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Professor Roy Green
Chairman
Queensland Competition Authority
Level 27, 145 Ann Street
Brisbane, QLD, 4000
Lodged at: www.qca.org.au/submissions

Dear Professor Green,

CANEGROWERS submission to QCA Regulated Retail Price Determination 2019-20

Thank you for the opportunity to make a submission to QCA's regulated retail electricity price determination review for 2019-20.

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. Over 85% of Australian sugar is exported into a highly volatile and competitive world market. The cost of the electricity is threatening the international competitiveness of Australian farmers.

CANEGROWERS is seeking efficient retail tariffs that reflect the spare capacity in Energy Queensland's networks, efficient and prudent retail costs and contain well targeted peak and off-peak charging windows as well as primary control load tariffs. It is premature to label the present transitional tariffs as obsolete and current tariffs should remain available until Energy Queensland's Regulatory Proposal and Tariff Structure Statement 2020-25 is finalised and approved by the AER.

Economic impact

According to the consultation paper, "*Under the Electricity Act, we can also have regard to any other matter that we consider relevant. We consider that the impact on customers is certainly a relevant factor*" (p8).

CANEGROWERS is deeply concerned about the impact of the current level of regulated electricity prices on the cost of pumping and the likely adverse impact of further price hikes.

The current level of retail tariffs is providing incentive for irrigators to make what might otherwise be considered inefficient farm business management decisions in order to manage the energy costs that flow from those inefficient electricity retail prices.

For some, this means diverting resources from activities that could otherwise lift agricultural productivity to investing behind the meter in alternative lower cost generation technologies, including diesel. Others are taking the risk of deferring their irrigation in hope of rain. In some irrigation areas across the state there has been a switch from intensive (irrigated) to extensive (dry land) agriculture in search of cost savings.

The adverse impact of high electricity prices on the price of irrigation water in Queensland is likely to be exacerbated as electricity prices are taken into account in the calculation of regulated irrigation water prices in the concurrent QCA Irrigation Pricing Review 2020-24.

Over the last decade, hikes in regulated prices have been a major driver of input price inflation facing irrigated agriculture in Queensland.

Retail costs

CANEGROWERS is concerned that the retail cost allowances established in 2016-17 significantly overstate actual retail costs. We note that regulated electricity prices in regional Queensland are 20 to 30 per cent higher than the tariffs paid by businesses in South-East Queensland.

Transitional tariffs

CANEGROWERS notes that QCA is "*required to consider reclassifying transitional tariffs as obsolete tariffs in 2019–20*" (p7). This requirement appears to pre-empt what might be contained in the forthcoming Energy Queensland Regulatory Proposal and Tariff Structure Statements 2020-25 for its Ergon Energy and Energex Networks.

CANEGROWERS has worked closely with Energy Queensland and the AER to understand the regulatory pricing framework and the factors driving electricity prices unsustainably higher across Queensland, particularly in Ergon's distribution network. We actively engaged in Energy Queensland's customer consultation program and retained the Sapere Research Group (Sapere) to independently and objectively analyse and prepare a single combined submission on Ergon Energy's September 2018 Network Tariff Consultation Paper, the Ergon component of 'Our Draft Plans 2020-25' and the Customer Consultation Summary produced by Energy Queensland. Sapere's report is **attached**.

CANEGROWERS has shared the issues and concerns raised by Sapere with the AER and with Energy Queensland.

Principal amongst these are that Energy Queensland's draft tariff proposals:

- continue to ignore the spare network capacity;
- ignore the recommendations of the Australian Competition and Consumer Commission Electricity Supply & Prices Inquiry;
- do not reflect the most recent demand forecasts;
- contain tariffs that increase in nominal terms;
- breach the National Electricity Law and impose a net economic cost;
- represent a substantial charge for services that are not in fact being supplied; and
- are based on a flawed method for setting the rate of return.

It is disappointing that these issues have not been materially dealt with in the draft Energy Queensland documents. However, having raised these issues and to reduce the inefficiencies and cross-subsidies in the current tariff design, CANEGROWERS is working with the AER to ensure the extensive spare capacity[1] currently in and expected to remain in the Energex and Ergon networks is taken into account in the final Regulatory Proposal and Tariff Structure Statements Energy Queensland submits for the forthcoming regulatory period, 2020-25.

[1] The Sapere analysis shows that Energex has more spare network capacity than Ergon (Energex has the second lowest (27 per cent) and Ergon the fourth lowest (43 per cent) maximum demand relative to maximum thermal capacity in the NEM). Not distinguishing between marginal and infra-marginal capacity, Ergon's congestion costs and long run marginal costs (LRMC) are over stated by two (2) orders of magnitude.

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CANEGROWERS is seeking an efficient tariff structure for Energy Queensland's networks that provides performance incentives for all in the electricity supply chain to efficiently and effectively deliver electricity to all customers. Efficient tariffs should reflect:

- the spare network capacity;
- contain peak and off-peak charging windows that reflect the spare capacity;
- take account of the most recent demand forecasts and, reflecting this;
- decline in nominal terms over the forecast period.

Modern efficient network tariffs should reflect the fact that the long run marginal cost of supplying electricity to users, including irrigators, on non-congested parts of the network are very low. Modern network tariffs would support base load and off-peak (infra-marginal) use profiles, including worthwhile time-of-use incentives, encouraging users to switch their usage to off-peak periods and over the weekend.

Modern network tariffs will enable the establishment of a suite of retail electricity tariffs for food and fibre production, meeting the needs of regional Queensland and those of irrigators. In this regard, it is pleasing that Energy Queensland is trialling the use of a control load tariff to offer as a possible primary agricultural tariff. This acknowledges the lack of congestion in the Ergon network and also provides an opportunity for irrigators and other agricultural users, where the tariff suits their usage profile, to be part of the solution. If they are willing to taking on some supply risk, users should be rewarded with a lower priced retail tariff.

Any reclassification of transitional tariffs as obsolete tariffs should be delayed until after the Energy Queensland Regulatory Proposal and Tariff Structure Statements 2020-25 has been approved by the AER.

Specifically, CANEGROWERS is calling for retail tariffs for food and fibre production with the following structure:

- **Base Load** – reflecting the fact that irrigation occurs on parts of the network that are not currently and are not forecast to be congested. The cost of delivery to these parts of the network is estimated to be not more than 8c/kWh equivalent.
- **Off-Peak** – reflecting the true LRMC of supplying electricity to parts of the network that are not currently and not forecast to be congested, provide a worthwhile incentive for off-peak use by further reducing the N-component (set N to zero) to encourage network use in low usage periods.
- **Weekend** – would be set at an equivalent to Off-Peak Tariffs to encourage weekend use.
- **Shoulder** – would be set at an equivalent to Off-Peak Tariffs to encourage use during shoulder periods.
- **Control Load** – reflecting the true LRMC of supplying electricity to parts of the network that are not currently and not forecast to be congested and Ergon's actual load profile, set N to zero with Energy Queensland retaining the right to cut supply during critical peak periods.

Conclusion

CANEGROWERS is seeking efficient retail tariffs that reflect the spare capacity in Energy Queensland's networks, efficient and prudent retail costs and contain well targeted peak and off-peak charging windows as well as primary control load tariffs. It is premature to label the present transitional tariffs as obsolete and current tariffs should remain available until Energy Queensland's Regulatory Proposal and Tariff Structure Statements 2020-25 is approved by the AER.

We look forward to discussing this submission with your team. In the meantime, please do not hesitate to contact Warren Males, CANEGROWERS Head-Economics for further information.

Yours sincerely

Dan Galligan
CHIEF EXECUTIVE OFFICER

Report for CANEGROWERS

Comments on Energy Queensland Consultation papers September 2018

Simon Orme, James Swansson

October 2018

sapere research group

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

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Introduction

The authors have been retained by CANEGROWERS to provide expert advice on a set of consultation documents relating to the price control period 2020-2025 published by Energy Queensland (EQL) in September 2018:

- *Energex and Ergon Energy Network Tariffs 2020-24 (Customer Consultation Feedback Summary, 25 June Consultation Papers.*
- *Ergon Energy Network Tariff Summary (EENTS)*
- *Our Draft Plans 2020-25 (ODP) – consultation for EQL Regulatory Proposals to the AER in January 2019.*

The focus for this report is the proposed tariffs for the period 2020-24, following EQL's May issues paper *Ergon Energy and Energex Network Tariffs 2020-25 Customer Consultation*. It also refers to an earlier prepared for CANEGROWERS entitled *Comments on Energy Queensland Tariff Structure Issues Paper 2018*.

Energy Queensland is not responding to matters raised in consultation

Best practice consultation requires responding to matters raised by stakeholders in previous consultation processes. EQL's September 2018 tariff proposals fail this test.

Except for the proposed capped tariff, the proposed tariffs are substantially the same as the existing tariffs. They are based on the same flawed long run marginal cost (LRMC) estimates.

EQL's September 2018 tariff proposals do not respond to the extensive criticisms of Ergon's Tariff Structure Statement (TSS) previously raised by the authors in a series of reports for CANEGROWERS, in the course of the 2017-20 Tariff Structure Statement (TSS) process and in our June 2018 report. The September documents contain no substantial responses to the matters raised in our June 2018 report.

EQL acknowledges customers question whether LRMC pricing is appropriate in an environment of flat demand growth but does not discuss this further and directs the conversation toward selection of the LRMC model. EQL notes that changes to the LRMC value will change tariff component prices, including any one of peak period demand, peak period energy or anytime energy, and require rebalancing components to recover the residual. But there is little transparency as to how the LRMC value is implemented in the proposed tariffs and, as discussed further below, based on the evidence of the indicative rates and implied bill cost, it appears tariff levels may have increased rather than decreased.

Spare capacity continues to be ignored in tariff proposals

The peak or LRMC component of the proposed tariffs continues to be calculated on the assumption available firm capacity is equivalent to maximum demand, and hence that LRMC related tariff components should apply regardless of the existence of spare capacity. Forward-looking spare capacity is not factored into the derivation of peak tariff levels and revenues at all.

Publicly available forward data on network deferral value forecasts to 2025 or thereabouts provided by the Australian Renewable Energy Agency (ARENA) demonstrate forward LRMC for Ergon and Energex is substantially lower than was assumed when current peak tariff levels were determined. There is no system wide network congestion for the foreseeable future for either of the two Queensland networks, based on publicly available data derived from the most recent 2017 Distribution Annual Planning Report (DAPR) for the two networks.

Tariff proposals ignore the recommendations of the ACCC Electricity supply & prices inquiry

The error of imposing congestion pricing in the absence of congestion is highlighted by the ACCC recommendation in its July 2018 final report *Restoring electricity affordability & Australia's competitive advantage*. The ACCC recommended 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.

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%

The proposed tariff design does not reflect the most recent demand forecasts

The proposed tariffs fail to distinguish between marginal and infra-marginal capacity. As a result, the proposed tariffs over-estimate congestion costs and long run marginal cost (LRMC) by more than two (2) orders of magnitude.

One component of this is the assumption of 2 percent annual growth in demand used in the 2015 LRMC calculation underpinning the proposed tariffs. Over a decade to 2025 this implies a total 22 percent growth in maximum demand. This is evident in Figure 2 of EQL's May 2018 TSS Issues Paper.

Our June 2018 report compared this projected growth with the 2017 Distribution Annual Planning Report (still the most recent). This showed that, over the 10 year period from 2006-07 to 2016-17 the system wide MW peak grew by just 53MW or 2.1 per cent over the decade – that is one tenth the assumed growth in the calculation of the LRMC quantum.

In the current set of EQL documents there no updated demand forecast information except the one datum citing 9 percent forecast demand growth over the decade to 2025 in *Our Draft Plans 2020-25*. This is less than half the assumed growth used in the calculation of the LRMC quantum that underpins proposed peak tariffs.

This means that the forward-looking or "peak" component of the proposed network tariffs substantially over-charges relative to the efficient cost. This component in tariffs represents a charge for services that are not in fact being supplied. Despite this, the proposed tariffs appear to increase the LRMC peak component of the proposed tariffs.

Proposed tariff levels increase in nominal terms

In the September 2018 EQL documents, there is no transparency regarding the application of the calculated 2015 LRMC quantum to derive proposed tariff rates. On currently available information, the underlying LRMC estimate can only be inferred from a tariff comparison between the first year (2020-21) of the next regulatory period and the current 2018-19 rates for the two "cost-reflective" tariff structures: Seasonal TOU Demand (STOUD) and Seasonal TOU Energy (STOUE) time varying tariffs, and the Inclining Block Tariff (IBT) that has no time varying component.

At face value the indicative 2020-21 rates appear to be largely based on the existing rates (and therefore the 2015 LRMC estimate) with some significant changes in STOUE and STOUD rates including (while other components largely remain the same):

- a four (4) percent increase in the peak rate for STOUE
- redistribution of the monthly demand charge involving a 15 percent reduction in the peak demand rate in STOUD, offset by 15 percent increase in the off-peak demand rate (the de facto monthly charge), as well as 28 percent reduction in the anytime energy component.

These tariffs produce significant cost increases for the example Standard Asset Connection (SAC) load we have previously used with both a typical (net system load profile or NSLP) and irrigator load profile, as shown in Table 1 and Table 2.

Table 1 Bill increases for 'typical' small customers

	STOUD	IBT	STOUE
Total annual bill 2018-19	$12,037	$13,344	$15,396
Total annual bill 2020-21	$13,502	$13,347	$19,392
Change	**112%**	**100%**	**126%**
Peak component 2018-19	78% ($9,339)	94% ($12,479)	46% ($7,129)
Peak component 2020-21	86% ($11,560)	93% ($12,479)	61% ($11,893)
Change	**110%**	**100%**	**133%**

Table 1 shows the bill increases expected for a 'typical' small customer of 12 and 28 percent respectively for the STOUD and STOUE tariffs, compared to minor variations in the time-insensitive IBT. Substantively, these total bill increases are driven by increases in the peak component of the tariffs – by 10 percent and 33 percent respectively for the STOUD and STOUE tariffs.

Table 2 Bill increases for a pump load

	STOUD	IBT	STOUE
Total annual bill 2018-19	$12,004	$13,344	$10,087
Total annual bill 2020-21	$12,868	$13,347	$10,451
Change	**107%**	**100%**	**104%**
Peak component 2018-19	78% ($9,306)	94% ($12,479)	7% ($663)
Peak component 2020-21	85% ($10,925)	93% ($12,479)	10% ($1,096)
Change	**109%**	**99%**	**143%**

Table 2 shows the bill increases expected for a pump load profile with the same total energy (hence the same IBT costs). The key characteristic of this profile is that nearly 80 percent of the energy is consumed in September. Previously, we have highlighted that, despite low demand during summer months when network utilisation is at its highest, this load receives only moderate reduction in costs relative to the typical profile under Ergon's preferred STOUD tariff. Table 2 further shows this pump load customer will experience bill increases of 7 and 4 percent respectively for the proposed STOUD and STOUE tariffs. Once again these are substantively driven by increases in the peak component of the tariffs.

These changes both suggest material and unexplained changes to the LRMC price component within tariffs. A significant factor in these increases is the extension of the summer peak window from 3 months to 5 months.

Proposed 'capped' tariff

The 2020-25 TSS proposes a new 'capped' tariff structure (Small Business Package) somewhat analogous to a mobile phone capped plan. This tariff structure responds to consumer desire for choice and bill smoothing by applying a 'cap' product within a time-of-use energy tariff. Each band includes a daily cap allowance for energy consumer during the summer peak window. The cost of this allowance is covered in the monthly charge, which is constant through the year. An 'excess' charge or top-up is applied. This excess is based on the day of highest peak usage within each month.

It appears that the Small Business Package offers a substantial discount relative to the STOUD/STOUE tariffs:

- the anytime energy rate of $0.05326/kWh in the capped tariff is discounted relative to the $0.07999/kWh off-peak energy rate in the STOUE tariff.
- our estimates of bill impacts suggest savings of 40-60 percent compared to STOUE tariff for 40-50 percent compared to the STOUD tariff.[1]

The application of LRMC price components is not transparent in the proposed tariffs and this discount is not reconcilable with the LRMC estimates used for STOUD and STOUE. While welcome from a consumer perspective, a discounted tariff raises efficiency and equity concerns that do not appear to be addressed in the September EQL documents.

Proposed changes

We acknowledge the proposals include some changes from the existing tariffs. However, these do not address the core errors in these tariffs and in some case reinforce the errors (as noted above).

EQL analysis in support of the definition of the peak charging windows is not fit for purpose. This is because it refers only to maximum demand, not available capacity. It represents applying congestion pricing in the absence of congestion. The outcome is that the peak window in Ergon network area has been extended from three to five "summer" months.

EQL is proposing a range of new tariffs that incorporate a bill smoothing element. As noted above our preliminary bill estimates suggest these tariffs incorporate a substantial discount relative to all other "cost reflective" tariffs. This may yield savings to SAC customers such as irrigators (but it has not been explained whether these are being subsidised by other customers). However, the effect of bill smoothing that is produced for 'representative' load profile is not produced for an irrigation profile, so that careful band selection is essential to minimising costs.

The proposed tariffs impose a net economic cost

The proposed tariffs will not result in avoided network investment and lower network future network prices, in contrast to the assertion made in the March 2018 EQL TSS Issues Paper (specifically Figure 2 on page 13). If this modelling took into account forecast spare capacity to 2026,[2] then there would be only a fractional difference between the two scenarios for the entire forecast period. Since there is a substantial difference between these two scenarios, it

1 We have calculated this bill based on the available description in the *Ergon Energy Network Tariff Summary*.

2 See figures 6 and 7 below.

is clear that the modelling does not take into account substantial spare capacity compared with forecast demand growth to 2026.[3]

On the other hand, the proposed tariffs impose costs. These costs would take the form of suppressed demand and greater investment in and use of otherwise less efficient alternatives.

Economy wide costs are substantial, while the network benefits are minimal. Consequently, the existing tariffs are economically inefficient, fail to meet the NEO and are inconsistent with the NEL.

The proposed tariffs breach the National Electricity Law

The proposed tariffs breach the Network Pricing Objective (NPO) in the National Electricity Rules (6.18.5(a)), alongside the distribution pricing principles outlined in 18.5 (f). Under this rule '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 [among other things] to (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network.

The proposed tariffs do not appear to be consistent with Section 29 of the Australian Consumer Law (Cth.) (ACL), under Schedule 2 of the Competition and Consumer Act 2010. This section concerns false or misleading representations about goods and services.

The September 2018 tariff proposals for the period 2020-25 *assume* that the current suite of network tariffs complies with the relevant national electricity rules and in particular the distribution network pricing objective and distribution pricing principles. Energy Queensland cannot proceed on the assumption the existing tariffs are compliant with the NEL.

The proposed tariffs are based on a flawed method for setting the rate of return

Our analysis of network rate of return data released by the AER in September shows that, over a 4 year period, the two Queensland networks have generated economic profits of more than $780m above allowed returns of $5,341m. This is shown in Table 11, which provides for comparison the actual earnings before interest and tax (EBIT) with the AER allowance for EBIT, and the resulting economic profit for each year. [4]

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3 The "bump" in demand in 2016 appears to relate to new demand arising from coal seam gas extraction and a 10 POE event. See discussion around page 57-58 of Ergon *Energy's Distribution Annual Planning Report 2017-18 to 2021-22.*

4 Over a period of time, a business making normal profits will remain in the industry and will only exit the industry if it is making losses in the long run. If, over time, total revenues exceed total economic cost, then the business may be described as making super normal profits.

Table 3 AER Actual RoA excluding incentives relative to the WACC

	2013-14	2014-15	2015-16	2016-17	Total
Energex					
Actual EBIT ($m)	$639.6	$902.7	$896.7	$789.1	$3228.2
Allowed EBIT ($m)	$951.0	$973.1	$469.0	$478.1	$2871.2
Economic Profit (%)	-2.63%	-0.58%	3.62%	2.60%	3.02%
Economic Profit $	-$311.39	-$70.38	$427.76	$311.02	$357.00
Ergon					
Actual EBIT ($m)	$706.6	$883.0	$597.7	$705.8	$2893.2
Allowed EBIT ($m)	$807.0	$832.4	$411.6	$419.1	$2470.1
Economic Profit (%)	-0.98%	0.48%	1.78%	2.72%	4.00%
Economic Profit $	-$100.34	$50.66	$186.09	$286.69	$423.09

Source: AER data on Actual RoA excluding incentives relative to the WACC.[5]

Except under limited conditions, economic profits are inefficient and unfair. They transfer wealth from consumers to networks and result in deadweight losses, reducing Gross Domestic Product and the international competitiveness of Australian exporters. Economic profits may also lead to investment by consumers in substitute assets and services at higher levels than otherwise, reducing the utilisation of network assets. As a result, economic profits reduce dynamic efficiency or economic efficiency over the long run.

What our critique does not do

Where Ergon has in the past responded to our critiques, it has typically misrepresented them. We therefore emphasise the following. points

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 2025 or beyond in publicly available forecasts. Therefore in any calculation of LRMC, even under conditions of higher demand growth than currently forecast, significant capital expenditures will be deferred and their current value will be proportionately discounted.

Tariff components relating to LRMC should be applied only in regions and at times when the future prospect of congestion is real. As demonstrated, both the value and the application of LRMC tariff components of the STOUD and the STOUE appear to be

5 Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses

overstated. There does not appear to be any case for retaining the IBT. A simple two part tariff would appear to be less distortionary and more efficient that either an IBT or a DBT.

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.

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 the STOUD and the STOUE could readily be transformed into efficient network tariffs compliant with the NPO. Part of the opportunity in the current round of tariff structure statements is to make that step forward along the cost-reflective spectrum.

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 serve consumers given their particular load profile, there should be no need for separate tariffs to distinguish separate consumer groups, even to the extent of small residential and business segments.

Conclusions

Energy Queensland needs to develop a completely new set of tariff proposals that are compliant with the NEL. Compliance with the NEL is not optional for Ergon and Ergon; it is required by law. Existing and proposed breaches of the NEL should be remedied at the earliest opportunity.

Any new proposed tariffs need to be underpinned by realistic forecasts of future network congestion, after taking account of existing spare capacity across most of the network. To the extent future network congestion arises from new connections rather than changes in demand from existing connections, there is no sound basis under the Network Pricing Principles for imposing higher tariffs on existing customers.

Best practice consultation requires responding to matters raised by stakeholders in previous consultation processes. Objections to the current and proposed tariffs identified during the 2017-20 TSS process and the first round of the 2020-25 TSS process have not yet been addressed.

1. Introduction

The authors have been retained by CANEGROWERS to provide expert advice through Energy Queensland Ltd (EQL) consultation process in the lead up to formal tariff structure statement (TSS) proposals to be submitted by Ergon and Energex for the period 2020-2025, by the end of 2018. This follows our engagement by CANEGROWERS regarding Ergon's tariff structure statement (TSS) for the period 2017-2020.

The current engagement commenced with *Comments on Energy Queensland Tariff Structure Statement Issues Paper 2018* in June 2018. That paper considered on *Ergon Energy and Energex Network Tariffs 2020-25 Customer Consultation* (TSS issues paper), that provided context on … current network tariffs, the case for change and 'how we have responded to customer feedback since the 2017-20 Tariff Structure Statement process'. Unfortunately, our primary finding was that 2018 TSS issues paper did not respond at all to the extensive criticisms of Ergon's TSS previously raised by the authors in a series of reports for CANEGROWERS, in the course of, and since the 2017-20 Tariff Structure Statement process.

The core economic themes of this work have been:

- Marginal or peak pricing of marginal demand is economically efficient as it provides price signals to consumers to avoid demand that would trigger additional otherwise unnecessary investment.
- Marginal or peak pricing of infra-marginal demand is economically inefficient as it unnecessarily suppresses infra-marginal demand for which there is zero marginal cost, reducing economic goods to the electricity sector and general economy, reducing the utilisation of network assets, promoting substitution and consumer investment in alternatives.

Ergon and Energex "cost reflective" tariffs impose marginal prices on infra-marginal demand, arising in two ways:

1. The LRMC or peak price component of these tariffs is excessive:
   (a) It refers only to maximum demand and does not take into account existing excess capacity.
   (b) The available public information suggests the LRMC calculation employs a forecast rate of rising demand that exceeds both recent historical trends and available public system planning forecasts of future demand over a 5 - 20 year timeframe.
   (c) There is no clarity in how the LRMC value is actualised in components of "cost reflective" tariffs.
2. The marginal or peak period of these tariffs is excessive:
   (a) The analyses of periods are based on the characteristics of consumer demand without reference to the characteristics of network supply of capacity – that is without evidence that demand is marginal.

(b) Constructed from the aggregated analysis of individual network components, the analysis is erroneously applied as if all intervals within the aggregate range were equally probable of being marginal, when the motivation for the analytical method is precisely that they are unequal. The argument offered is that this increases the certainty that the peak window captures periods of greatest network utilisation. The counter-argument is that this wide net approach

Therefore an excessive marginal price is applied to infra-marginal demand, with inefficient economic consequences.

On 7 September 2018, Energy Queensland published a set of consultation documents relating to the price control period 2020-2025:

- Energex and Ergon Energy Network Tariffs 2020-24 (Customer Consultation Feedback Summary, 25 June Consultation Papers.
- Ergon Energy Network Tariff Summary (EENTS)
- Our Draft Plans 2020-25 (ODP) – consultation for EQL Regulatory Proposals to the AER in January 2019.

The current paper reconsiders the previous analysis take into account new information contained in the September consultation documents.

This paper reviews these issues are discussed in Energy Queensland's papers, evidence of change and new issues.

2. The basis for the existing tariffs

The proposed tariffs are substantively the same as the existing tariffs (except for the capped tariff) and therefore assume the existing tariffs are sound. This assumption reflects the fact the Australian Energy Regulator approved the existing tariffs. The discussion below highlights a central error in the LRMC calculation underpinning EQL's proposed peak tariff rates.

2.1 Summary of the AER's 2017 approval

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.[6]

The AER stated that its role is largely one of assessing compliance with the national electricity rules and in particular the network pricing objective and associated pricing principles. The AER states that:

> *We must approve a proposed tariff structure statement unless we are reasonably satisfied that it does not comply with the distribution pricing principles or other applicable requirements of the Rules.*[7]

In other words, the AER concluded that Ergon's revised TSS reflected Ergon's efficient costs of providing those services to the retail customer. It also concluded that the TSS was based on the LRMC of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits and customer location.[8] It considered Ergon's tariffs appropriately signal the future investment costs associated with upgrading the distribution network.

The AER stated that 'we are satisfied the current levels of congestion have been taken into account by Ergon Energy in calculating its long run marginal costs.'[9] It stated further that:

> *Ergon Energy's consultant, has stated the there is no need for investment to be required (to avoid congestion or otherwise) in the next three or four years.*[10] *This is somewhat consistent with Canegrowers' assessment of the 2016 DAPR – that a requirement for network augmentation is unlikely to be triggered until mid-2021.*[11] *Hence, we conclude that the LRMC calculation does take into account the current capacity of Ergon Energy's network.*

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

7 NER, cl. 6.12.3(k).

8 See for example page 67, Op. Cit.

9 See page 70, Op Cit.

10 Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016, p.17.

11 Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017, p. 1.

Furthermore, Ergon Energy published calculations of the average incremental cost over a 25 year period with capital expenditure lagged by 3 years, as provided by its consultant, Harry Colebourn.[12]

The AER approved Ergon Energy's peak charging windows for residential and business customers. It stated it was satisfied that they contribute to the achievement of compliance with the pricing distribution pricing principles.[13] It stated that Ergon Energy's use of load profile data is an appropriate method for establishing charging windows.[14] It considered that a daily average profile was not inferior to a load duration curve in terms of assessing the cost reflectivity of tariff windows.[15]

The AER states that it does: '*not have any evidence that it is unreasonable for LRMC to be 50 per cent of total network costs, or any other figure.*' It also states that, it does '*not consider that just because a zone substation has spare capacity (i.e. demand is below the N-1 rating for the zone substation) that this implies that long run marginal costs will be close to zero.*'[16]

With respect to the STOUD tariff, the AER states that it regards 'Ergon Energy's use of customer peaks rather than network peaks for charging purposes, as contributing to compliance with the distribution pricing principles.[17]

With respect to the default Inclining Block Tariff (IBT), the AER stated that it creates an incentive for business customers to limit their use of the Energex network when it is most likely to experience high levels of maximum demand.[18]

The AER stated that:

> *'Our role is to assess if a distributor's proposed tariffs and charging windows comply with the distribution pricing principles in the Rules. Our role does not extend to deciding if one form of tariff is better than another and so should be substituted for the proposed tariff. … We have therefore focussed our review on whether Ergon Energy's proposal complies with this requirement, not whether short run marginal cost is superior to long run marginal cost for setting tariffs, or if some other form of cost reflective pricing is better than another."*[19]

The AER stated that it considers that

> *Canegrowers is proposing pricing for the irrigation sector that is more locational in design than Ergon Energy's current and proposed tariffs*[20]

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12 Ergon Energy, *Tariff Structure Statement 2018-2020 Appendices* – November 2015, p. 28.

13 See page 83, Op. Cit.

14 See page 84, Op. Cit.

15 See page 85, Op. Cit.

16 See page 73, Op. Cit.

17 See page 48, Op. Cit.

18 See page 57, Op. Cit.

19 See page 86, Op. Cit.

20 See page 47, Op. Cit.

2.2 The AER's 2017 approval does not imply the existing tariffs are sound

The basis for the AER's decision to set aside our critique is the AER's proposition that *'the LRMC calculation does take into account the current capacity of Ergon's network.'*[21] It also asserts that our analysis of congestion was limited to (then) current congestion, not future congestion.[22] In other words, the AER decision is based on the proposition that our November 2016 analysis related to short run marginal cost (SRMC), not LRMC.

2.2.1 LRMC and existing capacity

In support of the first proposition, the AER refers to Average Incremental Cost (AIC) calculation outcomes in Table 14 on page 28 of Ergon Energy, *Tariff Structure Statement 2018-2020 Appendices* – November 2015. On page 27 of that document there is a brief discussion of incremental demand. There is no statement here or elsewhere in this document where the LRMC calculation is adjusted to account for existing capacity.

The 25 year AIC with capital expenditure lagged by 3 years on page 28 is identical to the first Table on page 5 of a report to Ergon Energy entitled *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network* by Harry Colebourn Pty Ltd, dated March 2015. On the preceding page (4), this includes a more extensive discussion of incremental demand, in support of the 25 year AIC forecast, compared with the corresponding section in the November 2015 commentary. It states the demand forecast uses as its staring point RIN Table 5.3.1 – Raw and Weather Corrected Coincident MD at Network Level (Summed at Transmission Connection Point). It also stated that it:

> *used a variable growth rate averaging 1.4% over the 2015-20 regulatory period, with variation primarily as a result of individual large customer movements. This forecast envelope was projected to 2039/40, in similar manner to the capex forecast, using the average growth rate.*

The ultimate annual growth rate used is 2%. This takes into account the net effect of increased demand from new and upgraded connections (2%); and declining demand arising from customer disconnections, energy efficiency and customer preferences (1%).

The key point is that nowhere in the two documents which set out the AIC values and supporting calculations (and hence LRMC), relied upon by the AER, is there any reference to existing firm capacity relative to maximum demand. In addition, there is no adjustment or term in the calculation to derive the AIC to take into account existing spare firm capacity.

Figure 2 of our November 2016 report notes that the top five per cent of non-coincident maximum demand at each Zone Substation (ZS) is used by Ergon as the basis for the definition of peak charging windows.[23] This also suggests that no adjustment is made for existing capacity in the derivation of the LRMC component of tariffs. It appears that a

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21 See page 70, Op. Cit.

22 See page 70 of the 2017 TSS final decision.

23 See page 5, Op. Cit.

similar methodology has been applied to the derivation of the proposed charging windows for the 2020-24 period.

According to analysis of RIN data by the AER, Ergon has the fourth lowest maximum demand relative to maximum thermal capacity (43 per cent) in the NEM.[24] This means that the adjustment to raw LRMC needed to account for existing spare capacity is material and therefore needs to be an explicit step or term in the LRMC calculation.

This was pointed out in a memo sent to the AER dated 22 December 2016 extracted in full below: [25]

> In reaching its findings in its October Draft Decision, the AER does not refer to any evidence on the public record that Ergon adjusted the estimate of aggregate LRMC (on which the LRMC component of its tariff structures is based) to take into account existing and forecast spare capacity to mid-2021 and beyond. This should, however, be an explicit element in the calculation converting unit LRMC to aggregate LRMC (rates and charging windows). This key point is explained on page 114 of: *Our plan for the future: Sydney Water's prices for 2016-20; Appendices – Public version.*[26]
>
> > *'By definition, the LRMC of water resources is a forward-looking concept. It estimates the change in costs of the water supply system for a given change in output. LRMC ignores the cost of past investments for the purposes of calculating LRMC.* ***But it includes any unused capacity from those investments (technically, the benefit of that unused capacity in terms of water demand met and the costs of using it). For simplicity, we refer to this as 'spare' capacity. Starting from current levels of demand and supply capacity, the LRMC calculation estimates how long it will be before current 'spare' capacity is used up and hence when investment in new capacity is likely to be needed. The greater the spare capacity, the longer it will be before new investment is needed, and the lower the LRMC figure will be, because of the 'time value of money'.***[27] ***(Emphasis in the original is by way of yellow highlight.)***
>
> That is to say, there is no evidence adduced in the AER's Draft Decision that Ergon has taken existing spare network capacity into account in determining the LRMC component of its various tariff structures. To the extent the AER's conclusions in its

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24 See also Table 4 below which provides equivalent data for non-coincident spare firm capacity.

25 This version was in response to extensive information from Ergon provided by the AER to us on 21 December 2016. In its Final Decision, the AER refers to a slightly amended 13 January 2017 version of this memo. Note the empahsis is from the original memo. https://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20-%20Memorandum%20to%20AER%20-%2022%20December%202016_0.pdf

26 Available at https://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/sydney_water_s_proposal_to_ipart_on_prices_to_apply_from_1_july_2016_%E2%80%93_appendices_%E2%80%93_public_version.pdf

27 The principal reason the aggregate LRMC will be lower after inclusion of spare capacity is not because of the time value of money (discounting future costs). It is because the volume of LRMC will be reduced to the extent future increases in maximum demand utilise existing spare capacity rather than requiring augmentation (or replacement) capital expenditure.

Draft Determination take into account existing and forecast spare network capacity, this is not supported in the public body of evidence provided by Ergon, cited in the AER's Draft Determination.

This is not to assert that LRMC will be zero, but it does follow that the efficient aggregate LRMC for Ergon is substantially lower than that claimed using inputs to the AIC method employed by Harry Colebourn Pty Ltd.

In late 2016, Ergon engaged Frontier Economics to respond to our November 2016 report. Frontier's discussion of LRMC refers to a NERA report for the Australian Energy Market Commission in support of the general LRMC methodologies under discussion, including the observation that such methodologies are not dependent on short term (3 to 4 years) issues of congestion or spare capacity.[28] Frontier's key point is that the NPO and distribution pricing principles are forward looking and that '*it would not be practicable or efficient for DNSPs to wait until network congestion was present or impending before excising to invest…. DNSP's will tend to commit to investment decisions well in advance to ensure they continue to meet reliability standards in the future.*'[29]

The Frontier note referred to in the AER's 2017 TSS decision[30] does not consider whether Ergon's actual network capacity was taken into account by Ergon's consultant that undertook the calculating of LRMC, as referred to by the AER; Harry Colebourn Pty Ltd.

2.2.2 Short run vs. long run congestion

The section in the AER's 2017 TSS decision where our critique is set aside is headed 'Current congestion'.[31] It starts with the statement that *'The AER is satisfied that current levels of congestion have been taken into account by Ergon Energy in calculating its long run marginal costs'.*

In other words, the AER presented our November 2016 analysis as being about (then) current congestion (2016), not future congestion (to mid-2021 and beyond).[32] This misrepresents our analysis and falsely implies that we were unable to distinguish between SRMC and LRMC.[33]

Our argument was about the impact of then current spare capacity on future congestion, not the extent of congestion in or around 2016-2017. We referred to data in the 2016 DAPR regarding the latest peak load data for a small set of ZS, in 2015 or 2016.[34] But this came

28 NERA, Economic Concepts for Pricing Electricity Network Services, A Report for the Australian Energy Market Commission, 21 July 2014.

29 See page 17 of Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016

30 See especially sections 5 and 6 of Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016.

31 See page 70 of the 2017 TSS final decision.

32 For example see the extract from our 22 December 2016 memo above which refers to forecast spare capacity to mid-2021 and beyond.

33 The AER as well as Ergon's consultants misrepresented our analysis not only in the 2017 TSS Final Decision but also on a number of occasions during the 2016-17 Queensland TSS process.

34 See for example Table 6 on page 20.

after the statement that '…Ergon's own assessment is that forecast increases in maximum demand over [sic] to mid-2021 would not exceed summer firm capacity.'[35] At the end of 2016, this was four and a half years into the future and at the time the longest public forecast available for Ergon.[36] Our congestion measure therefore significantly overlapped with the 2015 AIC three year capex lagged forecasts by Harry Colebourn.

Our December 2016 memo in response to the December 2016 Frontier note, our November 2016 analysis was forward looking and our estimates of LRMC related to *future* network congestion using the 2016 DAPR forecast out to 2020/21. The AER was aware more than two months before its 2017 TSS decision that our analysis of congestion related to future congestion, not (then) current congestion.

2.3 Has forecast future congestion increased since 2016?

The 2017 Ergon Distribution Annual Planning Report (DAPR) shows that 2016/17 recorded the then highest ever maximum demand in the Ergon network.[37] It also showed that, over the 10 year period from 2006-07 to 2016-17 the system wide MW peak grew by just 53MW or 2.1 per cent.[38]

This is an annual average increase in maximum demand of 0.21 per cent.[39] This is only one tenth of the assumed forward demand growth rate underpinning the forward LRMC values relied upon by the ACCC in its final 2017 decision.[40]

A key reason for this slow rate of growth compared with previous forecasts is the impact of micro embedded solar generation. As shown in the 2017 DAPR, the capacity of these installations continues to increase.[41]

The DAPR also appears to show that annual maximum demand on 13 February 2017 was reduced by 60MW due to the contribution from embedded solar generation. This contribution represents around two (2) per cent of maximum demand.[42]

In other words, the historical contribution from embedded generation is more or less offsetting the forecast increase in maximum demand that underpins Ergon's LRMC estimate,

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35 See page 17 of our November 2016 report.

36 The AEMO's 2016 NEFR 10 year forecast refers to the whole of Queensland not to Ergon.

37 The 2018 TSS issues paper notes that maximum demand for the whole of Queensland in February 2918 was the highest recorded but does not provide data on Ergon.

38 See Figure 19 on page 58 of the DAPR.

39 If we assume that the two maximum events around a decade apart were both POE10 events.

40 See our discussion of the March 2015 Harry Colebourn report in previous section.

41 See for example Figure 14 on page 46 of the 2017 DAPR.

42 This is estimated by applying Ergon's value of 60MW relative to an assumed 2600MW for peak demand without solar, reading from Figure 15 on page 47 of the 2017 DAPR.

and from which the peak tariff levels are set.[43] Embedded micro-generation capacity is forecast to increase over the forward period of the DAPR.[44] Depending on the rate of increase in this capacity relative to organic demand growth, it is possible that future demand growth is more or less flat indefinitely.

Related to the 2017 DAPR demand forecast, the DAPR also notes a reduced capital expenditure (capex) program. It states that no new Regulatory Investment Test for Distribution (RIT-D) capital projects were identified to address emerging network limitations.[45]

While it was not available at the time of the AER's 2017 final decision on Queensland TSS the 2017 DAPR provides further compelling evidence that the LRMC component in the AER approved tariffs is excessive. Not only does the LRMC component ignore substantial spare capacity, it also substantially overstates future demand growth relative to demand growth over the decade to the summer of 2016/17 by a factor of 10. Our November 2016 quantification of the extent Ergon's October 2016 TSS overstated the value of congestion now appears too conservative and should be revised upward.

Recent updates

The 2017 DAPR has so far not been updated

Our Draft Plans 2020-25 uses a forecast 9 percent demand growth over a decade, compared to 17 percent increase in customer numbers. Over a decade the 2 percent annual growth used in the 2015 LRMC calculation implies 22 percent growth in peak demand, or more than double that in EQL's *Our Draft Plans 2020-25*.

2.4 Future network congestion in Queensland

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. There is no system wide network congestion for the foreseeable future for either of the two Queensland networks, based on publicly available data derived from the most recent DAPR for the two networks.

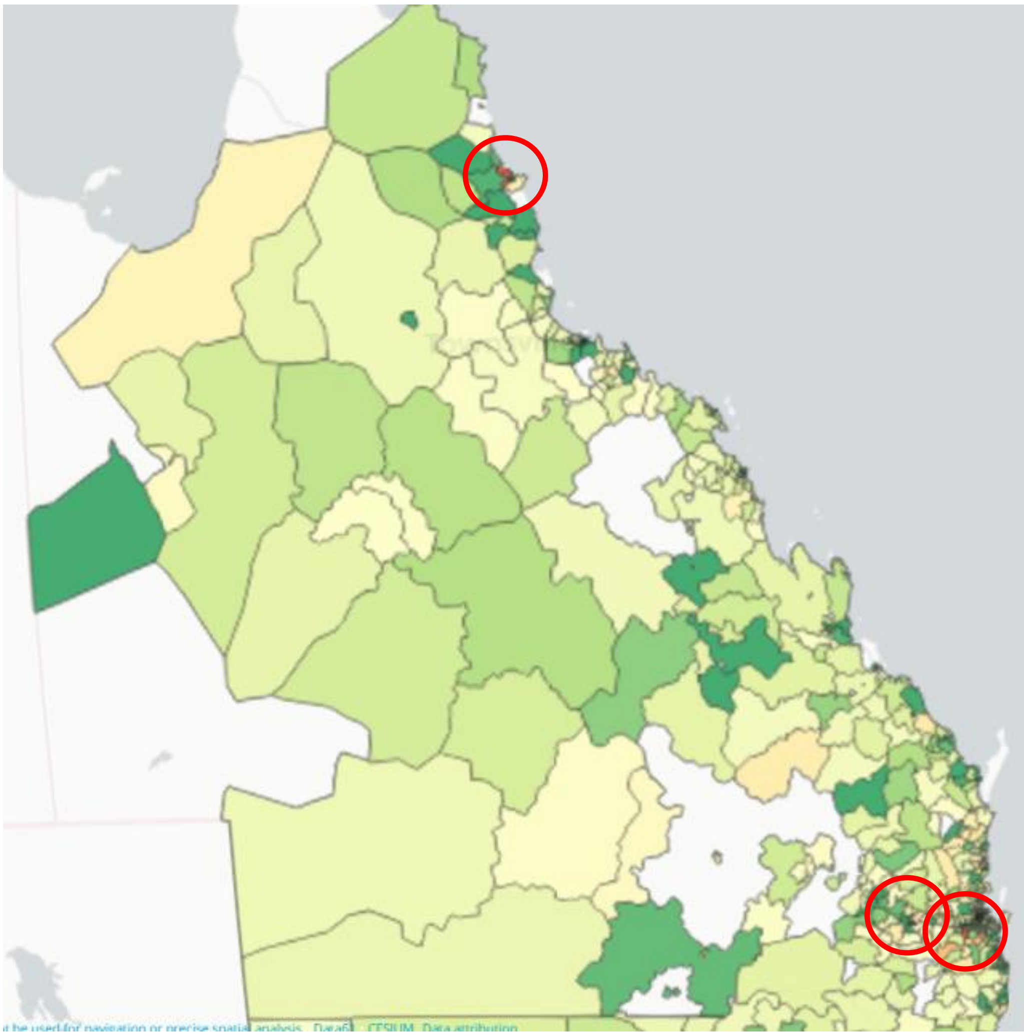
Publicly available data on future network congestion is now available from ARENA to mid-2026. Figure 1 and Figure 2 below are screen shots from the ARENA data.

43 As discussed earlier, Harry Colebourn's discussion of forward demand on which is LRMC estimates are based concludes with a net forward growth rate of 2 per cent per annum.

44 See figure 14 on page 46 of the 2017 DAPR.

45 See page 9 of the 2017 DAPR.

Figure 1 Available distribution capacity in mid-2026[46]



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 to be drawn from DAPR data prepared by Ergon and Energex. It shows that in all of Queensland there are just 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, relate to irrigation demand increasing or creating the need for network augmentation.

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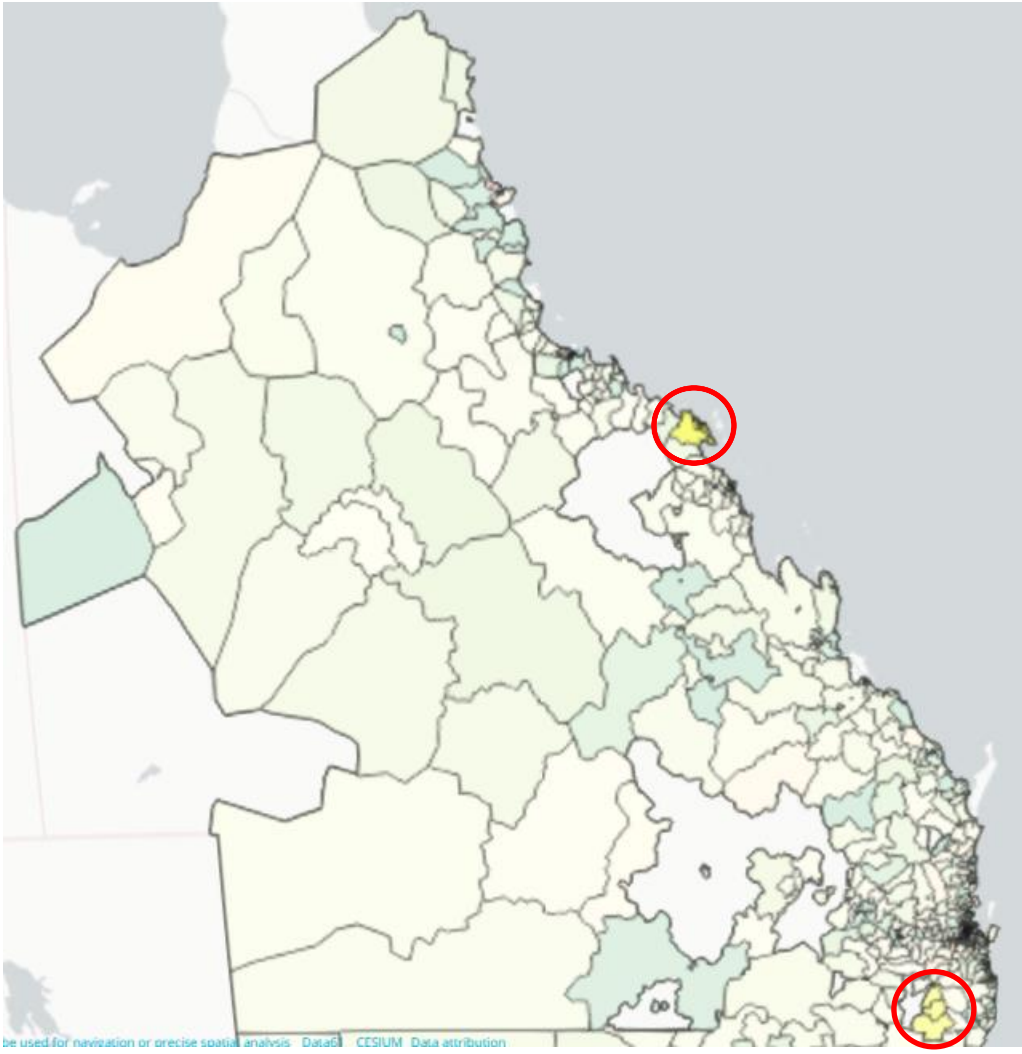
[46] The web interface is possibly ambiguous regarding the final forecast period, with one part referring to 2015 and another to 2026.

Figure 2 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.[47] 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.

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

2.5 ACCC recommendation for asset optimisation

The error of imposing congestion pricing in the absence of congestion is highlighted by the ACCC recommendation in its July 2018 final report *Restoring electricity affordability & Australia's competitive advantage*. The ACCC recommended 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.

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%

3. Over-recovery of efficient network costs

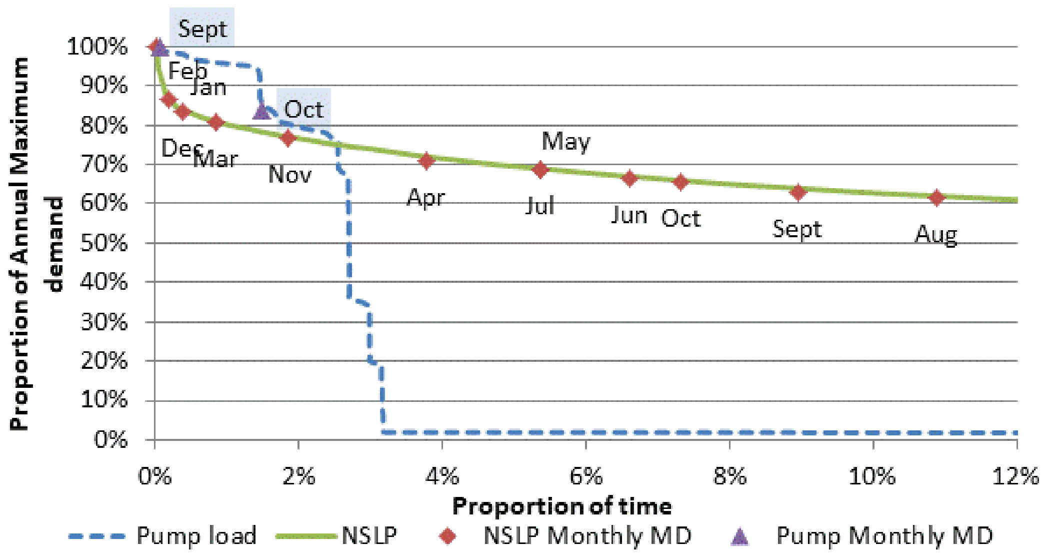
Our previous report included both a macro or top down analysis and a bottom up micro analysis of why the current suite of tariff structures employed by Ergon and Energex is not compliant with the NPO and distribution pricing principles. This section refreshes the bottom up micro analysis with the updated tariff information from *Ergon Energy Network Tariff Summary*. It shows how the present Ergon suite of tariffs results in network bill outcomes that cannot be reconciled with the NPO and distribution pricing principles.

3.1 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 peaks in maximum demand from SAC customers, collectively.

Figure 3 below shows the highest 12 per cent of the annual load duration curve for Ergon's small customer base, represented by the net system load profile (NSLP, providing ½ hourly interval data on coincident demand). The NSLP (represented by the green solid line) is the aggregate load profile for individual small customers, where interval metering data is not available.

Figure 3 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.

The small customer demand load duration curve– the green line in Figure 3 – is notable for being very "peaky". Demand above 20 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.

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 maximum demand in each month is also indicated in Figure 3. This highlights the 90 hours of maximum network demand 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.

Figure 3 also compares the load profile for the NSLP 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 curve indicates that demand is flat and very low for 97 per cent of the year. This includes the period when aggregate NSLP demand exceeds 80 per cent of its maximum demand - in the months of September and October. In other words, the irrigator load is negligible during periods of greatest utilisation of the network. The irrigator maximum demand is in September, when maximum demand by the NSLP is around two thirds of the NSLP maximum demand – well outside the periods of greatest utilisation of the network.

Our previous reports examined in detail why there is an economic cost to the state for marginal pricing of 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 reduce demand that is otherwise no costlier to supply, or to increase their 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.

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

The 2018 TSS issues paper correctly recognises that LRMC tariffs should not be applied to large customers should be limited to summer periods. It states:

> *The tariffs signal to large business customers to reduce their own peak demand every month, rather than just the peak months which, for Ergon Energy and Energex, only occur during and just before and after summer.*

The current *Ergon Energy Network Tariff Summary* states that "improved cost reflectivity would ensure that among other things, those customers that place a lower demand on the network would benefit through reduced network charges."

Previously we have concluded that the forward-looking component of approved network tariffs substantially over-charges relative to the efficient cost.

The following tables indicate the changes in the existing suite so called "cost reflective" tariffs by comparing the actual tariffs applying to Standard Asset Customers – Small (<100 MWh per Annum) for 2018-19 to the indicated rates for 2020-21. This focuses on Distribution Use Of System (DUOS) tariff components as Transmission Use Of System (TUOS) and other components only have fixed and total usage tariff components.

We note that while overall the rates remain the same in nominal terms, representing a decrease in real terms, key LRMC components have been increased in the STOUD and STOUE tariffs.

Table 4 East Business Seasonal Time-Of-Use Demand (STOUD) DUOS charges

	Fixed Charge	Actual Demand Charge		Volume Charge	
		Peak	**Off-peak**	**Peak**	**Off-Peak**
Unit	$/day	$/kW/mth	$/kW/mth	$/kWh	$/kWh
2020-21	$0.0000	$81.4210	$11.5000	$0.01710	$0.01710
2018-19	$0.0000	$97.0880	$10.0000	$0.0238	$0.0238
Change	100%	84%	115%	72%	72%

Table 5 East Business Inclining Block Tariff (IBT) DUOS charges

	Fixed Charge	Volume Charge		
		Block 1	**Block 2**	**Block 3**
Unit	$/day	$/kWh	$/kWh	$/kWh
2020-21	$1.2500	$0.02525	$0.07751	$0.11597
2018-19	$1.2500	$0.02525	$0.07675	$0.11597
Change	100%	100%	101%	100%

Table 6 East Business Seasonal Time-Of-Use Energy (STOUE) DUOS charges

	Fixed Charge	Volume Charge	
		Peak	**Off Peak**
Unit	$/day	$/kWh	$/kWh
2020-21	$1.25000	$0.46540	$0.07999
2018-19	$1.25000	$0.44672	$0.07999
Change	100%	104%	100%

Table 7 and Table 8 estimate the bill impact of these changes for 'typical' small customer load profiles represented by NSLP and for irrigation pump loads. In addition to the total annual bill, these tables show the proportion of the bill derived from the peak LRMC component in the tariff structure. Consistent with the rate changes above:

- there is minimal change for the time insensitive inclining block tariff
- there are significant increases for the irrigation load and substantial increases for the typical load (up to 26 percent increase of STOUE bill) for the time sensitive tariffs
- there are significant increases in the proportion of the STOUE/STOUD bill derived from the peak (LRMC, assumed not stated) component of the tariffs, and the peak component incurred in summer months

- a significant factor in these increases is the increase of the summer peak window from 3 months to 5 months, discussed in the following section, that is not sufficiently addressed by rebalancing the rates associated with these

Table 7 Bill increases for 'typical' small customers

	STOUD	IBT	STOUE
Total annual bill 2018-19	$12,037	$13,344	$15,396
Total annual bill 2020-21	$13,502	$13,347	$19,392
Change	**112%**	**100%**	**126%**
Peak component 2018-19	78% ($9,339)	94% ($12,479)	46% ($7,129)
Peak component 2020-21	86% ($11,560)	93% ($12,479)	61% ($11,893)
Change	**110%**	**100%**	**133%**

Table 7 shows the bill increases expected for a 'typical' small customer of 12 and 28 percent respectively for the STOUD and STOUE tariffs, compared to minor variations in the time-insensitive IBT. Substantively these total bill increases are driven by increases in the peak component of the tariffs – by 10 percent and 33 percent respectively for the STOUD and STOUE tariffs.

Table 8 Bill increases for a pump load

	STOUD	IBT	STOUE
Total annual bill 2018-19	$12,004	$13,344	$10,087
Total annual bill 2020-21	$12,868	$13,347	$10,451
Change	**107%**	**100%**	**104%**
Peak component 2018-19	78% ($9,306)	94% ($12,479)	7% ($663)
Peak component 2020-21	85% ($10,925)	93% ($12,479)	10% ($1,096)
Change	**109%**	**99%**	**143%**

Table 8 shows the bill increases expected for a pump load profile with the same total energy (hence the same IBT costs). The key characteristic of this profile is that nearly 80 percent of energy is consumed in September. Previously we have highlighted that despite largely lacking demand during those summer months when the network utilisation is high, this load receives only moderate reduction in costs relative to the typical profile under Ergon's preferred STOUD tariff. Table 2 further shows this pump load customer will experience bill increases of 7 and 4 percent respectively for the STOUD and STOUE tariffs. Once again these are substantively driven by increases in the peak component of the tariffs.

These changes both suggest material and unexplained changes to the LRMC price component prices. A significant factor in these increases is the extension of the summer peak window from 3 months to 5 months.

3.1.1 Transparency of LRMC in tariff components

EQL acknowledges customers questions regarding the transparency of the application of the LRMC value in tariff components. It provides a general indication that "the LRMC of supply is required to be recovered through a network tariff component designed to influence customers' consumption patterns" including, depending on customer and tariff, any one or combination of peak period demand, peak period energy or anytime energy. However, it provides no further information how the LRMC value is applied in particular tariffs, including how the apparent increases in rates and costs above, and the apparent discount in the proposed new Small Business Package tariff examined below.

3.2 The proposed tariffs breach the National Electricity Law

The proposed tariffs breach the Network Pricing Objective (NPO) in the National Electricity Rules (6.18.5(a)), alongside the distribution pricing principles outlined in 18.5 (f). Under this rule '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 [among other things] to (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network.

The proposed tariffs do not appear to be consistent with Section 29 of the Australian Consumer Law (Cth.) (ACL), under Schedule 2 of the Competition and Consumer Act 2010. This section concerns false or misleading representations about goods and services.

The September 2018 tariff proposals for the period 2020-25 *assume* that the current suite of network tariffs complies with the relevant national electricity rules and in particular the distribution network pricing objective and distribution pricing principles. Energy Queensland cannot proceed on the assumption the existing tariffs are compliant with the NEL.

Compliance with the NEL is not optional for Ergon and Ergon; it is required by law. Existing breaches of the NEL should be remedied at the earliest opportunity.

4. Summer peak window

Our previous analysis, together with other submissions, has highlighted that the form of analysis employed to determine the timing of network peaks during a day, month and season substantially overstates the duration of such peaks and the likelihood of a consumer's electricity consumption contributing to such peaks.

This is partly due to analysis focusing on maximums in consumer demand rather than minimums in the network supply of excess capacity (the threshold for augmentation). Being fully rather than partially dependent on the demand profile of a consumer group, this analysis generates a "peak window" nearly coincident with normal business hours. This period bears little resemblance to periods of greatest network utilisation, previously illustrated in the comparisons such as those in Figure 4 below.

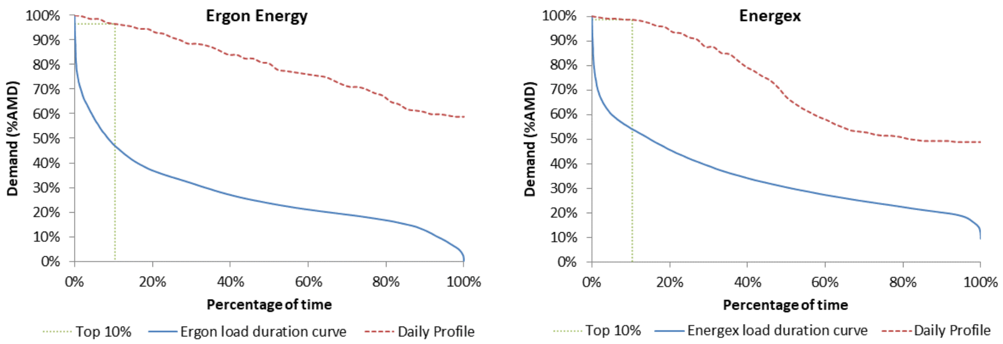
Energy Queensland is proposing to extend the "summer peak window":

> *For small business customers, the Summer Peak Window is week days from 10 am to 8 pm November to March inclusive.*

For Ergon customers, this extends the peak window from three to five months.

Figure 4 Mis-measuring consumption during periods of maximum utilisation of the network

Comparing small customer network utilisation represented by network net system load profile versus business daily profile



Source: Sapere, Evaluation of electricity distribution tariff structure proposals submitted by Ergon and Energex, September 2017

This exacerbates the economic inefficiency of these tariff designs. A theme of our analyses has been that economically (in)efficient pricing has significant consequences in the energy sector and economy more broadly. Marginal pricing of marginal demand reduces or avoids triggering a requirement for new investment in future. However marginal pricing of infra-marginal demand is likely to be both economically inefficient and inimical to energy productivity and security.

Marginal pricing of infra-marginal demand signals to consumers to reduce demand that is otherwise no costlier to supply, or to increase their 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.

5. Summer smoothing tariffs

Energex and Ergon are proposing a new tariff structure for residential and small business customers in addition to their current suite of "cost reflective" tariffs. This tariff structure responds to consumer desire for choice and bill smoothing by applying a 'cap' product within a time-of-use energy tariff. The tariff components for the Small Business Package tariff are shown in Table 9.

- Each band includes a daily cap allowance for energy consumer during the summer peak window (SPW). The cost of this allowance is covered in the monthly charge, which is constant through the year, smoothing the network bill.
- An 'excess' charge, called a top-up, is applied to the excess amount to only the one day of highest peak usage of the month.
- Usage is charged at a single fixed rate.
- Customers can choose the band that works for their needs.

Table 9 Summer peak allowance tariff – Small Business Package

Band	Daily Cap (kWh)	Monthly charge ($/month)	Summer Peak Window Top Up ($/kWh)	Volume ($/kWh)
Band 1	0	$25.979	$2.553	$0.05326
Band 2	10	$33.419		
Band 3	20	$40.859		
Band 4	30	$48.299		
Band 5	40	$55.739		
Band 6	60	$70.619		
Band 7	120	$115.259		

Source: Ergon Energy Network Tariff Summary, September 2018

The smoothing of monthly network charges is demonstrated in Figure 5 that plots estimates for a small business for each Small Business Package band using the NSLP profile (representative of a small customer). This demonstrates bill smoothing increasing with each band with the transfer of costs from peak months, where bills decrease with each higher band, to off-peak months where bills increase with each higher band. For this larger (75.7 MWh) consumer the lowest total cost and greatest monthly charge smoothing is achieved with Band 7.

Figure 5 Small Business Package - NSLP

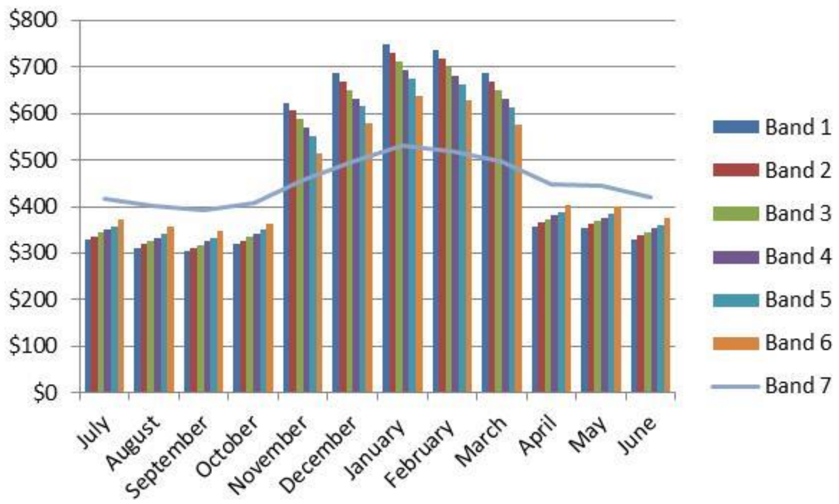
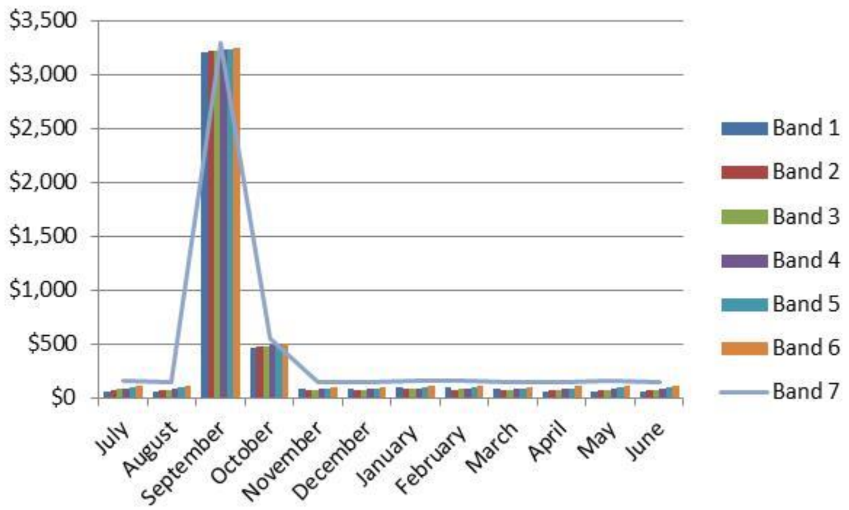


Figure 6 plots the monthly network charges using a typical irrigation consumption profile. In stark contrast to the representative profile, for this profile where actual consumption is concentrated in a few months there is no bill smoothing effect – in contrast the premium in the monthly charge for each band increases the total costs when higher bands are selected by the customer.

Figure 6 Small Business Package – irrigator profile



It would appear that the Small Business Package offers a substantial discount relative to the current "cost-reflective" tariffs – for example the anytime energy rate of $0.05326/kWh in the capped tariff is discounted relative to the $0.07999/kWh off-peak energy rate in the STOUE tariff.

Indicatively Table 10 compares the total costs for each of these loads in each Small Business Package band with the costs under the indicative rates for the STOUE and IBT tariffs. The

Small Business Package appears to offer a significant discount to existing "cost reflective" tariffs ranging from 40 – 60 percent of the STOUE tariff.

Table 10 Small Business Package network charge outcomes compared with current STOUE

Tariff	75.7MWh per annum		22.7 MWh per annum	
	NSLP	Pump load	NSLP	Pump load
IBT	$8,956	$8,956	$2,808	$2,808
STOUE	$13,080	$7,119	$4,243	$2,455
Band 1	$5,788	$4,478	$1,954	**$1,562**
Band 2	$5,749	**$4,443**	$1,916	$1,611
Band 3	$5,711	$4,524	$1,878	$1,700
Band 4	$5,672	$4,613	$**1,839**	$1,790
Band 5	$5,634	$4,702	$1,879	$1,879
Band 6	$5,557	$4,881	$2,057	$2,057
Band 7	**$5,432**	$5,417	$2,593	$2,593

As with our previous and current estimations of costs for the suite of "cost reflective" tariffs, the application of LRMC price components is not transparent in the proposed new capped tariffs and this discount is not reconcilable. There is no explanation from EQL.

sapere research group

6. Economic profit

In September 2018, the AER published data on *the* (actual) 'return on assets' for the 18 electricity network entities[48] for the four financial years preceding 30 June 2017. These allow an empirical estimate of the economic profit within actual returns, compared with the allowed rate of return (the estimated weighted average cost of capital or WACC).

Over the 4 year period, the two Queensland networks have generated economic profits of more than $780m above allowed returns of $5,341m. This is shown in Table 11, which provides for comparison the actual earnings before interest and tax (EBIT) with the AER allowance for EBIT, and the resulting economic profit for each year. [49]

Table 11 AER Actual RoA excluding incentives relative to the WACC

	2013-14	2014-15	2015-16	2016-17	Total
Energex					
Actual EBIT ($m)	$639.6	$902.7	$896.7	$789.1	$3228.2
Allowed EBIT ($m)	$951.0	$973.1	$469.0	$478.1	$2871.2
Economic Profit (%)	-2.63%	-0.58%	3.62%	2.60%	3.02%
Economic Profit $	-$311.39	-$70.38	$427.76	$311.02	$357.00
Ergon					
Actual EBIT ($m)	$706.6	$883.0	$597.7	$705.8	$2893.2
Allowed EBIT ($m)	$807.0	$832.4	$411.6	$419.1	$2470.1
Economic Profit (%)	-0.98%	0.48%	1.78%	2.72%	4.00%
Economic Profit $	-$100.34	$50.66	$186.09	$286.69	$423.09

Source: AER data on Actual RoA excluding incentives relative to the WACC, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses

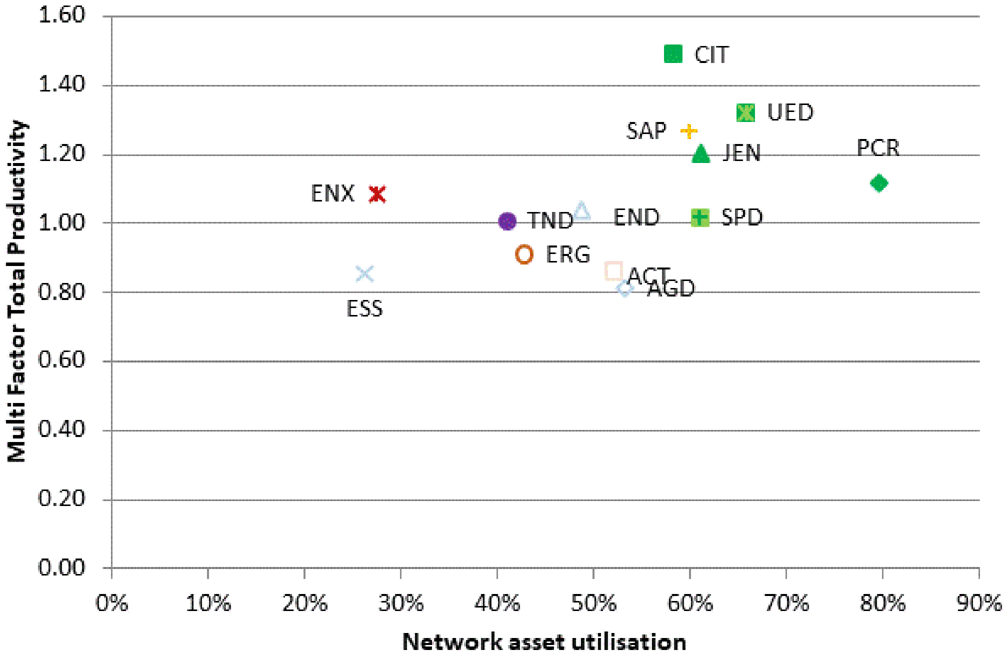
Except under limited conditions, economic profits are inefficient and unfair. They transfer wealth from consumers to networks and result in deadweight losses, reducing Gross Domestic Product and the international competitiveness of Australian exporters. Economic profits may also lead to investment by consumers in substitute assets and services at higher levels than otherwise, reducing the utilisation of network assets. As a result, economic profits reduce dynamic efficiency or economic efficiency over the long run.

48 Some entities such as Ausnet hold both regulated distribution and transmission networks.

49 Over a period of time, a business making normal profits will remain in the industry and will only exit the industry if it is making losses in the long run. If, over time, total revenues exceed total economic cost, then the business may be described as making super normal profits.

Figure 7 indicates that the utilisation of network assets for Energex (ENX) and Ergon (ERG) is already comparatively low to most other network businesses in the NEM.

Figure 7 Excess investment means spare capacity and low utilisation



Source: AER RIN data and productivity reports

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