QUEENSLAND
COMPETITION
AUTHORITY

Draft Decision

Benchmark Retail Cost Index for Electricity: 2011-12

December 2010

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SUBMISSIONS

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (the Authority). Therefore, submissions are invited from interested parties concerning its assessment of the 2011-12 Benchmark Retail Cost Index (BRCI). The Authority will take account of all submissions received by the due date.

Written submissions should be sent to the address below. While the Authority does not necessarily require submissions in any particular format, it would be appreciated if two printed copies are provided together with an electronic version on disk (Microsoft Word format) or by e-mail. Submissions, comments or inquiries regarding this paper should be directed to:

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The **closing date** for submissions is 11 February 2011.

For further enquiries, contact Mr Gary Henry on (07) 3222 0504.

Confidentiality

In the interests of transparency and to promote informed discussion, the Authority would prefer submissions to be made publicly available wherever this is reasonable. However, if a person making a submission does not want that submission to be public, that person should claim confidentiality in respect of the document (or any part of the document). Claims for confidentiality should be clearly noted on the front page of the submission and the relevant sections of the submission should be marked as confidential, so that the remainder of the document can be made publicly available. It would also be appreciated if two copies of each version of these submissions (i.e. the complete version and another excising confidential information) could be provided. Again, it would be appreciated if each version could be provided on disk. Where it is unclear why a submission has been marked "confidential", the status of the submission will be discussed with the person making the submission.

While the Authority will endeavour to identify and protect material claimed as confidential as well as exempt information and information disclosure of which would be contrary to the public interest (within the meaning of the *Right to Information Act 2009 (RTI)*), it cannot guarantee that submissions will not be made publicly available. As stated in s187 of the *Queensland Competition Authority Act 1997* (the QCA Act), the Authority must take all reasonable steps to ensure the information is not disclosed without the person's consent, provided the Authority is satisfied that the person's belief is justified and that the disclosure of the information would not be in the public interest. Notwithstanding this, there is a possibility that the Authority may be required to reveal confidential information as a result of a RTI request.

Public access to submissions

Subject to any confidentiality constraints, submissions will be available for public inspection at the Brisbane office of the Authority, or on its website at www.qca.org.au. If you experience any difficulty gaining access to documents please contact the office (07) 3222 0555.

Information about the role and current activities of the Authority, including copies of reports, papers and submissions can also be found on the Authority's website.

PREAMBLE

While electricity customers in Queensland are able to enter into a negotiated contract (market contract) with an electricity retailer of their choosing, customers who opt not to do so or who are not offered a market contract remain on a standard retail contract which is subject to notified (regulated) electricity prices. Customers consuming less than 100 MWh per annum who have entered into a market contract may revert to the standard retail contract at the notified price, subject to any contractual conditions that may apply to their existing negotiated contract.

Since 2007-08, the Authority has been delegated the responsibility for determining annual adjustments to notified prices, under the Benchmark Retail Cost Index (BRCI) methodology, to ensure that notified prices keep pace with the costs of producing, transporting and retailing electricity. The Authority is required by legislation (the Electricity Act 1994 and the Electricity Regulation 2006) to estimate the increase in the BRCI annually and to apply that increase to existing notified prices.

In making its 2011-12 Draft Decision, the Authority has applied essentially the same framework it has used in previous BRCI decisions. At this time, the Authority estimates the increase in costs for 2011-12 to be 5.83%.

Changes to the Federal Government's Renewable Energy Target (RET) scheme account for 2.91 percentage points of the increase. Had it not been for these changes, the increase in the BRCI for 2011-12 would have been 2.92%.

The overall increase of 5.83% in the BRCI is made up of:

(a) a 9.6% increase in transmission and distribution costs, reflecting the ongoing investment in Queensland's distribution networks approved by the Australian Energy Regulator (AER) for the 2010-11 to 2014-15 regulatory period. As network costs account for around 49% of total costs, they contribute 4.76 percentage points to the expected change in the BRCI (82% of the total increase).

(b) a 1.2% increase in total energy costs reflecting:

   (i) a 5% increase in the long-term costs of energy production, due to rising coal and gas costs;

   (ii) a 16% reduction in market-based costs for purchasing energy as wholesale electricity prices have continued to decline following the end of the drought;

   (iii) a 53% reduction in the cost of complying with the Queensland Gas Scheme due to lower market prices for Gas Electricity Certificates; and

   (iv) a significant increase in the cost of the Federal Government's RET scheme. Changes to the RET scheme from 1 January 2011 are expected to more than double the compliance cost for retailers in 2011-12. This more than offsets the estimated reductions in other components of the cost of energy.

   As energy costs account for around 41% of total costs, in total they will contribute 0.51 percentage points to the expected change in the BRCI (9% of the total increase).

(c) a 6% increase in retail costs, including the cost of customer acquisition and retention, reflecting increased operating and marketing costs for retailers mainly due to inflation and increased wage costs. As retail costs account for around 9% of total costs, they contribute 0.57 percentage points to the change in the BRCI (10% of the total increase).

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1. INTRODUCTION

The Electricity Act 1994 (the Electricity Act) requires that the rate of change in the Benchmark Retail Cost Index (BRCI) be used to adjust notified electricity prices each year.

The Electricity Act allows the Minister for Natural Resources, Mines and Energy and Minister for Trade (the Minister) to delegate the calculation of the BRCI to the Authority. The Minister has done so each year since 2007-08. The current delegation from the Minister under the Electricity Act is to calculate the increase in the BRCI for 2011-12 and to apply this to existing notified prices to establish new notified prices to apply from 1 July 2011.

Following the release of an Interim Consultation Notice on 23 September 2010, the Authority is now releasing this Draft Decision.

1.1 Background

Electricity customers in Queensland are able to choose their retailer by entering into a negotiated retail contract offered by a competitive retailer. However, customers who choose not to take up a market offer or who are not offered a market contract remain on a standard retail contract which is subject to notified (regulated) electricity prices. Customers who take up a market offer transfer from the default standard retail contract to a negotiated retail contract with their retailer of choice and are subject to the contract price they have accepted from the retailer as part of the market offer.

Small customers (those consuming less than 100 MWh per annum) who have accepted a market offer may revert to the default standard retail contract at the notified price, subject to any contractual conditions that may apply to their existing negotiated retail contract.

The Electricity Act specifies that the notified prices are to be adjusted annually according to changes in the cost of providing electricity as measured by changes in the BRCI.

The Electricity Act allows the Minister to delegate to the Authority the calculation of the BRCI and the annual adjustment of notified prices. The Authority has been delegated this responsibility since the commencement of retail competition in 2007-08.

On 21 September 2010, the Minister issued the Authority with a delegation which requires the Authority to calculate the BRCI for 2011-12, apply the annual change in the BRCI to existing notified prices and publish these prices by 31 May 2011 to come into effect from 1 July 2011 (see Appendix 1).

1.2 Scope of this Draft Decision

The Authority's Draft Decision on the BRCI for 2011-12 has been prepared in a manner consistent with the Final Decision on the BRCI for 2010-11 and does not seek to reiterate in detail matters previously considered by the Authority in that or other past BRCI decisions.

This Draft Decision should be read in conjunction with relevant public reports that are referenced herein.

1.3 Overview of the BRCI

The BRCI approach to determining the notified prices does not involve a calculation of the efficient retail price of electricity each year. Rather, the existing notified prices are escalated by the expected change in the underlying cost of supplying electricity to customers (that is, by the change in the BRCI).

The method for calculating many components of the BRCI are set out in the Electricity Act and the *Electricity Regulation 2006* (the Electricity Regulation). In broad terms, the BRCI for a particular year is calculated by dividing the total cost of supplying electricity in the year under review by the relevant load (the NEM load) for the preceding calendar year. The total cost of electricity must include the following elements:

(a) the cost of energy;

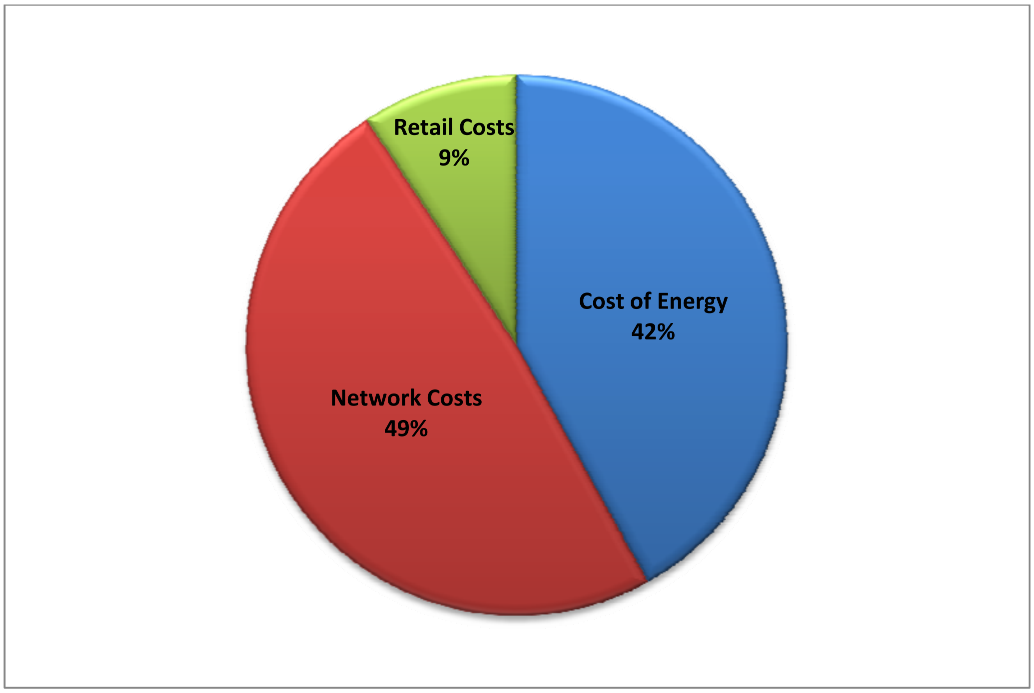
(b) network costs;

(c) retailers' costs (including a retail margin allowance); and

(d) any other costs considered relevant (for example, government fees).

The approximate size of the three main cost components in 2010 11 is illustrated in Figure 1.1.

Figure 1.1: BRCI cost components in 2010-11



Source QCA

The impact on annual notified prices of a change in any component of the BRCI will reflect both the size of the change in the component's cost and the weighting of the component in the overall BRCI.

As network costs (transmission and distribution) and the cost of energy (generation) account for around 91% of the total cost of supplying energy, any change in these two cost components will potentially have the greatest impact on movements in the index from one year to the next.

In addition to the certificate of delegation issued for the 2011-12 BRCI by the Minister, the following references provide important information regarding the legislative framework that the Authority is required to consider in calculating the BRCI:

(a) the *Electricity Act 1994* and the *Electricity Regulation 2006*, which can be accessed from the website of the Office of the Queensland Parliamentary Counsel at www.legislation.qld.gov.au;

(b) the judgment regarding the Authority's 2008 09 BRCI Final Decision, cited as *AGL Energy Ltd v Queensland Competition Authority & Anor; Origin Energy Retail Ltd v Queensland Competition Authority & Anor* [2009] QSC 90, which can be accessed from the Queensland Supreme Court website at www.courts.qld.gov.au; and

(c) the Authority's Final Decision on the BRCI for 2010 11, which can be obtained from the Authority's website at www.qca.org.au.

The current certificate of delegation also requires the Authority to consider certain policy objectives of the Queensland Government, including that:

(a) the annual indexation of electricity tariffs should ensure that retail headroom in the tariffs at the date of the Original Delegation remains relatively stable (although not necessarily the same from year to year); and

(b) the policy of enabling small market customers to revert to notified prices should not result in a retail entity providing retail services to such customers at a loss.

1.4 Calculation of the BRCI for 2011-12

On 23 September 2010, the Authority released an Interim Consultation Notice advising interested parties of the commencement of the process for calculating the BRCI for 2011-12. The Authority's Interim Consultation Notice proposed to adopt essentially the same methodology in calculating the BRCI for 2011-12 as that used in 2010-11.

Eight submissions were received in response to the Interim Consultation Notice – as listed in Appendix 2. A copy of the Interim Consultation Notice and the submissions received can be obtained from the Authority's website.

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on the cost of energy to be included in the BRCI for 2011-12. ACIL's initial report has been released and can be obtained from the Authority's website.

1.5 Timetable for determining the BRCI for 2010 11

The proposed timetable for determining the BRCI for 2011 12 is provided in Table 1 below.

Table 1: Timetable for BRCI calculation for 2011-12

Milestones	***Indicative Dates***
Interim Consultation Notice issued	23 September 2010
Submissions on Interim Consultation Notice closed	11 October 2010
Draft Decision released	17 December 2010
Submissions on Draft Decision close	11 February 2011
Release Final Decision and gazette notified prices for 2011-12	by 31 May 2011

Submissions in response to this Draft Decision must be received by the Authority by close of business 11 February 2010. In preparing its Final Decision, the Authority will consider all submissions received by the due date.

2. COST OF ENERGY

The Electricity Act requires that the cost-of-energy component of the BRCI in a particular year be based on the Authority's view of the likely total cost of purchasing energy to supply the National Electricity Market (NEM) load (see Chapter 5) in that year. In forming this view, the Authority is required to base its view on its latest estimate of the long run marginal cost (LRMC) of energy in that part of Queensland connected to the national grid and to take account of the actual cost of purchasing energy to meet the NEM load.

In estimating the cost of energy component for the 2011-12 BRCI, the Authority has estimated the LRMC of energy and the purchase cost of energy and then calculated an equally weighted average of these two costs. This is the same approach as was followed in recent BRCI decisions.

The estimate of the LRMC of energy is required by the Electricity Act to be based on a hypothetical economically efficient combination of generating technologies for Queensland. In arriving at its estimate of the change in LRMC for 2011-12 of 5 %, the Authority has continued with the same basic approach of using updated input costs as adopted in previous years.

The purchase cost of energy was estimated on the basis of a combination of the contract and spot market energy prices that a prudent and efficient retailer could be expected to purchase over a two-year period in order to meet the defined NEM load. This method is also the same as that used in recent BRCI decisions and resulted in an estimated 16% decrease in these costs.

Consistent with recent BRCI decisions, in establishing the total cost-of-energy component of the 2011-12 BRCI, the Authority has taken into account the impact of the Queensland Gas Scheme and the Federal Government's re-structured Renewable Energy Target (RET) scheme. Both these schemes are intended to reduce greenhouse gas emissions from the energy generation sector by imposing obligations on retailers to source a certain portion of their customers' energy from less carbon intensive generation sources in the case of the Queensland Gas Scheme, and renewable sources in the case of the RET scheme.

Following consideration of stakeholder submissions, the Authority has modified its method for estimating the cost of Gas Electricity Certificates (GECs) which are used to value the impact of the Queensland Gas Scheme on energy costs. Rather than basing its estimate on the penalty price (the shortfall charge), the Authority has moved to a market-based approach to estimating the cost of GECs. As required by section 107 of the Electricity Regulation, the Authority has re estimated the cost of the Queensland Gas Scheme in 2010-11 using this new methodology, resulting in a 53% decrease in these costs.

The Federal Government has re-structured the RET scheme into a two-part scheme from 1 January 2011. The cost of the re-structured RET scheme under the new Small-scale Renewable Energy Scheme (SRES) was estimated based on the number of Small-scale Technology Certificates (STC) expected to be created in 2011-12 and the fixed price of these certificates. The cost of the Large-scale Renewable Energy Target (LRET) scheme was estimated using expected LRET targets and market prices of Large-scale Generation Certificates (LGC). The change in the RET scheme resulted in an increase of 147% in these costs.

As in previous years, the Authority has also included the cost of NEM participant fees and ancillary services charges paid by retailers.

Summing each of the energy cost elements, the total cost of energy component of the BRCI is estimated to be $2,431.6 million in 2011-12, an increase of 1.17%.

2.1 Background

Typically, electricity is purchased by retailers from generators on behalf of their customers and delivered via transmission and distribution networks to customers' homes and businesses. At any point in time, the cost of energy to a retailer will reflect the various supply contracts the retailer has with generators as well as the prevailing demand and supply conditions in the NEM. This is the basis of the energy purchase costs.

In the long run, costs should tend to be more stable. Short run peaks and troughs are less relevant when considering the cost of supplying electricity to the market over a longer period. The LRMC of energy should be more stable and influenced by the changing costs of technology rather than the day-to-day supply and demand imbalances that affect the energy purchase costs.

2.2 Legislative Requirements

The Electricity Act requires that the cost of energy component of the BRCI in a particular year be based on the Authority's view of the likely total cost of purchasing energy to supply the NEM load in that year. In forming this view, the Authority is obliged to take account of its latest estimate of the LRMC of energy in the part of Queensland connected to the national grid and take account of the actual cost of purchasing energy (energy purchase costs) to meet the NEM load in the State in that year.

This view must also take account of the Queensland Gas Scheme under the Electricity Act and the RET scheme under the Federal Government's *Renewable Energy (Electricity) Act 2000 (Cth)* (the Renewable Energy Act).

The Electricity Act requires that the Authority's estimate of the LRMC of energy must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant tariff year. The Electricity Regulations state that the method used by the Authority to estimate the LRMC of energy must be a theoretical framework that:

(a) is generally recognised and understood in economic theory;

(b) produces a cost of energy in terms of dollars per megawatt hour ($/MWh);

(c) calculates the LRMC of energy needed to meet the State NEM load shape for each half hour trading period for the previous calendar year;

(d) avoids double counting the costs of the Queensland Gas Scheme and the RET scheme; and

(e) takes account of ancillary services needed to meet the NEM load of Queensland for the relevant tariff year.

Having established a method for estimating the LRMC of energy for 2010 11, section 107(1) of the Electricity Regulation requires that the LRMC theoretical framework must be the same, or substantially the same, from tariff year to tariff year unless:

(a) the pricing entity considers that there is a clear reason to change it; and

(b) the pricing entity has, under section 99, published draft decision material about the reason for the change.

2.3 Methodology for estimating cost of energy

Given the inherently complex nature of the LRMC modelling, the electricity demand forecast and the simulation of the wholesale energy market electricity prices required to model the energy purchase cost pricing outcomes, the Authority has relied on an expert consultant to provide the appropriate estimates of these cost components.

The Authority engaged ACIL Tasman (ACIL) to provide this expert advice. ACIL provided similar advice to the Authority for the 2010-11 BRCI and their continuing role provides modelling continuity in the calculation of energy costs between 2010-11 and 2011-12.

LRMC

The Authority's approach to estimating the LRMC of energy for the BRCI is driven by the legislative requirement of adopting a "greenfields" approach using the latest available information on generation capital and fuel costs. The Authority's theoretical framework for the calculation of the LRMC has the following features:

(a) Queensland's electricity grid is treated as part of the NEM rather than as an isolated region from a generation perspective;

(b) a 'greenfields approach' is used which assumes that the entire generation system is built new at the outset using the most efficient combination of new plant to meet the nominated load;

(c) the modelling uses a multi-year approach that attempts to capture the range and effect of demand and input cost variables over the longer term in identifying the optimal mix of plant chosen based on the lowest cost combination of generating plant to meet the projected load;

(d) the modelling approach also optimises generation investment across the NEM regions after taking account of the characteristics of the existing transmission system; and

(e) a load 'shape' which is developed on the basis of each half-hour period for the previous calendar year.

Energy Purchase Costs

The Authority's established approach to estimating the energy purchase cost for the BRCI is driven by the legislative requirement to take into account its view of the likely costs of purchasing electricity to meet the NEM load in the (forthcoming) tariff year. The energy purchase cost represents a short-term measure of energy supply costs and, in theory, is likely to be more volatile than the LRMC.

To estimate the energy purchase cost, the Authority must come to a view about the purchasing decisions that would be made by a prudent theoretical retailer operating in the Queensland market. The Authority has based its view on a combination of forecast wholesale spot market energy prices and the prices for contracts that a prudent and efficient retailer could be expected to purchase over a two-year period in meeting the forecast Queensland NEM annual demand for electricity in the (forthcoming) tariff year.

The two year contracting strategy (hedging strategy) is based on the assumption that a retailer's objective is to purchase contract cover that matches its load as closely as possible so that it is not exposed to the NEM spot market during peak periods and it is not over-contracted during off-peak periods. In doing so, it is assumed that a retailer would spread its purchases of contracts for each tariff year evenly over a period of two years in advance of the tariff year for which the energy is to be consumed. Consistent with this hedging strategy, the volume of contracts is then determined based on the following criteria:

(a) flat swaps are purchased up to the 80th percentile of off-peak load;

(b) peak swaps are purchased up to the 90th percentile of peak load; and

(c) $300 caps are bought beyond the cover of swaps to cover up to 105% of the maximum peak load.

The costs of these contracts are then typically sourced from the d-cypha Trade database for the assumed purchasing period.

A forecast of the annual demand for electricity (the load trace) is also required to estimate the energy purchase cost. This is based on the following factors or inputs:

(a) a forecast of the total demand for electricity (the annual energy);

(b) a forecast of the summer and winter maximum demand (summer and winter peaks); and

(c) a load shape generally sourced from the most recent annual period of actual data.

The Authority has relied on ACIL to produce the necessary load trace forecasts for the 2011 12 BRCI. ACIL's method for producing the necessary load trace forecasts uses two sources of official forecasts of annual energy and the summer and winter maximum demands: the Australian Energy Market Operator's (AEMO) Electricity Statement of Opportunities (ESOO) publication and Powerlink's Annual Planning Report (APR).

The ESOO publication is the commonly accepted official forecast of annual energy demand across the NEM and is provided to the industry annually by AEMO. The most recent ESOO was released on 31 August 2010 and remains the current industry forecast of demand for 2011-12.

Powerlink's APR also provides forecasts of annual energy and summer and winter maximum demand for the forthcoming year. The current Powerlink APR was released on 30 June 2010.

Although presented in different formats, the most recent ESOO and the 2010 APR present essentially the same forecasts for electricity demand in Queensland for 2011-12.

Queensland Gas Scheme

The Authority is also required to consider the impact of the Queensland Gas Scheme.

The Queensland Gas Scheme was established to encourage the development of the State's gas industry to reduce greenhouse gas emissions associated with the production and use of electricity in Queensland. The scheme operates by requiring retailers to source a prescribed percentage of their annual electricity supply from gas-fired generation.

Under this scheme, retailers are required to obtain and surrender a sufficient number of GECs to cover a set proportion of their annual customer load. The annual mandatory targets are prescribed under the Electricity Act. Currently, individual retailers are required to obtain GECs for at least 15% of their annual electricity load. The mandatory target is set to increase to 18% by 2020. Retailers that fail to meet their annual GEC obligation incur penalties (in terms of $/MWh) for any shortfall. The requirement to obtain GECs therefore creates an additional cost to retailers' in purchasing electricity for their customers.

GECs are created by accredited gas generators for each MWh of gas-fired electricity generated. The cost of GECs is effectively capped at the level of the shortfall penalty charge. However, the market prices of GECs are dependent on the interaction of the supply of and demand for GECs in the market. Market prices of GECs are not as readily available as GECs are primarily obtained by retailers through bilateral negotiations with eligible generators or are traded through specialised brokers.

To estimate the cost of future GEC prices requires information on the annual mandatory targets over the relevant period and the cost of obtaining GECs to meet those targets. The Authority had previously canvassed possible methods for determining the cost of GECs before settling on an approach based on the penalty price, or shortfall charge, that retailers must pay for not surrendering sufficient GECs. In other words, the penalty price (the shortfall charge) acted as a proxy for the price of GECs.

While the Authority acknowledged that market data would have been a preferable basis for estimating future costs, this had not been practical in the past as there was very limited market data on GEC prices upon which to base robust forecasts of future prices.

Renewable Energy Target (RET) Scheme

The Authority is required to take into account the impact of the Federal Government's RET scheme under the Renewable Energy Act. This scheme was established nationally to encourage additional generation of electricity from renewable energy sources to reduce greenhouse gas emissions that result from non-renewable generation fuels such as coal.

In August 2009, the Federal Government expanded the original RET scheme by increasing the annual target from 2% of Australia's energy supply to be derived from renewable sources in 2010 to 20% (or 45,000 GWh) by 2020. The expanded RET scheme affects retailers' wholesale energy purchase costs as it places a more stringent obligation on them to create or purchase an increasing number of Renewable Energy Certificates (REC) in line with their annual RET targets. If a retailer fails to meet its obligations to acquire sufficient RECs, it incurs a penalty for any shortfall.

In previous BRCI decisions, costs associated with the RET scheme have been estimated using weekly market data on REC prices as published by the Australian Financial Markets Association (AFMA).

From 1 January 2011, the RET scheme will be split it into two schemes – the SRES and the LRET scheme.

Under SRES, households and small businesses will receive $40 for each STC created by installing technologies such as solar panels and solar hot water systems. Retailers will have an obligation to acquire STCs based on expected rates of STC creation.

Under the LRET scheme, LGC targets for retailers will be established but, unlike the SRES, the LRET annual target will be determined with reference to achieving generation of 41,000 GWh by 2020 from large-scale renewable generation.

Under this new market structure, retailers will be required to surrender certificates purchased from both the SRES and LRET market to fulfil their RET obligations. As is the case with the existing RET scheme, if a retailer fails to meet its obligations, it will incur a penalty. The penalties are set at $65 per STC or LGC shortfall.

The introduction of the re-structured scheme will need to be reflected in the calculation of RET costs for 2011-12.

Market Participation Costs

In previous BRCI decisions, the Authority has recognised that retailers also incur additional NEM participant fees that they must pay to the market operator, which cover AEMO's operational expenditure, as well as any ancillary services charges to support key technical characteristics of the electricity system such as automatic generation control and load shedding operations.

The Authority's existing methodology for estimating the cost of AEMO participant fees is based on historical trends for which data is publicly available from AEMO's website.

The cost of ancillary services has in the past been estimated based on the average cost over the preceding 52 weeks of currently available ancillary services cost data from AEMO.

2.4 Submissions from stakeholders

Provision of input modelling data

Some stakeholders requested that the Authority again release all LRMC and energy purchase cost modelling input data.

Authority comment

The Authority is conscious of its obligations to consult with stakeholders and, as always, is committed to a consultation process that will ensure its decisions are made on a fully informed basis. As it has done in previous years, the Authority will release a number of data files and other information it has relied upon in arriving at its decision, at the same time (or soon thereafter) as it releases this Draft Decision.

LRMC

Both AGL and Origin Energy suggested that more up-to-date data on capital and fuel costs be used to calculate the 2011-12 LRMC.

Authority comment

As part of its LRMC modelling for the 2011-12 BRCI, ACIL has developed recent and reliable forecasts of fuel, capital and other operating and maintenance costs for the range of power stations in the NEM.

ACIL has sourced capital cost projections from a document it prepared for the Inter-regional Planning Committee of the (then) National Electricity Market Management Company (NEMMCO) in April 2009[1]. ACIL has also updated its coal and gas prices to reflect recent price levels and industry developments.

ACIL has also reviewed the components of the weighted average cost of capital (WACC) to make sure they remain current and has considered the impact of the significant appreciation of the Australian dollar against the US dollar in recent months. ACIL decided not to adjust its long term exchange rate assumption of $A1 buying $US0.75 in its LRMC model on the basis that the LRMC is a long term analysis and there is no reason to assume that the exchange will not trade within its usual historic range over the longer term.

[1] ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, Final Report prepared for the Inter-Regional Planning Committee, April 2009.

On this basis, the Authority is satisfied that ACIL's update of the capital and fuel cost parameters as part of its LRMC modelling is appropriate.

Energy Purchase Costs

Submissions generally supported the continued use of the Authority's existing methodology for estimating the energy purchase cost component of the BRCI.

However, the Queensland Government expressed its view that the cost of energy should be declining from 2010-11 given the significant decrease in wholesale energy prices that have been observed in the spot prices for the Queensland since 2008.

The Government noted that the wholesale energy spot price had fallen by about 30% from 2007-08 and that contract prices for peak, flat and off-peak hedging instruments had also shown a progressive decline. The Government argued that this decline should be reflected in the energy purchase cost estimate for 2011-12.

Authority comment

While the Authority notes the decline in wholesale spot prices and contract prices, the BRCI energy purchase cost is not simply a function of the historical spot market prices and current forward contract market prices but is rather more complex. For example:

(a) given the hedging strategy assumed by the Authority, energy purchase costs will be influenced by historical forward contract prices as retailers are assumed to have purchased those contracts at prices that were prevailing at that time;

(b) the legislative requirement of using the NEM load of the previous year to model costs for the following tariff year means that any abnormal weather conditions in this load data will influence modelling results; and

(c) it is forward looking and intended to reflect the buying conditions retailers are likely to face in the forthcoming tariff year rather than capturing changes in wholesale energy prices in previous years. There is no direct correlation between historical wholesale energy market prices and the BRCI energy purchase cost movements in the forthcoming tariff year;

The final cost of energy estimate for 2011-12 BRCI will also reflect the LRMC estimate, which is equally weighted in the cost of energy calculation.

Nevertheless, to the extent that prices are falling, they will progressively influence the purchase cost of energy as those lower prices filter through to forward contract prices for consumption in future years.

Weighting of LRMC and Energy Purchase Cost

EnergyAustralia suggested a move away from the equal weighting of the LRMC and energy purchase cost. It suggested that the cost of energy should be more heavily weighted towards the market-based energy purchase cost, with LRMC setting a price "floor" (similar to IPART's approach in its 2010-2013 retail price determination).

Authority comment

The issue of weighting the LRMC and energy purchase cost has been extensively canvassed in previous BRCI decisions. While there are arguments that could be made for a greater weighting either way, the 50/50 weighting adopted by the Authority in the past reflects this balance of argument and also recognises the emphasis in the BRCI legislation on LRMC as the basis for determining the cost of energy.

As there was no new or compelling argument provided to support a change in that view, the Authority is not persuaded to move away from the equal weighting of LRMC and energy purchase costs in calculating the energy cost component of the 2011-12 BRCI.

Queensland Gas Scheme

The Queensland Government requested that the Authority make use of available market data on GECs rather than relying on the penalty price approach it has adopted in the past. The Government noted that only 0.3% of the total GEC liability attracted the penalty price, leaving 99.7% that were settled at market prices.

The Queensland Council of Social Service (QCOSS) also suggested that the Authority adopt a market-based approach to estimating GEC costs and noted that the Authority's previous consultant, (CRA International) had recommended during the 2009-10 BRCI that a market based approach should be possible in the future as more data becomes available.

The only retailer to comment on this issue was Origin Energy which supported the continued use of the penalty price methodology.

Authority Comment

To date, the Authority has based its estimates of the cost of complying with the Queensland Gas Scheme on changes in the annual penalty charge that retailers would incur for not surrendering sufficient GECs.

This approach was initially adopted in preference to using available market data because there was limited market data available and what was available was considered unreliable. In this regard, GECs are primarily obtained by retailers negotiating bilaterally with eligible generators or are traded through specialised brokers and, as a result, available data was from a very thinly traded segment of the market which may not have reflected average GEC prices.

This issue was also raised in submissions on the 2010-11 BRCI. At that time, the Authority decided not to change its methodology primarily due to concerns related to the quality and reliability of the available market data on GECs. The available AFMA data was fairly thinly traded and the series was based on an ad-hoc phone survey of industry participants' views of GEC settlement prices.

The Authority also noted that its use of the penalty price method was not the primary reason costs associated with the Queensland Gas Scheme were expected to increase at that time. Rather, changes in the NEM load and the fact that the Queensland Government had increased the mandatory scheme target for retailers from 13% to 15% were significant drivers of this cost.

In response to submissions, the Authority has again sought advice from ACIL on whether the available market data on GECs has improved to the extent that it could be reasonably relied upon for estimating the Queensland Gas Scheme costs and whether adopting this alternate approach would have a significantly different impact on cost estimates.

In its Draft Report on the 2011-12 BRCI, ACIL suggested that annual movements in the cost of complying with the scheme will be better reflected by year-on-year changes in the market price of GECs than by continuing with the penalty price method if market prices can be sourced reliably and consistently each year.

ACIL therefore considered the quality and reliability of two potential sources of market data on GEC prices: the AFMA GEC data and data obtained from an independent broker, Next Generation Energy Solutions (Nextgen).

ACIL noted that the AFMA data is based on fairly thin GEC market data because the number of liable parties is small and limited to retailers who are only active in Queensland and that other large Queensland consumers who have a GEC liability are likely to enter the market only a few times a year to buy their GECs. While ACIL noted that the AFMA data is only collected weekly and there are a significant number of weeks when no price is provided because there have been very few or no trades at all, it was of the view that a weekly survey of prices is probably a reasonable indicator of GEC price movements given the nature of the market.

In order to corroborate whether the AFMA data could now be relied upon to provide a sufficiently robust market estimate of GEC price movements, ACIL compared AFMA quoted GEC prices to market data obtained from Nextgen. ACIL concluded that GEC price data from both sources followed a similar path throughout each year and there was no indication that one had consistently higher or lower prices than the other. The average year-on-year differences between the two sources were also very similar and resulted in a similar estimate for the change in GEC costs between 2010-11 and 2011-12, as shown in Table 2.1 below.

ACIL therefore concluded that AFMA data would now provide a reasonable source of GEC prices and that, with periodic checks against alternative sources, it would be reasonable to use this as a basis for estimating GEC costs for Queensland retailers.

Table 2.1: Comparison Queensland Gas Scheme costs using alternate data sources

	2010-11[1]	***2011-12***	***Change***
Using AFMA Data			
Price of GECs ($/MWh)	7.99	3.70	-4.29
Prescribed proportion of load	15%	15%	
Estimated Cost of Queensland Gas Scheme ($/MWh)	**1.20**	**0.56**	**-0.64**
Using Nextgen Data			
Price of GECs ($/MWh)	8.42	3.74	-4.68
Prescribed proportion of load	15%	15%	
Estimated Cost of Queensland Gas Scheme ($/MWh)	**1.26**	**0.56**	**-0.70**

1 Recalculated with market data available as at 31 March 2010.
Source ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011-12, Draft Report, 2 December 2010.

The Authority has accepted ACIL's advice to move to a market-based approach using AFMA data to estimating the cost of the Queensland Gas Scheme rather than using the previous penalty price approach. However, as this constitutes a change in methodology under the BRCI framework, the Authority will need to re-estimate the cost of the Queensland Gas Scheme in 2010-11 using this new method as required by section 107 of the Electricity Regulation.

In this regard, only AFMA GEC price data that would have been available at the time of the 2010-11 BRCI Final Decision will be used in recalculating the 2010-11 Queensland Gas

Scheme cost. Table 2.1 includes the re-calculated Queensland Gas Scheme cost for 2010-11 using AFMA data that would have been available as at 31 March 2010, the last cut-off date for all market data used in the 2010-11 BRCI Final Decision.

RET Scheme Costs

Comments in submissions were generally in favour of continuing to adopt a market-based approach to estimating SRES costs but views differed on the most appropriate approach to estimating LRET costs.

While the Government, QCOSS and Origin Energy suggested that LRET costs should be estimated using a market-based approach, AGL and EnergyAustralia suggested basing LRET costs on the difference between the LRMC of new-entrant renewable energy generation (wind generation) and coal energy prices. They argued that the difference between these estimates would represent the cost of LGCs since it reflects the opportunity cost of investing in renewable energy.

TRUenergy, EnergyAustralia and AGL also suggested that the Authority should allow for some ‘catch up’ in RET costs for the period from 1 January 2011 to 30 June 2011given that the cost of the scheme for that part of the year in the 2010-11 BRCI were based on the original RET scheme.

However, Origin Energy noted that the nature of the BRCI, being an index, ensured that the 2011-12 retail tariffs would be adjusted accordingly for the future impact of the new RET scheme.

Authority Comment

The Authority sought advice from ACIL on the most appropriate method to estimate the costs of SRES and LRET. ACIL was of the view that, in attempting to estimate the costs faced by retailers in purchasing electricity (and more importantly, the changes in the cost of purchasing electricity) through the BRCI, the most transparent approach would be to use market data when it is available. This approach is more likely to reflect changes in the costs that retailers face in purchasing the components of the energy package they deliver to consumers, including the costs of various government schemes that require consumers to subsidise certain energy generation technologies.

In considering the approach suggested by AGL and EnergyAustralia for estimating LRET costs, ACIL was of the view that, if a reliable market based measure was available, then it would be difficult to justify the use of some proxy measures. ACIL felt that the use of two proxies (as suggested) was likely to miss the significant variations in both electricity market prices and certificate prices over time and was unlikely to be representative of the actual costs of compliance with the LRET scheme. The markets for both electricity and LGCs are likely to be affected by periods of under and over supply, changing prices significantly and thereby affecting retailers’ costs in purchasing their energy. Such changes would not be picked up through a calculation of proxies.

ACIL also noted that the calculation of two LRMCs to help arrive at an LGC estimate would also be more complex than using consistent market data as it would involve making a number of assumptions on which it could prove difficult to reach agreement.

Furthermore, ACIL noted that the approach suggested by AGL and EnergyAustralia only covers a short period, which ACIL believes would lead to distortions in the calculation of the renewable LRMC and black (coal) energy proxies for the following reasons:

(a) the new RET legislation only applies until 2030. A wind farm which commences operation immediately will have to exist for the last five years of its life without any LGC subsidy. The longer the delay in construction of a renewable project, the fewer years of subsidy it will qualify for and the higher its threshold LRMC will be;

(b) black energy prices are unlikely to remain flat in real terms over the next 25 years due to cost increases, regulatory changes and potential introduction of carbon pricing;

(c) LGC prices will not be flat in real terms. Forward REC prices have exhibited a 5-8% premium for future years; and

(d) LRMCs for renewable technologies are unlikely to remain static. Even if wind is the dominant technology throughout, capacity factors are likely to reduce as the best sites are developed first, resulting in increasing LRMC estimates over time.

Given these concerns, ACIL rejected the methodology suggested by AGL and EnergyAustralia for estimating LGCs based on the difference between the LRMC of new-entrant renewable energy generation and black energy prices and recommended an approach that continues the use of market-based data as a basis for the estimation of these costs for the BRCI.

The Authority accepts ACIL's advice on this issue as it also prefers to rely on market data when it is available rather than proxies. The Authority has therefore accepted ACIL's proposal to estimate LRET costs for 2011-12 using expected LRET targets and market prices of LGCs based on data reported by AFMA. The Authority has also accepted ACIL's proposed method for estimating SRES costs based on the fixed price of STCs and the published Small-scale Technology Percentage (STP) for 2011 of 14.8% and the number of STCs expected to be created in 2012.

Both these approaches are consistent with the market-based approach supported by most stakeholders.

In relation to the allowance for the "catch-up" of the RET costs incurred between 1 January 2011 and 30 June 2011, as Origin indicated, the BRCI is an index, not a cost build-up and, as such, it is intended to measure the rate of change in costs between two years rather than provide retailers with a full recovery of the costs that they actually incur.

Moreover, section 91G(1) of the Electricity Act requires the Authority to determine the benchmark retail cost for the current tariff year by estimating the total costs of supplying customers in during that year.

2.5 Cost of energy estimate for 2011-12

LRMC for 2011-12

ACIL has applied the same methodology to calculating the 2011 12 LRMC component of the cost of energy as it did for the 2010-11 BRCI.

In its Draft Report for the 2011-12 BRCI cost of energy estimates, ACIL has estimated the 2011-12 LRMC based on the generation required to meet the total State NEM load for Queensland in the calendar year 2010. The load shape used for modelling the LRMC for 2011-12 was developed by ACIL on the basis of the half-hourly load for the previous calendar year (2010) as required by the legislation. As was the case last year, this load shape includes the loads of customers directly connected to the transmission network.

For this Draft Decision, the actual load data for the 2010 calendar year was only available for the period from 1 January to 30 September 2010. As per previous BRCI Draft Decisions, ACIL has constructed the load for the remainder of the year by including the load data from December quarter 2009 as a substitute. Actual load data for the full 2010 calendar year will become available in time for use in the Final Decision.

Consistent with the method followed in the 2010-11 BRCI Final Decision, ACIL applied AEMO's medium growth 50% Probability of Exceedance (POE) load forecast as reported in the 2010 ESOO to the load used for the LRMC calculation to forecast energy demand over the nine year modelling period.

Using updated generation capital and fuel input costs, ACIL estimated the LRMC for 2011-12 to be $61.51 per MWh. As shown in Table 2.2 below, this is approximately 5% higher than the LRMC estimated by ACIL for 2010-11 as used in the 2010-11 BRCI Final Decision. This increase is primarily due to the revised coal and gas price outlook.

Table 2.2: LRMC estimate for 2011 12 BRCI

Cost Component	*2010-11*[1]	*2011-12*[2]	*Change*
	$/MWh	*$/MWh*	*%*
LRMC	58.59	61.51	4.98

1 See the Authority's 2010-11 BRCI Final Decision.
2 See ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011-12, Draft Report, 2 December 2010.

Energy Purchase Costs for 2011-12

For the 2011-12 BRCI, ACIL has applied the same approach to calculating the energy purchase costs for 2011-12 as it used for the 2010-11 BRCI. The key inputs used by ACIL to estimate the energy purchase cost component are as follows:

(a) half-hourly NEM load trace forecast for Queensland based on the 10%POE, 50%POE and the 90%POE load forecasts for constructing a hedging strategy and settlement;

(b) contract price data published by d-cypha Trade; and

(c) half-hourly NEM pool price data based on 10%POE, 50%POE and the 90%POE load forecasts for settlement.

As was the case last year, ACIL has based its forecast of energy purchase costs on the NEM load (which excludes loads of directly connected customers). Detailed discussion of ACIL's approach to forecasting the energy purchase cost, including its method for forecasting the necessary NEM load trace is contained in its Draft Report. Table 2.3 below summarises ACIL's energy purchase cost estimates for 2011-12 for each of the three probability scenarios which are weighted in accordance with AEMO's energy demand weightings as used in the ESOO modelling (as shown in Table 2.3) to arrive at an overall estimate.

Table 2.3: 2011-12 Scenario weighted energy purchase cost estimates

	Scenario Weighting	*2010-11*[1]	*2011-12*[2]	*Change*
	%	*$/MWh*	*$/MWh*	*%*
Energy purchase cost 10%POE	30.40	57.88	47.88	-17.28
Energy purchase cost 50%POE	39.20	58.44	49.34	-15.57
Energy purchase cost 90%POE	30.40	59.23	50.45	-14.82
Energy purchase cost weighted	**100.00**	**58.51**	**49.23**	**-15.87**

1 See the Authority's 2010-11 BRCI Final Decision.
2 See ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011-12, Draft Report, 2 December 2010.
Note Totals may not add due to rounding.

In comparison with the energy purchase cost estimate for 2010-11, ACIL's 2011-12 estimate of $49.23/MWh is nearly 16% less than the 2010-11 Final Decision estimate.

In its Draft Report for 2011-12, ACIL noted that the key drivers of the fall in the energy purchase cost for 2011-12 were:

(a) the modelled spot prices for 2011-12 being higher on average than that calculated for 2010-11 for in the 2010-11 BRCI Final Decision; and

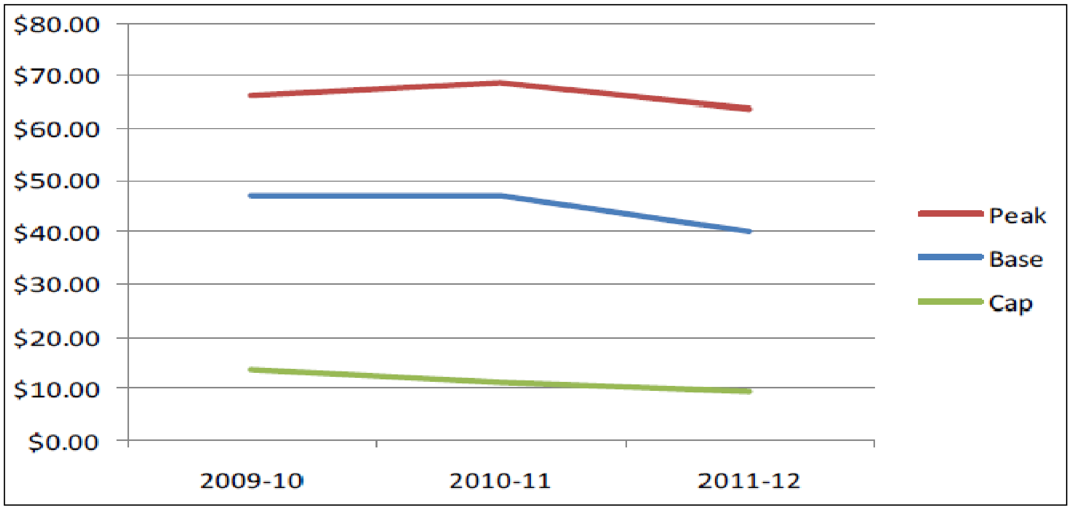
(b) the contract prices projected for 2011-12 being between 7% and 16% lower than corresponding prices used for the 2010-11 BRCI Final Decision.

ACIL noted that a significant factor affecting the higher spot prices in 2011-12 was the available NEM load data, which covers the 12 months ending 30 September 2010 and includes some abnormally warm weather conditions in November 2009 which caused electricity prices to spike to very high levels a number of times throughout the month. As a result, the modelled spot prices for 2011-12 are estimated to be on average about $5/MWh higher than might be the case with a more typical November weather pattern in the data.

For the Final Decision, more recent data will be available (from 1 October 2010 to 31 March 2011) and hence November 2009 data will drop out of the series. While an adjustment could be made to the November 2009 data for the purposes of this Draft Decision, the Authority prefers wherever possible to maintain a transparent approach which is not subject to the exercise of discretion. Furthermore, data yet to be revealed will determine the outcome for the Final Decision and there is no guarantee that this will be any more "normal" than that available now.

In its Draft Report, ACIL also noted that contract prices used in the 2011-12 energy purchase cost calculation have fallen substantially from those used in calculating the energy purchase cost for the 2010-11 BRCI. As shown in Figure 2.1 below, contract prices had been rising but are now falling between 2010-11 and 2011-12.

Figure 2.1: Average annual peak, flat (base) and cap contract prices 2009-10, 2010-11 and 2011-12 - $/MWh



Source ACIL Tasman analysis of d-cypha Trade data.

ACIL noted that forward contract prices have been falling since the high priced period from 2007 to 2009 which was caused by the prolonged drought in eastern Australia.

Prices in the NEM are now falling with the passing of the drought, a change in weather with a *La Niña* event bringing wetter and cooler weather to eastern Australia. The commissioning of new plant has also helped to dampen price spikes. ACIL suggests these factors are now showing through not only in spot prices but also in forward contract prices.

One other factor ACIL attributes the falling contract prices to is the shelving of the Federal Government's Carbon Pollution Reduction Scheme which had been influencing the price of longer term contracts and introducing enough uncertainty to affect the willingness of both sellers and buyers to contract for such terms, thus affecting the liquidity of the contract market.

Weighted Cost of Energy

Table 2.4 shows the effect of combining the cost estimate for the LRMC and the energy purchase cost for the 2011-12 BRCI. While the energy purchase cost estimate falls by 15.9%, this is partially offset by an increase in the LRMC resulting in the overall cost of energy only falling by 5.4%.

Table 2.4: Weighted Cost of energy estimate for 2011-12

Cost Component	***2010-11*** [1]		***2011-12*** [2]		***Change***
	$/MWh		*$/MWh*		*%*
LRMC *(50% weighting)*	58.59	*29.30*	61.51	*30.76*	4.98
Energy purchase cost *(50% weighting)*	58.51	*29.26*	49.23	*24.62*	*-15.87*
Cost of Energy based on 50% weighting		**58.55**		**55.37**	**-5.43**

1 See the Authority's 2010-11 BRCI Final Decision.
2 See ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011-12, Draft Report, 2 December 2010.
Note Totals may not add due to rounding.

Other Energy Costs

Queensland Gas Scheme Costs for 2011-12

The Authority has based the costs to retailers of complying with the Queensland Gas Scheme for 2011-12 on the market prices of GECs sourced from AFMA. Based on current market data and the prescribed percentage liable load of 15%, ACIL has estimated the cost for 2011-12 to be $0.56/MWh.

In order to ensure consistency in the BRCI methodological framework, the scheme cost for 2010-11 has been re-estimated using AFMA data that would have been available at the time of the previous BRCI Final Decision. This resulted in the cost for 2010-11 declining from the $2.84/MWh using the penalty price approach in the 2010-11 BRCI Final Decision to $1.20/MWh using the market data approach.

As a result, for the purpose of calculation the 2011-12 BRCI, the estimated cost of the Queensland Gas Scheme will decline by approximately 53% between 2010-11 and 2011-12.

RET Scheme Costs for 2011-12

The costs to retailers of complying with SRES in 2011-12 has been estimated by ACIL based on the fixed price of STCs at $40/MWh, the published STP for 2011 of 14.8% and the number of STCs expected to be created in 2012. Based on this approach, ACIL estimate the cost of complying with the SRES to be $4.73/MWh in 2011-12.

To estimate the cost of the LRET scheme in 2011 12, ACIL has estimated the targets under the LRET for 2011 and 2012 to account for the split of the scheme from 2011 and has based the cost of LGCs on weekly market prices for RECs as published by AFMA. Based on this approach, ACIL estimate the cost of complying with the LRET scheme to be $2.80/MWh in 2011-12.

As a result, the combined cost of the SRES and LRET schemes is estimated to be $7.53/MWh in 2011-12. This compares with the RET scheme cost which was estimated to be $3.05/MWh in the 2010-11 BRCI Final Decision. On this basis, the new scheme is significantly more expensive (147%) than the old scheme and will have a noticeable impact on the BRCI in 2011-12.

Market Participation Costs for 2011-12

As it did in previous BRCI decisions, the Authority has also taken into account NEM participant fees and ancillary services charges paid by retailers.

For 2011-12, ACIL estimated the cost of AEMO participant fees to be $0.42/MWh based on trends since 2004-05 for which data is publicly available from AEMO's website. On this basis, the Authority expects the total cost of NEM fees to increase by 24.9% from 2010-11.

Based on the average cost over the preceding 52 weeks of currently available ancillary services cost data, ACIL has estimated that the cost of ancillary services will be $0.43/MWh in 2011-12, an increase of around 9.3% from 2010-11.

2.6 The Authority's Position

In total, the Authority estimates that the cost of energy will rise from $2,403.5 million in 2010-11 to $2,431.6 million in 2011-12, an increase of 1.17%. In $/MWh terms, the total cost of energy is expected to increase from $63.53/MWh in 2010-11 to $64.31/MWh in 2011-12, as shown in Table 2.5 below.

Table 2.5: Cost of energy components, 2010-11 to 2011-12 – Draft Decision

Cost Component	*2010-11*[1]		*2011-12*[2]		*Change*
	$/MWh		*$/MWh*		*%*
LRMC (50% weighting)	58.59	*29.30*	61.51	*30.76*	4.98
Energy purchase cost (50% weighting)	58.51	*29.26*	49.23	*24.62*	*-15.87*
Weighted Cost of Energy		58.55		55.37	-5.43
RET Scheme Costs					
Small-scale Renewable Energy Scheme		*0.00*		*4.73*	-
Large-scale Renewable Energy Scheme		*0.00*		*2.80*	-
Total RET Scheme Costs		3.05		7.53	146.85
Queensland Gas Scheme Costs		1.20[3]		0.56	-53.33
Market Participation Costs					
NEM fees		*0.34*		*0.42*	*24.88*
Ancillary services		*0.39*		*0.43*	*9.32*
Total Market Participation Costs		0.73		0.85	16.49
Total BRCI Cost of Energy: $/MWh		**63.53**		**64.31**	**1.22**
$million		**2,403.5**		**2,431.6**	**1.17**

1 See the Authority's 2010-11 BRCI Final Decision.
2 See ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011 12, Draft Report, 2 December 2010.
3 Recalculated with market data as at 31 March 2010.
Note Totals may not add due to rounding.

3. NETWORK COSTS

In accordance with the provisions of the Electricity Act, the network cost component of the BRCI is the Authority's view of the likely total revenue requirements of transmission and distribution network service providers in Queensland.

The Authority has based its assessment of transmission network costs on the Australian Energy Regulator's (AER's) revised decision on Powerlink's 2007-08 to 2011-12 revenue cap and its estimate of the transmission related costs that the distributors pass through to customers. The transmission network costs will be revised for the Final Decision once final pass-through costs for 2011-12 are available from the distributors.

The distribution network costs for 2011-12 are based on the annual revenue requirements as approved by the AER in its 2010-2014 Final Determinations for Energex and Ergon Energy. These figures will also be updated in the Final Decision to reflect any amendments to the distributor's revenue cap that may result from the anticipated decisions of the Australian Competition Tribunal (the Tribunal) in response to applications by both distributors for a review of the AER determinations.

On this basis, the Authority has estimated the network costs for this Draft Decision to be $3,146.8 million in 2011-12, an increase of 9.59% from the previous year.

3.1 Background

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 to and from 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 distribution network services the south east Queensland region, 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 set by the 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 (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 to other distributors for transmission-like network services.

The combined cost of using the transmission and distribution networks typically accounts for around half of the total cost of providing electricity to households. However, the network share of total costs for larger customers can vary significantly depending on the pattern of their electricity use and their location.

3.2 Legislative Requirements

The Electricity Act requires that the network cost component of the BRCI reflect the Authority's view of the likely total revenue requirements for transmission and distribution network businesses in Queensland.

3.3 Estimating Network Costs for 2011-12

Transmission Costs

As in previous years, for the purposes of this Draft Decision, the Authority has based the transmission component of the total network costs in the BRCI on an estimate of the amount of TUOS charges that Powerlink is expected to charge Energex and Ergon Energy for using its services and other transmission-related costs.

The Authority has estimated these charges by calculating the proportion of Powerlink's maximum allowable revenue (MAR) in the previous year (2010-11) that accounted for the total transmission charges levied on distributors. This proportion of Powerlink's MAR was then applied to its 2011-12 MAR, as calculated by the AER in its *Final Decision on Powerlink Queensland transmission network revenue cap for 2007-08 to 2011-12 (June 2007)* and as later revised on 8 July 2008 to account for Powerlink's South Pine to Sandgate contingent project (AER's revised Powerlink Final Decision).

Other transmission costs incurred by the distributors have been estimated by escalating the 2010-11 values by the proportional change in the Powerlink charges between years.

As in previous years, no adjustment has been made to account for previous under- or over-recovery by Energex and Ergon Energy of TUOS revenue recovered from customers to meet the cost of TUOS charges levied on Energex and Ergon Energy by Powerlink.

These estimates will be updated for the Authority's Final Decision following better information becoming available from the distributors' 2011-12 Pricing Proposals to the AER. The Pricing Proposals will contain later, individual estimates of Powerlink's TUOS charges as well as specific estimates of the other transmission-related costs to be incurred by the distributors.

Distribution Costs

As in previous years, the estimate of distribution component of total network costs is based on the AER's approved annual revenue requirement of Energex and Ergon Energy as set out in its *Queensland Final Regulatory Determination – 2010 11 to 2014-15* (6 May 2010).

The AER determinations for both Energex and Ergon Energy are currently being reviewed by the Tribunal. If those reviews are successful, then the AER may be required to recalculate the annual revenue requirements for the distributors for the remaining regulatory period.

The Tribunal's decision was expected on 23 October 2010. However, on 22 September 2010, the Tribunal extended the period for the making of determinations to 7 February 2011.

Based on this timing, no allowance for any decision by the Tribunal is possible in this Draft Decision. However, the result of the reviews by the Tribunal should be known in time for inclusion in the Authority's Final Decision and any necessary adjustment will be made at that time. As far as potential impact on the BRCI is concerned, the outcome of the Tribunal review can only leave the distribution network component unchanged or increase it.

The BRCI methodology also requires that the Authority remove Mt Isa network revenue from Ergon Energy's annual revenue requirement. As the AER's Final Decision did not separately identify revenue associated with the Mt Isa network, the Authority will rely on information from Ergon Energy regarding the appropriate deduction to be made from its approved 2011-12 revenue requirement in order to remove Mt Isa revenue. This information will be available in time for inclusion in the Final Decision once Ergon Energy has finalised its 2011-12 Pricing Proposal to the AER.

For the purpose of this Draft Decision, the Authority has estimated the Mt Isa network revenue to be deducted for 2011-12 by assuming the Mt Isa network revenue will be growing at the same rate as Ergon Energy's total revenue.

3.4 Submissions from Stakeholders

There was general support from stakeholders for continuing to use the same methodology for estimating network costs for the 2011-12 BRCI as has been done in the past.

However, while acknowledging that the Authority is bound to apply the existing BRCI legislative framework with respect to how network costs are to be determined, AGL, Energy Australia and Origin Energy questioned the appropriateness of that approach given the requirement to include both the Energex and Ergon Energy annual revenue requirements to estimate the distribution costs when competition is generally confined to that part of the State covered by the Energex network.

AGL was also concerned that the BRCI methodology makes no allowance for the ability of Energex to re-balance its tariffs each year as its annual revenue requirement increases.

TRUenergy noted the current review of the AER's Final Determinations by the Tribunal and that any decision by the Tribunal that makes a significant adjustment to the Final Determinations needs to be factored into the BRCI.

3.5 The Authority's Position

The Authority has continued to use the same approach to calculating network costs for the 2011-12 BRCI as it used in calculating the 2010-11 BRCI.

As acknowledged in submissions, the Authority has no option but to include the distribution costs for both Energex and Ergon Energy. Accordingly, the network cost for 2011-12 has been calculated by taking into account both Energex and Ergon Energy's network costs.

Transmission costs

The Authority has determined its Draft Decision estimate of the total transmission charges that Powerlink is expected to levy on Energex and Ergon Energy in 2011-12 by applying the percentage share of Powerlink's 2011-11 MAR accounted for by these charges to the 2011-12 MAR determined in AER's revised Powerlink Final Decision.

As shown in Table 3.1 below, the total transmission charges levied on the distributors by Powerlink in 2010-11 was $611.5 million, approximately 83.3% of Powerlink's MAR of $734.2 million for 2010-11.

For this Draft Decision, this same proportion (83.3%) has been applied to Powerlink's MAR of $814.9 million for 2011-12, as determined by the AER in its revised Powerlink Final Decision, to derive an estimate of Powerlink charges to be levied in 2011-12.

Other transmission-related costs, such as avoided TUOS payments to embedded generators and payments to other distribution network service providers for transmission-like network services have also been estimated for 2011-12 by applying the proportion of these costs in 2010-11 to Powerlink's MAR for 2010-11.

On this basis, the Authority has estimated total transmission costs to be charged by Powerlink and recovered from customers by Energex and Ergon Energy for 2011-12 to be $694.3 million.

As noted previously, this estimate will be updated for the Final Decision once better information become available in the distributors' 2010-11 Pricing Proposals to the AER.

Distribution costs

Based on the AER's Final Determination for Energex and Ergon Energy, the Authority has estimated the regulated revenues for Energex and Ergon Energy to be $1,255.6 million and $1,196.9 million (excluding Mt Isa revenue) respectively. These estimates will be revised for the 2011-12 BRCI Final Decision should any adjustments be made by the AER following the Tribunal's decision in February 2011.

3.6 Network Costs

Table 3.1 provides the Authority's view of transmission and distribution network costs for use in the 2011-12 BRCI Draft Decision.

Table 3.1: Summary of Network Costs 2010-11 to 2011-12 – Draft Decision

Network cost	***2010-11*** ***$m***	***2011-12 Draft Decision*** ***$m***	***Change*** ***%***
Transmission			
Maximum Allowable Revenue (MAR)	*734.2*	*814.9*	*11.00*
Powerlink charges	611.5	678.8	11.00
Avoided TUOS payments	5.7	6.4	11.00
Unregulated Powerlink charges	6.0	6.7	11.00
Other Charges	2.2	2.4	11.00
Total transmission costs	**625.5**	**694.3**	**11.00**
Distribution			
Energex	1,135.1	1,255.6	10.6
Ergon Energy	1,110.9[1]	1,196.9[2]	7.75
Total distribution costs	**2,246.0**	**2,452.5**	**9.20**
Total Network Costs	**2,871.4**	**3,146.8**	**9.59**

Note Totals may not add due to rounding.
Source QCA 2010-11 BRCI Final Decision, AER revised Powerlink Final Decision (July 2008). AER Queensland Distribution Determination 2010-11 to 2014-15 Final Decision (May 2010).
1. *Excludes $12.2 million for network revenue associated with Mt Isa.*
2. *Excludes $13.2 million for network revenue associated with Mt Isa.*

4. RETAIL COSTS AND MARGIN

Retail costs relate to the services provided by a retailer to its customers. The retail cost component of the BRCI comprises retail operating costs, customer acquisition and retention costs and a retail margin. The Authority is required to consider costs in relation to a representative retailer, rather than an actual retailer, which has a significant share of the market, is efficient and has a customer base that is representative of all customers in Queensland connected to the NEM.

The Authority considers that, based on the degree of competition in the South East Queensland retail market, it is no longer appropriate to calculate a separate allowance for costs associated with customer acquisition and retention. Rather, the Authority proposes to combine this element with other retail operating costs. As this proposal involves a change to the method previously used to calculate customer acquisition and retention costs, the Authority has recalculated the 2010-11 retail cost component using this same approach to form a new, combined base amount for retail operating costs which has then been escalated to 2011-12 in the same manner that has applied to retail operating costs in previous years. In this way, the value of customer acquisition and retention costs calculated for 2010-11 has been preserved but in future this cost element will grow at the same rate as all other retail operating costs.

In accordance with the QCA Act, the Authority recently imposed fees on retailers to meet the Authority's cost of performing regulatory functions in respect of the retail electricity industry. The cost of these fees (for 2010-11) has been recognised in the 2011-12 retail operating cost estimate.

The Authority has maintained the net retail margin at 5% for the 2011-12 BRCI, on the basis that this should provide a reasonable return to a retailer for the risks that it faces and there is no evidence that the margin has changed from that allowed in 2010-11.

In total, retail costs are expected to increase by 5.97% from $545.4 million in 2010-11 to $578.0 million in 2011-12.

4.1 Background

The retail cost component of the BRCI relates to the services provided by an electricity retailer to its customers, excluding those costs over which they have limited or no control (energy costs and network costs). There are two broad categories of retail costs that are incurred by a retailer –customer acquisition and retention costs and other retail operating costs.

Customer acquisition and retention costs include marketing, advertising, sales overheads, door-to-door/commission/agent costs and telesales.

Other retail operating costs include customer administration (including call centres), billing and revenue collection, IT systems and regulatory compliance and may also include costs associated with metering and data services that are not already included in distribution charges.

The retail margin is the amount that a retailer earns from its activities, minus its costs. The gross retail margin can be defined as the retailer's revenue minus the cost of energy and network costs. Hence, the gross margin includes the retailer's costs. The (smaller) net retail margin is what remains after the retailer's operating costs are subtracted from the (larger) gross margin. References in the Queensland legislation to the retail margin refer to the net retail margin.

4.2 Legislative Requirements

The Electricity Act requires that retail costs must reflect the Authority's view of the likely cost of providing retail services to Queensland customers connected to the national grid. This view must be based on the cost of providing retail services for an efficient electricity retailer that:

(a) is operating separately from any other business (that is, the business is a stand-alone Queensland retailer);

(b) has a significant share of the retail electricity market in Queensland;

(c) provides retail services to a cross-section of customers throughout Queensland in the same proportions as the customer mix for Queensland as a whole; and

(d) earns a reasonable retail margin.

In addition, the Electricity Regulation requires that the Authority must consider the following cost categories in determining retail costs:

(a) billing;

(b) customer call centres;

(c) credit management;

(d) energy trading activities;

(e) corporate overheads, including, for example, treasury functions, human relations and facilities management;

(f) information technology systems; and

(g) any other cost category the Authority considers reasonable.

As in the past, the Current Delegation from the Minister requires that the Authority consider the policy objectives of the Queensland Government relating to the maintenance of retail headroom and preventing retailers incurring a loss where a customer reverts to a notified price.

4.3 Submissions from Stakeholders

Overall level of retail cost allowance

In its submission, the Queensland Government argued that there has been a growing disparity in recent years between retail cost allowance per customer in Queensland and that recognised by IPART. The Government noted that a retail cost benchmarking study undertaken by IPART suggested that the Authority's retail cost allowance was at the higher end of the range of retail costs reviewed elsewhere[2].

Authority comment

The apparent disparity referred to by the Government is due to the values reported by IPART being in real terms (except for the final year), rather than in nominal terms as indicated in the submission. Allowing for this difference, the data reported by IPART indicate that the

[2] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2012, Final Report*, March 2010.

estimates of retail allowance per customer accepted by the Authority have been lower than those of IPART in all but the latest year (2010-11).

As IPART indicated in its Final Report, the difference between the IPART and Authority retail cost allowances in 2010-11 reflected the significantly higher switching rates in Queensland which were used to calculate customer acquisition costs (reflecting higher level of market activity in Queensland). In addition, IPART noted that the Authority did not increase its retail operating cost allowance in real terms, nor did it increase unit acquisition costs in real terms and that the Authority's unit cost estimate for customers switching retailers is lower than the unit cost underpinning the IPART allowance.

The Authority also notes that, in its Final Report for 2010-13, IPART estimated that retail costs in 2009-10 ranged between $95 and $125 per customer ($2009-10). The Authority's 2010-11 retail cost estimate was within this range.

Escalation of Retail Operating Costs

Submissions provided general support for the continued use of the benchmarking approach to calculating retail operating costs adopted by the Authority. This approach involves escalating the benchmarked retail operating cost of $75 per customer estimated in 2006-07 to account for inflation and labour cost growth over the intervening period.

Integral Energy noted that the escalation process will have to recognise the regulatory fees to be charged by the Authority and that these will need to be incorporated into operating costs for 2011-12.

Authority comment

As noted by Integral, the additional costs associated with the Authority's decision to impose a regulatory fees on retailers for the Authority's costs of performing regulatory functions in respect of the retail electricity industry (as it does with other regulated industries) have been taken into account in estimating the retail operating costs in the 2011-12 BRCI. This is discussed further below.

Customer Acquisition and Retention Costs

Customer acquisition and retention costs (CARC) attracted significant comment in submissions. Retailers were largely in favour of continuing the existing methodology used to forecast the number of customers switching between retailers and transferring to market contracts[3]. However, TRUenergy also suggested that the approach be refined to reflect costs for a second tier retailer as, it was argued, they incur higher retail acquisition and retention costs than first tier retailers.

A number of (non-retailer) submissions expressed concern over both the methodology employed in arriving at an estimate of CARC and the data used. In particular, the Queensland Government suggested that:

(a) the current approach to estimating costs was generating perverse market outcomes since increased customer switches and transfers will contribute to price increases for customers. The Government suggested that customers should instead be seeing benefits from a more competitive retail electricity market, including lower prices; and

[3] *Switches* refer to customers moving from one retailer to another. *Transfers* refer to customers moving from a non-market contract to a market contract while staying with the same retailer.

(b) given the relatively mature state of the retail electricity market in Queensland and that an established retailer would likely allocate a consistent proportion of operating expenses to normal marketing activity, the Government argued that calculation of the retail cost should deliver relatively stable outcomes from year to year.

The Queensland Government, QCOSS and Queensland Consumers Association each expressed concerns about the accuracy and relevance of the AEMO statistics used by the Authority to forecast numbers of customers switching retailers. QCOSS suggested that increases in customer switching and transfer rates are also likely to include switches and transfers occurring as a result of inappropriate marketing tactics.

Queensland Consumers Association questioned the size of the estimated cost per customer for switches and transfers and argued that the use of the BRCI index-based approach to inflate costs does not provide an incentive for cost reductions arising from efficiency gains or changes in the mix of marketing methods used.

Authority comment

To date, the Authority has estimated CARC by escalating benchmark costs established in 2007-08 for a customer switching retailer and a customer transferring to a market contract with the same retailer to arrive at per customer cost estimates for the relevant tariff year. These cost estimates were then multiplied by forecasts of the number of customers switching and transferring in the market (market churn) to arrive at an overall CARC estimate for the year.

The Authority has calculated CARC as a separate (retail) cost item since the first BRCI Decision following the commencement of full retail competition (FRC) in 2007. In that context, with only two substantial incumbent retailers in the market, it was appropriate to recognise the customer acquisition costs likely to be incurred by a new market entrant trying to gain market share and the incumbents trying to defend their market share. Linking these costs to the rate of churn was a means of recognising the scale of these costs and encouraging the development of competition in the market.

While this was an appropriate approach at the commencement and during the early years of FRC, the Authority acknowledges that, as suggested in a number of (non-retailer) submissions, much has changed in the ensuing years with the rapid expansion of the level of competition from the initial staring position of two incumbent retailers covering the entire Queensland market. By way of comparison:

(a) as at November 2010, there were 12 retailers with small market customers operating in the state. Victoria, which has been fully deregulated since 1 January 2009, has a similar number of retailers (14);

(b) as at November 2010, 55 different types of retail market offers were available to Queensland customers;

(c) a substantial number of small customers in Queensland have moved to market contracts (41.7% as at September 2010). More importantly, the proportion of small customers on market contracts in the South East Queensland market now stands at 63.2%, comparable with that of the Victorian (60%)[4] and South Australian (66%)[5] markets at the time they were deemed to be competitive by the Australian Energy Market Commission.

[4] AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria, First Final Report*, 19 December 2007, p. ix.

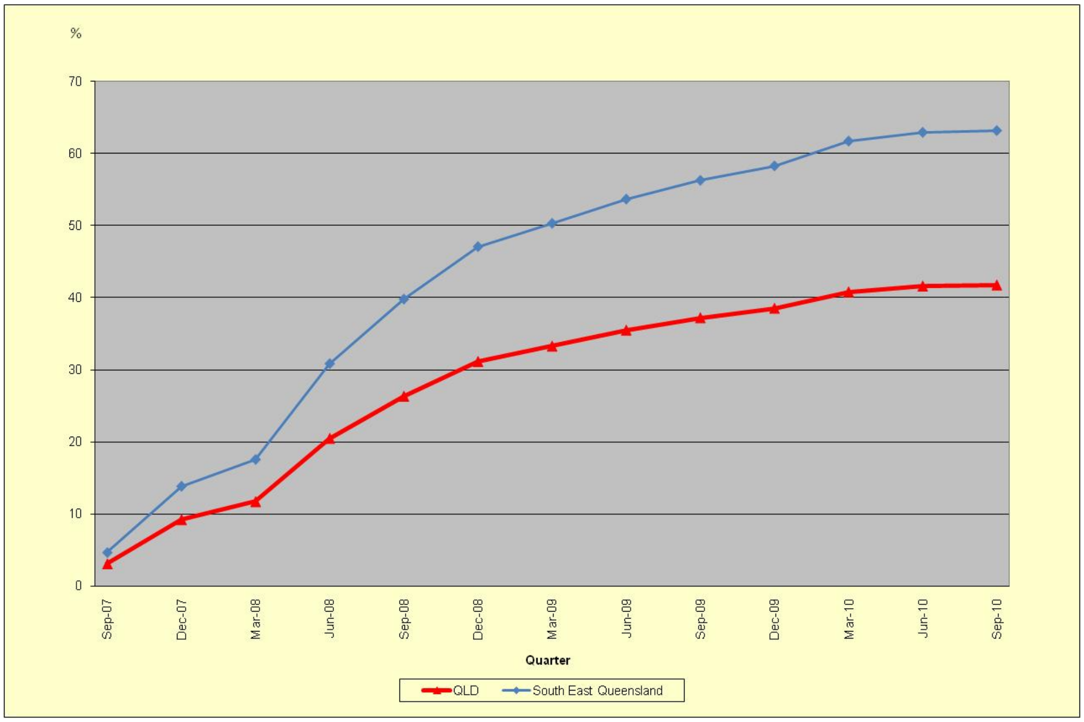
[5] AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report*, 19 September 2008, p. xi-xii.

In comparison, 34% of NSW small customers were on market contracts as at December 2009[6] and 19% of small customers in the ACT were on market contracts as at June 2009[7]; and

(d) the rate of customer switching, another indicator of market activity, is also high. For the 2009 calendar year, this was estimated to be 14.5% as a proportion of total Queensland customers and, as a proportion of South East Queensland customers, the switching rate was estimated to be 21.5%, exceeding that of NSW (13%) and South Australia (17%) and not far off the level of Victoria (26%)[8].

The growth of market contracts in both Queensland and South East Queensland are shown in Figure 4.1.

Figure 4.1: Proportion of small customers on market contracts



Small customers choosing to move to market contracts are reacting to a range of incentives. Based on data provided for the Authority's price comparator, more market contracts offer options costing more than the notified price than those costing less than the notified price. This suggests that retailers believe customers are interested in aspects of their electricity supply other than price alone.

Given the current state of competition in the market, it is questionable whether it remains appropriate to continue to calculate a specific allowance for CARC based on specific customer churn rates. This is not to suggest that such an allowance should be overlooked but rather that it would appear more appropriate to treat this (marketing) the same as any other retail operating cost.

[6] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 50
[7] ICRC, *Retail Prices for Non-contestable Electricity Customers, 2010-2012, Draft Decision*, April 2010, p. 3.
[8] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 50

Accordingly, the Authority is proposing an alternative approach to addressing CARC that, whilst acknowledging the ongoing requirement for expenditure related to customer acquisition and retention, recognises the current state of the Queensland retail market. This approach is discussed in detail below.

Retail Margin

Submissions from retailers reiterated their view expressed in response to previous BRCI Decisions that the proposed 5% margin failed to fully recognise the risks associated with a retail entity in operating in Queensland. AGL suggested that the Authority should consider the approach taken by IPART in its 2010-13 Final Report which used the mid-point of three methodologies to arrive at a benchmark figure of 5.4%.

Conversely, the Queensland Consumers Association and QCOSS argued that maintaining a retail margin of 5% resulted in retailers receiving a windfall gain when large increases occurred in other BRCI components. They considered that this overestimated the margin required by retailers and recommended that the Authority review whether the 5% margin is still appropriate.

Authority comment

In previous BRCI Decisions, the Authority has considered a retail margin of 5% of the total BRCI costs should provide a reasonable return to a retailer for the risk it faces. The retail margin has remained unchanged, as a fixed percentage of the total BRCI, since the first the commencement of full retail competition (FRC) in 2007-08. The 5% figure was originally determined by benchmarking against the margins accepted by regulators in other jurisdictions at that time. These ranged from 2% to 8%.

In its 2010-13 Final Report[9], IPART's consultant Strategic Finance Group suggested a range of 4.8% to 6.0% was reasonable for the retail margin. The 5% figure previously used by the Authority falls within that range.

While consumer groups suggested the figure use by the Authority was overly generous, they did not provide any data to substantiate that view.

As in the past, in the absence of compelling arguments to do otherwise, the Authority has maintained the retail margin at 5% of the total BRCI.

4.4 Estimating retail costs to be used in the 2011-12 BRCI

Retail operating costs

The Authority proposes to continue to use the escalation approach it has used in previous years to forecast the change in retail operating costs for 2011-12. However, given the current state of competition in the Queensland retail market, the Authority proposes to incorporate costs associated with customer acquisition and retention within retail operating costs, rather than a separately calculated cost item. In addition, fees recently imposed on retailers by the Authority to meet its costs of performing regulatory functions, will also be incorporated into retail operating costs. As a result, a new retail operating cost base will be established in this BRCI decision, rather than simply escalating forward the original 2007-08 benchmark costs, which will then be used as the base to be escalated forward to 2011-12.

[9] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report,* March 2010, p. 135.

Treatment of customer acquisition and retention costs

As noted above, several submissions questioned the role of CARC in a mature market, suggesting that it should be relatively stable from year to year and should not unnecessarily contribute to price increases for customers. Indeed, given the claimed link between competition and downward pressure on prices, rising customer churn should be delivering lower prices than would otherwise prevail, not the reverse.

In its 2010-11 BRCI decision, the Authority flagged its concern regarding the continuation of the current approach to calculating CARC given the level of competition evident in the market.

While the Authority acknowledges that the cost of customer acquisition and retention remains a legitimate business cost for retailers – all retailers will undertake some level of marketing expenditure – it considers that it is no longer appropriate to assess these costs as an item separate to other retail costs. Instead, these cost should be treated the same as all other operating costs.

To facilitate this approach, the Authority needs to estimate an appropriate CARC allowance per customer to incorporate with other retail operating costs. However, estimating such an allowance is problematic. Potentially, an estimate could be obtained by either benchmarking (to other jurisdictions or industries) or alternatively by reference to the actual ongoing customer acquisition and retention costs incurred by a representative retailer. But:

(a) benchmarking to other jurisdictions has a number of problems. In particular, there are a number of variations in the way regulators calculate and allow for CARC. Thus, direct comparisons are often misleading. For those jurisdictions in which an allowance is provided, this allowance is generally not separately identified making it difficult to achieve a sensible benchmark. Similarly, estimates of marketing costs in other industries such as telecommunications are difficult to obtain and are not necessarily directly comparable; and

(b) identifying the actual CARC for a representative retailer operating in the Queensland market is also difficult. In effect, this would require the Authority to perform a "cost build-up" in order to examine the efficient operating costs of a representative retailer. This is a detailed exercise requiring not only the determination of a "representative" retailer but also the identification of appropriate operating cost components and their efficient levels to ensure that costs are efficient and that there is no double-counting.

As an interim measure, the Authority could potentially use the CARC of larger retailers operating in Queensland (Origin Energy and AGL) as a proxy for a representative retailer. However, the retailers' data is not publicly available and, to the extent that the information could be obtained, determining whether the costs are efficient would be difficult.

Given these difficulties, a pragmatic approach would be to adopt the same CARC allowance per customer (in real terms) as calculated for the 2010-11 BRCI.

This approach provides a balance between recognising the cost to retailers of conducting their marketing activities while passing on some benefits of competition to customers by delinking the growth in these costs from the rate of change in customer churn.

New retail operating cost base

In the 2010-11 BRCI decision, the Authority included retail operating costs of \$85.89 per customer and CARC of \$40.52 per customer. Combined these would have given a cost per customer of \$126.41.

While not directly comparable due to the considerably lower rates of customer switching in both New South Wales and South Australia, IPART had a combined operating cost of $112 per customer[10] and South Australia $115 per customer[11]. In addition, IPART estimated the top end of the range of retail costs at $128 per customer[12].

Consistent with its previous approach to forecasting retail operating costs, the Authority proposes to estimate retail operating costs for 2011-12 by escalating this “new” 2010-11 retail operating cost base to reflect price inflation and wages growth.

Escalation factors

In previous BRCI decisions, the Authority has used a 60/40 weighted average of the Wage Price Index (WPI) and Consumer Price Index (CPI) to account for the impact of price inflation and wages growth on benchmarked retail operating costs and the per customer cost of customer acquisition and retention. Previously, this approach has involved escalating the benchmarked retail operating cost per customer estimated in 2006-07 to account for inflation over the intervening period.

Setting aside the costs themselves, submissions generally supported this escalation approach.

The Authority therefore proposes to escalate the newly established 2010-11 retail operating cost base by the weighted average of WPI (60%) and CPI (40%) to derive an estimate of retail operating costs per customer for 2011-12.

For the purposes of this Draft Decision, the Authority has drawn its estimates for the 12 months to 30 June 2012 for WPI (of 4.1%) from the ANZ *Australian Economics Toolbox* of 5 November 2010 (previously known as the ANZ Markets Weekly Report) and for CPI (2.75%) from the Reserve Bank of Australia (RBA) *Statement on Monetary Policy* of November 2010. These estimates will be updated in the Authority’s Final Decision as necessary once more recent data becomes available.

Applying the 60/40 weighting to WPI and CPI produces a cost escalation factor for the 12 months to 30 June 2012 of 3.56%.

Additional regulatory costs

Integral Energy made reference to the “additional regulatory costs” that are to be recovered by the Authority from retailers. As acknowledged above, this cost needs to be taken into account as part of the 2011-12 BRCI.

The aggregate of the fees to be paid to the Authority by electricity retailers in Queensland was 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. On this basis, the annual fee to be paid by retailers in 2010-11 was $2,795,000 and is estimated at $2,957,000 for 2011-12.

In its correspondence with retailers on this matter, the Authority acknowledged that the fee would add a small amount to retail costs and that this would be reflected in the 2011-12 BRCI

[10] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 111. Converted to $2010-11 using IPART inflation estimate of 2.4%.
[11] ESCOSA, 2010 *Review of Retail Electricity Standing Contract Price Path – Draft Inquiry Report* AND *Draft Price Determination*, September 2010, p. A-89. ($March 2011). Note: ESCOSA indicated that the estimate is heavily reliant on the IPART benchmark (p. A-96).
[12] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 125. Converted to $2010-11 using IPART inflation estimate of 2.4%.

retail cost component. Therefore, despite the fee being payable in both 2010-11 and 2011-12, the Authority has not adjusted the 2010-11 base for this year's BRCI calculation as the fee was not incorporated in the 2010-11 BRCI calculation.

Total retail operating costs per customer

Combining the three per customer costs discussed above ("old" operating cost, CARC and regulatory fees) produces an estimated 2011-12 retail operating cost of $132.35 per customer, an increase of 4.71% on the 2010-11 figure of $126.41 per customer reported in the Authority's 2010-11 Final Decision.

Customer numbers

The Authority requires an estimate of customer numbers to determine total retail operating costs for input into the BRCI calculation for 2011-12.

Consistent with the approach used in previous BRCI decisions, for this Draft Decision the Authority has escalated customer numbers for 2010-11 of 2,012,602 based on an annualised growth rate of customer numbers reported in the previous three years (2008-09 to 2010-11) of 1.43%, to arrive at an estimate of customer numbers in 2011-12 of 2,041,401.

The Authority expects to be able to update these customer numbers using the estimated customer numbers from Energex and Ergon Energy contained in the distributors 2011-12 annual pricing proposals to the AER. The Authority expects to receive these estimates from the distributors in March 2011.

Based on the total retail operating cost per customer above and the estimated number of customers in 2011-12, the Authority estimates total retail operating costs for 2011-12 to be $270.2 million, compared with $254.4 million provided in 2010-11, an increase of 6.2%.

Retail Margin

As indicated earlier, the Authority has maintained the retail margin at 5% of the total BRCI. As a result, the dollar value of the retail margin has increased from $291.0 million in 2010-11[13] to $307.8 million in 2011-12, an increase of 5.77%.

Other Issues

In arriving at its estimate of the increase in the BRCI for 2011-12, the Authority has not taken explicit account of the requirement in the Current Delegation to maintain the 'headroom' of incumbent retailers. As the Authority has noted in previous years BRCI Decisions, it does not have access to reliable information on the actual retail margin of either Origin Energy or AGL nor is it able to discern the headroom that may have existed in the retail prices at the time retail competition was introduced. However, as the Authority has accounted for all other sources of cost increase in the terms required in the legislation, it is of the view that it has met the obligation that the existing headroom (whatever it might be) should be broadly maintained.

Furthermore, as noted earlier, there has been an increase in the number of retailers in the market and also a high degree of market activity, both of which suggest that headroom has not been eroded. If anything, it implies that headroom may have increased from its pre-FRC level.

[13] The retail margin is slightly lower than that reported in the Authority's 2010-11 BRCI Final Decision due to the change in methodology for estimating the cost of the Queensland Gas Scheme for 2011-12 and the associated re-estimation of these costs for 2010-11 as required under section 107 of the Electricity Regulation 2006. This issue is discussed further in Chapter 2.

Finally, the Current Delegation requires the Authority ensure that the policy of enabling small customers to revert to notified prices should not result in a retailer having to provide services at a loss. This issue was not raised as a concern in submissions received nor is the Authority aware of any reasons why this would be the case as a result of implementing this Draft Decision. As notified prices have been increased in line with rising costs and market contracts generally match or offer some discount to the notified prices, it is unlikely that any of the limited number of customers who may have reverted to notified prices from a market contract (or who might choose to do so in the future) would, as a result, impose a financial loss on their retailer.

4.5 The Authority's position

A summary of the Authority's assessment for this Draft Decision of the costs of providing retail services in is provided in Table 4.1.

Table 4.1: Changes in Retail Cost Components ($m) 2010-11 to 2011-12 - Draft Decision

Retail Cost Component	***2010-11[1]***	***2011-12***	***Change***
	$m	*$m*	*%*
Retail costs	254.4	270.2	6.20
Retail margin (5%)	291.0[2]	307.8	5.77
Total Retail Costs	**545.4**	**578.0**	**5.97**

1. See the Authority's 2010-11 BRCI Final Decision.
2. Reduced slightly from the Authority's 2010-11 BRCI Final Decision due to the revised treatment of Queensland Gas Scheme costs - see chapter 2 for details.
Note Totals may not add due to rounding

In total, retail costs are estimated to increase by 5.97% from $545.4 million in 2010-11 to $578.0 million in 2011-12.

5. NEM LOAD

The Electricity Act requires that the BRCI be determined by dividing the total benchmark retail cost for the relevant tariff year (2011-12) by the NEM load for the previous calendar year (2010) in order to determine the unit cost of supplying electricity, expressed in c/kWh.

Given the timing of this Draft Decision, part of the NEM load for 2010 must be forecast. Load data for the full 2010 calendar year will be available in time to be included in the Final Decision to be released in May 2011.

For this Draft Decision, the Authority has estimated the 2010 NEM load to be 37,812 GWh, a marginal decrease of 0.05% from that used in calculating the 2010-11 BRCI.

5.1 Background

In the preceding chapters, the cost components of the BRCI have been considered. In order to determine the unit cost of electricity, the relevant quantity of electricity (the load) over which these costs are to be spread must be determined.

5.2 Legislative Requirements

The Electricity Act requires that the BRCI for the relevant tariff year be determined by dividing the total benchmark retail cost for the relevant tariff year by the NEM load for the previous calendar year in order to determine the unit cost of supplying electricity, expressed in c/kWh.

The Electricity Act defines the NEM load as the total of the loads for the State supplied at each transmission connection point to a supply network. The NEM load therefore excludes any customer loads supplied directly from the transmission network (directly connected customers), the loads of customers connected to isolated distribution systems not participating in the NEM (such as the Mt Isa network) and the loads of small non-registered generators embedded in the distribution networks of Energex and Ergon Energy that do not participate in the NEM.

5.3 Estimating the NEM load for 2010

As required by the legislation, for the 2011-12 tariff year, the relevant NEM load is that for the 2010 calendar year.

The Authority has obtained half-hourly load data for each Transmission Network Identifier (TNI) from AEMO. This data includes the loads of customers directly connected to the transmission network, loads supplied by registered embedded generators and loads supplied to some New South Wales (NSW) customers, consisting of loads passing through a single connection point dedicated to servicing Country Energy's network in NSW and also a portion of one other TNI load flowing into the NSW grid.

At the time of making this Draft Decision, only load data for the first three quarters of 2010 (1 January – 30 September 2010) was available from AEMO. Load data for the December quarter of 2010 has been forecast by ACIL based on the underlying trend of the total load for the December quarters over the last 10 years (1999-2009).

To arrive at the NEM load for 2010, the Authority has made the following adjustments to the data supplied by AEMO.

Loads of directly connected customers

With the assistance of Powerlink, the Authority has identified the loads of those customers directly connected to the transmission network and excluded their load from the AEMO data.

Loads of registered embedded generators

Data supplied by AEMO also included loads supplied by registered embedded generators participating in the NEM but excluded loads supplied by unregistered embedded generators[14]. As in previous years, only the loads met by registered generators embedded within the networks of Energex and Ergon Energy that are connected to the NEM have been included, while loads of unregistered embedded generators have been excluded from the calculation of the NEM load.

Embedded generators supply electricity that would otherwise be supplied through transmission connection points to the distribution systems of Energex and Ergon Energy. Embedded generators also have an impact on network costs which are accounted for in the distributors' revenue requirements. Including embedded generator loads in the calculation of the NEM load is consistent with the calculation of the network cost component of the BRCI. While the Authority was able to source annual load data for unregistered embedded generators from Energex and Ergon Energy, it was not able to source a matching load profile. Therefore, to ensure consistency in the process of calculating the 2011-12 BRCI, the Authority has not made any adjustment to include the loads of unregistered embedded generators when calculating the 2010 NEM load. This is the same approach that was used in calculating the 2009 NEM load for the BRCI for 2010-11.

Other exclusions

Energy passing through one TNI wholly dedicated to servicing Country Energy's network in NSW and a portion of one other TNI load which passes through a Queensland TNI but then flows into the NSW grid, were also excluded from the AEMO data on the basis that these loads were not supplied to Queensland customers. This is also consistent with the approach taken with the calculation of the 2009 NEM load.

5.4 Submissions from stakeholders

In response to the Interim Consultation Notice, no issues were raised by stakeholders concerning the calculation of the NEM load.

5.5 The Authority's position

The load data provided by AEMO for 2010 included one new (not directly connected) TNI that was not present in 2009.

Based on the load data obtained from AEMO, ACIL has forecast the 2010 total State NEM load to increase by 0.92%, consistent with actual growth observed over the last four years of around 1% per annum. However, the directly connected load (including load connected to the NSW network) for 2010 is forecast to increase by 4.41%.

The increase in the directly connected load is consistent with demand projections noted in Powerlink's 2010 APR associated with expansion in the mining industry and the flow on effect of this on demand from QR National, much of which would be supplied from direct connections to the transmission network.

On this basis, the Authority estimates that the NEM load for 2010, to be used as the denominator in calculating the 2011-12 BRCI, is 37,812 GWh, a marginal decrease of 0.05%

[14] The National Electricity Law requires all generators to be registered with AEMO unless an exemption has been granted by AEMO. AEMO has issued a standing exemption from registration for generators with a nameplate rating of less than 5MW. Generators with nameplate ratings between 5MW and 30MW can apply to AEMO for exemption from registering and satisfy certain criteria.

from the 2009 NEM load used in calculating the BRCI for 2010-11. Table 5.1 provides the components of this estimate.

Table 5.1: 2009 and 2010 NEM load

	2009[1]	***2010[2]***	***Change***
	GWh	*GWh*	*%*
Total State NEM load	48,451	48,899	0.92
Less loads of directly connected customers and loads connected to the NSW network	10,619	11,087	4.41
NEM Load	**37,832**	**37,812**	**-0.05**

Sources, AEMO and Powerlink.
1. *See the Authority's 2010-11 BRCI Final Decision.*
2. *The load for December quarter 2010 has been forecast.*

6. DRAFT DECISION – 2011-12 BRCI

The Authority estimates the BRCI to be 16.28 cents per kWh in 2011 12 compared to the 15.38 cents per kWh re estimated for 2010-11 due to minor changes in methodology. This represents an expected increase of 5.83% in the BRCI between 2010-11 and 2011-12.

The cost of energy is expected to increase by 1.17% in 2011-12 while total network costs are estimated to rise by 9.59% over the year. Retail costs are expected to be 5.97% higher in 2011-12.

The 2010 NEM load for this Draft Decision is estimated to be 37,812 GWh, a marginal decrease of 0.05% from that used in calculating the 2010-11 BRCI. This estimate, and several inputs to other cost components, will be updated using more recent data in the Final Decision.

6.1 Calculation of the BRCI for 2010-11 and 2011-12

In the preceding chapters, the Authority has set out its estimates of the individual components of the BRCI. A summary is provided in Table 6.1.

Table 6.1: Components of the BRCI in 2010-11 and 2011-12 - Draft Decision

	2010-11	*2011-12*	*Change (%)*
Cost of energy ($m)	2,403.5	2,431.6	1.17
Network costs ($m)	2,871.4	3,146.8	9.59
Retail costs ($m)	545.4	578.0	5.97
NEM load of Queensland (GWh)	37,832	37,812	-0.05

Note Totals may not add due to rounding.

Based on the figures contained in Table 6.1, the Authority has calculated that the BRCI will increase by an expected 5.83% in 2011-12, as shown in Table 6.2.

Table 6.2: Change in the BRCI and its components from 2010-11 to 2011-12 – Draft Decision

BRCI cost component	*2010-11*	*2011-12*	*Change*	*Share of total costs 2010-11*	*Change in BRCI*
	c/kWh	*c/kWh*	*%*	*%*	*%*
Cost of energy	**6.35**	**6.43**	**1.22**	**41.30**	**0.51**
LRMC of energy	2.93	3.08	4.98	19.04	0.95
Energy purchase costs	2.93	2.46	-15.87	19.02	-3.02
Other energy costs	0.50	0.89	79.51	3.24	2.57
Network costs	**7.59**	**8.32**	**9.65**	**49.33**	**4.76**
Distribution	5.94	6.49	9.26	38.59	3.57
Transmission	1.65	1.84	10.94	10.75	1.18
Retail costs	**1.44**	**1.53**	**6.03**	**9.37**	**0.57**
Operating costs	0.67	0.71	6.26	4.37	0.27
Margin	0.77	0.81	5.83	5.00	0.29
Total	**15.38**	**16.28**	**5.83**	**100.00**	**5.83**

Note Totals may not add due to rounding.

APPENDIX 1: CURRENT BRCI DELEGATION (SEPTEMBER 2010)

CERTIFICATE OF DELEGATION

Under section 90(3) of the *Electricity Act 1994* (Qld)

Delegation

In accordance with section 90(3) of the *Electricity Act 1994* (the Act), I delegate to the Queensland Competition Authority (QCA) the following functions and powers (the delegated activities) for 2011-2012:

1. Calculation of the Benchmark Retail Cost Index (BRCI) under Chapter 4, Part 2, Division 3 of the Act;
2. Application of the change in the BRCI to the tariffs for the previous tariff year as required by section 90(5) of the Act; and
3. Publication of the amended tariff schedule for the relevant tariff year in accordance with sections 90(2), 90(7) and 96 of the Act.

This delegation does not include the power to fix principles under section 95 of the Act.

Conditions of delegation

1. The QCA must apply the change in the BRCI to the tariffs for the previous tariff year, taking into account any other changes to notified prices made by the Minister under the provisions of section 90 of the Act which are not the subject of this delegation, which will be advised prior to the required date for publication of the tariffs in accordance with the Act and this delegation;

2. The QCA must consider the following policy objective of the Queensland Government when exercising the delegated powers and functions:

   a. the annual indexation of electricity tariffs by the index should ensure that existing retail headroom in the tariffs at the date of the Original Delegation made prior to the commencement of full retail competition[1] remains relatively stable (although not necessarily the same from year to year); and
   b. the policy of enabling small market customers to revert to notified prices should not result in a retail entity providing customer retail services to non-market customers at a loss;

3. The QCA must complete the delegated activities for the 2011-2012 tariff year no later than 31 May 2011;

4. On the same day that the QCA gazettes the tariff schedule for a tariff year, the QCA must make a public announcement of the change to the notified prices; and

5. Any other conditions formally notified by the Minister from time to time.

[1] The Original Delegation was made under section 90(3) of the *Electricity Act 1994* on 27 March 2007.

This delegation applies to the calculation of the BRCI for 2011-12 only.

[redacted]

STEPHEN ROBERTSON MP
Minister for Natural Resources, Mines and Energy
and Minister for Trade

Dated: 21 September 2010

APPENDIX 2: LIST OF SUBMISSIONS

Table A1: Submissions in response to Interim Consultation Notice

	Organisation/Individual
1.	AGL
2.	Energy Australia
3.	Integral Energy
4.	Origin Energy
5.	Queensland Consumers' Association
6.	Queensland Council of Social Service
7.	Queensland Government
8.	TRUenergy