whether the day or night loadings are applied.

Cost-reflective tariff structures are intended to signal to consumers the periods when reducing or shifting their demand is economically efficient. Monthly demand charges (whether or not they are smoothed, and particularly without seasonal differentiation) encourage irrigator loads to reduce consumption at times that do not provide economic benefit to consumers generally.

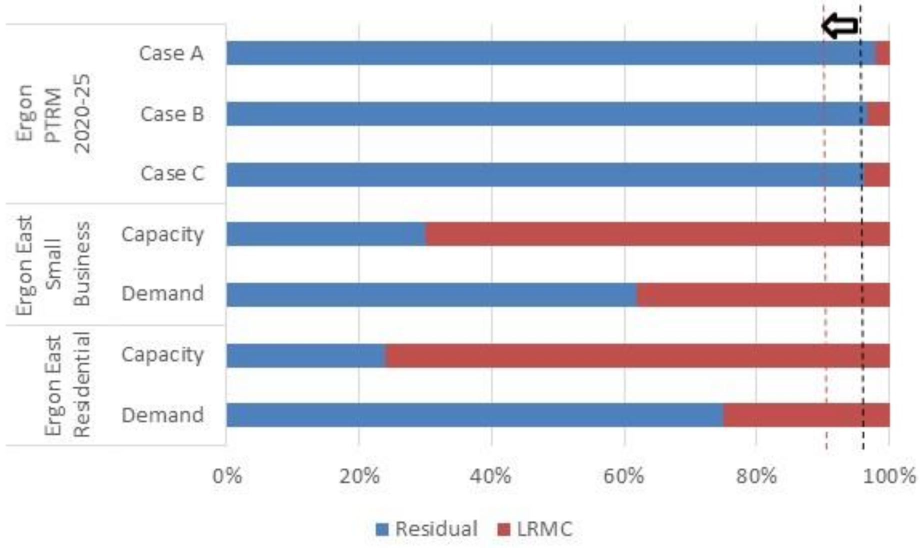
For these reasons there is no sound basis under the Network Pricing Objective (NPO) and distribution pricing principles for applying LRMC related charges to this irrigator demand profile. This would merely 'incentivise demand reduction beyond economically efficient levels.'

7. Conclusions

7.1 Results of our analysis

Figure 6 compares the LRMC component of Ergon revenue requirement with the LRMC component of the Ergon East Residential and Small Business tariffs as advised by Energy Queensland (see Table 4).

Figure 6 LRMC revenue requirement versus residential and small business tariff LRMC revenue forecast



This shows that the LRMC component of both capacity and demand tariffs, for both residential and small business customer classes taken as a whole, substantially exceed the LRMC revenue requirement. On the one hand, the LRMC revenue requirement is no more than seven (7) per cent of total revenue, while on the other hand, the LRMC component of the capacity tariff is between 70 and 76 per cent of forecast tariff revenue and the LRMC component of the demand tariff is between 25 and 38 per cent of tariff revenue.

The results in Figure 6 therefore mean that LRMC revenues from these two tariff designs do not correspond to or reflect the LRMC revenue requirement.

In other words, Energy Queensland's proposed tariffs are not cost-reflective.

The discrepancies between LRMC revenues and the LRMC revenue requirement do not appear to be motivated by the objective of reducing customer impacts from LRMC pricing (6.18.5(h). This would result in LRMC components below seven (7) per cent of the total revenue requirement.

Consequently, Energy Queensland's proposed tariff structures are not compliant with the efficiency principles in Chapter 6 of the NER.

This appears to reflect the absence of a clear methodology for converting an estimate of unit LRMC (the LRIC methodology) into an estimate of the LRMC component of the total revenue requirement to recovered from regulated tariff structures.

Accordingly, we suggest, **Energy Queensland's proposed tariff structures do not meet any of the three limbs of the proposed AER compliance assessment approach.**

We are not suggesting that the LRMC component of any individual customer bill should not exceed seven (7) per cent. Where the incremental LRMC revenue requirement can be ascribed to a subset of a customer class – where a demand profile is much higher than the average for the customer class during periods of greatest utilisation of the network – then the efficient LRMC component should be a substantial portion of the total bill.

We have also reviewed the LRMC revenue requirement for Energex (see section 4.3 below). This is broadly similar to Ergon – the LRMC revenue requirement for small residential and business customers is unlikely to exceed seven (7) per cent of the total revenue requirement. As for Ergon, the revenue tables in the input sheet to the PTRM have not been populated for Energex and it is therefore not possible to derive estimates of the LRMC proportion of customer bills from publicly available information.

Table 11 Bill impact of demand tariff

Small business load profiles	Estimated annual bill (demand tariff)	Penalty
"Typical" load (NSLP) (night)	~$6,300	
Pump load (night)	~$8,400	33%
Pump load (day)	~$7,000	10%

Table 1 indicates the prospect of significant penalties for irrigation loads that make a negligible contribution to demand during periods of the highest utilisation of the network, compared with the average demand profile. The penalties are between 10 and 33 per cent, depending on assumptions about whether the day or night loadings are applied.

If the demand tariff structure were cost reflective, both pumped load profiles in this example would result in lower annual bills and the savings would create an incentive to switching to a time of use tariff along with the associated interval metering. This is a further demonstration that the proposed demand tariff is not consistent with the pricing principles as it incorporates an LRMC component for a demand profile that only uses infra-marginal capacity.

Our previous reports examined in detail why there is an economic cost to the State from tariff structures that apply LRMC pricing to infra-marginal demand. Marginal pricing of marginal demand reduces or avoids triggering a requirement for new investment in future. Marginal pricing of infra-marginal demand signals to consumers to avoid demand where there is little or no marginal cost, or to increase investments to by-pass of network services.

There is no avoided network cost. Under these conditions, network pricing reform does not mean lower customer bills over the longer term.

The network prices Energy Queensland is proposing are neither cost reflective nor efficient and should therefore be rejected by the AER.

7.2 Responses to AER consultation questions

We make no observations on tariff assignment other than to note that default assignment to either the demand or capacity tariff would be contrary to the relevant rules.

We agree that time of use and demand tariffs can be designed to be cost reflective. Our analysis shows that the LRMC component of cost reflective tariffs should be less than seven (7) per cent. This could be further refined if the revenue forecast input sheets in Ergon's PTRM were populated by Energy Queensland.

The analysis of the bill impact of the proposed demand tariff structure on high and low cost profiles (relative to periods of greatest utilisation of the network) demonstrates that low cost profiles end up paying a bill penalty. Accordingly, the demand tariff is not suitable as a default tariff for customers with interval meters.

The extent LRMC should play a role in guiding the design of tariffs in Queensland is set out in the rules and hence appears outside the scope of the present consultation process.

We have no objection to the move away from the AIC method of deriving LRMC, as this in part appears to be an acknowledgement that the underpinning of the LRMC component in tariff structures approved by the AER in 2016 are inconsistent with the Rules. The LRIC is in principle a sound method and we do not dispute the derivation of the unit cost estimate for a notional network augmentation.

The LRMC model does not yield the LRMC component of the revenue requirement, either for Ergon and Energex as a whole, or for a particular customer class. This is because there is no volume component or reconciliation back to the demand and CAPEX forecast in the PTRM. Moreover, there is no method or process for allocating the LRMC component of the aggregate revenue requirement to specific customer classes. On its own, therefore, LRMC model does not provide the LRMC to be reflected in the LRMC component of cost reflective tariff structures applied to a customer class.

In its assessment of compliance, we therefore recommend that the AER as a matter of course consider the LRMC component of the total revenue requirement. It should also consider the allocation of the total LRMC related revenue requirement between customer classes. We note that, to undertake its compliance assessment properly, the AER should require Energy Queensland and all DNSPs to complete the revenue input sheet to the PTRM for their respective networks.

7.3 Energy Queensland Tariff Strategy principles

Energy Queensland's Tariff Strategy principles appear reasonable and more or less correspond to the relevant pricing principles. Our analysis has shown, however, that the proposed tariff designs are not cost reflective, do not comply with the NPO and therefore breach distribution pricing principles. In Table 12 we set out our assessment of tariff structure proposals relative to the Tariff Strategy Principles.

Table 12 Comments on EQ Tariff Strategy Principles

EQ Tariff Strategy principle	Comment
Effectively signal to customers the cost of providing network services.	LRMC revenue recoveries substantially exceed the LRMC revenue requirement and hence the proposed demand and capacity tariffs do not effectively signal the cost of providing network services. The large discrepancy in the LRMC component of the demand and capacity tariffs is further evidence the tariff design is not cost-reflective. Finally, the proposed demand tariff results in a higher bill for lower cost profiles which is the very opposite of what a cost reflective tariff should do.
Signal an efficient adoption of Distributed Energy Resource (DER) technologies, and encourage appropriate optimised use of that technology.	The proposed tariff structures may result in excessive investment in DER because they exaggerate the benefits of reducing demand, overall, but especially during periods where there are no network benefits whatsoever. The previous imperfect link to the periods of greatest utilisation of the network (charging windows that were too wide) has now been removed altogether.
Are as simple as possible in their structure, and resources and information are provided to improve understanding for customers and retailers.	While the new proposals are simpler than the existing tariff structures, it is possible customers would be unable to make rational choices between the demand and capacity tariffs given the discrepancy in the LRMC components.
Are underpinned by data-driven decision making.	There appears to be no reference to or reconciliation with the data on the LRMC revenue requirement embedded within the PTRM.
Are underpinned by genuine stakeholder engagement.	Without Energy Queensland disclosing either the LRMC component of the revenue requirement or the LRMC component of the two time of use tariffs, it is difficult to envisage how genuine stakeholder engagement could take place.
Have consideration for customer impacts in the pace and magnitude of change.	Energy Queensland has undertaken some analysis of the customer impacts but has not acknowledged the fact that its tariff proposals are not cost-reflective. A case study demonstrates a low cost profile is subject to a significant

EQ Tariff Strategy principle	Comment
	penalty under the proposed default Demand tariff relative to a higher cost profile.
Are flexible, innovative, and cognisant of the decisions made by other DNSPs.	Energy Queensland is not the only DNSP to apply a substantial loading to the LRMC component of tariffs that do not reflect the LRMC component of the revenue requirement. Many of the problems identified here apply to other parts of the sector, especially where the LRMC revenue requirement is modest due to past over investment in capacity.

7.4 What our analysis does not do

Where Ergon or the AER have in the past responded to analysis showing that the LRMC component of previous tariff structures was excessive, our analysis has been set aside based on a misrepresentation of our analysis. We therefore emphasise the following points.

1. We are not confusing short run with long run marginal cost. This is evident in the fact that the publicly available data indicates that in more than 95 per cent of Ergon's network there is no congestion for the foreseeable future – that is to 2026 or beyond in publicly available forecasts. Similarly, the LRMC revenue requirement embedded in the PTRM involves only a modest LRMC revenue requirement, with the limitation that the PTRM has only been populated by Energy Queensland to 2024-25.

2. Tariff components relating to LRMC should be applied only in regions and at times when the future prospect of congestion is real. As demonstrated LRMC components of the demand and the capacity tariffs are overstated relative to the LRMC component of the revenue requirement.

3. We are not suggesting that the LRMC component of any individual customer bill should not exceed seven (7) per cent. Where the incremental LRMC revenue requirement can be ascribed to a subset of a customer class – where a demand profile is much higher than the average for the customer class during periods of greatest utilisation of the network – then the efficient LRMC component should be a substantial portion of the total bill.

4. Our critique is not that the Ergon and Energex tariff structures are less efficient than an optimally designed tariff – it is not our responsibility to design cost reflective tariffs, precisely because our critique relies on publicly available data and we do not have access to the private data to substantiate such design. Instead, our critique is that these current tariff structures are not compliant with the NPO and distribution pricing principles.

5. Our critique does not imply that tariff structures could not be designed in compliance with the NPO and distribution pricing principles – as noted in our previous reports, we have highlighted that demand and capacity tariffs could readily be transformed into efficient network tariffs compliant with the NPO.

6. Our critique does not imply that distinct tariff structures are required for customer segments within the mass market of small-medium consumers. If tariff structures are genuinely reflective of a network's efficient cost to supply consumers, given their individual demand profiles, there should be no need for separate tariffs to distinguish separate consumer groups, even to the extent of small residential and business segments.

8. References

CANEGROWERS response to AER Issues Paper Tariff Structure Statement Proposals, Queensland electricity distribution network service providers, March 2016

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Review of AER Draft Decision; Tariff Structure Statement Proposals, Energex and Ergon, August 2016

https://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20report%20-%20Review%20of%20AER%20draft%20decision%20Tariff%20Structure%20Statement%20proposals%2C%20Energex%20and%20Ergon%2C%20August%202016%20-%20October%202016.pdf

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Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement, November 2016.

http://www.canegrowers.com.au/page/media/media-releases/2017/farmer-warn-of-more-power-rain

http://www.canegrowers.com.au/icms_docs/280686_canegrowers-sapere-electricity-report.pdf

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Sapere Memorandum to AER, 22 December 2016,

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https://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20-%20Memorandum%20to%20AER%20-%2022%20December%202016_0.pdf

Sapere Memorandum to AER, 13 January 2017,

https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ergon-energy-tariff-structure-statement-2017/revised-proposal

https://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20-%20Memorandum%20to%20AER%20-%2013%20January%202017.pdf

Evaluation of electricity distribution tariff structure proposals submitted by Ergon and Energex, September 2017, Sapere report for CANEGROWERS. We understand this was made available to EQL shortly thereafter.

Comments on Energy Queensland Tariff Structure Statement Issues Paper 2018, Report for CANEGROWERS,June 2018 https://www.talkingenergy.com.au/future-network-tariffs

Comments on Energy Queensland Consultation Papers, September 2018, report for CANEGROWERS dated October 2018.
https://www.talkingenergy.com.au/33399/documents/91014

sapere research group

Appendix 1 EnergyQ Correspondence

CANEGROWERS information request 21 May 2019

From: Warren Males
Sent: Tuesday, 21 May 2019 10:17 AM
To: KOLPAK Glen (EnergyQ)
Cc: MIZZI Kenny (EnergyQ); SORBELLO John (EnergyQ); Robert Telford; Chris Pattas; SMALES David (EnergyQ); 'Peter Price'
Subject: RE: Updated Tariff Structure Statement documentation that was submitted to the AER on Friday 17 May 2019

Hi Glen

Many thanks for the updated TSS.

We note the updated revenue allocation sheets from the PTRM that we have previously asked for are not included in this set of material.

Grateful if you could provide that material to enable an informed review of and response to the TSS and CANEGROWERS submission to the AER.

Regards

Warren

Warren Males | Head – Economics

CANEGROWERS

CANEGROWERS information request 30 May 2019

From: Warren Males
Sent: Thursday, 30 May 2019 9:43 AM
To: KOLPAK Glen (EnergyQ); SORBELLO John (EnergyQ)
Cc: Robert Telford; Chris Pattas; SMALES David (EnergyQ); PRICE Peter (EnergyQ); Simon Orme; PHILLPOTTS John (EnergyQ); MIZZI Kenny (EnergyQ); DART Michael (EnergyQ)
Subject: Updated Tariff Structure Statement documentation submitted to the AER on Friday 17 May 2019

Hi Glenn / John

We are working through the EQ TSS but have hit an information block. This is that the PTRM revenue forecast has not been populated to reflect the revised (May) tariff proposals.

In the various tariff structure explanation documents provided and those lodged with the AER, we have not been able to locate any discussion on the relationship between forecast LRMC and forecast LRMC revenue.

Our consultant is therefore unable to compare the LRMC component of the cost building blocks (the building block impact of augmentation and some replacement CAPEX), on the one hand, with the LRMC component of forecast revenues, on the other. It is therefore not possible to assess whether the proposed tariff structure is cost reflective and its compliance with the pricing principles.

It is possible this information is somewhere other than in the revenue forecast table in the PTRM. If this is so, we'd be very grateful if you could provide or point us to the spreadsheet that sets out the forecast revenue (from LRMC and other tariff components) for both the Ergon and Energex networks.

Regards

Warren

Warren Males | Head – Economics

CANEGROWERS

Energy Queensland response 31 May 2019

From: STAFFORD Karen (EnergyQ)
Sent: Friday, 31 May 2019 3:53 PM
To: Warren Males
Cc: KOLPAK Glen (EnergyQ); SORBELLO John (EnergyQ); Robert Telford; Chris Pattas; SMALES David (EnergyQ); PRICE Peter (EnergyQ); Simon Orme; PHILLPOTTS John (EnergyQ); MIZZI Kenny (EnergyQ); DART Michael (EnergyQ)
Subject: RE: Updated Tariff Structure Statement documentation submitted to the AER on Friday 17 May 2019

HI Warren

Thank you for your enquiry regarding revenue allocations for both our residential and small business tariffs.

I have provided the below percentage breakdown of revenue for these tariffs for Ergon East at the Distribution level for Nominal 2020-21.

	Ergon East Residential			Ergon East Small Business		
	Basic	Demand	Capacity	Basic	Demand	Capacity
Fixed Revenue	71%	44%	0%	31%	10%	0%
Demand Revenue	0%	25%	76%	0%	38%	70%
Volume Revenue	29%	31%	24%	69%	52%	30%

For both the Demand and Capacity Tariffs, the Demand Revenue is based on LRMC with the remaining revenue then allocated across both fixed and volume. You'll note the Basic tariffs have no Demand percentage, as this tariff does not include LRMC in its native form. This is done to support customers with older metering. I understand that these Basic tariffs, and the charges within blocks, are of interest and therefore have provided the attached calculation example for your information.

Does this assist? Please let me know if you need anything else. More than happy to help.

Kind regards

Karen

Karen Stafford
GM Legal, Regulation and Pricing
Energy Queensland Limited

CANEGROWERS clarification request 3 June 2019

From: Warren Males
Sent: Monday, 3 June 2019 12:12PM
To: STAFFORD Karen (EnergyQ)
Cc: KOLPAK Glen (EnergyQ); SORBELLO John (EnergyQ); Robert Telford; Chris Pattas; SMALES David (EnergyQ); PRICE Peter (EnergyQ); Simon Orme; PHILLPOTTS John (EnergyQ); MIZZI Kenny (EnergyQ); DART Michael (EnergyQ)
Subject: Updated Tariff Structure Statement documentation submitted to the AER on Friday 17 May 2019

Many thanks Karen,

Thank you very much for your response to our request for information. This information is very helpful.

As discussed between Sapere (our consultants) and your staff earlier last week, we want to make sure we are interpreting the information you provide correctly.

Accordingly, I'd be grateful if you could confirm whether any changes or qualifications are required to presenting the information you provided), along the lines of the table below relative to the operative clauses in the pricing principles (6.18.5), noting that, for the purposes of clause 6.18.5(i)) of the National Electricity Rules (v94) – customer comprehensibility, we have simplified the revenue buckets from three to two. The two revenue buckets correspond to the two operative clauses in the pricing principles, as shown below.

Ergon East	Residential		Small business	
	Demand	Capacity	Demand	Capacity
LRMC based revenue (6.18.5(f))	25%	76%	38%	70%
Residual revenue (6.18.5 (g))	75%	24%	62%	30%

Regarding any adjustments EQ may have made to the splits above in response to considerations under clause (6.18.5(h)), we'd be grateful if you could explain the impact. For example, for each cell in the table, was LRMC increased or reduced and if so by how much? If the impact of 6.185(h) is substantial, would it be possible to show the impact in percentage terms?

Again, many thanks for the information and look forward to your response to these few questions.

Regards

Warren

Warren Males | Head – Economics

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