SUBMISSION TO AUSTRALIAN ENERGY REGULATOR

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by
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on behalf of a Network of Electricity Users in Far North Queensland

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1.0 INTRODUCTION

Cummings Economics is a respected economic research firm based in Cairns that over the years has carried out a substantial volume of economic research for, and provided a great deal of guidance to, industries, firms and government in the Far North Queensland (FNQ) region. The firm is constantly involved in monitoring trends in the region's economy and factors influencing these trends. The firm has long standing close relations with, and often fulfils an advisory role to, key local industries and organisations like Chambers of Commerce, Tourism Tropical North Queensland, Advance Cairns and local Government.

Cost of energy has been a major issue in the region over many years. However recent rapid escalation of electricity prices has been viewed with alarm in the region's industries and among consumers and has caused substantial havoc to sectors of the economy.

This led to staff of the firm starting to take a special interest in the question towards the end of 2013. Since then, this concern led to staff of the firm seeking to learn more about why these trends were occurring, the regulatory processes affecting them, and playing a key role in helping regional industries and organisations to understand how they might influence future outcomes.

Late in 2014, with widespread support from local organisations, the firm applied for and received grant assistance from the Consumer Advocacy Panel to continue this role with a view to:

a) Assisting industries and organisations in the region prepare submissions;

b) Researching and coordinating an overarching submission from this region.

The following gives a list of organisations who have supported the initiative and indicated a willingness to participate.

1. Cairns Regional Council
2. Tablelands Regional Council
3. Cook Shire Council
4. Far North Qld Regional Organisation of Councils
5. Advance Cairns
6. Tourism Tropical North Queensland
7. Regional Development Australia FNQ&TS
8. Cairns Chamber of Commerce
9. Mareeba Chamber of Commerce
10. Atherton Tableland Chamber of Commerce
11. Innisfail District Chamber of Commerce
12. Urban Development Institute of Australia
13. Consolidated Tin Mines Ltd
14. Snow Peak Mining Pty Ltd
15. Tableland Canegrowers
16. Queensland Dairyfarmers Organisation

The first task has been to prepare this submission to the Australian Energy Regulator. It follows consultation with organisations and a meeting of network participants on 14th January 2015.

Time to prepare the submission to meet the deadline date has been an issue, especially given the Christmas, New Year and Australia Day holiday period, and following consultation with staff of AER, we have adopted a policy of raising issues and views and supplying information to hand even if it has not been fully researched.

It should be noted that we have not had the resources available to fully analyse and comment on some of the broader issues being addressed by others. We have tended to concentrate on bringing to the attention of AER, information and aspects of particular relevance to the Far North Queensland region.

We will be continuing to work on issues, including a number of concerns outside the AER process, and would welcome the opportunity to further research and supply information to the AER on the issues raised in this submission.

DISCLAIMER

"This project was funded by the Consumer Advocacy Panel (www,advocacypanel,com,au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission."

2.0 BACKGROUND ON FAR NORTH QUEENSLAND IN RELATION TO ELECTRICITY ISSUES

The Far North Queensland region, generally covers the area of Queensland that looks to the regional city of Cairns as a servicing capital – an area north to the Papua New Guinea border, west to the Gulf and Northern Territory border and down to the southern boundaries of the Cassowary Coast, Tablelands, Etheridge and other Gulf shires. The region is large. From north to south it covers half the latitudes of Queensland. It is as deep as the State of New South Wales and in area, about 1½ times the size of Victoria. (See Map, Appendix 1.)

The region is tropical and historically presented major challenges to a society with technology and population derived from north western Europe. Modern settlement was late and initially slow and hard won.

Increasingly the region's outstanding underlying resources are providing the base for an expanding population and economy, resources of plant growth potential (the region accounts for 26% of the continent's water runoff), of marine resources, minerals and outstanding tourism resources. Underlying factors assisting this growth include:

- Technology being developed suited to the area (not only in agriculture but in a whole range of areas affecting everyday living, including air-conditioning);
- World markets reaching out for previously underdeveloped resources (along with the Northern Territory Top End, it is the closest area of Australia to the great global growth areas in north east Asia);
- Transport and communication technology breaking down old barriers of remoteness from markets.

Population of Cairns and its region has expanded strongly. The region now leads in population in northern Australia. Cairns has grown from a population of 16,600 in 1947, to 48,000 in 1976, to 160,000 today. Since 1976, it has passed seven other regional cities in size.

For electricity supply, the region falls broadly into two major areas:

- A relatively heavily populated south east corner;
- The sparsely populated remote Peninsula, Torres and Gulf areas.

Surrounding Cairns in the south east corner is an area of higher rainfall, coastal plains backed by the highest mountains in Queensland and some of the steepest topography in Australia, offshore coral reefs, lush tropical rainforests, Tableland areas up to 1,000 metres above sea level, and in the west hilly tropical savannah woodland country.

Population in this area of over 240,000, mostly within two-hours' drive from Cairns, represents the highest concentration of population in northern Australia.

For electricity distribution, the topography of the area, heavy rainforest areas with conservation values, heavy rainfall, humid conditions and occasional cyclonic wind damage, represent special challenges.

For the Peninsula, Gulf and Torres area, the main issues are low level of industry demand and population.

The south east corner is connected to the national grid, with extensions in more recent decades west through the Gulf country to Normanton and Karumba and north to the Cooktown district in Cape York.

Outside this frontier of the grid system, electricity is supplied to communities by Ergon's stand-alone isolated supply networks. Individual mines and cattle stations provide their own power, mostly by diesel generators.

The 27 Ergon isolated power supplies in the region are not included in the Ergon regulatory proposal.

Rainfall and topography have led to two hydroelectric stations being able to supply peak load power on the Barron River and Tully River, built in the 1930s and 1950s respectively. The region's sugar mills supply a significant amount of power into the grid through "cogeneration". There are wind generation facilities in the area with plans for more. The number of households with solar systems has expanded strongly.

Otherwise all the power for the area in the national grid is supplied via Powerlink transmission lines from the major Queensland generating facilities in central and southern Queensland to Ergon's distribution network.

There are no large mineral processing facilities on the FNQ section of the grid area that are heavy users of electricity.

With hotel / motel room numbers in the region equal to or exceeding those in Brisbane, Perth and Adelaide, the tourist industry is a major consumer.

Ergon is a monopoly local distributor and retailer of electricity, having taken over the assets and role of the former locally based Far North Queensland Electricity Board.

At present, the question of leasing of Queensland electricity assets is an issue that could potentially affect electricity supply arrangements. This submission assumes that any replacement of Ergon would have similar structures and issues as Ergon.

3.0 OVERVIEW APPRECIATION OF THE SITUATION

Because of the monopoly position of Ergon, the role of the AER is to ensure that it acts in a way that is consistent with wider community interests. Looking back over the past determination period 2010-2015, we are concerned that this has not happened.

A primary concern of peak industry groups and councils in Far North Queensland is Ergon Energy's failure to comply with the National Electricity Objective and act in the long term interests of consumers of electricity in Queensland. The National Electricity Objective, as set out in the National Electricity Law, is to:

"*promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*

(a) price, quality, safety, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system"

We believe Ergon has tended to give low priority to the impact of its business on all consumers and instead tended to focus on how to maximise its own long term interests. We believe that the AER determination of 2010-2015 failed to suitably control Ergon's activities.

A major reason for Queensland's rising electricity bills in the last five years is the 2010-15 Ergon determination. As Ergon's network charges constitute the largest part of an electricity bill (approximately 40 percent), any increase in Ergon's prices will have a major flow on effect to the final electricity bill paid by consumers.

The following paper sets out an appreciation of:

- What went wrong in the 2010-2015 period;
- Its impacts especially on industries and consumers in the Cairns / Far North Queensland region; and
- Issues with the Ergon 2015-2020 proposal.

One of our major overarching concerns is that Ergon's medium term strategic goal is to simply limit increases in their average network charges to less than the Consumer Price Index. Many Far North Queensland industries are already indicating that due to ongoing electricity price hikes, combined with increases in other input costs, electricity bills are already affecting their long term viability. It is not in Ergon's interests to lose customers or have reduced consumption. This in turn affects their system utilisation which is already running at a very low 37 percent and falling. Against this background, we believe that the situation will only stabilise if a significant 'real' decrease in electricity prices is achieved.

In the last regulatory period from 2010-2015, Ergon's high prices were mostly attributed to their excessive demand forecasts which resulted in the approval of high capital and operational expenditure. Even though moderated by the AER, the forecasted electricity demand simply did not eventuate. One of our major issues with the 2015-2020 Regulatory Proposal is that we believe Ergon's demand forecasts will once again be wrong.

It is of concern that continuing high electricity prices will simply perpetuate the situation where falling demand due to high prices results in further increases in prices, and damage to the regional economy and impacts on household budgets.

We also have some issue with Ergon's demand management initiatives.

Reliability standards are of concern. They are set to fall to 2010-11 levels.

We are concerned with a number of other aspects that need to be attended to, if substantial curtailment of costs is to be achieved leading to the needed reduction of prices.

- Rate of return
- The valuation of the Regulatory Asset Base (RAB)
- Capital expenditure proposals
- Operating expenditure proposals
- Incentive schemes
- Consumer engagement

From a Far North Queensland prospective, falling or flat line consumption is an alarming indicator of reductions in economic activity and loss of regional jobs. We have not been in a position to comprehensively measure the economic impact of increased electricity prices to date and likely impact into the future, but examples are given elsewhere in this submission that indicate some of the problems and effects being felt.

The long term viability of Far North Queensland industries and businesses is at risk if significant changes are not made to Ergon's 2015-2020 Regulatory Proposal and a substantial reduction in prices is not achieved.

At a more fundamental level, we question whether the AER process of mainly relying on a revenue cap provides a flexible enough control system in the Ergon area where economic conditions can be quite volatile as set out in Section 4.1.4 and request that the AER look at a system that provides greater incentives for reducing system costs and improving efficiency.

4.0 DEMAND FORECASTING

4.1 Forecasting

4.1.1 General

The Australian Energy Regulator places a revenue cap on the amount of money Ergon can collect from electricity consumers for its Standard Control Services. The Australian Energy Regulator determines both the Total Revenue Requirement for five years and approves the Annual Revenue Requirement for each of the five years within a regulatory period.

In the 2010-15 regulatory period, the AER's decision resulted in the total revenue being reduced to $6,554m from Ergon's proposed $7,252m, a saving to consumers of $698m over five years (see **Tables #1 and #2**).

Table #1: Ergon's proposed annual revenue requirements and X factor 2010-11 to 2014-15 ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	149.8	152.4	156.1	170.7	153.1
Return on capital[a]	722.0	829.0	946.9	1068.8	1199.7
Operating expenditure[b]	381.8	407.0	418.5	428.3	428.1
Tax allowance	25.5	75.1	82.4	96.9	96.1
Capital contributions	–137.3	–149.1	–132.7	–144.5	–166.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4	0	0	0	0
Annual revenue requirements	1149.1	1311.2	1467.9	1616.9	1707.3
Expected revenues	1208.1	1317.2	1436.2	1565.9	1707.3
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–39.51	–6.42	–6.42	–6.42	–6.42

(a) Includes equity raising costs.
(b) Includes debt raising costs, DMIA and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

Source: AER, Ergon Final Distribution determination 2010-11 to 2014-15

Table #2: AER's decision on Ergon's annual revenue requirements and X factor 2010-11 to 2014-15 ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	145.0	146.9	150.3	164.1	144.6
Return on capital	694.7	782.4	867.7	956.2	1052.8
Operating expenditure	360.2	387.2	396.7	400.7	397.1
Tax allowance	9.6	27.4	29.6	34.4	33.4
Capital contributions	–111.8	–115.8	–120.4	–130.7	–141.5
Revenue from shared assets	–3.2	–3.3	–3.4	–3.4	–3.5
Accelerated depreciation	10.5				
Annual revenue requirements	1105.0	1224.8	1320.5	1421.3	1482.7
Expected revenues	1123.1	1210.1	1303.9	1404.9	1513.8
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	–29.61	–5.10	–5.10	–5.10	–5.10

Source: AER, Ergon Final Distribution determination 2010-11 to 2014-15

It is clear that the greatest failure of regulation in the 2010-2015 period was to correctly forecast demand and that this was the most important factor in setting regulated expenditure limits far too high, contributing to the 'blow out' of prices that has been so injurious to the region's industries and consumers.

More accurate demand forecasting is paramount to containing electricity price rises and improving the long term viability of industries in Far North Queensland and throughout Queensland.

It is clear that in the new regulatory period, much more attention needs to be given to this aspect.

4.1.2 Analysis

The AER "Revenue Cap" is related only to those services defined as "Standard Control Services" and does not cover a number of "Alternative Control Services".

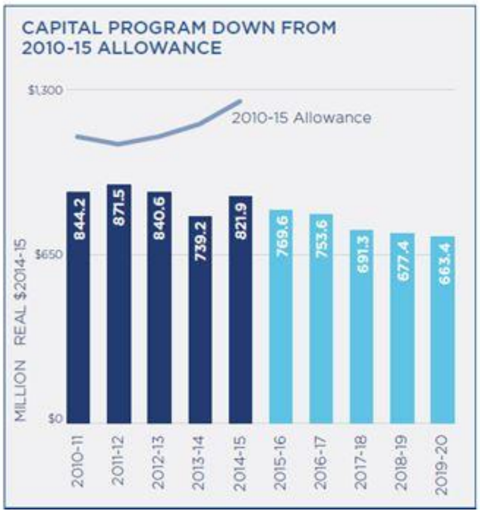
Ergon's Standard Control Services reflect core network, connection and metering services associated with access to and supply of electricity to customers via Ergon's distribution network. Ergon recovers the cost of Standard Control Services through network tariffs.

The network tariffs developed for Standard Control Services are cost reflective in that there is a direct relationship between network tariff for the service and the costs of delivering that service.

As capital and operating expenditure is the basis for establishing the annual revenue requirement, it is critical that Ergon's demand forecasts accurately reflect future demand. The 2010-2015 period indicates that Ergon over estimated by a very large margin.

The 2010-15 regulatory period overestimated demand is demonstrated by the large difference between Ergon's estimated capital expenditure and the AER's allowed capital expenditure in **Table #3** below.

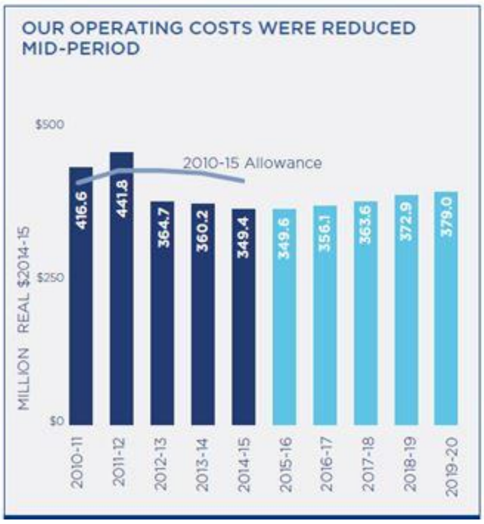
Table #3



Source: Ergon presentation to AER Public Forum, December 2014

The operating expenditure program for Standard Control Services in 2010-15 reduced mid-period to below the AER allowance for operating expenditure (see **Table #4** below).

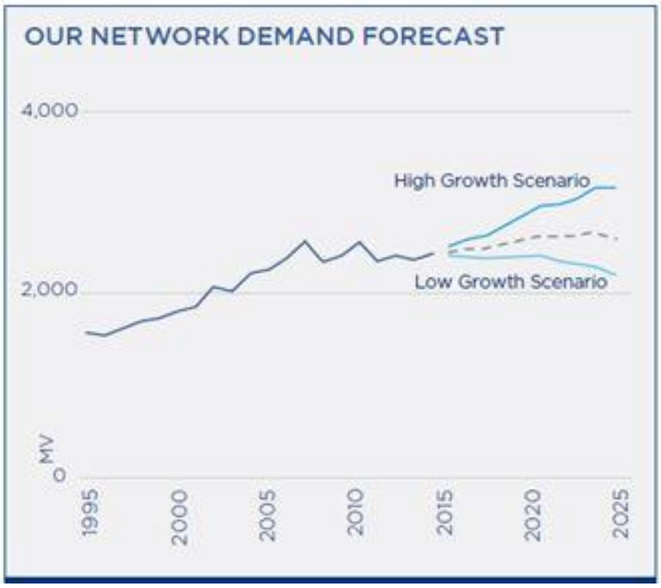
Table #4



Source: Ergon presentation to AER Public Forum, December 2014

Considering Ergon believes the low growth scenario (see **Table #5** below) is the most likely growth scenario for the 2015-2020 regulatory period, the proposed capital and operating expenditure for 2015-20 remains high. This capital and operating expenditure remains more questionable when it is followed by a negative growth scenario for 2020-25. Low growth in this case is a misnomer as the graph predicts no growth, with demand in 2025 approximating the demand prior to 2005.

Table #5 : Network demand forecast



Source: Ergon presentation to AER Public Forum, December 2014

Whilst Ergon customer connection numbers have increased by 1.62% per annum for the past four years, it is alarming to note that the number of non-residential connections has fallen 0.29% from 114,992 in 2012-13 to 114,654 in 2013-14 (see **Table #6**).

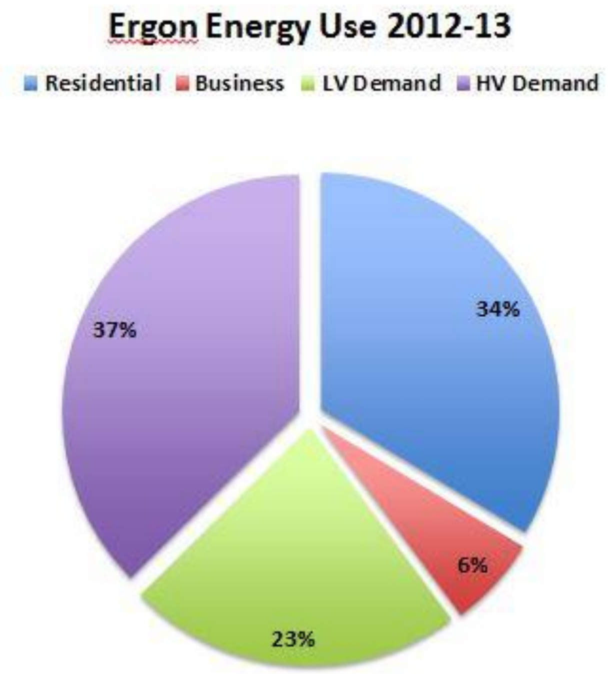
Table #6: Customer numbers, 2011-14

	2011	2012	2013	2014
Residential customer numbers	577,958	585,538	595,439	607,276
Annual residential customer growth rate	1.24%	1.31%	1.69%	1.99%
Non-residential customer numbers	111,001	113,726	114,992	114,654
Annual non-residential customer growth rate	4.61%	2.45%	1.11%	-0.29%
Total customer numbers	688,959	699,264	710,431	721,930
Annual growth rate	1.77%	1.50%	1.60%	1.62%

Source: Ergon Regulatory Proposal 2015 to 2020

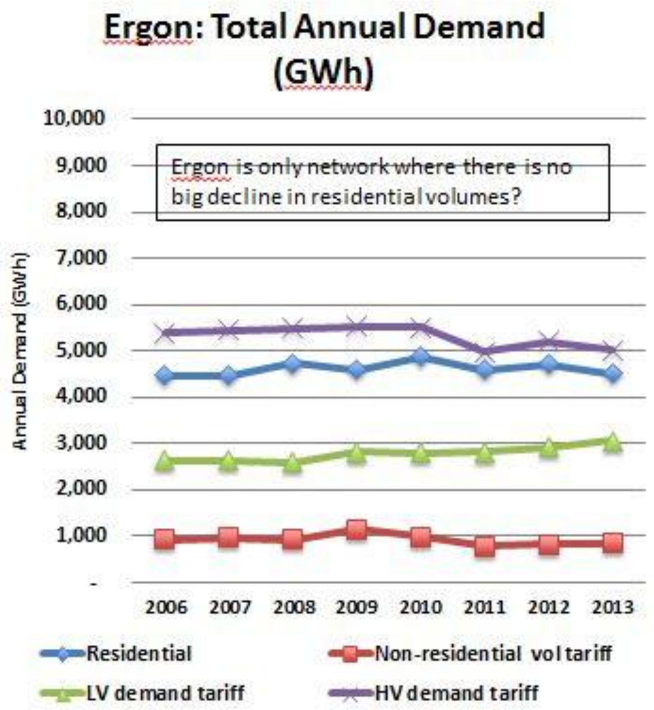
Non-residential customers represent 16 percent of Ergon's total customer numbers of 721,930, but their total energy demand is significantly higher (see **Tables #7 and #8** below).

Table #7



Source: Bev Hughson, AER Consumer Challenge Panel, 2 September 2014

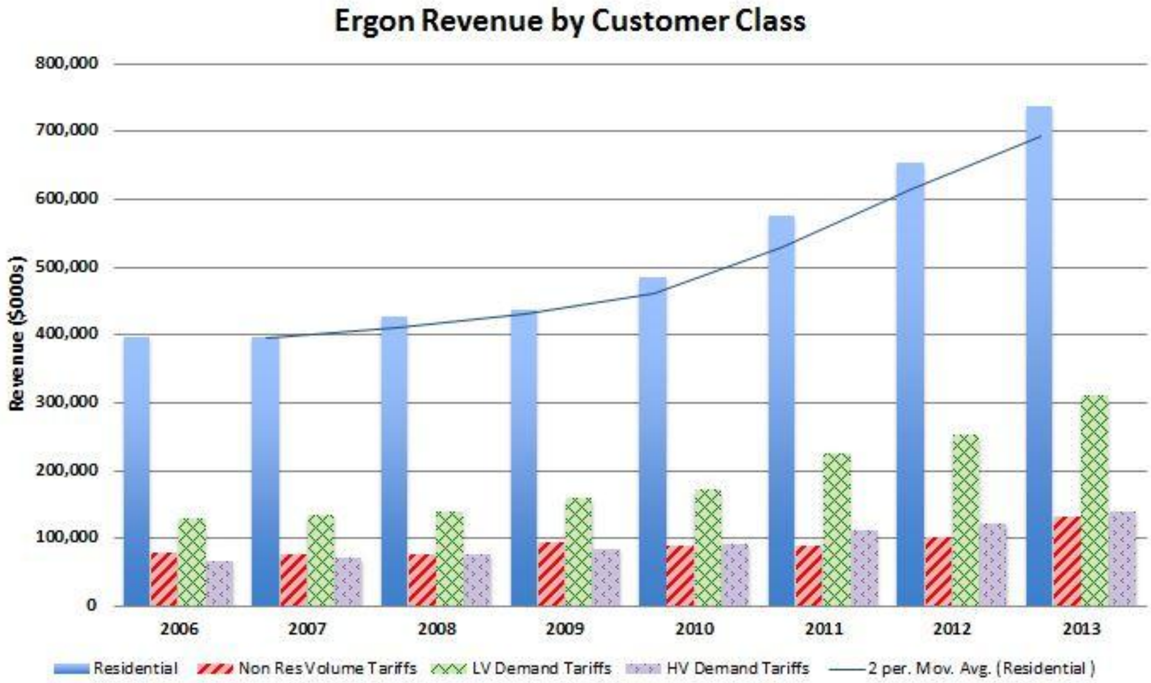
Table #8



Source: Bev Hughson, AER Consumer Challenge Panel, 2 September 2014

As per the following **Table #9**, the contribution to Ergon's revenue from non-residential customers is significant and hence it is important that Ergon understands what is driving their flat to falling consumption of electricity. There needs to be an equal weight of discussion and consumer engagement on both residential and non-residential issues despite the small number of non-residential customers compared to residential customers. Without the large energy demand from large users, network utilisation will fall even lower than the current poor level of 37 percent.

Table #9:



Source: Bev Hughson, AER Consumer Challenge Panel, 2 September 2014

The following is an excerpt from Ergon's latest Distribution Annual Planning Report published on 30 September 2014, which details how Ergon estimates customer demand for the purpose of network planning:

"5.3 NETWORK PLANNING PROCESS"

"Ergon Energy's planning process involves production of long -term strategic network development plans that assess the electricity supply infrastructure requirements for defined areas based on the most probable forecast 20 -year load growth projections. Where appropriate, scenario planning is also used to obtain alternative development plans for a range of possible outcomes (e.g. high growth, more intense weather patterns).Demographic studies based on local government plans are carried out to help indicate the likely long -term demand for electricity across a development area. These include scenario modelling to test various outcomes such as high or low customer response to demand management and energy efficiency initiatives."

"The long - term nature of strategic planning means that there is significant uncertainty around the estimations of load growth and location of load. The output of the strategic planning process gives direction to the short and medium term recommendations, while allowing land and easement acquisition and approvals to proceed. Specific outcomes of strategic network development plans are to identify areas where non - network solutions may be feasible to defer or avoid network augmentation."

"The subtransmission network planning process involves a continuous ongoing exercise of identifying current and future network constraints by comparing system capabilities against current and forecast future loads."

The above excerpts clearly emphasise that Ergon's network planning is about load "growth" and "constraints". Yet as per previous **Tablet #5**, Ergon's low growth scenario approximates a flat line demand for 2015-2020, with a more concerning negative growth for 2020-2025.

This flat to falling demand is shown in **Table #10** below where electricity distributed in 2013-14 has fallen to 15,247 GWh from 15,678 GWh in 2009-10, a reduction of 431 GWh or nearly three percent.

The energy distributed per customer has also fallen from 0.023 GWh in 2009-10 to 0.021 GWh in 2013-14. This combined with falling non-residential customer numbers highlights FNQ peak industry bodies' concerns that falling demand will translate to higher Ergon network tariffs and consequently higher retail electricity bills.

Table #10: Energy usage snapshot

ENERGY USAGE SNAPSHOT	2013-14	2012-13	2011-12	2010-11	2009-10
Population of Ergon Energy's Service Area[11]	**1.52m**	1.50m	1.48m	1.45m	1.44m
No. of Distribution Customers	**724,264**	712,634	700,989	690,708	680,095
Average Annual Electricity Use per Household	**6,396kWh**	6,811kWh	7,166kWh	7,242kWh	7,623kWh
Maximum Coincident Peak Demand	**2,441MW**	2,380MW	2,417MW	2,349MW	2,542MW
Electricity Distributed	**15,247GWh**	15,097GWh	15,212GWh	14,544GWh	15,678GWh
Electricity Generated by Ergon Energy	**111GWh**	114GWh	118GWh	117GWh	114GWh

11. 2013-14 estimate only. Other years are based on the most recent Census.

Source: Ergon Energy Distribution Annual Planning Report 2014/15 to 2018/19

Ergon's demand projections are currently based on the network user groupings, i.e. Individually Calculated Customer (ICC) (typically more than 40GWh pa.), Connection Asset Customer (CAC) (typically greater than 4GWh pa.), Standard Asset Customer (SAC) (all other mainly small customers consuming electricity) and Embedded Generation (EG) (the delivery of energy into the system rather than sourcing energy, but not including solar PVs).

Table #11: Ergon's network user groups

Network user group	Description	Basis of network tariffs
ICC	Those customers: ▪ with energy consumption typically greater than 40 GWh per annum (p.a.), or ▪ with energy consumption lower than 40 GWh p.a. where: ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network ○ there are only two or three customers in a supply system making average prices inappropriate ○ a customer is connected at or close to a TNCP, or ○ inequitable treatment of otherwise comparable customers will arise from the application of the 40 GWh p.a. threshold.	ICC network tariffs are based on: ▪ the actual dedicated connection assets utilised by the customer ▪ the customer's specifically identified portion of any shared distribution network utilised for the electricity supply ▪ whether the customer is subject to the pre or post 30 June 2010 arrangements for Large Customer Connections ▪ whether the customer is located in the East, West or Mount Isa Zone of Ergon Energy's network.
CAC	Those customers: ▪ with required capacity above 1,500 kVA ▪ with energy consumption typically greater than 4 GWh p.a., or ▪ with required capacity below 1,500 kVA where: ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network, or ○ inequitable treatment of otherwise comparable customers will arise from the application of the 4 GWh p.a. threshold.	CAC network tariffs are based on: ▪ the actual dedicated connection assets utilised by the customer ▪ average charges for use of the shared network ▪ whether the customer is subject to the pre or post 30 June 2010 arrangements for Large Customer Connections ▪ whether the customer is located in the East, West or Mount Isa Zone of Ergon Energy's network. The CAC group is further subdivided into categories based on voltage levels as follows: ▪ 66 kV – connected to either a 66 kV substation or a 66 kV line ▪ 33 kV – connected to either a 33 kV substation or a 33 kV line ▪ 22/11 kV Bus – connected to either a 22 kV or 11 kV substation ▪ 22/11 kV Line – connected to either a 22 kV or 11 kV line.
SAC	All other load customers. This includes customers with micro generation facilities (such as small scale photovoltaic (PV) generators) that have a similar service connection and usage profile as other SACs without such facilities. Customers taking supply at LV with a generator installed with a capacity less than or equal to 1 MW, will generally be classified as a SAC unless the connection assets are considered to be quite different from that supplying other SACs.	SAC network tariffs are based on: ▪ the averaged allocated connection asset costs ▪ the averaged allocated shared distribution network costs ▪ whether the customer is located in the East, West or Mount Isa Zone of Ergon Energy's network. The SAC group is further subdivided into network tariff categories based on whether: ▪ the customer's connection is metered or unmetered ▪ the customer is taking supply at high voltage or low voltage ▪ the customer's consumption is above or below 100 MWh p.a. ▪ the customer's consumption relates to residential or business use ▪ the customer has a meter installed capable of recording demand ▪ the customer's supply is capable of being controlled by Ergon Energy.
EG	Those network users that export energy into the distribution system. EGs do not include customers with micro generation facilities that have been classified as a SAC. EGs are separated into two categories: ▪ EGs that are connected to the distribution system and only generate into the distribution system ▪ EGs that are connected to the distribution system, generate and take load from the system.	For those EGs that are connected to the distribution system and only generate into the distribution system, the network tariffs are based on identifying the share of the dedicated connection assets utilised by the generator. For those EGs that are connected to the distribution system, generate and take load from the system: ▪ the generator side of the EG's network tariffs are based on identifying the share of the dedicated connection assets utilised by the generator ▪ the load side of the EG's network tariffs are based on identifying the share of dedicated and shared network assets utilised by the load, depending on the network user group allocated (i.e. ICC, CAC or SAC). All EG network tariffs are also based on: ▪ whether the customer is subject to the pre or post 30 June 2010 arrangements for Large Customer Connections ▪ whether the customer is located in the East, West or Mount Isa Zone of Ergon Energy's network.

Source: Ergon 2014-2015 Pricing Proposal – Version 1.1 – AER approved

The forecast for EGs is the amount of energy generated into Ergon's distribution system. For all other customer groups, it is energy consumption that is being forecast.

The annual projections for energy for all customer groups are based on extrapolations of historical data, with adjustments made for known additions and losses of load.

The projected load for ICC, CAC and EG customers who have Connection and Access Agreements are based on their contracted demand. If no agreement is in place, their forecast demand is based on extrapolations of historical demand data, with adjustments made for known additions and losses of load.

Demand is not measured or forecast for the SAC (typically under 4GWh pa.) customer grouping but sub-group demands are calculated using appropriate load factors which are then used as allocators in the pricing model.

As per **Table #12** below, SAC customers make up nearly 90 percent of Ergon's total revenue.

Table #12 : Weighted average annual revenue (GST exclusive)

Weighted average revenue (GST exclusive) $	-	-	-	-
Tariff Class	2013/14	%	2014/15	%
Individually Calculated Customer (Pre 30 June 2010) – East	44,270,700		48,240,871	
Individually Calculated Customer (Pre 30 June 2010) – West	15,511,040		18,041,871	
Individually Calculated Customer (Pre 30 June 2010) – Mt Isa	0		0	
Individually Calculated Customer (Post 30 June 2010) – East	1,047,655		1,289,757	
Individually Calculated Customer (Post 30 June 2010) – West	0		0	
Individually Calculated Customer (Post 30 June 2010) – Mt Isa	0		0	
Sub total	**60,829,395**	**3.78%**	**67,572,499**	**3.68%**
Connection Asset Customers (Pre 30 June 2010) – East	82,146,869		94,942,500	
Connection Asset Customers (Pre 30 June 2010) – West	11,441,634		13,797,156	
Connection Asset Customers (Pre 30 June 2010) – Mt Isa	0		0	
Connection Asset Customers (Post 30 June 2010) – East	4,876,636		5,651,283	
Connection Asset Customers (Post 30 June 2010) – West	866,628		1,005,700	
Connection Asset Customers (Post 30 June 2010) – Mt Isa	0		0	
Sub total	**99,331,767**	**6.18%**	**115,396,639**	**6.28%**
Embedded Generation (Pre 30 June 2010) – East	3,580,389		4,071,633	
Embedded Generation (Pre 30 June 2010) – West	310,152		360,741	
Embedded Generation (Pre 30 June 2010) – Mt Isa	0		0	
Embedded Generation (Post 30 June 2010) – East	16,494		19,810	
Embedded Generation (Post 30 June 2010) – West	0		0	
Embedded Generation (Post 30 June 2010) – Mt Isa	0		0	
Sub total	**3,907,035**	**0.24%**	**4,452,184**	**0.24%**
Standard Asset Customer – Large (>100 MWh p.a.) – East	310,116,943		354,170,263	
Standard Asset Customer – Large (>100 MWh p.a.) – West	81,279,897		90,257,050	
Standard Asset Customer – Large (>100 MWh p.a.) – Mt Isa	4,990,591		5,490,010	
Standard Asset Customer – Small (<100 MWh p.a.) – East	790,684,818		914,514,252	
Standard Asset Customer – Small (<100 MWh p.a.) – West	221,097,418		252,077,832	
Standard Asset Customer – Small (<100 MWh p.a.) – Mt Isa	13,163,973		14,799,536	
Standard Asset Customer – Unmetered – East	19,033,098		16,936,247	
Standard Asset Customer – Unmetered – West	2,783,367		2,250,645	
Standard Asset Customer – Unmetered – Mt Isa	319,229		351,957	
Sub total	**1,443,469,334**	**89.79%**	**1,650,847,792**	**89.80%**
Total	**1,607,537,531**	**100.00%**	**1,838,269,114**	**100.00%**

Source: Compiled from Ergon 2014-2015 Pricing Proposal – Version 1.1 – AER approved.

Since there is a direct relationship to cost recovery, it is imperative that Ergon understands what factors are affecting demand from SAC (smaller) customers.

To complicate matters, Ergon has commenced a restructuring of its network tariffs with the first changes implemented in 2014-15.

In particular, SAC (smaller) customers, will be impacted by Ergon's process of 'rebalancing' tariffs towards more fixed / less usage-dependent charges and new optional broad-based tariffs. This rebalancing will affect customer demand.

Ergon produces an econometric ten-year System Maximum Demand forecast based on identified factors which affect the load at a system-wide level. Inputs for the system maximum demand forecast include:

- Economic growth through the Gross State Product
- Temperature
- Air conditioning sales
- Solar PV penetration

Further to the System Maximum Demand, Ergon also produce a ten-year maximum demand forecast for all zone substations (described as a 'spatial forecasts') and aggregated to bulk supply point substations and connection points.

After participation in both AER Consumer Forums and Ergon stakeholder meetings, it is clearly evident to FNQ peak organisations that Ergon must expand its understanding of factors affecting regional growth and must engage with customer working groups in each of their six regions.

As discussed earlier, Ergon is accustomed to dealing with growth and system constraints, hence the greater than required revenue cap proposed and approved in 2010-15. Ergon is entering a path not trodden and will require quality engagement with stakeholder groups on a region-by-region basis, if it is to more accurately understand and forecast demand for 2015-2020 and beyond.

4.1.3 Information available

Information from Ergon regarding the classification of data, covering both current and future demand, reveals some cause for concern.

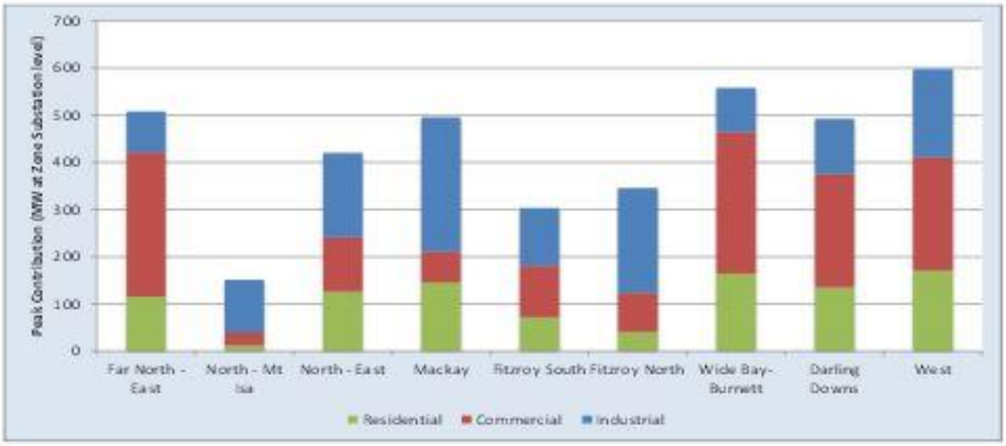
For instance, there does not appear to be information recorded on consumption by industry classifications, eg. tourism, retail, wholesale, construction, manufacturing – the framework within which most statistical data on the economy is recorded and in which much of projection of demand in the wider economy is formulated. Requests for information based on these industry classifications received responses from Ergon that it was not recorded.

On top of this, where existing demand and forecasting information is given, there is a confusing mix of definition.

Previous **Table #7** and following **Table #13** illustrate. **Table #7** shows a break up of non-residential between 'business', 'low voltage' and 'high voltage' and **Table #13** by 'commercial' and 'industrial'.

It is suggested that allocating a code for industries in a customer's retail bill would assist Ergon to track demand by industry and by each of the planning regions.

Table #13: Estimated customer segment contribution – 2025 summer mid-afternoon peak



Source: Ergon Energy Demand Management Plan 2014/15

If Ergon's demand forecasting is to be scrutinised properly, there is a real need for tightening up and extension of classifications, that will allow it to be related to other economic projections and thus improve transparency.

4.1.4 Volatility

In the area covered by Ergon, it needs to be accepted that there is likely to be more volatility in demand growth than in most other areas, especially metropolitan areas.

Most of the regions in the Ergon area are dependent on industries that earn income from outside the region, especially from overseas, and are subject to the volatility of world economic conditions and prices.

This volatility in outside earnings carries through to influence short term growth in the regional cities. While the long term trend is upwards, growth in the various regions tends to come in surges and vary markedly between regions and from state economic growth figures.

As an example, residential population growth in Cairns has fluctuated in recent decades from less than 1 percent to over 5 percent per annum, with an average between 2.5 and 3.0 percent.

Major surges in growth have occurred in the late 1980s, followed by a short sharp slowdown, then a major growth phase from 1992 through to the 1998 Asian Crisis. There was a recovery and strong upswing 2002-2007. This was followed by a slowdown 2008 to 2013 due to the GFC and an exceptionally high dollar. A gathering recovery is now looking like turning into a further major growth burst driven by a lower dollar and rapid increases in tourism from China to be consolidated by the $8bn Aquis Integrated Resort project. On the other hand, low coal and mineral prices are currently heavily impacting on the Townsville, Mackay and Rockhampton regions.

4.1.5 Sources of industry and organisation input

It is also obvious in a region like that covered by Ergon, that there is a need for two levels of interaction with industries, businesses and consumer groups to help predict future demand.

1) Service area wide organisation by industry and interest;

2) Groups in each of the component geographical regions.

For Ergon, the closest service area-wide organisations are the state-wide industry groups that are often heavily influenced by interests outside the Ergon service area.

It should be noted that the Queensland government projections of population growth in the various regional areas have been notoriously inaccurate.

However given the sheer size of the area involved, most community coordination, planning and forecasting occurs at a regional level and there seems to be current real deficiencies in Ergon's interaction at this level.

Under the former regional electricity board system, the board itself was composed of shire appointees and regional leaders who, by and large, were involved in the region's key industries and interacted with other organisations including harbour boards, development organisations, local and state government offices. They were highly aware of likely future trends in the individual economic sectors and the economy of the region as a whole.

Experience of the key industries and organisations involved in the regional network brought together in relation to this submission, indicates limited local interaction by Ergon with regional industry and organisations who are constantly looking forward to identifying likely effects on and trends in their industries and memberships.

If reasonably accurate demand forecasts are to be made, a better system for interaction at regional level needs to be established.

4.2 Demand Management

4.2.1 General

At present, Ergon's network utilisation of 37 percent is low and one of the objectives must be to increase it.

The cost of the network is driven by its need to invest in infrastructure that can cope with periods of peak demand during the day and on hot summer days and cold winter nights.

Around 10 percent of Ergon's network assets are required solely to meet demand for only a few days each year. Tariffs will play a role in improving the load profile.

However, Ergon needs to improve its education of consumers in the area of how to reduce peak demand and how large businesses (eg council sewerage and water plants) may be able to practice load curtailment in return for financial incentives. Reducing peak demand is in the long term interest of both the consumer and Ergon.

4.2.2 Pricing and tariffs

Demand management is very dependent on tariffs and it needs to be recognised that policy and approach on tariffs can heavily affect overall demand levels as well as the pattern of demand during a given day.

Previous charts illustrated how electricity distribution is highly capital intensive.

It shares this characteristic with a number of other major industry sectors including shipping, air services and irrigation. In these industries, there is a high degree of flexibility in pricing structures to maximise efficient usage and return from assets. The aviation industry works on the principle that it is better to fill an aircraft and gain marginal additional income from additional passengers on low airfares, rather than have the aircraft fly half empty. The same applies to cargo shipping, where, to some degree, a principle of "what the market will bear" applies.

For businesses with high capital intensity, a high degree of flexibility is needed in approach to tariffs. At times there will be no loss in revenue and a marginal gain if additional demand is stimulated by lower pricing.

There are indications that Ergon is now in a situation where lower demand is resulting in higher prices which in turn, is lowering demand. In this situation, there is a real need to adopt more flexible pricing policies aimed at stimulating demand and raising network utilisation.

4.2.3 Targeted demand moderation

It is recognised that in the network, there will be areas of expanding demand where growth is occurring that will require major capacity upgrading involving heavy capital expenditure. In these circumstances, some expenditure on demand reduction can postpone the need for this heavy capital investment.

There can be situations where this can be false economy with a risk of being caught in a situation of delayed supply that works against efficiently bringing new projects on stream as soon as possible.

The following gives examples in the Cairns region.

<u>Tourism</u>

Situation

The Cairns business community, with full support of the Queensland Government, is heavily focused on the construction of the proposed $8.15 billion Aquis Integrated Resort located in the Cairns Northern Beaches area.

The Aquis Project is the largest tourism project in Australia and will consist of a two-phase investment in construction of about 6,500 hotel rooms in a major integrated resort development over 12 years. Projected long-term operational jobs created is of the order of 18,000.

As per Ergon's Demand Management Plan dated April 2014, Ergon are continuing with their Cairns Northern Beaches Demand Management Project. The project's initial goal was to defer an estimated $50 million of capital investment into the proposed new Smithfield 132/22kV zone substation and 132kV feeders. The Cairns Northern Beaches Investigation reported the Smithfield zone substation was scheduled to be commissioned by summer 2013/14 in order to accommodate demand growth in the Cairns Northern Beach area and avoid breach of the N-1 security requirement on the Kamerunga 132/22kV substation (forecast to occur in 2014/15). Subsequent application of the new energy at risk planning criteria has seen a modification to the original requirement for demand management in the Cairns Northern Beaches area.

The Cairns Northern Beaches Demand Management Project, according to Ergon, "continues to be a high risk project due to proposed development uncertainties and the high levels of customer energy at risk".

Ergon's forecast demand management expenditure for the period July 2014 to June 2019 is estimated at $58.7 million. The Cairns Northern Beaches Demand Management Project has been allocated $3.725 million over the 5 year period.

Potential Outcome
Aquis commences construction in 2016. Ergon has spent nearly $2m on a demand management plan for the Cairns Northern Beaches instead of allocating $50 million in capital expenditure in the 2015-2020 regulatory period for a new zone substation. This continues the high risk constraint to existing Cairns Northern Beach customers and puts at risk the ability of the $8.15 billion Aquis project to progress smoothly.

Residential Growth Corridors

Situation
It is clear that Cairns is now entering a new accelerated growth phase. Building approvals are rising. Commencement of a new $400m unit, offices and shopping development has been announced along with other projects other than Aquis being canvassed with Council. It is evident that a further surge in population growth is developing. The major residential corridors earmarked to provide new housing is the Mt Peter and Gordonvale area.

Due to past forecasted growth in the Mt Peter and Gordonvale area there is a looming constraint on Ergon's sub transmission network. Ergon propose to use embedded generation to provide peak demand management in the area enabling a deferral of the building of the sub transmission network for three years. Ergon's Mt Peter/Gordonvale Program has committed a total of $0.729m for the required generators for the five years from 2014/15 to 2018/19.

Potential Outcome
With a large expansion of housing demand imminent in the Mt Peter / Gordonvale area, Ergon has not allocated any capital expenditure for a new sub transmission network in the 2015-20 regulatory period.

5.0 RELIABILITY / SERVICE QUALITY ISSUES

5.1 General

The year 2014 was the first time since 2008 that Ergon achieved all six reliability performance targets within the Minimum Service Standards (MSS) set by the Queensland Competition Authority. Favourable performance was also delivered against all six reliability targets set by the AER's Service Target Performance Incentive Scheme (STPIS).

In Ergon's Distribution Annual Planning Report 2014/15 to 2018/19, it states that Ergon " is planning for a future with lower levels of demand growth and increasing levels of customer choice".

Ergon is stating at meetings with customer groups that their customer feedback is calling for lower prices and less reliability.

In response Ergon has reduced reliability standards to 2010-11 levels.

In addition Ergon no longer has to comply with the 'N-X' security of supply criteria introduced following the Somerville Review 20014 and relaxed as part of the Electricity Network Capital Program (ENCAP) review in 2012.

Both these changes should be reflected in reduced capital and operational expenditure for the 2015-2020 Regulatory Proposal.

Suggesting that large businesses invest in backup generation is shifting the problem of blackouts/disruptions from Ergon to the business. Similarly residential consumers should not have to invest in generators to ensure a reliable supply to their home. Reliability and security of supply are imbedded in the National Electricity Objective.

Ergon uses the industry recognised reliability indices to report and assess the reliability performance of its supply network. The key measures used are:

- System Average Interruption Duration Index (SAIDI) - this reliability performance index indicates the total minutes, on average, that the system is unavailable to provide electricity during the relevant period
- System Average Interruption Frequency Index (SAIFI) – this reliability performance index indicates the average number of occasions the system is interrupted during the relevant period.

The Minimum Service Standards (MSS) for both SAIDI and SAIFI are applied separately for each defined distribution feeder category; urban, short rural and long rural.

Short rural feeders are less than 200 km.

A higher number of short rural feeders are included in the worst performing feeders list because this is the largest feeder category and services the majority of the customer base.

The southern and northern regions of Ergon's network dominate the worst performing feeder list for the short rural feeder category. This is because these regions have the highest number of short rural feeders compared to other supply regions and the category dominates their total distribution feeder base at 43% and 37% respectively.

Table #14: Far North reliability performance by feeder category

FAR NORTH	2009/10	2010/11	2011/12	2012/13	2013/14*
Duration Index (SAIDI)					
• Urban Distribution	278.35	100.92	127.16	135.11	72.40
• Short Rural Distribution	646.07	422.13	343.47	339.48	168.83
• Long Rural Distribution	1057.95	820.50	928.36	688.87	566.13
Frequency Index (SAIFI)					
• Urban Distribution	2.68	0.79	1.22	1.24	0.62
• Short Rural Distribution	6.02	3.76	3.34	2.69	1.62
• Long Rural Distribution	5.90	6.12	5.85	5.27	5.08

* YTD

Source : Ergon Energy.

Although Ergon does collect data on reliability performance by region and feeder category, it has not clearly spelt out to customers what the trade off in reliability standards will be in return for price relief. One FNQ mining operation experienced 10 disruptions totalling 636 minutes in December 2014. This experience demonstrates how on the ground reliability standards can be hidden by region or statewide statistics. It also further confirms the need for Ergon to map feeders and transmission lines to key regional industries such as mines, sugar mills and factories.

In some cases the reliability concerns affect whole towns such as the problems currently being encountered by Cooktown. Despite Ergon's assertions that the current line is "pristine", the council offices experienced over 10 disruptions in one week.

Poor reliability to key strategic industries and communities has the potential to impact significantly on regional income and jobs.

Ergon have kept up the mantra that there are no plans to close any depots. However, there is no confidence that the reduction in reliability standards to 2010-11 standards will not result in depot closures.

Major Event Days (MEDs) are excluded from MSS and STPIS reporting.

The AER's STPIS seeks to provide a financial incentive to Ergon to maintain and improve its service performance to customers.

The STPIS is designed to reward or penalise Ergon relative to a series of predetermined service targets. The distribution target applies to the distribution network as a whole. Although failure to meet the service targets incurs a penalty in the form of an Annual Revenue Requirement reduction, it is cold comfort to those industries, businesses and households that experience reliability concerns that are lost in state wide averages.

Table #15 : STPIS SAIDI targets and forecasts 2014/15

STPIS SAIDI		
Category		**2014/15**
Urban	Target	126.00
	Forecast	123.50
Short Rural	Target	279.00
	Forecast	312.37
Long Rural	Target	652.00
	Forecast	741.76

Source: Ergon Distribution Annual Planning Report 2014/15 to 2018/19.

Table #16: STPIS SAIFI targets and forecasts 2014/15

STPIS SAIFI		
Category		**2014/15**
Urban	Target	1.630
	Forecast	1.466
Short Rural	Target	2.910
	Forecast	2.977
Long Rural	Target	5.290
	Forecast	5.352

Source: Ergon Distribution Annual Planning Report 2014/15 to 2018/19.

5.2 Special Reliability Problems at the Margins of the Grid

As identified above, there is an issue especially at the margins of the grid in the region, The region has traditionally had smaller mine operations producing tin, wolfram, gold, copper and zinc, most located in the region at the margins of the grid. One mining operation with employment approaching 100 has been reporting regular problems with 'brown outs' and 'black outs'. Cook Shire report constant "brown out" and "black out" problems in the Cooktown area.

Brown outs are a problem to some regional businesses and industries. Ergon does not collect data on brown outs as their reliability performance measures only refer to black outs. Ergon claim that collecting brown out data would be too expensive. Ergon need to engage with regional customer working groups to understand the operational and financial impact of brown outs. The consultation would gauge whether brown outs have a long term effect on their customers.

We believe that:

- Special attention needs to be given to reliability standards on electricity feeders that are of strategic importance for industry development and employment such as mines, sugar mills, dairy factories and the like;

- Special action needs to be taken to encourage generation in areas at the margins of the grid to increase reliability.

5.3 Impact of Solar PVs on Reliability

Due largely to government incentives paid for by electricity customers, the number of solar photovoltaic (PV) systems connected at domestic premises within Ergon's area has increased significantly since 2010. As of 30th June 2014, Ergon had over 96,000 solar PVs connected supplying almost 330 MW.

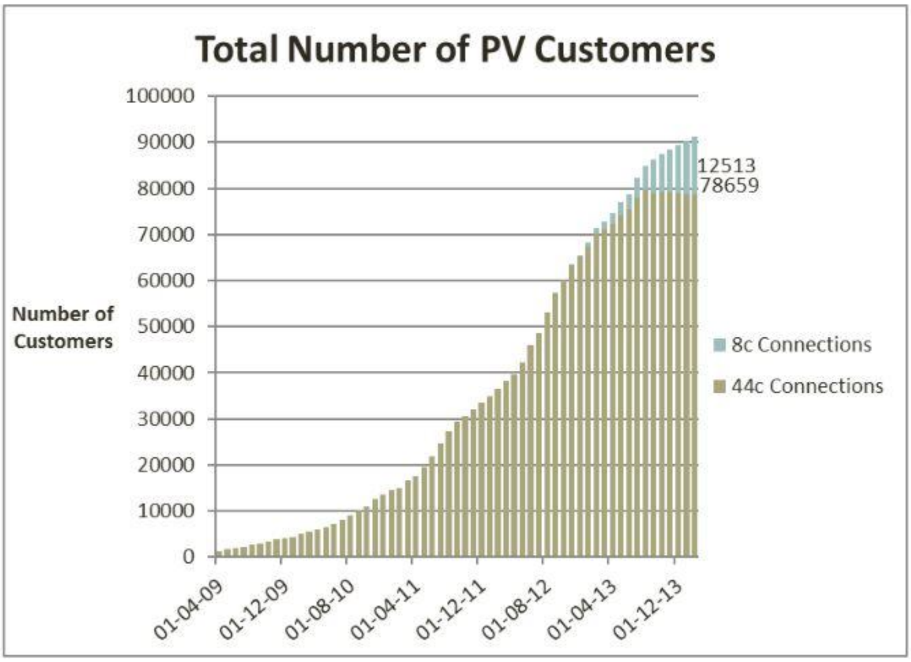
The Queensland Government's Solar Bonus Scheme pays eligible customers a feed-in tariff for the surplus electricity generated from solar PV systems and exported to the Queensland electricity grid.

Applications for the 44 cent per kilowatt hour feed in tariff rate closed on 9 July 2012 and the 44 cent tariff expires on 1 July 2028. The total cost of the 44 cent feed in tariff between now and its expiration in 2028 is $3.4 billion which forms part of every Queensland retail electricity bill.

The 8 cent feed in tariff commenced on 10 July 2012 and expired on 30 June 2014.

From 1 October 2014 the feed in tariff is 6.53 cents per kilowatt hour for Ergon Energy Retail customers. The Solar Bonus Scheme feed in tariff is set by the Queensland Competition Authority.

Table #17 : Solar PV connections and feed in tariffs



Source: Ergon Energy Demand Management Plan 2014/15

In addition to the feed in tariff incentive provided by the Queensland Government, the Federal Government's Small-scale Renewable Energy Scheme also has a large bearing on the uptake of solar PVs. The Small-scale Renewable Energy Scheme works by issuing Scale-scale Technology Certificates (STC). One STC is the equivalent of 1 megawatt hour (MWh) of renewable energy. STCs can be bought, traded and sold and their value fluctuates with supply and demand. The STC is generally assigned to the solar PV retailer or installer in exchange for a financial discount on the cost and installation of the solar PV system.

Table: #18: Number and approximate value of STCs by capital city

City	STCs	Retailer $15-$40 STC Price - In most cases STCs are traded at less than $40 in the STC market.
Adelaide	26	$390 -$1,040
Brisbane	21	$315 -$840
Canberra	26	$390 -$1,040
Darwin	21	$315 -$840
Hobart	26	$390 -$1,040
Melbourne	26	$390 -$1,040
Perth	26	$390 -$1,040
Sydney	26	$390 -$1,040

Source: Clean Energy Regulator

Initially the STCs had a certificate multiplier incentive offering 5x the usual number of STCs, this ceased on 1 January 2013 ie there is no longer any multiplier for STCs.

Table: #19: STC multiplier effect by installation period

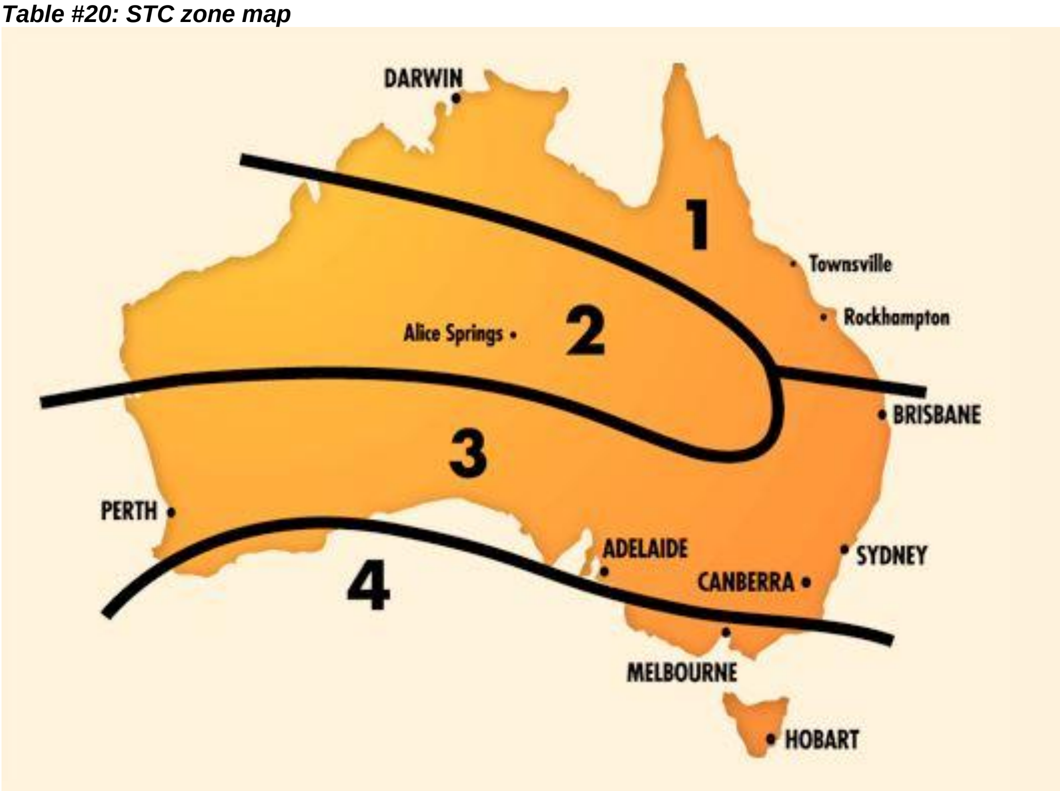
Installation Period	Multiplier
9 June 2009 - 30 June 2010	5 x *[number of eligible STCs]*
1 July 2010 - 30 June 2011	5 x *[number of eligible STCs]*
1 July 2011 - 30 June 2012	3 x *[number of eligible STCs]* *
1 July 2012 - 31 December 2012	2 x *[number of eligible STCs]*
1 January 2013 - onwards	1 x *[number of eligible STCs] (ie no multiplier)* *

** Unless the installation is eligible for the transitional arrangements.*

Source: Clean Energy Regulator

The value of a STC differs depending upon the zone. The highest zone subsidy is for Zone 1. Far North Queensland is Zone 1.

Table #20: STC zone map



Source: Ecosmart Solar website

The financial benefit/rebate to households installing solar PVs from the Federal Government's Small-scale Renewable Energy Scheme has been substantial. The Federal Government commissioned a review on the Renewable Energy Target (RET) in February 2014 in the wake of the Prime Minister, Tony Abbott, arguing that the RET was placing 'upward pressure on power prices'. The review was released in August 2014 and found that small-scale RET (that incentivises householders to install solar panels and solar hot water heaters) has over achieved its target and should be abolished or phased out.

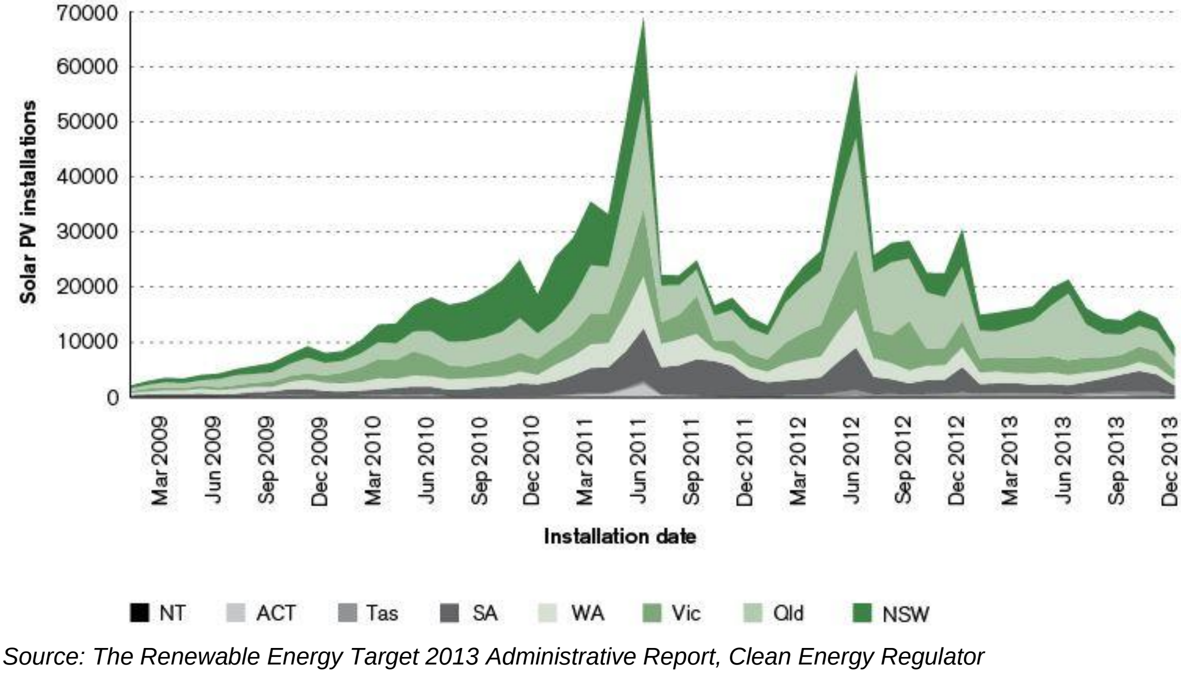
The connection of solar PVs affects the networks voltage level. When the concentration of solar PVs is too high this raises the network voltage level to the upper statutory limit risking a breach of the network voltage regulation level or tripping the customer's inverter. This results in customer quality of supply voltage complaints and potential subsequent network augmentation.

As solar PV connections affect network constraints (reliability) it is necessary to forecast the likely uptake of solar PVs. In April 2014 Ergon were still predicting the number of solar PV connections to continue at 1400 per month. In September 2014, Ergon forecasted there will be between 162,000 and 258,000 solar PV systems connected to the Ergon network impacting between 6.6% and 11.7% of low voltage networks.

The connection of 162,000 to 258,000 solar PVs by the end of the 2015-20 regulatory period would require 916 to 2,250 connections per month. With current State and Federal policies it would appear even the lower growth scenario of 916 connections would be optimistic. The outcome of the RET Review will be pivotal.

Ergon also need to address the issue of what will happen in 15 years' time if there are no government subsidies or incentives to replace the existing 96,000 solar PVs, especially in light of Queensland's aging demographic profile.

Table #21 : Solar panel installations by State, 2009 to 2013



Source: The Renewable Energy Target 2013 Administrative Report, Clean Energy Regulator

6.0 OPERATING EXPENDITURE ISSUES

Members of the network with detailed experience in and contact with the industry are concerned about cost efficiency of Ergon operations.

There are suggestions that a culture of overtime exists and that workforce remuneration levels are substantially above industry standards and that these factors add up to 20 percent on workforce related operating expenses. We believe that AER needs to fully investigate this aspect of operating costs.

7.0 CAPITAL EXPENDITURE ISSUES

7.1 Outsourcing

Concerns have been raised that capital works are still being carried out by Ergon staff that could be carried out more efficiently and at lower cost by private contractors.

The following sets out concerns raised in a submission by the Urban Development Institute of Australia:

7.2 Contestability

Ergon has provided a significant level of contestability for the private delivery of new infrastructure such as in the development of new residential land subdivisions. The UDIA would encourage that process to be extended, particularly to commercial and industrial subdivision. Further, the process of contestability should enable the development industry more certainty and control over the timing of delivery of services. This appears to 'fall down' once a subdivision has received Ergon Quality Assurance certificate. At this point, Ergon becomes responsible for energising the works, which can take up to 90 days under their rules. The industry expects Ergon to undertake its own quality assurance, however, once the works are accepted, there is no reason why private contractors cannot undertake the energising of subdivisions.

7.3 Materials

Similar to contestability, at the moment, private contractors engaged to install electrical subdivisional work must acquire materials from Ergon. Ergon can make this process expensive too, for instance if a job calls for 250m of low voltage cable that only comes in a 500m drum, the developer must buy the entire drum. In some cases, the industry would be able to buy in sufficient volumes to deal directly with the manufacturer instead of Ergon. This has the potential to save the development industry significantly and help reduce the cost of housing in Queensland.

7.4 Gold Plating of Infrastructure

While this topic comes up repeatedly, in Ergon's case, for residential subdivision designs, the network design is required to provide each home with 5kw capacity. Throughout the review process the issue of decreasing consumption leading to increasing unit charges is suggesting that, at least in the domestic situation, that 5kw capacity may be conservative. While the spare capacity created out of the 5kw load builds in some flexibility into the system; providing for future dual occupancy/ further subdivision; that should not be at the expense of the development industry and the buying public. Further, would such spare capacity be considered in the RAB and WACC, again, artificially increasing costs more than necessary?

7.5 Customer Initiated Capital Works

Further evidence of falling growth figures can be found in the value of customer initiated capital works. The value of customer initiated capital works has fallen in real 2014-15 values from $1,523m in 2005-10 to $1,045m in 2010-15, a drop of $478m. Ergon estimates this drop in customer investment will turn around in 2015-2020 and increase by $143m to a proposed $1,188m.

In light of the $478 million drop in customer initiated capital works in the previous five years, it would appear optimistic that the value would increase $143 million when Ergon is forecasting a flat demand for 2015-2020.

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8.0 RETURN ON INVESTMENT

Previous **Tables #1 and #2** indicate the highly capital intensive nature of electricity distribution. The tables indicate that of the order of two-thirds of Ergon's revenue needs to go to providing a return on investment.

Calculation of a fair return is composed of two major elements:

a) The appropriate rate of return on investments;
b) The determination of the appropriate value of those investments.

This section deals with return on investment. (In the AER terminology, this is referred to as WACC Weighted Average Cost of Capital.)

In assessing what is appropriate, the most important aspect to determine is the 'risk' level of investment in electricity distribution and retailing in the Ergon situation.

While there is substantial risk of variation in demand as has been illustrated by the unexpected reduction in demand over the period 2010 to 2015, the monopolistic position of Ergon (and any successor in the market area), is such, that in the short run of relatively inelastic demand, prices can be adjusted to guarantee a return on investment, including paying interest rates above the actual risk involved to government sources of capital.

While resulting increases in prices will result in longer term reductions in demand (increased elasticity over time), the fact remains that because of the monopolistic situation, returns can be maintained. Against this background, we believe that the rate of return allowed in the AER determinations in the past has been far too high, especially against the background of a major reduction in global and Australian interest rates.

While some return to interest rates marginally above current extremely low levels could be expected in the USA, it should be noted that Australian rates have been and are still well above those in the USA, Japan and Europe. More recently, the Reserve Bank of Australia has been recognising the effects on exchange rates in their efforts to improve the competitiveness of the Australian currency. We thus believe that over the next five years, interest rates will remain comparatively low compared with long term averages.

We note that the AER draft determination for Essential Energy provided for a WACC of 7.2 percent (Essential Energy in New South Wales covers a similar large rural area to Ergon).

We note arguments by the Alliance of Electricity Consumers for reductions to the order of 4 percent to reflect rates closer to a long term no risk rate including inflation. We are not in a position to make a definitive recommended figure but we believe a major reduction is needed on what applied in the past.

We draw attention to the likely impact this would have on demand and especially on the viability of those industries mentioned elsewhere in this submission that are at risk of closure because of the greatly heightened electricity costs.

9.0 VALUATION OF CAPITAL INVESTED

Members of our network have very substantial experience of the state of the asset base and believe that there is a need for a complete revaluation – that accepting past valuations and just adding capex and deducting depreciation is not appropriate.

We believe that inadequate depreciation may have been allowed for where now underused assets remained in existence but now had much reduced or no commercial value.

We believe the asset base needs to be revalued on commercial grounds.

We are also concerned that AER ensures that, where customers pay the capital costs of facilities to supply them with electricity, the value of those facilities are not included in Ergon's asset base for calculation of returns on investment.

10.0 REVIEW BY INDUSTRY SECTORS

10.1 Manufacturing Industry

Situation

An established major FNQ manufacturing business employing towards 100 people has experienced a 62 percent increase in their electricity bill since FY2010. Other costs such as wages and supplies have risen approximately 15 percent. Their electricity consumption over the last five years has remained constant.

The business is the second largest employer in a council area and vitally important to the regional economy.

Potential outcome

Any further electricity price increase from this point on could be the final straw for the business. It has been impossible for their customers to wear the increased cost of electricity. Ergon stands to lose an account worth almost $1 million per year. Ergon's system utilisation drops even further than the already poor 37 percent. The effect on the local regional economy is major.

10.2 Potato Industry

Situation

The Atherton Tableland potato industry has decreased over a 10-year period from 60,000 mt to 40,000 mt. All potato crops grown on the Atherton Tableland are irrigated with over 80 percent using electric pumps. Dryland potato production is not viable.

Electricity prices have increased 50 percent whereby other major inputs such as fertiliser and freight have increased by 15 percent and 10 percent respectively.

Potential Outcome

Atherton Tableland potato farmers are already opting to grow crops that require less water and less labour which is affecting regional income and regional jobs. The industry is at a tipping point whereby another 10,000 mt potato production is at risk with a gross value of $5 million.

The unexpected casualty of a reduction of 10,000 mt potatoes is the reduction of available back freight to Brisbane, Sydney and Melbourne. In recent years the back freight rates to southern cities, that are a major source of consumer goods to Far North Queensland, have increased due to freight companies knowing there is a reliable source of back freight available. Any reduction in back freight volumes will have to be recouped via higher freight rates 'to' Far North Queensland. This increases the cost of living pressures already being experienced in Far North Queensland.

10.3 Dairy Industry

Situation

The Atherton Tableland dairy industry consisted of 185 farmers in July 2000. The number has now fallen to 52 farmers in January 2015. The average dairy farm employs 2 FTE and the dairy factory at Malanda employs around 70 people. The dairy factory is the largest employer in Malanda and produces approximately 1 million litres milk per week distributed between Weipa, Mount Isa and Mackay. Any surplus is trucked to Brisbane.

The annual electricity bill for one typical dairy farmer has increased from $12,000 to $22,000 in a two-year period with no significant change in electricity consumption. The majority of dairy farmers rely on pumps powered by electricity. Whilst electricity prices have increased 83 percent, other inputs around 10 percent, the average milk price has increased 10 percent over the past two years.

Potential Outcome

The industry continues to lose farmers and the viability of the dairy factory in Malanda is put at risk. Potentially Far North Queensland could lose the major employer in Malanda and the loss of milk production worth a gross farm-gate value of $30 million. The loss of the local production of milk would increase the cost of a basic food ingredient to most households and increase cost of living pressures.

10.4 Tourism Industry

Situation

Ergon's corporate purpose is, "To provide safe, reliable, efficient and sustainable energy solutions to support our customers and the Queensland economy."

Currently Ergon manages a network across 1.7 million square kilometres of regional Queensland. Ergon's network includes 65,000 km of Single Wire Earth Return (SWER) lines representing one of the largest SWER networks in the world. The SWER network constitutes an integral part of Ergon's supply network for customers across the sparsely populated areas of regional Queensland. Beyond the reaches of the SWER network, Ergon uses a range of non-grid technologies to address the electricity needs of isolated communities, including remote areas of Torres Strait, Cape York and Gulf of Carpentaria, Palm Island and western Queensland. Ergon operates 33 isolated power stations with localised networks to supply these communities.

The Regulator under Section 195 of the Electricity Act 1994 (Queensland) issues the distribution authority to Ergon. The distribution authority expires on 31 December 2037.

There is only one area (see Map, Appendix 2) excluded from electricity supply in the whole of Queensland which is defined as:

SCHEDULE 2
Area Excluded from Supply

(1) The following area (the "excluded area") is excluded from the distribution area of the distribution entity under this authority—

The area bounded by the low water mark of the Pacific Ocean between the Daintree and Bloomfield rivers; to the North by the Southern bank of the Bloomfield River; to the South by the Northern bank of the Daintree river; and, to the West by the Western boundary of the Cape Tribulation National Park and extending from the junction of this Park with the Wet Tropics of Queensland World Heritage Area to a point on the Northern Bank of the Daintree River opposite Kilkeary Point, as delineated on Map ELEC/ERG/Daintree held by the Department of Energy and Water Supply.

(2) However, the above exclusion —

(a) does not apply to the extent that a customer in the excluded area is —

(i) being supplied electricity using the distribution entity's supply network existing as at 18 October 2000; or

(ii) capable of being supplied electricity using the distribution entity's supply network existing as at 18 October 2000, but only if, in order to provide customer connection services to the customer, it is not necessary for the distribution entity's supply network existing as at 18 October 2000 to be extended in any way other than the installation of a service line to the customer's premises; and

(b) does not prevent the distribution entity from owning or operating a stand alone power system for the purpose of supplying electricity to a customer in the excluded area

The current perceptions of the region by potential consumers is that Far North Queensland's tourism offering is primarily related to the reef and rainforest. The excluded area above encompasses the important Daintree- Cape Tribulation area, one of the major drawcards for tourists seeking a rainforest experience in Far North Queensland. Numbers visiting the Daintree-Cape Tribulation area approximate 300,000 per year.

Around 35% of the Douglas Shire's employees work in the retail, accommodation and service provision industries compared to 18% across Queensland – illustrating the depth of the Shire's dependence on tourists.

Far North Queensland is also heavily reliant on tourism with on average 34,400 visitors in the FNQ region each day hosted by 173 accommodation establishments. Tourism employment totalled 18,700 in 2007-08, gross regional product $1.3 billion and tax revenue of $215m. A total of 3973 tourism businesses facilitated visitor expenditure of $7.8m per day.

Potential Outcome

FNQ is the largest and most diverse geographical region in Queensland and has significant potential to grow and further develop tourism.

Tourism in the region has to compete internationally and to do this, they need affordable power.

The Daintree / Cape Tribulation businesses are struggling with the inefficiencies of solar and the cost of diesel fuelled generators. Options for electricity in the Daintree / Cape Tribulation area should be investigated by Ergon and options found which meets the needs of residents and businesses in the Daintree / Cape Tribulation area.

Sugar industry

Situation
The sugar industry is one of Queensland's largest and most important rural industries.

Far North Queensland accounts for 20 percent of the sugar produced in Queensland.

Rapidly rising electricity prices are having a severe impact on the viability of irrigated sugar cane.

Tableland canegrowers informed the Queensland Competition Authority in early 2014 that at current electricity prices they would not be farming in 2016. Canegrowers cannot cope with existing electricity prices let alone any price increase, even if the price increase is kept to the CPI. Electricity prices to canegrowers have risen 96% with irrigated canegrowers experiencing a double whammy of a 57 percent increase in water costs.

Tableland cane is processed at both the Tableland and Mossman sugar mills. The total direct workforce approximates 400 which includes a sugar mill workforce of around 95.

Potential Outcome
Irrigated cane currently accounts for just over 1 million tonnes or two thirds of the combined crush of the Tableland and Mossman sugar mills. Due to the combination of high electricity prices and the high cost of water, irrigated sugar cane production could fall significantly placing at risk the future viability of both sugar mills.

The gross farm-gate value of cane crushed through the two sugar mills at present is approximately $60 million.

Mining industry

Situation
A FNQ mining company employing over 100 people is looking to expand its operations.

Ergon's practice is to secure the credit risk of the multi-million upgrade with collateral in the form of cash deposits, bank guarantees, surety bonds or letters of credit. The electricity infrastructure upgrade is to be constructed by Ergon as it is not contestable.

Similar worrying trends can be seen in customer contributions for Standard Control Services (SCS).

The value of customer contributions for Standard Control Services has fallen in real 2014-15 values from $356m in 2005-10 to $353m in 2010-15, to a proposed $158m in 2015-2020.

Table #22: Proposed capital expenditure, 2015-20

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset Renewal	255,606	286,325	255,677	282,134	278,322	1,358,064
Corporation Initiated Augmentation	171,365	173,955	177,551	132,239	135,381	790,490
Customer Connection Initiated Capital Works	219,082	225,999	239,416	249,149	255,290	1,188,935
Reliability and Quality of Supply	3,361	3,400	3,527	3,603	3,638	17,528
Other System	42,070	31,050	20,613	29,432	25,708	148,872
Non-System	177,552	136,598	105,625	97,698	85,869	603,341
Gross capital expenditure	**869,035**	**857,326**	**802,408**	**794,254**	**784,208**	**4,107,231**
less Alternative Control Services customer contributions	*(99,420)*	*(103,750)*	*(111,130)*	*(116,850)*	*(120,790)*	*(551,940)*
Standard Control Services gross capital expenditure	**769,615**	**753,576**	**691,278**	**677,404**	**663,418**	**3,555,291**
less Standard Control Services customer contributions	*(29,750)*	*(30,390)*	*(31,860)*	*(32,860)*	*(33,400)*	*(158,260)*
Standard Control Services net capital expenditure	**739,865**	**723,186**	**659,418**	**644,544**	**630,018**	**3,397,031**

Source: Ergon Regulatory Proposal, 2015-2020

Potential Outcome

It has been suggested that Ergon's capital works are at least a 30 percent premium to private industry. In a mining feasibility study this premium could make the difference between a project progressing to a mining & processing operation or not.

Mines in Far North Queensland are significant regional employers injecting high salaries into rural and regional towns hit hard by the downturn in agricultural industries.

11.0 OTHER ISSUES

11.1 Queensland Tariff Equalisation

The AER has indicated that Queensland tariff equalisation (Community Service Obligation) does not form part of its 2015-2020 determination. However it is important that AER is aware that any changes to the Queensland Tariff Equalisation scheme arrangements has the potential to affect the price of electricity in the Far North Queensland region and throughout the State, along with patterns of electricity generation and as a consequence demand for electricity and viability of some industries.

It is important to realise that the equalisation scheme is not a pure subsidy. By linking the whole State and providing uniform tariffs allows economies of scale to be achieved in power generation that would not otherwise be possible. This benefits electricity consumers throughout the State.

This system however results in substantial transmission energy losses where power is delivered to areas more distant from the main power generation sources.

The tariff equalisation thus allows benefits of economies of scale in power generation to offset some of the additional costs that would otherwise fall on consumers more distant from the major power generation centre.

Any change from this would have a major impact on electricity prices in the regional areas, such as the Cairns / Far North Queensland region, more distant from power generation sources and on demand for electricity.

Almost certainly over time, it would change the location of power generation throughout the State with an incentive provided for more local supply.

Consumers in the southern part of the State would tend to lose the benefits of economies of scale in power generation.

In consideration of this issue, it needs to be recognised that the regions of northern Australia with 5.7 percent of the population, account for over half of Australia's export income.

11.2 Non-fossil Fuel Energy

It should be noted that the Cairns / Far North Queensland region has long made a special contribution to the Queensland electricity system through its hydroelectric stations on the Barron and Tully Rivers.

These power stations whose major capital costs have been written off years ago, are in a position to supply into the network's peak load power at very low prices, compared with other sources of peak load power.

In addition, through the region’s sugar industry cogeneration facilities, wind farms and increased solar installations, the region contributes substantially to meeting Renewable Energy Targets (RET) targets.

Because of the real cost of transmission losses from the major coal fired stations, there are economic benefits for cost effective renewable energy being delivered in areas where real costs of coal based power are higher due to transmission losses.

11.3 Consumer Engagement

Further to observations in Section 4.1.5 Demand Forecasting, we believe that there is a need for substantial improvement, especially at regional level.

11.4 Incentive Schemes

There is concern that the schemes whereby substantial incentives are allowed if capital and operating expenditure efficiencies are achieved may be encouraging inflation of capital and operating expenditure projections.

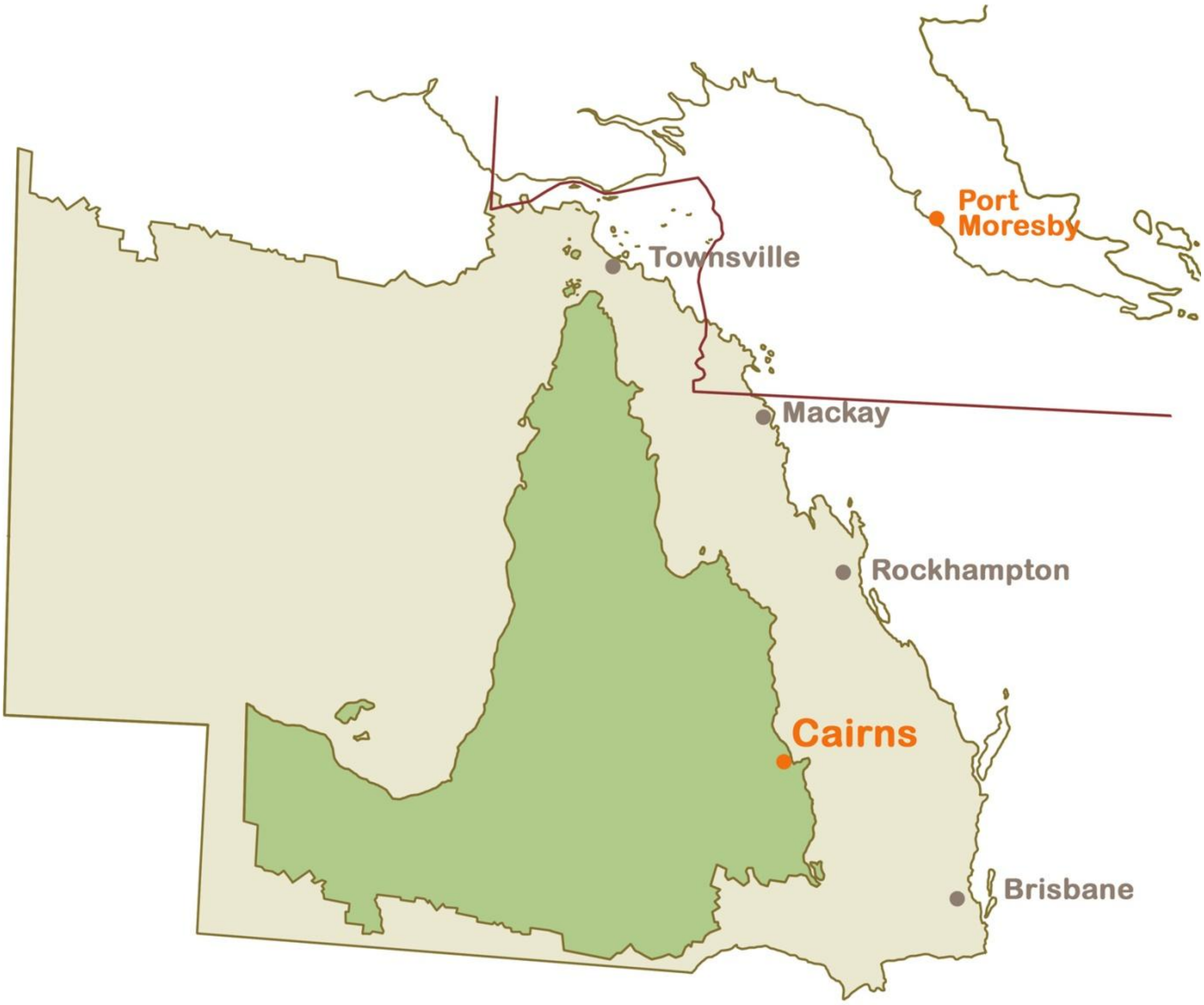
It has been suggested by network participants that the whole emphasis of incentives be reviewed.

SUBMISSION TO AUSTRALIAN ENERGY REGULATOR

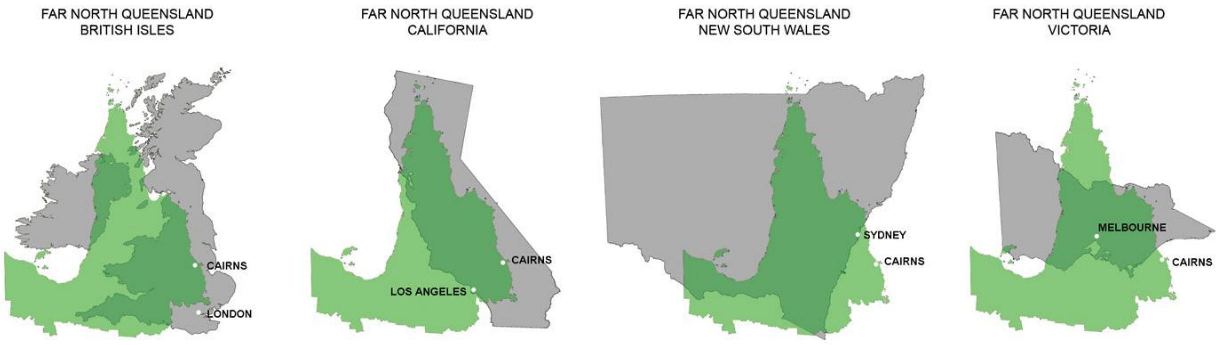
APPENDICES

APPENDIX 1

Map 1 – Comparative area and distances with rest of Queensland

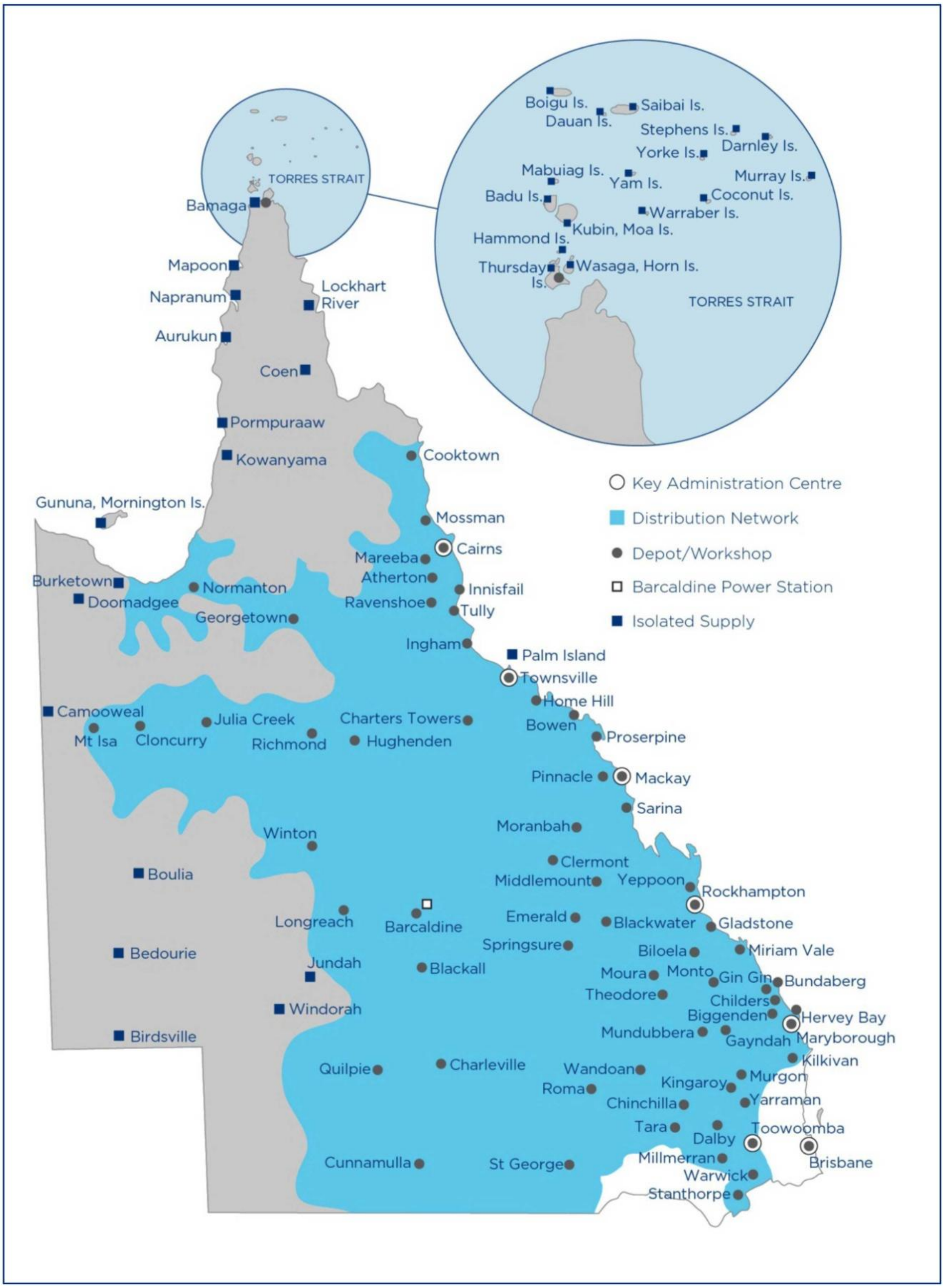


Map 2 – Comparative areas and distances



APPENDIX 2

Map - Ergon's distribution service area



Source: Ergon Distribution Annual Planning Report 2014-15 to 2018-19 – Part A