QUEENSLAND COMPETITION AUTHORITY

Final Decision

Benchmark Retail Cost Index for Electricity: 2010-11

May 2010

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PREAMBLE

Since the introduction of full retail competition (FRC), small electricity consumers have been able to purchase electricity from a retailer of their choice or remain on a notified (regulated) tariff. A small consumer is one who consumes less than 100 Megawatt hours (MWh) per annum. This equates to an annual electricity bill of around $17,000 per annum. A small electricity consumer can also choose to return to a regulated tariff with their chosen retailer, subject to the terms and conditions of their market contract.

Prior to the introduction of FRC, regulated tariffs were set by the Government. To ensure that regulated tariffs 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 these costs annually and to apply that increase to the existing regulated tariffs.

In making this 2010-11 Benchmark Retail Cost Index (BRCI) Final Decision, the Authority has applied the same framework established in its 2009-10 Final Decision, which also reflected the outcome of the judicial review of the Authority's 2008-09 BRCI Decision.

In this Final Decision, the Authority estimates the increase in costs to be 13.29% between 2009-10 and 2010-11, compared with an increase of 13.83% estimated in the Draft Decision. This increase is made up of:

(a) an increase in transmission and distribution costs of 17.4%, reflecting the ongoing significant investment in the distribution networks approved by the Australian Energy Regulator (AER). As these network costs account for around 47% of total costs, they contribute 8.21 percentage points to the change in the BRCI (61% of the total increase);

(b) an increase in energy costs of 8.7%, reflecting the impact of rising coal and gas costs on generation costs and higher energy market prices. As energy costs account for around 44% of total costs, they contribute 3.81 percentage points to the change in the BRCI (29% of the total increase); and

(c) an increase in retail costs of 13.7%, reflecting a significant increase in estimates of customer acquisition and retention costs. As retail costs account for around 9% of total costs, they contribute 1.27 percentage points to the change in the BRCI (10% of the total increase).

As a consequence, all existing notified electricity prices will be increased by 13.29% with effect from 1 July 2010.

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1. INTRODUCTION

Under the Electricity Act 1994 (the Electricity Act), the rate of change in the Benchmark Retail Cost Index (BRCI) is to be calculated annually and used to adjust existing notified electricity prices each year.

The Minister for Natural Resources, Mines and Energy and Minister for Trade (the Minister) delegated the responsibility for calculating the 2010-11 BRCI to the Authority. The Minister's delegation of 7 April 2010 requires the Authority to calculate the BRCI for 2010-11 tariff year, apply the annual change in the BRCI to existing notified prices and publish new notified prices for the 2010-11 tariff year by 31 May 2010.

1.1 Background

Full retail competition (FRC) in Queensland energy markets commenced on 1 July 2007. With the introduction of FRC, electricity retailers are able to offer to supply electricity to all consumers, including those on notified (regulated) prices. Consumers taking up such an offer transfer from the notified price to the market contract price they have accepted from the retailer.

However, notified electricity prices remain an important feature of the Queensland electricity market. In particular, customers who are not offered a market contract, or who choose not to accept an offer, remain on a notified price. In addition, small consumers who accept a market contract may revert to a non-market contract at the notified price in the future, subject to any contractual conditions that may apply to their market contract. In effect, the notified price sets a ceiling on the basic price that consumers are required to pay.

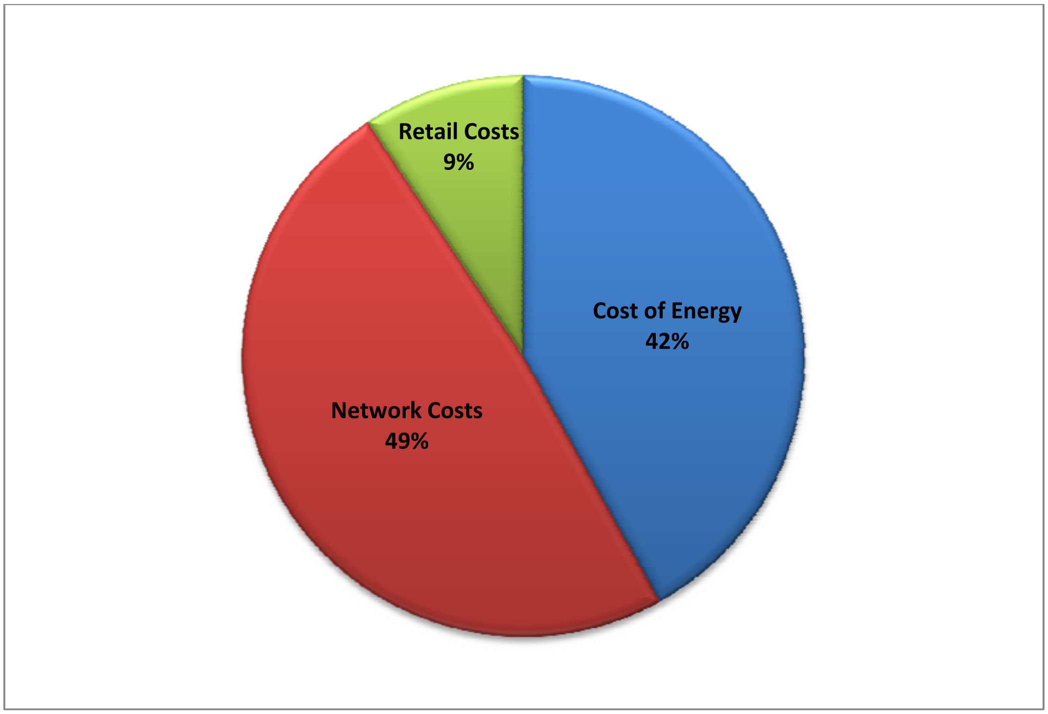
Under the Electricity Act, the notified price of electricity is to be adjusted annually according to changes in the cost of providing electricity. Specifically, the rate of change in the BRCI is to be used each year to adjust existing notified electricity prices.

1.2 Overview of the BRCI

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

The Electricity Act specifies three main cost components for the BRCI, namely: the cost of energy; network costs; and retail costs. The approximate size of each of these cost components in the BRCI for 2010-11 is illustrated in Figure 1.1.

Figure 1.1: BRCI cost components in 2010-11



Source QCA

The impact on annual electricity prices of a change in any component of the BRCI will reflect both the size of the change 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 90% of the total cost of supplying energy, changes in these cost components will potentially have the greatest impact on movements in the index from one year to the next.

In considering the components of the BRCI, the Authority is required to comply with the provisions of the Electricity Act and the *Electricity Regulation 2006* (the Electricity Regulation). These can be obtained from:

- http://www.legislation.qld.gov.au/legisltn/current/e/electrica94.pdf and
- http://www.legislation.qld.gov.au/legisltn/current/e/electricr06.pdf

The Electricity Act allows the Minister to delegate the calculation of the BRCI to the Authority.

1.3 Current Certificate of Delegation

The current Delegation was issued by the Minister on 7 April 2010 and is reproduced in **Appendix 1** to this Final Decision.

In his letter accompanying the previous (5 February 2010) Certificate of Delegation, the Minister noted that the Queensland Government was still considering the Authority's findings and recommendations with respect to its recent *Review of Electricity Pricing and Tariff Structures* (the Review).

In that Review, the Authority recommended a fundamental review of the existing tariff structures and prices and a different (to the BRCI) approach to the setting of notifies prices in future.

However, the Minister noted that, should the Government decide to adopt the Authority's proposed new retail pricing methodology, then the implementation of a new methodology would be deferred until 1 July 2011.

1.4 Calculation of the 2010-11 BRCI

On 23 October 2009, the Authority released an Interim Consultation Notice (ICN) advising interested parties of the process for calculating the BRCI for 2010-11 and seeking comment on all aspects of the calculation of the BRCI. The Authority noted that it intended to use the same methodological approach for estimating the cost of energy for 2010-11 as it had followed in making its 2009-10 BRCI Final Decision.

Nine submissions were received by the Authority in response to the ICN. A copy of the ICN and 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 component of the BRCI calculation for 2010-11.

The Authority released its Draft Decision on 18 December 2009 along with reports from ACIL and several data files relating to the modelling of energy costs. The Draft Decision addressed issues raised in submissions received in response to the ICN.

In response to the Draft Decision, the Authority received 14 submissions, including one from the Queensland Government. The Draft Decision and submissions received in response can also be accessed on the Authority's website.

This Final Decision on the BRCI for 2010-11 has been prepared in a manner consistent with the Final Decision on the BRCI for 2009-10 and the judgment of the Supreme Court of Queensland made in relation to the judicial review of the Authority's 2008-09 BRCI Decision.

In reaching its Final Decision, the Authority has taken into account matters raised in all submissions received from stakeholders, reports received from ACIL and the Delegation from the Minister, as well as its own investigations.

This Final Decision does not seek to reiterate in detail matters previously considered by the Authority in its Draft Decision or other past BRCI decisions. As such, this Final Decision should be read in conjunction with relevant public reports that are referenced herein.

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 2010-11 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 the 2009-10 BRCI Final Decision.

The LRMC of energy is estimated based on a hypothetical economically efficient combination of generating technologies for Queensland. In arriving at its estimate of the change in LRMC for 2010-11, the Authority has continued with the same basic approach adopted in the previous year of basing input costs on a trend regression analysis.

The purchase cost of energy is estimated based on a combination of 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 NEM load. This method is the same as that used in the 2009-10 BRCI Final Decision.

To maintain consistency between the cost estimates for 2009-10 and 2010-11, in its Draft Decision the Authority applied a modelling factor to the 2010-11 cost of energy estimates produced by its current consultant (ACIL) in order to account for differences between the proprietary model used by its previous consultant (CRA) in 2009-10 and that being used by ACIL in 2010-11. In the Draft Decision, this approach resulted in the LRMC estimate for 2010-11 being reduced by 0.65% and the energy purchase cost estimate being increased by 5.25%.

Following consideration of comments in submissions regarding the use of the modelling factor, and having considered the adjustment in the light of the Electricity Act and the court ruling on the 2008-09 BRCI Decision, the Authority has modified its approach and, rather than adjusting the 2010-11 cost of energy estimates by the modelling factor, it has used ACIL's cost of energy estimates for 2009-10 instead of the earlier estimates prepared by CRA. The effect on the BRCI of substituting the ACIL estimates for 2009-10 is almost identical to the effect of adjusting the 2010-11 estimates and either approach achieves the Authority's objective of ensuring that the change in the BRCI between years represents its best estimate of the change in the cost of supplying electricity.

In establishing the total cost-of-energy component of the 2010-11 BRCI, the Authority has taken into account the impact of the Queensland Gas Scheme and the Mandatory Renewable Energy Target (MRET) scheme (under the Renewable Energy (Electricity) Act 2000) consistent with the 2009-10 BRCI Decision. These costs were estimated using publicly available prices for Renewable Electricity Certificates (REC) and the penalty cost to retailers for not surrendering sufficient Gas Electricity Certificates(GEC).

The Authority also included the cost of NEM participant fees and ancillary services charges paid by retailers as it has done in previous years.

Summing each of the energy cost elements, the total cost of energy component of the BRCI is estimated to be $2,465.6 million in 2010-11, an increase of 11.62% from the $2,208.8 million estimated for 2009-10.

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 generally reflect the various supply contracts the retailer has with generators as well as the prevailing demand and supply conditions in the market.

In the short run, a retailer will overcome any shortfall in the amount of electricity it needs to meet customer demand by purchasing energy through the NEM. This market price therefore represents the short run marginal cost of energy and 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.

Judicial interpretation of the NEM Load for estimating cost of energy

In estimating the cost of energy, the Authority has taken account of the judgment on the judicial review of the 2008-09 BRCI on the definition of what constitutes the NEM load.

As noted in the 2009-10 BRCI Final Decision, the judicial interpretation was that the Electricity Act requires the calculation of the LRMC to be based on the load profile of the total State NEM load and the energy purchase costs on the NEM load, being the total State NEM load less the load of customers directly connected to the transmission network. Therefore, the Authority has made its Final Decision for 2010-11 BRCI on the cost of energy based on this judicial interpretation.

Long Run Marginal Cost (LRMC)

The Authority's approach to calculating the LRMC of energy is driven by the legislative requirement of adopting a "greenfields" approach. As outlined in the Authority's Final Decision for the 2009-10 BRCI, the LRMC calculation had the following features:

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

(b) a 'greenfields approach' was 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 used a multi-year approach that attempted 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 optimised generation investment across the NEM regions after taking account of the characteristics of the existing transmission system; and

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

Energy Purchase Costs

The Authority's approach to calculating the energy purchase cost 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 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 basis of this view was a forecast of the electricity demand in the (forthcoming) tariff year. This forecast of annual demand for electricity is commonly called the load trace and was based on the following factors or inputs:

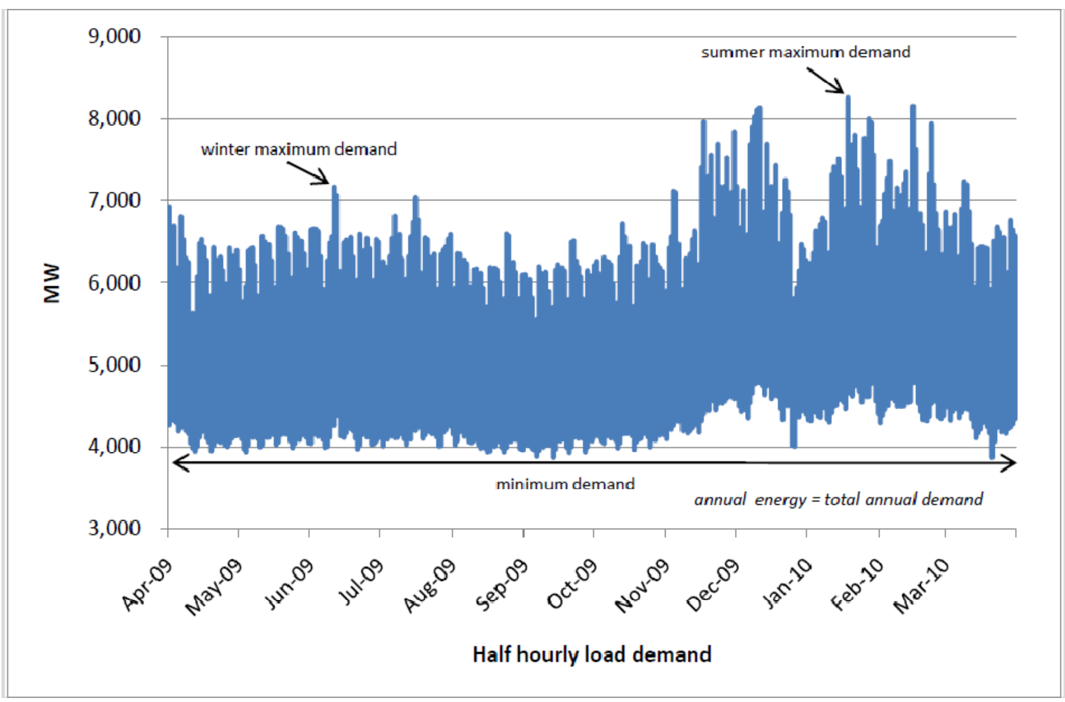
(a) a forecast of the total demand for electricity (annual energy);

(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.

These three elements, as illustrated in Figure 2.1 below, form the basis for deriving a load trace forecast.

Figure 2.1: NEM load from 1 April 2009 to 31 March 2010



Source AEMO data.

The pattern formed by the electricity demand across 17,520 half-hour periods in a year is known as the load shape. Figure 2.1 shows the load shape for the NEM load using the latest available 12 month data from the Australian Energy Market Operator (AEMO) for the period 1 April 2009 to 31 March 2010. Put simply, to make a forecast of a load trace in some future year requires a forecast of annual energy and the summer and winter maximum demands for that year and a load shape.

As discussed in the Authority's 2009-10 BRCI Final Decision, ACIL's method for producing the necessary load trace forecasts relies on two sources of official forecasts of annual energy and the summer and winter maximum demands: AEMO's 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 across the NEM and is provided to the industry annually by AEMO. The most recent ESOO was released on 27 August 2009 and remains the current industry forecast of demand in 2010-11.

Powerlink's APR also provides forecasts of annual energy and summer and winter maximum demand for the forthcoming year, updated on an annual basis. The current Powerlink APR was released on 30 June 2009.

Although presented in different formats, the most recent ESOO and the 2009 APR present essentially the same forecasts for electricity demand in Queensland for 2010-11.

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 MRET (now called expanded RET) scheme under the Commonwealth's *Renewable Energy (Electricity) Act 2000* (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 MRET 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 2009-10, 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 Use of the Modelling Factor

Draft Decision

In its Draft Decision, the Authority noted that a consequence of the change of consultant from the 2009-10 BRCI was that the proprietary models used by its current consultant (ACIL) to estimate some of the cost of energy components of the BRCI were unlikely to produce identical results to those produced previously by CRA International (CRA) despite applying the same theoretical framework and inputs.

In order to identify the potential differences that could be attributed to the switch in proprietary models from CRA to ACIL in estimating the LRMC and energy purchase cost components, the Authority engaged ACIL to re-produce the 2009-10 BRCI Final Decision cost of energy estimates using the same theoretical framework and the same data inputs as used previously by CRA[1].

Despite its best efforts, ACIL was not able to fully replicate the 2009-10 BRCI Final Decision LRMC and energy purchase cost estimates using its model. The Authority noted that this was understandable as each consultant's model used proprietary algorithms and decision rules to calculate these costs, despite working within the same theoretical framework.

Due to the resulting differences between the results of ACIL's proprietary model and that used by CRA, the Authority decided to correct for this modelling difference by applying a 'modelling factor' to adjust ACIL's 2010-2011 LRMC and energy purchase cost estimates. The Authority considered that this approach provided a pragmatic solution to addressing the inherent differences in the proprietary models and maintained consistency between the actual modelling results across the two years.

The Authority considered that, without the re-calibration of ACIL's 2010-11 estimates, the calculated increase in the BRCI between 2009-10 and 2010-11 would not represent its best estimate of the increase in the relevant costs between the two years as some of the increase would simply reflect the use of different proprietary models and not genuine cost increases.

Accordingly, based on the differences implied by ACIL's reworking of the 2009-10 results, the Authority reduced ACIL's 2010-11 LRMC estimate by 0.65% and increased ACIL's 2010-11 energy purchase cost estimate by 5.25% to arrive at its Draft Decision estimate of the LRMC and energy purchase costs for 2010-11.

Submissions in response to the Draft Decision

The Authority's decision to apply the modelling factor to ACIL's 2010-11 cost of energy estimates attracted comments from the Queensland Government and consumer representative groups.

The Queensland Government did not support the application of the modelling factor. It was of the view that the observed variance between the two models was not demonstrated to be systematic and reproducible and should therefore be used by the Authority to adjust ACIL's 2010-11 cost of energy estimates.

The Queensland Government questioned whether the use of the modelling factor was required to meet the intent of the Electricity Act. It argued that the change in proprietary models was neither a change of methodology nor a change in the dataset used for modelling and it therefore believed that the application of the different models in each year of the BRCI was in fact simply

[1] ACIL Tasman, *Report on the calculation of 2009-10 cost of energy using CRA's 2009-10 methodology*, December 2009.

a means of determining the best estimate of energy costs for the relevant year which was consistent with the intent of the BRCI legislative framework.

The Queensland Government argued that, unless the Authority was able to prove that applying the CRA model for 2010-11 would, in fact, generate the same results as the adjusted ACIL model estimates, then it should not seek to apply the modelling factor in calculating the BRCI for 2010-11.

Similarly, the Queensland Council of Social Service (QCOSS) expressed concern with the Authority's application of the modelling factor. QCOSS provided a report by Etrog Consulting (Etrog) that critically evaluated the Authority's decision to use the modelling factor.

In its report, Etrog suggested that the Authority's approach of comparing the two proprietary models over a single year (2009-10) did not provide a sufficiently robust basis to justify its decision to apply the modelling factor. Etrog was of the view that the Authority should first decide as to whether the change from using CRA's proprietary model to using ACIL's had constituted a change in the theoretical framework for the calculation in the cost of energy component of the BRCI.

Etrog was of the view that, if that decision was positive, then recalculation of the BRCI for 2009-10 would be required. If, as it believed the case was, that decision was negative, then the framework had not changed and the Authority should use the best available cost of energy estimates from ACIL for the 2010-11 BRCI.

Consumer representative groups, such as the Queensland Consumers' Association and the Queensland University of Technology Credit Commercial and Consumer Law Program (CCCL), also expressed concern regarding the Authority's decision to use the modelling factor to adjust cost of energy estimates for 2010-11. They noted that the modelling factor had a substantial impact on the estimates for 2010-11 BRCI and suggested that its use needed to be fully justified by the Authority.

Retailers, on the other hand, generally supported the Authority's use of the modelling factor in reconciling any perceived differences between the two consultant's proprietary models and measuring the change in costs between the two years.

Authority comment

In applying the modelling factor in its Draft Decision, the Authority was concerned that the decision to change consultant should not of itself impact on the change in the BRCI between two years. The objective of the BRCI approach is to adjust existing notified prices by an index representing the most likely change in the cost of supplying electricity to customers from one year to the next. A change in the index brought about by a change in the choice of consultant is unrelated to the most likely change in the cost of supplying electricity.

Prior to publishing the results of applying this approach in its Draft Decision, the Authority had discussed the perceived problem and its pragmatic solution with representatives from retailers, consumers and Government, with no objections being raised.

Given the comments that have now been made, the Authority is concerned to ensure that its solution to the problem of changing consultant is not only pragmatic and transparent, but also entirely consistent with the requirements of the legislation and the previous judicial review findings.

Having considered the comments made in submissions and sought legal advice on the correct interpretation of the legislation as it relates to this matter, the Authority has decided that its use of the modelling factor to adjust ACIL's estimate of LRMC and energy purchase costs for

2010-11 could be open to challenge, despite the best intention of the Authority to eliminate from the calculation of the index any extraneous influences unrelated to the cost of supplying energy.

While the use of the modelling factor may be contentious, the Authority remains of the view that, in order to meet the objects of the indexation regime for adjusting notified prices, it is necessary that the extraneous influences in the index generated by the change in consultant, and hence proprietary model, be removed from the BRCI calculation so that the change in notified prices due to the application of the index is commensurate with the change in costs over the relevant years.

The Authority is of the view that to ignore such influences would be inconsistent with the intent of the BRCI regime under the Electricity Act. If the Authority does not take into account the impact of the modelling change that is apparent, then applying the indexing formula to calculate the increase in the BRCI between 2009-10 and 2010-11 would not represent the increase in the relevant costs between the two years.

Rather than applying a modelling factor as it did in the Draft Decision, the Authority has decided, for the purposes of its 2010-11 BRCI Final Decision, to substitute the ACIL estimates of the 2009-10 LRMC and energy purchase costs for those of CRA and recalculate the 2009-10 base accordingly.

The Authority considers that such an approach is consistent with the legislation and the decision of the Supreme Court of Queensland in *AGL Energy Ltd v Queensland Competition Authority; Origin Energy Retail v Queensland Competition Authority [2009] QSC 90*. In that decision, the Supreme Court considered the extent to which the Authority in determining the BRCI for a year was required to use the previous year's BRCI or recalculate it. McMurdo J found that the Authority may recalculate the previous year's BRCI as part of the BRCI process for the next year but was not bound to do so.

Specifically, the judgment of McMurdo J permits the Authority to recalculate the preceding year's index if it considers that it is necessary in order for it to meet the objects of the BRCI indexation regime[2]. Further, the ability to recalculate the preceding year's index under the legislation is not limited to circumstances where the Authority changes theoretical framework.

While the Authority does not consider the change in proprietary model used in determining the cost of energy to be a framework change, the Authority does consider there are good reasons, consistent with the purposes of the legislation, to revisit the 2009-10 BRCI in so far as it is used in this year's process. For the purposes of its 2010-11 BRCI Final Decision, the Authority has reached the view that revisiting the calculation of the BRCI for 2009-10 is required in order to eliminate from the calculation of the index any extraneous influences unrelated to the cost of supplying energy.

In terms of the impact on the 2010-11 BRCI, the two approaches yield almost identical results. Table 2.1 compares the Authority's Draft Decision (where a modelling factor was applied to ACIL's 2010-11 cost of energy estimates) to how the Draft Decision would have appeared had the Authority instead adopted this alternative approach of using ACIL's 2009-10 cost of energy estimates in place of those provided previously by CRA.

Table 2.1 shows that adopting the alternate approach of substituting ACIL's LRMC and energy purchase cost estimates for 2009-10 for those of CRA impacts two components of the 2010-11 BRCI – cost of energy and retail margin. The change in the cost of energy estimate from

[2] See *AGL Energy Ltd v Queensland Competition Authority; Origin Energy Retail v Queensland Competition Authority* [2009] QSC 90

2009-10 is marginally higher under this approach than using the modelling factor approach as in the Draft Decision. This reflects ACIL's slightly lower cost of energy estimate for 2009-10 compared with that of CRA and the application of the 50% weighting to the revised estimates. Correspondingly, the change between years in the retail margin is higher than under the modelling factor approach used in the Draft Decision.

Table 2.1: Draft Decision results under alternate model correction approaches

BRCI Cost Components	***Draft Decision – 'modelling factor' applied to 2010-11***	***Change from 2009-10 Final Decision***	***Draft Decision - no 'modelling factor' applied to 2010-11***	***Change from 2009-10 using ACIL's cost of energy estimates for 2009-10***
NEM Load	37,483,145		37,483,145	
Cost of Energy				
LRMC	*$58.13*	*9.10%*	*$58.51*	*9.10%*
Energy purchase costs	*$61.80*	*7.10%*	*$58.72*	*7.10%*
50% of LRMC ($MWh)	*$29.06*	*9.10%*	*$29.26*	*9.10%*
50% of EPC ($MWh)	*$30.90*	*7.10%*	*$29.36*	*7.10%*
Cost of Energy (50/50 weighting)	$59.96	*8.06%*	*$58.61*	*8.09%*
Total Other Energy Costs	$6.64	*16.24%*	$6.64	*16.24%*
Total Cost of Energy ($MWh)	$66.60	8.82%	$65.25	8.87%
Total Cost of Energy ($m)	$2,496.6	10.69%	$2,445.9	10.73%
Network Costs ($m)	$2,860.6	20.11%	$2,860.6	20.11%
Total Retail Costs excl margin ($m)	$263.2	21.22%	$263.2	21.22%
Total costs excl margin ($m)	$5,620.3	15.79%	$5,569.8	15.85%
Retail Margin ($m)	$295.8	15.79%	$293.1	15.85%
Total costs incl margin ($m)	$5,916.2	15.79%	$5,862.9	15.85%
BRCI for 2010-11 ($/MWh)	**$157.84**	**13.83%**	**$156.42**	**13.90%**

Sources The Authority's 2010-11 BRCI Draft Decision, ACIL Tasman, Report on the calculation of 2009-10 cost of energy using CRA's 2009-10 methodology, December 2009, ACIL Tasman, Draft Report on the calculation of energy costs in the BRCI for 2010-11, December 2009, and Authority calculations.

In effect, for the purposes of this year's process, the Authority has recalculated the 2009-10 BRCI. In doing so, it has only been necessary for the Authority to recalculate the LRMC and energy purchase costs using the ACIL proprietary model. ACIL has used the same inputs as those used by CRA in calculating its LRMC and energy purchase costs estimates, which is again consistent with the decision of the Supreme Court. This is because these were the cost of energy components for which CRA provided advice for the 2009-10 BRCI. ACIL was responsible for developing the required load traces for the 2009-10 BRC.

The Authority considers no changes are required to the other components of the 2009-10 BRCI decision as they are unaffected by the change in proprietary model and there is no other need to revisit those components. In coming to this view, the Authority is conscious of the need to minimise the recalculation of the 2009-10 BRCI for this process as it could lead to distortions of the indexation process which would be inconsistent with the statutory purpose. In light of this, the Authority has simply used the other unaffected components of the 2009-10 BRCI in the remainder of this Final Decision; it has not been necessary to undertake a full and separate recalculation of 2009-10 BRCI and each of its components as part of this process.

The Authority's Final Decision

For the reasons discussed above and in order to maintain the integrity of the BRCI indexing approach to adjusting notified prices, the Authority has decided for this Final Decision to substitute ACIL's 2009-10 LRMC and energy purchase cost estimates for those of CRA. The adjusted 2009-10 LRMC and energy purchase cost estimates are provided in Table 2.2. This decision does not alter the Authority's 2009-10 BRCI Final Decision, but adjusts the 2009-10 LRMC and energy purchase cost estimates for the purpose of estimating the 2010-11 BRCI on a consistent basis.

Table 2.2: Adjusted 2009-10 LRMC and energy purchase costs

	***Original 2009-10 estimates*[1]**	***Adjusted 2009-10 estimates*[2]**
	$MW/h	*$MW/h*
LRMC	53.28	53.63
Energy purchase cost	57.70	54.83

1. See the Authority's 2009-10 BRCI Final Decision.
2. ACIL Tasman, Report on the calculation of 2009-10 cost of energy using CRA's 2009-10 methodology, December 2009.

2.4 Load

Draft Decision

In its Draft Decision, the Authority estimated the 2010-11 LRMC based on the generation required to meet the total State NEM load for Queensland in calendar year 2009. The load shape used for modelling the LRMC was developed by ACIL on the basis of the half-hourly load for the previous calendar year as required by the legislation. Consistent with the judicial review interpretation, this load shape includes loads of customers directly connected to the NEM transmission network in Queensland.

As the full load data for calendar year 2009 was not available from AEMO at the time of the Draft Decision, ACIL had to estimate the load data for the fourth quarter in order to undertake the LRMC modelling. The Authority noted in its Draft Decision that data for the full calendar year should become available in time for the Final Decision, eliminating the need to rely on ACIL's fourth quarter load estimate.

Consistent with the method followed in the 2009 BRCI Final Decision, ACIL applied AEMO's medium growth 50% Probability of Exceedance (POE) load forecast as reported in the 2009 ESOO to the load used for the LRMC calculation to forecast energy demand over the nine year modelling period.

Energy purchase costs were estimated on the basis of the forecast NEM load for Queensland. Consistent with the judicial review interpretation, the NEM load excluded loads of customers directly connected to the transmission network.

In order to derive the relevant load NEM load forecast, ACIL used the load from the most recent four quarters for which data was available to derive summer and winter maximum demands and the load shape for 2010-11. ACIL's method for producing the necessary 2010-11 load trace forecasts relied on the medium growth 50% POE demand projections from AEMO's 2009 ESOO and Powerlink's 2009 APR, as discussed in ACIL's Draft Report to the Authority[3].

The Authority released the full load data used in modelling the LRMC and the energy purchase costs to stakeholders at the same time as it released its Draft Decision.

Submissions in response to the Draft Decision

While all parties supported the approach used in the Draft Decision to derive the loads for modelling LRMC and energy purchase costs, AGL questioned whether the use of growth forecasts reported by AEMO in the 2009 ESOO may result in overly pessimistic demand forecasts. AGL noted that the AEMO 2009 ESOO was compiled at the time of the "Global Financial Crisis" and did not reflect the subsequent improvement in economic conditions in Australia. AGL also noted that, in a recent report to the Independent Pricing and Regulatory Tribunal (IPART) for the purpose of determining electricity costs in NSW, Frontier Economics used the "high economic growth" scenario from AEMO's 2009 ESOO on the basis that it felt the forecasts were somewhat conservative.

Authority comment

As noted by AGL, AEMO's 2009 ESOO was compiled at a time when there was a significant down turn in global economic conditions which was expected to reduce electricity demand across most NEM jurisdictions. Recent economic data indicate that the slowdown of the Australian economy was not as severe as was expected in early 2009 and that it has recovered more strongly than was anticipated.

In its Final Report to the Authority[4], ACIL provided its views on the continued use of AEMO's medium growth 50%POE demand forecast and on whether, as in IPART's recent decision, the high growth 50%POE demand forecasts might be more appropriate.

ACIL considered that, due to the methodology implemented by AEMO (which used a 10-year rolling average of historical diversity factors to develop the Queensland 50% POE maximum demand projection), the maximum demand forecasts provided by AEMO for Queensland have been significantly higher than observed recent historical values. ACIL also noted that AEMO has itself acknowledged that its projections for 2007-08 and 2008-09 missed an apparent slowing in actual maximum demand and energy growth.

In comparing Queensland's maximum demand for the 2009-10 summer with AEMO's medium growth and high growth 2009 ESOO forecasts, ACIL also found there to be significant variations between the observed values and AEMO's projected values under both scenarios. ACIL found similar differences when it compared AEMO's medium 50%POE 2009 ESOO forecasts to observed maximum demand for the 2009-10 summer in other Australian jurisdictions.

[3] ACIL Tasman, *The calculation of energy costs in the BRCI for 2010-11, Draft Report to the Authority*, December 2009

[4] ACIL Tasman, *The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority*, May 2010

ACIL also noted that AEMO's medium 50%POE forecast assumes a more significant recovery in underlying economic growth from the Global Financial Crisis in 2010-11 than the Commonwealth Treasury forecasts in the 2009-10 Federal Budget.

In light of the above, ACIL considered that the medium growth 50%POE demand forecast remains the most appropriate electricity demand forecast for use in the 2010-11 BRCI.

The Authority's Final Decision

The Authority considers that AEMO's 2009 ESOO remains the most appropriate source of demand forecasts available at present. While the forecasts were prepared at a time when the economic outlook was somewhat bleak, the method used by AEMO has tended to over-estimate outcomes in the past.

While economic activity is an important element in determining electricity demand growth, it is not the sole determinant. There are a multitude of factors that can affect electricity demand with weather being one of the more critical factors driving maximum demand. Given that it is not possible to favour one growth scenario over another without making implicit assumptions about the factors that drive electricity demand growth, the Authority has in the past adopted a more neutral approach by applying the medium growth 50%POE demand forecast to demand projections.

In the current circumstances, the Authority is not convinced that moving away from the medium 50%POE growth forecast will provide a more robust load demand forecast for Queensland for the 2010-11 BRCI. The Authority has therefore accepted the advice of ACIL and retained the medium 50%POE demand forecast approach which is consistent with its approach in the Draft Decision and the 2009-10 BRCI Final Decision.

The Authority will release the full load data used in this Final Decision in modelling the LRMC and the energy purchase costs to stakeholders at, or around, the time this Final Decision is released.

2.5 Long Run Marginal Cost (LRMC)

Draft Decision

In estimating the LRMC in its Draft 2010-11 Decision, the Authority considered a number of issues that were raised by stakeholders regarding LRMC methodology used in 2009-10. For example, both Origin Energy and AGL argued that the energy generation capital costs used in the LRMC calculation for 2010-11 should not rely on generation cost data provided by Concept Economics for the 2009-10 BRCI since, their opinion, this was out of date.

In light of their concerns, the Authority decided to use the more recent cost data produced by ACIL for AEMO's (then NEMMCO's) Inter-Regional Planning Committee in April 2009[5]. ACIL was also able to update the generation cost data in its AEMO report to reflect more recent developments in future coal and gas fuel costs due to significant movements in the Australian exchange rate that occurred since April 2009.

The Authority also gave consideration to a number of specific LRMC modelling issues raised by AGL, including:

(a) reducing the LRMC modelling period from nine years to a one to three year period;

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

(b) the specific formulation of the weighted average cost of capital (WACC) used in the LRMC modelling, which AGL suggested should not assume any benefit from a tax shield prior to a positive taxable income; and

(c) the treatment of interest during construction as fully capitalised and thus included in the determination of the average cost of new plant.

However, the Authority did not accept any of these suggestions in its Draft Decision.

On the basis of these and other considerations, the Authority accepted ACIL's estimate that the LRMC in 2010-11 would be $58.51/MWh, or $58.13/MWh after applying a modelling factor adjustment (discussed above) and representing a 9.1% increase from 2009-10.

Submissions in response to the Draft Decision

Stakeholders generally supported the Authority's approach to estimating the LRMC and considered the resulting 2010-11 estimate to be reasonable. Origin Energy and AGL also supported the Authority's decision to use ACIL's April 2009 AEMO report as the basis for capital and fuel cost estimates.

However, AGL questioned ACIL's treatment of the WACC for the new entrant generation projects within its LRMC model and suggested that, as ACIL's model applied immediate utilisation of the interest tax shield (that is, recognition of the deductibility of interest payments on cost of debt for tax purposes), it may not be consistent with the BRCI framework assumption of a stand-alone, project-financed new entrant LRMC.

Authority comment

In its Final Report to the Authority, ACIL has considered the technical issues raised by AGL concerning its new entrant financial model within its LRMC model.

ACIL notes that its new entrant LRMC model is a simplified discounted cash flow (DCF) model for greenfields generation projects and is designed to be suitable for a range of new projects. While the cash flows in its LRMC model do not separately identify the effects of the interest tax shield and dividend imputation credits, the effects are captured in the WACC using the "Officer" formula. As a result, the interest tax shield is allowed but effectively over the life of the greenfield project.

ACIL further noted that its new entrant financial model includes an estimate of build time for each of the new entrant technologies and corresponding capital expenditure is spread over this period. In this way, ACIL considered that its LRMC model provided a reasonable treatment of interest during construction for new entrant generation projects because:

> *…the discounted cash flow calculation is started from year zero (before any construction begins) and the first years record negative cash flows incurred through project capital expenditure discounted each year by the WACC. When positive cash flows commence they begin to reduce this accumulation of negative cash flow. Spreading out construction costs in this way means that capital costs have effectively been increased by interest costs over the construction period.*[6]

While a more transparent means of accounting for the interest tax shield may be achieved by incorporating it explicitly into the cash flows and using a "vanilla" WACC (which does not take account of the impact of taxes on required returns), it would then be necessary to make assumptions regarding the type, structure and tenure of debt finance for the new entrant generation projects. Given the complexities of this approach, ACIL was of the view that such

[6] ACIL Tasman, *The calculation of energy costs in the BRCI for 2010-11*, Final Report to the Authority, May 2010

an approach does not lend itself to the generic analysis required for the LRMC modelling for the purposes of the BRCI.

ACIL noted that, so long as the cash flows are consistent with the WACC definition, irrespective of which approach is used to account for the interest tax shield, the WACC would still provide an appropriate proxy for an investment decision hurdle rate in the new entrant financial model within its LRMC model.

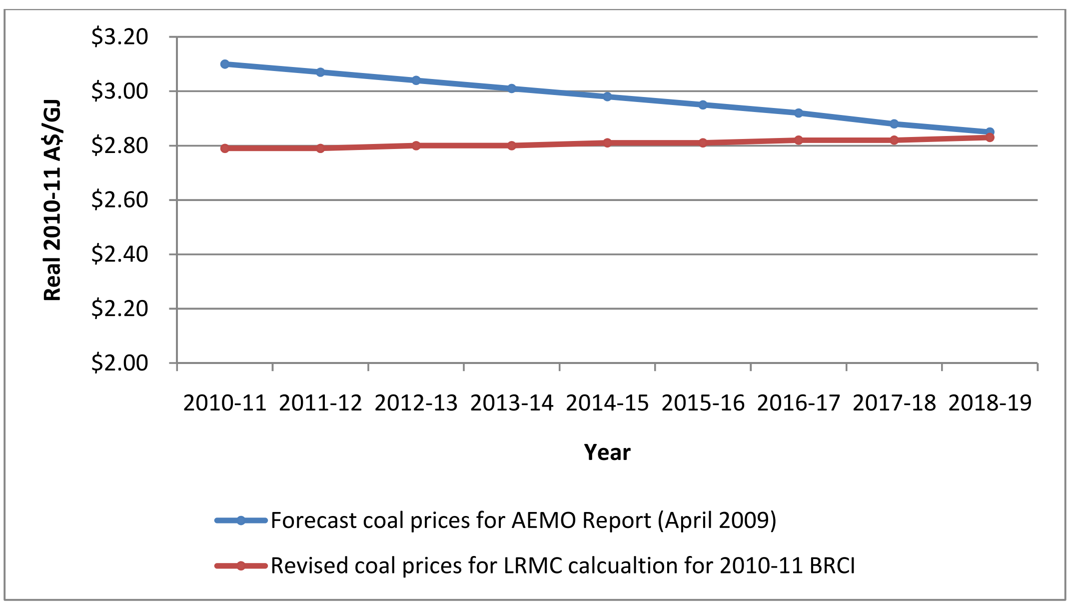
The Authority's Final Decision

For this Final Decision, the Authority has used the State NEM load data for the 2009 calendar year to estimate the LRMC for 2010-11 and has applied the medium 50%POE growth forecast reported by AEMO in its 2009 ESOO for Queensland over the nine year modelling period.

Given there was general support for the use of ACIL's April 2009 report to AEMO as the source of capital and fuel input costs for estimating LRMC for 2010-11, the Authority has continued with this approach in this Final Decision. As was done previously, ACIL has updated the coal fuel cost parameters to reflect the significant shift in exchange rates that have occurred since early 2009.

As a result, ACIL's "netback export price" of coal has changed significantly since April 2009 because of the appreciation of the Australian dollar against the currencies of Australia's major coal trading partners. ACIL's revised coal price forecast is shown in Figure 2.3 below.

Figure 2.3: Revised export prices of Coal forecast by ACIL



Source ACIL Tasman, The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority, May 2010

ACIL's revision of the export coal prices mainly affects the 2010-11 starting price of coal and involves reducing the "free on board" (FOB) coal prices by the amount implied by the recent appreciation of the Australian dollar against the US dollar. ACIL assumed that, over time, the exchange rate will return to its long term average and the FOB Australian dollar price reaches a similar level in both forecasts by 2018-19.

ACIL also updated the gas fuel cost projections from its April 2009 AEMO report. This revision is primarily driven by recent growth in the number of planned LNG export facilities that are scheduled to commence operations. ACIL updated its supply assumptions to include all existing and known, but undeveloped field developments and an assessment of undiscovered conventional and yet-to-be certified coal seam gas resources.

On the demand-side, ACIL's updated estimates on gas costs also include assumed growth in domestic demand, both through large industrial loads and general growth in reticulated gas to residential and commercial premises. The total assumed growth in gas demand – excluding NEM-scheduled power generation – is relatively modest at around 130 PJ (a growth rate of 2.6% per annum).

For this Final Decision on the 2010-11 BRCI, the Authority has accepted ACIL's final advice on the generation input costs to be used in the LRMC calculation. The capital and fuel costs used for modelling the LRMC for 2010-11 are discussed in more detail in chapter two of ACIL's Final Report to the Authority[7].

The Authority has considered the issue raised by AGL concerning ACIL's new entrant WACC treatment within its LRMC model. The Authority is satisfied that ACIL's cash flow and WACC assumptions are consistent with the BRCI framework for calculating the LRMC for greenfield generation projects.

Having updated its WACC parameters to reflect most recent market data, ACIL's estimate of the post-tax real WACC remains at 6.81%.

Final LRMC estimate for 2010-11

Consistent with the above discussion, the Authority estimates that the LRMC for 2010-11 is \$58.59/MWh, marginally higher than its estimate of \$58.13/MWh presented in the Draft Decision (with the application of the modelling factor as described above).

2.6 Energy Purchase Costs

Draft Decision

For its Draft Decision, the Authority accepted ACIL's energy purchase cost estimate for 2010-11 of \$58.72/MWh. In arriving at this estimate, ACIL applied the same approach to calculating the energy purchase costs for 2010-11 as was used in the 2009-10 BRCI Final Decision. The key inputs used by ACIL to estimate the energy purchase cost component were:

(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 settlements;

(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 settlements.

Detailed discussion of ACIL's approach to forecasting energy purchase cost was provided in its Draft Report to the Authority[8].

[7] See ACIL Tasman, *The calculation of energy costs in the BRCI for 2010-11*, Final Report to the Authority, May 2010

[8] See ACIL Tasman, *The calculation of energy costs in the BRCI for 2010-11*, Draft Report to the Authority, December 2009.

In reaching its Draft Decision, the Authority considered comments received from AGL that the methodology used by ACIL to develop the NEM Load forecasts for the 2009-10 BRCI Final Decision placed more energy in summer, at the expense of energy in winter, when compared to the historical records. To support its proposition, AGL provided the Authority with a report prepared by its consultant, Creative Energy Solutions (CES) which evaluated ACIL's methodology.

In reaching its decision on the issue, the Authority noted that all the technical aspects of ACIL's methodology for forecasting the NEM load traces had already been considered in detail as part of the 2009-10 Final Decision (including a review the CES report by ACIL). After receiving further advice from ACIL regarding the issues raised in the CES report, the Authority was satisfied that ACIL's methodology of forecasting NEM load was appropriate and consistent with the judicial interpretation of the load to be used to forecast energy purchase costs.

The Authority also clarified the use of loss factors in determining energy purchase costs, noting that, consistent with the 2009-10 BRCI Final Decision methodology, ACIL had applied the Average Loss Factor (ALF) as reported by Powerlink in its APR to the forecast load.

While the Authority accepted ACIL's energy purchase cost estimate for 2010-11 of $58.72/MWh, the Authority applied a modelling factor (discussed above) to derive an adjusted energy purchase cost estimate of $61.80/MWh for 2010-11, representing a 7.1% increase from 2009-10.

Submissions in response to the Draft Decision

There was general support from stakeholders for the Authority's decision to maintain the same approach to estimating energy purchase costs as it had used in the 2009-10 BRCI Final Decision.

While there were no significant areas of disagreement raised by stakeholders regarding ACIL's energy purchase cost modelling outcome, AGL considered ACIL's market spot price forecasts were low relative to historical analysis (due to ACIL's usage of "medium economic growth" forecasts in its modelling).

As discussed in section 2.4 above, AGL argued that, by using the medium economic growth forecasts presented by AEMO in the 2009 ESOO, the spot price was on average too low as the forecasts were premised on an overly pessimistic economic growth scenario.

AGL also suggested that the spot price forecasts ACIL produced for the Draft Decision did not align with market expectations as ACIL had forecast the highest spot prices to occur in Quarter 3 of 2010 and Quarter 2 of 2011 while, historically, the highest pool prices occur in Quarter 1 and Quarter 4, coinciding with periods of maximum demand.

AGL also noted that ACIL's spot price forecast for 2010-11 contained a number of extreme price events (>$1000/MWh) at times of relatively low demand, which seemed counter intuitive. Origin Energy made similar comments and requested the Authority check the occurrence of such events.

Authority comment

In its Final Report to the Authority, ACIL responded to the issues raised by AGL and Origin Energy regarding its modelled pricing outcomes. ACIL noted that, while it is a consistent feature of the swap contract market to have the highest contract prices occurring in Quarter 1 or Quarter 4 (the warmer summer seasons), this is not necessarily the case for quarterly pool prices.

In its Final Report, ACIL has presented analysis of quarterly and annual time weighted regional reference prices in Queensland for the last nine financial years, as shown in Figure 2.4 below.

ACIL notes that, over this period, the Quarter 1 price has been the highest quarterly price in only three years (2000-01, 2003-04 and 2007-08). ACIL suggested that its price projection for 2010-11 is typical of a market in which the excess of capacity over demand is relatively high and prices in the warmer summer months, when all capacity is made available, are suppressed. ACIL noted that, in such circumstances, higher prices will at times occur in Quarter 2 or Quarter 3 (as forecast in its Draft Report) when, for example, base load plant is taken out for scheduled maintenance or there are unscheduled outages, or several coincident unscheduled outages.

Figure 2.4: Queensland quarterly and annual 50%POE regional reference prices ($/MWh, 2000-01 to 2008-09)

Source ACIL Tasman, The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority, May 2010.

The Authority's Final Decision

In its Final Report to the Authority, ACIL has updated its pool price forecasts for 2010-11 by including the latest NEM load data up to the end of the first quarter 2010. The final pool prices forecast by ACIL for 2010-11 are shown in Table 2.5.

Table 2.5: Queensland quarterly pool prices project by ACIL Tasman for 2010-11 ($/MWh)

	10%POE	*50%POE*	*90%POE*
Quarter 3 2010	$35.59	$34.44	$31.67
Quarter 4 2010	$70.07	$45.10	$34.64
Quarter 1 2011	$57.53	$36.57	$31.34
Quarter 2 2011	$31.55	$30.06	$28.06
Annual average	$48.68	$36.56	$31.44

Source ACIL Tasman, The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority, May 2010.

The final pool prices forecast by ACIL are noticeably higher than the pool prices it projected in its Draft Report due to the availability of more recent load data. ACIL had used the NEM load traces for the year to 30 September 2009 in its Draft Report, whereas its final projections use NEM load traces for the year to 31 March 2010.

ACIL also noted that the loads in Quarter 4 2009 and Quarter 1 2010 are noticeably higher than those for Quarter 4 2008 and Quarter 1 2009 which they replaced and this has led to noticeable increases in the pool prices projected for Quarter 4 2010 and Quarter 1 2011 in its Final Report compared with those used in its Draft Report.

With the incorporation of the latest data, ACIL noted that the high temperatures leading to high demand periods in Quarter 4 of 2009 have now introduced high demand periods in the load trace for the 2010-11 year, resulting in the highest prices now forecast for Quarter 4 of 2010 (see Figure 2.4 above).

Contracting strategy and contract prices

In estimating the energy purchase costs estimate for 2010-11, ACIL has applied the same contracting strategy methodology as had been used in its Draft Report and the 2009-10 BRCI Final Decision, namely:

(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.

ACIL used the 2010-11 half-hourly NEM load trace forecast for Queensland (excluding the load of directly connected customers) to construct the hedging strategy. The NEM load trace forecast was developed by ACIL using the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50%POE, 10%POE and 90%POE based on AEMO’s 2009 ESOO and Powerlink’s 2009 APR.

The cost of the swap and cap contracts were estimated by ACIL using the same assumptions as used in the 2009-10 BRCI Final Decision – that the hypothetical retailer spreads its purchases of contracts evenly over 24 months up to the start of the tariff year (2010-11). ACIL also sourced the d-cypha Trade data for the same period (up to 31 March 2010) to estimate the cost of electricity swap and cap contracts following the 2009-10 BRCI methodology of averaging daily settled prices.

Table 2.6 below summaries ACIL's final estimates of the quarterly flat, peak and cap contract volumes purchased by an efficient retailer for 2010-11 under this strategy.

Table 2.6: Contract volumes and prices estimated by ACIL Tasman for 2010-11

	Flat contract volume	***Flat contract price***	***Peak contract volume***	***Peak contract price***	***Cap contract volume***	***Cap contract price***
	MW	*$/MW*	*MW*	*$/MW*	*MW*	*$/MW*
Quarter 3 2010	4,276	$36.92	1,172	$50.47	1,331	$4.58
Quarter 4 2010	4,646	$45.12	1,854	$66.10	1,413	$10.06
Quarter 1 2011	4,840	$66.80	1,711	$110.39	1,565	$25.21
Quarter 2 2011	4,275	$39.03	1,379	$47.59	1,244	$4.56

Source ACIL Tasman, The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority, May 2010.

Final Energy Purchase Costs estimate for 2010-11

Consistent with the approach adopted for the 2009-10 BRCI Final Decision, ACIL has used the half-hourly NEM load and the contracting prices and quantities for each half hour of the 2010-11 year to provide an estimate of the cost of purchasing energy in 2010-11. ACIL then applied an ALF of 3.7% (sourced from Powerlink's 2009 APR) to the settled pricing outcomes.

Table 2.7 below shows ACIL's 2010-11 energy purchase cost estimates for the three demand scenarios (10%POE, 50%POE and 90%POE). The weighted energy purchase cost for 2010-11 is estimated by ACIL to be $58.51/MWh.

Table 2.7: Energy purchase cost estimates for 2010-11 by ACIL Tasman

	Scenario weighting	*ACIL Tasman final estimate for 2010-11*
	%	*$/MWh*
Energy purchase costs 10%POE	30.40	$57.88
Energy purchase costs 50%POE	39.20	$58.44
Energy purchase costs 90%POE	30.40	$59.23
Total energy purchase costs (weighted)	100	**$58.51**

Source ACIL Tasman, The calculation of energy costs in the BRCI for 2010-11, Final Report to the Authority, May 2010.

Accordingly, the Authority estimates energy purchase costs for 2010-11 to be $58.51/MWh.

2.7 Weighting of LRMC and Energy Purchase Costs

Draft Decision

As with previous BRCI decisions, the Authority applied a 50/50 weighting to the LRMC and energy purchase costs estimates in calculating the energy cost component for the 2010-11 BRCI in its Draft Decision. The Authority considered the suggestion by some stakeholders to move away from the equal weighting of the LRMC and energy purchase costs. These submissions suggested that the cost of energy should be more heavily weighted towards energy purchase costs, with LRMC setting a floor to reduce risk exposure in underwriting generation sector investment (consistent with IPART's approach for 2010-2013 retail price determination).

However, the Authority noted that this issue had been extensively canvassed in previous BRCI decisions and that there were arguments that could be made for weighting the balance in either direction. The Authority considered that its 50/50 weighting approach reflected the balance of views and recognised the emphasis in the legislation on LRMC as the basis for determining energy costs.

Submissions in response to the Draft Decision

No comments were received from stakeholders on this issue.

The Authority’s Final Decision

As no further arguments were raised in submissions regarding the weighting of the energy cost components, the Authority has maintained its approach from the Draft Decision and applied a 50/50 weighting to the LRMC and energy purchase cost estimates for its Final Decision on the 2010-11 BRCI.

2.8 Carbon Pollution Reduction Scheme (CPRS)

Draft Decision

In its Draft Decision, the Authority considered a request by Origin Energy that it model the LRMC using some credible CPRS scenarios so that, in the event that it was clear before the

Authority's Final Decision what the actual CPRS would be, these results could be incorporated into the 2010-11 LRMC in the Final Decision.

The Authority noted that, while the proposed CPRS was at that time scheduled to commence from 1 July 2011, there was still considerable uncertainty surrounding the timing of the introduction of the scheme as well as the details of the scheme itself. The Authority also noted that the CPRS legislation had recently been defeated in the Senate, making the future of the proposed scheme entirely uncertain.

For these reasons, the Authority decided not to include any specific recognition of potential future carbon costs.

Submissions in response to the Draft Decision

No comments were received from stakeholders on this issue.

The Authority's Final Decision

The Authority notes that, on 27 April 2010, the Prime Minister announced that the Commonwealth Government would delay the introduction of the CPRS until at least the end of 2012. As a result, any consideration of introducing explicit CPRS costs in the Final Decision on the 2010-11 BRCI is now moot.

However, the Authority notes that some costs related to the risk of future carbon prices may already be reflected in market prices of various financial instruments in the electricity sector, and, if nothing else, these are likely to have already been captured in the contract prices used for estimating energy purchase costs for the BRCI.

2.9 Other Costs

Draft Decision **-** *Queensland Gas Scheme*

In establishing the overall cost of energy component for its 2010-11BRCI Draft Decision, the Authority considered the impact of the Queensland Gas Scheme under the Electricity Act as required by the BRCI framework.

Consistent with the Authority's previous BRCI decisions, the cost to retailers of complying with the Queensland Gas Scheme was based on the penalty price that retailers must pay for not surrendering sufficient Gas Electricity Certificates (GECs).

At the time of its Draft Report, no new information was available to ACIL on the change in the GEC penalty price to use as a basis for estimating the cost of complying with the Queensland Gas Scheme in 2010-11. In its Draft Report, ACIL simply escalated the 2010 penalty price estimated by CRA for the 2009-10 BRCI Final Decision by the consumer price index (CPI), to arrive at an estimated price for 2011. Assuming retailers would need to obtain GECs for 15% of their load in 2010-11, ACIL estimated that the average cost to a retailer of complying with the scheme would be $2.80/MWh in 2010-11, representing a 9.46% increase in the cost of complying with the scheme.

Submissions in response to the Draft Decision- *Queensland Gas Scheme*

In its submission, the Queensland Government questioned the decision to continue to apply the penalty price approach in calculating the GEC cost for 2010-11. The Queensland Government was concerned that ACIL's estimate for 2011 using the penalty price approach may be overestimating the actual costs faced by retailers in purchasing GECs. It suggested that the Authority should consider adopting a market-based methodology and noted that the spot price for GECs had been reducing with a GEC price in December 2009 of between $2.50/MWh and $3.50/MWh.

Authority comment - Queensland Gas Scheme

The Authority had canvassed possible methods for determining the cost of GECs in previous BRCI decisions before settling on the penalty price approach. While the use of market data may be preferable for estimating future costs, it has not been practical in the past as there was very limited market price data on GECs to make robust forecasts of future prices.

The primary independent source of GEC prices is market data collected and published by AFMA since February 2007. The Authority decided not to use the AFMA data in its 2008-09 and 2009-10 BRCI decisions because GEC's were initially fairly thinly traded and AFMA's market data series was not considered representative of the GEC market.

If the Authority were to move to a market-based approach to estimating GECs, as suggested by the Queensland Government submission, this could constitute a framework change under the current BRCI legislative provisions, requiring the Authority to recalculate this component of the 2009-10 Decision. However, the Authority has already considered that the market data that it would be required to use for this recalculation is unreliable and it is therefore not appropriate to move to this new approach for this year's BRCI calculation.

By maintaining the approach based on the use of the penalty prices for the 2010-11 BRCI, the Authority has ensured that the integrity of the index change in costs associated with GECs is maintained from year to year.

The method of estimating future GEC prices is not the primary reason costs associated with the Queensland Gas Scheme are increasing in 2010-11. Changes in the NEM load and the fact that the Queensland Government has increased the mandatory GEC target for retailers from 13% to 15% from 1 January 2010 are more significant. In the absence of these items, there would be no real increase in GEC costs from 2009-10 to 2010-11.

The Authority's Final Decision - Queensland Gas Scheme

For its Final Decision, the Authority has continued to apply the penalty price approach to estimating GEC costs used in previous BRCI Decisions.

Based on data now available, ACIL estimated GEC penalty prices for 2010 and 2011 and, on the basis that that GECs will account for 15% of retail load, ACIL estimated the average GEC cost to a retailer to be $2.80/MWh in 2010 and $2.88/MWh in 2011 to arrive at an average GEC cost for 2010-11 of be $2.84/MWh.

Draft Decision - Mandatory Renewable Energy Target (MRET)

For the Authority's Draft Decision, ACIL used weekly market prices for RECs published by AFMA to determine the costs to retailers of complying with the MRET scheme. Based on this approach and the available data up to 25 November 2009, ACIL estimated the cost of complying with the MRET scheme to be $3.02/MWh in 2010-11, an increase of 24.54% from 2009-10. This significant cost increase resulted largely from the new higher MRET target under the Commonwealth Government's expanded RET scheme.

Submissions in response to the Draft Decision - Mandatory Renewable Energy Target

In response to the Draft Decision, the Queensland Government suggested the Authority use market estimates to calculate the 2010-11 REC prices and claimed that ACIL's REC price estimate ($49.57/MWh for 2010 and $47.04/MWh for 2011) was above REC spot prices observed in 2009.

Conversely, AGL argued for using the LRMC of renewable generation in the determination of REC costs rather than market based costs. AGL believed that the LRMC approach provided a better representation of the costs that a retailer would have to pay for the majority of its REC purchases. AGL noted that large scale renewable energy projects generally require an "off-take agreement" in order to achieve project financing and, therefore, RECs from large scale renewable energy projects do not tend to trade in the market. As a consequence, AGL believed that a large proportion of RECs required to satisfy a retailer's obligation would necessarily be acquired from large scale projects for which a retailer will be incurring the LRMC of the project costs.

In addition, AGL suggested that ACIL may not have appropriately forecast the Renewable Power Percentages (RPP) by not taking into account the part exemption of the Emission Intensive Trade Exposed (EITE) customers. AGL noted that EITE customer exemptions will place a greater burden on electricity retailers which will push up the RPP.

Authority comment - Mandatory Renewable Energy Target

The Queensland Government appears to have misunderstood how REC costs for MRET compliance have been calculated for the BRCI. Both CRA in the past, and ACIL for 2010-11, have used a market based approach to estimating RECs that already includes market movements in REC prices, as suggested by the Queensland Government.

The existing methodology involves using weekly market prices for RECs published by AFMA (up to the cut-off date) to calculate average REC prices for each calendar year (2010 and 2011) and taking the average of the two years to produce a financial year estimate for the relevant tariff year (2010-11).

While ACIL's estimated average REC price was above the REC spot prices in late 2009, this is only true for that point in time (not on average). During the first half of 2009, REC spot prices were over $50/MWh. However, a number of factors contributed to its decline to around $35/MWh in the second half of 2009. The volatility was driven by uncertainly about the CPRS and oversupply of RECs caused by the extension of REC eligibility to small scale renewable generation technologies.

The Commonwealth Government recently announced significant changes to the REC eligibility to address the oversupply problem by splitting the existing scheme into two parts:

(a) the small scale Renewable Energy Scheme (SRES) under which households and small businesses will receive $40 for each REC created by small scale technologies such as solar panels and solar hot water heaters; and

(b) large scale Renewable Energy Target (LRET) under which a target of 41,000 GWh for 2020 has been set to achieve a level of large scale renewable electricity generation above what was expected under the existing RET[9].

The new SRES and LRET are intended to deliver more renewable energy than the existing 45,000 GWh target in 2020, with the degree to which the 20% target is exceeded depending on the uptake of small scale technologies by households and small businesses.

While retailers will be obligated to purchase RECs from both the SRES and LRET under the changes announced, precise details of the arrangements are yet to be finalised. The

[9] Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

Commonwealth Government released an industry consultation paper in March 2010[10] and, following consultation with stakeholders, released Bills[11] making changes to the RET scheme on 12 May 2010. While these changes are still being debated, the new arrangements could commence from 1 January 2011.

While the announced changes to the REC market creates some uncertainty in projecting RET costs, these are unlikely to be resolved until more details are known.

This uncertainty also weighs against AGL's suggestion of determining the RET compliance with reference to the LRMC of renewable generation assets. Given that the Commonwealth Government has proposed to create a distinct REC market for large scale renewable energy projects under its proposed LRET, it is questionable to what extent retailers will need to acquire a large proportion of its RECs by incurring the LRMC of the project costs as suggested by AGL. Presumably, the REC market prices created by eligible renewable generation assets under the LRET will already reflect the project costs.

In any event, ACIL, in its Final Report, has advised that changing from using actual market data to long term forecasting of REC prices based on the LRMC of renewable generation would serve no useful purpose for the purposes of the BRCI since REC prices are only required to be forecast one year ahead rather than over a longer term.

ACIL also noted that, while it is possible to forecast REC prices over the longer term for renewable generation projects, the robustness of the exercise would be complicated by the fact that a number of assumptions would need to be made regarding future carbon prices and its potential impact on the dispatch merit order for existing black coal generators. Given the uncertainty surrounding any future introduction of a CPRS and the recent changes to the REC market itself, ACIL was of the view that estimating REC prices based on actual market data continued to be the most practical way of estimating REC costs, especially over a short term as required under the BRCI.

Finally, in relation to AGL's comment regarding ACIL's forecast RPP, ACIL, in its Final Report, has noted that its RPP estimate for 2010-11 takes into account the recently announced RPP for 2010 (set at 5.98%) and includes an allowance in the load for EITE industries, which are subject to a reduced REC requirement.

The Authority's Final Decision - Mandatory Renewable Energy Target

The Authority is of the view that, unless there are clear and detailed announcements from the Commonwealth Government on how the expanded RET scheme is to be administered under the new market structure, it is prudent to retain the historical approach to calculating RET costs for the 2010-11 BRCI.

The Authority has therefore retained the same approach to estimating REC prices as used in its Draft Decision. On this basis, ACIL estimated the cost of complying with the MRET scheme at $3.05/MWh in 2010-11.

Draft Decision - NEM Participant Fees and Ancillary Services Charges

As in previous BRCI decisions, the Authority took into account NEM participant fees and ancillary services charges paid by retailers in reaching its Draft Decision on the overall cost of energy for 2010-11.

[10] Australian Government, *Discussion Paper – Enhancing the Renewable Energy Target*, March 2010.
[11] See http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query=Id:legislation/billhome/R4356

For 2010-11, ACIL estimated the cost of the AEMO participant fees to be $0.37/MWh based on trends over the period 2007-08 to 2009-10 for which data is publicly available from AEMO. On that basis, the Authority expected the total cost of NEM fees for 2010-11 to increase by13.78% from 2009-10.

The cost of ancillary services provided by the AEMO was also estimated by ACIL in its Draft Report to the Authority. Based on the average cost over the preceding 52 weeks of available ancillary services cost data up to 25 November 2009, ACIL estimated that the cost of ancillary services would be $0.45/MWh in 2010-11. For its Draft Decision, the Authority accepted ACIL's estimate which represented an increase of approximately 11.35% from 2009-10.

Submissions in response to the Draft Decision - NEM Participant Fees and Ancillary Services Charges

No comments were received from stakeholders on this issue.

The Authority's Final Decision - NEM Participant Fees and Ancillary Services Charges

Given that no issues were raised in response to the Authority's Draft Decision, the Authority has maintained the same approach to estimating NEM participation fees and ancillary service charges for its Final Decision on the 2010-11 BRCI.

In its Final Report to the Authority, ACIL estimates the NEM fees to be $0.34/MWh in 2010-11 and the cost of ancillary services to be $0.39/MWh in 2010-11 based on the ancillary services costs data up to 31 March 2010.

2.10 Final Decision on Cost of Energy for 2010-11 BRCI

Based on the Authority's consideration of issues outlined in the preceding sections, the Authority estimates that, in total, the cost of energy will rise from $2,208.8 million in 2009-10 to $2,465.6 million in 2010-11. This is an increase of 11.62%. In $/MWh terms, the total cost of energy is expected to increase from $59.94/MWh in 2009-10 to $65.17/MWh in 2010-11, as shown in Table 2.8 below.

Table 2.8: Cost of energy components, 2009-10 to 2010-11 – Final Decision

Cost Component	*2009-10*		*2010-11*		*Change*
	$/MWh		*$/MWh*		*%*
LRMC *(50% weighting)*	53.63[1]	26.82	58.59	29.30	9.25
Energy purchase cost *(50% weighting)*	54.83[1]	27.41	58.51	29.26	6.73
Cost of Energy		54.23[1]		58.55	7.97
Queensland Gas Scheme		2.56[2]		2.84	11.02
20% MRET		2.43[2]		3.05	25.77
NEM fees		0.33[2]		0.34	3.42
Ancillary services		0.40[2]		0.39	-2.67
Total: $/MWh		**59.94**		**65.17**	**8.73**
$million		**2,208.8**		**2,465.6**	**11.62**

1. *Estimates provided by ACIL using 2009-10 inputs*
2. *See the Authority's 2009-10 BRCI Final Decision.*

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 latest Powerlink and other transmission-related charges that the distributors are expected to pass through to customers in 2010-11.

In previous years, the Authority estimated distribution costs based on its 2005 Distribution Final Determination for Energex and Ergon Energy, adjusted to reflect subsequent Authority decisions. The Authority's 2005 Final Determination terminates on 1 July 2010 and the Australian Energy Regulator (AER) has determined the revenue requirements for both distributors for the following regulatory period. For this Final Decision, the distribution network costs for 2010-11 are based on the AER's Final Regulatory Determination for Energex and Ergon Energy.

On this basis, the Authority has estimated the relevant network costs to be $2,871.4 million for 2010-11, an increase of 20.57% over 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 cost of using the transmission and distribution networks typically accounts for around 50% of the total cost of providing electricity to households. 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 networks in Queensland.

3.3 Draft Decision

Transmission costs

As actual data was not available for the Draft Decision, the Authority estimated the transmission use of system (TUOS) charges Powerlink would apply to the distributors in 2010-11 by calculating the proportion of Powerlink's maximum allowable revenue (MAR) in the previous year (2009-10) represented by the total transmission charges levied on distributors and then applying this to Powerlink's 2010-11 MAR, as calculated by the AER in its (Revised) Final Decision on *Powerlink Queensland transmission network revenue cap for 2007-08 to 2011-12* from 8 July 2008.

Other transmission costs incurred by the distributors were estimated by escalating the 2009-10 values by the proportional change in the Powerlink charges between years.

The Authority indicated that these estimates would be updated in the Final Decision once better estimates were available from the distributors' 2010-11 Pricing Proposals that will be submitted to the AER.

As in previous years, no adjustment was made to account for previous under- or over-recovery of TUOS revenue by Energex and Ergon Energy.

Distribution costs

At the time of the Authority's Draft Decision, distribution network costs for Energex and Ergon Energy were based on the AER's *Queensland Draft Regulatory Determination - 2010-11 to 2014-15* (November 2009). These revenue forecasts excluded any adjustments for the annual under- or over-recovery of revenue by Energex or Ergon Energy.

The Authority indicated in its Draft Decision that these estimates would be updated in its Final Decision to reflect the AER's Final Regulatory Determination.

3.4 Submissions in response to the Draft Decision

In response to the Draft Decision, the Queensland Government queried whether the network cost estimates incorporated costs associated with non-distribution use of system (non-DUOS) services and costs associated with Ergon Energy's isolated Mt Isa network. The Queensland Government suggested that these costs should be excluded from the estimates, consistent with previous BRCI decisions.

Origin Energy and AGL reiterated their concern that the use of whole of Queensland network costs did not accurately reflect the increase in network costs faced by retailers in Energex's network area. They also noted that the BRCI takes no account of the capacity for Energex to re-balance its tariffs while remaining within the AER's approved annual revenue requirement.

Energy Australia suggested that network costs should be treated as a pass-through cost in the 2010-11 BRCI decision to ensure appropriate cost reflectivity of network charges to customers and to ensure that retailer headroom is maintained.

3.5 Final Decision on Network Costs for 2010-11 BRCI

The Authority has adopted the same approach to calculating network costs in the 2010-11 BRCI as was used in 2009-10 BRCI.

Transmission costs

In the Draft Decision, the Authority noted that its estimate of the TUOS charges Powerlink was expected to levy on Energex and Ergon Energy during 2010-11 and other transmission charges likely to be incurred by Energex and Ergon Energy would be updated in the Final Decision to reflect better estimates that would become available from the distributors.

Based on information provided by Energex and Ergon Energy from their Pricing Proposals to the AER, estimated transmission network costs are $42.0 million (7.21%) higher than estimated at the time of the Draft Decision which was simply based on the historical proportion of Powerlink's revenue raised from Energex and Ergon Energy. As shown in Table 3.1, transmission network costs are now estimated to be $625.5 million, compared to $583.4 million estimated at the time of the Draft Decision.

Distribution costs

For this Final Decision, distribution costs have been derived from the 2010-11 revenue caps for Energex and Ergon Energy provided by the AER in its *Queensland Final Regulatory Determination – 2010-11 to 2014-15* (6 May 2010).

In response to the two issues raised by the Queensland Government, the Authority notes that non-DUOS charges had not been included in the 2010-11 network cost estimates used in the Draft Decision. The AER categorises distribution services as either "Standard Control Services" or "Alternative Control Services". These categories are broadly consistent with the DUOS and non-DUOS service categories previously used by the Authority. The distribution network costs used by the Authority in preparing its Draft and Final 2010-11 BRCI Decisions are based on the AER's revenue estimates attributable to "Standard Control Services".

However, the Queensland Government had correctly identified that costs associated with Ergon Energy's Mt Isa network had been inadvertently included in the network cost estimates presented in the Draft Decision. The AER did not separately identify this component in its Draft Regulatory Determination.

As the AER was unable to separately identify costs associated with the Mt Isa network, the Authority sought advice from Ergon Energy regarding the appropriate deduction to be made from its revenue in order to remove Mt Isa costs. Ergon Energy estimates that costs associated with the Mt Isa network for 2010-11 will be $12.2 million. This figure is consistent with cost estimates prepared by the Authority for previous BRCI decisions ($10.5 million in 2009-10). For this Final Decision, the Authority has removed $12.2 million from the revenue approved by the AER for Ergon Energy in 2010-11.

A number of submissions from retailers noted perceived shortcomings of the current approach to calculating network costs. For example, the use of the whole of Queensland network costs in the calculation has resulted in a lack of cost-reflectivity in network charges faced by retailers within Energex's distribution area. Retailers also noted that the current approach failed to account for Energex's capacity to rebalance its network tariffs.

However, such issues are beyond the scope of the Authority's discretion in meeting the requirements of the legislation and the current Delegation. For this Final Decision, network costs have been calculated in line with the legislation and are entirely consistent with the approach adopted in the 2009-10 BRCI Final Decision.

The network cost component to be included in the calculation of the 2010-11 BRCI Final Decision are summarised in Table 3.1. The Authority estimates the relevant network costs to be $2,871.4 million in 2010-11, an increase of 20.57% from 2009-10. This compares with an increase of 20.11% proposed in the Draft Decision based on the AER's Draft Decision.

Table 3.1: Summary of Network Costs 2009-10 to 2010-11 – Final Decision

Network cost	***2009-10[1]*** *$m*	***2010-11 Final Decision*** *$m*	***Change*** *%*
Transmission			
Powerlink charges	514.0	611.5	18.97
Avoided TUOS payments	3.5	5.7	64.00
Unregulated Powerlink charges	5.9	6.0	2.20
Other Charges	2.2	2.2	-0.91
Total transmission costs	**525.5**	**625.5**	**19.02**
Distribution			
Energex	**1,000.3**	**1,135.1**	**13.48**
Ergon Energy	**855.8[2]**	**1,110.9[3]**	**29.80**
Total Network Costs	**2,381.6**	**2,871.4**	**20.57**

Source QCA 2009-10 BRCI Final Decision, AER Queensland Distribution Determination 2010-11 to 2014-15 Final Decision, and information from Energex and Ergon Energy's Network Tariff Pricing Proposals for 2010-11.

1. *See the Authority's 2009-10 BRCI Final Decision.*
2. *Excludes $10.5 million for network revenue associated with Mt Isa.*
3. *Excludes $12.2 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.

Consistent with its approach in the 2009-10 BRCI Final Decision, the Authority has estimated retail operating costs for 2010-11 by escalating the retail costs established in the 2007-08 BRCI to reflect price inflation and wages growth. Customer acquisition and retention costs have been estimated using the most recent estimates of customer switches and transfers.

The Authority has maintained the net retail margin at 5% for the 2010-11 BRCI, on the basis that this should provide a reasonable return to a retailer for the risks that it faces.

In total, retail costs are expected to increase by 16.70% from $470.2 million in 2009-10 to $548.7 million in 2010-11.

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 – retail operating costs and customer acquisition and retention costs.

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. Customer administration and billing generally account for over half of retail operating costs.

Customer acquisition and retention costs include the costs of acquiring new customers, retaining existing customers and encouraging existing non-market customers to transfer to market contracts. These costs include marketing, advertising, sales overheads, door-to-door/commission/agent costs and telesales. The estimation of customer acquisition and retention costs revolves around the level and cost of what are termed switches and transfers.

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.

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 notified prices.

4.3 Retail Operating Costs

Draft Decision

In its Draft Decision, the Authority continued with the benchmarking approach to calculating retail operating costs it had adopted since the 2007-08 BRCI decision. Most submissions received in response to the Interim Consultation Notice expressed support for this approach to be continued.

This approach involved escalating the benchmarked retail operating cost of $75 per customer estimated in 2006-07 to account for inflation over the intervening period. As in previous BRCI decisions, the Authority 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 the benchmarked retail operating costs.

The Authority based its forecast estimates of WPI on the ANZ Markets Weekly Report of 5 November 2009 and for CPI on the Reserve Bank of Australia (RBA) Statement on Monetary Policy of 6 November 2009. Based on this approach, the Authority estimated retail operating costs would increase from $83.19 per customer in 2009-10 to $85.42 per customer in 2010-11, a 2.7% increase on the 2009-10 estimate.

This retail operating cost was then applied to the total number of customers on the Energex and Ergon Energy distribution networks in order to arrive at the estimated change in total retail operating costs for the 2010-11 BRCI.

In previous BRCI decisions, the Authority had used customer numbers provided by Energex and Ergon Energy as part of their annual pricing proposals required under the Authority's 2005

Electricity Distribution Determination. However, as responsibility for setting distribution network prices in 2010-11 had been transferred to the AER, this information was no longer internally available to the Authority.

For the Draft Decision, the Authority escalated customer numbers reported in the 2009-10 BRCI Final Decision (1,978,965) based on the rate of growth in customer numbers over the previous two years. On this basis, the Authority estimated customer numbers in 2010-11 to be 2,030,624.

The Authority noted that, in its Final Decision, it would update the inflation forecasts to reflect more recent forecasts available at that time and revise the estimate of customer numbers using the distributors' own estimates as contained in their 2010-11 annual pricing proposals to the AER.

Submissions in response to the Draft Decision

Submissions from the Queensland Government and AGL commented on the Draft Decision estimate of retail operating costs for 2010-11.

The Queensland Government suggested that, as the Authority appeared to have based its benchmark retail operating cost estimate on IPART's 2007-10 retail electricity price determination (of $75 per customer), it would now be necessary for the Authority to rebase its retail cost estimate to reflect IPART's most recent estimate of retail operating costs (of $74.80 per customer for 2010-11[12]), provided in its Draft Determination on retail electricity prices in NSW for 2010-13[13].

Authority comment

The Queensland Government appears to have misinterpreted the source of the Authority's benchmarked retail operating cost estimate for the BRCI. The per customer retail operating cost estimate the Authority originally adopted for the 2007-08 BRCI was not based solely on IPART's decision on a retail operating cost allowance at that time.

In arriving at the estimate of $75 per customer in 2006-07, the Authority had undertaken a detailed benchmark comparison of retail operating costs accepted by regulators in a number of other jurisdictions, including New South Wales, Victoria, South Australia, Tasmania and the Australia Capital Territory, over the four years from 2003 to 2007[14]. The benchmark cost accepted by the Authority drew on all these jurisdictional decisions and was towards the bottom of the observed range.

On the other hand, while AGL generally supported the Authority's approach of escalating the 2006-07 retail operating cost estimate, it was of the view that this approach had not resulted in operating cost estimates that reflect the actual costs incurred by retailers.

The Authority has considered AGL's submission but does not consider there is sufficient evidence indicating that the Authority's benchmarked retail operating cost approach is too low

[12] IPART's estimate of $74.80 was reported in 2009-10 dollars which would have to be inflated to 2010-11 values if used in the 2010-11 BRCI.

[13] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013*, Draft Report and Draft Determination, December 2009.

[14] See QCA, *Draft Decision – Advice to the Minister for Mines and Energy Benchmark Retail Cost Index for Electricity: 2006-07 and 2007-08*, May 2007; QCA, *Final Decision: Benchmark Retail Cost Index for Electricity: 2008-09*, May 2008; and CRA International, *Draft Report prepared for the Queensland Competition Authority: Calculation of the Benchmark Retail Cost Index for 2006-07 and 2007-08*, May 2008.

and not reflective of actual costs faced by retailers in Queensland to warrant a departure from an approach which is broadly supported by the industry and consistent with previous decisions.

The Authority's Final Decision

Benchmark retail operating cost

The Authority considers that its existing approach of escalating its original estimate of retail operating costs based on a benchmark of other regulatory decisions at the time adequately captures changes in underlying costs faced by retailers. The Authority is also of the view that the resulting cost estimate for 2010-11 remains within the scope of other more recent regulatory decisions.

For this 2010-11 BRCI Final Decision, the Authority has decided to retain the approach it adopted for estimating retail operating costs in its Draft Decision, updated to reflect more recent information on price inflation and customer numbers, as flagged in the Draft Decision.

Inflation escalation factors

Consistent with the benchmarking and inflation escalation approach for estimating 2010-11 retail operating costs discussed above, the Authority has updated its WPI and CPI forecasts for 12 months to 30 June 2010 and 12 months to 30 June 2011.

As was the case for the Draft Decision, the Authority has sourced the latest WPI forecasts from ANZ Markets Weekly Report (of 7 May 2010) and the CPI forecasts are based on the RBA's Statement on Monetary Policy (of 7 May 2010).

Table 4.1 below shows the final escalation factors that the Authority has applied to the benchmarked allowance since 2006-07. The Authority has retained the 60% WPI and 40% CPI weighting for the escalation factor to be applied to the benchmarked retail operating cost estimate.

Table 4.1: Inflation escalation factors for 2010-11 – Final Decision

Period	*WPI*	*CPI*	*60/40 weighted average of WPI and CPI*
12 months to Jun 08 (Actual)[1]	4.28%	5.12%	4.61%
12 months to Jun 09 (Actual)[1]	3.69%	2.02%	3.02%
12 months to Jun 10 (Forecast)	2.80%	3.25%	2.98%
12 months to Jun 11 (Forecast)	3.30%	3.00%	3.18%

1. Actual WPI for 12 months to Jun 08 and 12 month to Jun 09 has changed from that used in Draft Decision due to a re-basing of the series by the ABS.
Source actual CPI figures based on ABS CPI Brisbane, CAT NO 6401.0 Table 5, forecast CPI figures based on RBA Statement on Monetary Policy 7 May 2010. Actual WPI figures based on ABS Labour Price Index – Australia, CAT NO 6345. Quarterly Index; forecast WPI figures based on ANZ Markets Weekly – 7 May 2010.

Based on the final weighted escalation factors, the Authority estimates that retail operating costs will increase to $85.89 per customer in 2010-11 from $83.19 per customer in 2009-10. This compares to the retail operating costs of $85.42 per customer estimated in the Authority's Draft Decision.

Customer numbers

As foreshadowed in its Draft Decision, the Authority has obtained updated customer numbers from both distributors for 2010-11 for this Final Decision. Energex and Ergon Energy have provided the Authority with the forecast customer numbers that they will include in their annual pricing proposal to the AER for 2010-11.

Based on the numbers reported by the distributors, the Authority has used a figure of 2,012,602 customers in 2010-11 to determine the overall BRCI retail operating costs for 2010-11. This represents an increase of 1.7% in the total customer base for the 2010-11 BRCI compared to the 2009-10 BRCI Final Decision and compares with the increase of 2.6% used in the Draft Decision.

4.4 Customer Acquisition and Retention Costs

Draft Decision

For its Draft Decision, the Authority maintained the two-step approach to estimating customer acquisition and retention costs in 2010-11 that it had used in 2009-10. The two steps involved:

(a) estimating the costs incurred by a retailer for each customer that switches to it from another retailer and estimating the costs incurred by the retailer for each customer that transfers to a market contract from a non-market contract while remaining with the same retailer; and

(b) estimating the number of customers switching retailer and those transferring to a market contract with the same retailer in Queensland.

To establish the cost of customers switching and transferring, the Authority escalated the cost benchmarks established in 2007-08 (the base year) for a customer switching retailer ($171.43) and a customer transferring to a market contract with the same retailer ($100.00) to arrive at costs for 2010-11. In a similar manner to the escalation of retail operating costs, the 2010-11 costs for switches and transfers were based on a 60/40 weighted average of WPI and CPI over the intervening period. This approach was consistent with the approach taken by the Authority in the 2009-10 BRCI Final Decision.

On this basis, the Authority estimated the cost per customer switching retailer in 2010-11 to be $186.69 and the cost per customer transferring to a market contract with the same retailer to be $108.90.

Using these costs and forecast customer churn rates of 461,000 customer switches and 33,000 customer transfers at the time of the Draft Decision, the Authority estimated that total customer acquisition and retention costs would be $89.8 million in 2010-11. When spread across all customers in Queensland (based on estimated total customer numbers of 2,030,624), this equated to $42.41 per customer for switches and $1.79 per customer for transfers.

Customer switching rate between retailers

In its Draft Decision, the Authority used data from the Australian Energy Market Operator (AEMO's) MSATS system to forecast customer switching behaviour. However, the Authority considered that the early data following the commencement of FRC should be excluded as it appeared too volatile and based its forecasts on the more recent and less volatile data since December 2008.

In the absence of a better method and given the limited available data, the Authority used a 12 month rolling average of the monthly increase in the number of customers switching retailers in

Queensland as reported by AEMO as the basis for its projections. The Authority acknowledged that this was a fairly rudimentary basis for forecasting customer behaviour.

The Authority noted in its Draft Decision that further data would become available before the Final Decision was released and that the most recent data available at that time of the Final Decision would be used. The Authority acknowledged that this approach could lead to a significant movement in these forecasts, depending on the rate of switching over the intervening months.

Based on this method, the Authority estimated that the average monthly growth in customers switching retailers over the 12 months to November 2009 was 3.2%. By applying this monthly growth rate, the Authority estimated that 22.7% of total customers would switch retailer in 2010-11(approximately 461,000 customers).

Customers transferring to market contract with the same retailer

For its Draft Decision, the Authority based its estimate of customers transferring to a market contract with the same retailer on the market customer numbers reported to it by retailers on a quarterly basis under the Electricity Industry Code (the Code).

Given the limited data and options for forecasting future customer transfers, the Authority derived its 2010-11 estimates by first calculating the number of customers moving each quarter from a non-market contract to a market contract and then weighting this estimate by the proportion of such customers who remained with their current retailer over the year to June 2009.

Based on this approach, the Authority estimated that the total number of transfers in 2010-11 would be approximately 33,000 customers. This figure implied that 1.6% of total customers would transfer onto a market contract with their current retailer in 2010-11. In terms of the customers in South East Queensland (where most of the customer churn is occurring), the implied rate of transfers was 2.6%.

As with its customer switching estimate for 2010-11, the Authority accepted that its customer transfer estimate for 2010-11 was derived in a relatively simplistic way. It also noted that data for at least one more quarter (and further revisions of past data by AGL) would become available before its Final Decision.

In its Draft Decision, the Authority proposed to use the most recent data available at that time for the purposes of estimating customer transfers in the Final Decision but noted that this also could lead to a significant movement in the forecasts, depending of the rate of transfers over the intervening few months.

Submissions in response to the Draft Decision

A range of comments was received from a number of stakeholders in response to the approach used in the Draft Decision to estimate customer acquisition costs.

The Queensland Government and consumer representatives queried the apparent large increase in the customer switching rate in 2010-11 when compared to 2009-10.

However, retailers generally supported the approach taken by the Authority, but observed that this approach did yield a somewhat higher customer switching rate for 2010-11 than has been historically observed. Retailers suggested that the Authority revisit both its forecasts of customer switches and transfers in its Final Decision when more data would be available.

The Queensland Government suggested that the Authority revise its estimates of customer switches to reflect a better balance between acquisition of new customers and retention of existing customers, with a stronger emphasis on retaining customers. It also suggested that the Authority consider adopting a fixed customer acquisition cost on a per customer basis to remove the apparent volatility from year to year.

The Queensland Government was of the view that changes in notified prices should not be sensitive to the rate of customers switching retailers, given the current maturity of the Queensland electricity market. It also suggested that customer acquisition costs should be relatively stable on the basis that the BRCI framework assumes retail costs for a retailer with a significant share of the retail electricity market.

The Queensland Council of Social Service (QCOSS) provided a report from Etrog Consulting (Etrog) that reviewed aspects of the Authority's Draft Decision. In its report, Etrog recommended that the Authority revert to the fixed customer switching rate of 217,536 customers as used in the 2008-09 and 2009-10 BRCI Decisions.

Etrog criticised the method used by the Authority to estimate the average increase in the number of customer switches and suggested that, if the Authority did choose to calculate customer switching rather than assuming a fixed number of customers churning, then it should calculate the monthly growth rate that would compound to the total growth rate over the most recent 12 month period.

Concerns about the robustness of the AEMO MSATS data and the comparison of switching rates in Queensland to those of other states in Australia were also raised in some submissions. For example, QCOSS and the Queensland Consumers' Association expressed concern that the MSATS data was not sufficiently robust and may over-state the actual number of customer switches in the Queensland market due to the high level of volatility apparent in the data.

QCOSS and Queensland Consumers' Association also suggested that the relevant switching rate to be used for comparison between Queensland and other states should be based on the customer switching rate for South East Queensland given that this is the only part of the state where competition is occurring. On this basis, they appeared to suggest that the South East Queensland customer switching rate estimated by the Authority of 35.5% for 2010-11 (as opposed to the state-wide switching rate of 22.7%) was considerably higher than rates observed in other jurisdictions in their fourth year of the FRC.

While retailers generally supported the approach taken by the Authority in estimating the customer switching rate in the Draft Decision, Integral Energy suggested that the number of customer switches likely to occur in 2010-11 would be much higher.

Integral Energy was of the view that competition had been limited since the beginning of FRC due to high and volatile wholesale prices and low retail margins. It suggested that softening wholesale prices and the Authority's recognition of the previously low retail margin that, according to Integral Energy, was reflected in the Authority's 2009-10 BRCI Final Decision, may lead to an increase in competition over the next 12 to 18 months and therefore an increase in the number of customer switches. Integral Energy also noted that many of the customers who signed up to market contracts at the commencement of FRC are likely to re-enter the market during 2010-11, which may lead to an increase the level of switching activity.

Alternatively, AGL suggested the Authority's estimate for 2010-11 may be higher than market expectations.

A number of stakeholders also questioned the Authority's forecast of customer transfers for 2010-11. For example, both Origin Energy and AGL suggested that forecast customer transfers were lower than expected and encouraged the Authority to revisit its estimates. The Queensland Consumers' Association expressed concern over the data used to forecast customer transfers.

However, while several stakeholders felt that the Authority's forecast of customer transfer in the Draft Decision was somewhat at odds with market expectations, none suggested a superior method of estimating customer transfers, nor did they identify an alternative data source the Authority could rely on to make the necessary forecast.

Authority comment

Benchmark customer acquisition costs

The Authority has previously considered the alternative approach of adopting a fixed customer acquisition cost per customer, as suggested by the Queensland Government, and concluded that the current benchmark approach was more appropriate[15]. The current approach to determining customer acquisition costs has also been generally supported by stakeholders.

The Authority's current approach to determining customer acquisition costs was developed during the early years of FRC and recognises that, at least initially, there will be costs associated with new entrant retailers to the Queensland market seeking market share and for incumbent retailers in defending their market share. Whether customer acquisition and retention costs have any place in determining notified prices in a more mature market is a matter for debate, though clearly some regulators have formed the view that they do not[16]. Nevertheless, it is clear that the rate of customer switching has not yet stabilised in Queensland (see Figure 4.2) or other Australian jurisdictions for that matter. Further, the Queensland market continues to attract new entrant retailers as evidenced by the arrival of two new retailers to the Queensland market during April 2010. Accordingly, the Authority considers that the current approach to determining customer acquisition costs more accurately reflects conditions in the Queensland market at this time.

Customer switching rate for 2010-11

Similarly, the Authority does not consider the suggestion by Etrog that it should use a fixed number of customers for estimating switching costs as the most appropriate approach. To do so ignores the clear evidence of growth in the customer switching rate that has occurred over the last eighteen months.

This view is reinforced by the suggestion by Integral Energy that competition and switching rates might actually prove to be higher than the Authority had estimated due to a more attractive retail margin and the timing of contract renewals for significant numbers of customers who initially opted to move to a market contract.

While there are some concerns regarding the use of AEMO MSATS data for estimating customer switches, the Authority considers that this data is the best independent source of information available for assessing customer switching rates at this time.

In New South Wales, IPART also relied on AEMO's MSATS data to forecast customer churn for its 2010-13 Final Determination, on the basis that it was transparent and objective[17].

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[15] See for example, CRA International, *Report prepared for the Queensland Competition Authority Calculation of the Benchmark Retail Cost Index, 2009-10, Final Report,* June 2009.

[16] See ICRC, *Retail prices for non-contestable electricity customers 2010-2012, Draft Decision,* April 200, pp 51-57.

[17] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report and Final Determination*, March 2009, p122.

Etrog also suggested that the Authority consider "cleansing" AEMO's MSATS data. However, the Authority is concerned that this task cannot be undertaken with any degree of precision and accuracy and would, of itself, generate concerns in the minds of some stakeholders (depending on the outcome) of the suitability of the "cleansing" process. Manipulating the MSATS data would require a number of assumptions to be made on what to include and exclude from the dataset. The resulting data would not necessarily provide a better basis for predicting customer switching rates.

Since the Authority released its 2009-10 BRCI Final Decision, AEMO has itself taken a number of steps to improve its MSATS data including removing customer movements within the same retail entity and estimating transfers based on the change in financially responsible market participant (FRMP) rather than simply any change to a customers' account status (as suggested by Etrog). AEMO has advised the Authority that it believes its MSATS data has now been adjusted to match as close as possible to actual customer switching between retailers and that it could not make any further refinements to the data to improve its accuracy.

Customer transfer rate for 2010-11

Forecasting customer transfer rates for Queensland presents similar challenges to forecasting the customer switching rate due to the limited availability of suitable data. In its Draft Decision, the Authority noted that some additional data would become available before the Final Decision was completed and that this would be included in its analysis for the Final Decision.

In its 2008-09 and 2009-10 BRCI decisions, the Authority relied on data from South Australia to estimate the number of customers likely to transfer to a market contract with the same retailer and used the same number of transfers (122,032 customers) in both decisions. However, that data is somewhat dated now and no longer appears to provide a realistic picture of the Queensland market, which appears to have developed more quickly than the South Australian market.

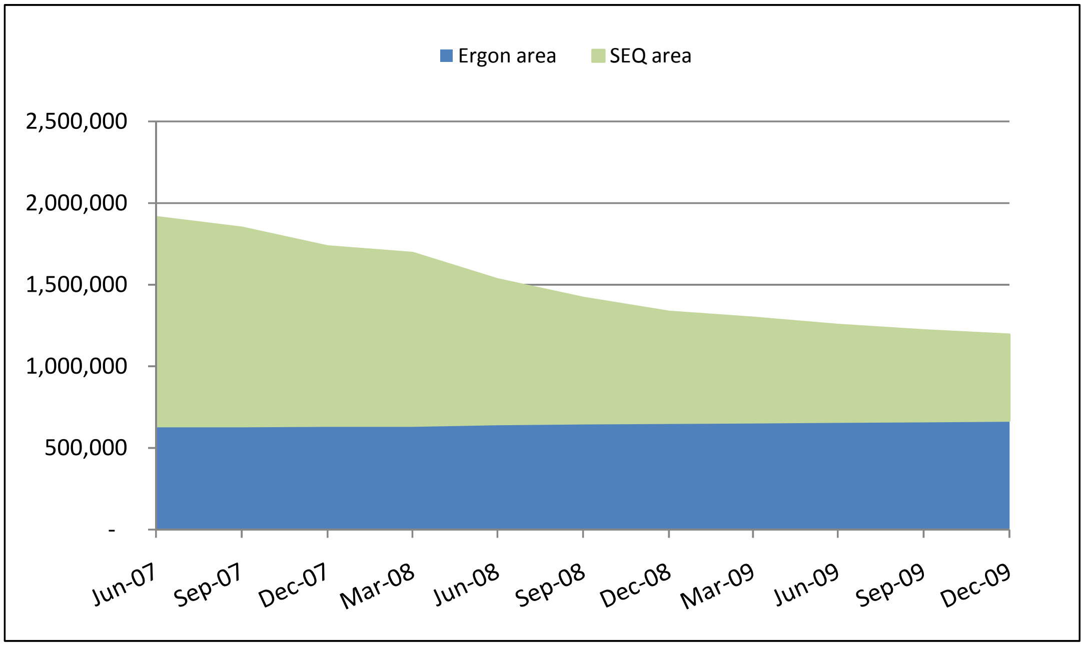
This may reflect the fact that the South Australian market is dominated by a single large incumbent (AGL SA) whereas the Queensland market is characterised by several large retailers, a more competitive situation that is likely to contribute to high rates of customer switching and transfer activity.

Since the introduction of FRC on 1 July 2007, there has been a clear trend in the movement of customers from standard (non-market) contracts onto market contracts with prices and terms agreed between the parties.

As at 31 December 2009, 39.6% of all Queensland customers had moved to a market contract. Of those remaining on non-market contracts, 55.7% were located in the Ergon Energy distribution area where there is limited retail competition and the majority of customers are unlikely to be offered market contracts. This leaves 44.3% (around 540,000) of the State's customers remaining on non-market contracts in South East Queensland, who could potentially transfer to a market contract in the future.

Figure 4.2 shows the number of customers on non-market contracts, based on the total NMI premises data provided to the Authority by distributors and the market NMI data provided by retailers.

Figure 4.2: Non-market customer numbers in Queensland as at 31 December 2009



Source data collated by the Authority using distributor quarterly NMI premises reports and retailer quarterly market NMI reports. Data is presented in aggregated form to protect confidentiality of individual retailer data.

The Authority's Final Decision

Benchmark customer acquisition costs

Given general stakeholder support and the evident continued growth in retail activity in the Queensland market, the Authority has applied the same method as used in its Draft Decision to forecast customer acquisition costs for this Final Decision.

The Authority has escalated the benchmark costs established in 2007-08 (the base year) for a customer switching retailer ($171.43) and a customer transferring to a market contract with the same retailer ($100.00) to arrive at forecast costs for 2010-11. Similar to the escalation of retail operating costs, the 2010-11 values for switching and transfers are escalated using a 60/40 weighted average of WPI and CPI over the intervening period (see Table 4.1).

On this basis, the Authority estimates customer acquisition and retention costs in 2010-11 to be $187.66 per customer switching retailer and $109.47 per customer transferring to a market contract with the same retailer. These estimates compare to $186.69 per customer switching retailer and $108.90 per customer transferring to a market contract estimated in the Authority's Draft Decision and reflect the updated CPI and WPI forecasts.

Customer switching rate for 2010-11

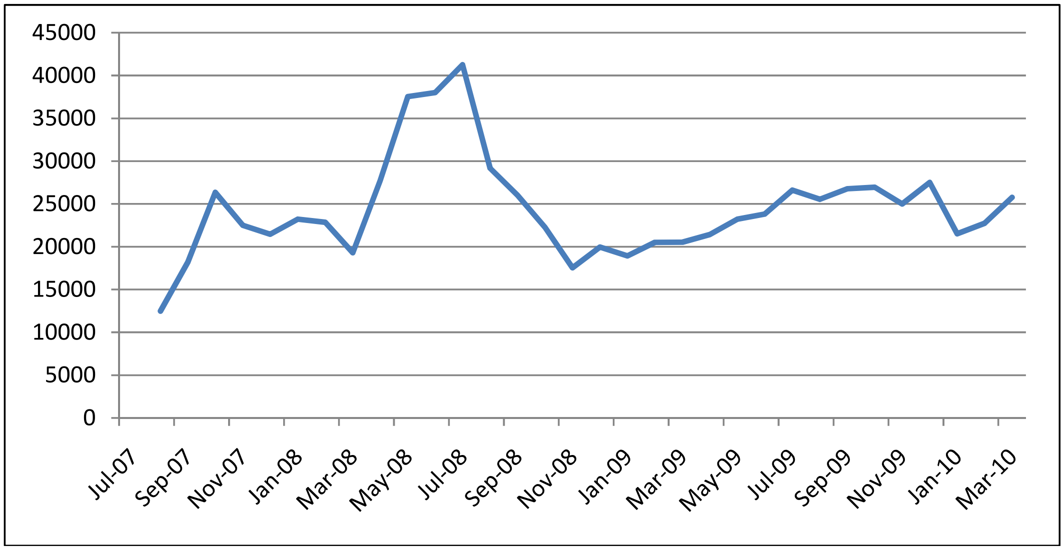
For this Final Decision, the Authority has decided to continue to use the AEMO MSATS monthly data as the basis for forecasting the number of customers switching retailers in Queensland for 2010-11[18].

[18] The AEMO MSATS data for December 2009 excludes customer transfers that automatically occurred in relation to the Jackgreen retailer of last resort event on 19 December 2009.

In considering further the method for forecasting customers switching retailer and in light of some of the comments in submissions, the Authority engaged ACIL to review the methodology proposed by Etrog and to provide expert advice on the most appropriate approach for forecasting customer switches using the MSATS data. ACIL's advice on this issue is available separately from the Authority's web site.

In its advice, ACIL suggested that the forecasting approach proposed by Etrog would be appropriate where a data series was relatively stable. However, where a data series was volatile (as with the MSATS data - see Figure 4.3), ACIL was of the view that Etrog's suggested approach would produce similarly volatile results. ACIL also considered that the method the Authority used in its Draft Decision would tend to automatically bias the growth projection above the historic trend and would not be particularly effective in mitigating the impacts of the volatility in the dataset.

Figure 4.3: AEMO monthly MSATS data for Queensland (July 2007 to March 2010)



Source AEMO MSATS data as at March 2010.

ACIL recommended that the Authority consider adopting an approach which combined elements of the methods used by the Authority in its Draft Decision and that proposed by Etrog. ACIL's proposal involves calculating the annual growth between the latest three months of switching data and the corresponding three months data of the previous year. This annual growth rate is then applied to a base observation in order to forecast customer switches for 2010-2011. The base observation used by ACIL was the average of the 12 most recent monthly observations.

Table 4.4 below compares the outcomes of using the three different methods for forecasting customer switching based on the MSATS data available at time of the Draft Decision (as at November 2009) as well as those based on the most recent MSATS data (as at March 2010).

Table 4.4: Comparison of customer switching growth forecasts using different methods.

	Results based on MSATS data available as at November 2009			*Results based on MSATS data available as at March 2010*		
	Authority's Draft Decision Method	*Etrog Consulting Method*	*ACIL Method*	*Authority's Draft Decision Method*	*Etrog Consulting Method*	*ACIL Method*
Monthly Growth Rate	3.2%	3.0%	1.5%	2. 4%	1.9%	1.3%
2010-11 Switches (number)	461,330	449,179	370,697	388,129	371,197	360,432
Proportion of Qld Customers Switching	22.7%	22.1%	18.3%	19.3%	18. 4%	17.9%
Proportion of SEQ Customers Switching	35.5%	34.6%	28.5%	29.2%	28.0%	27.2%

While all three growth forecasts were lower, and much closer to each other, when the latest MSATS data was included, this was largely a fortuitous outcome, due to the nature of the latest data, in the case of the Authority's Draft Decision approach and Etrog's proposed approach.

In its Draft Decision, the Authority sought submissions on an approach which would better reflect expected market outcomes and considers this is achieved by adopting the ACIL suggested approach which takes into account stakeholder submissions. The method proposed by ACIL appears to produce more consistent outcomes that are less prone to short-term fluctuations due to volatility in the final observation of the dataset. While this approach does differ to some degree from that used in past decisions, the Authority does not consider it to be a change, or at the very least does not consider it to be a substantial change, to the theoretical framework which would require recalculation of the 2009-10 BRCI.

Accordingly, for this Final Decision, the Authority has used the forecasting method proposed by ACIL to estimate the number of customers likely to switch retailers in 2010-11 based on the MSATS data available to March 2010. This approach results in a forecast of 360,432 customers switching retailers in 2010-11 and represents a customer switching rate of 17.9% as a proportion of total Queensland customers (see Table 4.4 above).

This estimated rate of customer switching for 2010-11 is markedly lower than that forecast in the Authority's Draft Decision, and more likely to be in line with stakeholder expectations.

However, as a proportion of customers in South East Queensland, where the majority of competition is occurring, the relevant switching rate is closer to 27.2%. As noted in the Authority's Draft Decision, this higher rate is perhaps more typical of the Queensland market where competition has been more vigorous more quickly following the introduction of FRC than was the case in other jurisdictions.

Customer transfer rate for 2010-11

In the absence of any alternate source of data or a better forecasting approach, the Authority has applied the same method used in its Draft Decision to estimate customers transfers but applied this to the latest available data which includes NMI data up to the December Quarter 2009.

On this basis, the Authority estimates that the total number of customer transfers in 2010-11 will be 127,036, which implies that 6.3% of Queensland customers will transfer to a new market contract with their current retailer in 2010-11. In terms of the number of customers in South East Queensland, the implied customer transfer rate is 9.6%.

This estimate is considerably higher than that forecast in the Draft Decision (33,000 customers or 1.6% of total Queensland customers). The increase is due solely to the inclusion of data for the September and December quarters 2009 and the exclusion of the earlier data for the June and September quarters 2008. At the time of the Draft Decision, the forecast was still very much influenced by the high number of customer transfers which occurred immediately following the introduction of FRC and a subsequent sharp decline in transfers to a more sustainable level. The inclusion of the later data (and the removal of the earlier data) means that the forecast rate of customer transfers forecast for 2010-11 is now more reflective of the reasonably stable rate of growth in transfers over recent times.

The use of updated data to forecast customer transfers and customer switching, as well as the revised method for forecasting switches, has affected the relativities between the number of customer switches and customer transfers forecast for 2010-11 – lowering forecast customer switches and raising forecast customer transfers. The relativity between customer switches and transfers is now more likely to be in line with stakeholder expectations.

Total customer acquisition and retention costs

Based on the above estimates of costs and numbers of customers switching and transferring retailers, total customer acquisition and retention costs are estimated to be $81.5 million in 2010-11, comprised of some 360,432 switches at $187.66 per switch and 127,036 transfers at $109.47 per transfer. When spread across all customers in Queensland (based on estimated total customer numbers of 2,012,602), this equates to $33.61 per customer for switches and $6.91 per customer for transfers.

This compares with an estimated total customer acquisition and retention cost of $89.8 million at the time of the Draft Decision, based on forecast customer switches of 461,000 at $186.69 per customer switching and 33,000 transfers at $108.90 per customer transferring.

4.5 Retail Margin

Draft Decision

As in previous BRCI Decisions, the Authority adopted a retail margin of 5% of total BRCI costs (excluding retail margin) in its Draft Decision. In applying the 5% margin, the dollar value of the retail margin increased from $255.5 million in 2009-10 to $295.8 million in 2010-11, an increase of 15.79%.

Submissions in response to the Draft Decision

Retailers maintained their previously expressed view that the proposed 5% margin failed to fully recognise the risks associated with operating a retail entity in Queensland. For example, Integral Energy suggested the Authority should consider the approach taken in IPART's 2010-13 Draft Determination along with other factors (such as the realistic treatment of depreciation) and raise the margin to between 5.5% and 6.5%. AGL suggested that the Authority should apply a minimum margin of 5.4%, which was the margin adopted by IPART.

The Queensland Consumer's Association noted that the size of the retail margin in dollar terms had increased significantly because of increases in the other components of the BRCI calculations and considered that this growth overestimated the margin required by retailers.

The Authority's Final Decision

In previous BRCI Decisions, the Authority has considered a retail margin of 5% of 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 Authority's first BRCI decision in 2007-08. The 5% figure was originally determined by benchmarking against the margins accepted by regulators in other jurisdictions, which, at that time, ranged from 2% to 8%.

While IPART's recent Draft Decision places the retail margin slightly above that previously used by the Authority, the retail margin of 5% previously adopted by the Authority falls within the range considered reasonable by IPART's consultant, Strategic Finance Group of 4.8% to 6.0% .

In the absence of compelling arguments to do otherwise, the Authority has maintained the retail margin at 5% of the total BRCI. As a result, the Authority estimates the dollar value of the retail margin to be $294.3 million in 2010-11. This compares to a retail margin of $295.8 million estimated at the time of the Draft Decision.

4.6 Other Issues

The Certificate of Delegation requires the Authority consider two policy objectives of the Queensland Government. First, the annual indexation of electricity tariffs should ensure that the 'headroom' available at the commencement of retail competition remain relatively stable. As the Authority noted in previous 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 this obligation has been met.

Second, the Government policy of enabling small customers to revert to notified prices should not result in a retailer having to provide services at a loss. 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 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.

4.7 Final Decision on Retail Costs and Margin for 2010-11 BRCI

A summary of the Authority's assessment for this Final Decision of the costs of providing retail services in 2010-11 and the change in those costs from 2009-10 is provided in Table 4.5.

Table 4.5: Changes in Retail Cost Components ($m) 2009-10 to 2010-11 - Final Decision

Retail Cost Component	***2009-10[1]*** ***$m***	***2010-11*** ***$m***	***Change*** ***%***
Retail costs (including customer acquisition and retention)	217.1	254.4	17.16%
Retail margin (5%)	253.0[2]	294.3	16.30%
Total Retail Costs	**470.2**	**548.7**	**16.70%**

1. See the Authority's 2009-10 BRCI Final Decision.

2. Reduced slightly from the Authority's 2009-10 BRCI Final Decision due to the substitution of ACIL 2009-10 cost of energy estimates - see chapter 2 for details.

Note Totals may not add due to rounding.

In total, retail costs are estimated to increase by 16.70% from $470.2 million in 2009-10 to $548.7 million in 2010-11, less than the $559.0 million estimated for 2010-11 at the time of the Draft Decision.

5. NEM LOAD

The Electricity Act requires that the BRCI be determined by dividing the total benchmark retail cost for the relevant tariff year by the NEM load for the previous calendar year (2009) in order to determine the unit cost of supplying electricity, expressed in c/kWh.

In this Final Decision, the Authority has determined that the 2009 NEM load was 37,832 GWh, an increase of 2.66% from the 2008 NEM load used in the Authority's 2009-10 BRCI Final Decision and, reflecting the use of final data, an increase of 0.93% on the 37,483 GWh NEM load estimated in the Authority's Draft Decision on 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 Draft Decision

The Authority's 2010-11 Draft Decision included an estimate of the 2009 NEM load as the actual load data for the entire year was not available at that time. The Authority noted that full year data for 2009 would become available from AEMO in time for the 2010-11 Final Decision and that it would use that actual data in preparing its Final Decision.

For the purposes of its 2010-11 BRCI Draft Decision, the Authority estimated the 2009 NEM load to be 37,483 GWh based on actual load data for the first three quarters of 2009 and a forecast for the December quarter 2009 prepared by ACIL.

5.4 Submissions in response to the Draft Decision

No submissions received in response to the Draft Decision raised any issues concerning the Authority's approach to the calculation of the NEM load.

5.5 The Authority's Final Decision

Estimating the NEM load for 2009

For the 2010-11 tariff year, the relevant NEM load is that for the 2009 calendar year. The Authority has followed the same approach to calculating the NEM load for 2009 as was used to calculate the 2008 NEM load used in the 2009-10 BRCI Decision.

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 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.

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 these loads from the AEMO data.

Loads of embedded generators

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 2010-11 BRCI, the Authority has not made an adjustment to include the loads of unregistered embedded generators in the calculation of the 2009 NEM load. This is the same approach that was adopted in calculating the BRCI for 2009-10.

Data supplied by AEMO included loads and load profiles supplied by registered embedded generators participating in the NEM and these have therefore been included in the calculation of the NEM load.

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.

2009 NEM Load

Based on the adjustments noted above, the Authority has estimated that the NEM load for 2009, to be used as the denominator in calculating the 2010-11 BRCI Final Decision, is 37,832 GWh, representing an increase of 2.66% from the 2008 NEM load used in calculating the 2009-10 BRCI and, reflecting the use of final data for the December quarter 2009, an increase of 0.93% on the 37,483 GWh NEM load estimated in the Authority's Draft Decision on the 2010-11 BRCI.

This increase primarily reflects load growth associated with new TNIs. Table 5.1 provides a breakdown of the components of the NEM load.

Table 5.1: NEM load for 2010-11 BRCI – Final Decision

	2008[1]	*2009*	*Change*
	GWh	*GWh*	*%*
Total State NEM load	47,367	48,451	2.29
Less loads of directly connected customers and portions of loads connected to the NSW network	10,517	10,619	0.97
NEM Load	**36,851**	**37,832**	**2.66**

Sources AEMO and Powerlink.
1. See the Authority's 2009-10 BRCI Final Decision.

6. FINAL DECISION – 2010-11 BRCI

The Authority estimates the BRCI to be 15.56 cents per kWh in 2010-11 compared to 13.73 cents per kWh in 2009-10. This represents an expected increase of 13.29% in the BRCI between 2009-10 and 2010-11.

6.1 Calculation of the BRCI for 2009-10 and 2010-11

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 2009-10 and 2010-11 - Final Decision

	2009-10	***2010-11***	***Change (%)***
Cost of energy ($m)	2,208.8	2,465.6	11.62
Network costs ($m)	2,381.6	2,871.4	20.57
Retail costs ($m)	470.2	548.7	16.70
NEM load of Queensland (GWh)	36,851	37,832	2.66

Note Totals may not add due to rounding.

Based on the figures contained in Table 6.1, the Authority estimates that the BRCI will increase by 13.29% in 2010-11, as shown in Table 6.2. This compares to an estimated increase of 13.83% in the Authority's Draft Decision.

Table 6.2: Change in the BRCI and its components from 2009-10 to 2010-11 – Final Decision

BRCI cost component	*2009-10*	*2010-11*	*Change*	*Share of total costs 2009-10*	*Change in BRCI*
	c/kWh	*c/kWh*	*%*	*%*	*%*
Cost of energy	**5.99**	**6.52**	**8.73**	**43.65**	**3.81**
LRMC of energy	*2.68*	*2.93*	*9.25*	*19.53*	*1.81*
Energy purchase costs	*2.74*	*2.93*	*6.73*	*19.96*	*1.34*
Other energy costs	*0.57*	*0.66*	*15.88*	*4.16*	*0.66*
Network costs	**6.46**	**7.59**	**17.44**	**47.06**	**8.21**
Distribution	*5.04*	*5.94*	*17.86*	*36.68*	*6.55*
Transmission	*1.43*	*1.65*	*15.93*	*10.38*	*1.65*
Retail costs	**1.28**	**1.45**	**13.67**	**9.29**	**1.27**
Operating costs (including customer acquisition and retention costs)	*0.59*	*0.67*	*14.12*	*4.29*	*0.61*
Margin	*0.69*[1]	*0.78*	*13.29*	*5.00*	*0.66*
Total	**13.73**	**15.56**	**13.29**	**100.00**	**13.29**

Note Totals may not add due to rounding.

As required by the Certificate of Delegation and section 90(5) of the Electricity Act, all existing notified electricity prices will be increased by 13.29% with effect from 1 July 2010.

APPENDIX 1: CURRENT DELEGATION (APRIL 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 2010-2011:

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. In calculating the 2010-2011 BRCI, the QCA must act according to law, and in particular have regard to the decision and reasons for decision of the Queensland Supreme Court in AGL Energy Ltd v QCA & Anor; Origin Energy Retail Ltd v QCA & Anor [2009] QSC 90.

4. The QCA must complete the delegated activities for the 2010-2011 tariff year no later than 31 May 2010;

5. 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

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

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

This delegation applies to the calculation of the BRCI for 2010-11 only, and revokes and replaces my delegation of 3 June 2009.

[redacted]

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

Dated: 7 March 2010

APPENDIX 2: LIST OF SUBMISSIONS

Table A1: Submissions in response to Draft Decision

	Organisation/Individual
1.	Australian Power & Gas
2.	AGL
3.	Chamber of Commerce & Industry Queensland (CCIQ)
4.	Queensland Government
5.	Energy Australia
6.	Energy Retailers' Association
7.	Energy Retailers' Association (additional)
8.	Ergon Energy
9.	Integral Energy
10.	Origin Energy
11.	P.V submission
12.	Queensland Consumers' Association
13.	Queensland Council of Social Service
14.	QUT Credit Commercial and Consumer Law Program

Table A2: Submissions in response to Interim Consultation Notice

	Organisation/Individual
1.	AGL
2.	Energy Australia
3.	Jackgreen
4.	Integral Energy
5.	Origin Energy
6.	Queensland Consumers' Association
7.	Queensland Council of Social Service
8.	QUT Credit Commercial and Consumer Law Program
9.	TRUenergy