QUEENSLAND COMPETITION AUTHORITY

Final Determination

Regulated Retail Electricity Prices 2012-13

May 2012

Level 19, 12 Creek Street Brisbane Queensland 4000
GPO Box 2257 Brisbane Qld 4001
Telephone (07) 3222 0555
Facsimile (07) 3222 0599

general.enquiries@qca.org.au
www.qca.org.au

The Authority wishes to acknowledge the contribution of the following staff to this report

Jennie Cooper, Adam Liddy, Rimu Nelson and Alicia Toohey

GLOSSARY

ACB	Australian Carbon Benchmark
ACIL	ACIL Tasman
ACIL Draft Methodology Report	ACIL Tasman, *Draft Methodology for Estimating Energy Purchase Costs, Prepared for the Queensland Competition Authority*, October 2011, available from: www.qca.org.au
ACIL Draft Report	ACIL Tasman, *Draft Report for Estimating* Energy *Purchase Costs for 2012-13 Retail Tariffs, Prepared for the Queensland Competition Authority*, March 2012, available from: www.qca.org.au
ACIL Final Report	ACIL Tasman, *Estimated Energy Purchase Costs for Use by the Queensland Competition Authority in its Final Determination on Retail Electricity Tariffs for 2012-13*, May 2012, available from www.qca.org.au
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
APG	Australian Power and Gas
APR	Annual Planning Report published by Powerlink
Authority	Queensland Competition Authority
BRCI	Benchmark Retail Cost Index
BRIG	Bundaberg Regional Irrigators Group
CAC	Connection Asset Customer
CARC	Customer Acquisition and Retention Costs
CCIQ	Chamber of Commerce and Industry Queensland
CEC	Clean Energy Council
CER	Clean Energy Regulator
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Service Obligation
DLF	Distribution Loss Factor
2009 Direction	The Direction issued on 25 June 2009, pursuant to section 10(e) of the *Queensland Competition Authority Act 1997*, directing the Authority to examine: the BRCI methodology and alternative price-setting methodologies for reflecting the costs of supplying electricity; and Queensland's existing retail electricity tariffs and alternative tariff structures which may assist in the long-term management of peak electricity demand and to encourage efficiency.

2011 Direction	The Direction from the Minister for Finance and the Arts and Acting Treasurer and Minister for State Development and Trade, pursuant to section 10(e) of the *Queensland Competition Authority Act 1997*, directing the Authority to investigate, and report on, a possible alternative retail electricity pricing methodology and schedule of retail electricity tariffs for the period commencing 1 July 2012 to 30 June 2013.
2011 Delegation	The Delegation of 13 September 2011, received from the Minister for Energy and Water Utilities, pursuant to section 90AA(1) of the *Electricity Act 1994*, directing the Authority to determine regulated retail electricity tariffs (notified prices) to apply from 1 July 2012 to 30 June 2013
2012 Delegation	The Delegation of 8 May 2012, received from the Minister for Energy and Water Supply, pursuant to section 90AA(1) of the *Electricity Act 1994*, directing the Authority to determine regulated retail electricity tariffs (notified prices), excluding the general residential supply tariff (Tariff 11) to apply from 1 July 2012 to 30 June 2013
Draft Methodology Paper	The Draft Methodology Paper issued by the Authority on 11 November 2011 (acting under the 2011 Delegation)
Draft Determination	The Draft Price Determination issued by the Authority on 30 March 2012 (acting under the 2011 Delegation)
DUOS	Distribution Use of System
EBITDA	Earnings before interest, tax, depreciation and amortisation
EEQ	Ergon Energy Queensland
Electricity Act	*Electricity Act 1994*
ERA	Economic Regulation Authority in Western Australia
ERET	Enhanced Renewable Energy Target Scheme
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities published by AEMO
FRC	Full Retail Competition
GEC	Gas Electricity Certificate
GST	Goods and services tax
GST Act	*Goods and Services Tax Act 1999 (Cth)*
GWh	Gigawatt hours
HV	High voltage
IBT	Inclining block tariff
ICC	Individually Calculated Customer
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
Issues Paper	The Issues Paper released by the Authority on 24 June 2011 (acting under the Direction)

Large customer	A customer that consumes more than 100 MWh of electricity per year
LECG	now Sapere Research Group
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
Minister	The Minister responsible for administering the *Electricity Act 1994*, currently the Minister for Energy and Supply
MW	Megawatt
MWh	Megawatt hours
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
Notified/regulated retail prices	The electricity prices that a retailer may charge its non-market customers, as defined under section 90 of the *Electricity Act 1994*
NSLP	Net System Load Profile
ORER	Office of the Renewable Energy Regulator
OTTER	Office of the Tasmanian Economic Regulator
POE	Probability of exceedance
Price Determination	The Authority's determination of notified prices to apply from 1 July 2012 to 30 June 2013 (acting under the 2012 Delegation)
QCA Act	*Queensland Competition Authority Act 1997*
QCOSS	Queensland Council of Social Service
RBA	Reserve Bank of Australia
Regulation	*Electricity Regulation 2006*
Relevant tariff year	The period 1 July 2012 to 30 June 2013
REES	Residential Energy Efficiency Scheme in South Australia
RET	Renewable Energy Target scheme
2009 Review	The Authority's *Review of Electricity Pricing and Tariff Structures* – Stages 1 and 2
ROC	Retail operating costs
ROLR	Retailer of Last Resort
RPP	Renewable Power Percentage
SAC	Standard Asset Customer
SEQ	South East Queensland
SFE	Sydney Futures Exchange
SFG	SFG Consulting
Small customer	A customer that consumes less than 100 MWh of electricity per year

SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
TFS	Tradition Financial Services
TOU	Time-of-use
TUOS	Transmission Use of System
UTP	The Queensland Government’s Uniform Tariff Policy
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WPI	Wage Price Index

PREAMBLE

The Minister for Energy and Water Supply (the Minister) has delegated to the Authority the task of setting notified prices for all regulated retail electricity tariffs in Queensland, except for the main residential tariff (Tariff 11). The Minister's Delegation and the Terms of Reference for this Price Determination are provided at **Appendix B**.

While many Queensland consumers have opted to enter into a market contract with the retailer of their choice, a significant proportion of Queenslanders (particularly in the Ergon Energy distribution area) remain on non-market contracts paying notified prices.

In previous years, the Authority has adjusted the existing notified prices annually according to its calculation of the Benchmark Retail Cost Index (BRCI). This year, the Authority is required to set notified prices for 2012-13 based on a new N+R cost build-up approach where the N (network cost) component is treated as a pass through and the R (energy and retail cost) component is determined by the Authority. This is a very different task to that undertaken previously and will establish a new set of retail tariffs aligned with the prevailing network tariff structure and retail prices which better reflect the cost of each customer's consumption.

In determining the notified prices to apply in 2012-13, the Authority is also required to have regard to the effect of its Price Determination on competition in the Queensland retail electricity market, the Queensland Government's Uniform Tariff Policy and the need for transitional arrangements for certain customer groups.

Unlike previous years under the BRCI where prices for all tariffs were increased by the same percentage, in establishing the new tariffs and prices this year, customers on different tariffs and different customers on the same tariff will be impacted differently. The size of these impacts will depend on how close the prices applying to the old tariffs may have been to actual costs and on the differing levels and patterns of consumption by customers on any particular tariff.

New Tariffs and Prices

The notified prices for 2012-13 have been influenced by a number of general factors including:

(a) further increases in network charges, with Energex and Ergon Energy expected to recover additional revenue from network charges of around 15.7% and 11.3% respectively;

(b) an increase in the underlying cost of energy for small customers of around 43%, primarily due to the carbon tax;

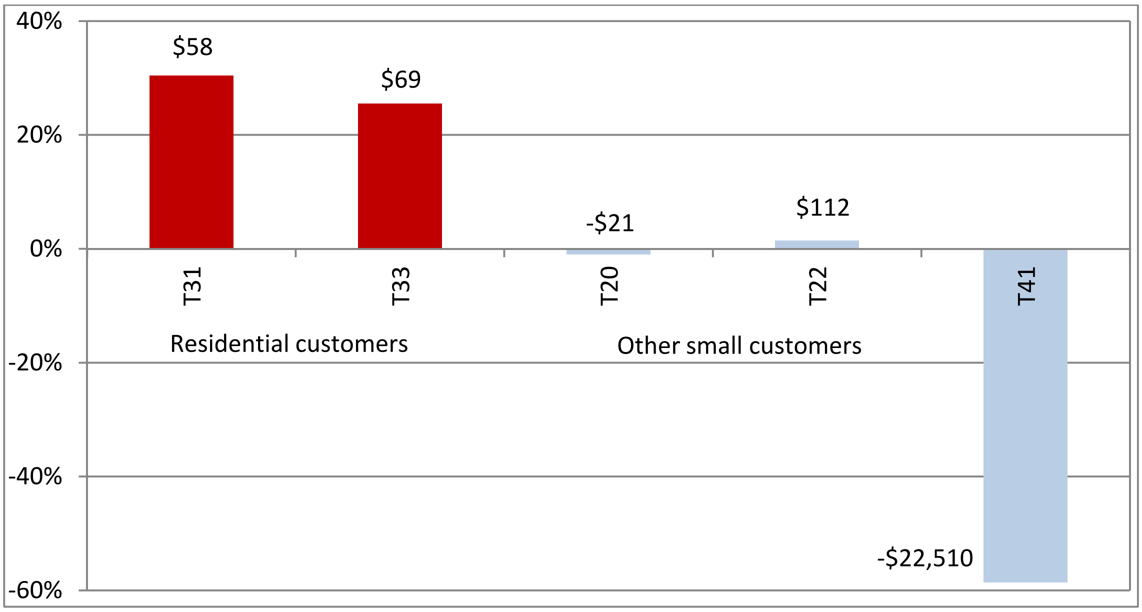
(c) retail operating costs for small customers remaining largely unchanged; and

(d) the one-off effects of moving from an ad hoc set of tariffs that had evolved over time to a new tariff structure more closely reflecting the true costs of supply which will have increased the prices for some tariffs and decreased the prices for others.

The last point is particularly important. There is nothing uniform about how different tariffs and customers may be impacted as we move from the old tariffs to the new. However, the extent of change occurring in this year is unlikely to be repeated in future years.

For this Final Determination, and using data provided by Ergon Energy, the Authority has been able to undertake more comprehensive assessments of likely customer impacts associated with the new notified prices. The following graph shows the impact that the new tariff structure and pricing arrangements will have (on average) for some small customer tariffs.

Change in typical small customer's annual electricity bill in 2012-13, by tariff



The relatively large percentage increases for Tariffs 31 and 33 (off-peak controlled load tariffs) are due to the new prices more accurately reflecting the costs of supply. Price impacts for other small customers (consuming less than 100 MWh per year) are, on average, relatively small or negative. However, customers on these tariffs who have levels or patterns of consumption different from the norm may experience very different outcomes.

Transitional Measures

The potential for significant price shocks for some customers was highlighted in numerous submissions the Authority received in response to its Draft Determination. In addition, following release of the Authority's Draft Determination, it became apparent that there were some physical constraints related to metering and systems changes that the distributors would have to resolve before many customers could move to the new tariffs. This was particularly the case for many larger customers.

In recognition of these physical constraints and also in view of the customer impacts revealed by the Authority's more comprehensive assessments, the Authority has implemented a wider range of transitional measures than proposed in its Draft Determination.

The Authority has retained the existing tariffs presented in the table below. These retained tariffs will operate concurrently with the new tariffs during 2012-13. While all of these tariffs will be retained in their current forms, the associated charges have been escalated as a transitional step towards the prices that will apply under the new tariffs to which these customers will eventually have to move. The amount of the price increase has been set at either 10% or 20% depending on the size of the gap between existing prices under the retained tariffs and the prices that would apply under the new replacement tariffs.

In all cases, the size of the transitional increase is substantially less than would otherwise have been required for many customers on those affected tariffs. It is also worth noting that the majority of customers (small and large) in the Ergon Energy distribution area will continue to receive the benefit of retail electricity prices which are below cost due to the Government's subsidy under the uniform tariff policy.

The assessment of customer impacts also shows that a significant number of customers will be better off by moving to the new tariffs. The transitional arrangements noted above will not prevent these customers from realising these benefits. Such customers are free to move to a new tariff, subject to the distributors' ability to address metering or other constraints. However, no new customers will be able to access the retained tariffs and existing customers will not be able to switch between retained tariffs.

At this time, the Authority envisages that these transitional provisions will cease from 1 July 2013 when the new tariffs will come into full effect and those existing tariffs that have been retained for transitional reasons will cease to be available. However, if the Authority is responsible for setting prices for 2013-14, it will review the state of play as part of the associated pricing review and, if necessary, may consider extending transitional arrangements for a further period.

Existing Regulated Retail Tariffs to be Retained for 2012-13

Existing 2011-12 retail tariff to be retained for 2012-13	***Level of transitional price increase 2012-13***
Obsolete and declining block tariffs – small and Ergon Energy large customers	
Tariffs 21, 37, 63, 64	20%
Tariff 62	10%
Farming and irrigation tariffs – small and Ergon Energy large customers	
Tariffs 65, 66	10%
Large customers in Ergon Energy's network area	
Tariff 20	10%
Tariffs 22, 41, 43, 53	20%

The Authority considers that the breathing space provided by these transitional arrangements will provide the opportunity for customers to review their usage relative to the likely impacts under the new tariffs, for distributors to review their network tariffs and charges which play such an important role in the final structure of retail tariffs and for the new Queensland Government to consider any broader policy issues in relation to electricity pricing which it may wish to address.

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1. INTRODUCTION

1.1 Background

Prior to 1998, all electricity customers in Queensland were on regulated retail electricity prices (notified prices) determined by the Queensland Government. For some large electricity customers, the option to choose their electricity retailer commenced in 1998. However, for the majority of customers, including all residential customers, the option to choose only came into effect with the introduction of Full Retail Competition (FRC) on 1 July 2007.

Since the introduction of FRC, electricity retailers have been able to offer to supply electricity to all customers, including those on notified prices. Customers who take up a market offer transfer from the notified price to the market contract price they have agreed with the retailer of their choice. Small customers who accept a market contract may revert to a non-market contract with their current retailer at the notified price on the expiry of their market contract, or as otherwise provided for in their market contract.

The relevant Minister (currently the Minister for Energy and Water Supply (the Minister)) has, pursuant to the *Electricity Act 1994* (the Electricity Act), delegated the function of determining notified prices to the Authority since the start of FRC. Prior to this current Determination, the Authority adjusted notified prices annually in accordance with the Benchmark Retail Cost Index (BRCI) process that was prescribed in the Electricity Act and *Electricity Regulation 2006* (the Regulation).

The current notified tariff schedule includes 20 regulated retail tariffs for which notified prices have been set. While some of the current tariffs were introduced more recently, most were introduced over 20 years ago. The current range of tariffs available to customers consists of residential, business and agricultural/farming tariffs.

As at 31 March 2012, there were 18[1] retailers supplying customers in the Queensland retail market (12 of these supplying small customers). However, competition in Queensland is largely limited to South East Queensland (SEQ) (Energex's distribution area) as a result of the Government's Uniform Tariff Policy (UTP)[2].

As at 31 December 2011, approximately 1.15 million (or 56.6%) of small customers and 7,129 (or 32.8%) of large customers in Queensland remained on notified prices, the majority of these in Ergon Energy's distribution area. Notified prices therefore remain an important feature of the Queensland retail electricity market.

The 2009 Review

On 25 June 2009, the Authority received a Ministerial Direction (the 2009 Direction) under section 10(e) of the *Queensland Competition Authority Act 1997* (the QCA Act) directing it to:

(a) examine the BRCI methodology and alternative price-setting methodologies for reflecting the costs of supplying electricity; and

[1] Some retailers hold more than one licence.

[2] The UTP works by subsidising customers in Ergon Energy's distribution area where network costs are considerably higher than in the more densely populated SEQ. Under the UTP, the Queensland Government subsidises the notified prices payable by regional customers supplied by Ergon Energy Queensland (EEQ) via a Community Service Obligation (CSO) payment. EEQ is the only retailer subsidised under the UTP. In general, subsidised notified prices, particularly for small customers, are below the prices available from other retailers offering market contracts.

(b) examine Queensland's existing retail electricity tariffs and alternative tariff structures which may assist in the long-term management of peak electricity demand and to encourage efficiency.

The *Review of Electricity Pricing and Tariff Structures* (the 2009 Review) was completed in two stages[3]:

In its Final Report on Stage 1 of the 2009 Review, the Authority concluded that the BRCI methodology had a number of flaws, and that the existing suite of notified prices was unlikely to fully reflect the costs of supply (at least not for each individual tariff group) and did not provide good signals to customers regarding the underlying costs of their electricity usage.

To achieve significant improvements over the existing BRCI methodology, the Authority recommended an alternative retail pricing approach based on a N (network) + R (energy and retail) approach, with the R component including appropriate allowances for energy and retail costs and the N component being a direct pass through of network costs to customers.

Following Stage 2 of the 2009 Review, the Authority recommended that retail tariffs be made as cost-reflective as possible, network and retail tariffs be aligned and a voluntary time-of-use tariff be introduced for residential customers who already had interval meters in place. The Authority also suggested including a seasonal component in some tariffs (though this suggestion was not subsequently accepted).

The 2011 Direction

On 11 May 2011, and in response to the Authority's recommendations, the Authority received a second Ministerial Direction (the 2011 Direction) under section 10(e) of the QCA Act requiring it to investigate, and report on:

(a) an alternative retail electricity pricing methodology for the determination of cost components under an N (network) + R (energy and retail) approach; and

(b) an alternative set of retail electricity tariffs, based on an N+R approach, which could be applied from 1 July 2012.

The 2011 Direction was a transitional measure to allow the 2012-13 pricing review process to commence while the necessary amendments were made to the Electricity Act and the Regulation to remove the BRCI approach to adjusting notified prices and to allow for the introduction of a new, cost-reflective price setting methodology.

The 2011 Delegation and Terms of Reference

The Electricity Act and the Regulation were amended on 13 September 2011. The amended Electricity Act allows the Minister to delegate the function of determining notified prices to the Authority. Section 329 of the Electricity Act provides that any investigations or consultations previously undertaken by the Authority under section 10(e) of the *Queensland Competition Authority Act 1997* (the QCA Act) will be deemed sufficient for the purposes of the 2012-13 price determination process.

On 22 September 2011, the Authority received a Delegation from the (then) Minister under section 90AA(1) of the Electricity Act (the 2011 Delegation) requiring it to determine

[3] *Review of Electricity Pricing and Tariff Structures – Stage 1, Final Report, September 2009 and Review of Electricity Pricing and Tariff Structures – Stage 2, Final Report,* November 2009, available from www.qca.org.au.

notified prices to apply from 1 July 2012 to 30 June 2013 (the price determination). The Delegation also included a Terms of Reference for the price determination.

Under section 90(5) of the Electricity Act, in making a price determination, the Authority is required to have regard to:

(a) the actual costs of making, producing or supplying the goods or services;

(b) the effect of the price determination on competition in the Queensland retail electricity market;

(c) any matter the Authority is required by delegation to consider; and

(d) any other matter the Authority considers relevant.

Under the 2011 Delegation, and in accordance with (c) above, the Authority was also required to have regard to:

(a) the Queensland Government's UTP, which ensures customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location; and

(b) a range of specific matters contained in an attachment to the Delegation.

The 2011 Delegation was broadly consistent with the 2011 Direction, with the exception of some minor amendments which provided more clarity regarding the Authority's task. In particular, the 2011 Delegation specified that the Authority should, to the extent possible, base its determination on an N + R cost build-up approach to setting notified prices, where:

(a) the N (or network cost) component is treated as a pass through – in determining the N component, the Authority must consider the network charges to be levied by Energex for each tariff for the relevant tariff year; and

(b) the R (or energy and retail cost) component is determined by the Authority.

Calculating the R component

Energy Costs

The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market (NEM) fees.

In calculating the energy cost component, the Authority must consider:

(a) the cost of energy;

(b) fees, including charges for market and ancillary services, imposed by the Australian Energy Market Operator (AEMO) under the National Electricity Rules (NER);

(c) energy losses as published by AEMO;

(d) the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;

(e) the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and

(f) a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

Retail Costs

In determining the retail cost component of each regulated retail tariff, the Authority must:

(a) consider the retail costs that would reasonably be incurred by an efficient, representative retailer, the characteristics of which should be determined by the Authority; and

(b) determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere.

Other Issues

In making its price determination, the Authority must have regard to the following matters contained in the Attachment to the 2011 Delegation:

(a) the general supply residential tariff (Tariff 11) is to be structured as an inclining block tariff (IBT);

(b) a new voluntary time-of-use tariff is to be established for residential customers and any customer who opts to transfer to this tariff, provided they have the appropriate metering, will be permitted to revert to the standard regulated tariff for residential customers in accordance with the requirements set out in the regulated retail tariff schedule;

(c) for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups, and consideration given to whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;

(d) an appropriate tariff is to be established for customers who are supplied under the Rural Subsidy Scheme, or are located in a drought declared area;

(e) an appropriate tariff for street lighting customers in Ergon Energy's network area is to be established, and consideration given to whether any transitional arrangements are needed for customers on the existing tariff (Tariff 71);

(f) consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs;

(g) from 1 July 2012, all existing and new non-residential customers in Energex's network area who consume more than 100 megawatt hours (MWh) per annum will be unable to access regulated retail electricity tariffs, and must be on a market contract; and

(h) as at 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff.

The 2011 Delegation and covering letter are provided in **Appendix A**.

1.2 Current Delegation and Terms of Reference

On 8 May 2012, the Minister provided the Authority with a revised Delegation under section 90AA(1) of the Electricity Act (the 2012 Delegation). The 2012 Delegation requires the Authority to determine notified prices for Queensland to apply from 1 July 2012 to 30 June 2013 but removes the requirement for the Authority to set Tariff 11 prices for 2012-13.

The Authority is required to publish its Final Determination and gazette the 2012-13 tariff schedule, including bundled retail prices, no later than 31 May 2012.

The Minister's covering letter and 2012 Delegation are provided in **Appendix B**.

1.3 The Review Process to Date

On 24 June 2011, the Authority released an Issues Paper advising interested parties of the commencement of the review. The Authority received 20 submissions in response to the Issues Paper. The list of submissions received is provided in **Appendix C**.

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on estimating energy costs to be included in the R component of regulated retail tariffs for 2012-13.

On 11 November 2011, the Authority released a Draft Methodology Paper, which set out for discussion the Authority's preliminary views and proposed approaches to determining the key elements of regulated retail tariffs and prices, with a particular focus on estimating energy and retail costs (the R component). The Authority hosted a workshop on 25 November 2011 to discuss the matters raised in the Draft Methodology Paper. The workshop was attended by 36 stakeholders.

The Authority received 28 submissions in response to the Draft Methodology Paper. The list of submissions received is provided in **Appendix C**.

The Authority released its Draft Determination on 30 March 2012, as required. The Draft Determination included draft regulated retail tariffs and prices for 2012-13 and explained how these were determined. The Authority received 40 submissions in response to the Draft Determination. The list of submissions received is provided in **Appendix C**.

The Authority is now releasing this Final Determination. In making its Final Determination, the Authority has taken into account the requirements of the Electricity Act and the 2012 Delegation, matters raised in submissions, ACIL's Final Report on the cost of energy and its own investigations.

The Authority accepts that the consultation period following the Draft Determination was very limited, particularly given the extent of the changes necessarily proposed by this fundamental review and the fact that the distribution tariff structure and prices which determine the retail tariff structure and have a substantial influence on retail prices were not the subject of prior consultation by the distributors. However, the Delegation required the Authority to release its Draft Determination on 30 March 2012 and requires the Final Determination to be released no later than 31 May 2012.

All reports and submissions received in relation to this price determination can be accessed from the Authority's website (www.qca.org.au).

2. NETWORK COSTS

Retail electricity prices comprise three main cost components. The first of these are the costs associated with transporting electricity through the transmission and distribution networks. Typically, network costs account for around 50% of the final cost of electricity for small customers.

The transportation of electricity from generators to consumers requires the use of both transmission and distribution networks. Transmission networks transport electricity at high voltages across the State (and interstate) while distribution networks distribute electricity at lower voltages from transmission connection points to households, small businesses and industrial users.

The main transmission network service provider in Queensland is Powerlink. The two main distribution networks in Queensland are owned and operated by Energex and Ergon Energy. Energex's network services South East Queensland (SEQ), while Ergon Energy's network extends across the remainder of the State.

As regulated monopoly businesses, the revenues to be raised via charges by Powerlink, Energex and Ergon Energy are determined by the Australian Energy Regulator (AER).

In addition to recovering their own distribution network costs, Energex and Ergon Energy also pass on to customers the cost of using Powerlink's transmission network (transmission use of system (TUOS) charges) as well as a number of other minor transmission-related costs, including avoided TUOS payments to embedded generators and other unregulated charges paid to Powerlink or distributors for transmission-like network services.

2.1 Treatment of Network Costs

In determining each cost component of the retail electricity tariffs, the Authority must have regard to the general provisions of the Delegation, including:

(a) the actual costs of supplying electricity;

(b) the effect of its determination on competition;

(c) the Queensland Government's UTP; and

(d) the particular matters raised in the attachment to the Delegation.

In establishing the tariff structure for 2012-13, the Delegation makes clear that, to the extent possible, the Authority's Determination should be based on an N+R cost build-up approach to setting notified prices, where N is treated as a pass through and R is determined by the Authority.

This is a different task to that undertaken by the Authority in previous years under the requirements of the BRCI approach to setting regulated retail prices and requires that (where possible) the retail tariff structure be based on the network tariff structure in order to enable network costs to be treated as a pass through to retailers.

In determining the network cost component of each regulated retail tariff, the Authority is also required, where possible, to consider the network charges to be levied by Energex for each tariff for the relevant tariff year (2012-13). This suggests that, where possible, the Energex network tariff structure and charges (rather than the Ergon Energy tariff structure and charges) should form the basis of the regulated retail tariffs. In combination with the

Government's UTP, this would mean that it would be the Energex tariffs and charges that, where possible, would form the basis of regulated retail tariffs across the State.

The Authority is also required to have regard to the specific matters raised in the Attachment to the Delegation (**Appendix B**). In respect of network costs, and in particular the role to be played by network tariffs as the basis for regulated retail tariffs, there are several matters to be considered here, including:

(a) a new voluntary time-of-use tariff is to be established for residential customers;

(b) the impact on customers on farming and irrigation tariffs and whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;

(c) an appropriate tariff is to be established for customers supplied under the Rural Subsidy Scheme or in drought affected areas;

(d) an appropriate tariff is to be established for street lighting in Ergon Energy's network area;

(e) from 1 July 2012, non-residential customers in Energex's network area who consume more than 100 MWh per annum will be unable to access regulated retail electricity tariffs and must move to a market contract; and

(f) from 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff.

If the Authority is to meet these requirements, the network tariffs that will form the basis of the regulated retail tariffs must be capable of accommodating them.

2.1.1 Residential and Small (less than 100MWh) Customer Tariffs

In its Issues Paper, the Authority noted that at that time Energex's 2011-12 tariffs did not provide a suitable basis for some of the retail tariffs the Authority is required to consider, including inclining block and voluntary time-of-use tariffs for residential customers, tariffs for farmers and irrigators, or tariffs for customers supplied under the Rural Subsidy Scheme or in drought declared areas.

The Authority also noted that there may be particular groups of customers in the Ergon Energy network area which are not represented in the Energex area, or are not sufficiently numerous in the Energex area to warrant a separate network tariff class.

Further, the Authority queried what network tariffs should be used for very large Ergon Energy customers (those consuming more than 4 gigawatt hours (GWh) per year) who would usually have network prices which are individually tailored to a greater or lesser extent depending on the characteristics of their consumption.

Following the release of Energex's proposed network tariffs for 2012-13 (see **Appendix D**), most of these concerns were removed. In response to the Authority's Draft Methodology Paper, there was general agreement that the 2012-13 network tariffs proposed by Energex would provide a suitable basis for most regulated retail tariffs.

However, following the release of the Authority's Draft Determination, which gave customers their first exposure to the notified prices based on Energex tariffs and included the Authority's proposal to base all notified prices for large customers on Ergon Energy's network tariffs, new concerns about the network component of notified prices were raised in submissions, as discussed below. The new Delegation also removed the requirement for the Authority to set Tariff 11 prices and noted that this would no longer be an inclining block tariff structure as previously required.

Residential Tariffs

Energex's proposed 2012-13 network tariffs include a voluntary time-of-use network tariff, for residential customers and provide a suitable basis for establishing network charges for residential customers on Tariff 31 and Tariff 33 (which, along with Tariff 11 to be set by the Minister, will also apply for customers with card operated meters).

Tariffs for Farmers, Irrigators and Customers Supplied under the Rural Subsidy Scheme or in Drought Declared Areas

The alignment by Energex of its proposed network tariffs with existing regulated retail tariffs provides the basis for regulated retail tariffs for farmers, irrigators and customers supplied under the Rural Subsidy Scheme or in drought declared areas. In particular:

(a) regulated retail Tariffs 66 (flat/demand – irrigation), 67 (flat – farm under Rural Subsidy Scheme) and 68 (flat – irrigation in drought declared area) align with Energex's proposed network tariff 8500 (flat – small/medium business); and

(b) regulated retail Tariff 65 (time-of-use – irrigation) aligns with Energex's proposed network tariff 8800 (time of use – small/medium business).

However, in response to the Draft Determination, a large number of submissions from organisations based in the Ergon Energy network area raised concerns about having to move to regulated retail tariffs based on Energex network tariffs and charges. For example, the Queensland Farmers Federation, Canegrowers and Growcom highlighted that farmers had made investment decisions based on the current tariffs and that moving to new tariffs with different structures could require considerable capital investment to adapt business processes.

Many submissions, including from farmers and irrigators, Ergon Energy and Origin Energy, expressed concern that the increase in the off-peak rate and the decrease in the peak rate under Tariff 22, which is to be based on Energex network tariff 8800, would significantly increase electricity costs for customers relying on cheap off-peak rates and reduce the incentive for customers to use off-peak electricity.

Farming groups such as Agforce, Pioneer Valley Water Co-operative, the Queensland Farmers Federation and Sucrogen also noted that the new notified prices would have flow on effects for farmers because water boards such as SunWater would be similarly affected and this could affect water prices paid by farmers.

Street Lighting and Other Unmetered Supplies

The current regulated retail tariff for street lighting (Tariff 71) aligns with Energex's proposed network tariff 9600 (flat – unmetered).

Ergon Energy and Origin Energy both supported using Energex's proposed network tariff for unmetered supplies as the basis for regulated retail tariffs for unmetered supplies.

However, Ergon Energy noted that some additional charges will also apply to some unmetered supply services. In order to avoid customer confusion about the application of these additional charges, Ergon Energy suggested that separate retail tariffs should be created for each different type of unmetered supply, even though they would be identical and based on the same Energex network tariff (9600).

The other existing regulated retail tariffs for unmetered consumption are regulated retail Tariffs 81 (traffic signals) and 91 (watchman service lighting). Both of these (along with Tariff 71 for street lights) align with Energex's proposed network tariff 9600 (flat – unmetered).

Obsolete and Declining Block Retail Tariffs

The Delegation requires that, from 1 July 2012, any customer currently on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff. This suggests that all obsolete and declining block tariffs are to be removed from the regulated tariff schedule.

The existing tariffs affected by this decision are set out in Table 2.1, along with the Energex proposed network tariff that most closely matches the redundant retail tariff.

Table 2.1: Obsolete and Declining Block Tariffs to be Replaced and Matching Network Tariff

Redundant retail tariffs	***Proposed network tariff***
Tariff 21	8500 – flat small/medium business
Tariffs 37, 62, 63, 64	8800 – time-of-use small/medium business

Customers currently on obsolete or declining block regulated retail tariffs will move to retail tariffs based on the network tariffs set out in Table 2.1. However, these customers may be able to move to an alternate tariff of their choice if there is one that better matches their usage and consumption.

Submissions from some organisations based in the Ergon Energy network area raised concerns about having to move to new regulated retail tariffs. For example, foundry operators Bundaberg Walkers and CQMS Razer indicated that having to move from the obsolete regulated retail Tariff 37, which does not have a demand charge, to a new (Energex based) regulated tariff with a demand charge that would apply to their high demand requirements could threaten their businesses.

Tariff for Card Operated Meters

In its Draft Determination, the Authority considered issues relating to card operated meters which would be based on Tariff 11. With the removal of the requirement for the Authority to set Tariff 11, these issues are no longer relevant.

2.1.2 The Authority's Position

Other than for the treatment of large customers, there were no suggestions in submissions that the network tariffs Energex proposed for 2012-13 could not provide the basis for regulated retail tariffs.

Residential Tariffs

These are all able to be accommodated within Energex’s proposed 2012-13 network tariff structure.

Tariffs for Farmers, Irrigators and Customers Supplied under the Rural Subsidy Scheme or in Drought Declared Areas

The Authority acknowledges the concerns raised about the potential costs to some customers of having to move to new regulated retail tariffs which may have some different features to those they are currently on. Unfortunately, there will not always be a perfect alignment between existing and new tariffs for all customers, particularly where there are currently multiple tariff choices being replaced by single new tariffs. However, one purpose of the current review is to rationalise the regulated tariff schedule and this will inevitably involve disruption for some customers. The issue here, for farmers and irrigators, may be more one relating to the timing of the required change than the extent of any change per se. In Chapter 6, the Authority has considered the impact of proposed changes on various customer groups and the need for any transitional arrangements to smooth the rate of change and consequent adjustment requirements for affected customers.

The Authority notes the concerns raised in submissions about the weak time-of-use signals in the new Tariff 22. Given that there is no time-of-use signalling in the R component of tariffs, as discussed in Chapter 5, the strength of signalling in Tariff 22 depends entirely upon that included in Energex’s network tariffs. While the Authority is required to treat network costs as a pass through, and noting that the structure of network charges is a matter for Energex and the AER, the Authority would encourage Energex to review its network prices to ensure they are sending appropriate pricing signals to customers regarding the differential costs associated with their time of use.

In relation to establishing appropriate tariffs for customers supplied under the Rural Subsidy Scheme or located in a drought declared area, the current tariff schedule includes separate tariffs (67 and 68) for these purposes. However, there is no clear economic basis for determining what the appropriate level of subsidy should be for those customers in these particular circumstances.

Rather than create two additional subsidised tariffs exclusively for these customers, the Authority considers it would be more appropriate for any special arrangements for these customers to be decided by Government and included in the terms and conditions that are associated with the notified prices. These arrangements have been included in the tariff schedule to be published with notified prices for 2012-13 (see **Appendix E**). Ergon Energy supported this approach. For those customers supplied under the Rural Subsidy Scheme or in drought declared areas of the State, Tariff 20 (based on Energex’s network tariff 8500 (flat – small/medium business) would be the relevant base tariff but would be subject to the special terms and conditions set out in the tariff schedule.

Street Lighting and Other Unmetered Supplies

In the Draft Determination, the Authority based the street lighting tariff on Ergon Energy network charges, for the same reasons it based retail tariffs for large customers on Ergon Energy’s network charges, as discussed below, while other unmetered supplies were based on Energex’s proposed network tariff 9600 (flat – unmetered).

Given the support for this proposal the Authority has followed the same approach in the Final Determination.

Obsolete and Declining Block Retail Tariffs

In accordance with the Delegation, customers currently on obsolete or declining block regulated retail tariffs are required to move to alternative regulated retail tariffs.

Many of the concerns raised in submissions regarding the use of Energex network tariffs as the basis for constructing regulated retail tariffs and hence the potential price impacts for some customers in moving to Energex based charges, are not actually about whether it is Energex or Ergon Energy network tariffs that are used but rather the fact that customers on obsolete and declining block tariffs are currently enjoying heavily subsidised electricity prices (such as those on obsolete Tariff 37) and will in future be required to move to new regulated tariffs which more accurately reflect their costs of supply.

While these tariffs are clearly slated to be removed, the Authority has considered the impact of this requirement on affected customers (as it is required to do) and has introduced some transitional measures to smooth the move to new tariffs (see Chapter 6).

Implementation Issues

While it appears that it will be possible to match all existing regulated retail tariffs (apart from customers consuming greater than 4GWh per annum) to a similar tariff within Energex's proposed 2012-13 network tariff structure, there will not always be a perfect alignment for all customers.

The Authority has considered the impacts of some of these changes and has introduced some transitional measures to smooth the move from old tariffs to new tariffs (see Chapter 6).

2.1.3 Tariffs for Large Customers

A key network issue to resolve relates to the appropriate basis for setting tariffs for large customers in light of the Government's policy decision to not allow non-residential customers consuming more that 100 MWh per annum in Energex's network area to access regulated retail tariffs. In particular, whether the Energex or Ergon Energy network tariffs and charges would form the most appropriate basis for determining tariffs for this group of customers.

The 2012-13 network tariffs proposed by Energex at the time the Authority released its Draft Determination included suitable tariffs to form the basis for regulated retail tariffs for the majority of large customers consuming up to 4 GWh per year. However, they did not include any tariffs intended for customers consuming more than 4 GWh per year. Beyond this level of consumption, Energex calculates individually tailored network prices which are not publicly available.

In its Draft Methodology Paper, the Authority suggested that, to establish suitable network tariffs, it could require Energex to calculate one or two network tariffs that reflect the average of its cost-reflective network tariffs for all of its very large customers. These could then provide the basis for calculating regulated retail tariffs for these customers. Energex and Ergon Energy disagreed with this proposed approach.

Energex was concerned that, due to the wide range of customer characteristics within its very large customer class (those consuming more than 4 GWh per year), calculating an average network charge based on the charges for these customers could result in notified prices for some customers that are lower than the market prices available to some of its existing customers. Energex also suggested that, as its network charges are subject to AER approval, this prevented Energex from creating tariffs for customers outside its distribution area. As an alternative, Energex suggested using its existing high voltage (HV) demand network tariff.

Ergon Energy suggested that the Authority had interpreted the Delegation too narrowly and that basing regulated retail tariffs for large customers on Ergon Energy's network charges would more closely match the network price signals applicable to large customers in the Ergon Energy distribution area. On this basis, Ergon Energy suggested that regulated retail tariffs for customers consuming between 100 MWh per year and 4 GWh per year should be based on Ergon Energy's publicly available network tariffs rather than Energex's, and that regulated retail tariffs for customers consuming more than 4 GWh per year should be based on an average of the network charges for Ergon Energy's very large customers rather than Energex's.

In its Draft Determination, the Authority proposed basing tariffs and charges for non-residential customers with consumption greater than 100 MWh per year (and for street lighting) on Ergon Energy's network charges, for reasons discussed below.

In response to the Draft Determination, Origin Energy and Power Choice supported this approach. Origin Energy suggested that this would allow large customers outside south-east Queensland to access the benefits of competition. While Power Choice supported the use of Ergon Energy network tariffs for large customers, it also made a more general suggestion that the Authority had not sufficiently considered underlying network costs, which Power Choice suggested were somehow different from the network charges approved by the AER.

However, the Authority notes that, from the perspective of retailers, network costs are the network charges approved by the AER and therefore rejects the suggestion by Power Choice that the Authority should in some way modify those network charges for the current exercise.

MSF Sugar, Sucrogen and Sunwater considered that using Ergon Energy network tariffs would have a significant impact on costs for water suppliers, which would ultimately have to be passed through to consumers. All three groups were of the view that the decision to use Ergon Energy network tariffs was inconsistent with the terms of the Delegation.

2.1.4 The Authority's Position

The Authority agrees with Ergon Energy that basing regulated retail tariffs for large customers on Ergon Energy's network charges would send better network price signals to large customers in the Ergon Energy distribution area. But this could be said of all the regulated retail tariffs which are to be based on Energex's network charges. The issue here is that the Government has a UTP which means that, in setting prices based on an N+R framework, they can either reflect the costs in the Energex area or the costs in the Ergon Energy area (or some amalgam of both) but they cannot reflect both distributors' actual charges without setting two sets of prices, one in the Energex area and a different set in the Ergon Energy area (which would not be consistent with the UTP).

The Delegation indicates that it should be Energex's network charges that prevail where possible. Given the lack of competition in the Ergon Energy network area, this seems a sensible in-principle approach.

However, the Government's decision to not allow large customers in the Energex network area to access notified prices means that, while ever this policy stance is maintained, it would be more appropriate, from a practical perspective, to set large customer tariffs (for the State) based on Ergon Energy's network charges as it will be only Ergon Energy large customers actually facing these costs.

As a result, the Authority has based regulated retail prices for large customers (those non-residential customers consuming more than 100 MWh per annum) on Ergon Energy network charges rather than those from Energex. This approach will put electricity prices for large Ergon Energy customers on a more economic (cost-reflective) footing, as required by the Delegation, but is likely to also result in some significant price increases for Ergon Energy's large customers on regulated tariffs. The impact of this decision on large customers is mitigated by the transitional measures the Authority has introduced (see Chapter 6).

Large Customers Consuming 100 MWh up to 4 GWh per year

Ergon Energy has three pricing zones – East, West and Mt Isa. The East pricing zone includes almost 90% of Ergon Energy's large customers. The Authority has used the network charges for Ergon Energy's East pricing zone as the basis for regulated retail tariffs for large customers.

Within the East pricing zone, there are a further three regions across which TUOS charges differ. However, Ergon Energy provided data that indicates the average TUOS charges for the three TUOS regions combined are similar to the charges in Transmission Region 1 and therefore proposed that the Authority use the TUOS charges that apply in Ergon Energy's East zone Transmission Region 1 to establish the network charges for notified prices for large customers. The Authority has adopted this approach.

For customers consuming between 100 MWh and 4 GWh per year, Ergon Energy has four network tariffs – Standard Asset Customer (SAC) Small, SAC Medium, SAC Large and High Voltage (HV) Demand. The Authority has used these Ergon Energy network tariffs as the basis for new retail Tariffs 44, 45, 46 and 47 (note that the numbering of these tariffs has been revised since the Draft Determination as some of the existing tariffs are to be retained as a transitional measure – see Chapter 6).

Very Large Customers Consuming More Than 4 GWh per year

In its submission on the Draft Methodology Paper, Ergon Energy suggested that the Authority base notified prices for customers consuming more than 4 GWh per year on the average of the network prices for Connection Asset Customers (CACs) for those customers consuming 4 GWh to 40 GWh per year and the average of the network charges for Individually Calculated Customers (ICCs) for those customers consuming more than 40 GWh per year.

The Authority adopted this suggestion in its Draft Determination but noted its concern that an average of ICC and CAC network charges, which cover a wide range of customer characteristics, is hardly representative of these groups.

Ergon Energy has now suggested that this approach would involve significant distortions to customers' costs. Ergon Energy has suggested that its (SAC) HV Demand network tariff be used as the basis for the regulated retail tariff for ICCs and CACs, on the basis that HV Demand tariff is based on the averages of the connection assets required to supply a customer at high voltage and their use of the shared network, and that the associated TUOS rates, which are averaged across customers in the TUOS Region 1, are not skewed by TUOS rates in other regions, as is the case for averages of ICC and CAC rates.

This is similar to the suggestion by Energex that, if its network charges were to be used for these customers (as has originally been proposed), its HV Demand network tariff would be the most appropriate (if not ideal) basis for establishing prices for this group of customers.

The Authority has therefore based the new retail Tariff 48 for very large customers on Ergon Energy's HV Demand network tariff (this is different to Tariff 47, which is also based on Ergon Energy's HV Demand tariff, because of a different allowance for retail operating costs, as discussed in Chapter 4). This has the advantage of being a publicly available network tariff, approved by the AER for connecting customers to the high voltage network.

However, the Authority notes that, while this may result in less impact on customers, presumably because the charges are lower than the average of the ICC and CAC charges, it still involves applying an average charge to a diverse group of customers. For this reason, the Authority is of the view that setting a regulated retail tariff for such a diverse group of customers is fraught with difficulty and that customers consuming over 40 GWh per year in Ergon Energy's network area should be required to move to a market contract and there should no longer be regulated prices set for these customers. A similar approach would also be the most practical solution for customers in Ergon Energy's network area consuming between 4 GWh and 40 GWh per year. This is consistent with the Government's decision that large non-residential customers (those consuming above 100 MWh per year) in the Energex network area will no longer have access to notified prices.

As discussed in Chapter 6, the transitional arrangements the Authority has put in place for large customers means that, in practice, in 2012-13 the new regulated retail tariff for very large customers (which is the same tariff available to small customers connected to the high voltage network) will only apply to new customers and any existing customers that do not make use of the transitional arrangements.

2.1.5 The Authority's Final Determination

The Authority's Final Determination is to base regulated retail tariffs for 2012-13 on:

(a) Ergon Energy network tariffs and charges for non-residential customers with consumption greater than 100 MWh per year and for street lighting; and

(b) Energex network tariffs and charges for all other customers, including other unmetered loads.

The resulting network charges to be used as the basis for regulated retail tariffs for 2012-13 are shown in Tables 2.2 to 2.4.

Table 2.2: Network Charges for 2012-13 Residential Regulated Retail Tariffs (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]* *c/day*	*Variable rate (flat)* *c/kWh*	*Variable rate 1 (off-peak)* *c/kWh*	*Variable rate 2 (shoulder)* *c/kWh*	*Variable rate 3 (peak)* *c/kWh*
Tariff 12 - Residential (time-of-use)	8900	35.000		7.496	11.369	23.525
Tariff 31 - Night rate (super economy)	9000		4.112			
Tariff 33 - Controlled supply (economy)	9100		7.456			

a. Charged per metering point.

Table 2.3: Network Charges for Other 2012-13 Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]* *c/day*	*Demand charge* *$/kW/month*	*Variable rate (flat)* *c/kWh*	*Variable rate (off-peak)* *c/kWh*	*Variable rate (peak)* *c/kWh*
Tariff 20 - Business (flat rate)	8500	61.000		10.088		
Tariff 22 - Business (time-of-use)	8800	61.000			8.383	10.259
Tariff 41 - Low voltage (demand)	8300	1488.000	17.680	1.018		
Tariff 91 – Unmetered	9600			8.088		

a. *Charged per metering point.*

Table 2.4: Network Charges for 2012-13 Large Customer Regulated Retail Tariffs and Street Lighting (GST exclusive)

Retail tariff[a]	*Ergon Energy network tariff*	*Fixed charge[b]* *c/day*	*Demand charge* *$/kW/month*	*Variable rate (flat)* *c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	533.900	27.002	1.751
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	1968.200	23.361	1.751
Tariff 46 - Over 100 MWh large (demand)	EDLT1	3173.900	22.444	1.751
Tariff 47 - High voltage (demand)	EDHT1	2039.500	17.935	1.702
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	2039.500	17.935	1.702
Tariff 71 - Street lighting[c]	EVUT1	0.500		22.694

a. *Tariffs 42, 43, 44 and 53 in the Draft Determination have been re-numbered as Tariffs 44, 45, 46 and 47, and Tariffs 54 and 55 in the Draft Determination have been replaced by Tariff 48.*

b. *Charged per metering point.*

c. *The fixed charge for street lighting applies to each lamp.*

2.2 Maintaining Alignment of Retail and Network Tariffs

As the Authority noted in its Issues Paper, adopting an N+R approach to setting regulated retail tariffs requires a formal process to ensure the ongoing alignment of network and retail tariffs to ensure the appropriate allocation of costs to (and recovery of costs from) groups of consumers covered by each tariff class. It would also ensure that distributors are able to engage in effective demand management initiatives that rely on price signals being passed through to customers.

The distributors' network prices are routinely approved by the AER just prior to the start of each financial year. Under the NER, the distributors are required to submit revised network prices at least two months prior to the commencement of the financial year. There is no formal limit under the NER on the time the AER can take to approve the pricing proposal.

The Authority is currently required to publish notified retail electricity prices to apply in the coming financial year by 31 May each year. Any change in the network tariffs proposed by the distributors and approved by the AER after the Authority had published final notified prices would potentially result in a misalignment of the two pricing structures.

Submissions in response to the Authority's Issues Paper identified the following potential options for maintaining alignment between retail and network tariffs:

(a) request the AER to revise its processes in order to approve network prices earlier;

(b) adjust regulated retail prices to apply from 1 August each year instead of 1 July to accommodate potentially late approval of Energex network prices by the AER; and

(c) request Energex to supply the Authority with its proposed network tariffs and prices when they are submitted to the AER and use these as the basis for notified prices to apply from 1 July each year. Should there subsequently be any change to those proposed tariffs and/or prices, regulated retail prices could be adjusted after 1 July if necessary.

In its Draft Methodology Paper, the Authority noted that:

(a) Option (a) is problematic because the AER is required to adhere to price approval timeframes stipulated in the NER and therefore has no discretion to change its approvals process. The Authority could pursue changes to the timeframes in the NER with the Australian Energy Market Commission (AEMC), but it would seem unlikely that the price approval process in the NER, which applies nationally, would be altered to suit circumstances in one jurisdiction.

(b) Option (b) may be more feasible than option (a). However, while option (b) would eliminate the potential for notified prices changing more than once each year, it would require changes to State-based legislative arrangements (amendment of the Regulation to include a definition of a 'tariff year' as commencing from 1 August).

    Option (b) would also result in current notified prices remaining effective until 1 August each year but new network tariffs would be charged to retailers from 1 July. Attempting to incorporate a fair and reasonable allowance in the revised 1 August prices to compensate retailers for any loss during the month of July (or consumers for any loss should prices have been set too high) would be an issue.

(c) Option (c) may also be problematic because the National Energy Customer Framework (NECF) will allow changes to retail prices only once every six months. While it may be possible for the Queensland Government to opt out of imposing this restriction in Queensland, changing all notified prices twice in quick succession (as could potentially be required) would impose additional costs on retailers and increase the potential for confusion amongst consumers.

    This is essentially the approach the Authority followed to date in determining the impact of network charges on retail prices under the BRCI. In practice there has not been a situation where network prices would have needed to be changed after July 1.

Given the difficulties associated with each of the available options and experience to date, the Authority proposed to adopt option (c).

There was general support for this approach in submissions.

AGL, Origin Energy, the Queensland Council of Social Service (QCOSS) and Energex supported the Authority's proposed approach to ensuring the ongoing alignment of network and retail prices. While supportive of the Authority's approach, Origin Energy queried how the Authority defined 'material' and suggested retailers should not incur costs due to timing differences between regulators. AGL noted that, without a pass-through mechanism, retailers were exposed to the risk that the AER might approve different network prices to those proposed by Energex and used for setting regulated retail prices. AGL argued that these risks should be reflected in the relevant cost allowances. QCOSS suggested revising regulated retail prices only if the AER approved Energex network prices were materially different to those proposed and that the Authority should set an explicit materiality threshold.

However, the Chamber of Commerce and Industry Queensland (CCIQ) suggested that businesses generally had limited opportunity to pass on fluctuating costs and was therefore concerned about the impact of within-year price changes on businesses. CCIQ also suggested that the proposed retail margin already allowed for unforeseen and systematic risks faced by retailers. The Authority disagrees with this latter statement, since network costs are to be treated as a direct pass through to customers and are not considered in setting the retail margin, which covers risks associated with the R component of tariffs only. However, it does acknowledge that fluctuating electricity prices could impose a burden on other businesses (and households) and would prefer that (as in the past) regulated retail prices were able to be set prior to the start of the financial year and remain unchanged for the remainder of that year.

The Authority also acknowledges that not adjusting regulated retail tariffs to reflect any changes in network charges approved by the AER, as proposed by CCIQ, would impose a financial risk on retailers. It could also be seen as inconsistent with the requirement in the Delegation to implement an N+R approach to pricing where network costs are to be treated as a pass through.

The Authority is mindful that changing all notified prices twice in quick succession would impose additional costs on retailers and increase the potential for confusion amongst consumers. For this reason, the Authority sees some merit in QCOSS's suggestion to revise regulated retail prices only if the AER approved network prices were materially different to those proposed by the distributors and used as the basis for retail prices. The Authority considers that materiality can only usefully be determined on a case by case basis at the time any adjustment is required. Such judgement may have regard for, among other things, the administrative costs of changing all notified prices and the financial impacts of revised prices on retailers and customers.

While option (c) remains the Authority's preferred approach, the NECF will only allow changes to retail prices once every six months. The Authority understands that the Queensland Government intends to opt out of imposing this restriction in Queensland. If this is the case, it would be possible to adjust notified prices at any time after 1 July if necessary.

2.2.1 The Authority's Final Determination

In order to maintain alignment between distribution and regulated retail tariffs, the Authority has requested Energex and Ergon Energy to supply the Authority with the proposed network tariffs and prices they intend to submit to the AER, including:

(a) for Energex, all tariffs and prices except for those with site specific charges; and

(b) for Ergon Energy, tariffs and prices for SACs and street lighting in the East pricing zone, Transmission Region 1.

The Authority has used these tariffs and prices in its Final Determination as the basis for notified retail prices to apply from 1 July 2012.

The Authority considers that, should the need arise, regulated retail tariffs that apply from 1 July 2012 could be amended to reflect any material changes to network tariffs that are approved by the AER, including any adjustment to compensate retailers for altered network charges incurred by them prior to regulated retail tariffs being adjusted. However, as per the Delegation, the Authority's role in relation to setting notified prices for 2012-13 ends on 31 May 2012.

3. ENERGY COSTS

3.1 Introduction

Under the Delegation, the R component of each retail tariff is to include appropriate allowances for energy and retail costs.

The Delegation requires that the energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and NEM fees.

Specifically, the Delegation requires that, in calculating the energy cost component, the Authority must consider:

(a) the cost of energy;

(b) fees, including charges for market and ancillary services imposed by the AEMO under the NER;

(c) energy losses as published by AEMO;

(d) the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;

(e) the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and

(f) a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

The Authority engaged ACIL Tasman (ACIL) to provide advice on each of these energy cost components. This chapter provides an overview of the approach proposed by ACIL and a summary of ACIL's findings. For more detail, see ACIL's reports to the Authority – *Estimated Energy Purchase Costs for Final Determination* (ACIL Final Report), *Estimated Energy Purchase Costs for 2012-13 Retail Tariffs* (ACIL Draft Report) and *Draft Methodology for Estimating Energy Purchase Costs* (ACIL Draft Methodology Report). All are available from the Authority's website.

3.2 Wholesale Energy Purchase Costs

Wholesale energy purchase costs (energy costs) relate to the costs incurred by a retailer in purchasing electricity to cover the load of its customers. While this electricity is purchased from the NEM (the spot market), there are a range of measures that a retailer can take in order to reduce its exposure to volatile prices in the spot market, including purchasing financial derivatives (futures, swaps, options etc.) to offset its exposure, entering longer-term power purchase agreements with generators or investing in generation assets.

To arrive at its estimate of wholesale energy costs, the Authority must decide its general approach to estimating these costs and then, implement its preferred approach, to arrive at estimates of:

(a) forecast customer load profiles which must be supplied in 2012-13;

(b) the hedging strategy to be used in settling the forecast load(s) against the forecast prices;

(c) forecast energy spot prices to apply in 2012-13; and

(d) the cost of carbon.

3.2.1 Approach to Estimating Wholesale Energy Purchase Costs

In its Issues Paper, the Authority identified that there are two broad approaches to estimating energy costs. A cost-based approach such as the long run marginal cost (LRMC) which estimates the costs of generation, or a market-based approach which estimates the costs a retailer would incur in purchasing electricity at prevailing market prices over a given period.

Under the BRCI, the Authority was required to consider both approaches and based its estimates of energy costs on a 50/50 combination of the outcomes from the two approaches.

In its Issues Paper (and previously in the 2009 Review), the Authority noted that its preference was to move to a solely market-based approach for estimating energy costs as it was of the view that this would better reflect the costs that a retailer is likely to incur in the relevant period. The Authority suggested that an approach similar to that used under the BRCI to estimate energy purchase cost appeared suitable for this purpose.

However, at the time of releasing its Draft Methodology Paper, uncertainty surrounding carbon costs for 2012-13 had led to a significant contraction in the level of electricity contracts traded on the Sydney Futures Exchange (SFE).

As a result, in its Draft Methodology Paper, the Authority presented an alternative approach to estimating market-based energy costs - ACIL's proposed price distribution approach - which estimated the cost that a retailer would be willing to pay in order to hedge risks related to weather and generator outages based on a distribution of possible price outcomes for 2012-13.

In response to the Draft Methodology Report, there was little support from stakeholders for the price distribution approach. Fortunately, by the time the Authority released its Draft Determination, improved data availability meant that the Authority was able to revert to a hedging-based approach (which had always been its preferred approach) for estimating energy costs for most tariffs, but continued to rely on the price distribution approach to estimate the cost of energy for controlled loads and unmetered supplies.

Approaches in Other Jurisdictions

For its 2010-2013 retail electricity pricing decision for New South Wales, the Independent Pricing and Regulatory Tribunal (IPART)[4] used a hedging-based approach to estimate energy purchase costs and was required by its terms of reference to include LRMC as a floor price.

In its decision on retail electricity prices in the ACT for 2010-2012, the Independent Competition and Regulatory Commission[5] (ICRC) developed a model for estimating energy costs based on corporate finance concepts rather than a hedging strategy, reflecting the ICRC's concerns about the nature of the electricity market which made it impossible to perfectly hedge. In its April 2012 Draft Report, the ICRC proposed to continue using this approach for the 2012-14 period[6], although it was considering options for including costs to account for the implementation of the carbon tax.

[4] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010.
[5] ICRC, *Retail Prices for Non-contestable Electricity Customers 2010-2012, Final Decision*, June 2010.
[6] ICRC, *Retail Prices for Franchise Electricity Customers 2012-2014, Draft Report*, April 2012.

In deciding on this approach, the ICRC noted that there were a number of reasons why the LRMC should not be used to estimate energy purchase costs. Amongst other things, the ICRC noted that the suggestion that generators would benefit from higher energy cost allowances in regulated retail tariffs, as a result of including LRMC in the calculation, was unproven and that higher energy cost allowances would not flow upstream to generators unless the retailer was altruistically supporting its suppliers. Furthermore, the ICRC considered that regulated retail prices should not be used to attempt to correct concerns about the long-term investment in electricity generation.

Due to insufficient liquidity in the contract market at the time, the Essential Services Commission of South Australia (ESCOSA) used a hybrid cost-based and market-based approach to estimate energy costs in its price determination for 2011-14[7]. Specifically, ESCOSA developed low and high estimates of LRMC to provide a price floor and price ceiling for its market-based energy cost estimate, which was based on a weighted average of market contract prices.

In estimating energy costs for Western Australia for 2012-2016, the Economic Regulation Authority (ERA) considered both the market costs that the incumbent retailer, Synergy, was likely to incur over the determination period and the LRMC of generation[8] and decided to use Synergy's actual contract costs for 2012-13 and 2013-14, on the basis that these were more appropriate to use in the earlier years of the determination. However, the ERA proposed to use LRMC for the latter years of the determination on the basis that LRMC provides an indication of the efficient level of costs over time.

Submissions

As noted above, submissions had not been supportive of ACIL's proposed price distribution approach, raising a range of issues, including that it lacked transparency and relied too heavily on complex black-box modelling. In response to the Draft Determination, TRUenergy, AGL, Ergon Energy and Origin Energy noted that the limited remaining use of the price distribution approach (for determining costs related to controlled loads and unmetered supplies) was inappropriate, as retailers would not be willing to face the risks of the spot market, even for loads that are predominantly off-peak.

While most retailers generally supported the use of a hedging-based approach to estimate energy costs, two key concerns with that approach were raised, including that:

(a) there was insufficient forward trading of electricity, due to uncertainty surrounding implementation of the proposed carbon tax, to use forward contract price data to estimate energy purchase costs; and

(b) electricity prices would become more volatile in future and that this volatility would be bad for consumers and retailers.

Most retailers proposed that the energy cost estimate should also include LRMC, typically as a price floor. Retailers suggested that this would also support investments in electricity generation capacity. In response to the Draft Determination, TRUenergy, AGL, Origin Energy, Click and APG reaffirmed this view, noting that:

(a) it was inconsistent for the Authority to rely on IPART for retail operating costs and margin estimates, but ignore its standpoint on LRMC;

[7] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010
[8] ERA, *Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs, Draft Report*, April 2012.

(b) the Authority's reliance on the ICRC's views on LRMC appeared to ignore the fact that competition has stalled in the ACT due to regulated retail tariffs being set too low; and

(c) the low level of trading on the SFE is evidence the market participants are using longer-term contracts such as power purchasing agreements (PPA) to source a considerable proportion on their electricity. While there is no transparent data source for PPA transactions, retailers contend that PPAs are based on LRMC calculations.

In contrast, Ergon Energy, QEnergy, Stanwell and the consumer groups were supportive of the Authority's proposed hedging-based approach, suggesting that the approach would provide valid, cost-reflective and unbiased estimates of wholesale energy costs for 2012-13. In particular, QCOSS supported a pure market-based approach on the basis that:

(a) the LRMC of generation is a theoretical concept and may not reflect the actual costs faced by retailers in purchasing wholesale energy in Queensland;

(b) calculating the LRMC of generation is opaque as it requires the Authority to rely on a consultant's 'black-box' model; and

(c) a market-based approach is based on transparent products that can be monitored and traded by all participants in the retail market.

The Authority's Position

LRMC

Despite some retailers' support for retaining at least some aspects of LRMC estimates in calculating energy purchase costs, there are a number of reasons, as the Authority has canvassed in the past, to move away from using LRMC in favour of using a market-based approach, including that:

(a) LRMC is an estimate of long term generation costs rather than the cost to a retailer of purchasing wholesale electricity in the forth coming year;

(b) LRMC ignores prevailing conditions in the electricity market, which can be influenced by a range of factors and which can have a significant influence on energy purchase costs;

(c) LRMC ignores the existence of the NEM and the major impact it has had on the wholesale price of electricity; and

(d) adopting a LRMC approach as a floor suggests that notified tariffs should be set at a level which underwrites generation which is not one of the requirements established by the Delegation.

The Authority is not convinced of the merits of including an LRMC "floor" in regulated retail prices. As the Authority noted previously, while adopting an LRMC floor in notified prices might provide additional security for investment in generation, the Authority is of the view that this is unnecessary given current market conditions as there appears to be sufficient reliable information available in the market for a firm to make a timely and efficient decision about investing in generation in the NEM.

Moreover, the Authority questions why this increased security would be needed with regulated prices but not if the market was entirely deregulated, in which case only market costs would be available. Furthermore, while it is possible that a regulated price based on energy purchase costs could be less than the actual costs faced by retailers (including the costs of PPAs), it would be expected that, if this were the expected long term situation, there would be little or no discounts to the regulated price available in the market place and competition would not be vigorous. But this is not the case in Queensland now and the new prices proposed are in excess of current levels.

ACIL also advised against using LRMC on the basis that it does not account for prevailing market conditions and therefore is unlikely to reflect actual wholesale energy purchase costs faced by retailers, as required in the Delegation.

While several retailers pointed to the inclusion of an LRMC floor in NSW regulated prices by IPART as evidencing some support by the regulator for the approach, this fails to recognise that IPART is required to adopt this approach by its terms of reference.

Similarly, the Authority considers that the ICRC's concerns regarding the use of LRMC are relevant, regardless of the approach to regulation the ICRC has adopted and despite AGL's view, and reflect the regulator's concern to set prices that reflect actual costs.

The Authority has now considered this issue in detail in a number of papers and forums. It is not convinced that an entirely LRMC approach or the inclusion of an LRMC floor in a market based approach is warranted or necessary and maintains its view that a market based approach should result in regulated prices for the year ahead reflecting the actual costs consumers are causing to be incurred through their consumption.

The Authority has adopted a market-based approach to estimating energy costs for 2012-13 and has not included estimates of LRMC in any way in its energy cost estimates.

Market-based Approaches

To help it form a view on which market-based approach to use for the Draft Determination, the Authority requested that ACIL develop energy cost estimates based on both the price distribution approach and a hedging-based approach similar to that used under the BRCI, and to provide advice on the most appropriate method to apply to retail tariffs. In response to concerns raised in submissions regarding the proposed price distribution approach, ACIL tried to amend the way in which its price distribution approach would be implemented. However, it encountered difficulty in quantifying how the risk aversion of different retailers might affect the premium over the spot price that retailers would be willing to incur in purchasing forward energy contracts.

At the Authority's request, ACIL also investigated further the availability of data for use in a hedging-based approach to estimating energy costs. While ACIL noted that trading was thin for a number of contracts, it was satisfied that, even through thinly traded, the contract pricing data then available could be used in a hedging-based approach to estimate energy costs for 2012-13 and recommended that the Authority proceed down this path.

The only exception to this was for controlled load and unmetered supply tariffs where ACIL suggested that the hedging-based approach was not suited to estimating energy costs because the loads for these tariffs mainly occur in off-peak periods which are difficult to cover with base, peak or off-peak contracts without significantly over-contracting.

The Authority had only proposed using ACIL's price distribution approach because, at the time the Draft Methodology Paper was being prepared, it appeared there would be insufficient market data to support continued use of a BRCI-type hedging-based approach. By the time the Draft Determination was prepared, this situation had changed and the Authority was able to pursue its preferred hedging approach for the majority of tariff classes.

Since the release of the Draft Determination, an additional 10 weeks of trading data has become available for use in preparing this Final Determination. This additional data has helped to further improve the robustness of the energy cost estimates developed by ACIL. However, the additional data did not have any noticeable impact on the estimates in the Draft Determination which provided more evidence that the earlier decision to use the hedging approach was sound.

In response to submissions, the Authority also requested that ACIL undertake further work on applying a hedging-based approach to the estimation of controlled load and unmetered tariffs. The method ACIL pursued used the hedging approach to calculate the total cost of supplying the NSLP with and without the control load and the difference in cost between the NSLP with and without the controlled load was taken as the cost of hedging the controlled load. The unit cost of the controlled load was then calculated by dividing the total cost by the MWh used. ACIL was satisfied that this hedging-based approach provides appropriate estimates for these tariffs.

For this Final Determination, the Authority has therefore calculated wholesale energy costs for all 2012-13 tariffs based on the hedging-based approach.

A more detailed discussion of the hedging approach can be found in ACIL's Final Report which is available from the Authority's website.

3.2.2 Customer Load Forecasts

To undertake its analysis of energy costs, the Authority requires forecasts of customer loads that will need to be purchased by retailers in 2012-13.

Under the BRCI, the Authority was required to use the 'NEM load' (being the total State NEM load less the load of customers directly connected to the transmission network) to calculate energy cost estimates. As the BRCI involved escalating all tariffs by a single rate, there was no need to calculate energy costs by tariff or settlement class.

In its Issues Paper, the Authority suggested that it would be necessary to estimate the load of customers in aggregate and on each network tariff in Energex's network area in order determine energy costs and proposed to use the Energex net system load profile (NSLP) for estimating energy costs for regulated retail tariffs as stakeholders had generally supported the use of this load profile when the Authority undertook its 2009 Review.

In its Draft Methodology Paper, the Authority noted the suggestion by ACIL that, in conjunction with its price distribution model, it could develop separate load forecast for each regulated retail tariff. The Authority considered this may improve the cost-reflectivity of the subsequent retail tariffs.

However, in its Draft Determination, having considered the way in which retailers are charged for electricity by AEMO, the Authority was able to simplify its approach to reflect the settlement process and construct loads for each AEMO settlement class. This involved using the Energex NSLP and two controlled load profiles for small customers and the Ergon Energy NSLP for large customers. The Authority also used the load profile for unmetered consumption in Energex's area as the basis for estimating energy costs for unmetered load and streetlight tariffs.

Approaches in Other Jurisdictions

In their most recent determinations, ESCOSA and ICRC both used the NSLP as the basis for their energy cost estimates. As required by their respective terms of references and regulations, IPART and the Office of the Tasmanian Economic Regulator (OTTER) both used the forecast load of contestable customers provided by the incumbent retailers in their regions. However, IPART also made a recommendation to the NSW Government that it consider amending the terms of reference for future price reviews to allow energy purchase costs to be based on the NSLP of each of the NSW Standard Retailers, rather than on the Standard Retailer's own forecasts of contestable customer load.

Submissions

There was general support from retailers and consumer groups for this approach because it reflected the basis upon which retailers' purchases are settled by AEMO while the alternative approaches considered previously would have introduced unwanted distortions between customer classes that are all, in fact, settled against the same load profile by AEMO.

Retailers suggested that, subject to some adjustments, Energex's NSLP was the most appropriate source of data for customer load forecasts. Origin Energy, AGL and TRUenergy all suggested that, if applied, the Energex NSLP should be adjusted to account for the required transfer of large customers (those customers that consume more than 100 MWh per annum) off notified prices and onto negotiated retail contracts.

Ergon Energy supported using Energex's NSLP to estimate energy purchase costs, but suggested that the Authority should use a historical trend analysis to adjust the NSLP rather than the ESOO, which Ergon Energy suggested had overestimated electricity demand and consumption in Queensland over the last few years.

Submissions in response to the Draft Determination raised a number of technical issues with the way in which ACIL had sourced and modified load data to arrive at its forecasts for 2012-13. In particular:

(a) Ergon Energy suggested that its NSLP was not representative of the load consumed by the customers that will actually face those tariffs based on Ergon Energy network charges (Tariffs 42, 43, 44, 53, 54 and 55). This was because the Ergon Energy NSLP is predominantly derived from the consumption of small customers while these tariffs relate only to large customers. It suggested that, in future years, the Authority might consider using representative curves for these tariffs.

(b) Origin Energy questioned Energex's advice to the Authority that the removal of large customers from the NSLP from 2012-13 would not impact the load shape. According to Origin, large customers currently account for approximately 10% of the NSLP. However, Ergon Energy also suggested that there was no need to adjust the NSLP for the removal of large customers;

(c) Origin Energy suggested that ACIL should remove the 2008 load from its calculations because it was considerably lower than 2009, 2010 and 2011. TRUenergy, on the other hand, suggested that 4 years of data was not enough because there had been fewer days over 32 degrees in recent years;

(d) Ergon Energy queried why ACIL had based its calculations on the 10% POE for 2012-13 rather than on the 50% POE (or some combination of the 10%, 50% AND 90% POE); and

(e) AGL and TRUenergy raised a number of additional concerns relating to the way in which ACIL had adjusted the historic load to make it appropriate for 2012-13. Origin, AGL and TRUenergy noted the difficulty in providing useful feedback given the lack of data provided by ACIL.

These issues are mentioned below but a detailed response is provided in ACIL's Final report.

The Authority's Position

Settlement Classes vs. Individual Load Profiles

In response to concerns raised in submissions on the Draft Methodology Paper, the Authority considers that the manner in which energy costs are settled by AEMO provides the most appropriate basis for estimating energy costs. The Authority has therefore determined energy costs based on load profiles for AEMO 'settlement classes' in order to reflect the actual costs incurred by retailers.

Under the AEMO settlement process, the majority of customers' consumption is settled against the NSLP for each distributor because the majority of individual customer meters are simple accumulation meters (or read as accumulation meters) and do not provide any information on the time of use, only the amount of energy consumed over an extended period (generally each quarter). Where customers have time-of-use meters that record both time and quantity data or this can be implied from the tariff type (for example, controlled loads), this information is used to settle the retailer's energy costs. However, it should be noted that many "time-of-use" tariffs for small customers are still settled against the NSLP because of meter inadequacies.

Therefore, the (Energex or Ergon Energy) NSLP has been used as the basis for estimating energy costs for all those tariffs that are settled against the relevant NSLP by AEMO. One of the downsides of this approach is that customers will receive no price signals regarding the time-of-use cost of their energy consumption via the energy charge as a single flat energy cost component will apply across all time periods in tariffs settled against the NSLP.

The NSLP approach means using the Energex NSLP and two controlled load profiles as the basis for estimating energy costs for regulated retail tariffs for small customers and the Ergon Energy NSLP as the basis for estimating energy costs for regulated retail tariffs for large customers.

As noted above, in the Draft Determination, the Authority used a load profile for unmetered consumption in Energex's area as the basis for estimating energy costs for unmetered load and streetlight tariffs. Having further considered this issue, ACIL has recommended that the Authority use the Energex NSLP for unmetered tariffs as this is the basis upon which AEMO charges retailers for these loads in South East Queensland. It would appear reasonable to adopt a similar position for the streetlight tariff, but as this tariff will only be available in the Ergon Energy area, the Authority has opted to base energy costs for this tariff on the Ergon Energy NSLP.

Potential Adjustments to Energex NSLP

In its Draft Determination, the Authority considered whether it should adjust the Energex NSLP to account for:

(a) the introduction of the residential IBT;

(b) the introduction of the voluntary residential time-of-use tariff; and

(c) the removal of large customers from accessing notified prices in the Energex area.

As it is no longer required to set Tariff 11 and this is also no longer to be an inclining block tariff, the first point becomes a non-issue.

On the second point, only those customers with relatively high levels of consumption who are willing and able to shift their consumption from peak to off-peak periods of the day are likely to benefit from moving to the residential time-of-use tariff. Moreover, the distributors will have constraints on how many new time-of-use meters they can install over the year to accommodate demand from any customers wishing to switch to this tariff. As a result, the likely take-up of the residential time-of-use tariff will be relatively slow at first and the Authority does not expect its availability to impact the NSLP in any measurable way in 2012-13. With the Government's decision to freeze Tariff 11 for the coming year, there is even less likelihood of large numbers of customers switching to the voluntary time-of-use tariff.

Regarding the impact of large customers being required to move from notified prices to market contracts, Energex has indicated that the removal of large customers from the NSLP is likely to have less than a 1% impact on the NSLP because the majority of large customers in the Energex area are already outside the NSLP and are being settled against their individual interval meter readings. While Origin Energy disputed this view, claiming the impact would be around 10%, Ergon Energy was of the same view as Energex. The Authority has accepted the distributors' view in relation to the likely impact on the NSLP and has therefore made no adjustment to the Energex NSLP to account for the removal of large customers from 1 July 2012.

ACIL Tasman also advised that the load factor of the NSLP has improved over the past three years from 39.9% in 2008/09 to 43.4% in 2010/11. This means that the NSLP has flattened even though new interval metered customers have been subtracted during this time. The load factor has clearly been affected by the mild conditions but additional solar PV and hot water would have also been a factor in reducing the summer afternoon peak. The load factor for the Energex NSLP for the median year used in calculating wholesale energy purchase costs was 40.1%.

Period of Historic Load Used

At the workshop, stakeholders suggested that ACIL's approach of constructing 41 years of load data from a single year of actual data could produce skewed outcomes if the actual data was based on a particularly cool or hot year.

While ACIL was satisfied that this was not the case, it modified its approach for the Draft Determination to base its load forecasts on four years of actual historical data – 2007-08 to 2010-11. Including the additional actual load data reduces the number of years of 'constructed' load data that needs to be developed to 37 years.

Both TRUenergy and Origin Energy noted some very specific anomalies in weather and load in recent years that highlight the difficulty in determining the most appropriate period of historic load to use. For differing reasons, TRUenergy suggests that ACIL has used too few years of data, while Origin Energy suggests it had used too many.

The Authority recognises that Queensland has seen some unusual weather events over the last few years but accepts ACIL's advice that the method they have adopted insulates the forecast loads from being overly influenced by historic weather anomalies. Adding the additional years of actual data has reinforced this view and will reduce any abnormal impact that these recent weather events may have on the constructed load profiles and, in turn, the energy cost estimates.

Furthermore, the 41 years of load profiles are adjusted so that the peak demand across the 40 years equals the 10% POE medium demand forecast and the annual energy forecast from

Powerlink's Updated 2011 Annual Planning Report (APR). This means that the weather conditions prevailing in the four actual years are not particularly critical to the analysis.

Constructed load shapes

To estimate energy costs for 2012-13, the Authority needs to develop forecast hourly load profiles for each of the relevant settlement classes – the Energex NSLP and the two Energex controlled loads and the Ergon Energy NSLP.

In its Final Report, ACIL has used the same method it proposed in its Draft Report. That is, ACIL used 41 years of weather data (1970-71 to 2010-11) and four years of load data (2007-08 to 2010-11) to 'construct' 37 additional years of weather adjusted load data for each settlement class. To construct the 37 additional years of load data, ACIL matched the weather on each day of the additional years with the weather on one day in the four sample years to find the closest match (using a least squares approach). Having matched each day in the additional years with one day in the sample year, ACIL applied the load from the day in the four actual years to the corresponding day in the additional year. Once it had constructed the 37 years of additional load data, ACIL then adjusted each of the 41 load profiles to reflect forecast consumption in 2012-13, as discussed below.

Escalating Load Profiles to 2012-13

At the time of the Draft Methodology Paper, ACIL proposed to adjust consumption and demand estimates for Queensland and other NEM regions according to the ESOO forecasts (which are based on the forecasts in Powerlink's APR). For tariff-specific load profiles, it proposed to use 2012-13 forecasts provided by the distributors.

Between the release of the Draft Methodology Paper and the Draft Determination, Powerlink published revised forecasts for 2012-13[9], which were later re-published in an updated ESOO[10]. These forecasts were used in the Draft Determination on the basis that they represented the most up to date Powerlink forecasts and appeared to be more consistent with past experience.

Since then, the AER has also developed alternative demand forecasts for Queensland in its review of Powerlink's revenue cap for 2012-13 to 2016-17[11]. ACIL reviewed these forecasts but noted that the AER had not provided corresponding annual energy forecasts. ACIL considered that it was not appropriate to use the updated demand forecasts without a corresponding annual energy forecast as this would result in a flattening of the load shape for 2012-13.

As such, ACIL has continued to rely on the earlier, updated APR and ESOO for its 2012-13 demand and consumption estimates used in the Draft Determination. As energy components are estimated according to settlement class, ACIL used the region-specific forecasts in the updated APR and applied them to the relevant load profiles.

ACIL has provided a detailed discussion of the process that it uses to adjust the 41 years of load profiles into 2012-13 forecasts in its Final Report. Rather than escalating each of the 41 load scenarios to the 10% POE (as suggested by Ergon Energy), ACIL lines up the 41 scenarios into one continuous load profile and sets the maximum demand over the entire 41 scenarios to the 10% POE. Given ACIL's process for constructing the historic load shapes by matching weather patterns, it is likely that the maximum load day would be chosen more than once over the 41 years, which would mean that the 10% POE demand would be

[9] Powerlink, *Annual Planning Report 2011 Update*, January 2012
[10] AEMO, *Electricity Statement of Opportunities Update*, March 2012
[11] EMCa, *Powerlink Revenue Determination 2013-17 Demand Forecast Review*, September 2011

achieved more than once in its modelling. ACIL then adjusts the continuous (41 year) load shape to ensure that the total volume of electricity consumed is equal to 41 times Powerlink's updated 2012-13 volume forecast. This step allows for consumption to be higher in some years and lower in others, but to match the medium growth outlook on average. ACIL's Final Report includes further detail to address the transparency concerns of AGL and TRUenergy.

ACIL then took the median load profile (from the 41 weather-adjusted annual load profiles for 2012-13) for each settlement class as the basis for estimating the volume of hedging contracts a retailer would need to purchase in order to meet those forecast loads.

3.2.3 Plant Outage Scenarios

To recognise variations in plant availability, ACIL developed 10 plant outage scenarios which have the same plant availabilities but variations in the random forced outages. The timing of forced outages is critical in the pool price formation process. A larger unit outage in a period of high demand can have a large influence on price but have little influence on price had it occurred overnight in a low demand period. The 10 sets of outages represent a realistic range of outage possibilities.

3.2.4 Load/Outage Years to Represent 2012/13

The 41 years of loads adjusted to match the 2012-13 load forecast are overlayed on the 10 outage scenarios to provide 410 representations of 2012-13 taking possible variations in load and outage which might occur.

Each of the 410 results are modelled by ACIL using the hedging approach, as explained in detail in their report, to produce 410 possible price outcomes for 2012-13. It is the median price outcome of these 410 possible prices which has been selected as the estimate of the 2012/13 wholesale energy purchase cost for use in the tariff schedule.

3.2.5 Hedging Strategy

For the Draft Determination, the Authority used basically the same hedging strategy as that used previously for the 2011-12 BRCI Final Decision. This hedging strategy assumed that a retailer would purchase:

(a) flat swaps up to the 80th percentile of off-peak load. (A 1 MW quarterly flat swap contract is an agreement between two parties to sell/buy 1 MW of electricity in each hour over the quarter);

(b) peak swaps beyond the level of flat swaps up to the 90th percentile of peak load. (A 1 MW peak swap contract is an agreement between two parties to sell/buy 1 MW of electricity for each hour between 7am and 10pm weekdays (excluding public holidays) over the duration of the quarter); and

(c) $300 caps beyond the cover of swaps to cover up to 105% of the maximum peak load. (Cap contracts only pay out when the spot price is above a particular price. For example, if a retailer purchases a $300 peak cap contract, it will face the spot price whenever the spot price is under $300/MWh but a maximum of $300/MWh at all other times).

However, rather than assuming that a retailer would spread its contract purchases evenly over 24 months up to the start of the tariff year (as was assumed under the BRCI), in applying the hedging strategy for 2012-13 this period was extended to four years and ACIL used whatever trades had been undertaken, in order to reflect the shortage of contract trading in some periods, and used a trade volume-weighted average of energy purchases over that period rather than assuming an even purchasing pattern as was done previously. There was general agreement at the workshop that a longer time period would better reflect the actual hedging strategies of retailers. While three years was suggested at that time, the move to four years for the Draft Determination picked up all possible trading in hedging contracts. Combined with the move to volume weighting, it was expected that this would produce a better representation of historical contract purchasing patterns.

The cost of purchasing the required hedging contracts to cover the forecast loads was based on d-cypha Trade contract price data.

However, where uncertainty over carbon had made the futures market illiquid (first quarter 2013 base and peak contracts and second quarter 2013 base contracts), ACIL made an exception to the four-year purchasing strategy by excluding sales that occurred prior to 8 November 2011 (the date the carbon tax legislation was passed by Parliament). From that date onwards, d-cypha Trade settlement prices were in-line with the over-the-counter (OTC) contract prices obtained from TFS which confirmed the reliability of the d-cypha Trade data.

Submissions

Submissions on the Draft Determination were generally supportive of the Authority's hedging strategy, with only Origin Energy suggesting that retailers would actually hedge to the extreme load, rather than to the average.

However, a number of submissions were concerned with either ACIL's sampling of d-cypha Trade data or the outcomes of the hedging process. In particular:

(a) TRUenergy, Origin Energy and AGL noted that there appeared to be an error in ACIL's hedging model relating to the timing of peak and off-peak periods;

(b) TRUenergy noted that hedging, on average, provides a lower cost than if a retailer faced the spot price and Origin found that the expected return for cap contracts was higher than the premium;

(c) QCOSS and CCCL suggested that ACIL should include all trades in all contracts (rather than excluding trades prior to 8 November 2011), on the basis that the earlier trades took place and should be accounted for. Conversely, Origin Energy and AGL raised concerns with including any trades from prior to 8 November 2011. In particular, Origin Energy suggested that some retailers may have had policies in place that prevented them from purchasing carbon inclusive contracts prior to the passing of the carbon tax legislation; and

(d) AGL suggested that the Authority should use TFS carbon exclusive prices for base contract prices, plus an allowance for the AFMA Australian Carbon Benchmark (ACB) addendum to overcome the lack of liquidity in some periods in d-cypha Trade data.

The Authority's position

As highlighted by submissions, ACIL has acknowledged that there was an error in its Draft Report hedging model relating to the peak and off-peak categorisation of time periods. ACIL has rectified this error in its Final Report and the impact on energy costs for 2012-13 was minor.

ACIL agrees with TRUenergy that the price distribution methodology produced generally higher prices than the hedging approach, noting that it could be related to the contract market expecting lower pool prices than ACIL forecasts in its modelling, potentially because market participants are using lower demand forecasts than ACIL. ACIL also notes that, in cases where the pool prices are high, Origin Energy is correct that the return to the cap contract will be higher than the premium. However, ACIL also notes that, when the opposite is the case, when pool prices are low, the return to the cap contract will be lower than the premium.

Having considered the issues raised in submissions, ACIL is still of the view that its approach of removing trades prior to 8 November 2011 from its analysis of contract prices where trading has been illiquid is most appropriate given that there were few trades in that period and that, by excluding those early trades, the d-cypha Trade data closely correlates with the TFS data. However, for contracts that were not affected by liquidity issues, or for cap contracts (that are not particularly affected by carbon costs), ACIL is satisfied that taking the trade-weighted average of all trades is the most appropriate method for estimating contract prices.

Finally, it is not clear how AGL's suggestion of using TFS carbon exclusive trades would rectify the issues with liquidity in d-cypha Trade data, given that TFS contracts have been traded considerably less than the d-cypha Trade contracts.

Further detail on the modelling-specific issues raised by stakeholders is provided in ACIL's Final Report.

The Authority is satisfied that ACIL's hedging strategy provides for a reasonable level of protection for retailers, without being overly risk averse. As such, ACIL has retained this hedging strategy in preparing its Final Report to the Authority, which approach the Authority accepts.

3.2.6 Spot Price Forecasts

While the previous two sections provide estimates of the forecast load and the cost of hedging contracts to cover that load, the actual outcome for the year in prospect (and hence the estimated cost of energy) will also be influenced by how well those forward purchases cover the actual load and the costs a retailer might incur due to its exposure to the spot market prices whenever its hedge coverage falls short, or proves to be in excess, of what is actually required.

While a retailer will typically try to purchase contracts to cover its forecast load as closely as possible, the inflexible nature of exchange traded contracts means that retailers will always have periods in which they are either over- or under-contracted. At these times, the retailer is exposed to the prices in the spot market.

Forecasting wholesale spot market prices with any degree of accuracy and credibility invariably requires the use of a proprietary electricity market simulation model, capable of simulating spot prices that would occur in the NEM.

However, ACIL provides evidence in its report that the contract strategy used in the hedging approach removes almost all of the pool price volatility. The evidence presented by ACIL for the 410 representations for 2012/13 show significant variation in the annual average load weighted pool prices and a very stable hedged price. On this basis, ACIL contends that prices from the hedging approach are not particularly sensitive the pool price projections.

Approaches in Other Jurisdictions

Previously, the Authority (in its BRCI decisions), IPART and ESCOSA have relied on expert consultants' proprietary electricity market simulation models to generate future spot prices. In its 2010-12 decision, the ICRC adopted a simpler modelling approach, relying on historical spot price outcomes against which it modelled forward contract prices.

Submissions

In response to the Issues Paper, AGL, Origin Energy and Ergon Energy favoured the use of forecast spot prices rather than historical prices. While each noted some of the shortfalls of proprietary models (largely relating to the subjectivity of assumptions and lack of transparency), it was considered that these models were favourable to using historical prices that are unable to take account of future market conditions (such as the introduction of a carbon tax).

QCOSS suggested that the Authority should not adopt a methodology that relied on a proprietary model that was not open for review and auditing. Rather, it suggested the Authority should adopt an approach similar to that followed by ICRC, which used transparent and publicly available historical spot prices.

QEnergy suggested that it was not necessary to develop spot price forecasts because, when businesses expose themselves to the spot market, they do it for speculative/trading reasons. QEnergy suggested that regulated retail tariffs should not account for activities that are unrelated to retailing.

Following the release of the Draft Methodology Paper, only AGL and Ergon Energy commented on the approach to forecasting spot prices. AGL reiterated its support for spot price forecasts (as opposed to the use of historical data) to the extent that they are used to settle financial contracts. Ergon Energy also supported the use of forecasts, but noted that the physical and financial markets are not perfectly correlated and that in most quarters there is a negative correlation between contract and spot prices (in periods where financial contracts were trading at higher prices, generators tend to contract a higher proportion of their load which reduces pool prices).

In response to the Draft Determination, submissions were generally supportive of using ACIL's proprietary model for forecasting spot prices, but raised a number of technical concerns with ACIL's approach. For instance:

(a) AGL queried why 74% of periods where the spot price exceeded $1,000/MWh were on non-working days, and suggested that more data should be made public;

(b) Ergon Energy questioned whether ACIL's reliance on the 10% POE forecasts from Powerlink was causing it to overstate 2012-13 spot prices; and

(c) Origin Energy suggested that ACIL should take transmission constraints into account, which it suggested can add up to $4/MWh to quarterly pool prices.

The Authority's Position

ACIL has responded in detail in its Final Report to the technical queries raised in submissions on the Draft Determination. In summary, it notes that:

(a) The issue noted by AGL was the result of an error in the modelling for ACIL's Draft Report which has been rectified for its Final Report;

(b) Ergon Energy's query results from a misunderstanding of the way in which ACIL has manipulated its load forecasts to reflect 2012-13. ACIL has provided more information on this process in its Final Report to help stakeholders understand its process; and

(c) while ACIL's Powermark modelling does not explicitly account for intra-regional transmission constraints, calibration of the model ensures that it can replicate price outcomes under normal market circumstances. ACIL suggests that the situation at Calvale-Wurdong referred to by Origin Energy is not a normal market characteristic.

While the Authority considers that the spot price is a key input to estimating the energy costs that a retailer is likely to face, it acknowledges that proprietary spot price forecasting models can be opaque and that some stakeholders would prefer an approach to determining spot prices that can be independently verified through publicly available data. However, using historical prices does not appear to be a viable alternative as this would ignore structural changes that might be reasonably expected to occur in the market in the future, for example, the likely imposition of a carbon tax on 1 July 2012.

As proposed in the Draft Determination, ACIL has used its Powermark proprietary model to develop NEM spot price forecasts for 2012-13. ACIL's model takes the 41 half-hourly load profiles for the NEM together with 10 generator outage scenarios to produce 410 half-hourly annual spot price scenarios for 2012-13. These scenarios reflect a range of potential load and spot price outcomes that may occur in 2012-13.

Under the BRCI, ACIL used three load and spot price scenarios (10%, 50% and 90% POE) to arrive at its estimate of energy costs for the following year. For each POE load scenario, ACIL forecast a set of corresponding spot prices. ACIL then estimated a weighted average of the costs that retailer would incur under each of these scenarios based its estimate of the likelihood of each outcome. Under this new approach, rather than using a weighted average of three scenarios, ACIL uses 41 load scenarios and 410 spot price scenarios to reflect the range and relative likelihood of costs being incurred by a retailer and uses the median price of the 410 prices as the energy purchase cost.

For each hour in the forecast year (2012-13), ACIL brings together the hedging costs for each settlement class (from section 3.2.5), the load forecasts (from section 3.2.2) and the spot price estimates (from section 3.2.6) to estimate the cost that a retailer would incur in that half hour. For each spot price scenario, ACIL then estimates the load-weighted average price that a retailer would pay over the year, resulting in 410 load-weighted average prices for 2012-13. It then takes the median of these as its estimate of the wholesale energy cost for 2012-13.

Table 3.1 shows the basic wholesale energy cost estimates for each settlement class in 2012-13.

Table 3.1: Wholesale Energy Cost allowances for 2012-13 Excluding Losses and Carbon

Settlement class	*Retail Tariff*	*Allowance ($/MWh)*	*Allowance (c/kWh)*
Energex NSLP and unmetered supply	12, 20, 22, 41, 91	41.59	4.159
Energex Controlled Load 9000	31	20.54	2.054
Energex Controlled Load 9100	33	28.86	2.886
Ergon Energy NSLP and streetlights	44, 45, 46, 47, 48, 71	35.64	3.564

Source: ACIL Tasman, Estimated Energy Purchase Costs for Final Determination, May 2012.

3.2.7 Carbon Costs

The Authority has noted that, if a carbon tax were to be implemented by the Commonwealth Government from 1 July 2012, the costs associated with this tax would need to be accounted for in its energy purchase cost estimates.

In the Draft Determination, ACIL prepared two sets of hedging-based energy costs – one set that was carbon inclusive and another that had carbon costs removed based on AFMA's ACB addendum. The Authority proposed to use ACIL's carbon-inclusive estimates for 2012-13 on the basis that the Clean Energy Futures legislation was passed by the Commonwealth in November 2011.

Approaches in Other Jurisdictions

A number of regulators in other jurisdictions have considered the likely impacts of a carbon tax on regulated retail tariffs.

IPART estimated the impacts of carbon costs in NSW for both its hedging-based approach to estimating energy costs and its LRMC approach by factoring the cost of carbon into a generator's short run marginal costs (SRMC), consistent with the way a generator considers the cost of fuel[12]. For the hedging-based approach (which is the most relevant to the Authority), the carbon costs feed into the bidding decisions made by generators. IPART estimated carbon costs for 2012-13 at $26 to $28/MWh under its hedging-based approach and $20/MWh under its LRMC approach.

Similar to IPART, OTTER has estimated the impacts of carbon in Tasmania for both its hedging-based approach and its LRMC approach[13]. OTTER used carbon inclusive contracts as the basis for its hedging-based approach. For its LRMC calculations, OTTER factored the cost of carbon into the SRMC of each generator. OTTER estimated carbon costs for 2012-13 at $13/MWh under its LRMC approach and noted that hedging-contracts appeared to include around $19/MWh for carbon.

While ICRC has not decided on the best way to incorporate carbon costs into its retail electricity prices, it has highlighted the potential to use carbon-exclusive contract prices in its

[12] IPART, *Changes in regulated electricity retail prices from 1 July 2012, Draft Report*, April 2012.
[13] IES, for OTTER, *Impact of the carbon pricing mechanism on the wholesale electricity price, Final Report*, April 2012.

market model and then uplift these contract prices by a carbon allowance calculated in accordance with the AFMA ACB addendum[14].

ESCOSA is currently undertaking a review of its retail electricity prices after AGL submitted an application for a special circumstances review, but it has not yet provided any details on how it might calculate these affects[15].

Submissions

Submissions received in response to the Issues Paper generally supported including an allowance for carbon costs in the 2012-13 regulated retail tariffs. Retailers suggested that the Authority should estimate a pass through for carbon costs separate to the energy cost allowance. AGL suggested that the Authority adopt the approach outlined in the AFMA ACB addendum that AFMA published, which estimates carbon costs according to $23 per tonne multiplied by the average emissions intensity of generators in the NEM. Following the release of the Draft Methodology Paper, retailers generally favoured this approach.

QCOSS suggested that carbon costs should be accounted for in the energy cost estimates and should not be a direct pass through. The Queensland Farmers Federation suggested that the Authority should also take into account the various compensation measures that were included in the Clean Energy Future legislation.

Following the release of the Draft Determination, a series of concerns about ACIL's simplistic approach to estimating the impacts of the carbon tax on wholesale electricity costs were raised in submissions. In particular, Ergon Energy, QCOSS and CCCL were concerned that such a simplistic approach may no longer be appropriate if the Government was inclined to hold T11 steady in 2012-13, but add a charge for carbon. QCOSS and CCCL noted that the AFMA pass-through is not a legislatively approved calculation of carbon costs, while Ergon Energy suggested that ACIL should re-run its pricing model with carbon-inclusive and carbon exclusive dispatch profiles.

In addition to concerns with ACIL's approach to estimating carbon costs, submissions questioned the emissions intensity factor that ACIL had used in its calculations. Stanwell, TRUenergy, AGL and Origin Energy suggested that ACIL's forecast 2012-13 emissions intensity for the NEM (0.87) was considerably lower than the historic emissions intensity of the NEM (currently 0.92). Stanwell noted that a carbon price of $23/tonne was unlikely to change the merit order in the spot market, which meant that the emissions intensity was unlikely to decrease in 2012-13. QCOSS and CCCL noted that there was still uncertainty as to how electricity prices in 2012-13 will be affected by the carbon tax, noting that, in 2009, Frontier Economics estimated emissions intensities as a result of the Carbon Pollution Reduction Scheme between 0.20 and 1.20.

The Authority's Position

The Authority accepts that the approach ACIL used to estimate carbon costs for the Draft Determination was simplistic. At that time, the Authority was satisfied that the carbon inclusive calculations that it was relying on for retail tariffs were correct, and the carbon exclusive estimate was included simply to provide stakeholders with an indication of the level of carbon costs in the energy cost calculations. To improve the quality of these estimates, ACIL has followed Ergon Energy's suggestions and re-run its spot price and hedging models excluding carbon tax costs.

[14] ICRC, *Retail prices for franchise electricity customers 2012-14, Draft Report*, April 2012.
[15] ESCOSA, *Review of 2011-2014 Electricity Standing Contract Price Determination, Statement of Regulatory Intent*, April 2012.

To estimate quarterly swap contract prices without carbon, ACIL continued to apply the AFMA ACB addendum methodology and has used the quarterly NEM emissions factors between 0.89 and 0.91 as projected for 2012-13 in its Powermark Model for 2012-13. ACIL is satisfied that its forecast emissions intensity factor is more appropriate than historic NEM intensities because it takes into account the impact of the carbon tax on each individual generator and recognises that this may affect the merit order at certain times.

As outlined in Table 3.2, at the legislated carbon tax rate of $23 per tonne, ACIL estimates carbon costs to be between $19.90 and $21.10/MWh at the regional reference node for 2012-13. While there are a range of factors that influence the extent of carbon pass through from state to state (plant mix, dispatch patterns, fuel costs, load profile, etc), the Authority notes that ACIL's carbon estimates fall at the midpoint of the carbon costs estimated by OTTER and IPART for 2012-13.

Table 3.2: Carbon Cost allowances for 2012-13 Excluding Losses

Settlement class	*Retail Tariff*	*Carbon Pass Through*	*Allowance ($/MWh)*	*Allowance (c/kWh)*
Energex NSLP and unmetered supply	12, 20, 22, 41, 91	87%	19.90	1.990
Energex Controlled Load 9000	31	92%	21.10	2.110
Energex Controlled Load 9100	33	87%	20.08	2.008
Ergon Energy NSLP and streetlights	44, 45, 46, 47, 48, 71	88%	20.29	2.029

Source: ACIL Tasman, Estimated Energy Purchase Costs for Final Determination, May 2012.

3.3 Other Energy Costs

In addition to wholesale energy costs, the Delegation requires that the Authority also consider other costs that a retailer might incur, including fees and charges imposed by AEMO, the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including future State and Commonwealth schemes) and a mechanism to address any new compulsory scheme that imposes material costs on retailers.

The Authority has therefore considered additional energy costs that retailers incur in relation to:

(a) the Queensland Gas Scheme;

(b) the Small-Scale Renewable Energy Scheme (SRES);

(c) the Large-Scale Renewable Energy Target (LRET) Scheme; and

(d) NEM participation fees and ancillary services charges.

The Authority has also considered the inclusion of a mechanism to address any new compulsory scheme that imposes material costs on retailers in Chapter 6, but concludes that it is not able to do so.

3.3.1 Queensland Gas Scheme

The Queensland Gas Scheme requires retailers to obtain and surrender sufficient Gas Electricity Certificates (GECs) to cover a prescribed proportion of their annual customer load or incur a penalty charge for each MWh shortfall. The requirement to obtain GECs therefore creates an additional cost to retailers in purchasing electricity for their customers.

When a national emissions trading scheme was previously proposed, the Queensland Government indicated that the Queensland Gas Scheme may be phased out. With the introduction of the carbon tax now imminent, there is no firm indication that the Queensland Gas Scheme will be removed. Until there is a clear commitment to remove the scheme, retailers will continue to incur Gas Scheme costs and the Authority is bound to include these costs in its estimate of energy costs.

To effectively estimate the cost of complying with the Queensland Gas Scheme, the following information is required:

(a) the annual mandatory targets to be covered by GECs in 2012 and 2013; and

(b) the cost of obtaining GECs to meet those targets.

The annual mandatory targets are prescribed under the Electricity Act. In 2012 and 2013, a retailer is required to obtain GECs equivalent to 15% of its annual electricity load[16].

The Authority has used different approaches in past BRCI decisions to estimate GEC costs, but its preference is to use a market-based approach to estimating these costs. In its 2011-12 BRCI decision, the Authority considered a suggestion from retailers that it adopt an approach based on the LRMC of gas-fired generation plant, but dismissed this idea on the basis that the LRMC approach would be less transparent and potentially more complicated than a market-data based approach.

Submissions

In response to the Authority's Issues Paper, several retailers were critical of using current market data to estimate GEC costs due to insufficient liquidity in the GEC market. Some retailers also suggested that current market data did not reflect the cost to retailers of purchasing GECs through long-term supply contracts between retailers and eligible generators. In contrast, QCOSS supported estimating GEC costs using market prices, arguing that these best reflected the actual costs faced by retailers. APG was also of the view that there was sufficient market data for the Authority to estimate compliance with environmental schemes.

To overcome some concerns about the lack of available market data, a number of submissions proposed using a longer time series of data than the Authority had previously used under the BRCI.

As an alternative to a market-based approach, Origin Energy suggested that the Authority adopt the LRMC of gas-fired generation to calculate GEC costs while AGL suggested consideration of a 'portfolio cost' approach, incorporating other sources of compliance.

Following the release of the Authority's Draft Methodology Paper and Draft Determination, QCOSS and Stanwell disagreed with the Authority's proposal to estimate GEC costs using a longer time series of data (as had been suggested by others), on the basis that the GEC market is currently oversupplied and that using a longer time series would therefore over-

[16] http://www.energyfutures.qld.gov.au/gas/qld-gas-scheme.htm

estimate the price of GECs paid by an efficient retailer. They suggested that GEC prices be calculated using an average of two years of historical market data, consistent with the 2011-12 BRCI decision. In support of this view, Stanwell argued that:

(a) new entrant retailers have sourced GECs from the open market rather than via long-term GEC contracts;

(b) Queensland incumbent retailers have the capacity to create GECs from their own gas-fired generation; and

(c) retailers are less willing to enter into long-term contracts due to the possibility that the Queensland Gas Scheme may be phased out in the near future.

The Authority's Position

The Authority considers that information on long-term GEC contracts might be a preferable basis for estimating future costs rather than using available market data. However, as noted by ACIL in its Final Report, this information is unavailable and the available market data is the only source of information on GEC costs.

The alternative of using an approach based on the LRMC of gas-fired generation has been considered by the Authority previously and found to be inferior to the more transparent and less complicated market-data based approach.

However, the Authority notes the concerns expressed by retailers about the current low levels of liquidity in the market for GECs, given that the market is characterised by a relatively small number of participants purchasing certificates that are created monthly at most and surrendered only once each year. Given that GECs have been acquired by various means, including long term contracts, and the fact that the GEC market is now oversupplied with low prices and very thin trading, ACIL was of the view that it would be appropriate to extend the historical period over which GEC prices are determined.

In calculating the 2011-12 BRCI, the Authority also considered that the movement in GEC prices would be better represented by a longer term view of market prices. However, at the time the 2011-12 decision was made, which required calculation of GEC costs for 2010-11, there was only sufficient market data to enable GEC costs to be calculated using a two year averaging period (with data from 1 July 2007). As another year has passed, there is now more historical market data available. The Authority has therefore extended the period over which GEC market prices are to be averaged from the two years used previously out to four years, consistent with the approach proposed in the Draft Determination. Using this extended period of data will help to smooth some of the unusual movements in market prices.

Based on current market data and the requirement for retailers to obtain GECs for 15% of their annual electricity load in 2012-13, ACIL estimated the cost of complying with the Queensland Gas Scheme for 2012-13 to be $0.85/MWh[17].

3.3.2 Enhanced Renewable Energy Target Scheme

On 1 January 2011, the Renewable Energy Target scheme was split into two separate schemes – the SRES and the LRET scheme, collectively known as the Enhanced Renewable Energy Target (ERET) Scheme.

[17] The cut-off date for AFMA data used is 23 April 2012.

The LRET sets annual targets for the amount of electricity that must be generated by large-scale renewable energy projects, such as wind farms. Retailers must purchase a set number of Large-Scale Generation Certificates (LGCs) determined by the Clean Energy Regulator (CER)[18] on the basis of achieving the annual target. The number of LGCs required to be surrendered by retailers to discharge their liability each year is determined by the CER's Renewable Power Percentage (RPP).

The SRES covers small-scale technologies such as solar panels and solar hot water systems installed by households and small businesses. Retailers must purchase Small-scale Technology Certificates (STCs) based on the expected rate of STC creation, which is determined by the Small-scale Technology Percentage (STP) published by the CER.

Retailers are required to surrender STCs and LGCs to fulfil their annual ERET obligations. If a retailer fails to meet its obligations, it will incur a penalty.

LRET Costs

For the 2011-12 BRCI, the Authority used a market-based approach to estimate LRET costs. ACIL based its estimate of 2011 LRET costs on weekly market prices for LGCs published by AFMA and the latest RPP and annual LRET targets set by ORER[19]. For 2012, ACIL estimated total liable energy and used the latest published LRET target to arrive at a forecast RPP.

Approaches in Other Jurisdictions

The ICRC (ACT) and OTTER (Tasmania) adopted market-based approaches to estimating retailers' cost of complying with the LRET scheme in their most recent determinations. While, OTTER estimated LRET costs based on its regulated retailer's forward purchasing strategy, in its Draft Report on the determination of 2012-13 regulated electricity retail prices, the ICRC estimated LGC costs based on spot market prices published by the industry association (Clean Energy Council, CEC). IPART (NSW) and ESCOSA (South Australia) based their cost estimates on the LRMC of renewable generation in their most recent determinations. While IPART estimated the cost of LGCs based on the LRMC of meeting the overall LRET target, ESCOSA estimated the cost of LGCs based on the difference between the LRMC of a new entrant wind generator and a Combined Cycle Gas Turbine generator.

All four regulators applied ORER's (now the CER) published and forecast RPPs in estimating LRET costs.

Submissions

Submissions included different views as to how LRET costs should be estimated. AGL, Origin Energy and TRUenergy suggested that LGC prices should be based on the LRMC of wind powered generation mainly reflecting their concerns about the current lack of liquidity in the market for LGCs.

Despite its preference for using an LRMC approach, AGL acknowledged that a market-based approach was a transparent way to determine short-term compliance costs but that other options for retailers to comply should be taken into account. AGL also considered that the LRET market was temporarily oversupplied and suggested that the Authority should not place too much weight on market prices.

[18] On 2 April 2012, the Office of Renewable Energy Regulator (ORER) was amalgamated into the Clean Energy Regulator (CER).
[19] Now published by the CER.

In contrast, Ergon Energy, APG, QEnergy, QCOSS and CCCL supported the proposal to continue using a market-based approach. QEnergy suggested that, if the market-based approach were to be used, the Authority should calculate LGC prices using an average of market price data commencing 1 January 2011 (which reflects the commencement of the ERET scheme) as prices were depressed immediately prior to this date. This view was also supported by Origin Energy.

The Authority's Position

The Authority previously considered whether an LRMC based approach should be used in its 2011-12 BRCI Decision and again in its Draft Determination, but determined that it was more appropriate to use actual market data than supply proxies such as the LRMC. As submissions received in response to the Draft Determination did not include any new information to persuade the Authority to change this decision, the Authority has calculated LGC prices using market data.

Although ACIL noted that retailers acquire most of their LGCs through long-term contracts with wind farms or through direct wind farm ownership, the prices in these contracts are not publicly available. Therefore, the Authority has to rely on market prices for LGCs published by AFMA.

While some retailers noted that there is a lack of liquidity in the market for LGCs, a low volume of trading does not necessarily mean market prices are unreliable. Following an examination of market prices over recent years, ACIL concluded that the market price has reacted as one would expect to prevailing market conditions. Nevertheless, in recognition of the current lack of liquidity, ACIL averaged LGC market prices published by AFMA over an extended period of 106 weeks for 2012 LGCs and 54 weeks for 2013 LGCs.

The Authority has used these averaged prices for LGCs, the CER's binding RPP for 2012 of 9.15%[20] and the CER's default estimate of the RPP for 2013 of 10.42%[21], to arrive at a cost for complying with the LRET scheme of $4.10/MWh in 2012-13.

ACIL has provided a detailed explanation of its calculation of LRET costs in its Final Report, along with information on LGC prices and assumptions underpinning the RPPs.

SRES Costs

For its 2011-12 BRCI Decision, the Authority used a market-based approach to estimate SRES costs, relying on ORER's Clearing House price of $40 per STC as well as ORER's final STP published for 2011 and ACIL's STP estimate for 2012. In its Draft Determination, the Authority proposed to maintain a similar approach, with the exception that the STP for 2013 be based on ORER's non-binding target.

Approaches in Other Jurisdictions

In their most recent price determinations, IPART (NSW), ESCOSA (South Australia) and OTTER (Tasmania) all adopted a market-based approach to estimate SRES costs based on ORER's Clearing House price of $40 per STC and ORER's binding and non-binding STPs for the relevant years.

[20] Clean Energy Regulator, 24 February 2012.
[21] Clean Energy Regulator, 24 February 2012.

However, in its Draft Report on its determination of 2012-14 regulated electricity retail prices, the ICRC (ACT) has estimated STC costs based on market prices published by the CEC[22] and ORER's binding and non-binding STPs for the relevant years.

Submissions

Submissions in response to the Authority's Issues Paper were broadly in favour of continuing to use a market-based approach, based on the fixed Clearing House price and binding and non-binding STPs, currently determined by the CER.

However, following the release of the Authority's Draft Methodology Paper and Draft Determination, QCOSS, Ergon Energy and Stanwell suggested that market prices for STCs should be used instead of the fixed Clearing House price given that there is an active market for STCs and the current market price is well below the Clearing House price. Ergon Energy suggested that the Authority should calculate STC prices using a 15 month average of historical market data. Stanwell and QCOSS were of the view that the information required to estimate STC costs using market data is widely available and suggested that the Authority should investigate other data sources such as information published by CEC[23] and ICAP Energy Australia.

TRUenergy supported the Authority's proposal to use the published binding and non-binding STPs, whereas AGL and Origin Energy had concerns with using the 2013 non-binding STP published by the CER in the absence of a cost pass-through mechanism in the current price setting arrangements. Origin Energy suggested that the Authority use costs associated with the 2012 calendar year to estimate 2012-13 SRES costs.

The Authority's Position

While the current market price for STCs may be below the fixed Clearing House price of $40 per STC, ACIL advised the Authority that there were difficulties with forecasting market prices of STCs over 2012-13 because the SRES market is still relatively new and there are a range of factors (such as changes in government policies) that may affect the proportion of STCs likely to be traded in 2012-13. Nevertheless, ACIL was of the view that the difference between current market prices for STCs and the Clearing House price reflects a short term mismatch between the levels of demand for, and supply of, STCs. ACIL was of the view that any excess STCs would be cleared from the market in the near future, through increased demand for STCs via the STP for 2012, which has accounted for the excess number of STCs created in 2012. This is likely to result in market prices for STCs moving closer to the Clearing House price.

Given the STC market is for spot sales and information on the volume of STCs traded in the open market is not publicly available, and ACIL's view that the market price is likely to move closer to the Clearing House price by 2013, ACIL recommended that the Authority continue to use the Clearing House price in calculating STC prices for 2012-13.

In response to suggestions that the Authority consider other sources of information, ACIL considered a number of other sources, such as information from energy brokers and certain industry associations, but concluded that the information provided by these sources was not readily available which would reduce the transparency in the Authority's approach to calculating costs with no necessary gain in forecasting accuracy.

[22] ICRC, *Draft Report, Retail Prices for Franchise Electricity Customers, 2012-14, Report 2 of 2012*, April 2012. The ICRC indicated that if publicly available prices are not available from the Clean Energy Council, a suitable alternative will be used.
[23] Spot prices for LGCs and STCs published by CEC are based on data provided by an energy broker, TFS Green.

The Authority acknowledges Origin Energy and AGL's concerns regarding using the CER's non-binding STP for 2013, but agrees with ACIL that the non-binding STP published by the CER represents the most transparent and publicly available estimate for the STP for 2013.

The Authority has therefore accepted ACIL's recommendations and based its estimate of the SRES costs for 2012-13 on the STC Clearing House price of $40 per STC, the CER's binding STP for 2012 of 23.96%[24] and non-binding STP for 2013 of 7.94%[25]. Based on this approach, the Authority has arrived at a cost of complying with the SRES of $6.38/MWh in 2012-13.

ACIL has provided a detailed explanation of its calculation of SRES costs in its Final Report, along with information on STC prices and assumptions underpinning the STPs.

3.3.3 NEM Participation Fees and Ancillary Services Charges

NEM participation fees are levied on retailers by AEMO to cover the costs of operating the national energy market and ancillary services charges cover the costs of the services used by AEMO to manage power system safety, security and reliability.

As NEM participation fees and ancillary services charges are relatively stable from year to year, the Authority has previously used historical data to forecast these costs.

Approaches in Other Jurisdictions

Two general approaches to estimating NEM participation fees and ancillary services charges have been used recently in other jurisdictions. IPART, ESCOSA and OTTER used an approach similar to the Authority, whereby they forecast NEM participation fees and ancillary services charges based on historical prices. ICRC escalated historical NEM participation fees and ancillary services charges by the consumer price index (CPI).

In addition to its forecasts, OTTER provided a pass-through allowance in its 2010 Determination to account for any differences between the forecasts in its 2007 Determination and the actual data published by AEMO over the determination period.

Submissions

Submissions in response to the Issues Paper, Draft Methodology Paper and Draft Determination generally supported the proposal by the Authority to continue using the approach to estimating NEM participation fees and ancillary services charges it had previously used under the BRCI. However, in its 11 May submission to the Authority, Origin Energy queried whether ACIL had inadvertently excluded NEM fees relating to the national transmission planner and smart metering.

The Authority's Position

As stakeholders have generally supported the Authority's approach to estimating ancillary services charges based on historical data, the Authority has continued with this approach for 2012-13, but using AEMO's draft fees for 2012-13 as the basis for estimating NEM participation fees[26].

[24] Clean Energy Regulator, 24 February 2012.
[25] Clean Energy Regulator, 30 March 2012.
[26] AEMO, *Electricity Draft Budget & Fees 2012-13*, March 2012.

Using AEMO's estimate of NEM fees, the Authority has estimated that total NEM fees will be $0.40/MWh in 2012-13. This is inclusive of fees relating to the national transmission planner and smart metering.

Using AEMO's settlements data for ancillary services over the year to January 2011, the Authority has estimated that ancillary services charges will be $0.46/MWh in 2012-13.

3.3.4 Summary of Other Energy Costs for 2012-13

Table 3.3 shows ACIL's proposed other energy costs for 2012-13 which will be applied uniformly across all tariffs.

Table 3.3: Other Energy Costs for 2012-13

Cost Component	*$/MWh*	*c/kWh*
GEC	0.85	0.085
LRET	4.10	0.410
SRES	6.38	0.638
NEM fees	0.40	0.040
Ancillary services	0.46	0.046
Total	**12.18**	**1.218**

Source: ACIL Tasman, Estimated Energy Purchase Costs for Final Determination, May 2012.
Note: Totals may not add due to rounding

3.4 Energy Losses

In delivering energy from a generator to a consumer, some losses occur. A retailer must purchase sufficient energy to supply its customers and allow for the transmission and distribution losses that will be incurred.

Under the BRCI, the Authority accounted for transmissions losses, but not distribution losses, on the basis that its energy cost estimate was based on the NEM load which included distribution losses but excluded transmissions losses. To account for transmission losses, the Authority increased energy cost estimates by the average loss factors published by Powerlink in its Annual Planning Report.

3.4.1 Submissions

In response to the Issues Paper, Origin Energy, TRUenergy, QEnergy, Ergon Energy and QCOSS all suggested that the Authority should take account of both transmission and distribution losses in the Energex area.

Ergon Energy suggested that the Authority adopt loss factors published by AEMO and that the highest transmission loss factor in the Energex area and the Energex distribution loss factors that apply to each customer type would be the most appropriate.

QCOSS also suggested that the transmission loss factors that AEMO publishes would be the most appropriate to use and that the AER-approved loss factors were most appropriate for distribution losses.

Following the release of the Draft Methodology Paper, submissions were generally supportive of the Authority's proposed treatment of energy losses which reflected suggestions made in submissions.

In response to the Draft Determination, QCOSS and CCCL were supportive of the way in which ACIL had accounted for energy losses, while other submissions made suggestions on how ACIL might better apply energy losses to its energy cost components. Ergon Energy suggested that ACIL should use DLFs that relate to the underlying network tariff category rather than the Ergon Energy NSLP.

AGL and Origin Energy also suggested that carbon costs need to be uplifted to account for losses between the generator door and the regional reference node and that renewable energy schemes such as SRES and LRET also need to be adjusted for losses.

3.4.2 The Authority's Position

The Delegation requires the Authority to use the loss factors published by AEMO. The Authority has therefore used the most recent transmission loss factors and AER-approved distribution loss factors that are available from the AEMO website at the time of preparing its Final Determination.

In its Draft Methodology Paper, the Authority proposed to only use Energex loss factors because, at that stage, all tariffs were to be calculated based on the Energex network tariffs and the load of customers in the Energex area.

As the Authority based tariffs for large customers in the Draft Determination on Ergon Energy network tariffs and charges, it also used the corresponding energy loss factors for the Ergon Energy area in calculating the accompanying energy costs for these tariffs.

The Authority agrees with Ergon Energy's suggestion that it would be an improvement to use the DLFs that reflect the underlying network tariff class. Following this suggestion, ACIL has applied the following DLFs:

(a) for SAC demand customers in Ergon Energy's area, ACIL has applied the LV line DLF;

(b) for SAC HV customers, ACIL has applied the 22/11kv line DLF; and

(c) for CAC and ICC customers ACIL has applied the SAC HV losses as these customers will be supplied under the SAC HV tariff.

The Authority also agrees with the comments by AGL and Origin Energy regarding the application of transmission and distribution loss factors to carbon and renewable energy schemes costs and it has applied loss factors across all energy cost components.

However, the Authority disagrees that there is a need to apply additional losses to carbon costs to account for the losses between the generator and the regional reference node (as suggested by AGL and Origin Energy), because ACIL has accounted for these losses in its modelling by adding carbon costs to the operating costs of generators prior to their 'bidding' in the Powermark model. Powermark then accounts for losses between the generator and the regional reference node prior to estimating its dispatch order.

Table 3.4 shows the loss factors that have been applied to the different energy cost estimates.

Table 3.4: Energy Loss Factors for 2012-13

Settlement class	*Retail Tariff*	*Transmission and distribution losses*
Energex NSLP and unmetered supply	12, 20, 22, 41, 91	7.2%
Energex Controlled Load 9000	31	7.3%
Energex Controlled Load 9100	33	7.3%
Ergon Energy NSLP- small, medium and large demand and streetlights	44, 45, 46, 71	12.8%
Ergon Energy NSLP- high voltage demand and customers over 4 GWh high voltage demand	47, 48	8.6%

Source: ACIL Tasman, Estimated Energy Purchase Costs for Final Determination, May 2012.

3.5 Total Energy Cost Allowances for 2012-13

Table 3.5 shows the total energy costs allowances for each settlement class and retail tariff for 2012-13.

Table 3.5: Total Energy Cost Allowances for 2012-13 by settlement class/tariff

Settlement class	*Retail Tariff*	*Wholesale energy allowance (c/kWh)*	*Other energy costs (c/kWh)*	*Energy losses (%)*	*Total energy allowance (c/kWh)*
Energex NSLP and unmetered supply	12, 20, 22, 41, 91	6.149	1.218	7.2%	7.941
Energex Controlled Load 9000	31	4.163	1.218	7.3%	5.807
Energex Controlled Load 9100	33	4.893	1.218	7.3%	6.595
Ergon Energy NSLP – small, medium and large demand and streetlights	44, 45, 46, 71	5.593	1.218	12.8%	7.808
Ergon Energy NSLP- high voltage demand and customers over 4 GWh high voltage demand	47, 48	5.593	1.218	8.6%	7.450

Source: ACIL Tasman, Estimated Energy Purchase Costs for Final Determination, May 2012.

4. RETAIL COSTS

The final cost component to be determined relates to the cost of services provided by a retailer to its customers.

4.1 Introduction

In determining retail costs, the Authority must have regard to the general provisions of the Delegation, including:

(a) the actual costs of supplying electricity;

(b) the effect of its determination on competition;

(c) the Queensland Government's UTP; and

(d) the particular matters raised in the attachment to the Delegation.

In addition, in determining the retail cost component, there are some specific requirements provided in the Delegation, namely, that the Authority must consider the retail costs that would reasonably be incurred by an efficient, representative retailer (the characteristics of which are to be determined by the Authority).

The Authority is also required to determine an appropriate retail margin, giving consideration to any risks not compensated for elsewhere.

4.2 Representative Retailer

The Delegation requires that the retail costs to be determined are those for a representative retailer (rather than an actual retailer), the characteristics of which are to be determined by the Authority.

Under the previous BRCI approach to setting notified prices, the Electricity Act defined the representative retailer as an incumbent, stand-alone Queensland electricity retailer with a substantial and representative cross-section of customer types.

The BRCI required the Authority to calculate the expected increase in the costs of this representative retailer over the forthcoming year, with the increase in costs so determined then used to increase existing tariffs. The Authority did not adjust the underlying existing tariffs to reflect the actual level of costs incurred by the representative retailer.

In contrast, the current Delegation requires the Authority to determine the appropriate level of costs for a representative retailer. As such, estimating the actual level of costs will have a direct impact on the resulting tariffs. This makes the determination of the representative retailer a more significant issue under the current arrangements than it was previously.

At the same time, the Delegation makes it clear that, in determining prices, it is important that the electricity market remain competitive, so that customers can benefit over the long term from the efficiencies and other benefits that competition can bring.

It is against this background that the definition of the representative retailer must be considered. The representative retailer is not meant to be an actual retailer nor is it meant to be some sort of average retailer. Rather, the representative retailer will have characteristics designed to achieve the desired market outcomes in terms of prices and competition.

4.2.1 Approaches in Other Jurisdictions

Unlike in Queensland, regulators in other jurisdictions are required to determine regulated retail electricity prices that must be offered by one, or a small number of, standard or default retailer(s) and tend to draw on cost information provided by that retailer(s). Nevertheless, in determining the appropriate level of costs to be recovered through prices, the regulators may also aim to reflect certain characteristics of a retailer that differ from those of the standard or default retailer(s).

In its final report on 2010-13 regulated retail prices in New South Wales (NSW), IPART aimed to establish the costs of a retailer that:

(a) is an incumbent retailer that has achieved economies of scale (has efficient costs);

(b) is a stand-alone retailer in NSW that is not vertically integrated with electricity distribution in NSW;

(c) serves retail customers, including small retail customers, in NSW and other jurisdictions across the NEM;

(d) can offer retail customers standard and negotiated customer supply contracts; and

(e) has an existing customer base to defend.

In its 2011-2014 pricing review in South Australia, ESCOSA decided that the regulated price should be set by reference to the small customer retail market in South Australia, rather than being based on the costs incurred specifically by the regulated retailer. It considered that adopting a new entrant retailer focus would ensure that electricity retailers are able to compete in the market and deliver the benefits of competition to customers.

In its 2010-2012 pricing review in the ACT, the ICRC estimated the efficient costs of an incumbent electricity retailer providing retail electricity services to a regulated customer segment, and has maintained this approach in its 2012-2014 pricing review draft report.

In its 2010-2013 pricing review in Tasmania, OTTER aimed to determine the efficient costs of supplying non-contestable customers.

4.2.2 Submissions

Retailers (except Ergon Energy) preferred that retail costs be determined for a new entrant, stand-alone retailer of small or moderate size providing retail electricity services. Retailers generally were of the view that this would encourage competition and ensure new entrants were not at a disadvantage to incumbents. TRUenergy suggested that the current level of competition might not be maintained if the Authority were to base costs on those of an incumbent retailer. While such a definition had been used in the BRCI, it was less significant under that approach because (as noted above) the BRCI was an index approach, whereas the current approach involves a cost build-up.

However, some retailers suggested the representative retailer should be a vertically integrated retailer. For instance, in its response to the Issues Paper, Origin Energy argued, when discussing the calculation of energy costs, that “an integrated retailer is more closely aligned to a representative retailer for which the QCA is seeking to establish efficient costs” but later preferred a stand-alone retailer as the basis for estimating retail costs.

Ergon Energy and non-retailers (including the CCIQ, Queensland Farmers’ Federation, Growcom, QCOSS, CCCL, Queensland Consumers Association and Canegrowers) continued to prefer a definition based on a larger incumbent retailer. Canegrowers also preferred an integrated retailer that was engaged in a range of business activities and could take advantage of economies of scope.

4.2.3 The Authority's Position

Incumbent or New Entrant

Determining costs on the basis of a relatively small new entrant (as preferred by most retailers) could lead to higher costs than would result from the previous BRCI definition. Conversely, Ergon Energy and consumers indicated a preference for costs to be based on those for a large, incumbent retailer able to access economies of scale. This would lead to the basis for determining costs being more in line with those estimated in the past and lower than under the retailer preferred alternative.

In deciding on the characteristics of the representative retailer, the Authority first reviewed the current level of competition in the market. The Authority considered that, if the current level of competition were seen as deficient, a definition based on a new entrant might be preferred over one based on an incumbent.

The higher costs that would flow from adopting a new entrant perspective would result in higher notified prices (relative to adopting an incumbent perspective) and encourage new retailers to enter the market, thus promoting the level of competition but also imposing higher prices on customers. Conversely, if the level of competition in the market were seen as adequate, then a definition based on an incumbent retailer would result in (relatively) lower notified prices that do not unnecessarily penalise customers.

As discussed in Chapter 1, the retail electricity market in Queensland, in particular in South East Queensland (SEQ), has developed considerably since the introduction of full retail competition in mid-2007. There are a large number of retailers servicing small and large customers and customer switching activity is strong.

As at 31 March 2012, there were 18 retailers[27] operating in Queensland – nine service both large and small customers, six only service large customers while three only service small customers.

While the Authority does not have access to information on the market offers available to business customers, there are currently 76 supply offers available to residential customers consisting of 27 for 'standard' electricity supply and 49 with green electricity options. These market offers provide customers (almost exclusively in SEQ) with a range of contractual terms and conditions combined with potential savings and other incentives.

The Authority is not aware of any market contracts generally available to residential customers in Ergon Energy's distribution area. While all retailers are licensed to operate across the State, each retailer will choose the locations in which it is prepared to make offers for supply and the types of customers it is seeking to attract.

As shown in Table 4.1, some 43.6% of customers in Queensland and 66.1% of customers in SEQ were on market contracts as at 31 December 2011. This suggests that a large number of customers have embraced the option to choose a market contract that is better suited to their needs than their previous regulated tariff.

[27] Some retailers hold more than one licence.

Table 4.1: Market and Non-Market Customers – as at 31 December 2011

Customer type	*Market customers*[a]		*Non-market customers*		*Total customers*		*% on market contracts*[2]	
	SEQ	*QLD*	*SEQ*	*QLD*	*SEQ*	*QLD*	*SEQ*	*QLD*
Small	876,128	879,060	455,920	1,148,571	1,332,048	2,027,631	65.8%	43.4%
Large[b]	12,457	14,637	530	7,129	12,987	21,766	95.9%	67.2%
All	888,585	893,697	456,450	1,155,700	1,345,035	2,049,397	66.1%	43.6%

Source: Information reported to the Authority under the Electricity Industry Code.
a. Assumes that any customer outside Energex's distribution area that is not serviced by Ergon Energy Queensland (retail) is on a market contract.
b. From 1 July 2012, all large non-residential customers in the Energex area will be on market contracts.

The rate of customer switching is often used to measure the level of activity in an electricity market. While not always the case, a high switching rate typically suggests that retailers are actively marketing in a region and that they are offering customers sufficient savings to incentivise them to switch retailers.

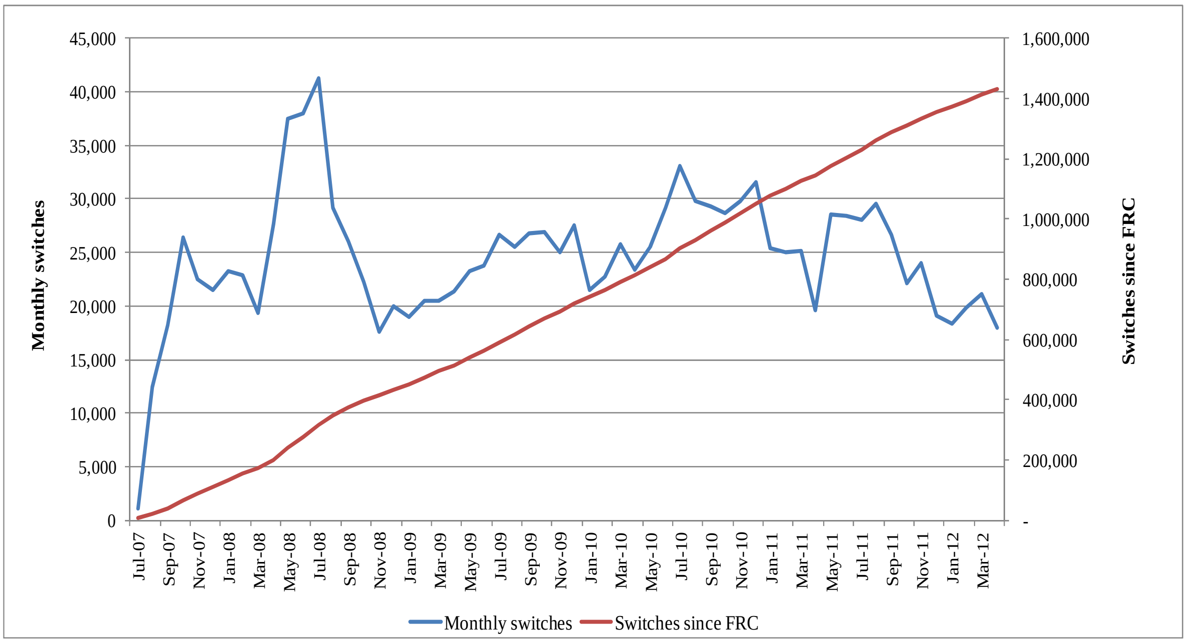
However, an abnormally active market might also suggest that potential profits in the market are high (perhaps due to the regulated retail tariffs being set too high) which would also encourage retailers to spend an unreasonable amount on marketing while offering customers large discounts.

Since FRC commenced in Queensland in 2007, the level of customer switching activity has been relatively high. Figure 4.1 shows monthly and total customer switches in Queensland since 2007. While there was considerable volatility in the switching rate over the initial 18 months of FRC, customer activity has typically stayed within the range of 20,000 to 30,000 customer switches per month in more recent years.

In comparison to other markets around the world, the level of customer switching activity in SEQ is particularly high, with the market being rated by one commentator as one of the most active retail electricity markets in the world[28].

[28] VaasaETT, *World Energy Retail Market Rankings, 2010,* December 2010.

Figure 4.1: Customer Switching Activity, Queensland, Since FRC



Source: AEMO Retail Transfer Statistical Data (Code M57B)

The above analysis suggests the Queensland electricity market (and particularly the SEQ market) is attractive to retailers who are actively seeking market share with a wide range of market offers for customers. Given the over-riding impact of the Government's uniform tariff policy throughout the Ergon Energy area, there does not appear to be any reason to believe that the level of competition is deficient or that further steps need to be taken to attract new entrants. On this basis, the Authority considers that the definition of the representative retailer should be based on an incumbent retailer, not a new entrant.

Other Characteristics

Table 4.2 provides a snapshot of the characteristics of those retailers currently operating in the Queensland market. The size of the retailer, its degree of vertical integration, whether it is solely Queensland based and whether it markets products other than electricity, will all determine the economies of scope and scale that the representative retailer enjoys and the associated costs which must be recovered through prices.

Table 4.2: Characteristics of Active Retailers in Queensland

Retailer	*Small customers*	*Large customers*	*Market customers*	*Non-market customers*	*Retails electricity in other region*	*Retails gas in SEQ*	*Other horizontal integration*	*Vertically integrated*
Origin	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**
AGL	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**
Powerdirect	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**Y**	**Y**
TRUenergy	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**Y**	**Y**
Sanctuary	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**N**	**Y**
Lumo	**Y**	**Y**	**Y**	**N**	**Y**	**N**	**Y**	**Y**
APG	**Y**	**N**	**Y**	**N**	**Y**	**Y**	**Y**	**N**
Click	**Y**	**N**	**Y**	**N**	**Y**	**N**	**N**	**N**
Dodo Power and Gas	**Y**	**N**	**Y**	**N**	**Y**	**N**	**N**	**N**
QEnergy	**Y**	**Y**	**Y**	**N**	**N**	**N**	**N**	**N**
Momentum	**Y**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
ERM	**N**	**Y**	**Y**	**N**	**Y**	**N**	**Y**	**Y**
Alinta Energy	**N**	**Y**	**Y**	**N**	**Y**	**N**	**Y**	**Y**
Diamond Energy	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
Aurora	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
OzGen	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
Stanwell	**N**	**Y**	**Y**	**N**	**N**	**N**	**N**	**Y**
Ergon Energy Queensland	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**	**Y**

As Table 4.2 indicates, active electricity retailers in Queensland are not homogeneous in nature but fall into three broad categories, as follows:

(a) Ergon Energy Queensland, which supplies only non-market customers and operates solely within the Ergon Energy distribution area;

(b) specialised retailers who supply only large market customers, with a number being predominantly generators who are registered as retailers to supply (often) very large customers; and

(c) retailers who supply large and small customers.

Within category (c), retailers generally:

(a) retail electricity in Queensland (predominantly in the Energex distribution area of SEQ) as stand-alone electricity retailers and not also as retailers of gas (although the two largest retailers of electricity also retail gas);

(b) serve small and large retail customers in Queensland and other jurisdictions across the NEM.

While some retailers pursue customers only in a particular market niche, most operating in Queensland supply a mix of small and large customers. There are notified prices for all tariff categories despite large customers (those consuming above 100 MWh per annum) in Energex's network being denied access to notified prices from 1 July 2012.

While not all retailers have non-market customers, small customers who accept a market contract may revert to a non-market contract with their current supplier at the notified price on the expiry of their market contract, or as otherwise provided for in their market contract; and

(c) are vertically integrated, however, the nature and extent of the vertical integration varies considerably. AGL and Origin Energy are the only retailers with significant customer bases that operate large-scale generation assets connected to the NEM in Queensland. All other retailers with generation assets have either relatively small customer bases in Queensland or generation assets in other states, or both. In general, new entrants are not vertically integrated.

In addition, the cost structure of the representative retailer will be affected by the size of its customer base. A large incumbent retailer will already have an established customer base while a smaller retailer may not be able to access the same economies of scale. However, there is also some evidence to suggest that reasonable economies of scale may be achieved with a relatively small customer base[29]. Smaller retailers may also gain the benefits of economies of scale that would naturally flow to a retailer with a larger customer base by outsourcing many back office functions to a third party. On this basis, size may not be as important an issue as it might otherwise appear, nevertheless, the Authority will define the representative retailer as having sufficient size to access economies of scale.

Summary

In arriving at its definition of the representative retailer, the Authority has recognised:

(a) the maturity and competitiveness of the Queensland market which supports a mix of retailers from small new entrants to large incumbents; and

(b) the importance of maintaining a competitive market in the future by not deterring the entry of new retailers which can drive efficiency in the market and potentially lead to lower prices and a wider range of services in the longer term.

While notified prices apply only to non-market customers, the reality is that these set the basis for determining prices for all customers, both market and non-market. In addition, most customers (probably all small customers) throughout the Ergon Energy distribution area will pay the notified prices set by the Authority as there is little if any competition in that part of the State meaning that customers are unable to choose an alternate supplier.

In practice, the Authority's task is a matter of balancing the desire by some stakeholders for higher regulated prices which will promote more activity in the market against the desire by others for lower electricity bills.

The Authority's task is to set prices that will sustain an appropriate level of competition in the market in order to place downward pressure on prices but not set prices so high as to deny customers the benefits that come from a competitive market in terms of greater efficiency and lower prices than might otherwise prevail.

[29] Frontier Economics, *Mass Market New Entrant Retail Costs and Retail Margin, Prepared for the Independent Pricing and Regulatory Tribunal*, March 2007.

Based on the above considerations, the Authority considers that the representative retailer is one that:

(a) is an incumbent retailer of sufficient size to have achieved economies of scale;

(b) serves small and large retail customers in Queensland and other jurisdictions across the NEM;

(c) has a mix of market and non-market customers;

(d) retails electricity on a stand-alone basis; and

(e) is not vertically integrated with an electricity generator.

4.3 Retail Operating Costs

Retail operating costs (ROC) relate to the costs of the services provided by an electricity retailer to its customers and typically include customer administration (including call centres), corporate overheads, billing and revenue collection, IT systems, regulatory compliance, and customer acquisition and retention costs (CARC) which also includes costs associated with marketing, advertising and sales overheads.

As noted at the start of this chapter, it is the ROC that would reasonably be incurred by an efficient, representative retailer that the Authority must consider.

4.3.1 Approach to Estimating ROC

There are two generally accepted approaches to estimating ROC. A bottom-up approach, which requires detailed information on each cost component, or a benchmarking approach, which relies on publicly available information and is therefore less data intensive. The two approaches can also be used together, with benchmarking used to assess the reasonableness of costs estimated under a bottom-up approach.

Under the BRCI, the Authority initially estimated ROC in 2006-07 by benchmarking costs to those allowed in other jurisdictions and subsequently escalating this benchmark each year to account for wages growth and price inflation over the intervening period.

Prior to the 2011-12 BRCI Decision, the Authority also calculated a separate cost item to cover CARC based on expected rates of customer churn (except for the first BRCI where a loss of scale approach was used). However, in its 2011-12 BRCI Decision, the Authority considered that, given the maturity of the Queensland market (particularly the SEQ market), it was no longer appropriate to calculate a separate cost for CARC but that these costs should be treated in the same manner as all other retail costs. Consequently, the Authority arrived at an overall estimate of ROC in 2011-12 which included an allowance for CARC.

The ROC estimate for the 2011-12 BRCI also included an additional cost associated with the regulatory fees levied by the Authority.

Approaches in Other Jurisdictions

The most recent approaches adopted by regulators in other jurisdictions are summarised below. Key differences in the approaches adopted in other jurisdictions relate to the treatment of CARC and the fact that other regulators have to estimate costs for an actual retailer.

IPART (NSW)

IPART estimated ROC using a bottom-up approach based on cost information provided by the three regulated retailers. It then benchmarked this estimate against its past determinations, regulatory decisions in other jurisdictions and cost information disclosed by publicly listed retailers.

IPART was required by its terms of reference to include an explicit allowance for CARC. IPART estimated CARC separately and for its 2010 determination used an approach based on customer churn (similar to the Authority's approach prior to the 2011-12 BRCI).

ESCOSA (South Australia)

ESCOSA adopted a similar approach to IPART in determining ROC in the initial year – an assessment of the regulated retailer's actual costs and benchmarking against other regulatory decisions, combined with benchmarking against market contracts in subsequent years. That is, ESCOSA determined a cost-reflective price for the start of the price path which was adjusted in subsequent years in line with movements in market contract prices (subject to prices sitting within a floor and ceiling).

ESCOSA included an implicit allowance for CARC in the ROC. ESCOSA justified accepting the regulated retailer's proposed ROC allowance (including CARC) on the basis that it was consistent with the ROC allowance recommended by its consultant, LECG (now Sapere Research Group), which had estimated CARC using a similar method to that adopted by IPART.

ICRC (ACT)

In its 2010-2012 pricing review, the ICRC maintained the approach adopted in previous years. Under this approach, an initial ROC estimate was established in 2003 on the basis of information provided by the regulated retailer and benchmarking. This estimate was then escalated in subsequent years according to movements in the CPI.

The ICRC did not include any allowance for CARC. The ICRC considered that the potential benefits of enhancing competition did not outweigh the potential negative impacts, including higher prices in the short term.

ICRC recently released its 2012-2014 pricing review draft report and proposed to continue with the same approach to estimating ROC and to exclude CARC.

OTTER (Tasmania)

OTTER benchmarked the regulated retailer's ROC against other jurisdictions. OTTER made no allowance for CARC as it considered CARC was not a valid cost element when dealing solely with customers who are not contestable.

Submissions

In response to the Authority's Issues Paper, retailers suggested different approaches to estimating ROC, such as:

(a) Origin Energy preferred benchmarking but noted that it can be difficult to compare decisions due to different methodologies and parameters used to approve costs. It therefore suggested that the current allowance should be retained and escalated;

(b) QEnergy supported the approach used to date, although it was not clear whether it was proposing that a new benchmark be established and escalated annually or that the current allowance should be retained and escalated;

(c) AGL supported benchmarking but with an allowance for Queensland specific costs and the incremental costs of a stand-alone new entrant retailer;

(d) Ergon Energy suggested that IPART's cost estimate should be adopted (with some Queensland specific adjustments) and that a high level assessment of this estimate could be undertaken against aggregated cost data provided by retailers; and

(e) APG, TRUenergy and Alinta Energy did not propose a specific approach, although TRUenergy emphasised the importance of accounting for Queensland specific costs and regulatory obligations, while Alinta Energy was of the view that the current allowance was reasonable, albeit conservative.

In later submissions, Alinta Energy, AGL, Origin Energy and Ergon Energy supported a benchmarking approach although, as noted previously, retailers would have preferred costs be based on a smaller new entrant representative retailer.

Of non-retailers, QCOSS and CCIQ also supported a benchmarking approach, while Queensland Consumers Association and Queensland Farmers' Federation preferred a bottom up approach. However, Queensland Farmers' Federation supported benchmarking as the next best option. CCIQ considered that the approach adopted should include mechanisms to reflect performance and productivity outcomes.

In relation to the treatment of CARC, retailers and CCIQ supported the inclusion of a CARC allowance, although they had different views as to how it should be calculated, including:

(a) TRUenergy considered that it should be calculated by reference to churn rates; and

(b) AGL and Origin Energy, in their submissions on the Issues Paper, preferred that CARC be calculated separately, but in later submissions supported the Authority's proposed approach of maintaining the current CARC allowance in real terms.

QCOSS, CCCL, Queensland Consumers Association, Queensland Farmers' Federation and Canegrowers were of the view that there was no justification for including an allowance for CARC.

In response to the Authority's Draft Methodology Paper, CCIQ agreed that it was appropriate to include an allowance for CARC, but suggested that a low and declining allowance would be consistent with a retailer maintaining high customer satisfaction and efficiency standards and a declining allowance would incentivise retailers to improve their performance. While the Queensland Consumers Association, QCOSS and CCCL did not support the inclusion of a CARC allowance, they considered that, in any event, the current CARC allowance was too high. Queensland Consumers Association also suggested that the present allowance was based on an assumption that most customers are acquired through expensive door-to-door marketing, which does not provide an incentive for retailers to pursue alternative and less intrusive marketing methods.

QCOSS and CCCL considered that the current CARC allowance should be benchmarked against the (lower) allowances adopted in NSW and South Australia and adjusted to reflect the lower proportion of customers in Queensland that have access to competition relative to the other states.

In contrast, QEnergy suggested that the current CARC allowance of $43 was too low and well below the costs of acquiring a customer. However, this allowance does not reflect the costs of acquiring a customer, because it applies to all customers. In establishing a baseline CARC allowance per customer for the 2010-11 BRCI (which has subsequently been maintained in real terms), the Authority used an estimate of $188 ($2010-11) per customer switch to a new retailer and $109 ($2010-11) per customer transferring onto a market contract and multiplied these estimates by the proportion of customers switching and transferring.

The Authority's Position

In order to undertake a bottom-up analysis of retail costs, the Authority would need to obtain detailed cost information from retailers. While Origin Energy, AGL and APG all indicated they would be willing to provide cost information, the Authority considers that there are a number of problems with this approach.

Firstly, there is no standard or default retailer(s) in Queensland as all retailers must offer regulated or notified prices. Under the Delegation, the Authority is required to consider the costs of an efficient, representative retailer, so it would need to either:

(a) determine which retailer or retailers best met the definition of the representative retailer and obtain cost information from those retailer(s); or

(b) ask retailers to provide an estimate of the costs likely to be incurred by the representative retailer, rather than providing cost information relating directly to their own business.

Even if the Authority were able to obtain reliable cost information, determining the efficiency and reasonableness of those costs would be difficult. Other sources of information on the disaggregated costs of retailers are not available to inform the Authority's assessment because retailers have not provided the Authority with ROC information in the past and, in other jurisdictions, if retailers provide disaggregated cost information to the regulator this tends to be on a confidential basis. Origin Energy also noted that the process of obtaining information would be data intensive and that it had been a contentious issue in other jurisdictions given the different structures and activities of the various retailers. Ergon Energy had similar concerns, noting that information may be classified quite differently between retailers, making comparisons difficult.

While the Authority could assess cost estimates using a high level benchmarking analysis, a potential problem would arise if there was a large discrepancy between the results of the benchmarking analysis and retailers' proposed costs or even between retailers themselves. This would likely require the Authority to choose one approach (or cost estimate) over the others and there may be little basis for doing so.

Given these difficulties, the Authority has decided not to pursue a bottom-up evaluation of ROC. Instead, the Authority has used its ROC allowance from the last BRCI (2011-12) as a starting point and benchmarked that allowance against those recently accepted in other jurisdictions in order to test its reasonableness. While the Authority notes that benchmarking has its drawbacks, it does not consider that an alternative approach would necessarily produce results that are any more robust or defensible.

Some retailers had suggested that Queensland specific costs and regulatory obligations need to be taken into account. Where reliable information on the individual components of ROC is readily available, the Authority has considered adjusting its estimate to include those costs.

Given the concerns of some (non-retailer) stakeholders regarding the treatment of CARC, the Authority considered whether it is appropriate to include an allowance for CARC. Under the Delegation, the Authority is required to consider the ROC that would reasonably be incurred by an efficient, representative retailer and, as discussed above, the Authority has defined the representative retailer as one that supplies customers on both market and non-market contracts. The Authority is also required to consider the impact on competition in the Queensland retail electricity market of its determination, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace.

While several consumer groups were concerned about the inclusion of CARC, the Authority considers that some level of cost associated with customer acquisition and retention is a reasonable and real cost normally incurred by retailers participating in a competitive market and supplying both market and non-market customers. Not recognising a legitimately incurred cost may have a detrimental impact on competition by reducing the incentive for retailers to actively participate in the market. In line with these requirements, the Authority considers that it is appropriate for CARC to continue to be reflected in the ROC.

The Authority's interest is in determining the appropriate costs upon which to base future prices not to manipulate those costs in order to influence retailer performance as suggested by CCIQ. Nor was the CARC allowance the Authority included in its 2011-12 BRCI Decision based on any particular form of retailer marketing activity, as suggested by the Queensland Consumers Association.

The Authority considered many of these same issues in great detail in arriving at its 2011-12 BRCI Decision. Having established an acceptable approach in that Decision, the Authority is not persuaded that there is any reason to change from that approach or that the amount included is inappropriate.

4.3.2 Implementing the Benchmarking Approach

Setting a Benchmark ROC Allowance for Small Customers

In undertaking the benchmarking analysis, a key point to note is that the Authority must determine regulated retail electricity prices for small customers and large customers (those consuming more than 100 MWh per annum), whereas regulators in other jurisdictions are required to set prices for small customers only, to be charged by specific retailers.

In other jurisdictions, customers are only eligible to be supplied under a regulated retail tariff if their annual consumption is below 160 MWh in NSW and South Australia, 100 MWh in ACT or 50 MWh in Tasmania[30]. Therefore, the benchmarks from these jurisdictions are most relevant in providing information on the costs of supplying relatively small customers.

In undertaking the benchmarking analysis, the Authority acknowledges the concerns of AGL and Origin Energy that the benchmarking exercise should be undertaken on a consistent basis and that differences in regulatory and market frameworks need to be taken into account. While QCOSS and CCCL cautioned that making substantial adjustments to the benchmarks from other jurisdictions requires an understanding of the individual components of the benchmarks, they agreed with the Authority that it is appropriate to make some adjustments to account for jurisdictional differences where reliable information on the individual cost components exists.

[30] Customers consuming between 50 MWh and 150 MWh per annum were eligible until July 2011. After that date, these customers became contestable and were unable to access regulated tariffs.

As noted previously, a key difference between jurisdictions is the treatment of, and basis for calculating, CARC. As it has not been possible to readily compare the costs attaching to CARC between jurisdictions, the Authority has based its benchmarking solely on comparable ROC allowances and, as in 2011-12, will maintain the current, perhaps generous, CARC component going forward.

Recent Regulatory Decisions

Table 4.3 compares the Queensland ROC allowance under the 2011-12 BRCI approach with allowances recently determined by regulators in other NEM jurisdictions. In order to improve comparability between jurisdictions, the allowances have been adjusted to exclude CARC (if it has been included) and all allowances are presented in 2011-12 dollars. Some other minor adjustments have also been made as noted below.

Table 4.3: Current ROC Allowances (per customer)

	ROC	*CARC*	*ROC (excl CARC)*	*ROC (excl CARC)[a] $2011-12*	*Comments*
Queensland (2011-12 allowance)	$130.74 ($2011-12)	$41.91 ($2011-12)	$88.83 ($2011-12)	$88.83	Excludes regulatory fees of $1.16. Retailers not allowed to charge late payment fee.
NSW[b] (IPART)	$112.10-$116.00 ($2009-10)	$36.80 ($2009-10)	$75.30-$79.20 ($2009-10)	$79.65-$83.78	Includes $2.30 cost associated with late payments (recovered through separate late payment fee).
South Australia (ESCOSA)	$115 ($2010-11)	$38.00[c] ($2010-11)	$77.00 ($2010-11)	$79.54[d]	Excludes allowance for Residential Energy Efficiency Scheme (REES) costs. Retailers allowed to charge separate late payment fee.
ACT (ICRC)[e]	$104.90 ($2010-11)	Not included	$104.90 ($2010-11)	$107.89	Includes cost of meter reading (not a ROC in Qld). Includes some sales and marketing costs.
Tasmania (OTTER)	$94 ($2010-11)	Not included	$94 ($2010-11)	$96.49	Set to recover costs of supplying non-contestable customers, so no allowance for impact of FRC.

a. *Allowances have been escalated to $2011-12 in accordance with each regulator's determination (except for ESCOSA allowance – see below).*
b. *A range is presented because ROC increases in each year of the determination period as a result of the need to recover fixed costs from a declining customer base. IPART, Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report, March 2010, pp. 120-121.*
c. *CARC allowance estimated from regulatory decision as not separately itemised. See: ESCOSA, 2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination, December 2010, p. A-86 & A-89; and Sapere Research Group, 2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin: Report to the Essential Services Commission of South Australia, April 2011, p. 45.*
d. *The regulated price is adjusted in line with movements in market contract prices (subject to a floor and ceiling price), so it is not possible to isolate the change in the underlying ROC component. Therefore, the allowance has been escalated by the CPI escalator used to establish the floor and ceiling price in each year.*
e. *ICRC has released a draft decision for 2012-14 which proposes to maintain the current (2011-12) ROC allowance in real terms.*

The Authority considers that the IPART and ESCOSA determinations are more comparable with the Authority's task than are allowances determined by the ICRC and OTTER. The allowances determined by IPART and ESCOSA were based on the costs of large retailers that are likely to have achieved economies of scale and this is consistent with the Authority's representative retailer definition.

While the allowances determined by ICRC and OTTER are higher than the Authority's 2011-12 allowance, the retailers in those jurisdictions supply small customer bases and are unlikely to be operating at scale[31]. The ICRC allowance also included the cost of meter reading (which is not a ROC item in Queensland) and some sales and marketing costs (which could not be separately identified), while OTTER set ROC to recover the costs of supplying non-contestable customers and excluded costs associated with the introduction of FRC (because it has not been introduced there yet).

Ergon Energy argued that the IPART benchmark was the most relevant because it relied on the cost information of multiple retailers, but also noted that it may be appropriate to adjust the benchmark to account for Queensland specific costs. In response to the Draft Methodology Paper, Origin Energy, on the other hand, argued against placing too much reliance on the IPART benchmark, because it was not consistent with the costs of operating in a contestable market either as an incumbent or new entrant. It was not clear which benchmarks Origin Energy considered to be more comparable, for example, it did not argue that ESCOSA's allowance was too low even though it is similar to that determined by IPART. However, in response to the Draft Determination, Origin Energy suggested that the IPART allowance was a reasonable benchmark.

Queensland Consumers Association argued that, if benchmarking was adopted, it was essential that it did not lock in existing levels of performance and productivity. The Authority does not consider that this is a likely outcome as retailers will have an incentive to lower their costs in order to increase their profit or offer discounts and/or other incentives to customers to attract them away from other retailers. The latter is more likely in a market where competition is effective.

Retailers also made general comments that there were differences in ROC between jurisdictions that had not been captured in the benchmarking analysis, but (except for Origin Energy) did not provide any further information on what those differences were or how they should be quantified.

Origin Energy argued that there were Queensland specific adjustments that needed to be taken into account, including:

(a) higher licence fees in Queensland than other jurisdictions;

(b) the lack of a late payment fee or credit card surcharge; and

(c) the Authority's regulatory fees.

While Origin Energy provided no information on the extent of difference in licence fees, the Authority understands that licensing will be the responsibility of the AER from 1 July 2012 (or soon thereafter) and this will, presumably, bring a degree of uniformity to these charges.

[31] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010-2012,* June 2010, pp. 39-40; OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Draft Report*, August 2010, p. 71; and OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania*, *Final Report*, October 2010, p. 77.

While the Authority understands that regulated retailers in NSW and South Australia are not able to charge customers for paying by credit card, the Authority acknowledges that, unlike Queensland retailers, retailers in NSW and South Australia are allowed to charge late payment fees. However, based on the information provided in IPART's determination, the ROC allowance has already been adjusted upwards (by $2.30 per customer) to include the costs associated with late payments. This may also partially explain why the ESCOSA allowance is lower than that of IPART.

The Authority has previously agreed that the regulatory fees that the Authority imposes on retailers would be recognised in setting retail costs.

Publicly Reported Costs

The Authority also considered publicly available information on ROC. AGL cautioned against using its reported cost data as it claimed this did not represent the total costs of operating its retail business. While the Authority reviewed the most recently available cost information reported by publicly listed Queensland retailers, it decided against relying on this information because:

(a) there were relatively large differences in reported costs between retailers;

(b) it was difficult to determine which costs were included or excluded; and

(c) actual costs may not reflect efficient costs.

Submissions

In its Draft Determination the Authority proposed a ROC allowance of $83.78 per (small) customer

Retailers generally considered that the proposed ROC allowance was too low.

QEnergy argued that NSW retailers would achieve lower costs per customer than Queensland retailers because there are a larger number of customers in NSW from whom to recover fixed costs. However, the Authority has adopted a very similar representative retailer definition to that adopted by IPART. Both regulators also assume that the representative retailer is of sufficient size to access economies of scale and supplies customers across the NEM.

QEnergy, APG and ERAA also argued that the Authority had not incorporated an allowance for the cost to retailers of providing bank guarantees to provide surety to counterparties, including, AEMO, hedge providers and network businesses. However, this is not a new cost incurred by retailers, nor is it a cost incurred only by Queensland retailers. The Authority expects that these costs would be accounted for in its benchmark analysis. By its nature, benchmarking does not attempt to attach a cost to every aspect of a retailer's normal business activities. To do so would be consistent with undertaking the alternate cost build up, not a benchmarking approach.

AGL argued that, although large retailers operate on a national basis there will still be differences in operating costs in various jurisdictions for a variety of reasons including demographics and geography and specific jurisdictional requirements. While this may be the case, the Authority has considered any jurisdiction specific costs that might need to be recognised in setting the ROC allowance.

While previously arguing that it considered the IPART allowance was too low, in response to the Draft Determination, Origin Energy noted that this allowance appeared appropriate given the available benchmarks. Nevertheless, it cautioned against adjusting the current allowance downwards given the significant changes in the Queensland market that were not reflected in the benchmarks, for example, the implementation of the NECF. The Authority has considered whether to make adjustments for any specific new costs likely to be incurred in 2012-13 below.

The Authority's Position

While AGL, Origin Energy and Alinta Energy indicated that they considered the 2011-12 ROC allowance in Queensland to be reasonable, the Authority's benchmarking analysis suggests that allowance is higher than the efficient costs of supplying small customers. In particular, the IPART and ESCOSA allowances (which the Authority considers to be the most comparable) are both lower than the Authority's allowance.

In the absence of any convincing arguments to adopt a different ROC allowance, the Authority considers that the ROC allowance of $83.78 per small customer proposed in its Draft Determination is appropriate. This is consistent with the top of the IPART range of $83.78 which, unlike the ESCOSA allowance, includes an allowance for the costs associated with late payments and appears to be the most appropriate benchmark ROC allowance per small customer. IPART's representative retailer definition is also comparable with that of the Authority, being based on a larger incumbent that has achieved economies of scale rather than a smaller new entrant.

In total, this would make the 2011-12 base ROC allowance $125.69 per customer (including CARC of $41.91 per customer). To arrive at its estimate of ROC for 2012-13, this base amount has been inflated as discussed below.

Escalating ROC to 2012-13 Values

As the benchmark ROC allowance accepted above is in 2011-12 dollars, it is necessary to reflect any change in costs between 2011-12 and 2012-13 in order to arrive at an allowance for 2012-13.

Under the BRCI, the Authority escalated retail costs from year to year using a 60/40 weighting of the change in the wage price index (WPI) and consumer price index (CPI) to reflect that labour costs account for approximately 60% of ROC.

However, the approach most commonly used in other jurisdictions to escalate costs from year to year within multi-year regulatory periods is to base increases solely on the change in the CPI.

While labour costs may be substantial, escalating those costs by WPI does not take into account any improvements in productivity (which is difficult to measure). It is also not clear that wages have been increasing at a higher rate than CPI in recent times. For example, AGL reported that labour rates increased in line with inflation in the 2010-11 financial year[32].

Due to the difficulties of accounting for cost increases net of efficiency improvements, the Authority suggested in its Draft Determination that it would be simpler and probably just as robust to escalate ROC just by the CPI. This approach was supported by QCOSS and CCCL.

Click Energy argued that adjusting ROC by CPI does not accurately account for collection costs (including bad debt and merchant service fees) because these costs increase at the same

[32] AGL Energy Limited, *Preliminary Final Report, Results for Announcement to the Market for the Year Ended 30 June 2011, Appendix 4E*, 25 August 2011, p. 11.

rate as the increase in customers' bills. Click Energy, therefore, recommended that ROC be escalated by a minimum of 3.9%. No other stakeholders raised this concern.

While some costs may increase by more than CPI, others may increase by less than CPI or even decrease. Therefore, the Authority considers that escalating ROC by CPI is, on average, a reasonable approach.

The Authority has therefore escalated ROC using the change in the CPI of 3.0% for the 12 months to 30 June 2013 which it has drawn from the Reserve Bank of Australia (RBA) Statement on Monetary Policy of May 2012[33].

Setting a Benchmark ROC Allowance for Large Customers

In addition to determining regulated retail prices for small customers, the Authority is required to determine regulated prices for large customers consuming more than 100 MWh per annum.

There is limited publicly available information upon which to determine an appropriate ROC allowance for large customers because, as noted above, regulators in other jurisdictions only set prices for smaller customers.

In a 2009 report for the Western Australian Office of Energy, Frontier Economics (Frontier) reviewed confidential cost data provided by the regulated retailer (Synergy) which suggested that the costs of supplying medium and large business customers was significantly higher than the costs of supplying small residential and business customers[34]. Frontier Economics suggested that this reflected more substantial marketing and account management costs and the additional cost of pricing large customer loads.

Frontier recommended that different ROC allowances should apply depending on the size of the customer as follows:

(a) for those tariffs where the majority of customers were consuming below the contestability threshold of 50 MWh per annum - $75 per customer (which excludes CARC as ROC was being estimated in this case for the supply of non-contestable small customers); and

(b) where the majority of customers were consuming above the contestability threshold:

    (i) $700 per customer for those tariffs where customers consumed around 200 to 400 MWh per annum on average; and

    (ii) $2000 per customer for those tariffs where customers consumed around 1.7 to 4 GWh per annum on average.

In 2011-12 prices, this would equate to $771 per customer where customers were consuming around 200 to 400 MWh per annum and $2,204 per customer at the higher level of consumption. Both of these allowances include CARC.

The Western Australian Office of Energy recommended price increases (including these ROC estimates for large customers) in order to make prices cost-reflective from 2009-10, but the Western Australian Government decided to approve lower price increases in recognition of the impact of the financial downturn and the financial pressure on consumers.

[33] This is the mid-point of the RBA's range of 2.5% to 3.5%.

[34] Frontier Economics, *Electricity Retail Market Review – Electricity Tariffs: Final Recommendations Prepared for the Western Australian Office of Energy*, January 2009, pp. 68-69.

In July 2011, the Economic Regulation Authority (ERA) in Western Australia was asked to undertake a further review of Synergy's costs and provide recommendations regarding cost-reflective tariffs. Frontier was again asked to advise on appropriate ROC allowances[35].

For this review, Frontier obtained forecast cost information from Synergy which projected significant increases in ROC (per customer) over the regulatory period. However, Frontier was unable to verify these forecasts and, in the end, recommended adopting the allowances from its earlier 2009 review (the 2009 allowances).

Frontier also noted that the 2009 allowances were based on Synergy’s estimates of the ROC of a new entrant retailer which may mean that the allowances are slightly overstated when considering the costs of an incumbent retailer. However, the Authority does not have any information upon which to base an appropriate adjustment.

In its draft report[36], ERA decided against adopting different ROCs for customers of different sizes and instead adopted a single average ROC to apply to all regulated tariffs.

Nevertheless, Frontier’s estimates suggest there is a significant difference in the retail costs of servicing larger customers. Comments in submissions provided mixed views as to whether any cost differences exist. For example, AGL suggested that there may be some differences in the costs of supplying residential, business and rural customers and Ergon Energy considered that higher ROC allowances for large (and very large) customers were appropriate (though it suggested that these not be introduced immediately). However, QEnergy considered that costs per customer were similar, regardless of the size of the customer.

Were the Authority to apply the above Frontier estimates for large customers, given that the underlying network tariffs for large customers are designed for customers consuming above or below 4 GWh per annum, the appropriate benchmark allowances would be:

(a) $771 for customers consuming between 100 MWh and 4 GWh per annum; and

(b) $2,204 for customers consuming more than 4 GWh per annum.

These ROC allowances would account for roughly 1% of a typical large customer’s bill and less than 1% of a typical very large customer’s bill. In comparison, the ROC allowance for small customers would have accounted for around 11% of a typical residential customer’s bill in 2011-12.

The Authority’s Position

The Authority acknowledges that there is limited evidence upon which to determine the appropriate amount of ROC to allow for large customers. As noted, there were also mixed views in submissions on this issue. However, it does seem reasonable that retailers may have to incur higher costs to target larger customers as they are less numerous and hence low cost blanket marketing would not be appropriate. They are also likely to require more time and effort to analyse their energy needs and construct appropriate offers. It would also seem reasonable that the larger the customer the more corporate time and effort may be required to maintain them and manage their accounts.

[35] Frontier Economics, *Retail Operating Costs – A Report Prepared for the Economic Regulation Authority of Western Australia*, February 2012.
[36] Economic Regulation Authority, *Inquiry into the Efficiency of Synergy’s Costs and Electricity Tariffs, (Draft Report)*, 4 April 2012.

Therefore, the Authority is of the view that a higher amount of ROC is appropriate for large and very large customers.

In the absence of any better measure or benchmark of what this amount might be, the Authority proposed in its Draft Determination to include a 2011-12 base ROC allowance of $771 per large customer (those consuming between 100 MWh and 4 GWh per annum) and $2,204 per very large customer (those consuming more than 4 GWh per annum) customer, and to inflate these costs to 2012-13 prices.

However, given the uncertainty that surrounds the appropriateness of these estimates and recognising that the Frontier estimates were for a new entrant rather than incumbent retailer, the Authority has decided to recognise the higher ROC costs associated with larger customers but to not escalate the original Frontier estimates in this first year.

On this basis, the Authority has set a ROC allowance of $700 per large customer (those consuming between 100 MWh and 4 GWh per annum) and $2,000 per very large customer (those consuming more than 4 GWh per annum).

Regulatory Fees

In its 2011-12 BRCI decision, the Authority included an amount ($2.358 million or $1.16 per customer) in ROC to reflect the imposition of regulatory fees by the Authority.

The aggregate of fees to be paid to the Authority by electricity retailers in Queensland is calculated by the Authority based on its estimate of the annualised actual cost of performing its functions over the five-year period from 1 July 2010 to 30 June 2015. The total cost to be paid by retailers in 2012-13 is $2.494 million.

Queensland Consumers Association questioned why there had not been a reduction in regulatory fees to reflect the Authority's reduced role in energy regulation from 1 July 2012. While the Authority understands that some of its functions are likely to be transferred to the AER under the NECF, it is not yet clear when this will occur and which roles it will lose. However, there is scope to adjust this estimate in future years to ensure that fees are not significantly higher or lower than the Authority's actual costs.

This total cost is recovered from retailers according to their market share. Based on the most recently available data on customer numbers of 2,054,914 (as at 31 March 2012), this translates into a per customer cost of $1.21 for 2012-13.

Accounting for New Costs in 2012-13

The Authority has previously indicated that, where reliable information on the individual components of ROC is readily available, it will consider adjusting its estimate to include those particular costs.

While Origin Energy considered that the benchmark allowance was appropriate given available benchmarks, it noted that they would not have accounted for new costs likely to be incurred in 2012-13, including:

(a) the implementation of the NECF from July 2012, which will require major system and process improvements;

(b) additional administration and reporting obligations associated with the introduction of the carbon tax; and

(c) the impact of the current tariff reform.

In its Draft Decision, the Authority noted that, to a greater or lesser degree, there will always be changes to retailers' operating and regulatory environments, which could increase or decrease retailers' costs. For instance, retailers may incur additional costs associated with regulatory changes in 2012-13, but compliance costs are likely to decrease with the centralisation of retail electricity regulation under the NECF. Therefore, it is not clear what the overall effect of these changes will be.

While there may be some additional costs associated with each of these events in 2012-13, they are not likely to be on-going costs and, to the extent that any increase was made to ROC in 2012-13 (if it could be determined what an appropriate amount might be), this would simply be offset by a reduction in ROC in 2013-14 when these one-off costs were removed.

In response, Origin Energy acknowledged that the actual costs are associated with these events are unknown, but also cautioned against adjusting the current (2011-12) allowance downwards to reflect other jurisdictional benchmarks which also don't account for these costs.

Consistent with the Draft Determination, the Authority has not made any further specific adjustments to its ROC estimate.

The Authority's Final Determination

For this Final Determination, the Authority has escalated small customer ROC (except for regulatory fees which have been separately estimated for 2012-13) by the CPI and, other than the latest estimate of regulatory fees, has included no new costs in 2012-13 that need to be separately accounted for.

The Authority has set three different ROC allowances to reflect the costs of supplying customers of different sizes. Table 4.4 below sets out these allowances and compares them to those proposed in the Draft Determination.

Table 4.4: 2012-13 ROC ($ per customer)

	2011-12 BRCI	*Draft Determination 2012-13[a]*	*Final Determination 2012-13[b]*
Small customers consuming up to 100 MWh/yr:[c]			
Benchmark ROC	88.83	86.50	86.29
+ CARC	41.91	43.27	43.17
+ Regulatory fees	1.16	1.22	1.21
Total ROC	**131.90[d]**	**130.99**	**130.67**
Large customers (consuming between 100 MWh and 4 GWh/yr):			
Benchmark ROC (incl CARC)	130.74	796.57	700.00
+ Regulatory fees	1.16	1.22	1.21
Total ROC	**131.90[d]**	**797.79**	**701.21**
Large customers (consuming more than 4 GWh/yr):			
Benchmark ROC (incl CARC)	130.74	2275.92	2000.00
+ Regulatory fees	1.16	1.22	1.21
Total ROC	**131.90[d]**	**2,277.14**	**2001.21**

a. Where relevant, using CPI escalation factor of 3.25% (RBA forecast, March 2012).
b. Where relevant, using CPI escalation factor of 3.0% (RBA forecast, May 2012).
c. While some residential customers may consume more than 100 MWh per year, the small customer ROC has been applied to residential customer Tariff 12 (the time-of-use residential tariff). The Authority has not been delegated the function of setting Tariff 11 (the general supply residential tariff).
d. Under the BRCI, the same ROC applied to all customers.

4.3.3 Fixed and Variable Components

In its Issues Paper and the Draft Methodology Paper, the Authority discussed the allocation of ROC to individual tariffs and whether this should be as a fixed or variable charge or some combination of both.

In theory, cost reflectivity is achieved when the costs of supply are applied to each retail tariff on the basis of the driver or cause of those costs. Such an approach should lead to more efficient use of electricity because customers would pay for the costs they cause an efficient retailer to incur, no more and no less. Therefore, as a general rule, the mix of prices for each tariff between fixed and variable components should reflect the manner in which the underlying costs are incurred. Fixed costs are best recovered as fixed charges and costs that vary with consumption are best recovered as variable charges.

Approaches in Other Jurisdictions

In other jurisdictions, regulated retailers tend to have the flexibility to set their own prices subject to a weighted average price cap (WAPC) determined by the regulator. Setting a

WAPC is a more light-handed form of regulation than determining individual tariffs and prices and, therefore, many of the issues that the Authority faces in applying costs to retail tariffs do not arise in other jurisdictions. As noted by IPART in its final report on 2010-13 regulated retail prices:

> *Under a WAPC approach, IPART determines the maximum average percentage by which each [regulated retailer] can increase its regulated tariffs (weighted by the relevant quantity) in each year of the determination period. The [regulated retailer] can then adjust the level and structure of individual regulated tariffs as it sees fit, provided that on average, these tariffs do not increase by more than the maximum percentage.*[37]

In setting the WAPC, IPART split energy and retail costs into fixed components (costs that do not vary with electricity consumption) and variable components (costs that do vary with the level of consumption) and then weighted the fixed components of prices by customer numbers and the variable components by estimated electricity consumption. In undertaking this task, IPART assumed that:[38]

(a) energy costs were fully variable;

(b) ROC (excluding CARC) was 75% fixed and 25% variable;

(c) CARC was fully fixed; and

(d) the retail margin was fully variable.

Submissions

Retailers were generally of the view that most (if not all) ROC was driven by customer numbers rather than electricity consumption and that it would be appropriate to apply ROC either fully (AGL, QEnergy and Origin Energy) or largely (Ergon Energy) to the fixed component of retail tariffs.

In suggesting that a small proportion of costs could be applied to the variable component of retail tariffs, Ergon Energy suggested that the approach adopted by IPART (which treated 75% of ROC and 100% of CARC as fixed costs and 25% of ROC as variable costs) was a sound basis to follow.

In its Draft Methodology Paper, the Authority noted that there are two possible options for applying ROC to each retail tariff:

(a) estimating the total ROC allowance applicable to each retail tariff group by multiplying the relevant (small, large and very large) per customer allowance by the total number of customers in that group and applying those costs as partly fixed and partly variable, as IPART did, as follows:

    (i) 75% of costs (and 100% of CARC) equally to the fixed component of each retail tariff within the retail tariff group; and

    (ii) 25% of costs equally to the variable or consumption component of each retail tariff within the retail tariff group; or

(b) applying the relevant per customer ROC allowance directly to the fixed component of the relevant retail tariff.

[37] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p.61.
[38] Ibid., p.141 and p.220.

In the Draft Methodology Paper, the Authority proposed to adopt option (a) because it was consistent with the approach chosen by IPART. There was general support for this approach in submissions on the Draft Methodology Paper.

However, after further consideration in its Draft Determination, the Authority was of the view that it had misinterpreted the IPART approach and that the variable component of ROC identified by IPART and Frontier is one that varies with customer numbers, not with changes in electricity consumption. Since the fixed component of prices that the Authority is to determine is a cost per customer, in the Draft Determination, the Authority considered that option (b) appeared to be the appropriate approach to follow rather than option (a).

In response to the Draft Determination, some stakeholders supported the Authority's position to apply ROC as a fixed cost per customer. For example, while Origin Energy had previously supported the treatment of a small portion of costs as variable in order to mitigate customer impacts, in response to the Draft Determination, it supported treating ROC as 100% fixed given the largely fixed nature of these costs.

Click Energy argued that 65% of costs should be treated as fixed and 35% as variable. This argument appears to be based on Click Energy's view that the costs of bad debt and merchant service fees are a fixed percentage of a customer's bill (and so depend on the size of the bill) and that these costs comprise around one third of total ROC.

Ergon Energy maintained its view that the Authority should adopt option (a). Ergon Energy argued that the retail margin analysis conducted for IPART's 2010 pricing review by its consultant, SFG Consulting (SFG), relied upon 25% of ROC being variable with respect to consumption. However, the following statement from SFG's report suggests otherwise (emphasis added):[39]

> *The costs which are considered to be unrelated to volume are **retail operating costs**, depreciation and amortisation and the fixed charges component of network fees.*

Queensland Consumers Association also preferred option (a) suggesting that there were other influences on costs in addition to the number of customers served, including the quality of service, the retailer's efficiency, and customer type (but did not identify the fixed or variable nature of these influences). It also argued that treating costs as fully fixed would provide no incentives for consumers to reduce their consumption.

The Authority's Position

The Authority relied on a range of evidence in deciding on the appropriate approach. While it has not been able to find any evidence to suggest that retail costs vary with electricity consumption (and no evidence was provided by stakeholders), the Authority considers that there is evidence to suggest that some costs may vary with customer numbers. However, as the Authority is seeking to determine a cost per customer, this would translate to a fixed cost per customer.

Furthermore, the Authority disagrees with the suggestion by Queensland Consumers Association that some ROC should be recovered through the consumption component of tariffs to incentivise consumers to reduce consumption. If ROC is not driven by electricity consumption then it should not be recovered as a consumption charge. To do otherwise will not reflect the manner in which costs are incurred.

[39] SFG Consulting, *Estimation of the Regulated Profit Margin for Electricity Retailers in New South Wales*, 16 March 2010, p. 13.

In the absence of any compelling evidence to the contrary, and consistent with its Draft Determination, the Authority has adopted option (b) and has allocated ROC to the fixed component of tariffs.

Consistent with this approach, the Authority also considers that each customer should pay for ROC only once (regardless of the number of tariffs under which they may be supplied). For example, a residential customer may receive supply under Tariffs 11, 31 and 33 given the different applications to which each of these tariffs applies. If a fixed ROC allowance was included in each tariff, this customer would in effect be paying three fixed (per customer) charges when only one was required. Therefore, the fixed ROC allowance will be applied to all retail tariffs except:

(a) controlled load tariffs (Tariffs 31 and 33), because customers accessing these tariffs will also be supplied under the general supply residential tariff (Tariff 11); and

(b) unmetered tariffs (Tariffs 71 and 91), because customers accessing these tariffs are also likely to be supplied under another general supply business tariff.

Although this may not capture all circumstances where customers are accessing multiple tariffs, the rationalisation of tariffs is likely to reduce the possibility of customers paying ROC more than once.

The Authority's Final Determination

The Authority has applied the relevant ROC allowance (for small, large and very large customers) to the fixed component of each retail tariff, as follows:

(a) the small customer ROC of $130.67 per customer per annum will apply to all small customer tariffs where consumption is up to 100 MWh per annum (Tariffs 12, 20, 22 and 41);

(b) the large customer ROC of $701.21 per customer will apply to tariffs where consumption is generally between 100 MWh and 4 GWh per annum (Tariffs 44, 45, 46 and 47);

(c) the very large customer ROC of $2,001.21 per customer will apply to the tariff where consumption is generally greater than 4 GWh per annum (Tariff 48); and

(d) no ROC will apply to controlled load tariffs (Tariffs 31 and 33) or unmetered tariffs (Tariffs 71 and 91).

Table 4.5 converts these allowances to daily charges as will be applied in the relevant regulated retail tariffs for 2012-13 and compares these to the outcomes proposed in the Draft Determination.

Table 4.5: Final Determination - ROC Allowances for 2012-13 – Fixed charge

Retail Tariff	*Draft Determination (c/day)[a]*	*Final Determination (c/day)[a]*
12, 20, 22, 41	35.887	35.800
44, 45, 46, 47	218.572	192.113
48	623.873	548.278

a. Charged per metering point.

4.4 Retail Margin

The retail margin represents the reward to investors for committing capital to a business and for accepting risks associated with providing retail electricity services. A retail margin which is not sufficient to compensate investors for their capital investment and exposure to systematic risks will lead to under-investment by existing retailers, deter entry into the market by new retailers and stall the development of effective competition.

4.4.1 Approach to Estimating the Retail Margin

In previous BRCI decisions, the Authority set the retail margin on an earnings before interest, tax, depreciation and amortisation (EBITDA) basis which meant that an allowance for depreciation and amortisation was implicitly included. It was also calculated as a percentage of total costs.

For the 2007-08 BRCI, by reference to retail margins accepted in other jurisdictions, the Authority concluded that a retail margin of 5% appeared appropriate. The 5% margin was maintained for all subsequent BRCI decisions because the Authority considered that there was no evidence to suggest that the risks of retailing electricity in Queensland had changed from one year to the next and that changes in all other cost components had been captured elsewhere in the BRCI methodology.

In its Draft Methodology Paper, the Authority noted that the retail margin should compensate retailers for systematic risks while non-systematic risks are compensated for elsewhere in the determination. Systematic risks are the result of exposure to overall economic or market conditions (also known as economic, market or non-diversifiable risk).

The Authority considered two alternative approaches to estimating the retail margin:

(a) undertaking an extensive and detailed financial analysis of the appropriate retail margin, such as a bottom-up and/or expected returns approach; or

(b) assessing the appropriateness of the current retail margin by benchmarking it against margins adopted in other jurisdictions.

Approaches in Other Jurisdictions

Consistent with the Authority's approach under the BRCI, other regulators calculate the retail margin on an EBITDA basis and (except in South Australia) calculate the margin as a percentage of total costs. In South Australia, the margin is calculated as a percentage of 'controllable costs' (that is, including retail and energy costs but excluding network costs).

While it is clear that the margin is intended to compensate retailers for their exposure to systematic risks in some jurisdictions (such as NSW), it is often not clear what risks are being compensated for in other jurisdictions. The most recent approaches adopted by regulators to estimate the retail margin in other jurisdictions are summarised below.

IPART (NSW)

Of all the regulators, IPART has undertaken the most extensive analysis in estimating the retail margin for its most recent determination. It engaged SFG to provide advice on a feasible range for the margin using three alternative approaches - expected returns, benchmarking and bottom up. IPART then selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.4% margin it selected was consistent with the mid-point of the reasonable range recommended by SFG.

ESCOSA (South Australia)

ESCOSA engaged LECG to advise on the retail margin for its most recent determination. LECG undertook a combination of benchmarking and a return on investment analysis (based on financial data provided by the regulated business). However, ESCOSA noted that it had relied more heavily on the results of the benchmarking analysis in arriving at its estimate of 10% of controllable costs (approximately 5.2% of total costs), given the numerous assumptions and judgements that were required in developing the bottom-up margin estimate.

ICRC (ACT)

In its 2010-2012 pricing review, the ICRC paid particular attention to the margin estimated by IPART given the extensive analysis underpinning that estimate. However, in adopting the same margin as IPART (5.4%), it considered that this may slightly over-compensate the regulated retailer for the risks it faces, given that compensation for energy purchase cost risks was already provided in the energy cost allowance and the broad range of matters eligible for pass through to retail prices.

In its 2012-14 pricing review draft report, the ICRC has proposed to maintain the retail margin at 5.4%.

OTTER (Tasmania)

OTTER adopted a combination of benchmarking and return on investment analysis to estimate a retail margin of 3.7%. In adopting a lower retail margin than other jurisdictions, OTTER noted that the regulated retailer faced significantly lower energy price and volume risk than retailers in those jurisdictions[40].

Submissions

Origin Energy, Queensland Government and CCIQ supported benchmarking to estimate the retail margin. However, Ergon Energy argued that a simple benchmarking analysis would not provide adequate compensation for current financial market volatility and the rising cost of debt and equity. It instead argued that the retail margin should be determined by assessing the appropriate systematic return for the representative retailer, as SFG had done for IPART.

[40] OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. 80 and pp. 89-99.

Despite commenting on the appropriate level of the margin and, in some cases, the risks that should be compensated for, most submissions did not provide any guidance as to what they considered an appropriate estimation approach would be.

The Authority's Position

While, as suggested by Ergon Energy, an extensive and detailed analysis of the appropriate retail margin might ensure adequate compensation to retailers for current financial market volatility, the Authority was not convinced that it would deliver significant benefits over the benchmarking approach.

For instance, despite extensive analysis, IPART still needed to exercise judgement to select an appropriate margin within a relatively wide recommended range of 4.8% to 6%. Furthermore, benchmarking is likely to implicitly take account of current financial market volatility. For instance, IPART noted its valuations of the weighted average cost of capital (WACC) (which were used to model the retail margin) were '... commensurate with prevailing market conditions and reasonably reflect the post-global financial crisis environment.'[41]

Therefore, given the general support for benchmarking in submissions, the Authority has assessed the appropriateness of the current margin of 5% by benchmarking it against margins adopted in other jurisdictions.

4.4.2 Implementing the Benchmarking Approach

The retail margins adopted in relevant jurisdictions are provided in Table 4.6 below. As noted above, all jurisdictions set the retail margin on an EBITDA basis.

Table 4.6: Retail Margin in NEM Jurisdictions

	Regulatory Period	*EBITDA Retail Margin (% of total costs)*
Queensland (current)	July 2011 – June 2012	5%
NSW (IPART)	July 2010 – June 2013	5.4%
South Australia (ESCOSA)[a]	January 2011 – June 2014	5.2%
ACT (ICRC)	July 2012 – June 2014	5.4%[b]
Tasmania (OTTER)	July 2010 to June 2013	3.7%

a. Applied as 10% of controllable costs (energy costs + ROC) but converted for comparison purposes. See: ESCOSA, 2010 Review of Retail Electricity Standing Contract Price Path: Final Inquiry Report & Final Price Determination, December 2010, p. A-92; and Sapere Research Group, 2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin: Report to the Essential Services Commission of South Australia, April 2011, p. 53.

b. ICRC has released a draft decision for 2012-14 which proposes to maintain the current retail margin.

The retail margins adopted in NSW, South Australia and ACT are slightly higher than the 5% margin currently adopted by the Authority. While the retail margin adopted in Tasmania is much lower, it is unlikely to be a relevant comparator as it reflects OTTER's view (as noted above) that the regulated retailer (which is the monopoly provider of retail services to

[41] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 232 & p. 234.

non-contestable customers in Tasmania) faces significantly lower energy price and volume risk than retailers in other NEM jurisdictions[42].

The retail margin decisions in South Australia and the ACT were heavily reliant on benchmarking against other regulatory decisions and are therefore considered less relevant than the IPART decision, where a much more comprehensive analysis was undertaken. For this reason, the Authority has paid particular regard to the analysis underpinning the IPART estimate and has considered its applicability to a representative Queensland retailer.

IPART Approach

In estimating the retail margin, IPART's objective was to compensate the regulated retailers for the systematic risks they face, including:[43]

(a) the risk of variation in their regulated load profile due to changes in economic conditions that affect the demand for their electricity;

(b) the risk of variation in wholesale electricity spot and contract prices due to changes in economic conditions and demand; and

(c) general business risk due to changes in economic conditions.

IPART engaged SFG to provide advice on a feasible range for the retail margin using three alternative approaches – expected returns, benchmarking and bottom up[44].

Expected Returns Approach

The expected returns approach was applied by estimating the cashflows that a retailer would earn from small customers and a retail margin was estimated to compensate investors for the systematic risk associated with these cashflows.

Using this approach, SFG estimated a range of 3.4% to 4.8%, with a mid-point of 4.1% – the lowest of all three approaches.

Bottom-up Approach

The bottom-up approach was applied by starting with an assumed investment base and cost estimates, then determining the earnings and revenue which would allow the retailer to earn an expected return equal to its estimated cost of capital.

Using this approach, SFG estimated a range of 4.5% to 6.3%, with a mid-point of 5.4%.

Benchmarking Approach

The benchmarking approach was applied by examining the reported profit margins of over 300 retailers across six sub-industries in Australia, the United States and the United Kingdom over a 29-year period. SFG also considered the profit margins of retail energy businesses in Australia.

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[42] OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. XXXII, p. 80 & pp. 89-99.
[43] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 128.
[44] SFG Consulting, *Estimation of the Regulated Profit Margin for Electricity Retailers in New South Wales*, 16 March 2010.

Using this approach, SFG estimated a range of 6.4% to 6.9%, with a mid-point of 6.7% – the highest of all three approaches.

Summary

SFG applied equal weight to each of the estimates derived from the three methodologies, in the absence of evidence that any one of the methodologies was more reliable than the other. Based on SFG's advice, IPART selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.4% margin it selected was consistent with the mid-point of the reasonable range of 4.8% to 6% recommended by SFG.

Submissions

Most retailers maintained that the current retail margin of 5% was too low, although QEnergy considered that it was, nevertheless, reasonable. Most retailers considered that a margin of 5.4% (as adopted by IPART) was also too low, although Ergon Energy and Origin Energy considered that it was reasonable. However, Origin Energy's support was conditional on the Authority increasing the energy cost allowance.

AGL and TRUenergy reiterated their view that the risks of retailing in Queensland were higher than in NSW and that a higher margin was warranted.

APG and ERAA considered that a retail margin of 5.4% is minimal compared to a more than 9% margin provided to distributors who are lower risk businesses. However, APG and ERAA appear to be comparing the WACC of distribution businesses to the margin of retail businesses, which is not a valid comparison because the WACC is applied to the asset base, while the retail margin is applied to total costs. Furthermore, IPART used a WACC of 9.1% (real pre-tax) as an input to its bottom-up analysis of the appropriate retail margin.

Of consumer groups, QCOSS considered that the current 5% margin was realistic, but noted that it could arguably be lower, while CCIQ considered that it was too high. QCOSS, CCCL and Queensland Consumers Association argued that there was no justification for increasing the margin to 5.4% because the risks retailers face are lower than under the BRCI. QCOSS and CCCL also argued that 5% fell within the reasonable range suggested by SFG.

The Authority's Position

The determination of an appropriate retail margin is an imprecise exercise. The Authority has previously noted that its current retail margin of 5% falls within the reasonable range of 4.8% to 6% suggested by SFG. Furthermore, IPART noted that it could have exercised its regulatory discretion to use any margin within that range, but exercised its judgement in selecting the mid-point of 5.4%. In this context, the current 5% margin in Queensland is not unreasonable.

However, the Authority notes that some retailers (including TRUenergy and AGL) have argued that the risks of retailing in Queensland are greater than those in NSW and that a higher retail margin is warranted. For instance, TRUenergy argued that NSW has:

(a) well defined cost pass-through provisions and uses final network tariffs (whereas the Authority determines retail tariffs and prices before network tariffs and prices are finalised); and

(b) a more stable and predictable regulatory process with retail costs and the margin being set for three years, network tariffs being passed through and annual reviews of energy purchase costs under a set methodology.

While the Authority is not able to incorporate a cost pass-through mechanism in its determination (see Chapter 6), this is a less significant issue in Queensland where regulated prices are set for one year, than it would be in NSW where prices are set for a three-year period. TRUenergy argued that the lack of a cost pass through mechanism is a major issue even in a one year price period as illustrated by the underestimation of SRES costs resulting from the difference between the forecast and published STP for 2012. Origin Energy, on the other hand, considered that the Authority had attempted to deal with this risk exposure by including an allowance for headroom (see Chapter 6).

The Authority has acknowledged that it would be appropriate to account for the material impacts of unforeseen or uncertain events on a retailer's costs, if it were able to do so. However, it also notes that the longer the price path, the higher the risks of costs differing from forecasts or unforeseen events arising that might have a significant influence (up or down) on previously estimated costs. Furthermore, the risk of network tariffs changing after the Authority has determined retail prices is likely to be small. As noted in Chapter 2, there has not been a situation where network prices would have needed to be changed after July 1.

While a longer price path may provide greater stability and predictability to retailers, as acknowledged by consumer groups, the new pricing approach being established in this determination should reduce the risks faced by retailers in Queensland relative to the previous BRCI approach, including better alignment of the cost structure and price structure and the pass through of network costs.

Some retailers also argued that the inclusion of an LRMC floor in the NSW energy cost allowance provided certainty and reduced retailers' risks and that the Queensland retail margin should be higher to account for this. QEnergy argued that setting prices by reference to the LRMC had been an implicit source of headroom in tariffs (which is not the purpose of the retail margin). Origin Energy also considered that the Authority had attempted to deal with the lack of an LRMC floor by including a headroom allowance. While the Authority has rejected the idea of basing its energy cost estimates on the LRMC (of generation) or including an LRMC floor to energy costs, the inclusion of an LRMC floor in NSW will reduce the risk exposure of retailers in that state. However, as noted above, the Authority has considered the issue of headroom explicitly in Chapter 6.

Even if the risks of retailing in NSW were lower than in Queensland, the Authority considers that IPART's retail margin estimate is still valid for Queensland because it was not necessarily NSW-specific. While the bottom up and expected returns approaches relied on some NSW specific assumptions and estimates, these approaches also produced lower margin estimates (mid-points of 4.1% and 5.4% respectively) than the benchmarking analysis which analysed the margins of retailers from a broad range of retail sub-industries in three countries (mid-point of 6.7%).

Given the detailed analysis undertaken by IPART, the Authority considers that it is reasonable for the retail margin in Queensland to be lifted to be the same as that adopted by IPART, but does not consider that there is justification to increase it any higher.

The Authority also notes that, unlike IPART, it has included a specific allowance for head room of 5% which, in combination with the margin, means that the potential gap over total allowed costs available to retailers is close to 11% in total.

The Authority's Final Determination

The Authority has set the retail margin at 5.4% of total costs, inclusive of the margin[45], which is equivalent to applying a margin of 5.7% on top of total allowed costs.

[45] The Authority (under the BRCI) and IPART both expressed the retail margin in this manner. The Authority's previous 5% margin under the BRCI was equivalent to applying a margin of 5.26% on top of allowed costs.

5. COST-REFLECTIVE RETAIL TARIFFS AND PRICES

Under the N+R approach, retail tariffs are to be aligned with network tariffs. Chapter 2 set out the Authority's decisions on the relevant network tariffs (the N component), upon which retail tariffs are to be based.

Chapters 3 and 4 set out the Authority's decisions on energy costs and retail costs which together comprise the R component of retail tariffs.

This chapter brings together the network tariffs and prices with the energy and retail operating cost (ROC) estimates from those earlier chapters and then adds on the retail margin to arrive at the bundled (cost-reflective) retail tariffs and prices.

5.1 Network Costs

As discussed in Chapter 2, the Authority has based the 2012-13 regulated retail tariffs on network tariffs drawn from both Energex and Ergon Energy as follows:

(a) Ergon Energy network tariffs and charges for non-residential customers with consumption greater than 100 MWh per year and for street lighting; and

(b) Energex network tariffs and charges for all other customers, including other unmetered loads.

The network charges applicable to each retail tariff include fixed and variable charges, as well as demand charges for some tariffs, which reflect the make-up of costs incurred by the network operator.

The network tariffs and charges form the basis of the regulated retail tariffs presented in Tables 5.1, 5.2 and 5.3.

5.2 Energy Costs

As discussed in Chapter 3, the Authority estimated energy costs for each retail tariff directly on a dollars per MWh basis. This reflects the manner in which retailers incur costs because energy costs are entirely dependent on the level (and time) of consumption, the more one consumes the more it costs.

In order to achieve cost reflectivity, the relevant energy cost estimate for each retail tariff has been applied to the variable component of that tariff as follows:

(a) 7.941 cents per kWh for tariffs where consumption is settled on the Energex NSLP (Tariffs 12, 20, 22, 41 and 91);

(b) for tariffs where consumption is settled on the Ergon Energy NSLP:

  (i) 7.808 cents per kWh for SAC demand tariffs (Tariffs 44, 45, 46) and the street lighting tariff (Tariff 71); and

  (ii) 7.450 cents per kWh for the SAC HV tariffs (Tariffs 47 and 48); and

(c) for controlled load tariffs:

  (i) 5.807 cents per kWh for the night rate (super economy) tariff (Tariff 31); and

  (ii) 6.595 cents per kWh for the controlled supply (economy) tariff (Tariff 33).

The energy costs that will apply to each regulated retail tariff are shown in Tables 5.1, 5.2 and 5.3.

5.3 Retail Operating Costs

As discussed in Chapter 4, the Authority estimated three different fixed per customer ROC allowances for customers of different sizes – small, large and very large – which have been applied to the fixed component of each retail tariff, as follows:

(a) 35.800 cents per customer per day has been applied to tariffs where consumption is less than 100 MWh per annum (Tariffs 12, 20, 22 and 41);

(b) 192.113 cents per customer per day has been applied to tariffs where consumption is generally between 100 MWh and 4 GWh per annum (Tariffs 44, 45, 46 and 47);

(c) 548.278 cents per customer per day has been applied to the tariff where consumption is generally greater than 4 GWh per annum (Tariff 48); and

(d) no ROC has been applied to controlled load tariffs (Tariffs 31 and 33) or unmetered tariffs (Tariffs 71 and 91).

The ROC that will apply to each regulated retail tariff are shown in Tables 5.1, 5.2 and 5.3.

5.4 Retail Margin

As discussed in Chapter 4, the Authority has decided to set the retail margin at 5.7% on top of total costs excluding the margin (and the allowance for headroom discussed in Chapter 6).

Given that the retail margin is calculated as a percentage of total costs, the appropriate approach is to apply the retail margin equally (on a percentage basis) to each component (fixed, variable and demand) of each retail tariff. This will mean that all customers pay the same margin as a percentage of their total bill but, in dollar terms, larger customers will pay more than smaller customers.

QCOSS, Origin Energy and CCIQ generally supported this approach. However, BRIG and Ergon Energy did not. BRIG suggested that the approach "appeared to be at odds with stated objectives and standard commercial practice", although it did not suggest an alternative approach. Ergon Energy considered that it would result in large customers paying an excessively higher margin than they would be required to pay under market contracts. Ergon Energy argued that the Authority should instead apply different margins to different customer groups, for instance, on the basis of differences in risk.

While the Authority acknowledges that there may be justification for applying different margins to different customer groups, such as on the basis of differences in risk, Ergon Energy did not provide any guidance as to how this would apply in practice and the Authority considers that it would be highly subjective.

Therefore, the Authority has maintained the approach it proposed in the Draft Determination by applying the retail margin equally (on a percentage basis) to each component of each retail tariff.

The retail margin that will apply to each regulated retail tariff is shown in Tables 5.1, 5.2 and 5.3.

5.5 Cost-Reflective Retail Tariffs

Table 5.1: Cost-Reflective 2012-13 Residential Regulated Retail Tariffs (GST Exclusive)

Retail tariff	*Energex network tariff*	*Tariff component*	*Fixed charge [a]* *c/day*	*Variable rate (flat)* *c/kWh*	*Variable rate 1 (off-peak)* *c/kWh*	*Variable rate 2 (shoulder)* *c/kWh*	*Variable rate 3 (peak)* *c/kWh*
Tariff 12 - Residential (time of use)	8900	Network	35.000		7.496	11.369	23.525
		Energy			7.941	7.941	7.941
		Retail	35.800				
		Margin	4.036		0.880	1.101	1.794
		Total [b]	*74.836*		*16.317*	*20.411*	*33.260*
Tariff 31 - Night rate (super economy)	9000	Network		4.112			
		Energy		5.807			
		Retail					
		Margin		0.565			
		Total [b]		*10.485*			
Tariff 33 - Controlled supply (economy)	9100	Network		7.456			
		Energy		6.595			
		Retail					
		Margin		0.801			
		Total [b]		*14.852*			

a. Charged per metering point.
b. Totals may not add due to rounding.

Table 5.2: Cost-Reflective 2012-13 Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Tariff component*	*Fixed charge [a]*	*Demand charge*	*Variable rate (flat)*	*Variable rate (off-peak)*	*Variable rate (peak)*
			c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	8500	Network	61.0		10.088		
		Energy			7.941		
		Retail	35.800				
		Margin	5.518		1.028		
		Total [b]	*102.318*		*19.057*		
Tariff 22 - Business (time of-use)	8800	Network	61.0			8.383	10.259
		Energy				7.941	7.941
		Retail	35.800				
		Margin	5.518			0.930	1.037
		Total [b]	*102.318*			*17.255*	*19.238*
Tariff 41 - Low voltage (demand)	8300	Network	1488.0	17.680	1.018		
		Energy			7.941		
		Retail	35.800				
		Margin	86.857	1.008	0.511		
		Total [b]	*1610.657*	*18.688*	*9.470*		
Tariff 91 - Unmetered	9600	Network			8.088		
		Energy			7.941		
		Retail					
		Margin			0.914		
		Total [b]			*16.943*		

a. Charged per metering point.
b. Totals may not add due to rounding.

Table 5.3: Cost-Reflective 2012-13 Large Customer Regulated Retail Tariffs and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Tariff component*	*Fixed charge* [a] *c/day*	*Demand charge $/kW/month*	*Variable rate (flat) c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	Network	533.900	27.002	1.751
		Energy			7.808
		Retail	192.113		0.0
		Margin	41.383	1.539	0.545
		Total [b]	*767.396*	*28.541*	*10.103*
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	Network	1968.200	23.361	1.751
		Energy			7.808
		Retail	192.113		0.0
		Margin	123.138	1.332	0.545
		Total [b]	*2283.451*	*24.693*	*10.103*
Tariff 46 - Over 100 MWh large (demand)	EDLT1	Network	3173.900	22.444	1.751
		Energy			7.808
		Retail	192.113		0.000
		Margin	191.863	1.279	0.545
		Total [b]	*3557.876*	*23.723*	*10.103*
Tariff 47 - High voltage (demand)	EDHT1	Network	2039.500	17.935	1.702
		Energy			7.450
		Retail	192.113		0.0
		Margin	127.202	1.022	0.522
		Total [b]	*2358.815*	*18.957*	*9.674*
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	Network	2039.500	17.935	1.702
		Energy			7.450
		Retail	548.278		0.0
		Margin	147.503	1.022	0.522
		Total [b]	*2735.281*	*18.957*	*9.674*
Tariff 71 - Street lighting [c]	EVUT1	Network	0.500		22.694
		Energy			7.808
		Retail			
		Margin	0.029		1.739
		Total [b]	*0.529*		*32.240*

a. Charged per metering point.
b. Totals may not add due to rounding.
c. The fixed charge for street lighting applies to each lamp.

6. COMPETITION, TRANSITIONAL AND OTHER ISSUES

This chapter discusses other issues relevant to the price determination process that have not been dealt with elsewhere, namely:

(a) the impact of the Authority's price determination on competition in the Queensland retail electricity market;

(b) transitional arrangements for customers; and

(c) eligibility criteria and other terms and conditions for retail tariffs.

6.1 Competition Considerations

Whether to Make an Allowance for Head Room

In response to the Draft Methodology Paper, retailers were generally of the view that the Authority had not given sufficient consideration to the potential impact of its proposed methodology on competition. They suggested that to maintain the current level of competition would require maintaining the excess profit, or 'head room', included to varying degrees in the existing regulated retail tariffs.

The 2012 Delegation requires that, in calculating notified prices, the Authority should ensure its price determination has regard to the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the market place.

As noted in the Draft Determination, this suggests that there is some longer term benefit to be derived by maintaining an actively competitive market rather than pursuing a short term minimum price approach which may stifle or eliminate competition from the market.

The longer term benefit derives from the downward pressure on prices that competition naturally brings to the market. By setting regulated prices somewhat higher than full cost, retailers will be attracted to enter the market and, as they compete for market share, non-regulated prices will be driven down. The more active the competition, the closer retailers will reduce prices to their individual, efficient costs of supply. While regulated prices will be unaffected, customers should be able to access lower priced market offers from competing retailers. Consumers should also benefit from improved service quality and choice.

As the Delegation directs the Authority to have regard to both the actual costs of supply and the impact of its determination on competition, this suggests that some trade-off is to be made between these twin objectives. Allowing for some head room above the efficient costs of supply (as presented in Chapter 5) will, as the retailers noted, sustain an actively competitive market. Failing to do so might see a substantial reduction in market activity and the range of offers available to consumers.

While an explicit allowance for head room is not included by regulators in setting regulated retail electricity prices in any other jurisdiction, in NSW and South Australia, IPART[46] and ESCOSA[47] both noted that certain aspects of the way they calculated regulated prices meant that new entrant retailers could face lower costs, for example, by supplying more than the

[46] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010.
[47] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.

regulated load or by using lower cost energy trading strategies. Both regulators examined the state of competition in their markets and found that the regulated price was not a major barrier to entry in the respective markets.

In contrast, in its 2010-12 price determination for the ACT, the ICRC set the regulated price based on the actual costs incurred by the sole incumbent retailer, on the basis that this price was likely to be lower than any competitive price that might result if the regulated rate was set higher to encourage competition in the market. The ICRC has maintained this approach in its 2012-14 pricing review draft report.

The concept of head room to facilitate competition is not relevant in Tasmania because regulated retail prices are only determined for customers that are not contestable.

In its Draft Determination, the Authority proposed to include an allowance of 5% head room in support of continued competition in the market.

In response to the Draft Determination, QCOSS, CCCL, Queensland Consumers Association and AgForce argued that there was no justification for including an allowance for head room in notified prices.

QCOSS suggested that the Authority was going beyond its Delegation because head room was not explicitly mentioned in the Delegation. However, as noted above, the Authority is required by the Delegation (and the Electricity Act) to have regard to the effect of its determination on competition in the Queensland retail electricity market. Under the Electricity Act, the Authority may also have regard to any other matter it considers relevant.

Consumer groups also claimed that there are no long term benefits of including head room in notified prices because the benefits of competition come from retailers operating more efficiently or providing a better quality service than the incumbent retailers. However, as pointed out by the AEMC[48], regulation will always be an imperfect substitute for competition because regulators have imperfect information upon which to determine efficient prices and regulated prices are not as responsive to changes in costs as competitively determined prices.

Moreover, including an allowance for head room in regulated retail prices does not preclude attainment of the very benefits identified by consumer groups and, in fact, many would argue that making some allowance for headroom provides the incentive for competition which delivers these benefits.

QCOSS also argued that the Authority would be radically departing from accepted practice by including head room in regulated prices. However, this is contrary to the acknowledgement by QCOSS that head room is implicitly included in current (2011-12) notified prices.

The Authority generally agrees with retailers that setting regulated prices at a level above the estimated cost reflective level is appropriate in a market where competition is effective because retailers will compete to offer the best value to their customers, thereby revealing efficient costs. This view has been borne out in practice to date in the competitive sections of the Queensland market with retailers prepared to compete away existing head room by making market offers to customers at substantial discounts to the regulated price.

If the cost of supplying consumers was fairly even across the State, it would be a relatively simple matter to determine an amount of head room to include in regulated prices. The more

[48] AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, Stage 2 Final Report*, 3 March 2011, p. 8.

head room, the greater the level of competition and the more resulting market prices (as opposed to regulated prices) would be squeezed down as retailers battled to attract customers. The Authority recognises that, as pointed out by consumer groups, including head room will not benefit customers that choose to remain on notified prices and it has taken this into consideration when determining the appropriate level of head room (see below).

It is unlikely that any reasonable level of head room allowed in the Energex network area would be sufficient to encourage retailers to offer market contracts to small customers in Ergon Energy's network area. As a result, and as pointed out by consumer groups, customers in the majority of the State will have to pay the regulated price, inclusive of any allowance for head room. Nevertheless, notified prices are still likely to be lower than the costs of supplying this group of customers, meaning that the inclusion of head room will have the effect of moving prices closer to cost reflective levels, while maintaining the uniform tariff policy.

The Authority's Position

While the Authority notes that including an explicit allowance for head room in regulated retail tariffs provides a "free kick" to those retailers with large numbers of non-market customers, those customers able to access a market contract can avoid this additional cost and, in those areas of the state where a lack of competition does not provide this choice, customers are generally not facing the full cost of supply due to the subsidy provided through the Government's uniform tariff policy.

In order to maintain a competitive market, the Authority has decided to include an allowance for head room.

How Much Head Room to Allow

Having decided to include some allowance in notified prices for head room, the question is what level of head room to allow.

Under the BRCI approach, the Authority was specifically required to maintain head room but never had to consider what the level of head room in existing tariffs was, as it assumed that, having reflected changes in all underlying costs, any head room (whatever it was) should have been maintained (in an aggregate sense).

In early submissions, retailers suggested that the head room available in existing prices was integral to the development of competition in the Queensland market. While retailers generally suggested that the Authority needed to include an allowance for head room in 2012-13 prices sufficient to ensure that the current level of competition is maintained, only QEnergy quantified this, suggesting that the way notified tariffs were originally set meant that there was 20% and 30% head room in residential and business tariffs respectively.

In considering this issue in the Draft Determination, the Authority analysed the most common 2011-12 notified prices and noted that a number of them, particularly non-residential tariffs, were significantly higher than the efficient cost of supply.

Figure 6.1 presents a cost breakdown of the annual (2011-12) electricity bill for an average customer on notified prices under a group of common tariffs.

Figure 6.1 is based on:

(a) Energex network costs (distribution use of system (DUOS) plus TUOS), given that most of the customers supplied by retailers operating in the competitive market in Queensland are located in Energex's network area; and

(b) other cost estimates calculated for the 2011-12 BRCI. While different stakeholders disagreed with different aspects of these costs, the approach is well understood and has been used as the basis of comparison by retailers with their costs. In particular, retailers have consistently argued that the BRCI under-estimated their actual costs of supply.

As the cost breakdown is for a customer with an average level of consumption for the particular tariff, the estimates of head room would be lower for below-average levels of consumption and higher for above-average levels of consumption because the fixed charges in notified prices do not fully reflect the fixed network and retail costs of supplying customers. As a result, retailers would recover less revenue relative to costs for smaller customers and more revenue relative to costs for larger customers.

As shown in Figure 6.1, the level of head room in Tariff 11 in 2011-12 is estimated to be around 6% whereas the level of head room in most other common tariffs is much higher, ranging between 12% and 23%.

Figure 6.1: Cost Breakdown of Average Annual Electricity Bill in 2011-12 by Tariff Class

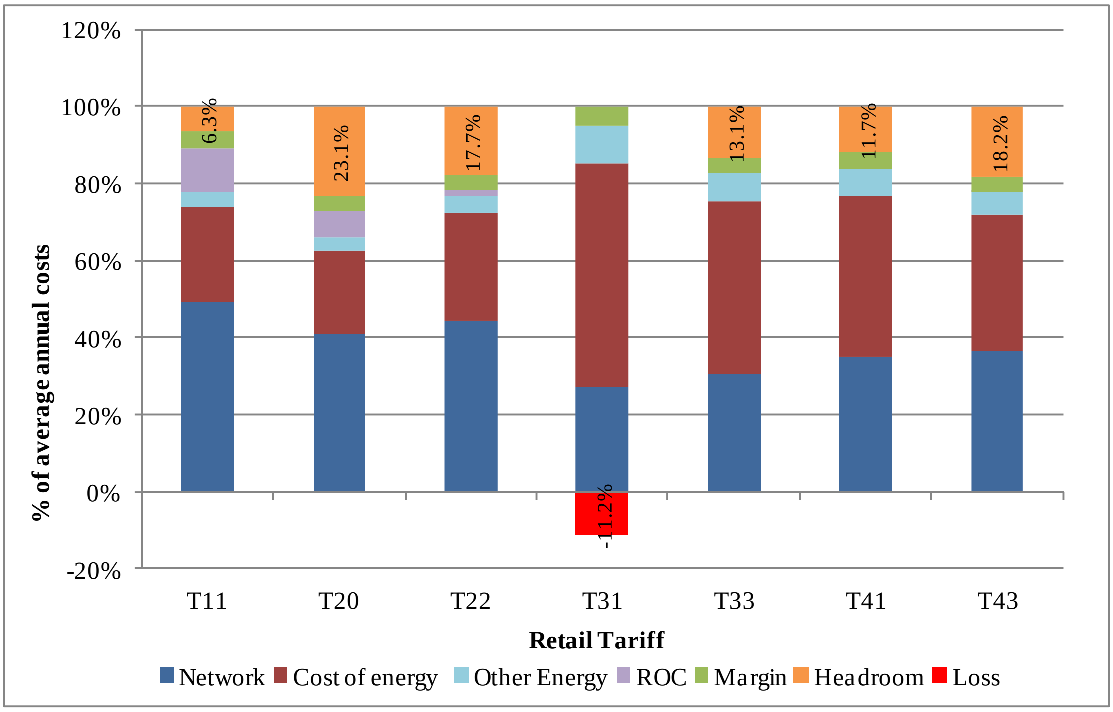


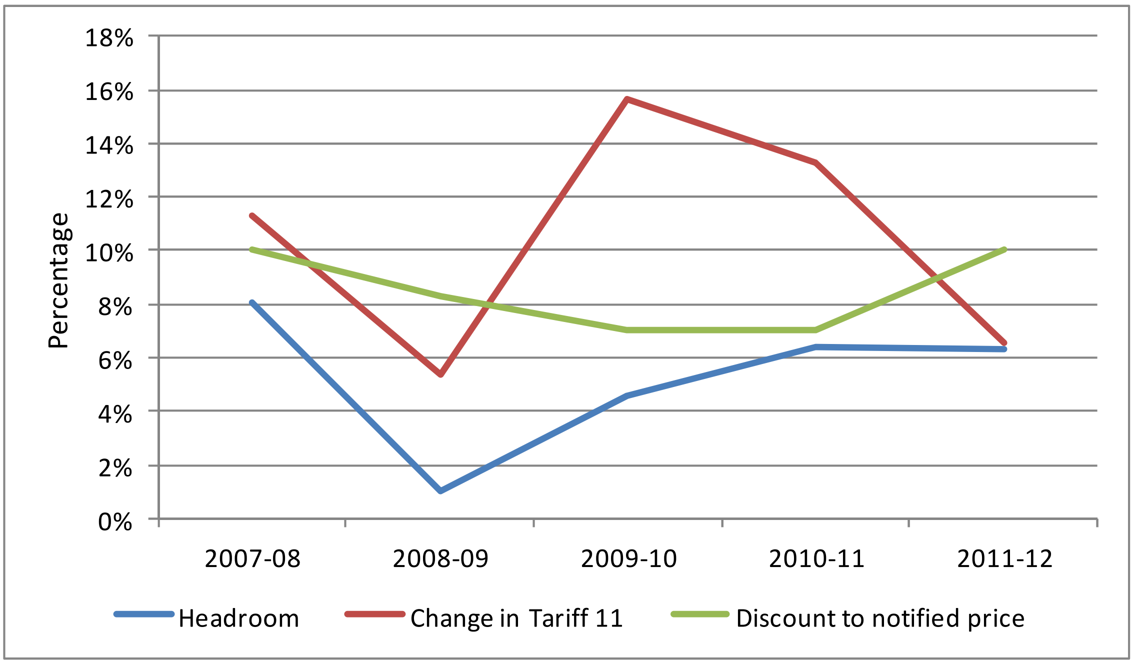
Figure based on 2011-12 Energex network tariffs, 2011-12 BRCI cost inputs (Cost of Energy $55.47/MWh, other energy costs (SRES, GEC, market fees etc.) $9.21/MWh, ROC $131.90, and margin 5%) and average consumption by network tariff (as provided by Energex).

However, this analysis is not without its problems. For example, the negative head room (indicating an annual loss to retailers) shown for Tariff 31 is not likely to be correct and highlights a weakness of the BRCI approach in that it did not reflect differences in costs of supplying different tariffs. In reality, retailers would most likely incur lower energy costs for supplying controlled load tariffs than for other tariffs where energy costs are settled based on the NSLP.

Nevertheless, the residential market (Tariff 11) comprises by far the largest number of customers and consumption and is also the market segment where there is reasonable information on discounts to the notified price offered in market contracts by retailers and other statistics such as churn rates.

Figure 6.2 shows how prices, discounts and head room for Tariff 11 have varied since the start of FRC.

Figure 6.2: Head Room, Available Discounts and BRCI Price Increases in Tariff 11



Discounts to the notified price reflect the maximum discounts based on offers available on the Authority's Price Comparator, including equivalent discounts for one month free offers.

Since the commencement of FRC, the estimated level of (effective) head room in Tariff 11 has averaged 5.3%. The low level of head room in 2008-09 resulted from the initial BRCI increase for that year of 5.38% which was increased following judicial review, but applied to notified prices for all but the last five minutes of 2008-09. The following 15.5% increase in notified prices between 2008-09 and 2009-10 reflects the extra 3.68% increase to 2008-09 prices that resulted from the re-made decision after judicial review in addition to the BRCI increase for 2009-10 of 11.82%.

Given the importance of price to customers in choosing to take up a market contract with a retailer, discounts to the notified price offered by retailers may also provide an indication of the level of head room available to retailers in Tariff 11.

As shown in Figure 6.2, the maximum discount to the notified price offered by retailers under market contracts has ranged between 7% and 10% since the commencement of FRC. However, on average, the level of discounting is likely to be somewhat less than this as the maximum discount offered does not apply to all products nor is it necessarily available throughout the entire year. This may explain why the level of discounting shown in Figure 6.2 is always higher than the level of head room.

The above analysis suggests that there is a reasonably modest amount of head room of around 6% currently in Tariff 11. While the Authority has no data on retailers' actual costs, as retailers consistently argued in the past that the BRCI underestimated their actual costs, it would seem reasonable to conclude that actual head room is no greater than the levels suggested in Figure 6.2.

This is contrary to claims by QEnergy that head room is actually significantly greater than 6%. For this to be true, the BRCI must have substantially over-estimated retailers' actual costs. If this was the case, it would have implications for setting some elements of notified prices for 2012-13 given the similar approach to estimating some costs under the BRCI and the current process. However, the Authority has not yet made any changes to cost estimates for this reason as it is not clear what other retailers' views might be on the existing level of head room.

As the Authority does not have any information about the level of discounts that may have been offered by retailers in market contracts for customers on tariffs other than Tariff 11, it is not possible to duplicate the above analysis for other tariff categories. However, given that the available head room in Tariff 11 appears to have been sufficient to foster a healthy amount of competition in the market for residential customers, the Authority considers that the same level of head room is likely to be sufficient to support competition for customers on notified prices under all other regulated tariffs.

Based on this analysis, the Authority proposed in its Draft Determination to include an allowance for head room of 5% of cost-reflective prices for all tariffs. While retailers generally appeared supportive of the proposed level, this support was qualified given their view that other components of notified prices (particularly the cost of energy) had been underestimated meaning that the value of the available head room was lower than they would have liked.

However, QEnergy considered that 5% was too low and argued that it should be increased to reflect current market discounts (relative to notified prices) of 5 to 10% for residential customers and 15 to 20% for business customers in order to maintain the current level of competition. QEnergy also argued that, while residential customers are willing to switch retailers when offered a 5% discount, business customers needed larger discounts. In support of this assertion, QEnergy cited the larger discounts currently available to business customers.

While the Authority notes that 5% is in the range that QEnergy considered reasonable for residential customers, it is not clear why business customers would require larger discounts than residential customers in order to switch retailers. In fact, one could argue that the opposite is more likely, with business customers likely to be more responsive to price discounts than residential customers, particularly if electricity is a significant input cost to their business. If current discounts for business customers are higher than for residential customers, this probably simply reflects the higher levels of head room in some existing business tariffs than the level of discount customers actually require before they will switch retailers.

The Authority's Position

The Authority has decided to include an additional allowance for head room of 5% of cost-reflective prices for all tariffs, as shown in Tables 6.1 to 6.3. This is the same as was proposed in the Draft Determination.

The Authority considers this represents a reasonable trade-off between the interests of retailers seeking to enter the market and the interests of those consumers who may not have access to, or choose not to take up, alternative market offers.

Table 6.1: 2012-13 Regulated Retail Tariffs and Prices for Residential Customers, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* [a]	*Variable rate (flat)*	*Variable rate 1 (off-peak)*	*Variable rate 2 (shoulder)*	*Variable rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 12 - Residential (time-of-use)	Cost reflective tariff	74.836		16.317	20.411	33.260
	Headroom	3.742		0.816	1.021	1.663
	Total [b]	*78.578*		*17.133*	*21.432*	*34.923*
Tariff 31 - Night rate (super economy)	Cost reflective tariff		10.485			
	Headroom		0.524			
	Total [b]		*11.009*			
Tariff 33 - Controlled supply (economy)	Cost reflective tariff		14.852			
	Headroom		0.743			
	Total [b]		*15.595*			

a. Charged per metering point.
b. Totals may not add due to rounding.

Table 6.2: 2012-13 Regulated Retail Tariffs and Prices for Other Small Customers and Unmetered Supplies Other Than Street Lighting, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* [a]	*Demand charge*	*Variable rate (flat)*	*Variable rate (off-peak)*	*Variable rate (peak)*
		c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	Cost-reflective tariff	102.318		19.057		
	Head room	5.116		0.953		
	Total [b]	*107.434*		*20.010*		
Tariff 22 - Business (time-of-use)	Cost-reflective tariff	102.318			17.255	19.238
	Head room	5.116			0.863	0.962
	Total [b]	*107.434*			*18.118*	*20.200*
Tariff 41 - Low voltage (demand)	Cost-reflective tariff	1610.657	18.688	9.470		
	Head room	80.533	0.934	0.474		
	Total [b]	*1691.190*	*19.622*	*9.944*		
Tariff 91 - Unmetered	Cost-reflective tariff			16.943		
	Head room			0.847		
	Total [b]			*17.790*		

a. Charged per metering point.
b. Totals may not add due to rounding.

Table 6.3: 2012-13 Regulated Retail Tariffs and Prices for Large Customers and Street Lighting, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* [a] *c/day*	*Demand charge* *$/kW/month*	*Variable rate (flat)* *c/kWh*
Tariff 44 - Over 100 MWh small (demand)	Cost reflective tariff	767.396	28.541	10.103
	Headroom	38.370	1.427	0.505
	Total [c]	*805.766*	*29.968*	*10.609*
Tariff 45 - Over 100 MWh medium (demand)	Cost reflective tariff	2283.451	24.693	10.103
	Headroom	114.173	1.235	0.505
	Total [c]	*2397.624*	*25.927*	*10.609*
Tariff 46 - Over 100 MWh large (demand)	Cost reflective tariff	3557.876	23.723	10.103
	Headroom	177.894	1.186	0.505
	Total [c]	*3735.770*	*24.909*	*10.609*
Tariff 47 - High voltage (demand)	Cost reflective tariff	2358.815	18.957	9.674
	Headroom	117.941	0.948	0.484
	Total [c]	*2476.756*	*19.905*	*10.158*
Tariff 48 – Over 4 GWh High voltage (demand)	Cost reflective tariff	2735.281	18.957	9.674
	Headroom	136.764	0.948	0.484
	Total [c]	*2872.045*	*19.905*	*10.158*
Tariff 71 - Street lighting [b]	Cost reflective tariff	0.529		32.240
	Headroom	0.026		1.612
	Total [c]	*0.555*		*33.852*

a. *Charged per metering point.*
b. *The fixed charge for street lighting applies to each lamp.*
c. *Totals may not add due to rounding.*

6.2 Customer Impacts and Transitional Arrangements

The 2012 Delegation requires the Authority to consider whether any transitional arrangements should be provided for farming and irrigation customers, customers currently on obsolete and declining block tariffs, and street lighting customers currently on Tariff 71. While the Authority has not been directed to consider transitional arrangements for customers on other tariffs, it has also looked at the impacts of the new tariffs and prices on the remaining customer groups.

At the outset of this review, the Authority was concerned (as were many stakeholders) that the imposed timetable for reporting and decision making did not leave adequate time for consultation or for the Final Determination to be implemented, let alone provide adversely affected customers with an opportunity to change their operations in order to reduce pricing impacts before those prices came into effect.

Ideally, the Authority would have preferred that changes of the magnitude being contemplated in this review were introduced over a two year period so that all customers and other stakeholders had at least a 12-month period in which to interact with the Authority over the changes to be made, followed by a further 12 months in which to review their consumption and/or business operations in light of the new tariffs and prices that would become fully operational at the end of that second year. Such an approach would have provided all customers with a default transitional arrangement in moving from the old to the new. However, the Authority had no capacity to amend the reporting deadlines set in the Delegation.

As it turns out, submissions from distributors (discussed below) have revealed that there are a number of practical limitations on the pace at which some customers could physically be moved from some old tariffs to new ones. These limitations relate to the re-programming of meters, the availability of suitable meters and the systems changes that distributors would face in moving customers to their appropriate new tariff. As a result, the Authority has had to retain many of the existing tariffs (particularly for large Ergon Energy customers) to operate concurrently with the new tariffs during 2012-13. As a result, many customers will in fact be able to transition to their new tariff over the coming year.

The existing tariffs that are retained will be termed obsolete tariffs from the start of 2012-13 and no new customers will be able to access any of them. All new customers will go onto their appropriate "new" tariff immediately. For many customers, the move to the new tariffs will offer lower costs or better supply arrangements. Those customers who wish to move immediately or during the next 12 months to their appropriate new tariff will be able to do so as soon as any metering requirements are able to be met by the distributors. At the end of this 12 month period, the Authority will review the state of play at that time to determine if any of the "old" tariffs need to be retained for a further period. This will also provide the Government with an opportunity to consider any requirements it may wish to impose on the future transition process when delegating the price setting task for 2013-14 to the Authority.

This outcome should not be confused with a "tariff freeze" as the Government has announced for Tariff 11. Rather, what will be retained are the old tariffs and the access conditions that went with them. The prices for each retained tariff will be increased to move customers part way towards the prices that would apply had they been required to move immediately to their appropriate new tariff. The amount of any price increase is discussed below and may vary according to the size of the gap between the prices currently charged for the old tariff and the cost reflective price of the new replacement tariff.

Submissions

In submissions received, consumer groups strongly supported the inclusion of transitional arrangements due to concerns about the potential for price and other impacts from implementing new regulated retail tariffs on 1 July 2012.

For example, AgForce and the Bundaberg Regional Irrigators Group (BRIG) noted that there had been significant investment in irrigation equipment based on the characteristics of specific tariffs and suggested that two years notice of any tariff changes was required to allow upgrading or replacement of that equipment. BRIG also suggested that some form of financial assistance be provided to irrigators to assist them in transitioning to new tariffs. Similarly, Canegrowers suggested that phasing in the new tariffs over a period of several years would give those customers facing significant changes time to adjust before the full impact was felt.

Foundry operators Bundaberg Walkers and CQMS Razer highlighted the need for transitional arrangements for those customers on obsolete and declining block tariffs. Both businesses indicated that having to move from obsolete Tariff 37, which does not have a demand charge, to a new tariff with a demand charge that would apply to their high demand requirements could threaten the financial viability of their businesses.

The Australian Industry Group also raised concerns about the removal of certain existing regulated retail tariffs (such as Tariff 37) and suggested that additional time be provided for large customers to transition to negotiated market contracts. IOR Terminals also requested additional time to transition from Tariff 20 to a market contract.

The Australian Sugar Milling Council expressed concern that Tariff 22 would no longer be available to large customers and proposed that a moratorium be imposed for one to two years on all substantial and structural changes identified in the Draft Determination for large customers. The Australian Sugar Milling Council and Sucrogen both expressed concern about the potential impacts of changes to Tariff 22 on their small customers. Sucrogen also recommended that an energy only tariff with a strong time-of-use signal be retained for irrigators and suggested a transitional period of two years following a one year consultation period to confirm the new tariff structure.

QCOSS, CCCL and the Queensland Consumers Association suggested the Authority should consider transitional arrangements for tariffs other than those where it was explicitly required in the Delegation. Similarly, the Australian Prawn Farmers Association requested that the existing Tariff 43 not be increased while Pioneer Valley Water Co-operative Ltd suggested that price impacts for customers on Tariff 22 needed more careful consideration.

Some retailers acknowledged the potential for customers to experience significant price increases as a result of implementing the new tariffs, but suggested that any associated social welfare concerns would be best dealt with through direct assistance from the Government rather than by continuing to distort electricity prices. As a result, retailers generally did not support transitioning customers to the new tariffs over a period of time. For example, Origin Energy opposed the Authority’s proposal to provide a one year transitional period for Tariff 37, stating that this would cost Origin Energy almost $700 per customer per annum.

Ergon Energy said that it will transfer all large customers currently on Tariff 21 (which Ergon Energy later confirmed comprised only a single customer) to Tariff 20 by 1 July 2012 and that it supported the removal of Tariffs 63 and 64 (provided Tariffs 62 and 65 were retained) as well as the removal of Tariffs 67, 68, 81 and 91.

However, while generally supporting the introduction of the new tariffs, Ergon Energy stated that it would not be able to shift customers currently on Tariffs 37, 62, 65, 66 and 71 to new tariffs by 1 July 2012 due to the practical constraints related to metering and its operating systems and requested that these tariffs be retained for a two year transitional period. Ergon Energy subsequently advised the Authority that, with the removal of the inclining block residential tariff, it would now be able to complete the system changes needed to implement the new Tariff 71 by 1 July 2012.

Ergon Energy also sought a two year transitional period for large customers, including those on Tariffs 20, 22, 41, 43 and 53, because time would be needed to change or modify customers’ metering to support the use of the new demand-based charges and in order for customers to adjust their electricity consumption before being shifted to the new tariffs. Ergon Energy indicated that it would use this time to consider including a time-of-use component in its network tariffs for large customers.

Energex proposed that the three different peak-time options available under Tariffs 64 and 65 be retained for irrigation customers in order to allow a level of diversity around load switching to be maintained and to remove the need to reprogram meters or time switches. Failing this, Energex indicated that it would take 12 months to re-program meters and/or time switches in order to shift customers on Tariffs 64 and 65, as well as Tariff 37, to alternative tariffs and therefore requested that these tariffs be retained for a one year transitional period.

Local Buy also suggested there was insufficient time to re-program large customers' meters in time to implement the new tariffs on 1 July 2012. Sucrogen and MSF Sugar recommended that large customers be given time before having to transition to new tariffs in order to mitigate any associated financial impacts.

The Authority's Position

As a general principle, the Authority agrees with the view put by retailers that any social welfare concerns arising from implementing the new regulated retail tariffs would be best addressed through direct assistance by the Government rather than by continuing to distort electricity prices. From a practical point of view, it is unclear how vulnerable residential customers could be targeted for transitional assistance in setting retail prices, as suggested by QCOSS and CCCL, to the exclusion of all other residential customers.

However, while the Government could provide financial assistance to those in need, this is not necessarily the appropriate solution for all adjustment issues. For example, the issue for commercial or farming customers adjusting their operations to the reality of the new tariff structures is likely to be more about the time needed to make appropriate changes than about the welfare needs of the customer.

Providing some transitional relief by continuing to hold a tariff below its cost-reflective level or delaying the movement of some customers to fully cost-reflective prices implies that either retailers will suffer some financial loss or that higher prices will continue to be applied to other customers to support on-going cross subsidies. Imposing such a burden on retailers could potentially hamper competition in the Queensland retail electricity market while continuing to force other customer groups to pay higher prices would deny them the benefits of the more cost-reflective prices to which they might otherwise be entitled.

While the Authority is reluctant to implement transitional arrangements, the practical limitations to implementing some of the new tariffs from 1 July 2012 cited by Energex and Ergon Energy leave no other option than to include some transitional arrangements because it will not be possible for retailers to charge customers on the basis of some new tariffs until metering requirements and other physical changes can be implemented.

In light of the practical difficulties identified by Energex and Ergon Energy, the Authority has no choice but to retain the existing regulated retail Tariffs 37, 62, 64, 65, and 66, as well as existing Tariffs 20, 22, 41, 43 and 53 for Ergon Energy's large customers only, in order to allow the distributors time to make the metering and any other system changes necessary to implement the new tariffs. However, the Authority questions whether this task would take two years to complete, as proposed by Ergon Energy and, at this point in time, is only prepared to commit to retaining the existing tariffs for the next 12 months but will review the state of progress again when setting prices for 2013-14.

The Authority is unable to provide transitional arrangements for large non-residential customers in Energex's network area (should they be deemed desirable), as suggested by the Australian Industry Group, IOR Terminals, the Australian Sugar Milling Council and Sucrogen, as the Government has decided that these customers will no longer have access to notified prices from 1 July 2012 and therefore any transitional arrangements would be meaningless.

The Authority has also decided to not accept Energex's proposal to retain the three different peak-time options available under Tariffs 64 and 65 because doing so would not reflect the underlying network charges, which is a requirement of the N + R approach.

Customer Impacts Expected in 2012-13

While several existing regulated retail tariffs will have to be retained for practical reasons, as discussed above, providing a transitional path for customers subject to those tariffs, the Authority is still required to consider whether any further transitional arrangements are warranted for customers on specific tariffs.

Table 6.4 shows the re-alignment of existing farming, irrigation, obsolete, declining block and street light tariffs to new network based retail tariffs for 2012-13. In the Draft Determination, the Authority suggested that Tariff 66 aligned with the new Tariff 41. However, in its submission, Energex indicated that Tariff 66 was more likely to align with its network tariff 8500, which is the basis for the new Tariff 20. This change lessens the customer impacts suggested in the Draft Determination, as discussed below.

Table 6.4: Alignment of Existing Regulated Retail Tariffs with New 2012-13 Regulated Retail Tariffs (and Underlying Network Tariffs)

Existing 2011-12 retail tariff	*New 2012-13 retail tariff (underlying network tariff)*
Obsolete and declining block tariffs	
Tariff 21	Tariff 20 (Energex network tariff 8500 – flat small/medium business)
Tariffs 37, 62, 63 and 64	Tariff 22 (Energex network tariff 8800 – time-of-use small/medium business)
Farming and irrigation tariffs	
Tariff 65	Tariff 22 (Energex network tariff 8800 – time-of-use small/medium business)
Tariffs 66, 67, 68	Tariff 20 (Energex network tariff 8500 – flat small/medium business)
Street lights	
Tariff 71	Tariff 71 (Ergon Energy network tariff EVUT1 – street lighting, East price region, transmission zone 1)

A number of submissions received in response to the Draft Determination indicated that, as noted by the Authority, individual customers could experience significantly different impacts to those presented for a typical customer due to them having significantly different levels and patterns of consumption. To get a better understanding for the extent of this problem (the diversity of consumption), Ergon Energy provided the Authority with a comprehensive analysis of customer impacts that has allowed the Authority to broaden its assessment. Energex is unable to provide similar data because, unlike Ergon Energy, it does not have access to customer data at the retail level.

Ergon Energy provided figures that show changes in annual electricity bills that different proportions of customers would have experienced if they moved from current regulated retail tariffs to the new regulated tariffs presented in Table 6.4. It is important to note that these impacts reflect prices from the Draft Determination. As prices in this Final Determination are very similar to those in the Draft Determination, the Authority considers Ergon Energy's analysis provides a sufficiently accurate guide for deciding on the need for transitional arrangements.

In response to submissions that suggested that dismissing seemingly modest dollar impacts was not appropriate, particularly in situations where single customers received supply under a number of different tariffs, the Authority has based its consideration on percentage impacts on bills. However, figures showing dollar impacts are also presented in **Appendix G** for stakeholders' information.

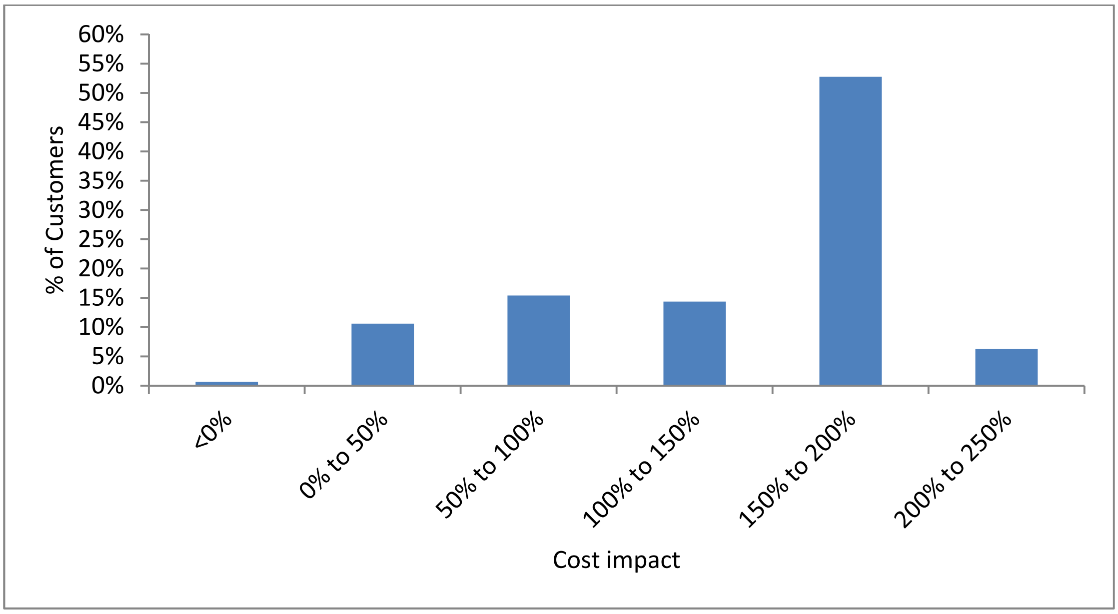
Obsolete and Declining Block Tariffs (Tariffs 21, 37, 62, 63 and 64)

Tariffs 21 and 62 are declining block tariffs. Tariffs 37, 63 and 64 are obsolete tariffs and have been so since 2007 (Tariff 37) and 1995 (Tariffs 63 and 64).

As discussed above, Tariffs 37, 62 and 64 are already set to be retained due to the practical problems identified in transferring customers to new tariffs by 1 July 2012.

Figures 6.3 to 6.7 show that the majority of small customers currently on Tariffs 21, 37, 62, 63 and 64 would experience significant price increases if moved to the regulated retail tariffs indicated in Table 6.4, although impacts are somewhat lower for customers on Tariff 62.

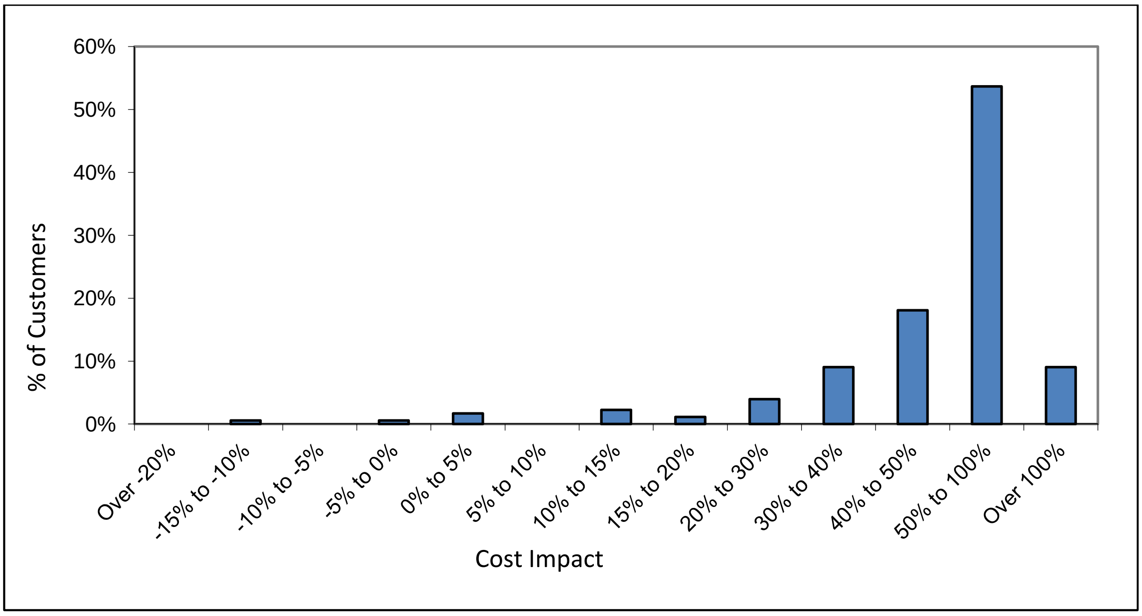
Figure 6.3: Change in Electricity Bills in 2012-13 for Customers on Tariff 21



Source: Ergon Energy

Increases for customers on Tariff 21 arise due to the re-balancing of prices towards higher fixed charges and lower consumption charges in 2012-13 which has occurred generally under the new cost-reflective approach to setting notified prices.

Figure 6.4: Change in Electricity Bills in 2012-13 for Customers on Tariff 37



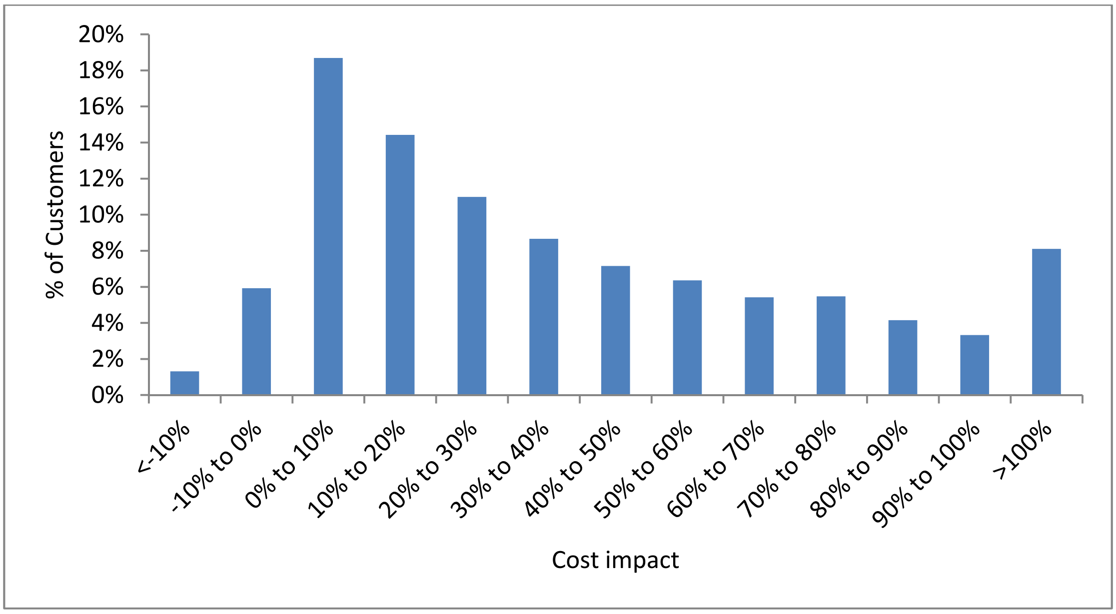
Note: 37% load factor assumed

Source: Ergon Energy

Increases for customers on Tariff 37 arise because these customers currently enjoy low off-peak charges for almost all of the standard 8am to 5pm work day whereas these hours are charged at peak rates under the replacement Tariff 22.

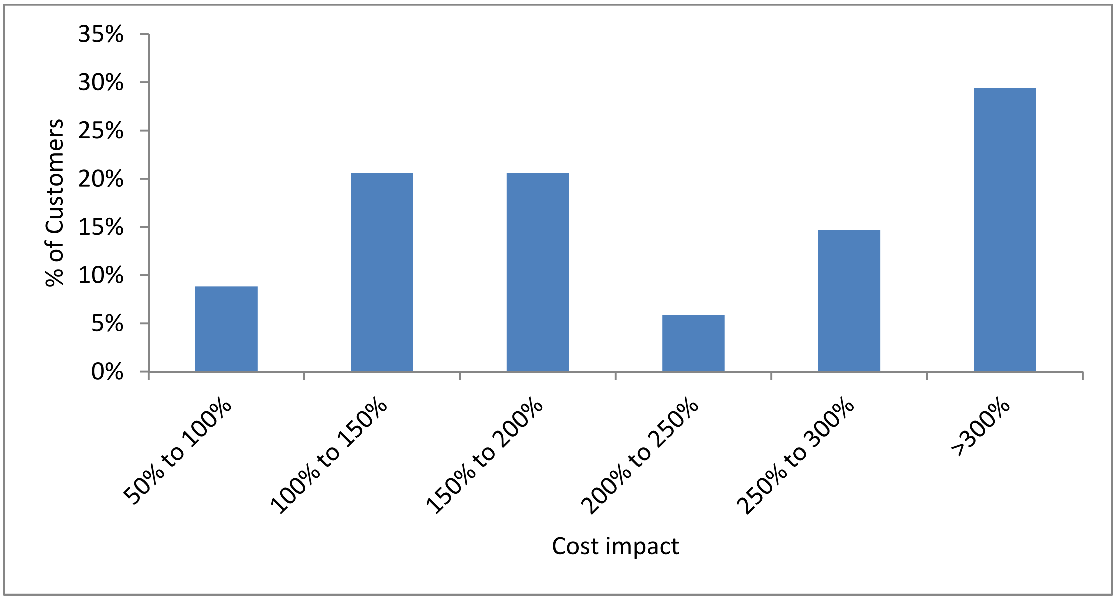
While the current off-peak daytime charges under Tariff 37 are clearly an unsustainable arrangement, customers have made investments and planned businesses around these rates being available. As a result, substantial changes may be required by these customers in restructuring their business model or operations to reduce the impact of moving to the new tariff.

Figure 6.5: Change in Electricity Bills in 2012-13 for Customers on Tariff 62



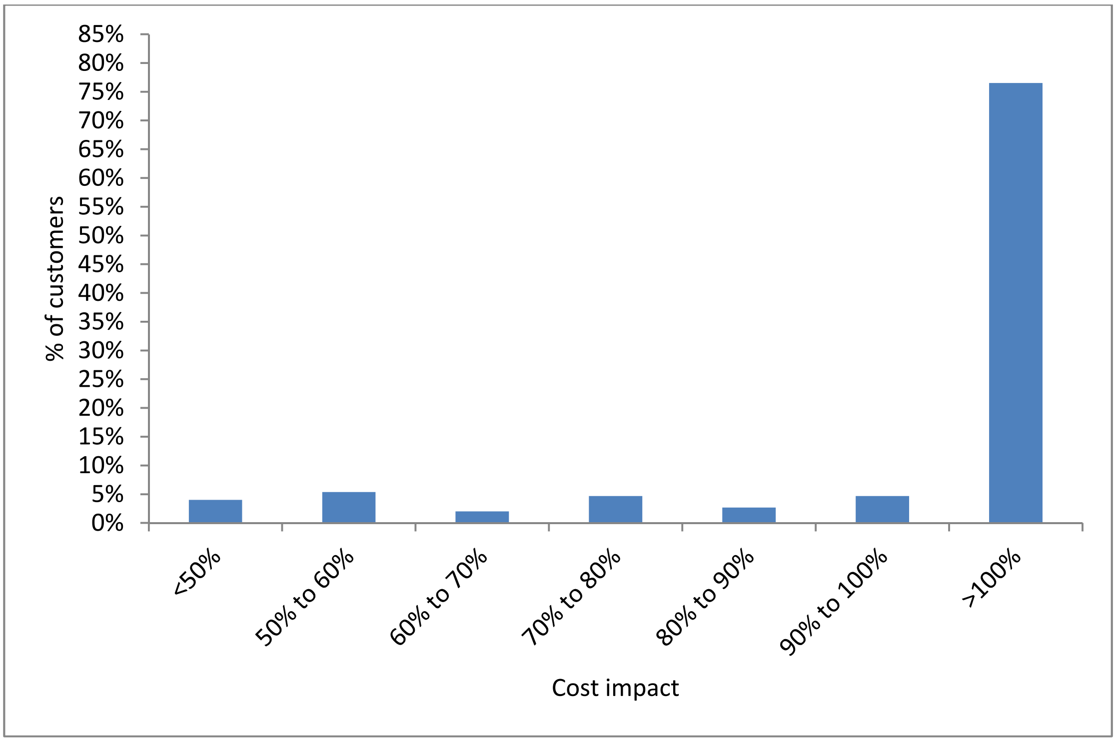
Source: Ergon Energy

Figure 6.6: Change in Electricity Bills in 2012-13 for Customers on Tariff 63



Source: Ergon Energy

Figure 6.7: Change in Electricity Bills in 2012-13 for Customers on Tariff 64



Source: Ergon Energy

Increases for customers on Tariffs 62, 63 and 64 arise mainly due to the significant increase in the off-peak rate in the new Tariff 22 relative to those under existing Tariffs 62, 63 and 64. For some of these customers, there may be ways to adjust their pattern of consumption in order to lessen the impact of the new tariffs.

In light of the customer impacts identified for customers on obsolete and declining block tariffs discussed above, the Authority has decided to also retain Tariffs 21 and 63. All of these tariffs (21, 37, 62, 63 and 64) will be retained in their current forms for 2012-13, but with 20% higher charges for Tariffs 21, 37, 63 and 64, and 10% higher charges for Tariff 62, as transitional steps towards the replacement Tariffs 20 and 22, which will continue to operate for new customers. The differing level of price increases reflects the different gap between what customers on Tariffs 21, 37, 63 and 64 are currently paying and what they would be required to pay under the new tariffs compared to customers on Tariff 62 where the gap is less.

Any customers that would be better off by moving to the new tariffs (or a market contract) are free to do so, subject to distributors' ability to address metering or other constraints. New customers will not be able to access the retained Tariffs 21, 37, 62, 63 and 64.

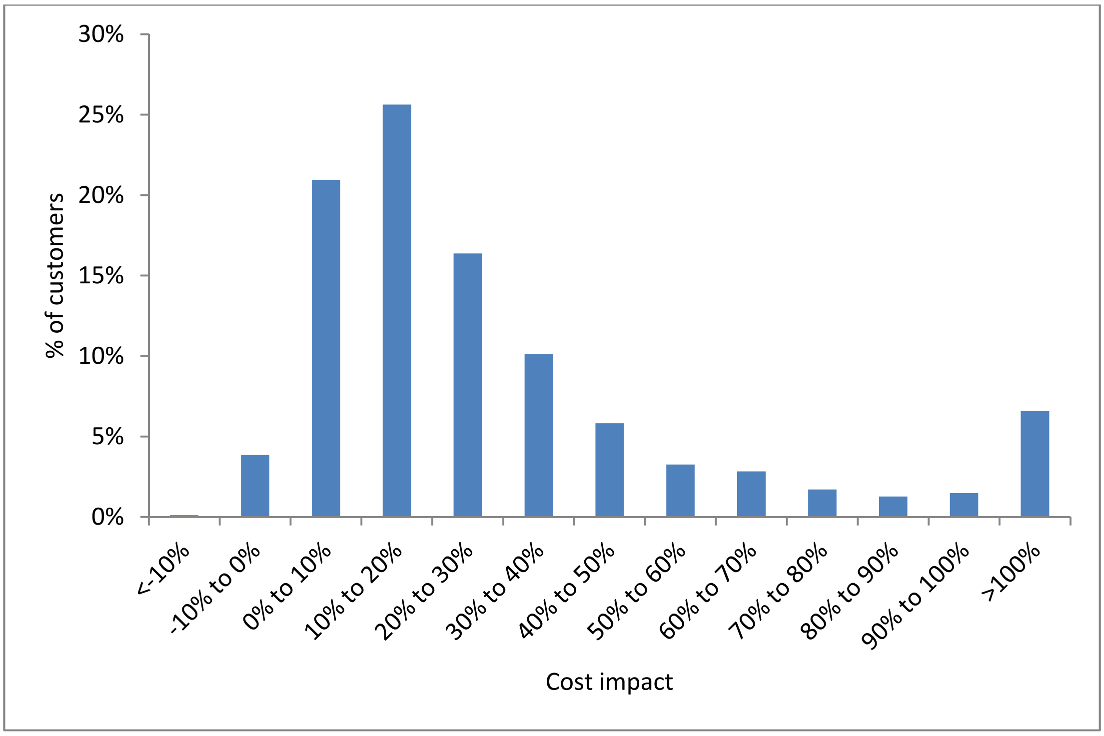
This arrangement provides an additional 12 months for affected customers to review their operations and power use to minimise, where possible, the impact of moving to the new tariffs. It also provides time for Energex and Ergon Energy to review the structure of some of their network tariffs in order to ensure that the peak versus off-peak signals provided in those tariffs are sufficient to encourage users to switch some consumption towards off-peak usage and deliver the demand management outcomes which best suit the distributors' networks.

Farming and Irrigation Tariffs (Tariffs 65, 66, 67 and 68)

Figures 6.8 and 6.9 show the potential impact for customers on Tariffs 65 and 66 in moving to new regulated tariffs 22 and 20, respectively.

Ergon Energy has confirmed that there are currently no customers on Tariff 67, which is only available to customers supplied under the Rural Subsidy Scheme, and that no customers will be on Tariff 68 by 1 July 2012. As a result, no consideration has been given to customer impacts for these tariffs.

Figure 6.8: Change in Electricity Bills in 2012-13 for Customers on Tariff 65

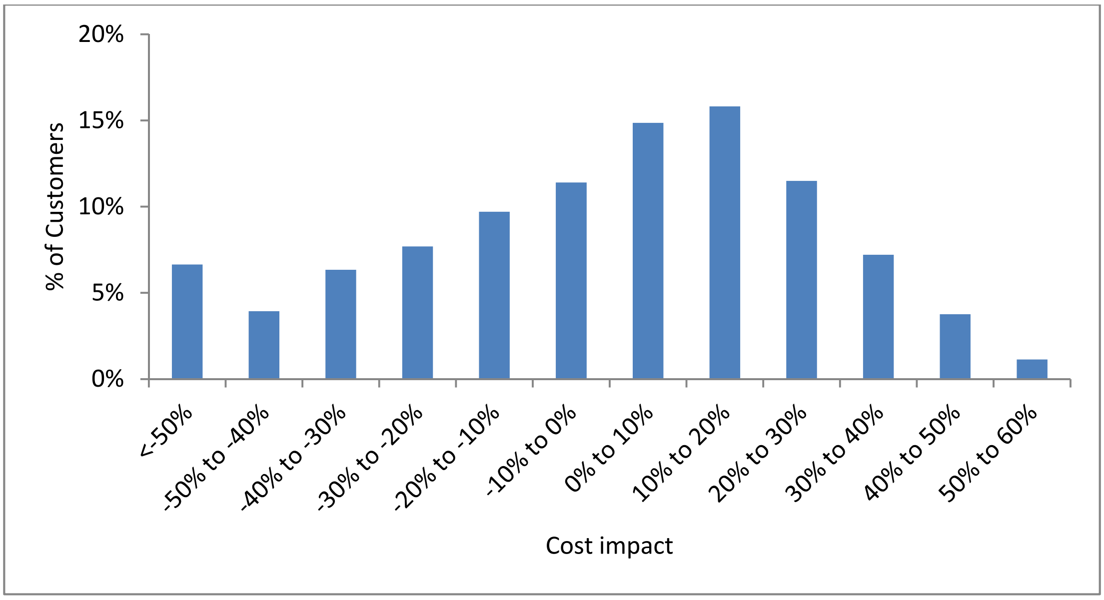


Source: Ergon Energy

As shown in Figure 6.8, most small customers on Tariff 65 can expect their annual bills to increase if they move to the new Tariff 22, though around 5% are likely to be better off on the new tariff. The increases are mainly due to a significant increase in the off-peak rate in the new Tariff 22 relative to that available under Tariff 65 and a consequent narrowing of the gap between peak and off-peak rates.

Price impacts for customers on Tariff 66 are not as great as for Tariff 65, as shown in Figure 6.9, and are less than indicated in the Draft Determination, where it was incorrectly assumed these customers would transfer to Tariff 41 instead of Tariff 20. As can be seen in Figure 6.9, almost half of the small customers on Tariff 66 would experience a decrease in their annual bill by moving to the new Tariff 20.

Figure 6.9: Change in Electricity Bills in 2012-13 for Customers on Tariff 66



Source: Ergon Energy

As noted in submissions, customers on Tariffs 65 and 66 have planned their operations and businesses around the availability and cost of the current tariffs and may have to rearrange their farming practices and use of equipment in order to reduce, where possible, the impact of these changes on their business model. However, for the next 12 months the existing tariffs are already set to be retained due to the practical problems identified in transferring customers to the respective new tariffs.

While the existing Tariffs 65 and 66 are to be retained in their current forms for 2012-13, charges will be increased by 10% as a transitional step towards the replacement Tariffs 22 and 20, which would be the operative tariff for any new customers.

Any customers that would be better off by moving to the new tariffs (and it appears that a significant number of customers on Tariff 66 would be better off on the new Tariff 20) are free to do so, subject to the distributors' ability to address metering or other constraints. New customers will not be able to access the retained Tariffs 65 and 66.

This arrangement provides an additional 12 months for affected customers to review their operations and power use to minimise, where possible, the impact of moving to the new tariffs. It also provides time for Energex and Ergon Energy to review the structure of some of their network tariffs in order to ensure that the peak versus off-peak signals provided in those tariffs are sufficient to encourage users to switch some consumption towards off-peak usage and deliver the demand management outcomes which will benefit the distribution networks.

Street Lighting Tariff (Tariff 71)

Assessing the impact of the new street lighting tariff is problematic because notified prices for street lighting currently comprise 18 different sets of fixed and variable charges depending on the type of street light and the extent to which the distributor bears the capital costs of the street lights. As a result, the Authority has not been able to assess price impacts for street lighting customers, but notes that, in its submission on the Draft Determination, Ergon Energy stated that the move to Tariff 71 would not cause significant financial impacts for customers. Regardless, the Authority would question whether any transitional arrangements would be justified given that any impacts will be on local councils that provide services to large groups of customers rather than individual residential or business customers.

For these reasons, the Authority has decided not to implement any transitional arrangements for street lighting.

Large customers in Ergon Energy's network area

Some of Ergon Energy's large customers are on Tariffs 37, 62 and 65, where the Authority is required to consider whether transitional arrangements might be required in order to reduce the burden of adjusting to new tariffs. In considering (above) the impact of moving to new tariffs for small customers on Tariffs 37, 62 and 65, the Authority has decided to retain these existing tariffs for a period of 12 months. The Authority has considered (below) the impact for large customers on these three tariffs. While not required, the Authority has also considered the impact of the new tariffs on other Ergon Energy large customers.

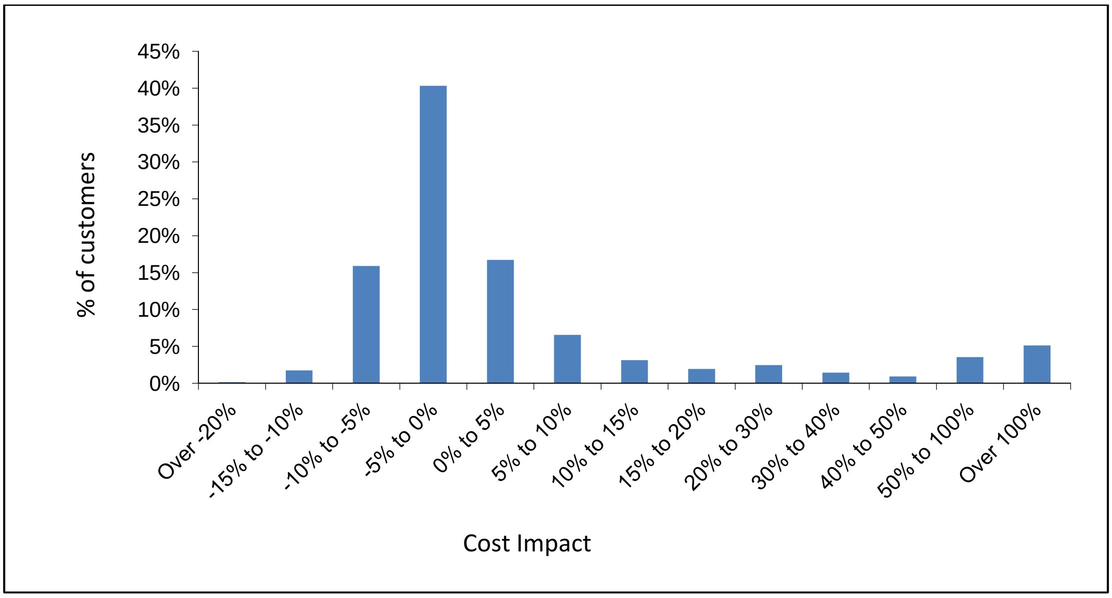
Following the release of the Authority's Draft Determination, Ergon Energy also provided the results of a separate analysis it had completed on the expected impacts of the Draft Determination on its large customers.

The majority of Ergon Energy's large customers are currently on regulated retail Tariffs 20 and 22. While these tariffs will still appear in the new tariff schedule, they will only be available for small customers. As a result, most of Ergon Energy's large customers would need to shift to alternative tariffs that are more suited to customers of their size. The appropriate tariffs for such large customers would be Tariffs 44 to 48 (depending on individual customer usage and requirements), which are demand-based tariffs. As discussed in Chapter 2, Ergon Energy's very large customers - those consuming more than 4 GWh per year - will now move to Tariff 48 instead of Tariffs 54 or 55, as proposed in the Draft Determination.

The remainder of Ergon Energy's large customers are on Tariffs 37, 41, 43 and 53, and a small number of large irrigators and farmers are on Tariffs 62 and 65. All of these customers will also have to move to new Tariffs 44 to 48.

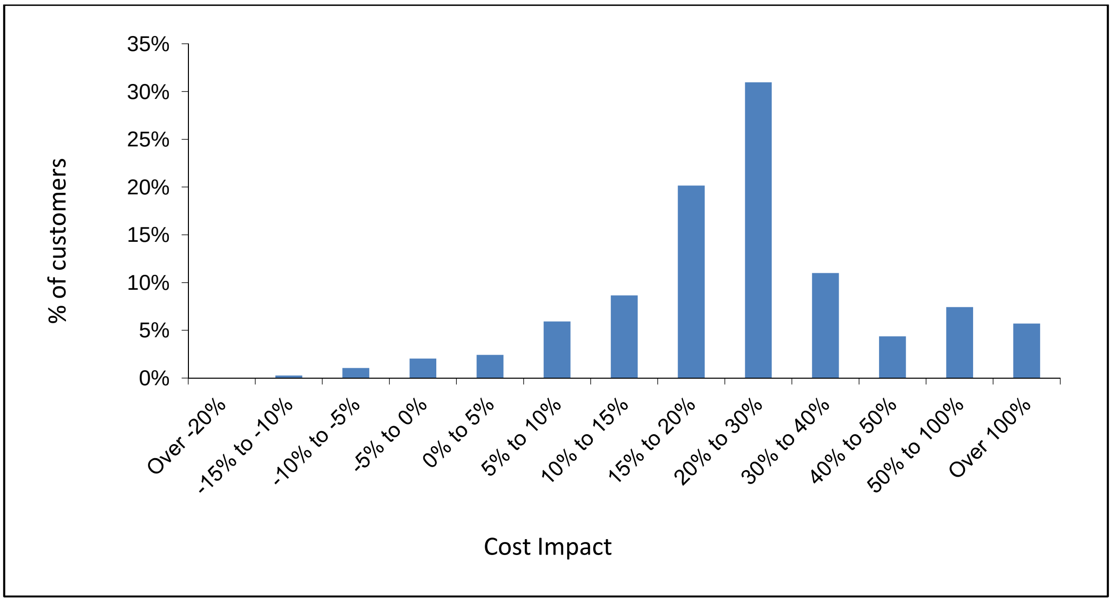
Figures 6.10 to 6.17 show that the majority of Ergon Energy's large customers on most tariffs will experience increases in their annual bills by moving to the new tariffs designed for large customers, and that the increases will be significant for many customers. The exception is for Tariff 20, where more than half of customers would experience a decrease in their annual bill. However, even for Tariff 20, around 15% of customers would experience increases of more than 20% and almost 10% would experience increases of more than 50%.

Figure 6.10: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 20



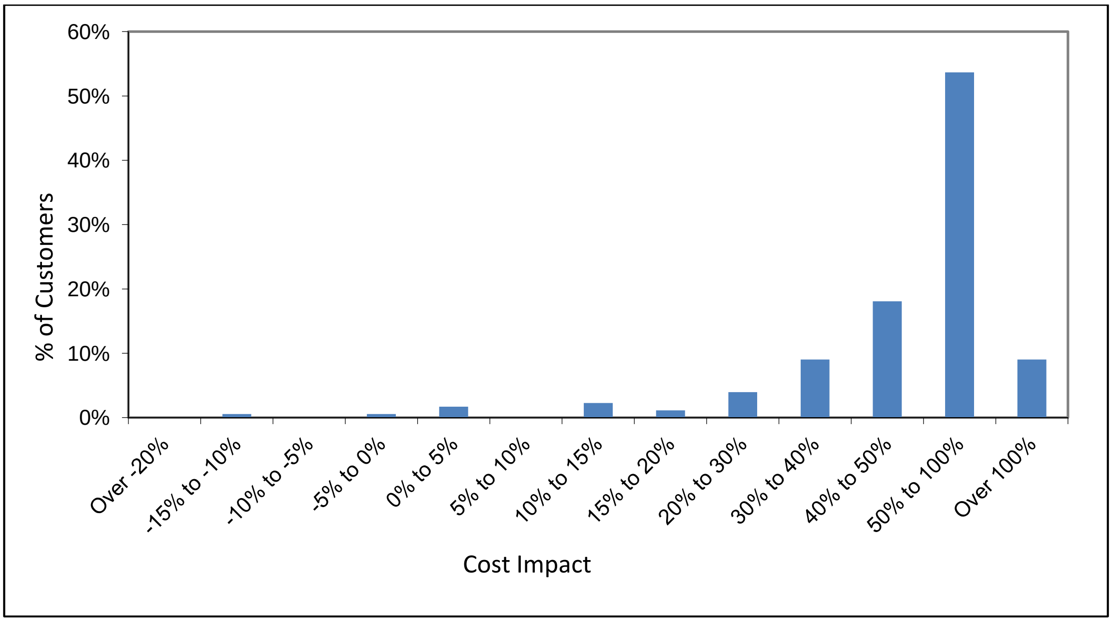
Source: Ergon Energy.
Note: load factor of 37% has been applied for calculating demand values.

Figure 6.11: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 22



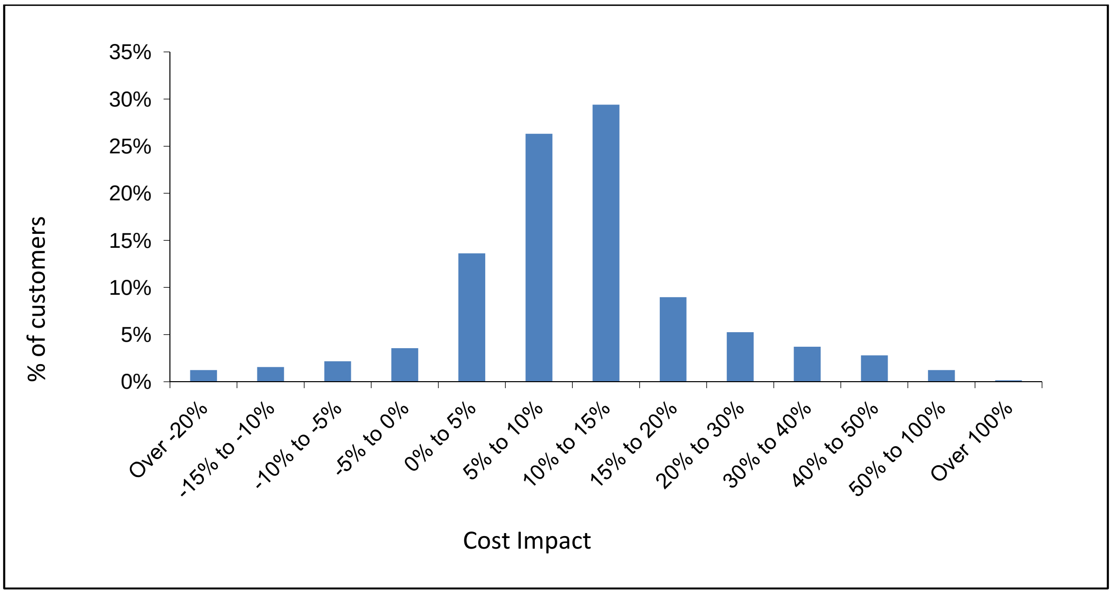
Source: Ergon Energy.
Note: load factor of 37% has been applied for calculating demand values.

Figure 6.12: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 37



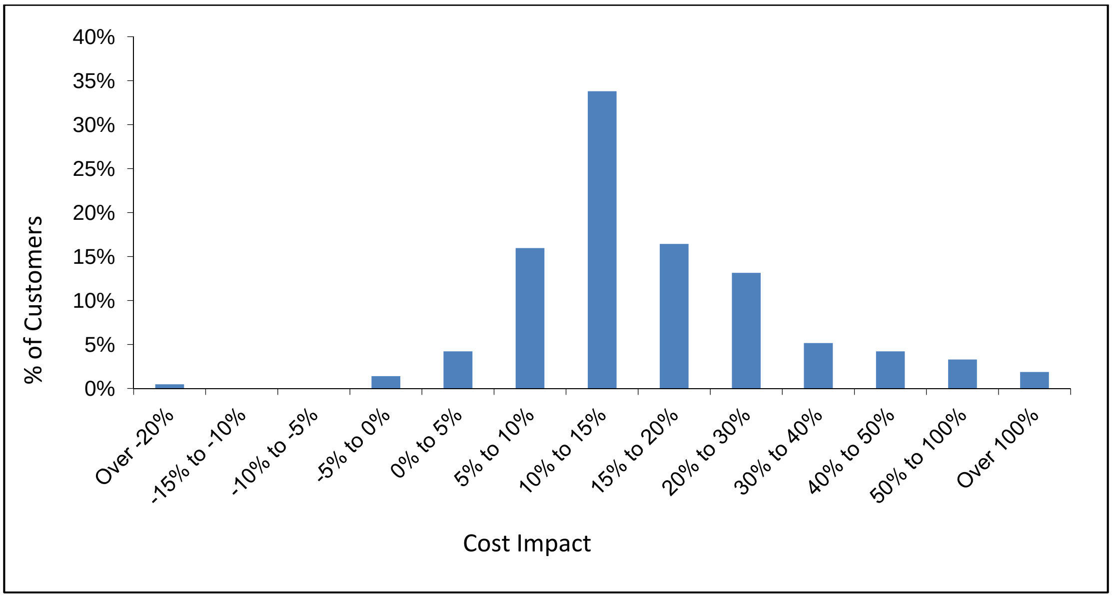
Source: Ergon Energy.
Note: load factor of 37% has been applied for calculating demand values.

Figure 6.13: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 41



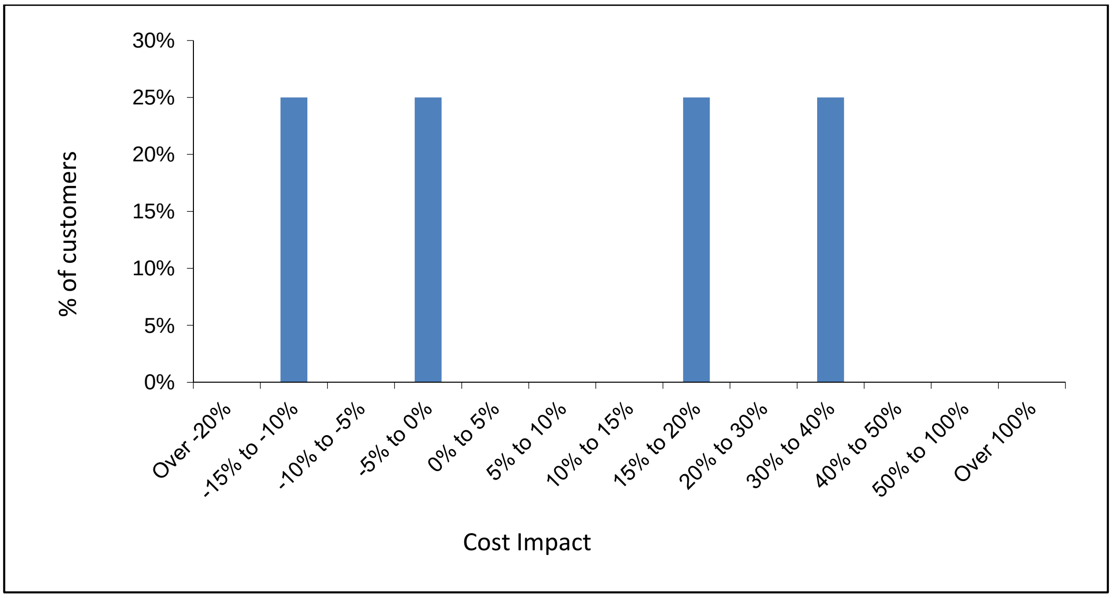
Source: Ergon Energy.

Figure 6.14: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 43



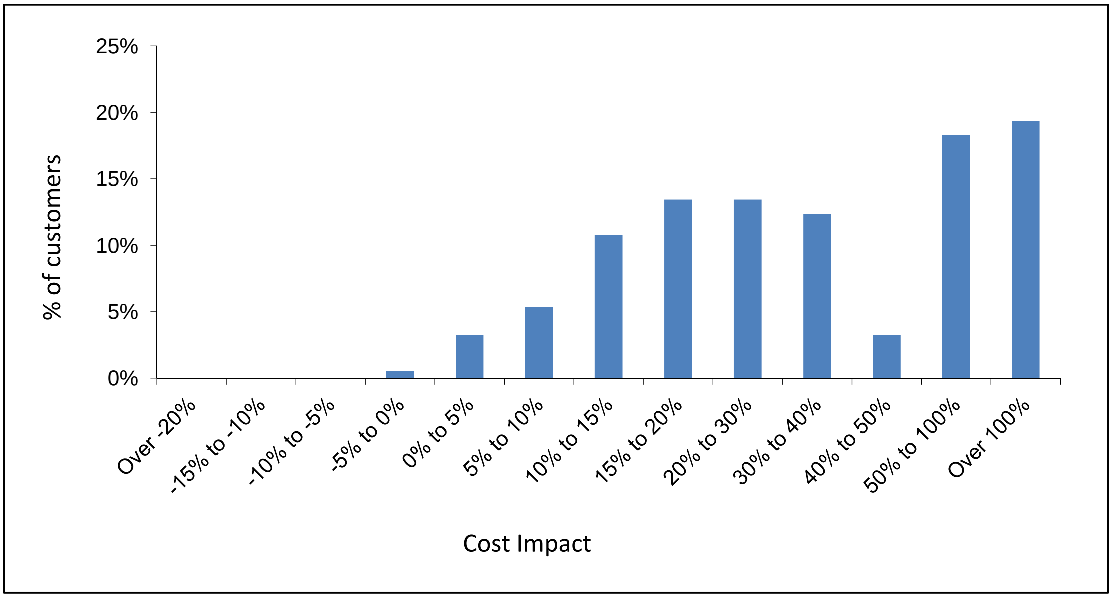
Source: Ergon Energy.

Figure 6.15: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 53



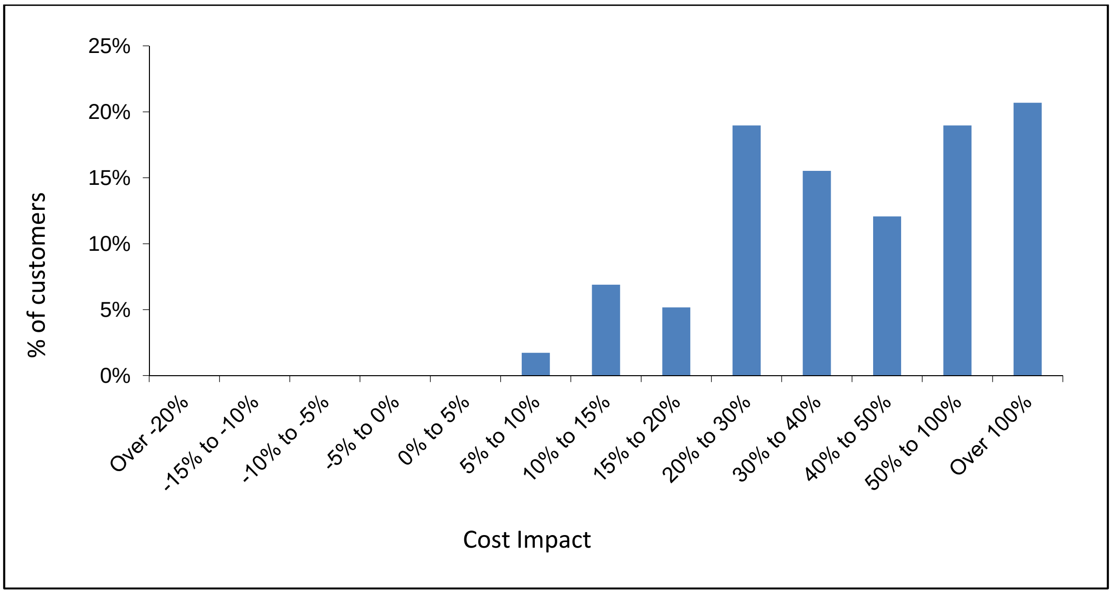
Source: Ergon Energy.

Figure 6.16: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 62



Source: Ergon Energy.
Note: load factor of 37% has been applied for calculating demand values.

Figure 6.17: Change in Electricity Bills in 2012-13 for Large Customers on Tariff 65



Source: Ergon Energy.
Note: load factor of 37% has been applied for calculating demand values.

There are two main reasons for the price impacts affecting Ergon Energy's large customers. First, many are currently paying for their electricity usage based on regulated retail tariffs that do not reflect the true costs of their supply. This is especially the case for very large customers that are currently on regulated retail tariffs such as Tariffs 20 and 22 that are more suited to much smaller customers. The Authority's decision to base regulated tariffs for large customers on the network charges Ergon Energy's distribution business charges its retail business to supply these customers means that the new regulated tariffs better reflect the costs of supply, for example by charging for customers' demand requirements rather than just on the basis of how much energy they consume.

Secondly, the Ergon Energy network tariffs that form the basis for the new regulated retail tariffs for large customers do not include any time-of-use elements (no peak and off-peak charges). Many large customers are currently on 'inappropriate' small customer tariffs which do include peak and off-peak charges. For these customers, moving to the new large customer tariffs not only involves an increase in the basic cost but also removes the option of off-peak charging for some of their consumption.

Regardless of how this situation came about, those large customers on existing regulated tariffs will have planned their operations and businesses around the availability and cost of the current tariffs and may have to rearrange their practices and use of equipment in order to reduce, where possible, the impact of these changes on their businesses. The Authority has therefore decided to retain Tariffs 20, 22, 41, 43 and 53 (for existing large customers only) in their current forms for 2012-13, but with 20% higher charges for Tariffs 22, 41, 43 and 53 and 10% higher charges for Tariff 20 (reflecting the lower impacts of moving to the new tariffs) as a transitional step for these customers moving towards the replacement Tariffs 44 to 48.

Transitional arrangements for Tariffs 37, 62 and 65 have already been discussed above in considering the impacts on small customers. Large customers on these tariffs will be treated in the same manner as for small customers, given the existing Tariffs 37, 62 and 65 (which are already set to be retained for 12 months) do not differentiate between small and large users.

Any customers that would be better off by moving to the new tariffs (and it appears that many customers on Tariffs 20 and 37 would be better off) are free to do so, subject to the distributors' ability to address metering or other constraints. New large customers will not be able to access the retained Tariffs 20(large), 22(large), 41(large), 43 and 53.

As noted previously, this arrangement provides an additional 12 months for affected customers to review their operations and power use to minimise where possible the impact of moving to the new tariffs. It also provides time for Ergon Energy to review the structure of its large customer network tariffs and consider whether to include some time-of-use charging for these customers in order to promote the demand management objectives of the distribution business.

Other customers

While not required, the Authority has considered price impacts for the remaining tariffs not considered above. Table 6.5 shows the alignment of the remaining current regulated retail tariffs with the new 2012-13 regulated retail tariffs.

Table 6.5: Alignment of Existing Regulated Retail Tariffs with New 2012-13 Regulated Retail Tariffs

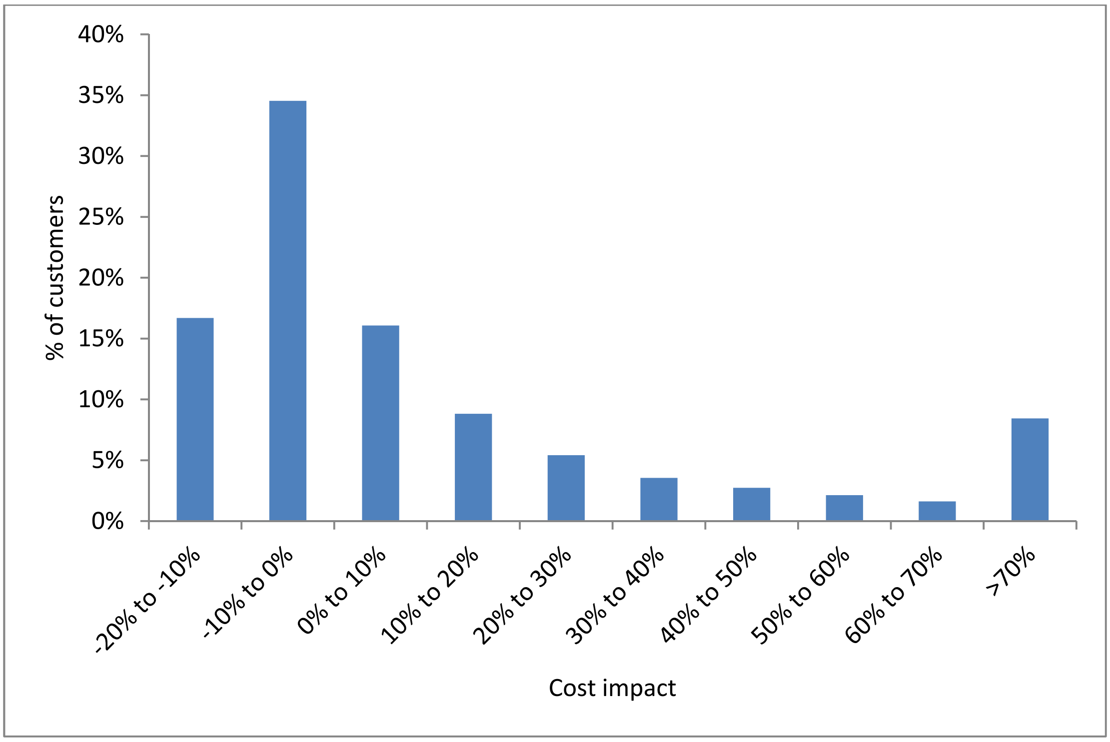
Existing 2011-12 retail tariff	*New 2012-13 retail tariff*
Residential tariffs	
Tariff 31	Tariff 31 – Night rate (super economy)
Tariff 33	Tariff 33 – Controlled supply (economy)
Other small customer tariffs	
Tariff 20	Tariff 20 – Business (flat rate)
Tariff 22	Tariff 22 – Business (time-of-use)
Tariff 41 (<100 MWh/annum)	Tariff 41 – Low voltage (demand)
Tariff 81 and 91	**Tariff 91 – Unmetered**

The charge structure for Tariffs 31 and 33 has changed from a consumption-based structure with a minimum charge to a solely consumption-based structure. A typical customer on these tariffs, with annual consumption of 2,064 kWh and 1,985 kWh respectively, will experience a price increase of 30.5% (or $59 per year) for Tariff 31 and 25.5% (or $69 per year) for Tariff 33 in 2012-13. This reflects the increases in the consumption charge for each tariff. However, the removal of the current minimum monthly charge means that some customers with very low levels of consumption (less than 600 kWh per annum for Tariff 31 and less than 425 kWh per annum for Tariff 33) will experience lower costs that are proportional to their consumption, rather than being charged the minimum fixed amount.

Assessing customer impacts for Tariffs 81 and 91 is problematic because the old lamp-watt-based tariffs are not comparable to the consumption-based tariff proposed for Tariff 91 in 2012-13. Submissions on the Draft Determination were generally supportive of folding Tariff 81 into Tariff 91. For these reasons, the Authority has not considered any transitional provisions for these tariffs.

Ergon Energy provided the results of its analysis of expected impacts of the Draft Determination for customers on Tariffs 20, 22 and 41, which are presented in Figures 6.18 to 6.20. Since customers on these tariffs will generally experience lower costs or relatively modest increases, no transitioning arrangements have been proposed.

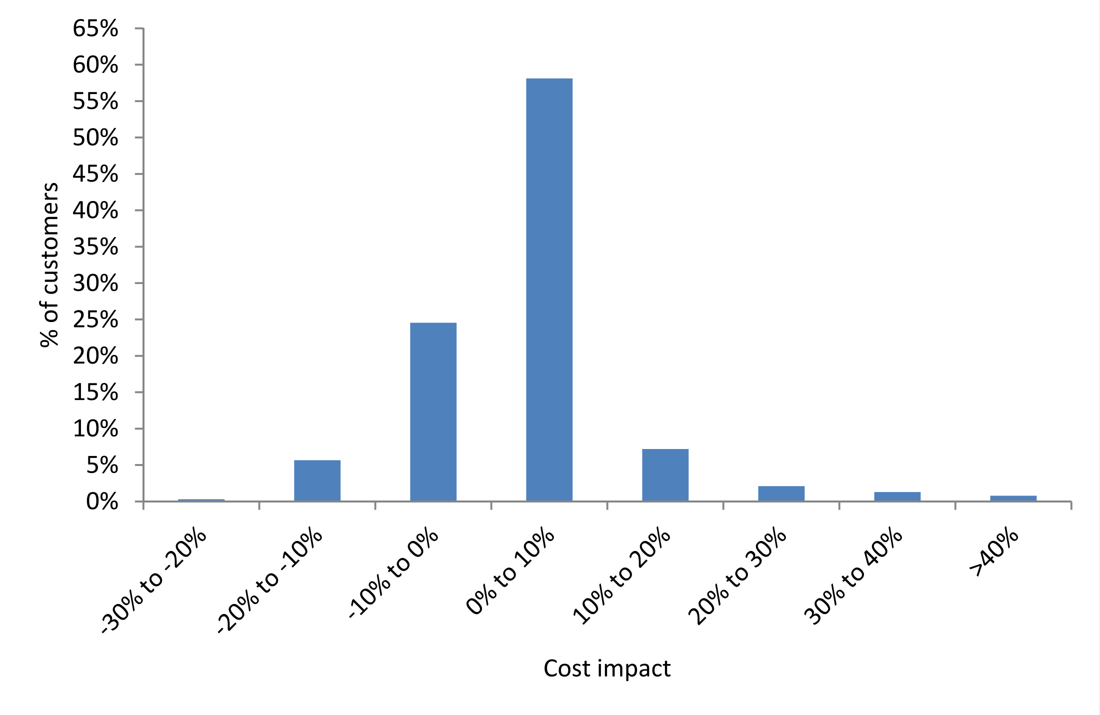
Figure 6.18: Change in Electricity Bills in 2012-13 for Customers on Tariff 20



Source: Ergon Energy.

Figure 6.18 shows that just over half the customers on Tariff 20 will experience a price decrease. However, as shown in **Appendix G** (Figure G.1), where customers experience price increases they are relatively modest in dollar terms. These impacts arise due to the re-balancing of prices towards higher fixed charges and lower consumption charges in 2012-13 (which has occurred generally under the new cost-reflective approach to setting notified prices).

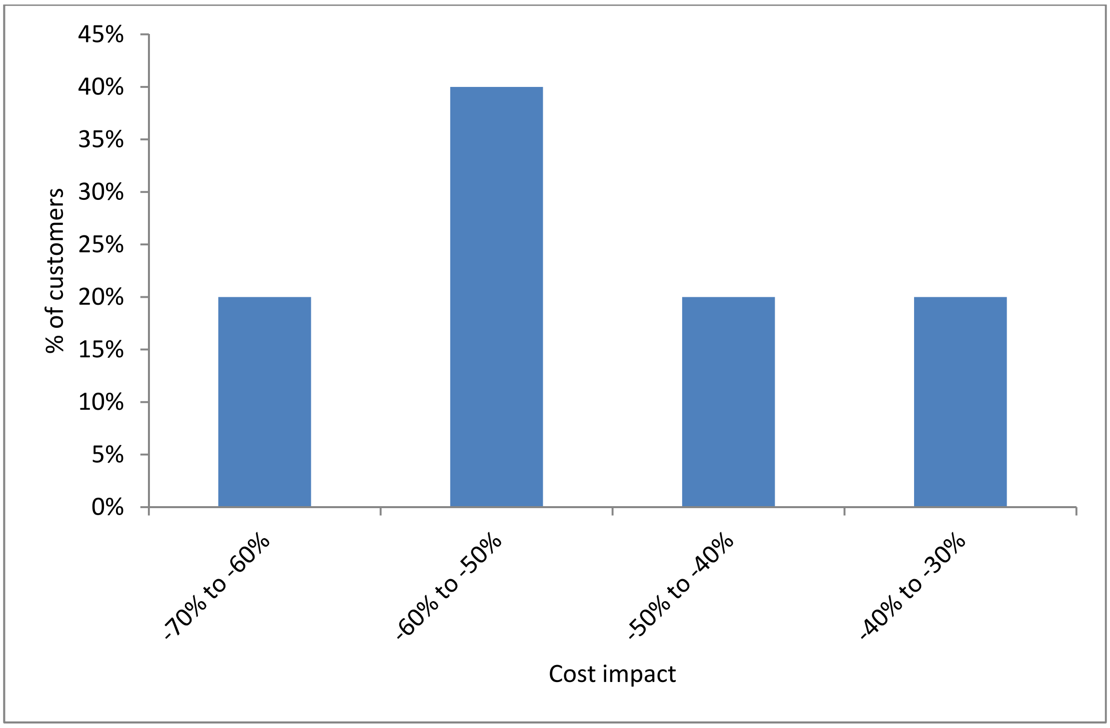
Figure 6.19: Change in Electricity Bills in 2012-13 for Customers on Tariff 22



Source: Ergon Energy.

Figure 6.19 indicates that the majority of small customers currently on Tariff 22 will experience a price decrease or a price increase no greater than 10%. These price impacts arise due to lower peak charges and higher off-peak charges under the new Tariff 22 relative to the current Tariff 22. As a result, customers using most of their electricity during peak times are likely to be somewhat better off while those using more electricity during the off-peak period are likely to experience price increases. As noted previously, this outcome may not be optimal from the point of view of the networks and both Energex and Ergon Energy have indicated they will review the make-up of their network tariffs which may lead to some of the incentive for customers to move their load to off-peak times being restored.

Figure 6.20: Change in Electricity Bills in 2012-13 for Customers on Tariff 41



Source: Ergon Energy

Small customers on Tariff 41, of which the Authority understands there is only a handful, are all set to experience significant price decreases, as shown in Figure 6.20. These impacts are due to the lower demand charges under the new Tariff 41 relative to those under the existing Tariff 41.

Conclusion on transitional arrangements

A summary of the Authority's Final Determination on transitional arrangements is provided in Table 6.6. Existing tariffs to be retained will be retained for 2012-13 and will be available for existing customers only. New customers will be required to go onto new tariffs.

Table 6.6: Existing Regulated Retail Tariffs to be Retained for 2012-13

Existing 2011-12 retail tariff to be retained for 2012-13	*Level of transitional price increase 2012-13*
Obsolete and declining block tariffs – small and Ergon Energy large customers	
Tariff 21	20%
Tariff 37	20%
Tariff 62	10%
Tariff 63	20%
Tariff 64	20%
Farming and irrigation tariffs – small and Ergon Energy large customers	
Tariff 65	10%
Tariff 66	10%
Large customers in Ergon Energy's network area	
Tariff 20(large)	10%
Tariff 22(large)	20%
Tariff 41(large)	20%
Tariff 43	20%
Tariff 53	20%

The Authority considers that these transitional arrangements will allow time for the distributors to address the practical constraints to implementing new tariffs and also give them time to review and amend their network tariffs to provide better time-of-use price signalling.

The Authority considers that the transitional arrangements also address the concerns raised in many submissions about the potential size of price impacts for some customers who would otherwise have to move to new tariffs from 1 July 2012. The transitional arrangements will allow most of these customers time to review their operations and, where possible, make changes that will reduce the eventual impact of moving to the new, more cost reflective, retail tariffs.

At this time, the Authority envisages that these transitional provisions will cease from 1 July 2013 when the new tariffs will come into full effect and those existing tariffs that have been retained for transitional reasons will cease to be available. However, the Authority will review the state of play as part of its next pricing review and, if necessary, may consider extending transitional arrangements for a further period.

The Authority expects that most of the financial impact that will result from the transitional arrangements it has put in place will be felt by Ergon Energy Queensland (EEQ), which will continue to receive the support of the Government through the payment of the Community Service Obligation which is an integral part of the Uniform Tariff Policy. Financial impacts for non-EEQ retailers are expected to be relatively modest because they are likely to have relatively small numbers of customers on these tariffs and the escalation of retained existing tariffs will help to reduce the financial impact of the arrangements for them.

Nevertheless, retailers may incur some costs as a result of these transitional arrangements, which will only serve to hamper competition in the Queensland market for as long as they remain in place. As a result, the Authority does not consider it appropriate to retain transitional arrangements for any longer than necessary to address the adjustment issues resulting from the unusual extent of change brought about by moving to more cost reflective tariffs.

6.3 Accounting for Unforeseen or Uncertain Events

The Authority has given consideration to whether it may be appropriate to include a mechanism to account for the impact of certain clearly defined events that lead to a material and unforeseen change in retailers' costs. While such a mechanism is more commonly used by regulators setting multi-year price paths, there remains the possibility that, even in a single-year pricing period, there may be changes which may need to be accommodated by amending retail prices.

In past BRCI decisions, the legislative framework did not allow the Authority to include either:

(a) a cost pass-through mechanism, which would allow for price adjustments within the tariff year; or

(b) a catch up mechanism, which would account for cost impacts from a previous year in the subsequent tariff year.

As a result, retailers supplying non-market customers, at times, had to absorb any changes in costs that arose during the relevant year.

Approaches in Other Jurisdictions

In their most recent retail price determinations, all of which were multi-year determinations, IPART (NSW), the ICRC (ACT)[49], ESCOSA (South Australia) and OTTER (Tasmania) included a cost pass-through mechanism to allow retailers to pass through to customers the incremental, efficient costs associated with defined regulatory or taxation change events.

The mechanisms adopted by all four regulators were symmetrical so that tariffs may also be adjusted downwards by the regulator to reflect any similar cost decreases. Examples of the types of events covered under these arrangements included changed obligations in relation to green energy schemes, unforeseen events instigated by AEMO (such as a reserve trader or direction event) and retailer of last resort (ROLR) events.

Submissions

In submissions received in response to the Issues Paper and Draft Methodology Paper, retailers were unanimously of the view that a mechanism was required to account for the impact of unforeseen events on the R component of tariffs but acknowledged that the new legislative framework may preclude the Authority from doing so. Origin Energy, AGL and Momentum Energy suggested that, if the Authority could not include a cost pass-through

[49] In its Draft Report on the *2012-14 Retail Prices for Franchise Electricity Customers*, the ICRC has maintained the existing cost pass-through arrangements.

mechanism, the risk of unforeseen or uncertain events occurring needed be accounted for elsewhere in the determination.

Conversely, non-retailers such as QCOSS, Queensland Farmers' Federation, Growcom and CCIQ did not support the inclusion of such a mechanism. QCOSS argued that a cost pass-through mechanism would:

(a) usually only be included where the price path is longer than a year;

(b) prevent retailers from managing risks; and

(c) be unfair to consumers.

CCIQ was of the view that the risk of unforeseen events occurring had already been accounted for in the retail margin.

In response to the Draft Determination, QCOSS, the Queensland Consumers Association and CCCL were of the view that a cost pass-through mechanism was warranted, but only if the Queensland Government issues the Authority with a new Delegation that allows it to amend regulated retail prices during 2012-13.

The Authority's Position

While the Delegation requires that the Authority must consider a mechanism to address any new compulsory scheme that imposes material energy cost imposts on the retailer, and the Authority considers that it would be appropriate to include some form of mechanism to account for the material impacts of unforeseen or uncertain events on a retailer's costs, the Authority does not consider that it has the capacity to include any such arrangements in its price determination for 2012-13.

This is because the Authority has only been delegated the role of determining notified prices to apply from 1 July 2012 to 30 June 2013, which it is required to do by 31 May 2012, and it has no on-going role in administering the price determination.

The Authority is also of the view that, given the current annual nature of the Delegation and price setting process, it would not be possible for it to commit to some form of catch-up mechanism which would allow for unforeseen cost impacts from one year to be accounted for in setting prices for the following tariff year, because:

(a) the Authority has only been delegated the function of setting notified prices for the 2012-13 tariff year, not the 2013-14 tariff year; and

(b) the Minister could decide not to delegate the function of setting notified prices in the following tariff year to the Authority, thus making any commitment worthless.

AGL and Origin Energy also suggested that the Authority should allow for some 'catch-up' of actual and forecast costs under previous BRCI decisions, particularly in relation to the ERET scheme. However, the Authority does not believe that it has any power to withdraw or amend past BRCI decisions in light of subsequent events.

The Authority's Final Determination

The Authority is of the view that it is precluded from including a cost pass-through or catch-up mechanism in its determination of regulated retail tariffs for 2012-13.

6.4 Terms and Conditions of Retail Tariffs

The regulated retail tariffs and prices are published in a tariff schedule which includes a range of other information, including the eligibility criteria and other terms and conditions for each retail tariff.

While the Authority is responsible for determining the retail tariffs and prices, the Queensland Government (in conjunction with Energex and Ergon Energy) is responsible for determining the associated eligibility criteria and other terms and conditions.

The Minister has not delegated to the Authority the determination of charges or fees relating to customer retail services covered under section 90(1)(b) of the Electricity Act, which includes charges for the provision of historical billing information and dishonoured payments.

The terms and conditions applying to regulated retail tariffs for 2012-13 are provided in **Appendix E**.

7. FINAL DETERMINATION

This chapter sets out the Authority's Final Determination of regulated retail electricity prices (notified prices) to apply from 1 July 2012 to 30 June 2013, as well as expected customer impacts.

7.1 Final Determination

The Authority's Final Determination is that the notified prices to apply for the period 1 July 2012 to 30 June 2013 are the prices set out in Tables 7.1 to 7.4 below.

A retail entity must charge notified prices to its non-market customers. From 1 July 2012, new and existing non-residential customers in the Energex distribution area who consume over 100 MWh per annum will not be able to access notified prices and must be on a market contract.

Table 7.1: 2012-13 Regulated Retail Tariffs and Prices for Residential Customers (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]* *c/day*	*Variable rate (flat)* *c/kWh*	*Variable rate 1 (off-peak)* *c/kWh*	*Variable rate 2 (shoulder)* *c/kWh*	*Variable rate 3 (peak)* *c/kWh*
Tariff 12 - Residential (time of use)	8900	78.578		17.133	21.432	34.923
Tariff 31 - Night rate (super economy)	9000		11.009			
Tariff 33 - Controlled supply (economy)	9100		15.595			

a. Charged per metering point.

Table 7.2: 2012-13 Regulated Retail Tariffs and Prices for Other Small Customers and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]* *c/day*	*Demand charge* *$/kW/month*	*Variable rate (flat)* *c/kWh*	*Variable rate (off-peak)* *c/kWh*	*Variable rate (peak)* *c/kWh*
Tariff 20 - Business (flat rate)	8500	107.434		20.010		
Tariff 22 - Business (time of use)	8800	107.434			18.118	20.200
Tariff 41 - Low voltage (demand)	8300	1691.190	19.622	9.944		
Tariff 91 - Unmetered	9600			17.790		

a. Charged per metering point.

Table 7.3: 2012-13 Regulated Retail Tariffs and Prices for Large Customers and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge*[a] *c/day*	*Demand charge* *\$/kW/month*	*Variable rate (flat)* *c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	805.766	29.968	10.609
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	2397.624	25.927	10.609
Tariff 46 - Over 100 MWh large (demand)	EDLT1	3735.770	24.909	10.609
Tariff 47 - High voltage (demand)	EDHT1	2476.756	19.905	10.158
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	2872.045	19.905	10.158
Tariff 71 - Street lighting [b]	EVUT1	0.555		33.852

a. Charged per metering point.
b. The fixed charge for street lighting applies to each lamp.

As discussed in Chapter 6, for transitional purposes, the Authority has retained 12 existing regulated retail tariffs that would otherwise have been unavailable from 1 July 2012. The Authority's Final Determination on the notified prices that will apply to these tariffs is set out in Table 7.4 below. New customers will be excluded from accessing these tariffs from 1 July 2012 and the Authority anticipates that these 12 tariffs will cease to be available to existing customers from 1 July 2013.

Table 7.4: 2012-13 Transitional Regulated Retail Tariffs and Prices[a]

Retail tariff	Fixed charge[b] c/day	Min Charge c/day	Variable rate 1[c] c/kWh	Variable rate 2[d] c/kWh	Variable rate 3[e] c/kWh	Variable rate (flat)[f] c/kWh	Demand flat $/kW/mth	Capacity (Up to 7.5kw) $/kW/yr	Capacity (Over 7.5kw) $/kW/yr
Obsolete and declining block tariffs – small and Ergon Energy large customers									
Tariff 21		50.858	34.560	32.472	24.720				
Tariff 37		20.777	14.796		37.008				
Tariff 62	54.932		32.571	27.544	11.517				
Tariff 63			63.036	38.580	30.216	13.296			
Tariff 64		53.618	30.792		16.908				
Farming and irrigation tariffs – small and Ergon Energy large customers									
Tariff 65	54.932		25.982		14.311				
Tariff 66	121.068					13.618		26.411	79.409
Large customers in Ergon Energy's network area[g]									
Tariff 20(large)	52.149					25.509			
Tariff 22(large)	125.332		33.804		11.904				
Tariff 41(large)	191.803					8.616	40.980		
Tariff 43(large)	191.803		17.532		7.008		17.748		
Tariff 53(large)[h] (11-33kV)	496.046					8.160	38.820		
Tariff 53(large)[i] (66kV)	496.046					7.932	37.440		

a. *New customers are not eligible for these retail tariffs.*
b. *Charged per metering point.*
c. *Tariff 21 – first 100kWh, Tariff 22(large) – 7am-9pm M-F, Tariff 37 – 10:30pm-4:30pm, Tariff 43 – 7am-11pm M-F, Tariff 62 – 7am-9pm M-F first 10,000kWh, Tariff 63 – 7am-9pm M-F first 100kWh, Tariffs 64, 65 – 12hr peak.*
d. *Tariff 21 – 101-10,000kWh, Tariff 62 – 7am-9pm M-F over 10,000kWh, Tariff 63 – 7am-9pm M-F 101-10,000 kWh.*
e. *Tariff 21 – over 10,000 kWh, Tariff 22(large) – all other times, Tariff 37 – 4:30pm-10:30pm, Tariff 63 – 7am-9pm M-F over 10,000 kWh, Tariffs 43, 62, 64, & 65 – all other times.*
f. *Tariff 63 – all other times.*
g. *Only available to existing large customers already on these tariffs.*
h. *Additional night excess charge of $10.992 /kW/month, which applies to the number of kW by which the demand recorded outside the interval 7am-9pm M-F exceeds the demand recorded within this interval. Minimum total demand charge of 300kW charged at $38.820 kW.*
i. *Additional night excess charge of $10.668 /kW/month, which applies to the number of kW by which the demand recorded outside the interval 7am-9pm M-F exceeds the demand recorded within this interval. Minimum total demand charge of 300kW charged at $37.440 kW.*

The regulated retail tariffs and notified prices are published in a tariff schedule which includes a range of other information, including the eligibility criteria and other terms and conditions for each regulated retail tariff.

The tariff schedule for 2012-13 is provided in **Appendix E**.

APPENDIX A: 2011 DELEGATION AND COVERING LETTER

Hon Stephen Robertson MP
Member for Stretton

Queensland Government

Minister for Energy and Water Utilities

2 2 SEP 2011

MBN5236

Mr B Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001

Dear Mr Parmenter

I refer to the Government's decision, in May 2011, to implement a new electricity pricing methodology based on a Network (N) + Retail (R) (N+R) cost build-up (building block) approach and establish a new set of regulated retail electricity tariffs (notified prices), to commence from 1 July 2012.

In accordance with this decision, the Electricity Price Reform Amendment Bill 2011 (the Bill) was passed by the Queensland Parliament on 7 September 2011 and received assent on 13 September 2011. The Bill contains the key legislative amendments necessary to allow for the implementation of a new electricity price-setting methodology and set of tariff structures in 2012-13.

I now attach a certificate which provides my delegation to the Queensland Competition Authority (the Authority), as the pricing entity, to determine the notified prices that retail entities may charge non-market customers in the 2012-13 tariff year. The delegation is authorised under section 90AA(1) of the Electricity Act 1994 (the Electricity Act).

The Delegation also contains a Terms of Reference which impose conditions on the Authority when undertaking the delegated function.

Consistent with the Terms of Reference, the Authority is required to undertake an open consultation process with all relevant parties and consider all submissions received within the consultation period.

The Authority must publish its draft methodology paper on the R component no later than December 2011, its draft price determination on 30 March 2012, and its final price determination by 31 May 2012.

Level 17
61 Mary Street Brisbane Qld 4000
PO Box 15216 City East
Queensland 4002 Australia
Telephone +61 7 3225 1861
Facsimile +61 7 3225 1828
Email energy@ministerial.qld.gov.au

The Queensland Government remains concerned about the pressure that increases in the cost of living, including rising electricity costs, are placing on household budgets, and has consistently advocated in previous pricing decisions that only genuine increases in costs of supply be passed on to consumers.

With the introduction of the new price setting methodology in 2012-13, the Government wishes to again stress that the Authority must consider the impact of price rises on consumers when determining regulated prices.

It is acknowledged that a move to cost reflective tariffs will have an adverse affect on some consumers. To assist in mitigating these impacts, the Government has approved an inclining block tariff (IBT) structure for residential customers.

An IBT is designed to encourage customers to conserve electricity by charging a fixed supply charge and a series of consumption blocks priced so the more you use, the more you pay. Under this approach, the impact of moving to a cost reflective pricing structure on lower consumption customers will be lessened.

The Queensland Government will also undertake additional work to further investigate a range of customer assistance measures to further mitigate the impacts of a move to cost reflective tariffs and the increasing cost of living on small residential electricity customers. It is expected these options will be considered as part of the 2012-13 Budget process.

Delegation and Terms of Reference

In undertaking the delegated function, the Authority should consider the following:

- The network charges to be levied by ENERGEX when determining the N component of the regulated retail tariffs;
- The cost of energy component should seek to balance the long term need for maintaining pricing stability with ensuring customers are not subjected to unnecessary price volatility in the short term;
- The Government has endorsed the establishment of an IBT structure for residential customers to apply from 1 July 2012;
- The Government has endorsed the establishment of a new voluntary time-of-use tariff for residential customers from 1 July 2012;
- It is the Government's intention that any customer on an obsolete or declining block tariff will be required to move (or transition) to an alternative regulated tariff from 1 July 2012;
- Before making any changes to farming and irrigation tariffs, the Authority should consult with relevant stakeholders and industry groups and consider whether any transitional arrangements may be required;
- The Authority should consider an appropriate tariff for street lighting customers in Ergon Energy's network area and whether any transitional arrangements may be required; and
- It is the Government's intention that from 1 July 2012, all existing and new non-residential customers in ENERGEX's network area, who consume over 100 megawatt hours per annum, will be unable to access regulated tariffs and must be on a market contract.

This Delegation (and Terms of Reference) replaces the previous Direction Notice, issued to the Authority on 11 May 2011 under section 10(e) of the Queensland Competition

Authority Act 1997 (QCA Act), requiring the Authority to investigate and provide a report on:

- An alternative retail electricity pricing methodology for the determination of the cost components under an N+R approach; and
- An alternative set of retail electricity tariffs, based on an N+R approach, which could be applied from 1 July 2012.

Please be assured the process and intent reflected in the Direction Notice issued under the QCA Act will be deemed sufficient for the purposes of the price determination process for 2012-13, in accordance with section 329 of the Electricity Act.

If you have any questions about my advice to you, Ms Kathie Standen, Director, Electricity Pricing Policy of the Department of Employment, Economic Development and Innovation will be pleased to assist you and can be contacted on telephone 3225 8256.

Yours sincerely

[redacted]

STEPHEN ROBERTSON MP

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

As the Minister for Energy and Water Utilities, pursuant to section 90AA(1) of the *Electricity Act 1994*, I hereby refer to the Queensland Competition Authority (the Authority) the determination of regulated retail electricity tariffs (notified prices) for Queensland to apply from 1 July 2012 to 30 June 2013, in accordance with the requirements set out in the following Terms of Reference.

Terms of Reference

1. Matters to be considered

In calculating the regulated retail electricity tariffs for the relevant tariff year, the Authority should ensure its price determination has regard to:

- the actual costs of supplying electricity;
- the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace;
- the Queensland Government's Uniform Tariff Policy, which ensures customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location; and
- the information contained in the Attachment.

Methodology for calculating regulated retail tariff prices

Retail electricity tariffs comprise three main cost components:

- network costs;
- energy costs; and
- retail costs.

In calculating the regulated retail tariffs for the relevant tariff year, the Authority should, to the extent possible, base its determination on a Network (N) plus Retail (R) cost build-up approach to setting notified prices, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the Authority.

Network Costs

In determining the network cost component of each regulated retail tariff, the Authority must consider the network charges to be levied by ENERGEX for each tariff for the relevant tariff year.

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Energy Costs

The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market fees.

In calculating the energy cost component, the Authority must consider:

- the cost of energy,
- fees, including charges for market and ancillary services, imposed by Australian Energy Market Operator (AEMO) under the National Electricity Rules;
- energy losses as published by the AEMO;
- the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;
- the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and
- a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

Retail Costs

Retail costs relate to the services provided by a retailer to its customers.

In determining the retail cost component of each regulated retail tariff, the Authority must consider the retail costs that would reasonably be incurred by an efficient, representative retailer, the characteristics of which should be determined by the Authority. The Authority is also required to determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere.

2. Consultation

The Authority should consult with stakeholders, conduct workshops and consider submissions, within the timetable for making the price determination and publishing the draft and final reports. The Authority must make its reports available to the public.

3. Timing

(a) Draft Methodology Paper

The Authority must publish a paper outlining its draft methodology for calculating the R component of regulated retail electricity prices no later than December 2011.

(b) Draft Price Determination

The Authority must publish a report on its draft price determination of regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, on 30 March 2012.

Page 2 of 4

The Authority must publish a written notice inviting submissions about the draft determination. The notice must state a period (the *consultation period*) during which anyone can make written submissions to the Authority about issues relevant to the draft determination.

The Authority must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

(c) Final Price Determination

The Authority must publish a report of its final price determination on regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, and gazette the (bundled) retail tariffs, no later than 31 May 2012.

STEPHEN ROBERTSON

[redacted]

The Hon. Stephen Robertson MP

Level 17 61 Mary Street, Brisbane

PO Box 15216, Brisbane
City East 4002 Australia

Telephone +617 3225 1861
Facsimile +617 3225 1828

Page 3 of 4

ATTACHMENT

Determination of regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013

In making its price determination on regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013, the Queensland Competition Authority (the Authority) must have regard to the following:

- the general supply residential tariff (existing Tariff 11) is to be structured as an inclining block tariff;
- a new voluntary time-of-use tariff is to be established for residential customers;
- for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups, and consideration given to whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;
- an appropriate tariff is to be established for customers who are supplied under the Rural Subsidy Scheme, or are located in a drought declared area;
- an appropriate tariff for street lighting customers in Ergon Energy's network area is to be established, and consideration given to whether any transitional arrangements are needed for customers on the existing tariff (Tariff 71); and
- consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs.

In making its price determination, the Authority should note the following:

- From 1 July 2012, all existing and new non-residential customers in ENERGEX's network area, who consume more than 100 megawatt hours per annum, will be unable to access regulated retail electricity tariffs, and must be on a market contract;
- As at 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff;
- In relation to the establishment of a voluntary time-of-use tariff for residential customers, any customer who opts to transfer to this tariff, providing they have the appropriate metering, will be permitted to revert to the standard regulated tariff for residential customers in accordance with the requirements set out in the regulated retail tariff schedule.

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APPENDIX B: 2012 DELEGATION AND COVERING LETTER

Queensland Government

Ref: EWS/000287
MBN6007

8 May 2012

Mr B Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001

Dear Mr Parmenter

I refer to the Queensland Competition Authority's (QCA) Draft Price Determination of regulated retail electricity prices released on 30 March 2012 in accordance with the current Certificate of Delegation.

As required by the current Delegation, the QCA has based its calculation of notified prices on a cost-reflective Network (N) plus Retail (R) approach, where N is essentially a pass-through of the actual network costs for each tariff and R is the combined total of the energy and retail costs for each tariff.

The move to a cost-reflective price-setting approach, where the actual cost of supplying electricity to customers on each tariff is calculated separately, represents a significant shift from the previous flawed Benchmark Retail Cost Index (BRCI) approach, where all tariffs were escalated annually using the same percentage increase. Unlike the BRCI, the new methodology represents a more accurate and transparent approach to determining notified prices.

However, the Government is concerned that a move straight to cost-reflective prices will impact adversely on some customer groups, particularly residential customers on the standard residential tariff (Tariff 11).

Determination of notified prices for 2012-13

The Queensland Government remains committed to tariff reform and the need to move towards a more cost-reflective price-setting methodology, however it is deeply concerned about the pressure that increases in the cost of living, including rising electricity costs, are placing on household budgets. As a result, the Government has acted to mitigate these price impacts in the short term by freezing Tariff 11 prices for the 2012-13 tariff year. To achieve this, the Government will freeze the existing prices at 2011-12 levels but with an escalation for the cost of the Commonwealth Government's carbon tax to be added.

/2

Level 13, Mineral House, 41 George Street, Brisbane
PO Box 15456, City East, Qld 4002
P: 07 3896 3046 F:07 3012 9115
E: energyandwater@ministerial.qld.gov.au

Whilst shielding households from significant price rises in 2012-13, this decision will also allow Government time to consider options for addressing the key drivers of energy cost increases and retail price-setting arrangements over the coming year.

To implement a price freeze approach, in accordance with the current legislation, it will be necessary for the Minister for Energy and Water Supply, rather than the QCA, to set the Tariff 11 prices for 2012-13. Accordingly, the current Delegation to the QCA for the determination of 2012-13 notified prices for has been amended to remove the requirement for the QCA to set Tariff 11 prices for 2012-13.

It should also be noted that the Government is currently considering customer impacts and implementation issues for all large customers in Queensland.

I attach my amended Delegation to the QCA, as the pricing entity, to determine the notified prices that retail entities may charge non-market customers in the 2012-13 tariff year (refer **Attachment 1**). The amended Delegation is authorised under section 90AA(1) of the *Electricity Act 1994* (the Act) and replaces the previous Delegation issued to the QCA on 22 September 2011.

In accordance with the amended Delegation, the QCA is required to publish its Final Price Determination for 2012-13 by 31 May 2012.

Request for advice from QCA

Whilst the Queensland Government is committed to implementing a price freeze on Tariff 11 for 2012-13 commencing 1 July 2012, Queensland households will still experience increased electricity bills as a direct result of the introduction of the Commonwealth Government's carbon tax. Whilst the Commonwealth Government will be compensating households separately for the impact of the carbon tax, the Queensland Government will ensure that the estimated costs of the carbon tax will be detailed on household electricity bills. This will provide openness and transparency to residential electricity customers in Queensland.

To enable this calculation, I am issuing a separate direction to the QCA, under section 253AA of the Act, requiring it to provide Government with a final estimate of the total cost impact of the carbon tax on retail electricity costs (Tariff 11) for residential customers in 2012-13 and what the per kWh price of Tariff 11 would have been in 2012-13 (inclusive of the cost of the Commonwealth's carbon tax) without the Government's decision to freeze the tariff. In this regard, the QCA should assume that Tariff 11 will have a flat price structure (as in 2011-12) not an inclining block tariff structure as required under the previous Delegation.

I would appreciate the requested advice being provided to me as close to 31 May 2012 as is practicable.

To support the Government's commitment to reforming electricity pricing in Queensland and addressing the long term cost pressures, an Inter-departmental Committee will be established as a priority, to consider and report on future residential pricing options, and strategies to address cost pressures (such as network costs). The Government will also reconsider the benefits of inclining block tariff structures.

/3

If you have any questions about my advice to you, Mr Benn Barr, Acting Deputy Director-General, Energy Division of the Department of Energy and Water Supply will be pleased to assist you and can be contacted on telephone 3239 0039.

Sincerely

[redacted]

Mark McArdle MP
Minister for Energy and Water Supply

Att

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

As the Minister for Energy and Water Supply, pursuant to section 90AA(1) of the *Electricity Act 1994*, I hereby refer to the Queensland Competition Authority (the Authority) the determination of regulated retail electricity tariffs (notified prices) for Queensland, excluding the general supply residential tariff (Tariff 11), to apply from 1 July 2012 to 30 June 2013, in accordance with the requirements set out in the following Terms of Reference.

Terms of Reference

1. Matters to be considered

In calculating the delegated regulated retail electricity tariffs for the relevant tariff year, the Authority should ensure its price determination has regard to:

- the actual costs of supplying electricity;
- the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace;
- the Queensland Government's Uniform Tariff Policy, which ensures customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location; and
- the information contained in the Attachment.

Methodology for calculating regulated retail tariff prices

Retail electricity tariffs comprise three main cost components:

- network costs;
- energy costs; and
- retail costs.

In calculating the delegated regulated retail tariffs for the relevant tariff year, the Authority should, to the extent possible, base its determination on a Network (N) plus Retail (R) cost build-up approach to setting notified prices, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the Authority.

Network Costs

In determining the network cost component of each regulated retail tariff, the Authority must consider the network charges to be levied by ENERGEX for each tariff for the relevant tariff year.

Page 1 of 4

Energy Costs

The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market fees.

In calculating the energy cost component, the Authority must consider:

- the cost of energy,
- fees, including charges for market and ancillary services, imposed by Australian Energy Market Operator (AEMO) under the National Electricity Rules;
- energy losses as published by the AEMO;
- the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;
- the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and
- a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

Retail Costs

Retail costs relate to the services provided by a retailer to its customers.

In determining the retail cost component of each regulated retail tariff, the Authority must consider the retail costs that would reasonably be incurred by an efficient, representative retailer, the characteristics of which should be determined by the Authority. The Authority is also required to determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere.

2. Consultation

The Authority should consult with stakeholders, conduct workshops and consider submissions, within the timetable for making the price determination and publishing the draft and final reports. The Authority must make its reports available to the public.

3. Timing

(a) Draft Methodology Paper

The Authority must publish a paper outlining its draft methodology for calculating the R component of regulated retail electricity prices no later than December 2011.

(b) Draft Price Determination

The Authority must publish a report on its draft price determination of regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, on 30 March 2012.

The Authority must publish a written notice inviting submissions about the draft determination. The notice must state a period (the *consultation period*) during which anyone can make written submissions to the Authority about issues relevant to the draft determination.

The Authority must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

(c) Final Price Determination

The Authority must publish a report of its final price determination on the delegated regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, and gazette the (bundled) retail tariffs, no later than 31 May 2012.

MARK McARDLE

[redacted]

The Hon. Mark McArdle MP

Level 13, 41 George Street, Brisbane

GPO Box 15456, Brisbane
City East QLD 4002 Australia

Telephone +617 3896 .3691
Facsimile +617 3012 9115

ATTACHMENT

Determination of regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013

In making its price determination on the delegated regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013, the Queensland Competition Authority (the Authority) must have regard to the following:

- a new voluntary time-of-use tariff is to be established for residential customers;
- for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups, and consideration given to the impact on customers and whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;
- an appropriate tariff is to be established for customers who are supplied under the Rural Subsidy Scheme, or are located in a drought declared area;
- an appropriate tariff for street lighting customers in Ergon Energy's network area is to be established, and consideration given to whether any transitional arrangements are needed for customers on the existing tariff (Tariff 71); and
- consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs.

In making its price determination, the Authority should note the following:

- From 1 July 2012, all existing and new non-residential customers in ENERGEX's network area, who consume more than 100MWh per annum, will be unable to access regulated retail electricity tariffs, and must be on a market contract;
- As at 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff;
- In relation to the establishment of a voluntary time-of-use tariff for residential customers, any customer who opts to transfer to this tariff, providing they have the appropriate metering, will be permitted to revert to the standard regulated tariff for residential customers in accordance with the requirements set out in the regulated retail tariff schedule.

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APPENDIX C: SUBMISSIONS

Table C.1: Submissions in Response to the Issues Paper

Organisation/Individual
1. AGL
2. Alinta Energy
3. Australian Pensioners' and Superannuants' League Qld
4. Australian Power & Gas
5. Bundaberg Regional Irrigators Group
6. Canegrowers Australia
7. Chamber of Commerce & Industry Queensland
8. Council on the Ageing Queensland
9. Donhad
10. Electrical and Communications Association
11. Energex
12. Energy Supply Association of Australia
13. Ergon Energy
14. Origin Energy
15. QEnergy
16. Queensland Consumers Association
17. Queensland Council of Social Service
18. Tableland Canegrowers and Mareeba District Fruit and Vegetable Growers Association
19. Alan Telfer (Individual)
20. TRUenergy

Table C.2: Submissions in Response to the Draft Methodology Paper

Organisation/Individual
1. AGL
2. Alinta Energy
3. Australian Industry Group
4. Australian Power and Gas
5. Bundaberg Regional Irrigators Group
6. Bundaberg Walkers Engineering Ltd
7. Canegrowers Australia
8. CQMS Razer
9. Chamber of Commerce and Industry Queensland
10. Department of Employment, Economic Development and Innovation (Queensland Government)
11. Energex
12. Energy Retailers Association of Australia Ltd
13. Ergon Energy
14. Growcom (Queensland Fruit and Vegetable Growers)
15. Lumo Energy
16. Momentum Energy
17. Origin Energy
18. Power Trading Technology
19. QEnergy
20. Queensland Farmers' Federation
21. Queensland Chicken Growers Association
22. Queensland Council of Social Service
23. Queensland Consumers Association
24. Queensland Consumers Association Supplementary
25. Stanwell
26. TRUenergy
27. Alan Telfer (Individual)
28. UBS Australia

Table C.3: Submissions in Response to the Draft Determination

[Received by the due date]

Organisation/Individual
1. AGL
2. AgForce Queensland Industrial Union of Employers
3. Australian Power and Gas
4. Australian Sugar Milling Council
5. Bundaberg Regional Irrigators Group
6. Canegrowers ISIS
7. Click Energy
8. Energy Options Australia
9. Energy Retailers Association of Australia
10. Ergon Energy
11. Energex
12. IOR Terminals
13. Local Buy Pty Ltd
14. Mabb, John
15. Origin Energy
16. Power Choice
17. Pioneer Valley Water
18. Queensland Consumers Association
19. Queensland Council of Social Service
20. QEnergy
21. Stanwell Corporation Limited
22. Sucrogen
23. SunWater
24. TRUenergy

[Received after the due date]

Organisation/Individual
1. AGL (supplemental)
2. Alinta Energy
3. Australian Prawn Farmers Association
4. Canegrowers
5. Energy Retailers Association of Australia (supplemental)
6. Growcom
7. Lumo Energy
8. MSF Sugar Limited
9. Origin Energy (supplemental)
10. QEnergy (supplemental)
11. Queensland Aquaculture Industries Federation
12. Queensland Council of Social Service (supplemental)
13. Queensland Farmers’ Federation
14. Queensland University of Technology
15. Shopping Centre Council of Australia
16. Sucrogen (supplemental)

APPENDIX D: ENERGEX'S PROPOSED (2012-13) NETWORK TARIFFS

	2012-13 Tariff Mapping			Notified Tariffs – Queensland Gazette																
				T11	T20	T22	T31	T33	T41	T43	T53	T71	T81	T91	T11 (A)	T62	T65	T66	T67	T68
				Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing	New	Existing	Existing	Existing	Existing	Existing
	NTC	**Description**	**Approx cust. Numbers 2011-12**	*IBT – Domestic*	*Flat – Business*	*TOU – Business*	*Flat – Controlled Load 1*	*Flat – Controlled Load 2*	*Demand – min 75kW*	*Demand – min 400kW*	*Demand – HV*	*Public Lamps*	*Flat – Unmetered (Rename Required)*	*Watchman Lights*	*TOU – Domestic*	*TOU – Farm*	*TOU – Irrigation*	*Flat/ Demand – Irrigation*	*Flat – Farm*	*Flat – Irrigation Drought Area*
ENERGEX Network Tariffs	**8400**	*Domestic IBT*	*1,227,588*	✓																
	8900 New	*Domestic TOU*	*n/a – proposed tariff*												✓					
	8500 **8600**	*Business Small - Flat* *Business Medium - Flat* **Combined into one tariff: *Business Flat (8500)***	*73,932 (Small)* *19,422 (Medium)*		✓													✓	✓	✓
	8700 **8800**	*Business Small – TOU* *Business Medium - TOU* **Combined into one tariff: *Business TOU (8800)***	*7,265 (Small)* *8,278 (Medium)*			✓										✓	✓			
	9000	*Controlled Load 1 - Flat*	*216,000*				✓													
	9100	*Controlled Load 2 - Flat*	*511,000*					✓												
	9600	*Unmetered - Flat*	*n/a – volume charge only*									✓	✓	✓						
	8300	*Demand Small*	*4,795*						✓											
	8100	*Demand Large*	*403*							✓										
	8000	*HV Demand*	*29*								✓									

Obsolete Retail Tariffs

Notified Tariff	Description
Tariff 21	*Declining Block Tariff – Business*
Tariff 37	*TOU – Non – domestic heating*
Tariff 63	*TOU – Farm*
Tariff 64	*TOU – Irrigation*

Other Energex Network Tariffs

NTC	Description	Approx current cust. numbers	Proposal for 2012-13
9400	*Streetlights - Flat*	*n/a – volume charge only*	Network tariff to be removed – all unmetered supply is to be mapped to NTC 9600.
9500	*Watchman lights - Flat*	*n/a – volume charge only*	Network tariff to be removed – all unmetered supply is to be mapped to NTC 9600.
8200	*Demand Medium*	3,041	Network tariff to be removed – all existing customers transferred to Demand Small or Demand Large
Site specific	*ICC, CAC, EG*	488	Designed for customers > 4 GWh – ENERGEX network tariff only, not available in the gazette

APPENDIX E: TARIFF SCHEDULE FOR 2012-13

Queensland Government Gazette

RETAIL ELECTRICITY PRICES FOR CUSTOMERS ON STANDARD RETAIL CONTRACTS AND STANDARD LARGE CUSTOMER RETAIL CONTRACTS

Electricity Act 1994

Pursuant to the Certificate of Delegation from the Minister for Energy and Water Supply (dated 8 May 2012) and sections 90(2) and 90AB of the *Electricity Act 1994* (the Electricity Act), I hereby state that the Queensland Competition Authority (QCA) decided that, on and from 1 July 2012, the notified prices that a retail entity must charge its customers on a Standard Retail Contract or Standard Large Customer Retail Contract (also referred to as a Standard Retail Contract), subject to the provisions of sections 55, 90, 91 and 91A of the Electricity Act, are the applicable prices set out in the attached Tariff Schedule or, as the case may be, the prices obtained by applying the applicable methodology or process set out in the attached Tariff Schedule.

This Tariff Schedule does not apply to customers on a Standard Retail Contract supplied under Origin Energy Electricity Limited's Special Approval number SA02/11 (being customers on a Standard Retail Contract connected to Essential Energy's New South Wales network which extends into southern Queensland). Under the terms of the Special Approval, these customers will generally pay no more for electricity than other Queensland customers on a Standard Retail Contract of similar usage categories or classes.

The Tariff Schedule does not apply to customers in Energex Limited's distribution area who consume 100 megawatt hours (MWh) per annum or more, unless the customer is classified as residential. From 1 July 2012, non-residential customers in the Energex distribution area who consume 100 MWh per annum or more will not have access to notified prices.

The QCA was not delegated responsibility for determining the standard residential retail electricity tariff (Tariff 11). The Tariff 11 charges for 2012-13, and any related tariffs or conditions, shall be determined by the Minister for Energy and Water Supply.

As required by section 90AB(4) of the Electricity Act, I state that the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) ('the GST Act').

In addition to the applicable tariff, a retail entity may charge a customer on a Standard Retail Contract an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity consumption), but only if –

(a) the customer voluntarily participates in such program or scheme;

(b) the retail entity has obtained the customer's consent (as defined in the Electricity Industry Code) to charge the customer an additional amount (and whether such amount is inclusive or exclusive of GST), provided that if a customer is participating in such a program or scheme at 30 June 2012 the customer is taken to have provided explicit informed consent for the retail entity to charge the customer the additional amount payable under the program or scheme; and

(c) the retail entity gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Dated this XX day of May 2012.

Brian Parmenter, Chairman
Queensland Competition Authority

QUEENSLAND GOVERNMENT GAZETTE No. xx [xx May 2012]

TARIFF SCHEDULE

Note 1: For the purposes of sections 55, 90, 91 and 91A of the Electricity Act, the tariffs and other retail fees and charges in this Tariff Schedule are exclusive of GST payable under the GST Act.

Note 2: This Tariff Schedule is structured in several Parts:

Parts 1 to 5 (inclusive) apply to customers on a Standard Retail Contract.

Part 6 applies to eligible customers on a Standard Retail Contract of Ergon Energy Queensland Pty Ltd. Eligible customers on a Standard Retail Contract of other retail entities may apply directly to the Department of Energy and Water Supply for relief from electricity charges if a drought declaration is in force – see Part 6 for more detail.

Note 3: To ensure the correct application of the tariffs set out in this Tariff Schedule, the retail entity and the customer must have regard to Part 4 (Application of Tariffs for Customers on Notified Prices – General).

Note 4: Any reference in this Tariff Schedule to a time is a reference to Eastern Standard Time.

Note 5: "NMI" means the National Metering Identifier and is applicable to the point at which a premises is connected to a distribution entity's network.

Note 6: Only days that supply is connected are to be counted for billing of charges.

Note 7: Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

Part 1

TARIFFS FOR RESIDENTIAL, COMMERCIAL AND RURAL APPLICATIONS

***Tariff 11* – Residential (Lighting, Power and Continuous Water Heating) –**

The relevant charges and conditions for this tariff shall be determined by the Minister for Energy and Water Supply.

***Tariff 12* – Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) –**

This tariff is applicable to a customer who is classified as residential by the relevant retail entity and can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 21, 22 or 41) at the same NMI.

This tariff is also applicable to electricity used in separately metered common sections of residential premises consisting of more than one flat or home unit.

This tariff cannot be used in conjunction with Tariff 11 (Residential) at the same NMI.

Where a NMI has multiple meters, the consumption for all meters that record consumption for Tariff 12 will be aggregated for billing purposes.

No large business customers are eligible for this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

All consumption	
Weekdays:	
Off-Peak (10pm-7am)	**17.133 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**21.432 c/kWh**
Peak (4pm-8pm)	**34.923 c/kWh**
Weekends:	
Off-Peak (10pm-7am)	**17.133 c/kWh**
Shoulder (7am-10pm)	**21.432 c/kWh**

plus a Service Fee per metering point per day of **78.578 c**

***Tariff 20* – Business General Supply –**

This tariff can not be accessed by large business customers. Refer Part 2 for transitional tariffs for existing large business customers.

Residential customers can access this tariff providing
- the electricity is used in separately metered common sections of residential premises consisting of more than one flat or home unit; or
- it is in conjunction with a primary residential tariff at the same NMI.

All Consumption **20.010 c/kWh**

plus a Service Fee per metering point per day of **107.434 c**

***Tariff 21* – Business General Supply (Obsolescent) –**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 21 at 30 June 2012.

This tariff shall not apply in conjunction with Tariff 20, 22, 62 or 63.

First 100 kilowatt hours per month **34.560 c/kWh**

Next 9,900 kilowatt hours per month	**32.472 c/kWh**
Remaining kilowatt hours per month	**24.720 c/kWh**
plus a Minimum Payment per day of	**50.858 c**

Tariff 22 **– Business General Supply – Time-of-Use –**

This tariff cannot be accessed by large business customers. Refer Part 2 for transitional tariffs for existing large business customers.

Residential customers can access this tariff providing:

- the electricity is used in separately metered common sections of residential premises consisting of more than one flat or home unit; or
- it is in conjunction with a primary residential tariff at the same NMI.

Customers must have the appropriate metering installed in order to access this tariff.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive -

All Consumption	**20.200 c/kWh**

For electricity consumed at other times -

All Consumption	**18.118 c/kWh**
plus a Service Fee per metering point per day of	**107.434 c**

Tariff 31 **– Night Rate (Super Economy) –**

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity.

This tariff is applicable when electricity supply is:

- permanently connected to apparatus; or
- connected to apparatus by means of a socket-outlet as approved by the distribution entity; or
- permanently connected to specified parts of apparatus;

as set out below (but not applicable, except as described in (c) below, if provision has been made to supply such apparatus or the specified part thereof under a different tariff during the restricted period) -

(a) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

The following conditions shall apply to any booster heating unit fitted -

(i) its rating shall not exceed that of the main heating unit;

(ii) it shall be connected so as to prevent it being energised simultaneously with the main heating unit;

(iii) electricity consumed by the booster heating unit shall be metered under and charged at the tariff applicable to general power usage at the premises concerned;

(iv) it shall be located in accordance with the provisions of the above Standards.

(b) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity. If a circulating water pump is fitted to the system, continuous supply will be available to the pump, and electricity consumed shall be metered under and charged at the tariff applicable to general power usage at the premises concerned.

(c) One-shot boost for solar-heated water heaters with electric heating units as described in (b) above. A current held changeover relay may be fitted to the water heater to deliver, at the customer's convenience, a 'one-shot boost' supply to the electric heating element at times when supply is not available under this Tariff 31 (generally between the hours of 7.00 am and 10.00 pm). Such supply is subject to thermostatically controlled switchoff. Electricity consumed during operation of the one-shot boost shall be metered under and charged at the tariff applicable to general power usage at the premises concerned. Supply and installation of a current held changeover relay, including the cost of same, is the responsibility of the customer.

(Reference in this Tariff Schedule to a 'booster heating unit' does not mean a current held changeover relay which is capable of delivering a 'one-shot boost'.)

(d) Heatpump water heaters. Where the rated electrical input, as shown on the nameplate, exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(e) Heatbanks. Booster heating units are permitted in heatbanks in which the main element rating is at least 2 kilowatts. The following conditions shall apply to any booster heating unit fitted –

(i) its rating shall not exceed 70 percent of the rating of the main heating unit;

(ii) it shall be connected so as to prevent it being energised simultaneously with the main heating unit;

(iii) electricity consumed by the booster heating unit shall be metered under and charged at the tariff applicable to general power usage at the premises concerned.

(f) Loads other than water heaters and heatbanks, but is not applicable -

(i) to arc or resistance welding plant;

(ii) where the apparatus is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 8 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.

All Consumption **11.009 c/kWh**

***Tariff 33* – Controlled Supply (Economy) –**

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity.

This tariff is applicable when electricity supply is:

(a) connected to apparatus (e.g. pool filtration system) by means of a socket-outlet as approved by the distribution entity; or

(b) permanently connected to apparatus as set out below (but not applicable if provision has been made to supply such apparatus under a different tariff in the periods during which supply is not available under this tariff) –

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

(ii) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(iii) Heatpump water heaters. Where the rated electrical input, as shown on the nameplate, exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(iv) As a sole supply tariff at the absolute discretion of the distribution entity.

(v) Other individual loads in domestic installations, but is not applicable –

- to arc or resistance welding plant;
- where the apparatus is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 18 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity.

All Consumption **15.595 c/kWh**

***Tariff 37* – Non-Domestic Heating – Time-of-Use (Obsolescent) –**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 37 at 30 June 2007.

Applicable to permanently connected –

(a) Electric storage water heaters in non-domestic installations with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

The heating unit rating shall not exceed 40.5 watts per litre of heat storage volume for heat exchange type water heaters or 46.5 watts per litre of rated hot water delivery for other storage type water heaters.

(b) Apparatus for the production of steam.

(c) Heating loads other than (a) and (b) above. The minimum total connected load under this section of this tariff is 4 kilowatts. Supplementary load that is permanently connected as an integral part of the installation may be supplied under this section provided that the aggregated rating of such supplementary load does not exceed 10 percent of the heating load.

For electricity consumed between the hours of 4.30 pm and 10.30 pm **37.008 c/kWh**

For electricity consumed between the hours of 10.30 pm and 4.30 pm **14.796 c/kWh**

Minimum Payment per day of **20.777 c**

Tariff 41 **– Business Low Voltage General Supply (Demand) –**

This tariff can not be accessed by large business customers. Refer Part 2 for transitional tariffs for existing large business customers.

Demand Charge –

$19.622 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **9.944 c/kWh**

plus a Service Fee per metering point per day of **1691.190 c**

The chargeable demand in any month shall be the maximum demand recorded in that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 44 **– Business Over 100MWh (Demand Small) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Small.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$29.968 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **10.609 c/kWh**

plus a Service Fee per metering point per day of **805.766 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 30kW to apply.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 45 **– Business Over 100MWh (Demand Medium) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Medium.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$25.927 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **10.609 c/kWh**

plus a Service Fee per metering point per day of **2397.624 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 120kW to apply.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 46 **– Business Over 100MWh (Demand Large) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Large.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$24.909 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **10.609 c/kWh**

plus a Service Fee per metering point per day of **3735.770 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 47 **– Business - High Voltage General Supply (Demand) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand High Voltage.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$19.905 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **10.158 c/kWh**

plus a Service Fee per metering point per day of **2476.756 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 48 **– Business - High Voltage General Supply (>4 Gigawatt Hours (GWh)) (Demand) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff can be accessed by business customers who are classified as Connection Asset Customers or Individually Calculated Customers by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand High Voltage.

A Connection Asset Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 4GWh.

An Individually Calculated Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 40GWh.

Demand Charge –

$19.905 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **10.158 c/kWh**

plus a Service Fee per metering point per day of **2872.045 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Credits for high voltage supply are not applicable to this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 62 **- Farm - Time-of-Use (Obsolescent) -**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 62 at 30 June 2012.

This tariff shall not apply in conjunction with Tariff 20, 21, 22 or 63 at the same NMI.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive –

First 10,000 kilowatt hours per month **32.571 c/kWh**

Remaining kilowatt hours **27.544 c/kWh**

For electricity consumed at other times -

All Consumption **11.517 c/kWh**

plus a Service Fee per metering point per day of	**54.932 c**

Tariff 63 **– Farm – Time-of-Use (Obsolescent) –**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 63 at 30 June 2012.

This tariff shall not apply in conjunction with Tariff 20, 21, 22 or 62 at the same NMI.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive –

First 100 kilowatt hours per month	**63.036 c/kWh**
Next 9,900 kilowatt hours per month	**38.580 c/kWh**
Remaining kilowatt hours	**30.216 c/kWh**

For electricity consumed at other times -

All Consumption	**13.296 c/kWh**

Under this tariff, the required minimum annual consumption at 'other times' shall be 3,000 kilowatt hours. If the annual consumption at 'other times' is less than 3,000 kilowatt hours, the shortfall will be charged at the rate applicable at 'other times' at the time that the charge for the shortfall is being calculated.

Tariff 64 **– Irrigation – Time-of-Use (Obsolescent) –**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 64 at 30 June 2012.

For electricity consumed in a fixed 12 hour daily pricing period (as agreed between the retail entity and the customer from the range 7.00 am to 7.00 pm; 7.30 am to 7.30 pm; or 8.00 am to 8.00 pm) Monday to Sunday inclusive –

All Consumption	**30.792 c/kWh**

For electricity consumed at other times -

All Consumption	**16.908 c/kWh**
Minimum payment per day	**53.618 c**

No alteration to the selected daily pricing period shall be permitted until a period of twelve months has elapsed from the previous selection.

Tariff 65 **- Irrigation - Time-of-Use (Obsolescent) -**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 65 at 30 June 2012.

For electricity consumed in a fixed 12 hour daily pricing period (as agreed between the retail entity and the customer from the range 7.00 am to 7.00 pm; 7.30 am to 7.30 pm; or 8.00 am to 8.00 pm) Monday to Sunday inclusive -

All Consumption	**25.982 c/kWh**

For electricity consumed at other times –

All Consumption	**14.311 c/kWh**
plus a Service Fee per metering point per day of	**54.932 c**

No alteration to the selected daily pricing period shall be permitted until a period of twelve months has elapsed from the previous selection.

Tariff 66 **– Irrigation (Obsolescent) –**

This tariff will be retained for 2012-13. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 66 at 30 June 2012.

Annual Fixed Charge (in respect of each point of supply) - per kilowatt of connected motor capacity used for irrigation pumping –

First 7.5 kilowatts	**$26.411** per kW
Remaining kilowatts	**$79.409** per kW

Energy Charge –

All Consumption	**13.618 c/kWh**
plus a Service Fee per metering point per day of	**121.068 c**

Minimum Annual Fixed Charge - As calculated for 7.5 kW (Note – 7.5 kW is equivalent to 10.05 h.p.).

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected under this tariff.

Part 2

TRANSITIONAL TARIFFS FOR EXISTING LARGE BUSINESS CUSTOMERS

Tariff 20 (Large) **– Business General Supply (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 20 at 30 June 2012.

This tariff can not be accessed by small business or residential customers.

All Consumption	**25.509 c/kWh**
plus a Service Fee per metering point per day of	**52.149 c**

Tariff 22 (Large) **– Business General Supply – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 22 at 30 June 2012.

This tariff can not be accessed by small business or residential customers.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive -

All Consumption **33.804 c/kWh**

For electricity consumed at other times -

All Consumption **11.904 c/kWh**

plus a Service Fee per metering point
per day of **125.332 c**

Tariff 41 (Large) **– Business Low Voltage General Supply (Demand) (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 41 at 30 June 2012.

Demand Charge -

$40.980 per kilowatt per month of chargeable demand.

Energy Charge -

All Consumption **8.616 c/kWh**

plus a Service Fee per metering point
per day of **191.803 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent of the highest maximum demand recorded in any of the preceding eleven months; or
(c) 75 kilowatts,
whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers taking supply under this tariff will not be supplied under any other tariff at the same NMI.

Tariff 43 (Large) **– General Supply Demand – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 43 at 30 June 2012.

Demand Charge –

$17.748 per kilowatt per month of chargeable demand.

Energy Charge –

For electricity consumed between the hours of 7.00 am and 11:00 pm, Monday to Friday inclusive -

All Consumption **17.532 c/kWh**

For electricity consumed at other times -

All Consumption **7.008 c/kWh**

plus a Service Fee per metering point
per day of **191.803 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent of the highest maximum demand recorded in any of the preceding eleven months; or
(c) 400 kilowatts,
whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 53 (Large) **– Business – High Voltage General Supply (Demand) (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 53 at 30 June 2012.

Supply voltage –	11kV to 33kV	66kV and above
Demand charge ($/kW/month)	**38.820**	**37.440**
Night excess* demand charge ($/kW/month)	**10.992**	**10.668**
Energy charge (c/kWh)	**8.160**	**7.932**

plus a Service Fee per metering point
per day of **496.046 c**

***Night Excess** for a billing month is the number of kilowatts by which the demand recorded outside the interval 7.00 am to 9.00 pm Monday to Friday inclusive exceeds the demand recorded within this interval in the month.

The minimum total demand charge applicable in any month shall be equivalent to 300 kilowatts charged at **$38.820** per kilowatt for voltages up to 33kV and **$37.440** per kilowatt for voltages at 66kV and above, or 60 per cent of the highest charge at the rates applicable in accordance with the requirements of this tariff to the metered monthly demands for any of the preceding eleven months, whichever is the higher.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Customers taking supply under this tariff will not be supplied under any other tariff at the same NMI.

Part 3

TARIFFS FOR UNMETERED SUPPLY INCLUDING STREET LIGHTS, TRAFFIC SIGNALS, WATCHMAN LIGHTING AND TEMPORARY SERVICES

***Tariff 71* – Street Lights –**

Notified prices for Tariff 71, published in accordance with section 90 of the Electricity Act, will only apply in Ergon Energy Corporation Limited's distribution area. The *Electricity Regulation Amendment (No.1) 2008* provides that, from 1 July 2008, street lighting customers in Energex Limited's distribution area will be defined as market customers and so will not have access to the notified prices.

Street lighting customers are as defined in Queensland legislative instruments, being State or local government agencies for street lighting loads.

Street lights are deemed to illuminate roads. In Queensland, there are two main types of roads, being:

- **Local government roads** – roads for which a local government has control. These roads comprise land that is:
  - dedicated to public use as a road; or
  - developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public;
  - a footpath or bicycle path; or
  - a bridge, culvert, ford, tunnel or viaduct,

  and excludes State-controlled roads and public thoroughfare easements; and
- **State-controlled roads** – roads that are declared under the *Transport Infrastructure Act 1994* (Qld) to be a State-controlled road, for which the relevant Minister for that Act has control (i.e. of the Department of Transport and Main Roads).

All consumption will be determined in accordance with the metrology procedure issued by the Australian Energy Market Operator.

All Consumption	**33.852 c/kWh**
plus a Service Fee per lamp per day of	**0.555 c**

***Tariff 91* - Other Unmetered Supply –**

Unmetered electricity supply is available to other small loads, as approved by the distribution entity.

Unmetered Supply applies where:
1. the load pattern is predictable;
2. for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and
3. it would not be cost effective to meter the connection point taking into account:
   (i) the small magnitude of the load;
   (ii) the connection arrangements; and
   (iii) the geographical and physical location.

Charges are based on consumption determined by the distribution entity.

All Consumption	**17.790 c/kWh**

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the above charge for electricity supplied.

Part 4

APPLICATION OF TARIFFS FOR CUSTOMERS ON NOTIFIED PRICES – GENERAL

Customers on a Standard Retail Contract may choose to be charged on any of the tariffs that the retail entity agrees are applicable to the customer's installation and provided that appropriate metering is in place.

Tariffs are applied to the electricity consumed at a connection point (as identified by a National Metering Identifier or NMI), as measured by the meter or meters at that connection point. The distribution entity is responsible for the establishment of connection points. Whilst customers have the ability to, at their expense if applicable, request additional meters at their connection point to enable particular tariff arrangements, the distribution entity will only create a new connection point where they have a legislative right or obligation to do so.

If there has been a material change of use at the customer's premises, such that the tariff on which the customer is being charged is no longer applicable, the retail entity may require the customer to transfer to a tariff applicable to the changed use.

If a change to the customer's meter is required to support the applicability of a tariff, other than Tariff 12, to a customer, the customer may request the retail entity to arrange for the required meter to be installed at the customer's cost.

For all tariffs, excluding Tariff 11 and Tariff 12, customers have the option, on application in writing or another form acceptable to the retail entity, of changing to any other tariff that the retail entity agrees is applicable to the customer's installation. Customers shall not be entitled to a further option of changing to another tariff until a period of twelve months has elapsed from a previous exercise of option. However, a retail entity at the request of a customer may permit a change to another tariff within a period of twelve months if –

(i) a tariff that was not previously in force is offered and such tariff is applicable to the customer's installation; or
(ii) the customer meets certain costs associated with changing to another tariff.

Customers previously supplied under tariffs which have now been discontinued or redesignated (whether by number, letter or name) will be supplied under other tariffs appropriate to their installations.

Residential customers will have the option, from 1 July 2012, on application in writing or another form acceptable to the retail entity, of switching from Tariff 11 to Tariff 12, provided they have the appropriate metering installed. Prior to 30 June 2013, customers will also be entitled to a further option of switching back to Tariff 11. Additional charges may apply should a customer wish to switch tariffs again prior to 30 June 2013.

The date of effect of a tariff change will be:

- the date of the last meter read (provided it is an actual meter read, not an estimated meter read); or
- if field work is required to support the change in tariff (e.g. a new meter is required to be installed), the date the field work is completed.

Billing information for application of monthly or annually based charges

The monthly or annual charges shall be calculated pro rata having regard to the number of days in the billing cycle that supply was connected (days) and one-twelfth of 365.25 days (to allow for leap years). That is:

$$Pa = \frac{P \times 12}{365.25} \times \text{days} \quad \text{for monthly charges}$$

$$Pa = \frac{P1}{365.25} \times \text{days} \quad \text{for annual charges}$$

Where
Pa is the amount to be billed
P is the monthly charge
P1 is the annual charge
days is the number of days in the billing cycle that supply was connected

Supply Voltage

(a) Low Voltage

Except where otherwise stated, the tariffs in Parts 1 and 2 will apply to supply taken at low voltage (480/240 volts or 415/240 volts, 50 Hertz A.C., as required by the distribution entity).

(b) High Voltage

(i) Customer plant requirements

By agreement between the customer and the distribution entity, supply may be given and metered at a standard high voltage, the level of which shall be prescribed by the distribution entity.

Where high voltage supply is given, a customer shall supply and maintain all equipment including transformers and high voltage automatic circuit breakers but excepting meters and control apparatus beyond the customer's terminals.

(ii) Credits where L.V. tariff is metered at H.V.

Where supply is given in accordance with (i) above and metered at high voltage then, except in cases where high voltage tariffs are determined or provided by agreement to meet special circumstances, the tariffs applied will be those pertaining to supply at low voltage ("the relevant tariff"), EXCEPT THAT, after billing the energy and demand components of the tariff, a credit will be allowed of –

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33 kV; and
- 8 percent of the calculated tariff charge where supply is given at voltages of 66 kV and above,

(provided that the calculated tariff charge after application of the credit must not be less than the Minimum Payment or other minimum charge calculated by applying the provisions of the relevant tariff.)

Card-operated Meters in Remote Communities

If a customer is a small excluded customer for a premises (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with:

(a) the relevant local government authority on behalf of the customer; and
(b) the customer's retail entity, that the electricity consumed by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being consumed by a customer at a premises is being measured and charged by means of a card-operated meter, the electricity consumed at the premises may continue to be measured or charged by means of a card-operated meter.

The methodology for applying the appropriate tariffs to customers subject to card-operated meters is as follows:

(a) If electricity supplied to a residential customer is measured and charged by means of a card-operated meter:
   (i) for Tariff 11 (Residential – Lighting, Power and Continuous Water Heating), the rates shall be determined by the Minister for Energy and Water Supply;
   (ii) for Tariff 31 (Night Rate – Super Economy), all consumption shall be charged at the 'All Consumption' rate (**11.009 cents/kWh**); and
   (iii) for Tariff 33 (Controlled Supply – Economy), all consumption shall be

charged at the 'All Consumption' rate (**15.595 cents/kWh**).

(b) If electricity supplied to a business customer is measured and charged by means of a card operated meter, all consumption shall be charged at the 'All Consumption' rate under Tariff 20 (General Supply) (**20.010 cents/kWh**), plus a Service Fee of **107.434** per day shall apply.

Other Retail Fees and Charges

Other fees and charges that a retail entity may charge its customers on a Standard Retail Contract will be determined by the Minister for Energy and Water Supply.

Part 5

CONCESSIONAL APPLICATIONS OF TARIFFS 11 and 12 (RESIDENTIAL)

Tariff 11 **– Residential (Lighting, Power and Continuous Water Heating)**

Concessional arrangements for Tariff 11 shall be determined by the Minister for Energy and Water Supply.

Tariff 12 **– Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) are available to customers satisfying the criteria set out in any one of A, B or C, as follows:**

A. Those separately metered installations where all electricity consumed is used in connection with the provision of a Meals on Wheels service or for the preparation and serving of meals to the needy and for no other purpose.

B. Charitable residential institutions which comply with all the following requirements—

(a) Domestic Residential in Nature. The total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included as part of the total installation; and

(b) Charitable and Non-Profit. The organisation must be:
   (i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and
   (ii) a non-profit organisation that:
      A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or
      B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

C. Organisations providing support and crisis accommodation which comply with the following requirements—

The organisation must:

(a) meet the eligibility criteria of the Specialist Homelessness Services (formerly known as Supported Accommodation Assistance Program) administered by the State Department of Housing and Public Works and is therefore eligible to be considered for funding under this program. (Funding provided to organisations under the Specialist Homelessness Services is subject to Part 3, Sections 10 to 13 inclusive, of the *Family Services Act 1987*); and

(b) be a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

Part 6

RELIEF FROM ELECTRICITY CHARGES WHERE DROUGHT DECLARATION IN FORCE

Customers of Ergon Energy Queensland Pty Ltd

A customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared under Queensland Government administrative processes is eligible for one or more of the following forms of relief from electricity charges:

(A) Waiving of Fixed Charge Components of Electricity Charges

If a customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared has no water to pump, the fixed components of the customer's electricity charges shall be waived. These fixed charge components include minimum payments, service fees, annual fixed charges under Tariff 66 and guarantee agreement shortfall charges.

Provided the drought declaration remains operative, the waiver applies to all fixed charges applicable to any account covering the period in which pumping ceased and to any subsequent account until the customer once again has water to pump. If the operative drought declaration is revoked before the customer once again has water to pump, the waiver shall continue to apply until water is available or until 12 months after the revocation of the drought declaration, whichever is the earlier.

(B) Deferral of Payment

If a customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared cites financial difficulties as a result of the drought, the customer is entitled to defer payment of the customer's electricity accounts relating to farm consumption.

Ergon Energy Queensland Pty Ltd may charge interest on deferred accounts. However, the rate of any interest charged must not be more than the Bank Bill reference rate for 90 days, as published on the first business day of each quarter.

Subject to the maximum rate of interest that may be charged, the terms of the deferred payment and the repayment of deferred amounts following revocation of the drought declaration will be as agreed between Ergon Energy Queensland Pty Ltd and the customer concerned.

Eligibility for Relief

A customer of Ergon Energy Queensland Pty Ltd seeking relief from electricity charges on the basis that the customer is a farmer who is in a drought declared area or whose property is individually drought declared, must apply in writing to Ergon Energy Queensland Pty Ltd.

If required by Ergon Energy Queensland Pty Ltd, the customer must provide:

(a) evidence that the customer's property is in a drought declared area or is individually drought declared, including the effective date of such drought declaration;

(b) evidence of the water pumping restrictions applicable to the customer's property; and

(c) evidence that the customer is experiencing financial difficulties as a result of the drought.

Standard Retail Contract customers of other retail entities

Standard Retail Contract customers of retail entities other than Ergon Energy Queensland Pty Ltd who are farmers in drought declared areas or who have a property which is individually drought declared under Queensland Government administrative processes can apply directly to the Department of Energy and Water Supply for relief from electricity charges as outlined in (A) above.

APPENDIX F: ASSUMPTIONS USED TO DETERMINE CUSTOMER IMPACTS

Table F.1: Tariff assumptions

Retail tariff	*Demand*	*Variable Rate (flat)*	*Variable Rate (off peak)*	*Variable Rate (peak)*
	kW per month	*kWh per annum*	*kWh per annum*	*kWh per annum*
Tariff 20 - Business (flat rate)		7,480		
Tariff 22 - Business (time of-use)			*51%* 18,415	*49%* 17,796
Tariff 31 - Night rate (super economy)		2,064		
Tariff 33 - Controlled supply (economy)		1,985		
Tariff 41 - Low voltage (demand)	14	50,133		

Source: Ergon Energy

APPENDIX G: ERGON ENERGY CUSTOMER IMPACTS

All data supplied by Ergon Energy.

Figure G.1 Change in Electricity Bills in 2012-13 for Customers on Tariff 20

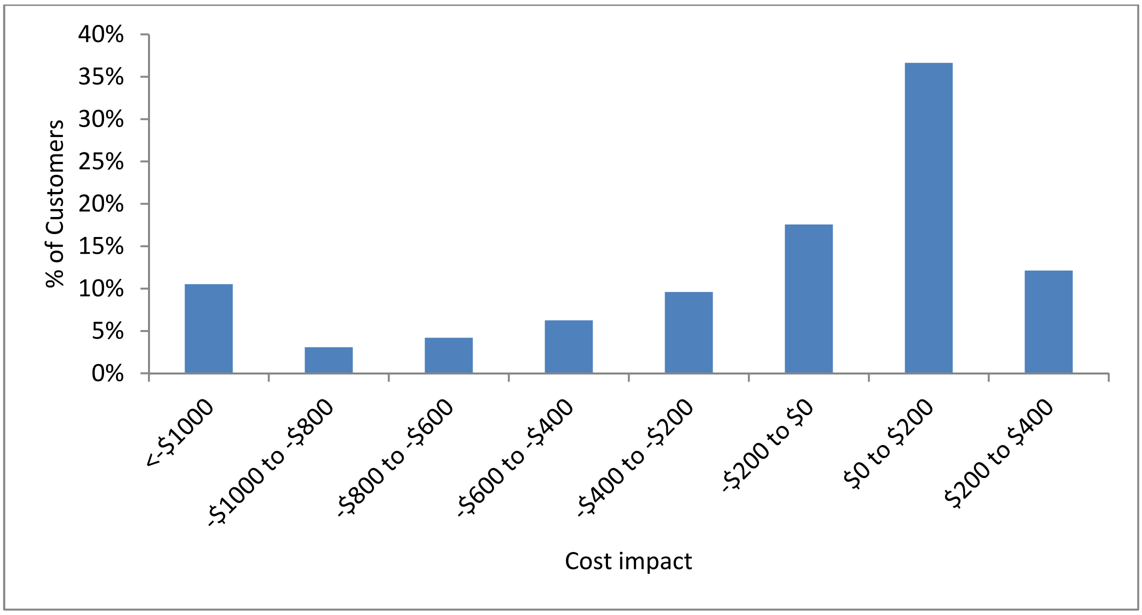


Figure G.2 Change in Electricity Bills in 2012-13 for Customers on Tariff 21

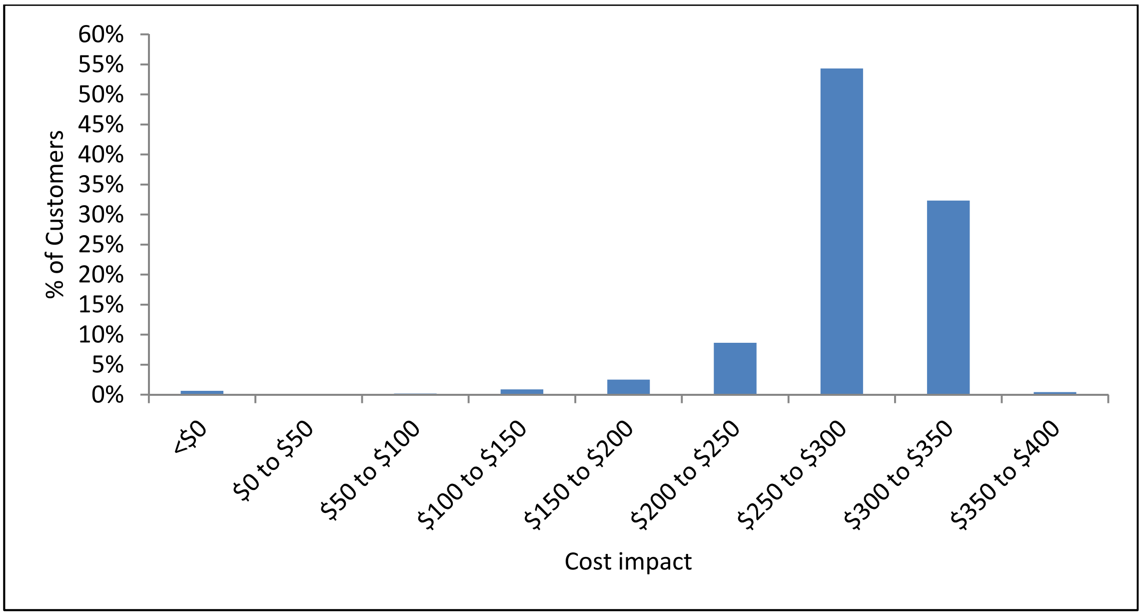


Figure G.3 Change in Electricity Bills in 2012-13 for Customers on Tariff 37

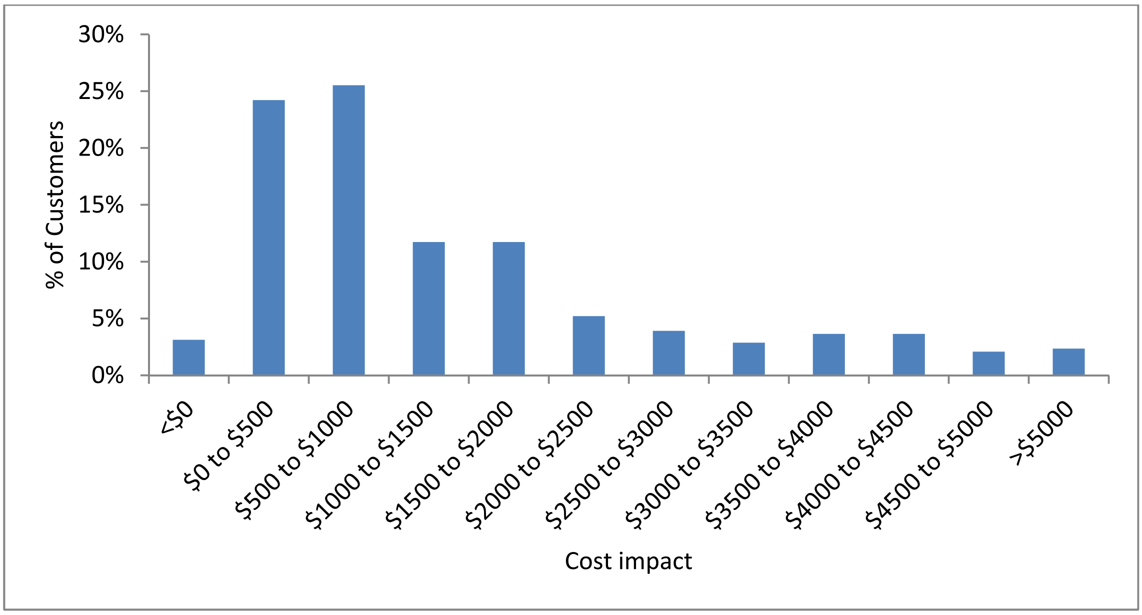


Figure G.4 Change in Electricity Bills in 2012-13 for Customers on Tariff 62

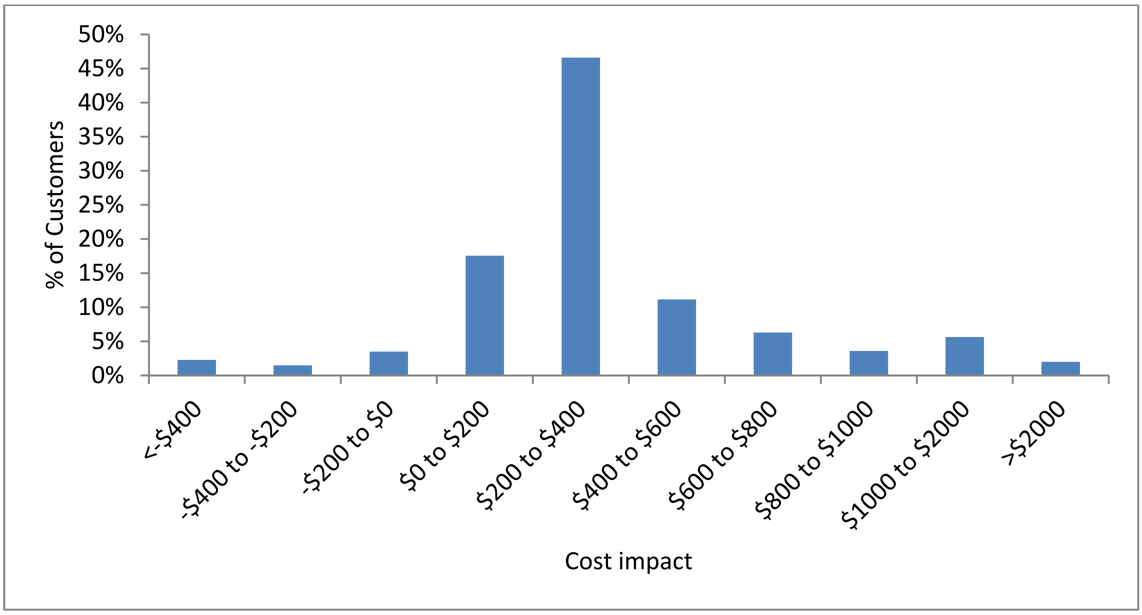


Figure G.5 Change in Electricity Bills in 2012-13 for Customers on Tariff 63

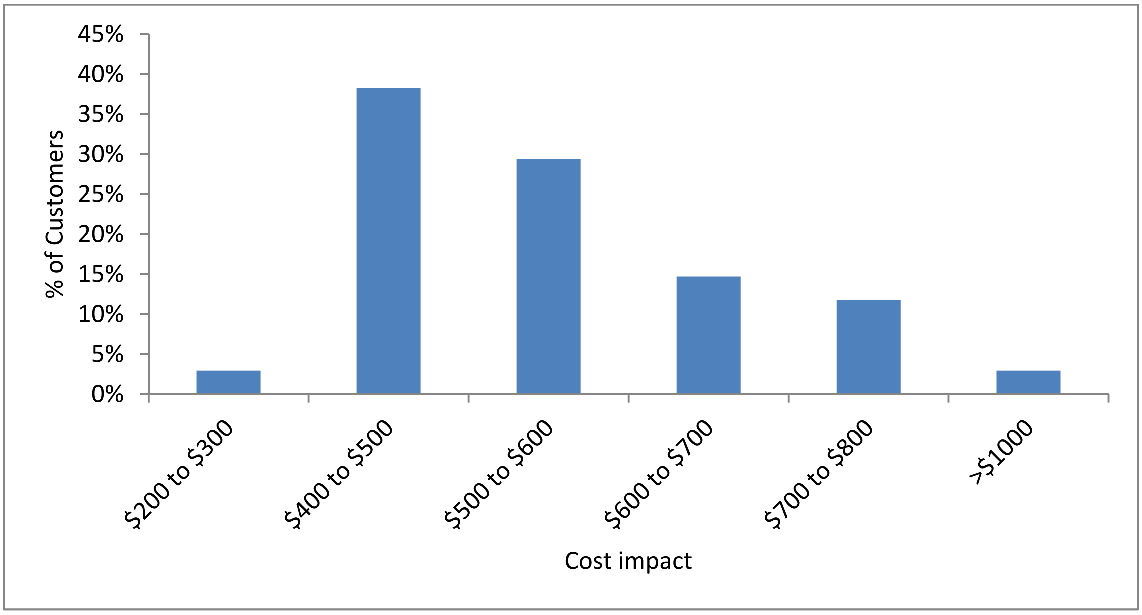


Figure G.6 Change in Electricity Bills in 2012-13 for Customers on Tariff 64

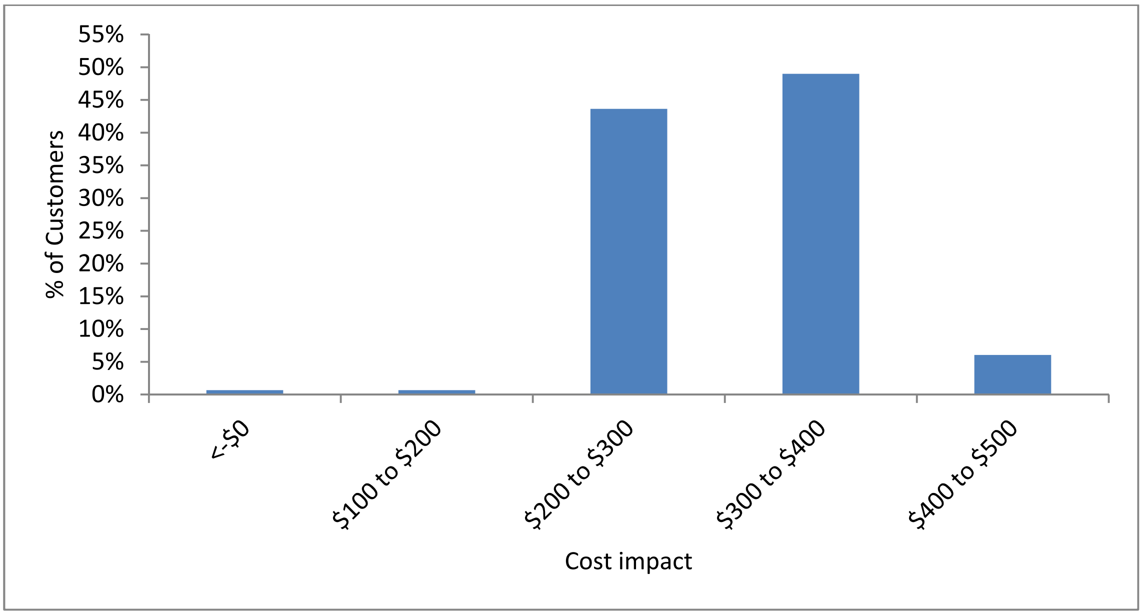


Figure G.7 Change in Electricity Bills in 2012-13 for Customers on Tariff 65

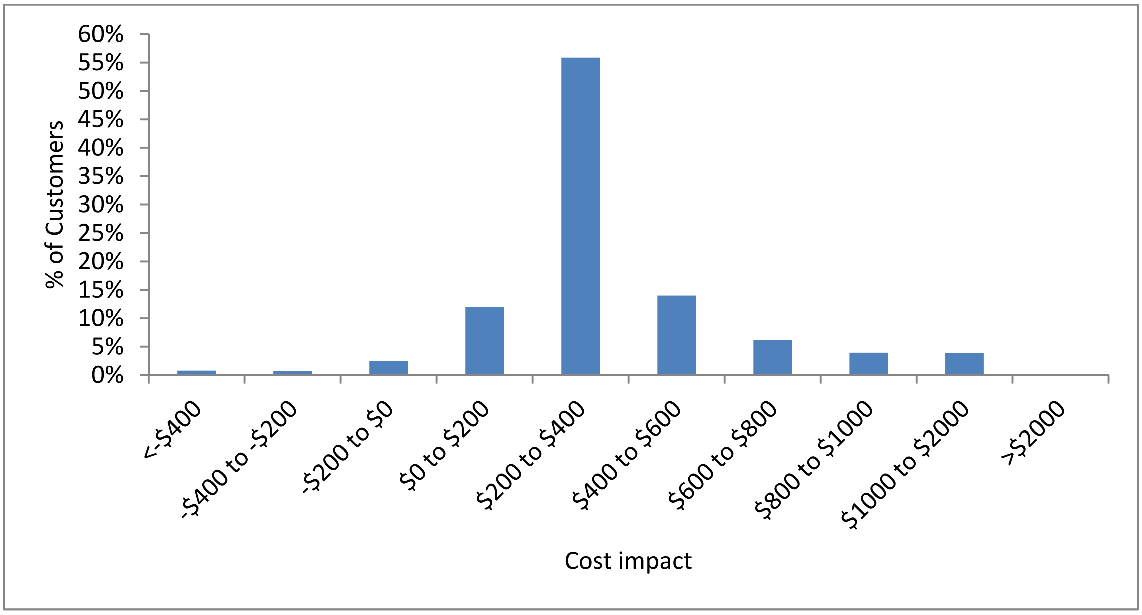


Figure G.8 Change in Electricity Bills in 2012-13 for Customers on Tariff 66

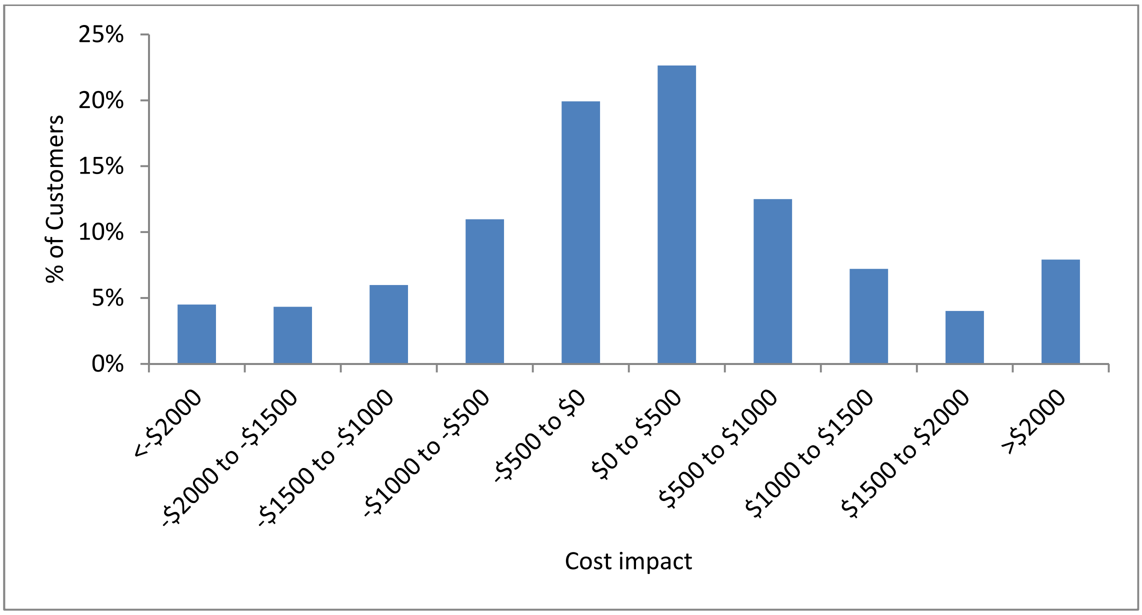


Figure G.9 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 20

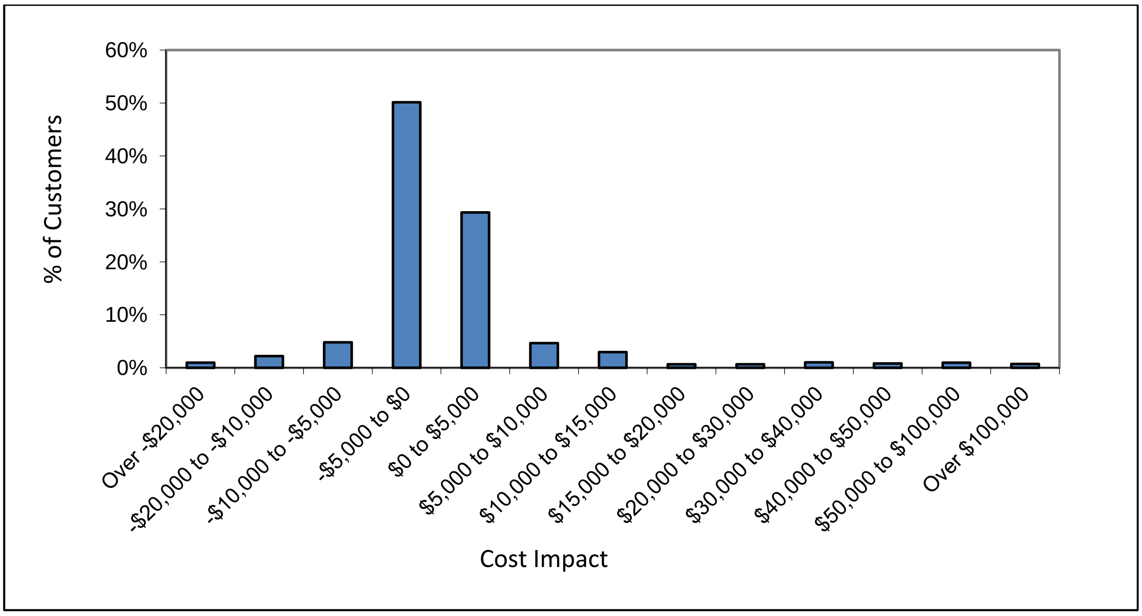


Figure G.10 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 22

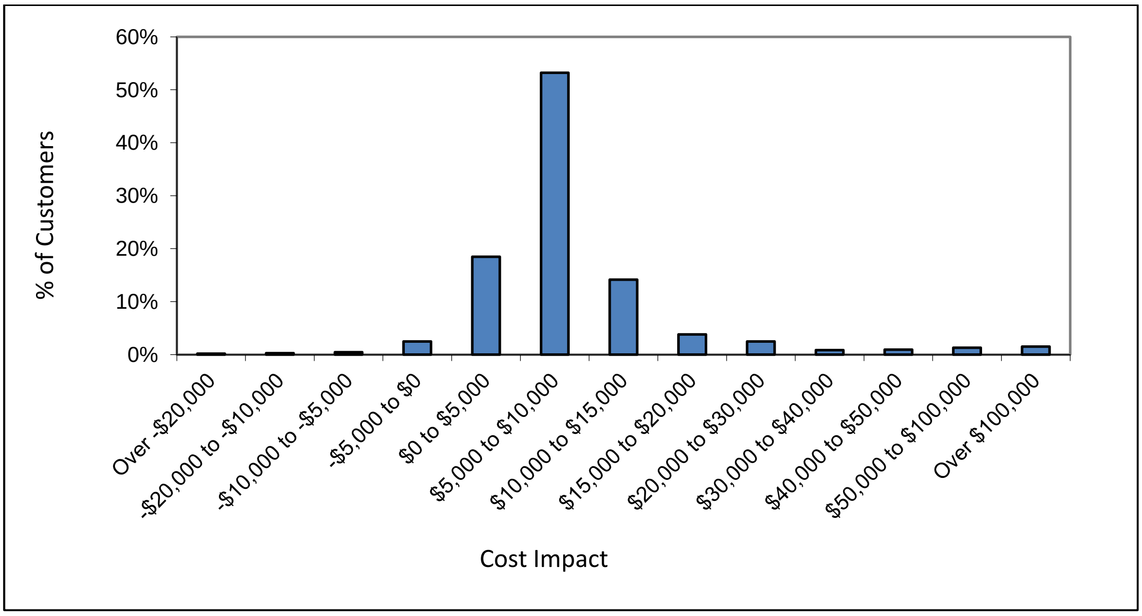
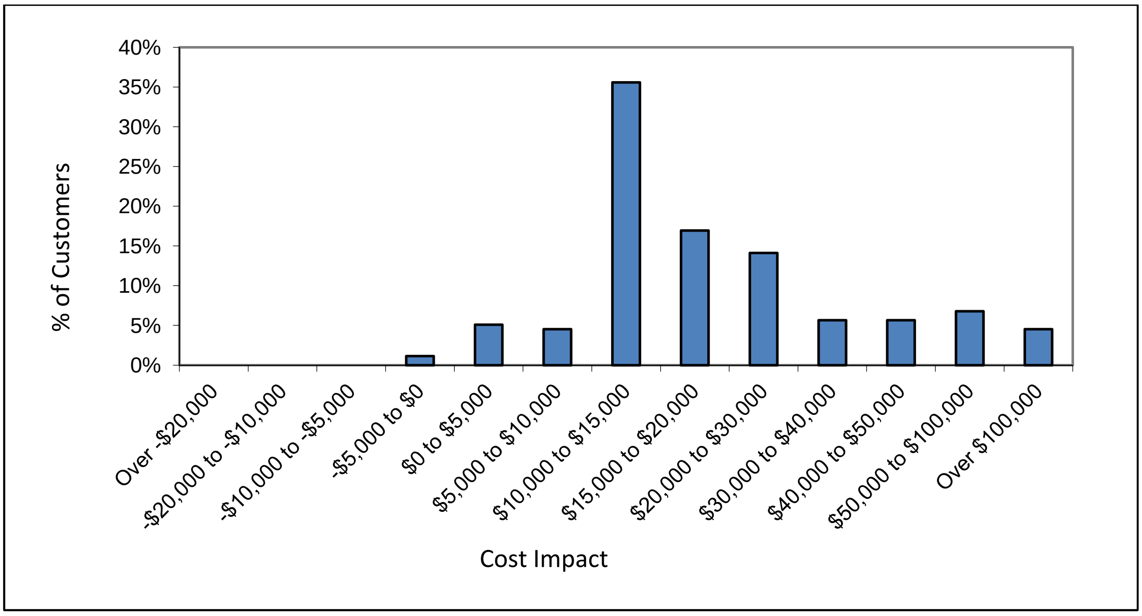
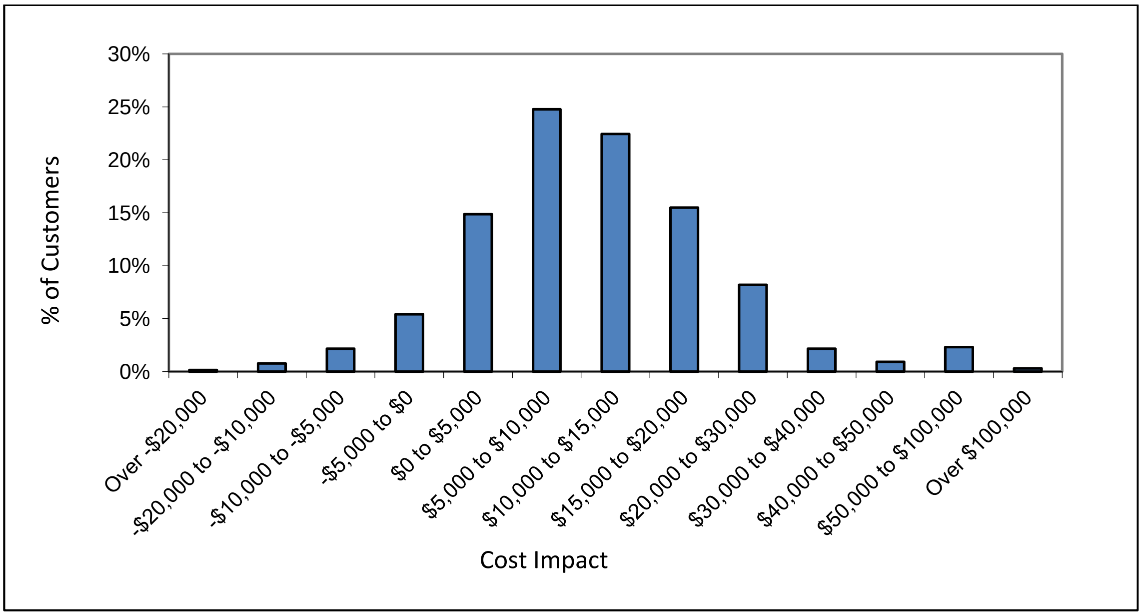


Figure G.11 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 37



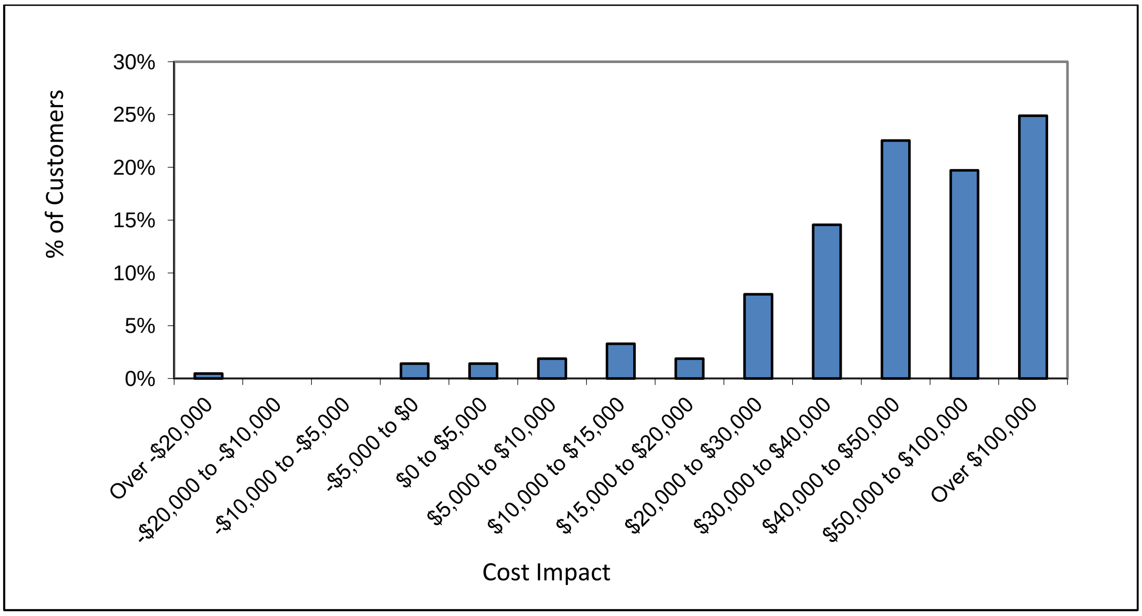
Note: load factor of 37% has been applied for calculating demand values.

Figure G.12 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 41



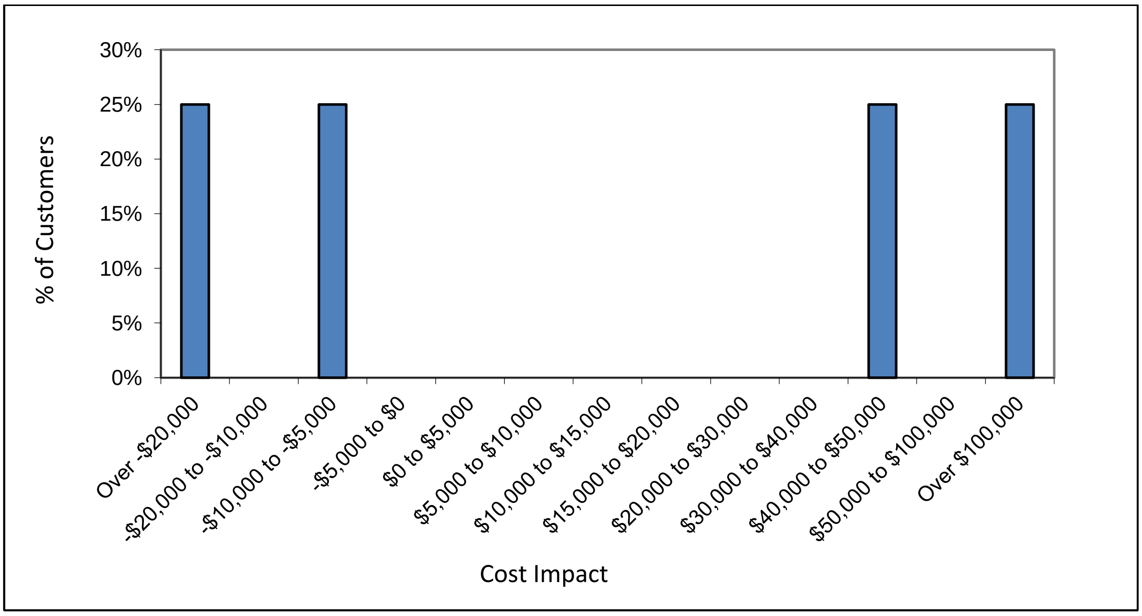
Note: load factor of 37% has been applied for calculating demand values.

Figure G.13 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 43



Note: load factor of 37% has been applied for calculating demand values.

Figure G.14 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 53



Note: load factor of 37% has been applied for calculating demand values.

Figure G.15 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 62

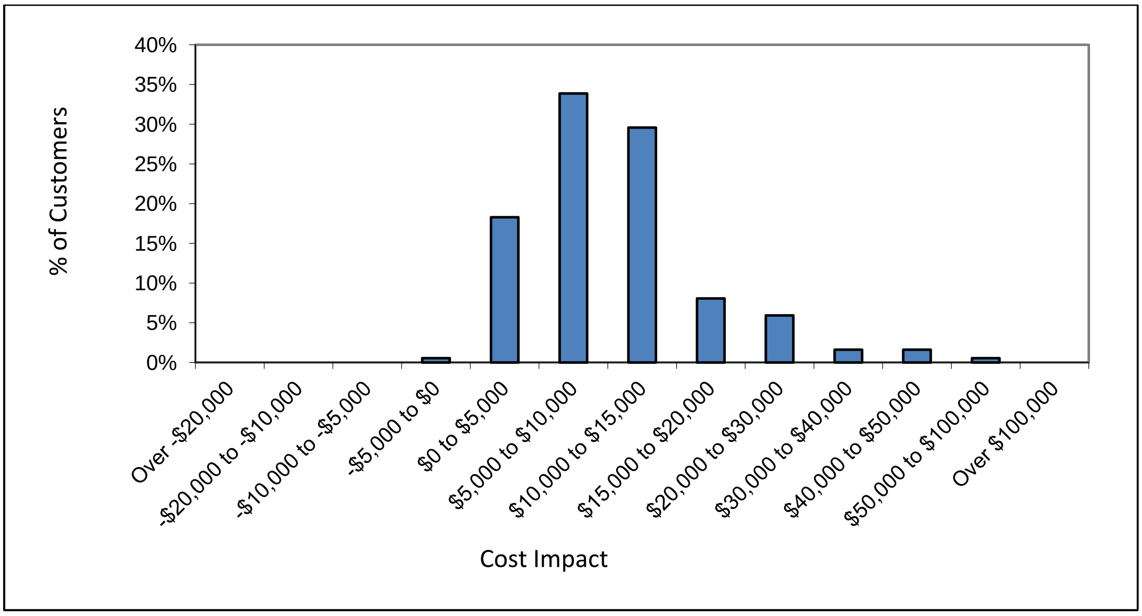


Figure G.16 Change in Electricity Bills in 2012-13 for Large Customers on Tariff 65