CANEGROWERS

100 Edward Street (GPO Box 1032)
BRISBANE QLD 4001
T: 07 3864 6444 F: 07 3864 6429
enquiry@canegrowers.com.au
www.canegrowers.com.au

14 March 2016

Mr Kim Wood
Principal Commissioner
Queensland Productivity Commission
PO Box 12112
George Street
BRISBANE QLD 4003

Dear Mr Wood,

**Public Inquiry into Electricity Prices**

Thank you for the opportunity to respond to Queensland Productivity Commission's (QPC) Electricity Pricing Inquiry Draft Report that was released on 3 February 2016.

CANEGROWERS seeks the introduction of an electricity pricing system and tariff structure that mirror those resulting from a competitive market structure. Prices and tariffs should provide performance incentives, encourage reductions in cost across the supply chain and enable electricity users, particularly those in the traded goods sector, to remain internationally competitive.

The sharp increases in electricity prices that have occurred in recent years are unsustainable. With energy prices worldwide at their lowest levels in many years, the adverse impact of inflated electricity prices on the international competitiveness of irrigated agriculture is a significant concern.

The QPC's draft report clearly and succinctly identifies the root cause of the electricity pricing problem, "Queensland's electricity price increases have largely been driven by escalating network costs, although the costs of the Solar Bonus Scheme (SBS) and the Australian Government's Renewable Energy Target (RET) have also played a role" (QPC draft report, p viii).

**Flawed Network Pricing Framework**

During a public lecture in January[1], Professor Ross Garnaut reminded his audience of an economic proposition by Averch and Johnson[2] published in the American Economic Review in 1962. "In regulating prices in a natural monopoly, avoid setting prices primarily by reference to the rate of return on investment". The reason is as simple as it is compelling. The regulated businesses, cautious to avoid underinvestment, argue for higher rates of return. The inevitable occurs. Rates of return set at levels higher than required lead to wasteful over-investment. Professor Garnaut cites the national electricity market (NEM) as a case in point.

The driver of escalating network costs is investment in network capacity that has occurred to meet the peak load demands of urban and industrial users[3], not the needs of irrigated agriculture. The costs of this investment have been spread across all consumers. They are not being borne by those users

[1] Ross Garnaut (2016), "Australia After Paris: Will we use our potential to be the energy superpower of the low-carbon world?" Public lecture hosted by the Young Energy Professionals, State Theatre Centre of Western Australia, Perth, 21 January.
2 Averch, H. and Johnson, L.L. 1962, "Behavior of the Firm Under Regulatory Constraint", American Economic Review, 52 (5): 1052–1069.
[3] According to AEMC, around 45 per cent of network investments have been made to cater for periods of peak demand estimated to occur for very short periods of time. "Around 6 per cent of Ergon Energy's network capacity is used for only 0.1 per cent (less than nine hours) of the year" (QPC Draft Report, p65).

contributing to the peak load demand. This approach means the network prices, neither cost reflective nor efficient, are encouraging peak load demand and discouraging network use at other times. As well as undermining the international competitiveness of irrigated agricultural industries across Queensland, the electricity pricing framework is putting jobs in regional communities at risk as local businesses contract and services are withdrawn.

An associated problem identified in the QPC report is that the regulated asset base is simply too high. With network investment growing strongly at a time of declining network use[4], this is clearly the case. In submissions made to the Queensland Competition Authority, the Australian Energy Regulator, Ergon, the Senate, the federal Productivity Commission, the Queensland Government's Interdepartmental Committee on Electricity Sector Reform (2013) and Independent Review Panel on Network Costs (2013), CANEGROWERS has consistently argued that the present electricity pricing framework encourages the investment in surplus capacity, provides incentives for the underutilisation of sunk investments and risks assets becoming obsolete and/or stranded in the face of declining electricity use. This pattern has been widely described as the electricity price "death spiral".

To avoid this adverse price spiral, it is important that the value of non-performing and under used assets in the regulated asset base (RAB) be written down and shareholders be required to face the risks associated with their network investment decisions. This fundamental market discipline, faced by all firms in the competitive sector of the economy, is not one faced by Ergon, Energex or their shareholder, the Queensland Government. In this regard, although acknowledging the issue, it is disappointing that the QPC has "not attempted to quantify the costs of writing down the RABs of Queensland's network businesses' asset base" (QPC Draft Report, p83).

***CANEGROWERS recommends that QPC quantifies the costs <u>and</u> benefits to the Queensland economy of writing down the RABs of Queensland's network businesses' asset base.***

This cost benefit analysis should take account of the impact on: the credit ratings and cost of finance faced by the businesses; shareholder revenues; the need for equity injections; and implications for sovereign risk. It should also take account of the impact of the price reductions that would flow from the write down on: the level of network use; the revenues that networks would collect; the lower capital requirement associated with more commercial investment decisions; the economic viability of businesses in Queensland's traded goods sector; and the impact on employment, investment and the social and economic vibrancy of the state's rural and regional communities.

Driven by poorly targeted network investment decisions, Queensland's electricity network prices are the highest in Australia. Charging users a higher price for electricity to recover the costs of these investments is a very inefficient way of dealing with the problem. It unnecessarily inhibits the development of irrigated agriculture and other energy-intensive industries across the economy and, by raising the cost of electricity to the wider community, it lowers living standards across the state. Standard economic principles suggest that in the long term the adverse economy wide consequences of electricity prices that are set too high will more than offset the short term impact on credit ratings, cost of finance, shareholder revenues, need for equity injections and implications for sovereign risk of writing down the value of RAB to an economically efficient level.

**Tariff structure**

To address the problem of declining use of already underused network assets, there is a strong case for tariffs to reflect the demands and needs of different classes of customers and, where possible, to encourage load to be shifted from peak to off-peak periods.

There is a strong case for the treatment of irrigation as a separate customer class and for the continuation of a suite of electricity tariffs for use in food and fibre production.

[4] "Energex and Ergon Energy's RAB grew 168 percent cumulatively from 2004–05 to 2014–15. At the same time, however, distribution network utilisation has fallen from an average of around 38 per cent in 2006 to 33 per cent in 2015" (QPC Draft Report, p82).

As input to Ergon's tariff structure statement and the Australian Energy Regulator's (AER) review of that statement, CANEGROWERS commissioned an independent analysis using Ergon data to better understand the impacts and opportunities that these proposed tariffs present for Queensland's irrigators. The attached report prepared by the Alternative Technology Association's (ATA) Energy Projects Team is part of a project funded by Energy Consumers Australia.

ATA's key findings are that:

- Cane growers will be better off with optional location specific 'cost reflective' pricing options that are targeted at particular irrigation types.
- Ergon Energy's proposed 'top 4 energy days' is actually preferable to a conventional peak demand charge (Max ½ hourly kW demand) for some irrigators.
- Opportunities for cane growers to load shift are materially improved for many 'winch' and 'pivot' irrigators if Ergon Energy's proposed 10-hour summer peak period is shortened (to 5 hours).
- Tariffs with demand charges impact irrigators adversely if they cannot shift load.
- Critical Peak Pricing and Peak Time Rebates are effective tools to enable all cane growers, including furrow irrigators, to share the benefits of reducing peak load on the network.

ATA found that in its view there is a clear case for there to be a range of network tariffs available that reflects the different demands irrigators place on the network compared to other users.

The report identified the interrupt ability of furrow irrigation during critical peak periods and the ability of winch and low pressure overhead irrigation systems to be operated in off-peak times.

These characteristics support the following irrigation tariff structures:

- Critical peak pricing – which could provide an incentive for furrow irrigators to switch off loads during critical peak summer days.
- Peak and off-peak pricing:
    - Peak – daily peak pricing period of no more than 5 hours.
    - Off-peak – all other times with tariffs low enough to provide an incentive to load shift and not subject to 'any-time' peak demand charges (such as the off-peak demand charge proposed by Ergon).

A tariff structure not canvassed by ATA, but one which CANEGROWERS has discussed with Ergon, is for irrigators to be able to access a "Lock-Off" tariff. Under this tariff, irrigators would be denied access for electricity at critical peak times. In this way, irrigators who choose the "Lock-Off" tariff would not be responsible for critical peak or contributing to network investments designed to meet critical peak load needs. In exchange, they would receive lower tariffs reflecting their willingness to be "Locked-Off" the network at critical peak times and Ergon's lower CAPEX.

As the ATA analysis shows, consistent with the national electricity rules, truly cost reflective pricing would take account of the different pressures different user groups place on the network and contain pricing structures designed to influence usage patterns designed to optimise the existing network. The report strongly supports CANEGROWERS call for a suite of tariffs for irrigation use.

CANEGROWERS is committed to working with Ergon and the AER to achieve a more flexible tariff structure ahead of the Queensland Competition Authority's 2016-17 regulated retail electricity price determination.

***CANEGROWERS recommends that network tariffs be designed to ensure that irrigators are not required to meet the costs of network investments made to meet the peak load demands of urban and industrial users.***

**Conclusion**

The abundant availability of low cost energy should be one of Queensland's comparative advantages. Despite this Queensland's electricity network prices are the highest in Australia and, on available evidence[5], are arguably the highest of any network world-wide. A direct consequence is that electricity prices in Queensland are too high. This is slowing and in some cases undermining the growth and development of Queensland's regional economies and the communities they support.

CANEGROWERS calls on the QPC to:

- Undertake a comprehensive analysis of the economy-wide costs and benefits of addressing the central electricity pricing problem, writing down the size of Queensland's network businesses' regulated asset base to a prudent and economically efficient level. This assessment must go beyond the superficial assessment of the short term financial impact on the Queensland Government's revenues contained in the draft report. It must assess the impact of unsustainably high electricity prices on the international competitiveness of Australia's export and import competing industries and the communities they support.

- Recommend that network tariffs be designed to ensure that irrigators are not required to meet the costs of network investments made to meet the peak load demands of urban and industrial users.

We look forward to an opportunity to discuss this submission with you in greater detail.

Yours sincerely

Dan Galligan
Chief Executive Officer

**Attachments**

- Alternative Technology Association (2016), "Tariff Design Options"

- Carbon Market Economics (2013), "Rising electricity prices in Queensland: Evidence and Reasons for Action"

[5] Carbon Market Economics (2013) Rising electricity prices in Queensland: Evidence and Reasons for Action.

# Tariff design options

**Report for CANEGROWERS**

ATA

December 2015

# 1.0 Document Information

| Document Version | Date | Prepared By | Reviewed By | Comments |
|---|---|---|---|---|
| **Canegrowers v1.0** | 18/12/15 | Kate Leslie | Craig Memery | |
| **Canegrowers v1.1** | 18/12/15 | Craig Memery | | Draft for client review |
| **Canegrowers v1.2** | 21/12/15 | Hugh Grant | | Initial client suggestions |
| **Canegrowers v2.0** | 21/12/15 | Kate Leslie | Craig Memery | Incorporating further client comments |
| **Canegrowers v2.1** | 21/12/15 | Craig Memery | Kate Leslie | Version for discussion |
| **Canegrowers v2.2** | 22/12/15 | Kate Leslie | Warren Males | |
| **Canegrowers v2.3** | 07/01/16 | Craig Memery | Kate Leslie | |

© 2016 Alternative Technology Association. All rights are reserved. No part of this report may be reproduced without acknowledgement of source.

**Prepared for CANEGROWERS**

### Disclaimer

This project was funded by Energy Consumer Australia (www.energyconsumersaustralia.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 Energy Consumers Australia.

**ATA Energy Projects Team**
Prepared by: Kate Leslie, Craig Memery
Cover photograph: none

**Alternative Technology Association**
Level 1, 39 Little Collins St, Melbourne VIC 3000
+61 3 9639 1500
+61 3 9639 5814
www.ata.org.au

# Contents

# 2.0 Introduction

The objectives of this report are to

- Assist in quantifying the impacts and opportunities that Ergon Energy's proposed new tariffs present for Queensland's irrigators
- Identify which 'cost reflective' tariff options are better reflect the needs of irrigators served by the Ergon Energy electricity network and allow them opportunity to reduce costs
- Assist CANEGROWERS in engaging with Ergon Energy and the AER in relation to Ergon Energy's TSS approval process.

CANEGROWERS has raised the following concerns regarding new tariffs proposed by Ergon Energy

- Ergon Energy's proposed 10am - 8pm summer kW peak window is too wide to enable many irrigators to respond effectively without comprising crop yields
- Ergon Energy's different approaches to summer peak calculation (top 4 energy days) and off-peak (Max ½ hourly kW demand) is confusing and limits consumers' ability to implement measures that respond effectively to tariffs in the summer period
- Location-specific voluntary tariffs that appropriately incentivise different types of irrigators to reduce demand at peak times are required.

To quantify these matters, ATA has analysed

- Tariffs proposed by Ergon Energy in their proposed tariff structure statement
- Alternative tariff designs considered by CANEGROWERS and ATA to be
  - appropriate in the context of the new distribution pricing rules
  - suited to Ergon Energy's network
  - potentially better suited to meet the needs of irrigators, in particular canegrowers.

ATA's approach to this analysis is detailed further within this report.

## 2.1 Key findings

The analysis

- strongly supports the view that cane growers will be better off with optional location-specific 'cost reflective' pricing options that are targeted at particular irrigation types
- suggests that Ergon Energy's proposed 'top 4 energy days' is actually preferable for some irrigators than a conventional peak demand charge (Max ½ hourly kW demand).

If Ergon Energy's proposed 10 hour summer peak period was shortened (to 5 hours for example), opportunities for load shifting for canegrowers are materially improved for many 'winch' and 'pivot' irrigators. Indeed, most may be able to avoid peak periods altogether if they are short enough.

Tariffs with demand charges tend to impact irrigators adversely if they cannot shift load, as is the case for many furrow irrigators.

Critical Peak Pricing and Peak Time Rebates are effective tools to enable all cane growers, including furrow irrigators, to share the benefit of reducing peak load on the network.

Ergon Energy’s proposed ‘anytime’ peak charge for non-summer months provides irrigators with no incentive to load shift or to reduce that charge in any other practical way. It would be preferable for irrigators if the summer demand structure was consistent across the full year, at least with respect to the peak periods.

The way Ergon Energy’s proposed SAC peak summer charge is calculated affects whether cane growers are better off with a longer (10 hour) or shorter (5 hour) peak window. Irrigators that have an ability to load shift are generally better off with a shorter peak period, whereas most others are worse off, particularly if they can’t shift load and their average load is higher during the shorter window than the longer window.

# 3.0 Background

## 3.1 Ergon Energy's Proposed Demand Tariffs

In March 2015 Ergon Energy published a consultation paper[1]. New optional demand tariffs were proposed within that paper. [2]

In November 2015, Ergon Energy submitted to the Australian Energy Regulator a Tariff Structure Statement[3]. The key features of the tariff structure[4] and the proposed numbers[5] appeared to be unchanged from the March 2015 consultation paper.

Ergon Energy's tariffs differentiate between small or large users. Key features of the optional seasonal time of use tariffs for large users (>100MWh), 'Seasonal TOU Demand East' (ESTOUDC), are-

| | | |
|---|---|---|
| Fixed Charge | $32 | Dollars per day |
| Consumption charge non-summer | $0.03364 | Dollars per kWh |
| Consumption charge summer | $0.00 | Dollars per kWh |
| Demand threshold Summer | 20 | kW |
| Demand threshold Non-Summer | 40 | kW |

[1] Ergon Energy, Consultation Paper Our Network Tariff Reform Report *Network Tariff Reforms 2015-16 * Tariff Structure Statement, 2016-20, June 2015. https://www.ergon.com.au/__data/assets/pdf_file/0016/270610/Consultation-Paper-Network-Tariff-Reform-AMENDED.pdf
[2] See pages 34 & 35 for Small Asset Customers Large users, and pages 38 & 39 for Small Asset Customers Small customers.
[3] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ergon-energy-tariff-structure-statement-2015/proposal
[4] Ergon Energy, Tariff Structure Statement 2017-18 to 2019-20, 27th November 2015, page 22 for Small Asset Customers (using <100MWh) and page 26 for Large customers (>100MWh).
[5] For LRMC see p29 of Appendices. For Small Asset Customers see p48 Seasonal Time of Use Demand Business East (EBTOUD). For Small Asset Customers Large see p51 Seasonal Time of Use Demand East (ESTOUDC).

Key features of the optional seasonal time of use tariffs for small business users (<100MWh), 'Seasonal TOU Demand Business East' (EBTOUD), are-

| | | |
|---|---|---|
| Fixed charge | $0 | Dollars per day |
| Consumption charge | $0.02835 | Dollars per kWh |
| Summer Peak Period: Start of period | 10:00 | |
| Summer Peak Period: End of period | 20:00 | |
| Summer Peak Period: Include weekends? | No | |
| Summer peak charge[6] | $80.554 | Dollars per kW |
| Non-Summer peak charge | $12.000 | Dollars per kW |
| Non-summer min. Dmd | 3.00 | kW |

## 3.2 Matters investigated and ATA's approach

### 3.2.1 Peak periods

CANEGROWERS has raised concern that Ergon Energy's proposed 10am to 8pm summer kW peak window is too wide to enable many irrigators to respond effectively without comprising their crop yields, thereby limiting the effectiveness of the price signal and the ability to implement regular timer-based operations[7].

CANEGROWERS asked Ergon Energy to consider reducing the 10am to 8pm summer peak window, and consider location-specific pricing to send a more cost reflective signal that consumers can respond to effectively.

ATA has analysed the price impacts of reducing the length of the peak window period.

**In ATA's view, a four-hour peak window is adequate to capture the actual system peaks at a given location, therefore this analysis uses a five-hour peak, which can be considered broadly representative of a four to six-hour window in terms of price and irrigation impacts.**

[6] "The monthly demand charges, for both summer and non-summer, are based on the average demand the customer places on the network in the daily demand window. For business customers, the demand window is the half hours between 10.00 am and 8.00 pm on Weekdays... We look at the highest four demand days in the month, determined by the average demand recorded in these daily demand windows. We apply the monthly demand rate to the average of these top four demand days." Ergon Energy, Tariff Structure Statement 2017-18 to 2019-20, November 2015, p22.

[7] Further, ATA notes that charging consumers in all parts of the system similarly (irrespective of when the system serving them peaks) over a 10 hour period, may result in them shifting some loads within that period in a manner that moves some loads towards the actual peak. This would clearly be a perverse outcome.

As location-specific charges might be required to justify shorter peak periods, ATA analysed low, medium and high off peak kW charges, reflective of a plausible range of LRMC values in different locations, whereby

- Low $/kW charge = an unconstrained location with low LRMC
- Medium $/kW charge = equivalent to system wide average charge proposed by Ergon Energy
- High $/kW charge = a location with emerging constraints and therefore high LRMC

### 3.2.2 Peak charging approach

CANEGROWERS raised concern that Ergon Energy's different approaches to summer peak calculation (top 4 energy days) and off-peak (Max ½ hourly kW demand) is confusing and limits the ability of consumers to implement measures that respond effectively to tariffs in the summer period.

ATA's analysis compares the effectiveness of the two options for charging for peak demand in terms of consumer impact, for the 10 hour peak window proposed by Ergon Energy and the alternate 5 hour peak window outlined above.

### 3.2.3 Critical Peak Pricing and Peak Time Rebates

CANEGROWERS requested that Ergon Energy also introduce voluntary tariffs that appropriately incentivise different types of irrigators to reduce demand at peak times. It is clear that a one size tariff does not fit all irrigation types[8].

For cane growers that use furrow irrigation, interrupting their operations daily would cause unacceptable impact. However they are still able to interrupt their loads from time to time. A tariff that incentivises up to 10 load-switching events per summer with a very high price on the highest demand days (commonly known as a Critical Peak Price (CPP)) can address peak demand in constrained networks, and most irrigators could respond by reducing or eliminating loads on those days.

A Peak Time Rebate (PTR) is similar to a CPP in terms of timing and triggers, but rather than including a higher tariff the network business makes a payment to the irrigator if they reduce their load on those days.

ATA analysed the impacts of CPP and PTRs for cane growers.

---

[8] *"Irrigators don't require power every day ... What further complicates things is that water requirements vary from 15mm/week to 60mm/week depending on the season and crop age. Irrigation systems are designed to meet the 50mm or 60mm/wk demand which is required in summer. In the non summer months there is potential for pivot and winch to avoid peak hours but in summer without any relief from rain they too operate 24/7. Irrigators make 100% use of off peak and weekend hours but often this is insufficient time to complete the task." Rajinder Singh, Director Canegrowers Tablelands, email 5th November 2015*

## 3.3 Load Profiles

This analysis is based on

- Interval data sourced from metered irrigation sites and supplied by Ergon Energy
- Synthesised interval data developed by using other information to represent the load profiles of canegrowers in the Bundaberg and Tablelands regions.

Ergon Energy provided a number of meter data files representing different load profiles.

Most of the files provided were of less than 6 months duration, so not representative of the whole year.

The files with 12 months worth of data are –

**Table 3-1: Useful Load Profile Files**

| NMI | IrrigScale | IrrigType | Region |
|---|---|---|---|
| 3033626847 | <100MW | Furrow | Burdekin |
| 3041667174 | <100MW | Furrow | Bundaberg |
| 3041667905 | <100MW | Furrow | Bundaberg |
| 3042007054 | <100MW | Winch | Bundaberg |
| 3052073629 | <100MW | Furrow | Burdekin |
| QEEE7000713 | >100MW | Pivots and furrow | Tableland |
| 30309955583 | <100MW | Pivot | Tableland |
| 30310108738 | >100MW | Pivots and furrow | Tableland |

Of the 8 usable (>12 months) load profiles, four are furrows, two are pivots and furrow and there is one each of pivot and winch. Two irrigators use more than 100MWh annually.

The key variables that needed to be represented in the load profiles were

- type of irrigation
  - furrow
  - winch or
  - pivot
- Region
  - Bundaberg or
  - Tablelands

CANEGROWERS and ATA were concerned that the sample of winch and pivot loads was not representative, however sufficient meter data to address this issue was not available. Dr Martin Gill was engaged to simulate more 'pivot and winch' load profiles using various source. Dr Gill generated 7 load profiles for a year with average rainfall as follows:

**Table 3-2: Additional Load Profiles Generated**

| File name | Region | Irrigation Type | Dr Gill Comment |
|---|---|---|---|
| Simulated Scenario 40KW | Bundaberg | Winch | Simulation using rain deficit approach for a pump size of 40kW |
| Simulated Scenario 25KW | Bundaberg | Winch | Simulation using rain deficit approach for a smaller crop and pump size of 25kW |
| Winch Bundaberg 40KW | Bundaberg | Winch | Scaled NMI 3042007054 to a pump size of 40kW (false peaks removed) |
| Winch Bundaberg 11KW | Bundaberg | Winch | Scaled NMI 3042007054 to a pump size of 11kW (false peaks removed) |
| Winch Bundaberg 25KW | Bundaberg | Winch | Scaled NMI 3042007054 to a pump size of 25kW (false peaks removed) |
| Pivot Tablelands 25kW | Tablelands | Pivot | Provided pump start and stop times for a pump size 25kW |
| Pivot Tablelands 55kW | Tablelands | Pivot | Provided pump start and stop times for a pump size 55kW |

## 3.4 Tariffs Model

ATA developed a model for calculating Ergon Energy's optional Seasonal Time of Use Demand tariffs from load profiles based on half hour time intervals. The model also has load shifting analysis capability.

The model calculates tariffs for four combinations of assumptions based on the load profile: Large 1, Large 2 (a variation of Large 1), WA1 and WA2 (a variation of WA1). The model has many variables including:

- the values of inputs
- which months to consider as Summer
- whether peak tariffs apply to weekends; and
- which timeframes to include in peak windows.

Large 1 and WA1 assumptions are consistent with the Ergon Energy's Tariff Structure Statement for Large and Small Standard Asset Customers respectively. The table below outlines the standard assumptions/inputs for the four output tariffs:

| Tariff Components | | Standard Asset Customers | | |
|---|---|---|---|---|
| Descriptor | **ATA Terminology** | Large | Small | **Unit** |
| | | >100MWh | <100MWh | |
| **Fixed Charge** | Large1 | $32 | $0 | Dollars per day |
| **Consumption charge non-summer** | Large1 | $0.03364 | $0.02835 | Dollars per kWh |
| **Consumption charge summer** | Large1 | $0.00 | $0.00 | Dollars per kWh |
| **Demand threshold Summer** | Large1 | 20 | 0 | kW |
| **Demand threshold Non-Summer** | Large1 | 40 | 0 | kW |
| **Demand charge Summer** | Large1** | $ 47.829 | $ 80.554 | Dollars per kWh, max per month |
| **Demand charge Non-summer** | Large1 | $ 12.936 | $ 12.000 | Dollars per kWh, max per month |
| **Fixed Charge** | Large2 | $32 | $0 | Dollars per day |
| **Consumption charge non-summer** | Large2 | $0.03364 | $0.02835 | Dollars per kWh |
| **Consumption charge summer** | Large2 | $0.00 | $0.00 | Dollars per kWh |
| **Demand threshold Summer** | Large2 | 20 | 0 | kW |
| **Demand threshold Non-Summer** | Large2 | 40 | 0 | kW |
| **Demand charge Summer** | Large2** | $ 47.829 | $ 90.000 | Dollars per kWh, max per month |
| **Demand charge Non-summer** | Large2 | $ 12.936 | $ 12.000 | Dollars per kWh, max per month |
| **Fixed charge** | WA1 | | $0 | Dollars per day |
| **Consumption charge** | WA1 | | $0.02835 | Dollars per kWh |
| **Summer Peak Period: Start of period** | WA1 | | 10:30 | End of time interval |
| **Summer Peak Period: End of period** | WA1 | | 20:00 | End of time interval |

| | | | |
|---|---|---|---|
| **Summer Peak Period: Include weekends?** | WA1 | No | |
| **Summer peak charge (aka Optional Locational Charge)** | WA1 | $ 80.554 | Dollars per kW |
| **Non-Summer peak charge** | WA1 | $ 12.000 | Dollars per kW |
| **Non-summer min. Dmd** | WA1 | 3.00 | kW |
| **Fixed charge** | WA2 | $0 | Dollars per day |
| **Consumption charge** | WA2 | $0.02835 | Dollars per kWh |
| **Summer Peak Period: Start of period** | WA2 | 11:30 | End of time interval |
| **Summer Peak Period: End of period** | WA2 | 16:00 | End of time interval |
| **Summer Peak Period: Include weekends?** | WA2 | No | |
| **Summer peak charge (aka Optional Locational Charge)*** ** | WA2 | $ 90.000 | Dollars per kW |
| **Non-Summer peak charge** | WA2 | $ 12.000 | Dollars per kW |
| **Non-summer min. Dmd** | WA2 | 3.00 | kW |

## 3.5 Analysis

ATA developed a model for calculating Ergon Energy's optional Seasonal Time of Use Demand tariffs from load profiles based on half hour time intervals. The model also has load shifting analysis capability.

Ergon Energy proposes a peak window of 10am-8pm for business customers (10 hours). ATA modelled tariffs for an alternative 5 hour peak window. A window of 11am-4pm was chosen after observing the pattern of use among the non-furrow irrigators, and to represent times with some full pumping load (to avoid underestimating the benefit of load shifting) and some low load (to avoid overestimating the benefit of load shifting), while assuming a plausible local system peak time.

A tariff that incentivises up to 10 load-switching events per summer with a very high price on the highest demand days (commonly known as a Critical Peak Price or CPP) can address peak demand in constrained networks, and most irrigators could respond by reducing or eliminating loads on those days.

A Peak Time Rebate (PTR) is similar to a CPP in terms of timing and triggers, but rather than including a higher tariff the network business makes a payment to the irrigator if they reduce their load on those days.

There are two main variables for sensitivity testing:
- different Long Run Marginal Costs (LRMCs); and
- the times of the peak window.

Sensitivity tests were conducted on a number of variables reflecting different long run marginal costs (LRMC) with three optional location charges - low @ $20/kW/month, average @$90/kW/month or High @$200/kW/month.

The variable used in ATA's model (the mechanism) for the calculation was WA2 summer peak charge. The high charge of $200/kW is consistent with approximately $500/kVA LRMC.

## 3.6 Loadshifting rationale and logic

A Bundaberg Regional Irrigators Group options briefing paper[9] prepared by Dale Hollis summarised that furrow irrigation has high labour input so is "best operated in daylight or early evening hours" (p2) whereas for winch irrigation "wind impacts highly on efficiency, [so is] best operated in overnight hours [when winds are lower, to minimise evaporation losses]" (p3).

For cane growers that use furrow irrigation, interrupting their operations daily would cause unacceptable impact, however they are able to interrupt their loads from time to time. By contrast, 'pivot and winch' irrigators have more options to shift load, and may be able to respond to peak windows that either occur every day, all year, every day during Summer months, or during critical periods.

Loads are only shifted from peak charging periods to other periods. CANEGROWERS nominated 72 intervals (36 hours) as a maximum period for deferring shifted load before the impacts on crop yield were unacceptable. ATA's model therefore treats that as an absolute limit: the load shifting macro within the model identifies load in peak periods and defers those load to the next non-peak interval that has no load, unless doing so would move that load more than 36 hours from its original interval. This approach allows an assessment of load shifting potential within the limits of crop requirements.

[9] Undated document supplied by Dale Hollis to Craig Memery on 22 September 2015 14:36.

# 4.0 Results

## 4.1 Furrow Irrigators

Given the load profiles, the components of electricity bills for furrow irrigators with Ergon Energy's proposed peak window of 10am-8pm are outlined below:

| | |
|---|---|
| Scale | <100MW |
| IrrigationType | Furrow |
| OptionalLocationTariff | 90 |
| Loadshifting | None |

| | NMI | | | |
|---|---|---|---|---|
| **Values** | **3033626847** | **3052073629** | **3041667905** | **3041667174** |
| WA1_FixedCost | $0 | $0 | $0 | $0 |
| WA1_ConsumptionCost | $2,585 | $220 | $600 | $713 |
| WA1_DemandCostSummer | $8,113 | $1,337 | $1,504 | $5,140 |
| WA1_DemandCostNonSummer | $2,308 | $365 | $1,845 | $1,666 |
| WA1Total | $13,005 | $1,922 | $3,948 | $7,518 |

A shorter 5 hour peak window provides no benefit for furrow irrigators. Here would be the components of electricity bills with a Summer peak window of 11am-4pm.

| | |
|---|---|
| Scale | <100MW |
| IrrigationType | Furrow |
| OptionalLocationTariff | 90 |
| Loadshifting | None |

| | NMI | | | |
|---|---|---|---|---|
| **Values** | **3033626847** | **3052073629** | **3041667905** | **3041667174** |
| Average of WA2_FixedCost | $0 | $0 | $0 | $0 |
| Average of WA2_EnergyCost | $2,585 | $220 | $600 | $713 |
| Average of WA2_DemandCostSummer | $8,972 | $1,455 | $2,481 | $7,195 |
| Average of WA2_DemandCostNonSummer | $2,308 | $365 | $1,845 | $1,666 |
| Average of WA2Total | $13,865 | $2,040 | $4,925 | $9,573 |

## 4.2 Load-shifting

The statistics on load-shifting present the number of periods and kWh shifted for Ergon Energy's proposed 10 hour window and for the shorter 5 hour window. Please refer to Section 3.6 for more information about load-shifting rationale and logic.

| | NMI | | | |
|---|---|---|---|---|
| | Loadshifting 10am-8pm | | Loadshifting 11am-4pm | |
| | No.intervals | kWh | No.intervals | kWh |
| **<100MW** | **551** | **3835** | **224** | **1436** |
| **Winch** | | | | |
| 3042007054 | 556 | 5687 | 220 | 2172 |
| RainDeficitSim B'berg 25kW | 978 | 5748 | 390 | 2083 |
| RainDeficitSim B'berg 40kW | 832 | 7886 | 300 | 2638 |
| Bundaberg 11kW | 542 | 1461 | 220 | 573 |
| Bundaberg 40KW | 542 | 5320 | 220 | 2085 |
| Bundaberg 25KW | 542 | 3323 | 220 | 1303 |
| **Pivot** | | | | |
| 30309955583 | 216 | 21 | 122 | 12 |
| Tablelands25kW | 202 | 1233 | 102 | 621 |
| **>100MW** | **200** | **1936** | **117** | **1122** |
| **Pivot** | | | | |
| Tablelands55kW | 202 | 2731 | 102 | 1377 |
| **Pivots and Furrow** | | | | |
| QEEE7000713 | 342 | 3017 | 216 | 1956 |
| 30310108738 | 56 | 60 | 32 | 34 |

## 4.3 Optional Locational Charge

The total annual electricity bills for small SAC customers assuming the peak window as proposed by Ergon Energy (10am-8pm) are outlined below. The Summer peak charge (WA1) is $80.554/kW/month. Loadshifting in Summer could reduce the bills for winch and pivot irrigators. Winch operators particularly benefit, with savings of around 60%.

| Scale | <100MW |
|---|---|

| Average of WA1Total | NMI | | Difference | |
|---|---|---|---|---|
| Row Labels | None | Loadshifting 10am-8pm | $ | % |
| **Winch** | | | | |
| 3042007054 | $11,025 | $4,324 | -$6,700 | -61% |
| RainDeficitSim Bundaberg 25kW | $5,478 | $2,432 | -$3,046 | -56% |
| RainDeficitSim Bundaberg 40kW | $8,640 | $3,642 | -$4,998 | -58% |
| Bundaberg 11kW | $3,014 | $1,212 | -$1,802 | -60% |
| Bundaberg 25KW | $6,669 | $2,650 | -$4,018 | -60% |
| Bundaberg 40KW | $10,590 | $4,157 | -$6,433 | -61% |
| **Pivot** | | | | |
| 30309955583 | $392 | $361 | -$31 | -8% |
| Tablelands25kW | $9,451 | $8,945 | -$506 | -5% |

Alternatively with a shorter time window 11am-4pm (and with a consequentially increase to the demand charge to $90), the total annual electricity bills for variable LRMCs (a Summer peak charge of $20, $90 or $200/kW/month) are outlined below:

| Scale | <100MW |
|---|---|

| Average of WA2Total | NMI | | | | | |
|---|---|---|---|---|---|---|
| | | None | | | Loadshifting 11am-4pm | |
| Row Labels | 20 | 90 | 200 | 20 | 90 | 200 |
| **Winch** | | | | | | |
| 3042007054 | $5,202 | $11,510 | $21,423 | $3,519 | $3,941 | $4,603 |
| RainDeficitSim B'berg 25kW | $3,305 | $6,351 | $11,138 | $2,432 | $2,432 | $2,432 |
| RainDeficitSim B'berg 40kW | $5,029 | $9,878 | $17,499 | $3,642 | $3,642 | $3,642 |
| Bundaberg 11kW | $1,478 | $3,142 | $5,757 | $1,022 | $1,133 | $1,308 |
| Bundaberg 25KW | $3,177 | $6,960 | $12,904 | $2,168 | $2,420 | $2,818 |
| Bundaberg 40KW | $5,000 | $11,056 | $20,573 | $3,384 | $3,789 | $4,425 |
| **Pivot** | | | | | | |
| 30309955583 | $358 | $404 | $475 | $349 | $365 | $390 |
| Tablelands25kW | $4,947 | $10,153 | $18,333 | $4,822 | $9,588 | $17,079 |

# 5.0 Critical Peak Pricing and Peak Time Rebates

Critical peak periods are typically several hours long on a given day, and occur up to 10 times per year, possibly during heat waves. Customers would be informed of a Critical Peak Pricing (CPP) event at least a day in advance. With critical peak pricing, those consumers who can reduce their energy use on those days, or already have lower energy use, will save money, whereas others won't.

With CPP pricing it is assumed that cane growers would choose not to irrigate their crops on any critical peak days, hence avoiding CPP charges altogether. This would have the same effect on bills as removing any peak charges. The benefits of this are calculated accordingly.

The value of the Peak Time Rebate (PTR) is estimated to be only 50% of 'demand' value attributed to a CPP, owing to the risks under a PTR being shared between consumers and the network.

With CPP, the composition of annual electricity bills for SAC Small customers are set out in the first three columns, with the total bill in column "Average of CPP_WA1". The charge under a PTR is set out in the last column.

| Scale | <100MW | | | | Charge Avoided | |
|---|---|---|---|---|---|---|
| | **Values** | | | | | |
| **Row Labels** | **Average of WA1_Fixed Cost** | **Average of WA1_Energy Cost** | **Average of WA1_Demand CostNon-Summer** | **Average of CPP_WA1** | **Average of WA1_Demand CostSummer** | **Peak Time Rebate** |
| **Winch** | | | | | | |
| 3042007054 | $0 | $1,758 | $1,640 | $3,399 | $4,489 | $2,245 |
| RainDeficitSim B'berg 25kW | $0 | $1,390 | $1,042 | $2,433 | $1,897 | $948 |
| RainDeficitSim B'berg 40kW | $0 | $2,042 | $1,600 | $3,642 | $3,084 | $1,542 |
| Bundaberg 11kW | $0 | $448 | $539 | $987 | $1,181 | $590 |
| Bundaberg 25KW | $0 | $1,054 | $1,041 | $2,095 | $2,692 | $1,346 |
| Bundaberg 40KW | $0 | $1,688 | $1,581 | $3,269 | $4,310 | $2,155 |
| **Pivot** | | | | | | |
| 30309955583 | $0 | $21 | $324 | $345 | $31 | $15 |
| Tablelands25kW | $0 | $2,227 | $1,232 | $3,460 | $5,732 | $2,866 |

For SAC Large users, annual electricity bills would be –

| Scale | >100MW | | | | Charge Avoided | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | Values | | | | | |
| Row Labels | Average of Lg1_FixedCost | Average of Lg1_EnergyCost | Average of Lg1_DemandCostNonSummer | Average of CPP_Lg1 | Average of Lg1_DemandCostSummer | Peak Time Rebate |
| **Pivot** | | | | | | |
| Tablelands55kW | $11,680 | $3,532 | $0 | $15,212 | $1,054 | $527 |
| **Pivots and Furrow** | | | | | | |
| QEEE7000713 | $11,680 | $3,861 | $79 | $15,620 | $596 | $298 |
| 30310108738 | $11,680 | $11,136 | $2,766 | $25,582 | $2,800 | $1,400 |

# 6.0 Discussion

## 6.1 Consumer classification and tariffs

In ATA's view, there is a clear case for there to be a range of network tariffs available that reflects the nature of irrigators having a higher-than-average load factor compared to other consumers, and being

- interruptible at times of critical peak in the case of furrow irrigation, and
- able to be operated in the off-peak in the case of winch and low pressure overhead irrigation.

In this respect, for the purpose of tariff design in the context of the current network tariff rules, it would appear appropriate that irrigators are treated as a separate class of energy consumer in regions where they constitute a significant portion of the overall consumer base. For example:

- Tariffs for furrow irrigators could include critical peak pricing to provide an incentive for those irrigators to switch off loads during critical peak summer days, as determined by Ergon, on which demand peaks or network constraints may occur.
- Other irrigation tariffs would have peak and off-peak rates, with
  - A daily (or weekday) peak period of no more than 4 or 5 hours for any location. ATA's analysis considered an 11am to 4pm peak window, which would suit some locations but not others. For example, a 3pm to 8pm period may be more appropriate in locations where residential use has more effect on peak demand, and
  - off peak periods
    - being all other times,
    - having low enough charges to incentivise more energy use, and
    - not being subject to 'any-time' peak demand charges (such as the off-peak demand charge proposed by Ergon).

## 6.2 Long Run Marginal Costs (LRMC)

There is a lack of reliable and granular information of the incidence of costs across Ergon's network. Ergon Energy also do not differentiate between customer types and voltage connection levels. In ATA's view, this approach should be questioned. Our discussion with Ergon Energy about their process of converting LRMC to a summer tariff is included in Appendix A below.

## 6.3 Assessment of consumer impacts

ATA appreciates the effort Ergon Energy's efforts in providing us with some meter data to assist this assessment of the impacts of different tariff options. Given the lack of capture and retention of existing interval meter data, we question however whether Ergon can, or do, adequately analyse the impact of proposed network tariffs on different classes of customers.

## 6.4 Load shifting

Based on the tariffs proposed by Ergon, load shifting has different effects according to whether the irrigator's energy use is <100MWh or >100MWh.

For SAC Small customers

- Load shifting only makes sense in summer months. There is no financial benefit to load shifting at other times, as non-summer demand charges occur at anytime (compared to summer demand charges). This appears to reflect the lack of network constraints outside of summer months. While lower capacity pumps or VSDs would reduce the non-summer peak demand, the charge itself is so low that any upfront cost appears unlikely to pay for itself.
- Some small SAC customers may be able to shift the whole of their loads out of the peak window, bringing the Summer peak demand charge down to zero. An example is the Simulated 25kW Bundaberg winch. This irrigator has Summer peak loads of 12-18kWh which are able to be shifted to another period.

Large SAC customers – None of the load profiles analysed resulted in decreased bills as a result of load shifting. Load shifting would only be useful if it impacts maximum monthly demand charge. Two examples included:

- Pivot and Furrow SAC Large NMI 30310108738, 60kWh shifted (with period 10am-8pm) but didn't impact bills because it didn't change maximum monthly demand.
- The simulated Tablelands pivot 55kW shifted 2,731 kWh, with no effect on bills as the maximum monthly demand during the peak window was unchanged.

# 7.0 Appendix A – Relationship Between LRMC and Demand Charges

**From:** CROWN Brendon (Ergon) [mailto:brendon.crown@ergon.com.au]
**Sent:** Thursday, 8 October 2015 11:05 PM
**To:** Craig Memery
**Cc:** 'Warren Males'; Kate Leslie; COLLINS Sara (FN)
**Subject:** RE: Questions for Ergon - relationship between LRMC and demand charges

Hi Craig
My apologies for not getting back to you earlier. I have been out of the office this week.
There is a reasonably complex but necessary process in converting the LRMC calculation to a customer's tariff. I will try and provide more context and references when I am back in the office. Hopefully the below explanation can suffice for now.
Our LRMC value by voltage type is calculated on a $ per KVA per annum. We have not applied the full LRMC value to our peak charge in all circumstances. The LRMC value we calculated was based on the capital expenditure, growth and WACC assumptions in our October 2014 regulatory proposal. We will need to review LRMC calculations (presumably downward) with the outcome at the end of this month. We also need to balance cost reflectivity with customer impact, particularly as our LRMC based tariffs are "opt in" for customers.
We apply this LRMC (peak charge) value to the peak time period. To do this we need to allocate the $/KVA/year value to the months (summer) and periods in which LRMC will be allocated. We also take into account the level of diversity or the likelihood that the customers demand will coincide with the network peak. All this is done to ensure we don't over-recover the LRMC through the peak charge.
In summary, the peak charge is the application of the LRMC value to the periods most likely to contribute to incremental investment in the network. The off-peak demand charge does not recover LRMC. We use a combination of off-peak demand, fixed and energy charges to recovery the non-LRMC or residual costs
I will try and get to the specifics of the numbers when I get back to the office. From memory, one of the tables in the consultation paper represented the regulated retail tariff (which would incorporate both retail and network elements) which caused concern for another stakeholder.
Thanks again for your ongoing interest.

**Brendon Crown**
**P** 07 3851 6785 **F** 3851 6780 **M** 0400 384 894
**ergon.com.au**

**From:** Craig Memery [mailto:craig.memery@ata.org.au]
**Sent:** Monday, 5 October 2015 4:25 PM
**To:** CROWN Brendon (Ergon)
**Cc:** 'Warren Males'; Kate Leslie; COLLINS Sara (FN)
**Subject:** FW: Questions for Ergon - relationship between LRMC and demand charges

Hi Brendan, hope you are well
We are working with CANEGROWERS to understand the impacts of proposed tariffs and understand different tariff options for food and fibre producers.
We have the following questions about Ergon's approach to LRMC:
How has the peak Summer charge been calculated?
How has the non Summer peak charge been calculated?
How was LRMC calculated?

What is the relationship between the LRMC and the Summer peak charge?
The purpose of these questions is to help us to apply credible charges to revised structures that we are testing for our own analysis.
Please copy Kate (cc'd) into these communications.
Cheers,
Craig

**From:** Kate Leslie
**Sent:** Monday, 5 October 2015 4:39 PM
**To:** Craig Memery
**Subject:** Questions for Ergon - relationship between LRMC and demand charges

Hi Craig,
On p17 of Ergon's June Consultation paper, the only reference to "application of LRMC to tariffs" is this -

> *For SAC <100 MWh p.a. – application to the average of the customer's demand recorded during peak times for the highest four peak demand days in the month in the SToUD tariff and equalisation of the peak and shoulder energy rates in the Season ToU Energy (SToUE) tariff*

As they say on page 18 -

> *"We have been consulting with customers on our approach to calculating the LRMC. We released*
> *the following papers this year:*
> *Aligning Network Charges to the Cost of Peak Demand*
> *Long Run Marginal Cost Considerations in Developing Network Tariffs*
> *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network*
> *The Case for Demand Based Tariffs.*[6]*"*

I've had a quick peek at the first two documents, but I haven't seen anything that helps us understand how they get from LRMC of $189 per kW per annum (e.g SAC < 100 MWh p.a. Business, East) to proposed Summer peak charge of $80.554 per kW per month for a customer's Top 4 days.
So I've got questions for Ergon around "How's the peak Summer charge been calculated? How's the non Summer peak charge been calculated? What is the relationship between the LRMC and the Summer peak charge? How was that calculated?"
Thanks,
Kate

# 8.0 Appendix B – Dr Martin Gill's Interval Data Files

**Introduction**

While many of the electricity meters installed on the irrigation pumps are programmed to store interval data, Ergon does not collect the interval data. The only interval data made available for this analysis was provided by a special meter read. The number of days of data is therefore limited to the limited storage internal to the meter.

Compounding the problem was that many of the meters contain less than 6 months of data. With the special meter read being performed in September this 6 month period coincides with the period during which many canegrowers do not irrigate their crops rendering the files useless.

Of the interval data files obtained from Ergon only 10 contain more than 6 months of data.

The interval data was also obtained from canegrowers using a variety of irrigation methods. For this analysis only pivot and winch irrigation was required (so sites with Furrow Irrigation were to be ignored)

A summary of all files containing more than 6 months of data are shown in the following table.

| NMI | Data Avail | File name | Irrig Type | Region |
|---|---|---|---|---|
| 3033626847 | >12Months | 3033626847_91310455_LS1 | Furrow | Burdekin |
| 3041667174 | >12Months | 3041667174 | Furrow | Bundaberg |
| 3041667905 | >12Months | 3041667905 | Furrow | Bundaberg |
| 3042007054 | >12Months | 3042007054 | Winch | Bundaberg |
| 3052073629 | >12Months | 3052073629_91310276_ LS1 | Furrow | Burdekin |
| QEEE7000713 | >12Months | FT100_0010_Ft0010_20150909092547_91015349_ls1 | Pivots and furrow | Tableland |
| 30309955583 | >12Months | FT100_0010_Ft0010_20150909092615_91122292_ls1 | Pivot | Tableland |
| 30310108738 | >12Months | FT100_0010_Ft0010_20150909092625_91215749_ls1 | Pivots and furrow | Tableland |
| 3041666585 | 6-12Months | 3041666585 | Furrow | Bundaberg |
| 3041667018 | 6-12Months | 3041667018 | Furrow | Bundaberg |

The two useful interval data files are highlighted in the table and are analysed in the following sections.

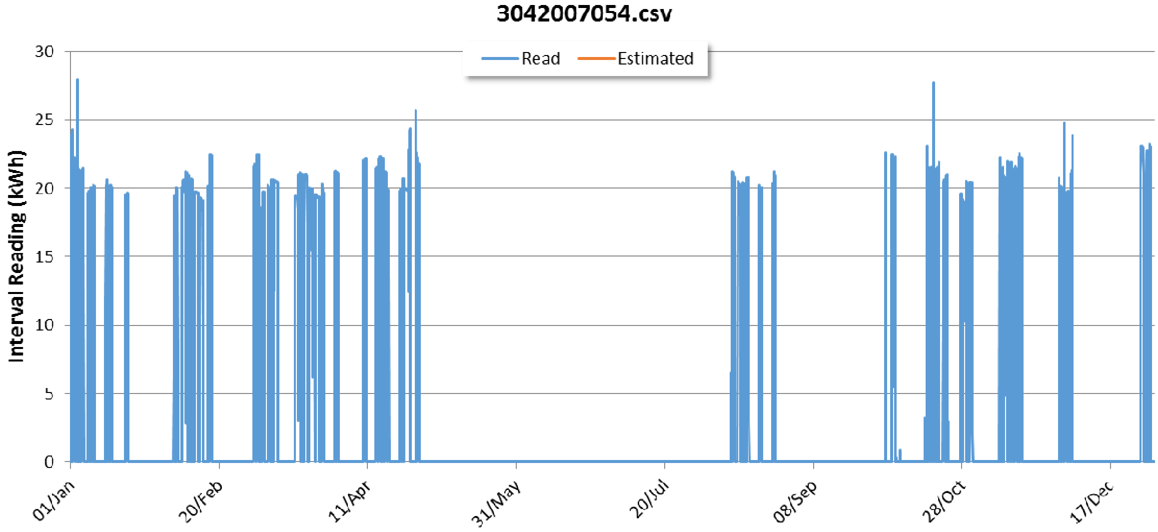
**Processing**

The required interval data files are to cover the 1st Jan 2016 to 31st Dec 2016. To achieve this the existing interval data is read and then copied to the closest date corresponding to the same day of the week). For example the specified year is a leap year so interval data for 29th Feb 2016 (a Monday) is copied from Monday 2nd March 2015.

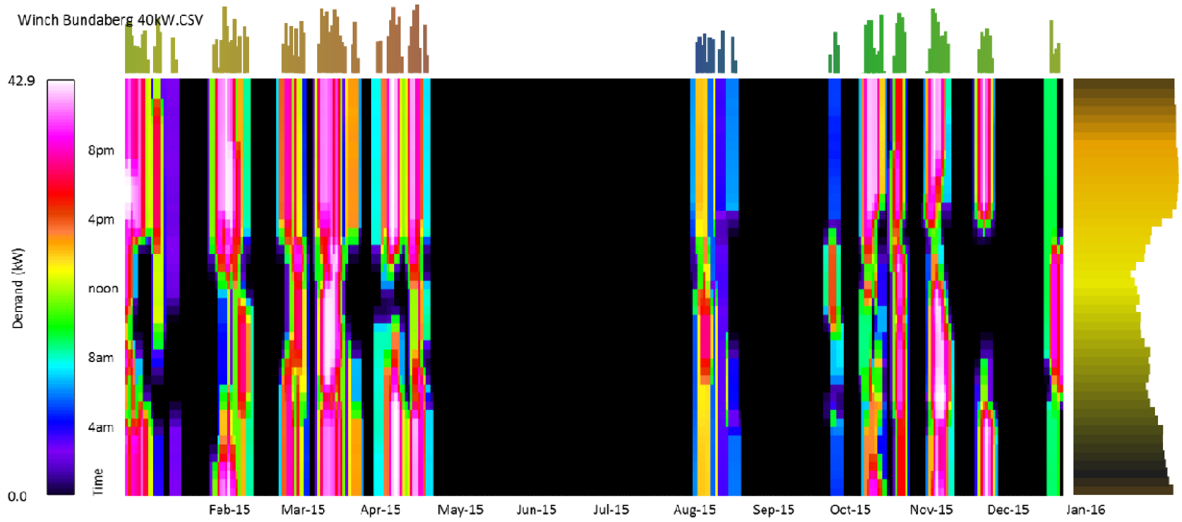
The program also allows the output to be scaled, clipped (to remove large unexplained demand peaks) and manually adjusted.

**Bundaberg Winch (NMI 3042007054)**

This site has a pump with a demand of 80kW. Most of the other sites appeared to use pumps with a demand of 40kW. The file was therefore scaled to a demand of 40kW.




The file has been saved as Winch Bundaberg 40kW.csv. The heat plot for this file is shown below:

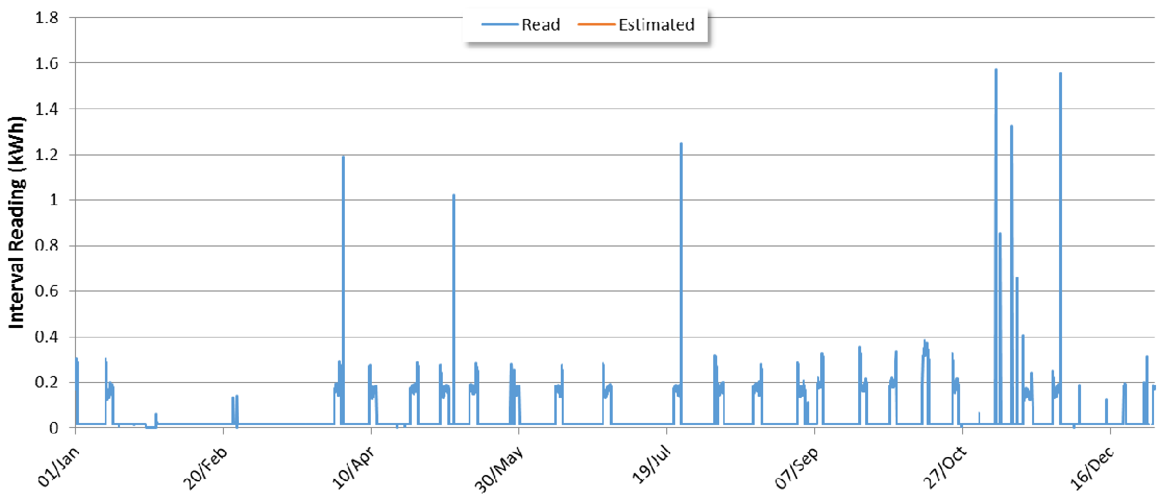



The pump run times for Winch Bundaberg 40kW.csv are show in Appendix A.

Two other pump sizes have also been provided corresponding to 11kW (Winch Bundaberg 11kW.csv) and 25kW (Winch Bundaberg 25kW.csv).

**Pivot Tablelands (NMI 30309955583)**
The raw data are shown in the following figure

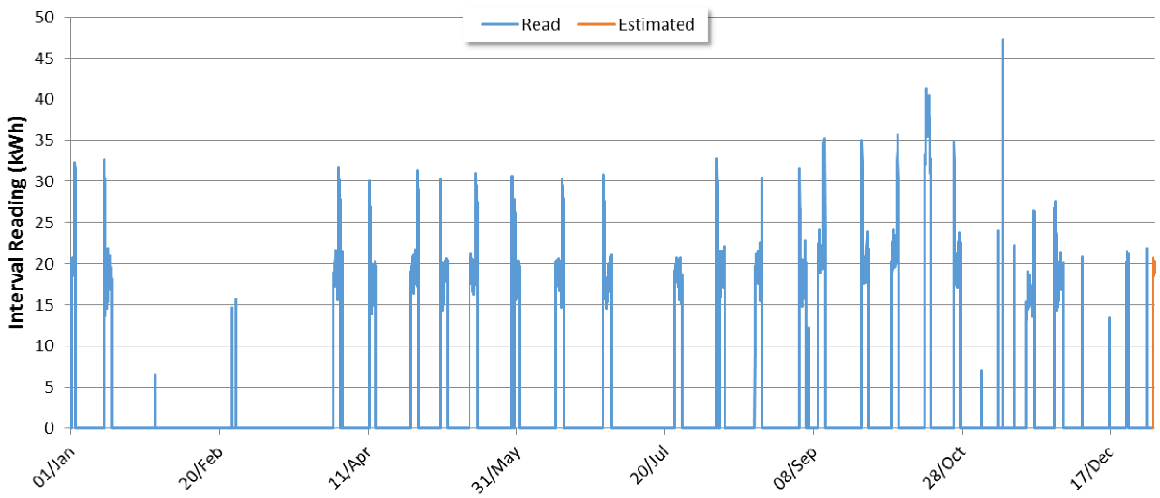
FT100_0010_Ft0010_20150909092615_91122292_ls1.xlsx



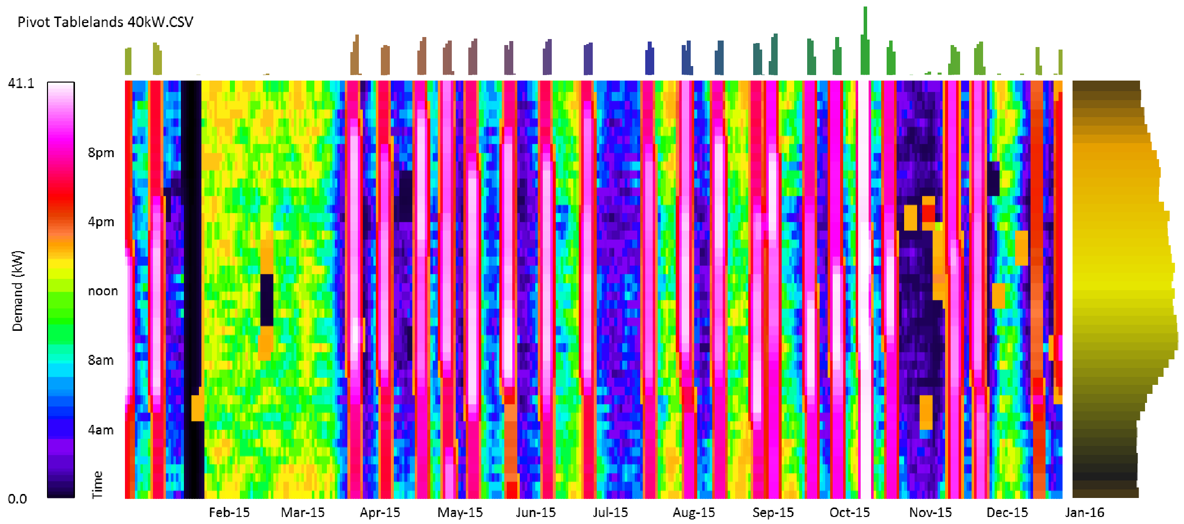

This file is suspicious for two reasons. Firstly the kWh demand is unrealistically low clearly there is an error in the entered transformer factor) and secondly the file shows significant large peaks.

The adjusted file therefore has been scaled to the assumed demand of 40kW and the suspiciously large peaks have been reduced. The final profile is shown below:

FT100_0010_Ft0010_20150909092615_91122292_ls1.xlsx




The file has been named Pivot Tablelands 40kW.csv. The heat plot for this file is shown below:




Note that the average daily profile shown on the right hand side of the heat plot indicates that irrigation starts in the morning and continues throughout the day (unlike winch irrigation which attempts to avoid windy periods in the middle of the day).

The pump switch times for Pivot Tablelands 40kW.csv are shown in Appendix A.

Two other pump sizes have been created Pivot Tablelands 11kW (an 11kW pump size) and Pivot Tablelands 25kW (a 25kW pump size).

**Creating Simulated Interval Data Files**
**Based on Effective Water Deficit**

Canegrowers have prepared a report “Irrigation Energy Cost Relationship”. The report highlights the importance of using irrigation to recover the water deficit. Specifically canegrowers only irrigate when useful natural rainfall does not satisfy crop demand (reducing crop stress increases the yield).

A key table from the report shows average *EFFECTIVE* water deficit in the Bundaberg region. The effective water deficit takes into account varying crop needs throughout the growing season. It is emphasised that it is insufficient to look at average rainfall figures, since not all rainfall is useful, for example in a heavy downpour much of the rainfall runs off and does not contribute to soil moisture. The table from the report is shown below:

| Farm monthly crop moisture demand<br>Irrigation demand | Sept | Oct | Nov | Dec | Jan | Feb | Mar | April | May |
|---|---|---|---|---|---|---|---|---|---|
| Average crop effective deficit (mm/mth) | -13 | -34 | -64 | -70 | -73 | -49 | -58 | -50 | -12 |

**Creating simulated interval data files using the effective deficit**

An Excel Macro has been written which enables the creation of irrigation pump interval data files. A simple model is used to convert the monthly effective water deficit into the pump runtimes. A number of parameters are used to convert the effective deficit into an interval data file.

The fundamental input to the simulated files is the effective average rainfall deficit. Since the interval data files are required to cover a full year the effective water deficit figures in the Bundaberg region for a full year become:

| Bundaberg | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Effective Deficit (mm) | -73 | -49 | -58 | -50 | -12 | 0 | 0 | 0 | -13 | -34 | -64 | -70 |

The parameters used to convert the effective deficit into interval data were inferred from another table included in the Canegrowers report "Irrigation Energy Cost Relationship". Specifically their Scenario 1

1. Travelling irrigator operating 22 hrs per day during peak demand period (start 4.00 pm stop 2.00 pm next day) – crop stress days nil – maximises production

   Wind effect – strongest mid-afternoon 3.00 pm (partially avoided) – the system is shut down for 50% of highest wind period (1.00 – 5.00 pm daily)

   Current most suitable tariff 66

| Ha per system | Operating hrs/day | Lane spacing (m) | Irrigated ha/day | Flow rate L/sec | ML/pumped per day | Rain eq (mm/irrig) | Irrigation cycle (days) | Avail moisture mm/day |
|---|---|---|---|---|---|---|---|---|
| 30 | 22 | 75 | 3.0 | 25 | 1.98 | 65 | 10 | 6.5 |

The critical parameters are the Crop Area, Hours of Operation, Rate of Coverage and Flow Rate which were implemented in the Excel macro as shown in the following table:

| Parameters | Value | Unit |
|---|---|---|
| Crop Area (per system) | 30 | Ha |
| Irrigation Cycle (min) | 10 | days |
| Flow Rate | 25 | litres/sec |
| Inefficiency | 20% | |
| Pump Start Time | 16:00 | |
| Pump Stop Time | 14:00 | |
| Pump Demand | 40 | kW |
| Coverage Rate | 0.136 | Ha/hr |
| Random Start | 60 | minutes |
| Random Stop | 120 | minutes |
| Random Demand | 5% | |

**Description of the parameters**
"Crop Area" is the irrigated size of the Crop (in Hectares)

"Coverage Rate" is the speed of the irrigation system or the number of Hectares of the crop covered per hour.

These two figures allow the time for the irrigation system to cover the required crop area

$$Time\ To\ Water\ Whole\ Crop = \frac{Crop\ Area}{Coverage\ Rate}$$

Assumption: Each time irrigation is undertaken the Crop Area will be covered. Hence the total time the irrigation system is used each month with be an integral number of times multiplied by the Time to Water the Whole Crop.

Flow Rate is the number of litres delivered per second. This is used to calculate the Equivalent Rainfall per hour of operation of the irrigation system.

$$Equivalent\ Rainfall\ per\ hour = 0.36 \times \frac{Flow\ Rate}{Coverage\ Rate}$$

Pump Start Time and Pump Stop Time: Typically Canegrowers attempt to avoid particular times of the day. For example high winds in the middle of the day make winch irrigation much less effective, so irrigation during these hours is avoided.

$$Operating\ Hours\ per\ Day = Pump\ Stop\ Tme - Pump\ Start\ Time$$

Random Start and Random Stop: Pumps are typically manually started and stopped hence the actual start and stop time vary each time the pump is used. These parameters have been added to make the profiles more realistic. For example in the above table the parameters assume the pump may be started an hour either side of the start time and stopped 2 hours either side of the stop time.

Inefficiency: Not all the applied water is useful. The inefficiency factor is used to adjust the Monthly effective deficit to the Number of mm of water that must be applied to the crop.

$$Water\ Requirement\ = Effective\ Monthly\ Deficit\ x\ (1 + Inefficiency)$$

The above figures are sufficient to calculate the Average Gap Between Runs.

Total Hours (of irrigation) per Month

$$Total\ Hours\ Per\ Month = \frac{Time\ to\ Water\ Whole\ Crop\ \times Water\ Requirement}{Equivalent\ Rainfall\ per\ hour}$$

Number Of Times to Run per month

$$Number\ of\ Times\ to\ Run = \frac{Total\ Hours\ Per\ Month}{Operating\ Hours\ per\ Day}$$

Note the Number of Times to Run is always converted into the next largest integer value (Ceiling())

$$Average\ Gap\ Between\ Runs = \frac{Days\ In\ Month}{Number\ of\ Times\ To\ Run}$$

The first time the pump is turned on is the first day of the month + Average Gap Between Runs / 2

The other parameters scale the electricity usage for the installed pump size

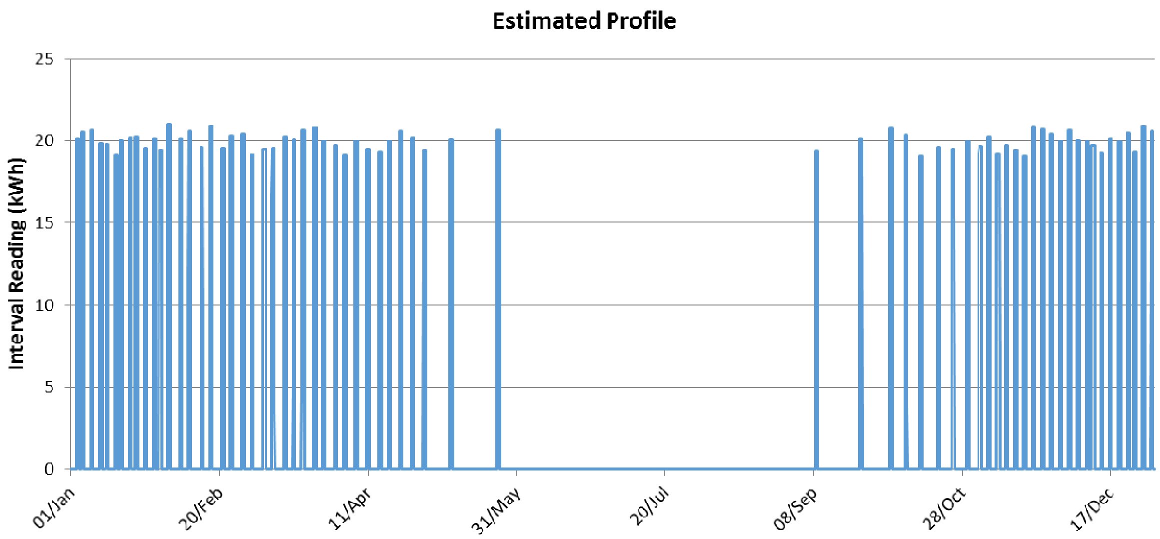
Pump Demand is the nominal rating of the pump (in kW)

Random Demand is used to vary the Pump Demand each time the pump is turned on

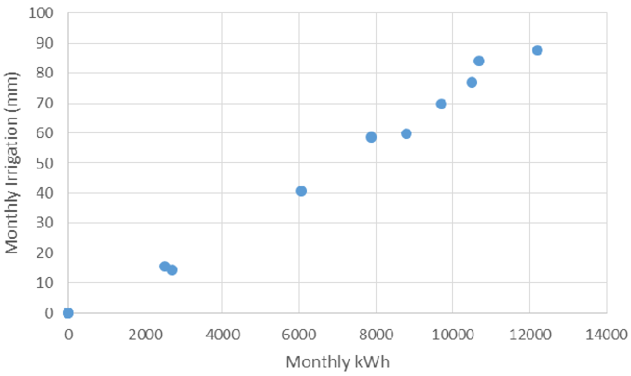
Irrigation Cycle (min) is not currently implemented. It is intended to limit the minimum Average Gap between Runs. (A similar result can be achieved by changing the monthly Rainfall deficit figure).

**Example Simulated file**

Using the effective deficit for Bundaberg and parameters shown above results in the profile

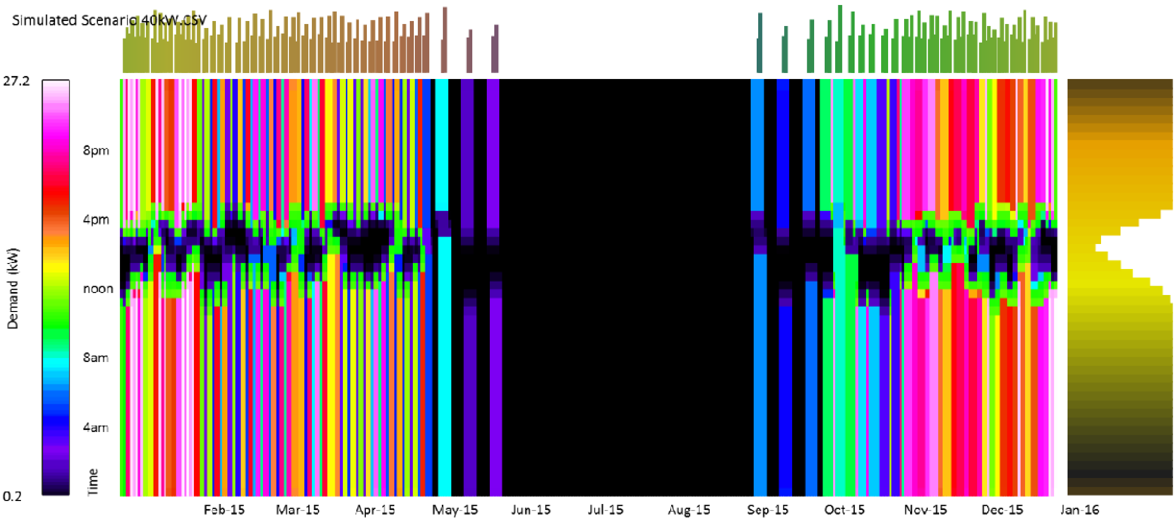



Creating the interval data profile based on the effective water requirements ensures that pump electricity use and water application are directly related. This is confirmed by plotting monthly irrigation target (in mm) again electricity use (in kWh).




The above interval data file has been saved as Simulated Scenario 40kW.csv. The corresponding pump turn on and off times are shown in Appendix A.

The heat plot for this file is




The V shape in the average daily profile shown on the right hand side corresponds to the avoided times of the day.

**Comment on Algorithm Accuracy**

The accuracy of the simulated files is directly related to the algorithm and input parameters.

It is clearly stated that both the algorithm and corresponding parameters were created by someone with no special knowledge of irrigation systems. Specifically it remains unclear how (or even if) the same simulation methodology can be used to create files representing pivot and winch operation.

Given the high level of uncertainty around the simulation methodology minimal error checking of the input parameters has been implemented. The entry of unreasonable input parameters results in program crashes and/or the production of unrealistic profiles.

**Acknowledged Issues with the Simulation Methodology**

Several parameters are reasonably linked. A larger pump is required to water larger Crop Areas.

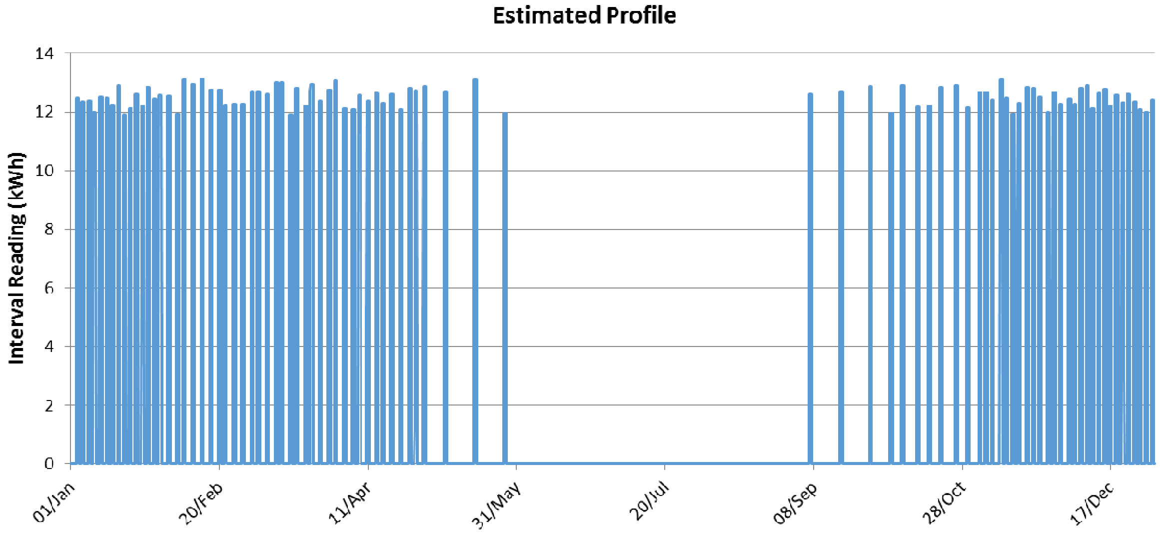
It is unclear if installed irrigation systems provide adjustment of Flow Rate and Coverage Rate. Such adjustment would allow growers fine control of the effective amount of water applied each time the crop is irrigated. It is apparent that these parameters are also likely to be related to the pump size.

A request was received very late in the development to add the capability to simulate the response to particular tariffs. This has only been partially implemented. The Pump Start and Pump Stop times provide one means of adjusting pump use in response to tariffs. Several current tariffs also offer off peak rates for the entire weekend. The program does not currently support an option to run the pumps continuously over the weekend.

While not confirmed it has been assumed that the implemented algorithm is describing winch irrigation. This assumption is based on the need to avoid winch irrigation when windy, in the middle of the day. By contrast pivot irrigation appears to be run continuously.

**Another Simulated File**
Modifying the other parameters results in different profiles. For example an attempt at lowering the size of the pump (down to 25kW) has been simulated by reducing the flow rate and the size of the Crop Area (rightly or wrongly the Coverage Rate was left the same)

| **Parameters** | | |
|---|---|---|
| Crop Area (per system) | 20 | Ha |
| Irrigation Cycle (min) | 10 | days |
| Flow Rate | 15 | litres/sec |
| Inefficiency | 20% | |
| Pump Start Time | 17:00 | |
| Pump Stop Time | 13:00 | |
| Pump Demand | 25 | kW |
| Coverage Rate | 0.136 | Ha/hr |
| Random Start | 30 | minutes |
| Random Stop | 60 | minutes |
| Random Demand | 5% | |




This file has been saved as Simulated Scenario 25kW.csv.

Creating a profile based on an automated system is also possible. When the pumps are started and stopped automatically then the Random Start and Random Stop time should be set to a small value.

**Profiles for the Tablelands Region**
Late in the development of the simulated profiles the effective water deficit for Cane crops in the Tablelands Region was provided. It is repeated here only for reference:

| Tableland | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Effective Deficit (mm) | 150 | 28 | 32 | 0 | 30 | 52 | 25 | 49 | 65 | 76 | 114 | 114 |

**Create Pump Profiles from Start and Stop times**

A second method was proposed to create interval data. This method uses pump start and stop times. The following table was included in the document "Pivot Tablelands.dox".

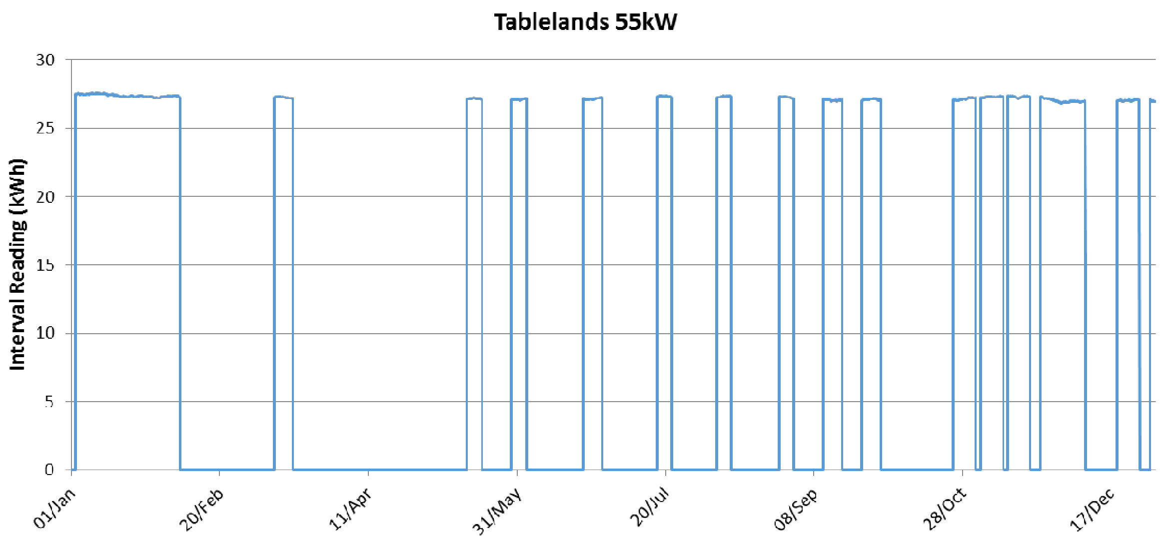
| Pump Start Date | Start Time | Pump Stop Date | Stop Time | Water Applied (mm) |
|---|---|---|---|---|
| 2/1/15 | 06:19 | 8/1/15 | 13:19 | 32 |
| 8/1/15 | 13:19 | 14/1/15 | 20:19 | 32 |
| 14/1/15 | 20:19 | 23/1/15 | 23:01 | 50 |
| 23/1/15 | 23:01 | 31/01/15 | 5:55 | 32 |
| 31/01/15 | 05:55 | 6/02/15 | 12:55 | 32 |
| 10/03/15 | 07:51 | 16/03/15 | 14:51 | 32 |
| 14/05/15 | 05:20 | 19/05/2015 | 04:20 | 25 |
| 29/05/15 | 06:46 | 03/06/15 | 05:46 | 25 |
| 22/06/15 | 07:50 | 28/06/15 | 14:50 | 32 |
| 17/07/15 | 06:23 | 22/07/15 | 05:23 | 25 |
| 06/08/15 | 05:08 | 11/08/15 | 04:08 | 25 |
| 27/08/15 | 06:51 | 01/09/15 | 05:51 | 25 |
| 11/09/15 | 06:50 | 17/09/15 | 13:50 | 32 |
| 24/09/15 | 05:25 | 30/09/15 | 12:25 | 32 |
| 17/10/15 | 06:27 | 24/09/15 | 20:27 | 38 |
| 24/10/15 | 20:27 | 1/11/15 | 10:27 | 38 |
| 03/11/15 | 07:12 | 10/11/15 | 21:12 | 38 |
| 12/11/15 | 5:09 | 19/11/15 | 19:09 | 38 |
| 23/11/15 | 05:46 | 30/11/15 | 19:46 | 38 |
| 30/11/15 | 19:46 | 08/12/15 | 9:46 | 38 |
| 19/12/15 | 05:22 | 26/12/15 | 19:22 | 38 |
| 30/12/15 | 05:19 | 06/01/16 | 19:19 | 38 |

Several of the pump stop times are the same as start times meaning that the pump was actually left on continuously (the longest continuous period was from the 2nd Jan to the 6th Feb).

A note in the accompanying email detailed the pump size for the above data:

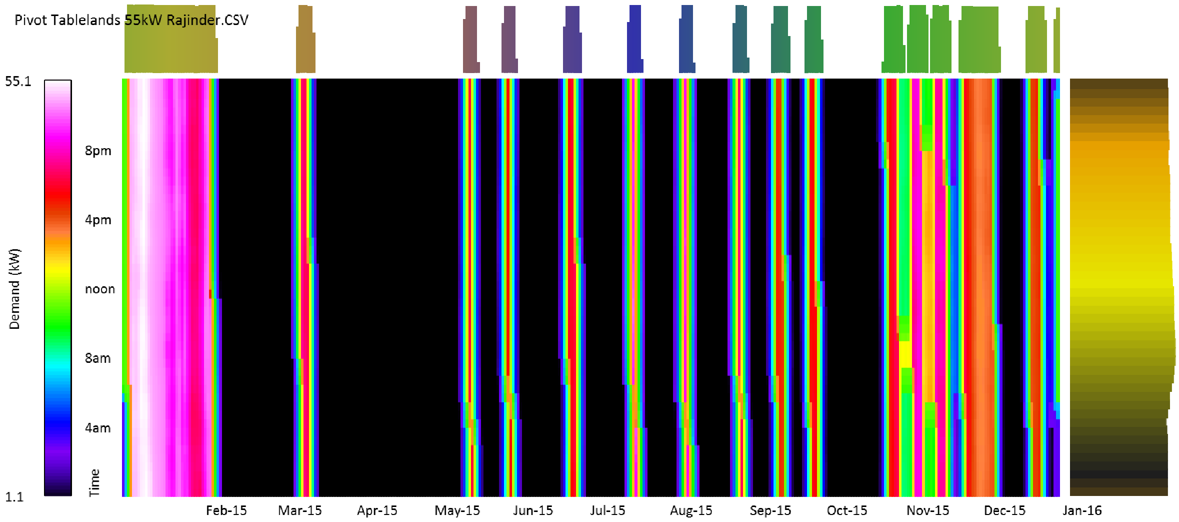
This pivot waters 80ha and uses a 25 kW water. This motor is smaller than what is typical for the Tableland because for this particular location the centre of the pivot is at the highest part of the paddock. A 55kW motor would be the most common size on the Tableland.

For this reason two files have been created from the table of start and stop times, one with a pump size of 25kW (Pivot Tablelands 25kW.csv) and the second with a pump size of 55kW (Pivot Tablelands 55kW.csv). The final profile for the 55kW pump is shown below.



Note that a small amount of randomisation has been applied to the half hourly pump demand to make the profile look more realistic.

The heat plot for this file is shown below:



**Pump Run Times for files**

A separate program will create a simulated profile from entered pump start and stop times. Analysis of the existing files shows the start and stop times.

Winch Bundaberg xxkW.csv

| | | | |
|---|---|---|---|
| Thu, 01/Jan/2015 | 07:44 | Thu, 01/Jan/2015 | 16:30 |
| Thu, 01/Jan/2015 | 16:18 | Fri, 02/Jan/2015 | 10:00 |
| Fri, 02/Jan/2015 | 14:38 | Sat, 03/Jan/2015 | 05:00 |
| Sat, 03/Jan/2015 | 05:50 | Sat, 03/Jan/2015 | 07:00 |
| Sat, 03/Jan/2015 | 10:12 | Sat, 03/Jan/2015 | 20:00 |
| Sun, 04/Jan/2015 | 14:41 | Mon, 05/Jan/2015 | 10:00 |
| Tue, 06/Jan/2015 | 14:44 | Wed, 07/Jan/2015 | 06:00 |
| Wed, 07/Jan/2015 | 15:11 | Thu, 08/Jan/2015 | 07:30 |
| Thu, 08/Jan/2015 | 15:43 | Fri, 09/Jan/2015 | 06:00 |
| Mon, 12/Jan/2015 | 14:55 | Tue, 13/Jan/2015 | 04:58 |
| Tue, 13/Jan/2015 | 07:44 | Tue, 13/Jan/2015 | 23:30 |
| Wed, 14/Jan/2015 | 09:28 | Thu, 15/Jan/2015 | 01:00 |
| Mon, 19/Jan/2015 | 10:40 | Tue, 20/Jan/2015 | 06:00 |
| Wed, 04/Feb/2015 | 13:14 | Thu, 05/Feb/2015 | 04:00 |
| Thu, 05/Feb/2015 | 14:06 | Fri, 06/Feb/2015 | 03:00 |
| Sat, 07/Feb/2015 | 12:06 | Mon, 09/Feb/2015 | 07:00 |
| Mon, 09/Feb/2015 | 14:11 | Tue, 10/Feb/2015 | 04:00 |
| Tue, 10/Feb/2015 | 15:44 | Wed, 11/Feb/2015 | 02:00 |
| Wed, 11/Feb/2015 | 12:56 | Thu, 12/Feb/2015 | 21:00 |
| Fri, 13/Feb/2015 | 14:23 | Sat, 14/Feb/2015 | 15:00 |
| Mon, 16/Feb/2015 | 05:28 | Mon, 16/Feb/2015 | 12:00 |
| Mon, 16/Feb/2015 | 14:39 | Tue, 17/Feb/2015 | 13:00 |
| Tue, 03/Mar/2015 | 14:25 | Wed, 04/Mar/2015 | 08:30 |
| Wed, 04/Mar/2015 | 14:47 | Thu, 05/Mar/2015 | 10:00 |
| Fri, 06/Mar/2015 | 06:10 | Sat, 07/Mar/2015 | 07:30 |
| Sun, 08/Mar/2015 | 07:38 | Mon, 09/Mar/2015 | 06:00 |
| Mon, 09/Mar/2015 | 13:24 | Mon, 09/Mar/2015 | 15:30 |
| Tue, 10/Mar/2015 | 05:33 | Wed, 11/Mar/2015 | 15:30 |
| Tue, 17/Mar/2015 | 13:39 | Thu, 19/Mar/2015 | 13:30 |
| Thu, 19/Mar/2015 | 16:30 | Fri, 20/Mar/2015 | 06:00 |
| Fri, 20/Mar/2015 | 06:44 | Fri, 20/Mar/2015 | 13:30 |
| Fri, 20/Mar/2015 | 14:07 | Sat, 21/Mar/2015 | 15:30 |
| Sun, 22/Mar/2015 | 07:12 | Tue, 24/Mar/2015 | 06:00 |
| Tue, 24/Mar/2015 | 08:30 | Wed, 25/Mar/2015 | 14:55 |
| Thu, 26/Mar/2015 | 13:38 | Fri, 27/Mar/2015 | 11:00 |
| Mon, 30/Mar/2015 | 14:26 | Tue, 31/Mar/2015 | 09:26 |
| Tue, 31/Mar/2015 | 14:38 | Wed, 01/Apr/2015 | 06:00 |
| Thu, 09/Apr/2015 | 13:57 | Fri, 10/Apr/2015 | 11:30 |
| Mon, 13/Apr/2015 | 12:13 | Tue, 14/Apr/2015 | 09:00 |
| Tue, 14/Apr/2015 | 14:27 | Wed, 15/Apr/2015 | 12:00 |
| Wed, 15/Apr/2015 | 13:39 | Thu, 16/Apr/2015 | 07:30 |
| Thu, 16/Apr/2015 | 14:03 | Fri, 17/Apr/2015 | 11:30 |
| Fri, 17/Apr/2015 | 15:10 | Sat, 18/Apr/2015 | 07:00 |
| Tue, 21/Apr/2015 | 14:25 | Wed, 22/Apr/2015 | 06:30 |
| Wed, 22/Apr/2015 | 12:50 | Thu, 23/Apr/2015 | 05:55 |
| Thu, 23/Apr/2015 | 07:13 | Sat, 25/Apr/2015 | 09:00 |
| Mon, 27/Apr/2015 | 05:44 | Mon, 27/Apr/2015 | 08:00 |
| Mon, 27/Apr/2015 | 08:31 | Mon, 27/Apr/2015 | 14:00 |
| Mon, 27/Apr/2015 | 14:37 | Tue, 28/Apr/2015 | 07:00 |
| Tue, 11/Aug/2015 | 11:14 | Tue, 11/Aug/2015 | 13:00 |
| Tue, 11/Aug/2015 | 13:35 | Wed, 12/Aug/2015 | 13:30 |
| Thu, 13/Aug/2015 | 14:44 | Fri, 14/Aug/2015 | 15:30 |
| Sat, 15/Aug/2015 | 07:16 | Sat, 15/Aug/2015 | 12:30 |
| Sun, 16/Aug/2015 | 12:00 | Mon, 17/Aug/2015 | 13:00 |

| | | | |
|---|---|---|---|
| Thu, 20/Aug/2015 | 16:09 | Fri, 21/Aug/2015 | 16:30 |
| Tue, 25/Aug/2015 | 05:12 | Tue, 25/Aug/2015 | 10:00 |
| Tue, 25/Aug/2015 | 15:55 | Wed, 26/Aug/2015 | 05:30 |
| Fri, 02/Oct/2015 | 04:45 | Fri, 02/Oct/2015 | 06:30 |
| Fri, 02/Oct/2015 | 10:40 | Fri, 02/Oct/2015 | 16:30 |
| Sun, 04/Oct/2015 | 10:10 | Mon, 05/Oct/2015 | 11:30 |
| Thu, 15/Oct/2015 | 11:06 | Thu, 15/Oct/2015 | 12:30 |
| Fri, 16/Oct/2015 | 06:24 | Fri, 16/Oct/2015 | 13:26 |
| Fri, 16/Oct/2015 | 14:26 | Sat, 17/Oct/2015 | 08:00 |
| Sat, 17/Oct/2015 | 13:45 | Sun, 18/Oct/2015 | 05:29 |
| Sun, 18/Oct/2015 | 11:58 | Mon, 19/Oct/2015 | 01:30 |
| Mon, 19/Oct/2015 | 15:46 | Tue, 20/Oct/2015 | 03:00 |
| Tue, 20/Oct/2015 | 05:17 | Tue, 20/Oct/2015 | 09:25 |
| Wed, 21/Oct/2015 | 16:25 | Thu, 22/Oct/2015 | 07:30 |
| Thu, 22/Oct/2015 | 07:41 | Thu, 22/Oct/2015 | 15:30 |
| Thu, 22/Oct/2015 | 16:36 | Fri, 23/Oct/2015 | 01:30 |
| Fri, 23/Oct/2015 | 10:06 | Fri, 23/Oct/2015 | 11:30 |
| Tue, 27/Oct/2015 | 14:11 | Tue, 27/Oct/2015 | 21:00 |
| Wed, 28/Oct/2015 | 04:47 | Thu, 29/Oct/2015 | 15:30 |
| Thu, 29/Oct/2015 | 16:07 | Fri, 30/Oct/2015 | 10:30 |
| Fri, 30/Oct/2015 | 10:39 | Fri, 30/Oct/2015 | 15:00 |
| Fri, 30/Oct/2015 | 16:29 | Sat, 31/Oct/2015 | 15:25 |
| Mon, 09/Nov/2015 | 16:47 | Mon, 09/Nov/2015 | 18:00 |
| Tue, 10/Nov/2015 | 15:58 | Wed, 11/Nov/2015 | 05:30 |
| Wed, 11/Nov/2015 | 05:37 | Thu, 12/Nov/2015 | 13:00 |
| Thu, 12/Nov/2015 | 15:47 | Fri, 13/Nov/2015 | 02:00 |
| Fri, 13/Nov/2015 | 04:06 | Fri, 13/Nov/2015 | 15:55 |
| Fri, 13/Nov/2015 | 17:57 | Sat, 14/Nov/2015 | 08:00 |
| Sat, 14/Nov/2015 | 10:10 | Sat, 14/Nov/2015 | 13:00 |
| Sat, 14/Nov/2015 | 19:33 | Sun, 15/Nov/2015 | 14:00 |
| Mon, 16/Nov/2015 | 04:51 | Mon, 16/Nov/2015 | 12:00 |
| Mon, 16/Nov/2015 | 16:29 | Tue, 17/Nov/2015 | 11:00 |
| Sun, 29/Nov/2015 | 15:11 | Mon, 30/Nov/2015 | 08:30 |
| Mon, 30/Nov/2015 | 17:12 | Tue, 01/Dec/2015 | 06:00 |
| Tue, 01/Dec/2015 | 15:23 | Wed, 02/Dec/2015 | 10:00 |
| Wed, 02/Dec/2015 | 16:17 | Thu, 03/Dec/2015 | 06:00 |
| Thu, 03/Dec/2015 | 16:06 | Fri, 04/Dec/2015 | 06:00 |
| Sun, 27/Dec/2015 | 07:15 | Mon, 28/Dec/2015 | 07:00 |
| Tue, 29/Dec/2015 | 06:14 | Tue, 29/Dec/2015 | 15:30 |
| Wed, 30/Dec/2015 | 06:19 | Wed, 30/Dec/2015 | 16:00 |
| Fri, 30/Dec/2016 | 16:18 | Sat, 31/Dec/2016 | 05:30 |
| Sat, 31/Dec/2016 | 14:47 | | |

Pivot Tablelands xxkW.csv

| | | | |
|---|---|---|---|
| Thu, 01/Jan/2015 | 06:19 | Fri, 02/Jan/2015 | 15:29 |
| Mon, 12/Jan/2015 | 05:55 | Wed, 14/Jan/2015 | 17:59 |
| Thu, 29/Jan/2015 | 05:08 | Thu, 29/Jan/2015 | 06:29 |
| Tue, 24/Feb/2015 | 08:48 | Tue, 24/Feb/2015 | 09:59 |
| Wed, 25/Feb/2015 | 09:19 | Wed, 25/Feb/2015 | 10:30 |
| Wed, 25/Feb/2015 | 13:49 | Wed, 25/Feb/2015 | 14:59 |
| Mon, 30/Mar/2015 | 07:51 | Wed, 01/Apr/2015 | 22:29 |
| Thu, 02/Apr/2015 | 09:14 | Thu, 02/Apr/2015 | 10:59 |
| Sat, 11/Apr/2015 | 07:22 | Mon, 13/Apr/2015 | 20:59 |
| Sat, 25/Apr/2015 | 06:46 | Mon, 27/Apr/2015 | 23:29 |
| Tue, 05/May/2015 | 07:50 | Fri, 08/May/2015 | 03:29 |
| Fri, 15/May/2015 | 05:20 | Sun, 17/May/2015 | 20:29 |
| Fri, 29/May/2015 | 06:43 | Fri, 29/May/2015 | 21:59 |
| Sat, 30/May/2015 | 06:23 | Mon, 01/Jun/2015 | 01:29 |
| Sat, 13/Jun/2015 | 05:08 | Mon, 15/Jun/2015 | 20:59 |

| | | | |
|---|---|---|---|
| Mon, 29/Jun/2015 | 06:51 | Wed, 01/Jul/2015 | 23:29 |
| Thu, 23/Jul/2015 | 06:51 | Sat, 25/Jul/2015 | 20:59 |
| Thu, 06/Aug/2015 | 08:25 | Fri, 07/Aug/2015 | 00:59 |
| Fri, 07/Aug/2015 | 06:27 | Sun, 09/Aug/2015 | 06:59 |
| Wed, 19/Aug/2015 | 07:12 | Fri, 21/Aug/2015 | 22:29 |
| Thu, 03/Sep/2015 | 05:09 | Sat, 05/Sep/2015 | 17:59 |
| Sun, 06/Sep/2015 | 15:45 | Sun, 06/Sep/2015 | 16:59 |
| Wed, 09/Sep/2015 | 15:21 | Fri, 11/Sep/2015 | 21:29 |
| Thu, 24/Sep/2015 | 05:46 | Sat, 26/Sep/2015 | 12:29 |
| Sun, 04/Oct/2015 | 07:39 | Tue, 06/Oct/2015 | 14:29 |
| Thu, 15/Oct/2015 | 08:26 | Sat, 17/Oct/2015 | 11:29 |
| Sat, 17/Oct/2015 | 11:43 | Sat, 17/Oct/2015 | 12:59 |
| Sat, 17/Oct/2015 | 12:56 | Sat, 17/Oct/2015 | 16:29 |
| Sun, 25/Oct/2015 | 09:23 | Tue, 27/Oct/2015 | 15:29 |
| Tue, 03/Nov/2015 | 16:08 | Tue, 03/Nov/2015 | 17:29 |
| Mon, 09/Nov/2015 | 04:46 | Mon, 09/Nov/2015 | 06:29 |
| Tue, 10/Nov/2015 | 17:00 | Tue, 10/Nov/2015 | 17:59 |
| Sat, 14/Nov/2015 | 12:16 | Sat, 14/Nov/2015 | 14:29 |
| Wed, 18/Nov/2015 | 13:45 | Sat, 21/Nov/2015 | 15:59 |
| Sat, 28/Nov/2015 | 07:21 | Tue, 01/Dec/2015 | 06:59 |
| Mon, 07/Dec/2015 | 11:56 | Mon, 07/Dec/2015 | 12:59 |
| Wed, 16/Dec/2015 | 14:17 | Wed, 16/Dec/2015 | 15:59 |
| Tue, 22/Dec/2015 | 05:22 | Wed, 23/Dec/2015 | 07:29 |
| Tue, 29/Dec/2015 | 08:57 | Tue, 29/Dec/2015 | 09:59 |
| Thu, 31/Dec/2015 | 06:19 | | |

## Simulated Scenario 40kW.csv

| | | | |
|---|---|---|---|
| Fri, 02/Jan/2015 | 15:33 | Sat, 03/Jan/2015 | 13:00 |
| Sun, 04/Jan/2015 | 15:11 | Mon, 05/Jan/2015 | 13:30 |
| Tue, 06/Jan/2015 | 16:19 | Wed, 07/Jan/2015 | 15:00 |
| Thu, 08/Jan/2015 | 14:37 | Fri, 09/Jan/2015 | 13:30 |
| Sat, 10/Jan/2015 | 15:48 | Sun, 11/Jan/2015 | 14:30 |
| Tue, 13/Jan/2015 | 16:23 | Wed, 14/Jan/2015 | 16:30 |
| Thu, 15/Jan/2015 | 16:20 | Fri, 16/Jan/2015 | 16:00 |
| Sat, 17/Jan/2015 | 15:43 | Sun, 18/Jan/2015 | 13:30 |
| Mon, 19/Jan/2015 | 15:40 | Tue, 20/Jan/2015 | 15:00 |
| Thu, 22/Jan/2015 | 14:36 | Fri, 23/Jan/2015 | 13:30 |
| Sat, 24/Jan/2015 | 15:16 | Sun, 25/Jan/2015 | 14:00 |
| Mon, 26/Jan/2015 | 16:47 | Tue, 27/Jan/2015 | 14:30 |
| Wed, 28/Jan/2015 | 16:46 | Thu, 29/Jan/2015 | 16:00 |
| Fri, 30/Jan/2015 | 16:27 | Sat, 31/Jan/2015 | 15:00 |
| Mon, 02/Feb/2015 | 15:21 | Tue, 03/Feb/2015 | 12:30 |
| Thu, 05/Feb/2015 | 14:49 | Fri, 06/Feb/2015 | 14:00 |
| Sun, 08/Feb/2015 | 15:03 | Mon, 09/Feb/2015 | 13:00 |
| Wed, 11/Feb/2015 | 16:33 | Thu, 12/Feb/2015 | 15:30 |
| Sun, 15/Feb/2015 | 16:23 | Mon, 16/Feb/2015 | 15:00 |
| Wed, 18/Feb/2015 | 16:52 | Thu, 19/Feb/2015 | 14:00 |
| Sat, 21/Feb/2015 | 15:57 | Sun, 22/Feb/2015 | 15:30 |
| Tue, 24/Feb/2015 | 15:29 | Wed, 25/Feb/2015 | 14:00 |
| Fri, 27/Feb/2015 | 16:07 | Sat, 28/Feb/2015 | 16:30 |
| Mon, 02/Mar/2015 | 15:54 | Tue, 03/Mar/2015 | 13:00 |
| Thu, 05/Mar/2015 | 15:28 | Fri, 06/Mar/2015 | 14:30 |
| Sun, 08/Mar/2015 | 15:50 | Mon, 09/Mar/2015 | 15:00 |
| Tue, 10/Mar/2015 | 16:42 | Wed, 11/Mar/2015 | 16:30 |
| Fri, 13/Mar/2015 | 15:08 | Sat, 14/Mar/2015 | 13:30 |
| Mon, 16/Mar/2015 | 15:39 | Tue, 17/Mar/2015 | 14:30 |
| Thu, 19/Mar/2015 | 14:53 | Fri, 20/Mar/2015 | 14:30 |
| Sun, 22/Mar/2015 | 15:55 | Mon, 23/Mar/2015 | 16:00 |
| Tue, 24/Mar/2015 | 17:27 | Wed, 25/Mar/2015 | 15:59 |

| | | | |
|---|---|---|---|
| Fri, 27/Mar/2015 | 16:21 | Sat, 28/Mar/2015 | 16:00 |
| Mon, 30/Mar/2015 | 16:31 | Tue, 31/Mar/2015 | 13:27 |
| Thu, 02/Apr/2015 | 15:22 | Fri, 03/Apr/2015 | 14:30 |
| Sun, 05/Apr/2015 | 16:07 | Mon, 06/Apr/2015 | 13:29 |
| Wed, 08/Apr/2015 | 16:24 | Thu, 09/Apr/2015 | 14:00 |
| Sat, 11/Apr/2015 | 16:23 | Sun, 12/Apr/2015 | 14:30 |
| Tue, 14/Apr/2015 | 16:35 | Wed, 15/Apr/2015 | 15:00 |
| Fri, 17/Apr/2015 | 16:52 | Sat, 18/Apr/2015 | 16:30 |
| Mon, 20/Apr/2015 | 14:42 | Tue, 21/Apr/2015 | 13:30 |
| Thu, 23/Apr/2015 | 14:51 | Fri, 24/Apr/2015 | 14:30 |
| Sun, 26/Apr/2015 | 14:40 | Mon, 27/Apr/2015 | 15:00 |
| Wed, 29/Apr/2015 | 14:45 | Thu, 30/Apr/2015 | 16:00 |
| Wed, 06/May/2015 | 16:58 | Thu, 07/May/2015 | 17:00 |
| Sat, 16/May/2015 | 14:45 | Sun, 17/May/2015 | 12:30 |
| Tue, 26/May/2015 | 14:51 | Wed, 27/May/2015 | 13:30 |
| Sun, 06/Sep/2015 | 16:14 | Mon, 07/Sep/2015 | 16:00 |
| Wed, 16/Sep/2015 | 14:40 | Thu, 17/Sep/2015 | 13:00 |
| Sat, 26/Sep/2015 | 16:10 | Sun, 27/Sep/2015 | 13:57 |
| Sat, 03/Oct/2015 | 16:18 | Sun, 04/Oct/2015 | 13:30 |
| Wed, 07/Oct/2015 | 16:15 | Thu, 08/Oct/2015 | 17:30 |
| Mon, 12/Oct/2015 | 15:21 | Tue, 13/Oct/2015 | 15:25 |
| Fri, 16/Oct/2015 | 15:56 | Sat, 17/Oct/2015 | 13:00 |
| Tue, 20/Oct/2015 | 15:24 | Wed, 21/Oct/2015 | 13:00 |
| Sun, 25/Oct/2015 | 15:01 | Mon, 26/Oct/2015 | 12:30 |
| Thu, 29/Oct/2015 | 15:22 | Fri, 30/Oct/2015 | 14:26 |
| Mon, 02/Nov/2015 | 15:29 | Tue, 03/Nov/2015 | 14:00 |
| Wed, 04/Nov/2015 | 15:21 | Thu, 05/Nov/2015 | 15:30 |
| Sat, 07/Nov/2015 | 15:21 | Sun, 08/Nov/2015 | 16:30 |
| Mon, 09/Nov/2015 | 16:23 | Tue, 10/Nov/2015 | 13:30 |
| Thu, 12/Nov/2015 | 16:59 | Fri, 13/Nov/2015 | 15:00 |
| Sat, 14/Nov/2015 | 15:51 | Sun, 15/Nov/2015 | 15:00 |
| Tue, 17/Nov/2015 | 15:47 | Wed, 18/Nov/2015 | 13:26 |
| Thu, 19/Nov/2015 | 15:48 | Fri, 20/Nov/2015 | 15:57 |
| Sun, 22/Nov/2015 | 16:07 | Mon, 23/Nov/2015 | 15:30 |
| Tue, 24/Nov/2015 | 16:27 | Wed, 25/Nov/2015 | 16:00 |
| Fri, 27/Nov/2015 | 15:05 | Sat, 28/Nov/2015 | 14:00 |
| Sun, 29/Nov/2015 | 15:11 | Mon, 30/Nov/2015 | 13:30 |
| Wed, 02/Dec/2015 | 17:27 | Thu, 03/Dec/2015 | 16:00 |
| Fri, 04/Dec/2015 | 15:59 | Sat, 05/Dec/2015 | 13:30 |
| Sun, 06/Dec/2015 | 15:47 | Mon, 07/Dec/2015 | 12:30 |
| Wed, 09/Dec/2015 | 15:18 | Thu, 10/Dec/2015 | 14:26 |
| Fri, 11/Dec/2015 | 16:49 | Sat, 12/Dec/2015 | 13:30 |
| Mon, 14/Dec/2015 | 15:14 | Tue, 15/Dec/2015 | 13:00 |
| Wed, 16/Dec/2015 | 16:22 | Thu, 17/Dec/2015 | 15:00 |
| Fri, 18/Dec/2015 | 16:20 | Sat, 19/Dec/2015 | 16:30 |
| Mon, 21/Dec/2015 | 15:15 | Tue, 22/Dec/2015 | 15:30 |
| Wed, 23/Dec/2015 | 15:14 | Thu, 24/Dec/2015 | 13:00 |
| Sat, 26/Dec/2015 | 16:11 | Sun, 27/Dec/2015 | 15:00 |
| Mon, 28/Dec/2015 | 16:49 | Tue, 29/Dec/2015 | 13:30 |
| Wed, 30/Dec/2015 | 16:27 | Thu, 31/Dec/2015 | 13:30 |

carbon + energy markets

Rising electricity prices in Queensland: Evidence and Reasons for Action

A report to CANEGROWERS

**May 2013**

**EXECUTIVE SUMMARY**

CANEGROWERS represents around 80% of Queensland's sugarcane growers. Its members export around 80% of their production. Their businesses are in jeopardy as a result of declining sugar prices, the relatively high Australian dollar and rising input costs, of which the increase in the price of electricity has been the most significant.

CANEGROWERS has asked us to provide evidence of rising electricity prices, to explain why this has happened and to advise what the Queensland Government might be reasonably asked to do about it. This report has been written pursuant to those instructions.

Data from the Australian Bureau of Statistics shows that electricity prices paid by households increased by more than 60% (constant currency) between 2008 and 2012. Comparable index data is not available for irrigators, but irrigator tariffs have increased by 90% (nominal) between 2008 and 2014 including the most recent increase recommended by the Queensland Competition Authority from 1 July 2013.

The main reason for retail price increases has been increases in Energex, Ergon and Powerlink's charges. These are Queensland's network service providers (NSPs) which for the sake of brevity we generally refer to by this acronym in the rest of this report.

Environmental charges have also become significant in recent years and are expected to grow further over the next few years.

Rising NSP charges have resulted in sharply higher pecuniary benefits for the Queensland Government. The total benefit increased from $632m in 2007/8 to $1,380m in 2011/12. The net benefit (after-tax profits plus debt fees plus income tax equivalents less Community Service Obligation payments) grew from $46m in 2007/8 to $970m in 2011/12, a compound annual growth rate of 114% per year.

We also examined a measure of the rate of return: the quotient of the total pecuniary benefit (before subtracting CSO payments) divided by the total equity for all NSPs. This rose from 10% in 2007/8 to 16% in 2011/12. At face value this rate of return on equity is not excessive. However, this result is distorted by routine asset revaluations (which increase equity and hence reduce the rate of return on equity).

For example between 2007/8 and 2011/12, Energex revalued its assets upwards by $847m. On the revalued assets, its return on equity increased from 8% in 2007/8 to 15% in 2011/12. However excluding the effect of the asset revaluations, the return on equity increased almost three-fold from 8% in 2007/8 to 21% in 2011/12.

These data show that the large increase in NSP charges between 2007/8 and 2011/12 has delivered a large increase in pecuniary benefits to the Queensland Government.

High profits do not reflect efficient operation: the charges for distribution network services in Queensland, per connection served, compare unfavourably with those in New South Wales, Tasmania, South Australia and Victoria. They are now significantly higher, and have risen at a much faster rate, since 2007 than has occurred in these other states.

The main reason for the rising distribution NSP charges is the increase in the return on assets. This reflects the rapid expansion of the regulated asset base, as a result of substantially higher capital expenditure. In this respect the size of the regulated asset base per connection in Queensland is now far higher than in these other states (about 250% higher than in Victoria in 2014, compared to 60% higher in 2001).

There have been numerous reviews to understand why NSP expenditure – particularly by state-government owned NSPs - has increased as it has. These have all concluded that exogenous factors (ageing assets, rising peak demand, higher network planning standards) do not adequately explain outcomes. Instead they point to failures in the design and conduct of regulation.

In Queensland in particular, the Independent Review Panel has suggested that significant efficiency improvements by Queensland's NSPs ($5bn by 2019/20) can be achieved.

Following the reviews, some changes have been made to the design of regulation (giving the AER greater discretion) and changes are under-way to give consumers a stronger voice in regulatory reviews. It is premature to judge the impact of these changes, but even at best their impact will only be felt in the long term. In addition, the more challenging recommendations from the Productivity Commission, the Limited Merits Review and the Costello Audit Report have yet to be embraced by state governments. As such, the job is far from done.

We have suggested four reasons why it would be reasonable to request the Queensland Government's shareholding ministers to instruct the directors of its NSPs to reduce their regulated revenues. This is an administratively straight-forward matter, and it would not require a change to the National Electricity Law or National Electricity Rules or consent from the AER or QCA.

The administrative mechanisms to achieve price reductions to short order therefore exist. The bigger challenge for the Queensland Government will be to accept lower profits, income tax equivalents and possibly also competitive neutrality fees that will result from lower income (unless offset by even greater reductions in NSP expenditure). The rest of this summary sets out four reasons that justify action that will deliver this.

**Reason 1: The Government's receipt of income tax and competitive neutrality fees**

The Australian regulatory regime assumes that all NSPs are privately owned. The regime is based largely on a design introduced in Britain in the 1980s when the British Government privatised its NSPs. The British government introduced this regime to protect consumers from the newly privatised NSPs, and also to protect shareholders from expropriation through political opportunism.

However, the state governments in Queensland, New South Wales and Tasmania have chosen to continue to own their NSPs. The decision to apply, ipso facto, a regulatory regime designed for privately owned NSPs, to government-owned NSPs is misguided. While a strong case can be made for independent economic regulation to protect private investors from appropriation associated with political opportunism, the same argument is irrelevant if the government is the owner: in what sense can it be meaningful to protect a government-owned NSP from appropriation by the government that already owns it?

The implication of adopting this approach is that the calculation of regulated prices ignores the income (from debt fees and income tax equivalents) that NSPs provide their government owners. These debt fees and income taxes are a "free kick" to the state governments that have chosen to continue to own their networks, at consumers' expense.

The Queensland Government has in the past rejected arguments that electricity price regulation should recognise ownership. If the Government chose to revise its position on this, it would mean reducing the Weighted Average Cost of Capital to reflect lower government debt costs and it would also mean sacrificing the allowance for income taxes that is included in the AER's calculation of regulated prices/revenues. This could result in a significant permanent reduction in allowed revenues and hence prices (in the order of 10-20%).

**Reason 2: Excessive network investment**

In the last five year regulatory control period, Queensland's NSPs incurred capital expenditure of $11.6bn (2012$), and for the regulatory control period under way the AER has set prices on the assumption that they will incur capital expenditure of $14bn (2012$).

It is now clear that demand growth has fallen well short of the ambitious expenditure projections that underlie a large part of the expansion of the regulated asset that has occurred. For example in the period from 2007 to 2012, the average NEM demand declined by 18 MWs per year. Over this period the annual peak demand has grown at a trend rate of just 50 MW per year, and the peak demand in 2012 (an exceptionally hot summer) was lower than the peak demand in 2009.

In addition to over-estimating demand growth, Queensland's NSPs have had to meet more stringent network planning standards, the need for which has never been clear. As a result of these two factors, there is likely to be substantial excess, under-utilised, network capacity in Queensland. Under the current regulatory regime the costs of this (depreciation plus return) are nonetheless recovered from users in regulated charges.

This approach differs to that common in North America where a test of whether an asset is "used and useful" is undertaken before including that asset in the regulated asset base. Where assets are not found to be used or useful they may be permanently written down, or may be placed in an escrow account from which the utility obtains no financial return until the assets are found to be used and useful and hence taken out of the escrow account and put back into the regulated asset base.

Arguments can be made on the grounds of fairness and efficiency, that the Queensland Government (through its equity in its NSPs) should bear the cost of assets that are not used and useful:

- The fairness argument is that users have no control over regulated charges, whereas the Queensland Government, as owner of its NSPs does. Users did not play a part in over-estimating demand – to the contrary they warned against this in their submissions to regulatory decisions. On grounds of fairness therefore, the Queensland Government, not users, should bear the costs of regulatory and utility failures.

- The economic argument is that the Queensland Government, through its diversified income and broad spread of assets, is better able to bear (excess) sunk costs than energy users. This argument seems to have particular weight in the context in which electricity prices have risen to such a level that energy users are considering highly inefficient technology substitution (for example diesel rather than electric pumps in irrigation).

**Reason 3: Lower expenditure during the current regulatory period**

We understand that the Queensland Government has been putting considerable pressure on its NSPs to reduce their expenditure. As a result we understand that they are all likely to spend substantially less than the AER had assumed in its calculation of allowed revenues for the five-year regulatory controls currently under way. A part of the benefit of this will be reflected in lower prices when the AER sets allowed revenues/prices in the next five-year regulatory control period.

However the existing regulatory allowance was too generous partly because of flaws in the regulatory design (which the AER said had caused it to make decisions that were too generous to the NSP) and partly because the NSPs over-stated their efficient expenditure needs. Energy users made these arguments in their submissions to the AER. The issue, therefore, is that the regulatory allowances (and the expenditure assumptions underlying them) are excessive and so this should be addressed now, not when the next set of five year regulatory decisions are due to be made.

This argument is persuasive in view of the recognition by all parties (the AER, the Queensland Government, the Independent Review Panel, the NSPs and users) that the existing price/revenue controls are excessively generous to the NSPs. By implication the gains (in the form of higher profits) that the Queensland Government will derive from the reduction in expenditure of its NSPs during the current regulatory period, should be passed through to users in the form of lower prices during the current regulatory control period. This argument would seem to have particular weight, having regard to the evidence of the extraordinary growth in the pecuniary benefits that the Queensland Government has derived from its NSPs over the last six years.

**Reason 4: Asset stranding**

A successful regulatory regime should protect consumers from the exercise of monopoly power, provide incentives for efficiency and provide reasonable certainty to investors that they will recover their investments. The current regulatory regime has failed at the first two and instead, as the data shows, has provided a financial bonanza for the NSPs' owner.

As a result, electricity prices have risen to the level that energy users of all types seem to be seeking opportunities to substitute electricity for other fuels (photovoltaics in the case of households, diesel, gas and coal in industry and agriculture). The trend rate of contraction of electricity consumption in Queensland since 2007 seems to provide evidence of this.

Where consumers are unable to substitute electricity for other fuels, there seems to be some evidence of inefficient reductions in consumption, and record rates of residential user disconnection. In the case of trade-exposed cane growers, rising electricity prices has had a leveraged impact on farm profitability. We understand that electricity prices are resulting in significantly lower irrigation and hence farm yield. The reduction in production has a multiplier effect in sensitive regional economies. Effectively, rising electricity prices seems to be stranding the electrical infrastructure that energy users have invested in, and is resulting in welfare-reducing demand reductions. This is likely to undermine the Queensland Government's Four Pillars economic policy.

In addition, demand reduction will increasingly jeopardise the viability of existing electrical infrastructure. Using contemporary estimates for the long term own-price elasticity of demand (-0.5% to -0.7%) (see Fan and Hyndman (2011)), the 60% (constant currency) increase in electricity prices over the last 6 years can be expected to result in long term demand reductions of 30% to 42%, from what it otherwise would be.

Bringing this evidence together, action by the Queensland Government to reduce electricity prices will not only reduce the extent of energy users' asset stranding, and welfare-reducing demand reductions, but will also reduce the extent of stranded NSP assets.

## TABLE OF CONTENTS





carbon + energy markets

## Glossary

| | |
|---|---|
| AER | Australian Energy Regulator |
| AEMC | Australian Energy Markets Commission |
| NEM | National Electricity Market |
| NSP | Network Service Providers |
| QCA | Queensland Competition Authority |
| SCER | Standing Council on Energy and Resources |

## Table of Figures

# 1 Introduction

CANEGROWERS Australia represents around 80% of Queensland's sugarcane growers. Its members export around 80% of their production. Their businesses are in jeopardy as a result of declining sugar prices, the relatively high Australian dollar and rising input costs, of which the increase in the price of electricity has been the most significant.

To address electricity price challenges, CANEGROWERS has called on the Government of Queensland to change arrangements for the payment of the Community Service Obligation in order to facilitate retail competition in Ergon's area of supply; to change the structure of tariffs affecting its members and to limit future price increases to increases in the Consumer Price Index.

As part of its advocacy program on electricity prices, Canegrowers has asked us to provide evidence of rising electricity prices, to explain why this has happened and to suggest what the Queensland Government might do to address the problem. This report has been written pursuant to those instructions.

Rising electricity networks charges have been the main reason for rising retail electricity prices in Queensland. Hence the main focus in this report is on the electricity networks owned by the Queensland Government. This includes Powerlink (the transmission network service provider), Energex and Ergon (the two distribution network service providers). Addressing network pricing problems is substantially within the Queensland Government's grasp and its action in this area has the potential to bring significant price relief to CANEGROWERS' members, and to other energy users.

The report is set out as follows: Section 2 establishes evidence on prices, profits, costs and assets and the reason for the changes in these. Section 3 examines reasons for action by the Queensland Government in the short term. It starts with a brief overview of changes currently being considered or implemented across the National Electricity Market (NEM). It then suggests specific actions that the Queensland Government, as owner of its networks, might take to address the challenges.

# 2 Evidence

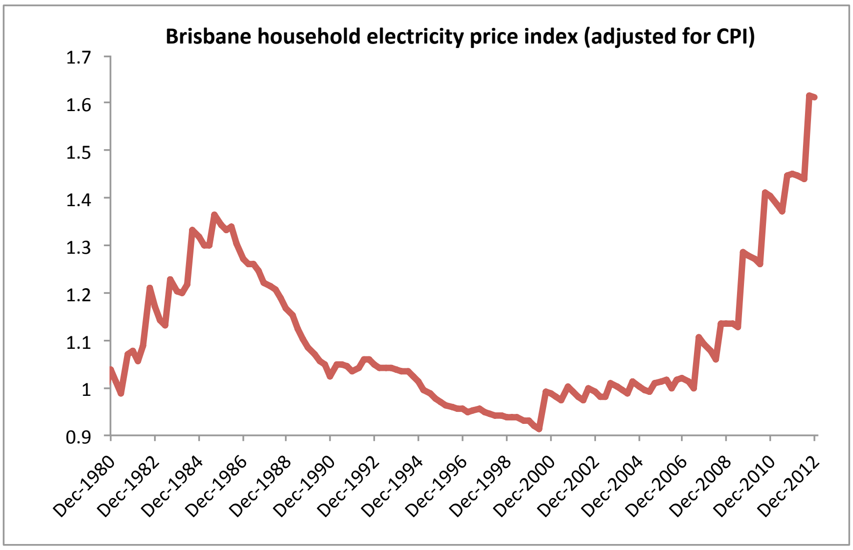
The purpose of this section is to provide a broad span of factual evidence on electricity price increases, its impact on cane growers and the extent to which the Queensland Government has derived pecuniary benefits as a result of price increases. The section then examines the regulated revenues, expenditures and assets of the network service providers. The last section reviews the reasons for price increases by the network service providers.

## *2.1* Electricity price increases

### 2.1.1 Overview

Various factors have accounted for the increase in electricity prices over the period from 2007/8 to 2012 during which prices escalated significantly, as shown in Figure 1 below.

**Figure 1. Electricity price increases to households in Brisbane**




*Source: CME analysis, ABS data*

The relative significance of different factors will vary for different types of customers depending on their usage pattern and their size. There is a reasonable level of transparency of the factors that affect household energy users. The main factors are as follows:

- **Environmental charges:** The AEMC's analysis (Australian Energy Markets Commission 2011) showed that in the period to 2011/12, environmental charges had a small impact on electricity bills (0.91 c / kWh on an average Queensland household price of 22 c/kWh). Environmental charges are likely to increase significantly in the next few years partly as a result of the expanded Large Scale Renewable Energy Target, large volume of credit creation from the Small Scale Renewable Energy Scheme and the Queensland Government's Solar Bonus

Scheme. The emission reduction scheme (colloquially known as the carbon tax) has so far also raised average household prices by around 2.4 c / kWh in 2012/13.

- **Generation charges:** These charges have been stable and average wholesale prices in the Queensland region of the National Electricity Market have declined over the period from 2008 to 2012.
- **Network charges:** Almost all of the increase in retail electricity prices in the period from 2007 to 2012 has been due to rising network charges.

Reliable indices for electricity prices paid by non-residential energy users are not available, however the impacts of different elements (network, generation, retail and environmental) will be broadly similar except for the very largest users for whom network charges are a relatively smaller part of their bills.

### 2.1.2 Irrigation electricity tariff increases

For irrigators, the explanation for rising electricity prices is likely to broadly match those for households. It should also be made clear that Queensland's experience with rising retail prices and network cost underlying those has not been unique in Australia. In New South Wales and Tasmania retail electricity prices rose by similar amounts (more in NSW and less in TAS) for the same main reason of rapidly rising network charges.

The gazetted tariffs 64, 65, 66 and 68 are specific to irrigators, while tariffs 62, 63 and 67 apply also to farm use, of which irrigation may be a part. Tariffs 63 and 64 have been obsolete since 1995 and thus restricted to customers on those tariffs at that time. There are understood to only be a few customers on Tariffs 63 and 64, and these tariffs will no longer apply from 1 July 2014. Tariffs 62 and 65, which are similar to Tariffs 63 and 64, were declared obsolete in 2012/13 but will be retained for seven more years. Tariff 66 has also been made obsolete but will also be retained for seven more years.

We do not have data on the number of cane growers on the various tariffs, but we understand that Tariff 62 accounts for around 60% of sugarcane irrigation users for travelling irrigators. Table 1 below shows how the various parameters on Tariff 62 have changed. It shows that all parameters have increased by 90% (except the off-peak charge which increased by 88%). This is a broadly consistent increase (after adjusting for inflation) to price rises experienced by households, as show in the ABS data in Figure 1.

**Table 1. The terms of Tariff 62 from 2008 to 2014**

| Tariff 62 | Service charge ($/month) | Energy charge < 10 kWh per month in peak (c/kWh) | Energy charge > 10 kWh per month, in peak (c/kWh) | Off-peak (c/kWh) |
|---|---|---|---|---|
| 2008 | $10.32 | 20.11 | 17 | 7 |
| 2009 | $10.88 | 21.19 | 17.9 | 7.49 |
| 2010 | $12.59 | 24.52 | 20.73 | 8.67 |
| 2011 | $14.26 | 27.78 | 23.49 | 9.82 |
| 2012 | $15.20 | 29.61 | 25.04 | 10.47 |
| 2013 | $16.71 | 32.57 | 27.54 | 11.52 |
| 2014 | $19.64 | 38.27 | 32.36 | 13.13 |
| **Percentage change 2008 to 2014** | **90%** | **90%** | **90%** | **88%** |

All irrigators on the remaining irrigation tariffs are being encouraged to shift to Tariff 22 (and will be forced to do so over the next seven years). The future increases in the now obsolete irrigation tariffs and in Tariff 22 are not known, but if an irrigator on Tariff 62 was moved to Tariff 22, the change in tariff parameters will be as shown in Table 2. The QCA's calculation (shown in Figure 6.14 of the QCA Draft Decision) shows that around 4 in 10 customers on Tariff 62 can expect prices to decrease when they shift to Tariff 22, while 6 in 10 can expected prices to increase.

**Table 2. Difference between Tariff 62 and 22**

| | | | | |
|---|---|---|---|---|
| **Tariff 22** | $42.00 | 38.03 | 38.03 | 13.39 |
| **Percentage change from Tariff 62** | **114%** | **-1%** | **18%** | **2%** |

### 2.1.3 Impact of electricity price increases on cane growers

In their submission to QCA on its Draft Decision on 2013/14 electricity prices, CANEGROWERS analysed the effect of the proposed 17.5% increase in electricity prices (from 2012/13 to 2013/14) on "farm business income" – a measure of pre-tax net profit. This showed that the impact of this price rise would reduce farm business income by 26% in Burdekin. This is despite electricity being a relatively small proportion of farm costs (5.3% in Burdekin). The main reason for the significant impact is that around 80% of sugarcane production is exported and hence priced in international markets. Thus Queensland cane growers have no or limited ability to recover rising input costs through higher prices.

We understand that the impact is likely to be reduced production and potential mill closures, which may in turn lead to industry restructuring, at a time where the Queensland Government is seeking to double agricultural production

We understand, anecdotally, that some cane growers are considering converting their irrigation power supplies to diesel engines in order to reduce their exposure to electricity. It seems that rising electricity prices have started to strand cane growers' investment in electrical devices.

In response to rising electricity prices, CANEGROWERS has proposed a number of changes to tariffs including:

- removing the return on capital for investments made on reliability, security and peak infrastructure from network charges;
- recognising the benefits provided to NSPs by irrigation's base load and off-peak load profile and developing a price differential accordingly
- removing the cost of the 44c/kWh Solar Bonus Scheme from network charges for irrigators

.
CANEGROWERS has also noted that the water tariffs that its members pay for irrigated water takes account of renewals expenditure and maintenance and operating costs, but does not include a rate of return on the underlying asset. CANEGROWERS has sought similar treatment of underlying assets in the pricing of electricity for irrigation purposes.

## *2.2* Queensland Government's pecuniary benefits from its NSPs

Rising electricity price have delivered rising electricity revenues to Queensland's NSPs. In the next sub-section we examine the extent to which rising revenues are explained by rising costs. In this subsection we examine the extent to which rising network revenues have led to rising profits. These profits are attributable to the Queensland Government as sole owner of its network businesses.

The Queensland Government derives (pecuniary) benefits from its ownership of its network business:

- From its claim on the net profits of the businesses (whether paid out in dividends or retained in the reserves of the businesses);
- On the income tax equivalents on those net profits – which under the Constitution of Australia accrue to state government from the corporatised businesses that the states own (the Constitution prevents the Commonwealth from taxing state governments);
- From fees on the debt that the Queensland Treasury provides to the NSPs.

All three of these represent a financial return to the Queensland Government. In its submissions to regulatory reviews, the Queensland Government has suggested that debt fees (known as "competitive neutrality fees") and income tax equivalents should not be counted as part of the return from its network businesses. In other words, when working out what the regulated prices should be, the regulator is encouraged to imagine that the state government does not receive this income. The regulatory arrangements reflect this assumption.

We have obtained data from the published financial accounts of Energex, Ergon and Powerlink from 2007/8 to 2011/12 to assess how the pecuniary benefits appropriated by the Queensland Government have varied over the period that electricity prices have increased.[1] Figure 2 charts the evolution of net profits after tax, debt fees (competitive neutrality fees) and income tax equivalents.

[1] It should be noted that separate financial accounts for Ergon's retail and distribution business are not published and our data unavoidably uses the aggregate of both. However, this is likely to understate the profits and profitability of NSPs in Queensland since Ergon's retail business is not profitable, as evidenced by the need for around $450m per year of CSO payments. The results are also affected to a minor extent by profits from unregulated businesses, but these are insignificantly small.

**Figure 2. Pecuniary benefits collected by the Queensland Government from its electricity network service providers**

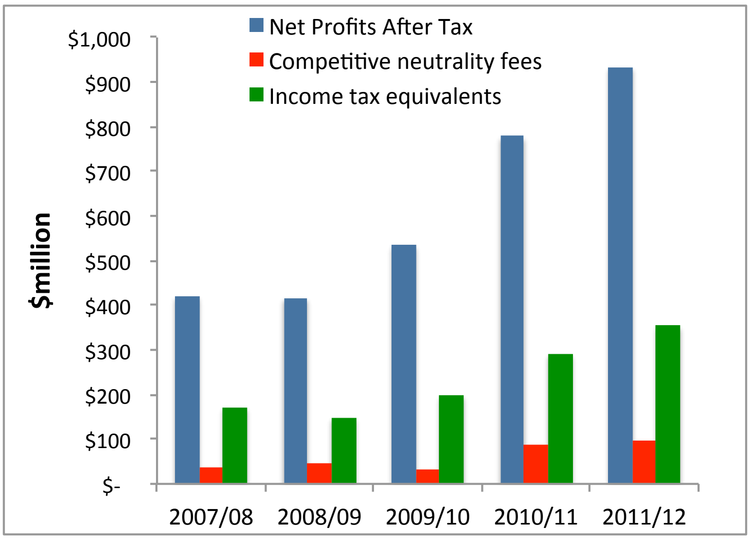
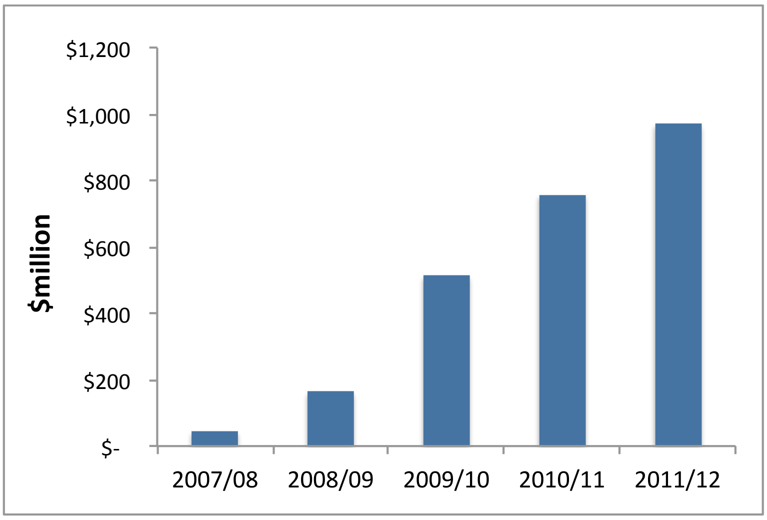



Figure 1 is a measure of the Queensland Government's gross pecuniary receipts from its NSPs. The compound annual growth rate of the gross pecuniary benefit has been 22% per annum from 2007/8 to 2011/12.

It would be misleading not to also count the Community Service Obligation (CSO) payments that the Queensland Government pays to Ergon in order to deliver the Government's Uniform Tariff Policy. The main purpose of these payments is to offset Ergon's higher network charges in rural Queensland. The Queensland Government's net receipts should deduct its CSO payments. The net pecuniary benefit to the Queensland Government from its NSPs (total pecuniary benefit less CSO) is shown in Figure 3.

**Figure 3. Total pecuniary benefit less Community Service Obligation payments**




Source: Company annual finance statements, CME analysis

Figure 3 shows the net benefit growing from $46m in 2007/8 to $970m in 2011/12, a compound annual growth rate of 114% per year.

We also examined a measure of the rate of return, as the quotient of the gross pecuniary benefit (i.e. before subtracting CSO payments) divided by the total equity for all NSPs. This rose from 10% in 2007/8 to 16% in 2012/13. At face value this rate of return on equity is not excessive. However, this result is distorted by routine asset revaluations (which increase equity and hence reduce the rate of return on equity).

For example between 2007/8 and 2011/12, Energex revalued its assets upwards by $847m. On the revalued assets, its return on equity increased from 8% in 2007/8 to 15% in 2011/12. However, if these asset revaluations are excluded from the calculation, Energex's return on equity actually increased almost three-fold from 8% in 2007/8 to 21% in 2011/12.

These data show that the large increase in retail electricity prices between 2007/8 and 2011/12 has delivered an even larger increase in pecuniary benefits to the Queensland Government.

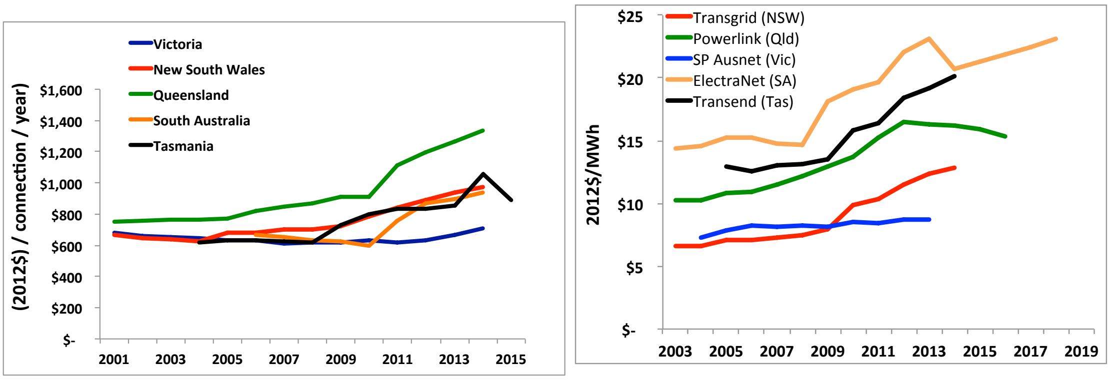
## *2.3* Energex, Ergon and Powerlink revenues and regulated assets

The previous sub-sections have charted price and profit changes. To what extent is this reflected in the regulated revenues of the NSPs, and in their regulated asset bases, the return on which is the largest element of regulated revenues?

### 2.3.1 Energex, Ergon and Energex regulated revenues

Figure 4 shows the change in regulated revenues for Queensland's distribution NSPs, per connection (in the left hand chart) and the chart next to it shows the regulated revenues for Queensland's transmission NSP. The left hand chart shows that per connection Queensland's distributors charged more than other distributors in the NEM in 2007/8 but that this gap has since widened. The right hand chart shows that prices charged by the Queensland transmission NSP have risen significantly, although are now moderating. They remain substantially above the charges for the NSPs in Victoria and New South Wales which have comparable through-put.

**Figure 4. Regulated revenue per connection for Queensland's distribution NSPs (LHS) and regulated revenue per connection for Queensland's transmission NSP**




**Source: AER and jurisdictional regulator price and revenue control decisions. CME analysis.**

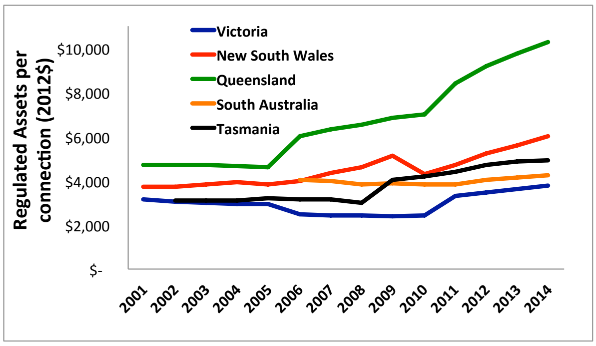


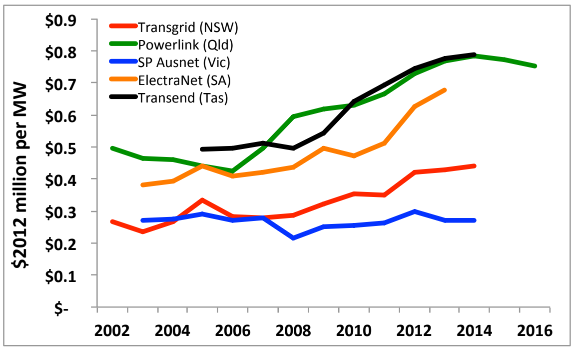
carbon + energy markets

### 2.3.2 Energex, Ergon and Powerlink regulated asset base

Figure 5 below shows the regulated asset base of the Queensland distribution NSPs per connection (left hand chart) and transmission NSP per MW (right hand chart). The charts show, that the Queensland NSPs have the highest (distribution) or near the highest (transmission) level of investment per connection or MW of peak demand served. Since the regulated return on assets is a function of the size of the regulated asset base, this explains why regulated revenues per connection or MWh are relatively higher in Queensland than elsewhere in the NEM.

**Figure 5. Regulated asset base per connection for Queensland distribution NSPs (left hand chart) and per MW of demand for Queensland transmission NSP (right hand chart)**




**Source: AER and jurisdictional regulator price and revenue control decisions. CME analysis.**

## *2.4* Why have network charges increased ?

Network prices in Queensland (as in New South Wales and Tasmania and to a lesser extent South Australia) have risen significantly because the regulated return on assets has risen. This return has risen largely because the regulated asset base has expanded. The regulated asset base expanded largely because of significantly higher capital expenditure. This raises the question: was the capital expenditure necessary? If it was necessary then the price increases that have been seen, other factors besides, are unavoidable and energy users would not have reason to complain.

Over the last four years there has been debate over outcomes delivered by the regulation of monopoly network service providers. The NSPs have long contended that the higher capital expenditure was needed to meet rising demand, asset ageing and catering for historic under-spending. The Australian Energy Regulator (AER) initially supported this. Energy users disagreed with this forcefully in their submissions to the AER's NSP regulatory decisions.

Mountain and Littlechild (2010) suggested that flaws in the design and conduct of regulation, and the impact of government ownership (and consequential conflicts of interest) rather than exogenous factors (demand growth, asset ageing, historic underspending) seem to have been the main reasons for rising prices. This initial research was followed by more detailed research commissioned by the Energy Users Association of Australia ((Mountain and Littlechild 2010; Mountain 2011; Mountain 2012). This evidence was contested by the Energy Networks Association (see (Energy

Networks Association 2012)) who concluded on the advice of their consultants, NERA, that there was no significant flaw in the conduct and design of regulation and that the analysis in Mountain and Littlechild (2010) and Mountain (2011) was flawed.

These contrasting views were assessed by the Productivity Commission, the Australian Energy Markets Commission, the Limited Merits Review and in Queensland by the Independent Review Panel. All of these institutions and reviews have accepted the main conclusions in Mountain and Littlechild (2010) and Mountain (2011) (see (Productivity Commission 2012a), (Australian Energy Market Commission 2012), (Independent Review Panel 2012; Yarrow, Egan et al. 2012). Subsequent research by the Grattan Institute (Wood 2012) confirmed and extended the earlier findings.

The main contentions of the impact of conflicts of interests of state governments, and flaws in the design and conduct of regulation also found wider support by leading Australian commentators and researchers including Professors Garnaut, King and Parry. In this sense, some of the more controversial issues in the debate seem to be largely settled, and consequently discussion (and action) has moved to find ways to address the problems, discussed in the next section.

In Queensland in particular, the Independent Review Panel has suggested that significant efficiency improvements by Queensland's NSPs ($5bn by 2019/20) can be achieved. We understand that significant effort is being made by the Queensland NSPs to deliver efficiency improvements.

# 3 Reasons for action

This subsection considers possible solutions to the problem of Queensland electricity prices. It has two main sub-sections.

The first sub-section briefly summarises NEM-wide changes that are currently being considered and in some areas, implemented. Numerous reviews of electricity prices took place during 2012 and it might be suggested that the job is done and that users should now wait for changes to be implemented, to deliver price relief. Is this right?

The second sub-section presents reasons that justify action that the Queensland Government might consider to address rising prices, with specific regard to reductions in the regulated revenues of its network service providers. We emphasise that this is just part of the electricity price challenge. Other issues, for example retail competition, environmental charges and network planning standards also merit detailed examination and action

## 3.1 NEM-wide changes currently being considered

### 3.1.1 Summary of the changes

**Changes to the National Electricity Rules and National Gas Rules**

At the end of 2011, the AER proposed a number of changes to the National Electricity Rules and National Gas Rules. The broad thrust of these changes is to give the AER greater discretion to set the regulated revenues and prices of NSPs. The changes sought to address criticisms that the AER made, that the Rules resulted in a high level of prescription that had constrained the AER's ability to exercise discretion, and thus had caused it to determine regulated revenues that were higher than they should have been. The Australian Energy Markets Commission broadly acceded to the AER's request and made a number of changes to the Rules along the lines that the AER suggested.

**Development of regulatory guidelines**

One of the outcomes from the changes to the Rules, is the requirement that the AER produce guidelines on how it intends to regulate NSPs. Pursuant to this, at the end of 2012, the AER announced a program of consultation that will result in guidelines that will explain how it intends to set the allowed rates of return, the regulatory incentives to promote efficient spending, how it will set expenditure allowances and how it intends to involve consumers in regulatory processes.

**Development of a Consumer Challenge Panel**

The AER has said that it intends to form a Consumer Challenge Panel to act as a "critical friend" of its work. The CCP will consist of individuals who are meant to be expert in their fields rather than representative of stakeholder organisations. The CCP members will be involved in regulatory determinations and will report, confidentially, to the AER on their findings.

**Changes to the arrangements for review of the merits of AER decisions**

In 2012, the Standing Council on Energy and Resources created a Panel, lead by Professor George Yarrow, to advise on the arrangements for the review of the merits of decisions by the AER. These merits reviews, conducted by the Australian Competition Tribunal, had attracted strong criticism for the impact they had had on raising electricity prices and that energy consumers had been unable to advocate effectively in these quasi-judicial merits review processes.

The Panel's report was highly critical of many aspects of the economic regulation of networks and made strident recommendations on changes to the arrangements for the review of the merits of AER decisions.

The Standing Council on Energy and Resources is currently consulting on changes to possibly implement the Panel's recommendations.

**Creation of a national energy consumer advocacy body**

In late 2012 SCER appointed a two-person panel to advise on the creation of a national energy consumer advocacy body. This new body is meant to provide strategic and technical expertise, representing the interests of energy users, in regulatory and other decisions affecting energy users. The two-person panel has completed its work, and at the time of writing an announcement on the creation of a national advocacy body is awaited.

**Productivity Commission review of regulatory frameworks**

In early 2011, the Federal Treasurer asked the Productivity Commission to review the regulatory frameworks and the arrangements for interconnection between regions of the NEM. The Productivity Commission delivered its Draft Report in October 2012 and its Final Report was delivered to the Government on 9 April 2013. At the time of writing it is yet to be publicly released.

The Productivity Commission's Draft Report was highly critical of many issues. It recommended many fundamental changes.

### 3.1.2 Has the job been done?

It is premature to make a definitive assessment of the changes under way or what might occur following the Productivity Commission's report or the governments' decisions on the recommendations of the Limited Merits Review. However we would not hesitate to suggest that the job is far from done. The changes to the Rules, the AER's guidelines, the creation of the CCP and a national energy consumer advocacy body have the potential to put downward pressure on electricity prices in future. But this is far from certain.

In Queensland, in addition to the various NEM-wide reviews, the Costello Audit Report suggested that the Queensland Government should seek to more clearly differentiate the roles of regulator, owner and policy maker.

The Queensland Government is, we understand, considering the more far-reaching recommended changes that have the potential to significantly reduce prices. It is changes in these areas that have most potential to create serious pressure for long term sustained efficiency improvements.

## 3.2 Reasons that justify Government action in the short term

The focus in this last sub-section is on actions that the Queensland Government can take to reduce electricity prices by reducing the revenue recovered by its NSPs.

The AER sets the maximum income that Powerlink and Ergon are allowed to recover during five year regulatory controls. For Energex, the AER sets the maximum weighted average price it can charge, also in five year controls.

The NSPs are able to recover lower revenues than the AER has set, if they choose to. None of the NSPs have ever chosen to recover less than the maximum allowed, although the Queensland Government has instructed its NSPs not to recover additional revenues that it could have recovered following a successful appeal against an AER decision in the Australian Competition Tribunal.

The Queensland Government, through its two shareholding ministers in each NSP is able to instruct the NSPs' Directors to reduce revenues. This is an administratively straight-forward matter, and it would not require a change to the Law or Rules or consent from the AER or QCA.

The administrative mechanisms to achieve price reductions to short order therefore exist. The bigger challenge for the Queensland Government will be to accept lower profits, income tax equivalents and possibly competitive neutrality fees that will result from lower income (unless offset by even greater reductions in NSP expenditure).

A decision to reduce the regulated revenue recovered by Queensland's NSPs should be motivated by reasonable argument that this would be fair and economically efficient. In the rest of this section we set out four reasons that we consider meets this criterion.

### 3.2.1 Reason 1: The Government's receipt of income tax and competitive neutrality fees

The previous section explained that the Australian regulatory regime assumes that all the NSPs are privately owned. The regulatory regime used in Australia is based largely on a design introduced in Britain in the 1980s at the time that the British Government privatised its NSPs. The British government introduced this regime to protect



carbon + energy markets

consumers from the newly privatised NSPs, and also to provide confidence to investors that their investments would be secure against opportunistic political intervention.

However, the state governments in Queensland, New South Wales and Tasmania have chosen to continue to own their NSPs. The decision to apply, *ipso facto*, a regulatory regime designed for privately owned NSPs, to government-owned NSPs, is misguided. While a strong case can be made for independent economic regulation to protect private investors from expropriation through political opportunism, the same argument has no meaning if the government owns the NSPs: in what sense can it be meaningful to protect a government-owned NSP from expropriation by the government that already owns it?

The outworking of this misguided approach is that the regulatory rules (and their application) looks past the fact that the state governments also derive significant income from debt fees and income tax equivalents provided by their NSPs. Since the regulation assumes that the NSPs are privatised (and hence equity holders do not accrue income taxes or debt fees), the receipt of these debt fees and income taxes is a substantial "free kick" to the state governments that have chosen to continue to own their networks.

Whether or not it is defensible to treat government-owned NSPs as if they are privately owned has been publicly debated following a proposal to change this through changes to part of the National Electricity Rules. This proposal was brought by the Energy Users Rule Change Committee (whose membership included Amcor, Australian Paper, Coles/Wesfarmers, Westfield, Woolworths, Simplot and Rio Tinto). The Australian Energy Market Commission rejected their proposal, and the Queensland Government supported this rejection.

Rather than rehearse the arguments here, readers are pointed to the argument for the proposal (Energy Users Rule Change Committee 2011) and (Energy users Rule Change Committee 2012) and (Energy Users Association of Australia 2012), and the AEMC's argument against the proposal (Australian Energy Market Commission 2012a) and (Australian Energy Market Commission 2012) and (Australian Energy Markets Commission 2012b) (these are all available on the AEMC's website). A submission to the Productivity Commission by AMP Capital (AMP Capital 2012) also clearly sets out the arguments against the assumption that government-owned NSPs are privately owned (this is available from the Productivity Commission's website).

State governments' persistence with the assumption that government-owned NSPs should be regulated as if they are privately-owned reflects an understandable desire not to lose significant income. However, the argument against this on grounds of economic efficiency (reducing incentives to over-capitalise) are persuasive and supported by the evidence.

If the Queensland Government chose to revise its position on this, it would mean reducing the Weighted Average Cost of Capital to reflect lower debt costs (excluding the Competitive Neutrality fee) and it would also mean sacrificing the allowance for income taxes that is included in the AER's calculation of regulated prices/revenues.

This could result in a significant permanent reduction in allowed revenues and hence prices (in the order of 10-20% depending how the calculations are done).

### 3.2.2 Reason 2: Excessive network investment

The previous section showed that the regulated asset base of all Queensland's NSPs has expanded significantly. In the last five year regulatory control period they incurred capital expenditure of $11.6bn (2012$). For the regulatory control period under way the AER has set prices on the assumption that they will incur capital expenditures of $14bn (2012$).

It is now clear that the expansion of the regulated asset base has been based on assumptions of far higher demand growth than has occurred. This is documented in Mountain (2012) in the case of transmission. In fact, demand growth in Queensland over the period that regulated assets (and prices) have risen so strongly, has been weak. For example in the period from 2007 to 2012, the average NEM demand in the Queensland region declined by 18 MWs per year. Over this period the annual peak demand has grown at a trend rate of just 50 MW per year, and the peak demand in 2012 (an exceptionally hot summer) was lower than the peak demand in 2009.

In addition to over-estimating demand growth, Queensland's NSPs have had to meet more stringent network planning standards. The need for such higher standards has not been clear (as set out in Mountain (2011)).

As a result of these two factors, there is likely to be substantial excess, under-utilised, network capacity in Queensland. Under the current regulatory regime the costs of this (depreciation plus return) are nonetheless recovered from users in regulated charges.

This approach contrasts to that used in North America where a test of whether an asset is "used and useful" is undertaken before including that asset in the regulated asset base. Where assets are not found to be used or useful they may be permanently written down, or may be placed in a form of escrow account from which the utility obtains no financial return until the assets are found to be used and useful and thus taken out of the escrow account and put back into the regulated asset base.

In January this year, the Standing Council on Energy and Resources (SCER) asked the AEMC to investigate the extent to which demand had been over-estimated and the impact of this on regulated charges. We understand that the AEMC has reported back to SCER on this, although at the time of writing this is not in the public domain.

Arguments can be made on the grounds of fairness and efficiency, that the Queensland Government (through its equity in its NSPs) should bear the cost of assets that are not used and useful.

The fairness argument is that users have no control over regulated charges, whereas the Queensland Government, as owner of its NSPs does. Users did not play a part in over-estimating demand – to the contrary they warned against this in their submission to the

AER in its regulatory decisions. On grounds of fairness therefore, the Queensland Government, not users, should bear the costs of regulatory and utility failures.

The economic argument is that the Queensland Government, through its diversified income and broad spread of assets, is better able to bear deadweight losses than energy users. This argument seems to have particular weight in the context in which electricity prices have risen to such a level that energy users are considering highly inefficient substitution (diesel rather than electric pumps in irrigation) and welfare-reducing demand is likely to be occurring.

### 3.2.3 Reason 3: Lower expenditure during the current regulatory period

We understand that the Queensland Government has been putting considerable pressure on its NSPs to reduce expenditure. As a result we understand that they are all likely to spend substantially less than the AER had assumed in its calculation of allowed revenues. A part of the benefit of this will be reflected in lower prices when the AER sets allowed revenues/prices in the next five year regulatory control period. In some ways, this is what the regulatory design was intended to deliver – incentives to reduce expenditure, which would deliver higher profits during the regulatory control period, and lower prices to consumers in the subsequent regulatory period.

However the argument is that the regulatory allowance was too generous partly because of flaws in the regulatory design (which the AER said had caused it to make decisions that were too generous to the NSP) and partly because the NSPs over-stated their efficient expenditure needs. Again, energy users made these arguments in their submissions. The issue, therefore, is that the regulatory allowances and the expenditure assumptions underlying them) are excessive and so this should be addressed now, not when the next set of five year regulatory decisions are due to be made.

This argument should be persuasive in view of the recognition by all parties (the AER, the Queensland Government, the Independent Review Panel, the NSPs and users) that the existing regulatory controls are excessively generous to the NSPs. By implication the gains (in the form of higher profits) that the Queensland Government will derive from the reduction in expenditure of its NSPs, should instead be passed through to consumers in the form of lower prices during the current regulatory control period. This argument would seem to have particular weight, having regard to the evidence (in the previous section) of the extraordinary growth in the pecuniary benefits that the Queensland Government has derived from its NSPs over the last six years.

### 3.2.4 Reason 4: Asset stranding

A successful regulatory regime should protect consumers from the exercise of monopoly power, provide incentives for efficiency and provide reasonable certainty to investors that they will recover necessary investments plus a reasonable return. The current regulatory regime has failed at the first two and instead, as the data shows, has provided a financial bonanza for NSPs' owners.

As a result, electricity prices have risen to the level that consumers of all types seem to be seeking opportunities to substitute electricity for other fuels (photovoltaics in the case of households, diesel, gas and coal in industry and agriculture). The trend rate of contraction of electricity consumption in Queensland since 2007 seems to provide evidence of this.

Where consumers are unable to substitute electricity for other fuels, there seems to be some evidence of inefficient reductions in consumption, and record rates of residential user disconnection. In the case of trade-exposed cane growers, CANEGROWERS' analysis shows that rising electricity prices has had a leveraged impact on farm profitability. We understand that electricity prices are resulting in significantly lower irrigation and hence farm yield. The reduction in production has a multiplier effect in sensitive regional economies. Effectively, rising electricity prices seems to be stranding the electrical infrastructure that energy users have invested in, and is resulting in welfare-reducing demand reductions. This is likely to undermine the Queensland Government's Four Pillars economic policy.

In addition, demand reduction will increasingly jeopardise the viability of existing electrical infrastructure. Using contemporary estimates for the long term own-price elasticity of demand (-0.5% to -0.7%) (see Fan and Hyndman (2011)), the 60% (constant currency) increase in electricity prices over the last 5 years can be expected to result in long term demand reductions of 30% to 42%, from what they otherwise would be.

Bringing this evidence together, action by the Queensland Government to reduce electricity prices will not only reduce the extent of energy users' asset stranding, and welfare-reducing demand reductions, but will also reduce the extent of stranded NSP assets.

## References


AMP Capital (2012). AMP Capital Submission to the Productivity Commission: The capital efficiency of Australian electricity distributors.

Australian Energy Market Commission (2012). Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Draft Rule Determinations. Sydney.

Australian Energy Market Commission (2012a). "Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Directions Paper."

Australian Energy Markets Commission (2011). Possible future retail electricity price movements: 1 July 2011 to 30 June 2014: Final Report.

Australian Energy Markets Commission (2012b). "Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Rule Determination."

Energy Networks Association (2012). Response to AEMC Directions Paper - Economic Regulation of Network Service Providers". Canberra.

Energy Users Association of Australia (2012). Submission to the Australia Energy Market Commission on its Draft Decision on changes to the National Electricity Rules proposed by the Australian Energy Regulator and the Energy Users Rule Change Committee.

Energy Users Rule Change Committee (2011). Proposal to change the National Electricity Rules in respect of the calculation of the Return on Debt.

Energy users Rule Change Committee (2012). Submission on AEMC Directions Paper.

Fan, S. and J. Hyndman (2011). "The price elasticity of electricity demand in South Australia." Energy Policy **39**(6): 3709-3719.

Independent Review Panel (2012). Interim Report: Summary findings and Draft Recommendations. Brisbane.

Mountain, B. R. (2011). Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors. A report for the Energy Users Association of Australia.

Mountain, B. R. (2012). A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market, Energy Users Association of Australia.

Mountain, B. R. and S. C. Littlechild (2010). "Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria." Energy Policy **38**: 5770-5782.

Productivity Commission (2012a). Electricity Network Regulatory Frameworks, Draft Report. Canberra.

Wood, T. (2012). Putting the customer back in front: How to make electricity cheaper. Melbourne, Grattan Institute.

Yarrow, G., M. Egan, et al. (2012). Review of the Limited Merits Review: Stage Two Report.


- 