QUEENSLAND
COMPETITION
AUTHORITY

Draft Decision

Benchmark Retail Cost Index for Electricity: 2010-11

December 2009

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SUBMISSIONS

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (the Authority). Therefore submissions are invited from interested parties concerning its assessment of the 2010-11 Benchmark Retail Cost Index (BRCI). The Authority will take account of all submissions received by the due date.

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

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The **closing date** for submissions is 12 February 2010.

Confidentiality

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

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

Public access to submissions

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

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

PREAMBLE

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, which 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 on the expiry of the contract with their chosen retailer.

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 Draft Decision, the Authority has applied the framework established in its 2009-10 Final Decision, which reflected the outcome of the judicial review of the Authority's 2008-09 BRCI Decision.

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

(a) an increase in transmission and distribution costs of 20.1%, reflecting the ongoing significant investment in the distribution networks approved by the Australian Energy Regulator (AER). *Transmission and distribution costs account for 47% of total costs; hence the 20.1% increase contributes 8.43 percentage points to the change in the BRCI (61% of the total increase);*

(b) an increase in energy costs of 10.7%, reflecting the impact of rising coal and gas costs on generation costs and higher energy market prices. *Energy costs account for 44% of total costs; hence the 10.7% increase contributes 3.90 percentage points to the change in the BRCI (28% of the total increase);* and

(c) an increase in retail costs of 18.3%, reflecting a significant increase in estimates of customer acquisition and retention costs. *Retail costs account for 9% of total costs; hence the 18.3% increase contributes 1.51 percentage points to the change in the BRCI (11% of the total increase).*

The Authority invites submissions from interested parties on this Draft Decision. Submissions should be received by the Authority no later than 12 February 2010.

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1. INTRODUCTION

Under the Electricity Act 1994 (the Electricity Act), the rate of change in the BRCI is to be used to adjust notified electricity prices each year.

While the Authority recently provided a report to Government on electricity pricing and tariff structures, pursuant to a formal direction from the Premier and the Treasurer (the Ministers), the Authority has a current delegation under the Electricity Act to calculate the increase in the BRCI and to apply it to existing notified prices to establish new notified price to apply from 1 July 2010.

Following the release of an Interim Consultation Notice on 23 October 2009, the Authority is now releasing this Draft Decision.

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 to adjust notified electricity prices each year.

The Authority recently provided a report to Government on electricity pricing and tariff structures, pursuant to a formal direction from the Premier and the Treasurer (the Ministers). The Authority’s Review of Electricity Pricing and Tariff Structures may result in an alternative methodology to the BRCI being used to determine notified electricity prices in Queensland at some time in the future.

However, at this time, the Authority continues to be required to calculate the increase in the BRCI, apply this to existing notified prices and gazette the resulting 2010-11 notified prices by 1 June 2010.

1.2 Scope of this Draft Decision

This report provides the Authority’s Draft Decision regarding the BRCI for 2010-11. It has been prepared in a manner consistent with the Final Decision on the BRCI for 2009-10 and does not seek to reiterate in detail matters previously considered by the Authority in that or other past BRCI decisions.

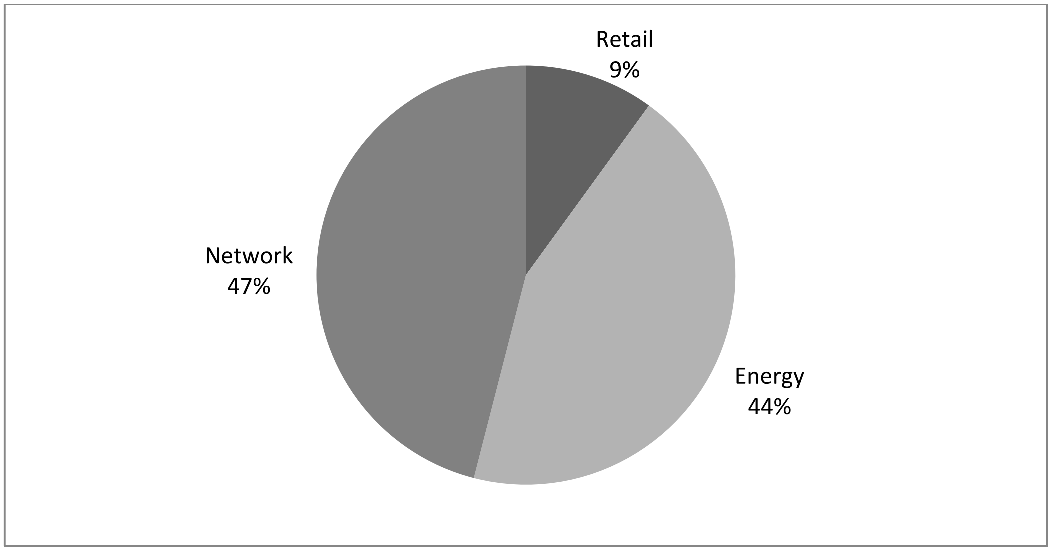
As such, this Draft Decision should be read in conjunction with relevant public reports that are referenced herein.

1.3 Overview of the BRCI

The BRCI approach to determining the notified price(s) 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 change in the underlying cost of supplying electricity to consumers (that is, by the change in the BRCI).

The BRCI has three main components, namely: the cost of energy; network costs; and retail costs. The approximate size of these cost components in the BRCI are illustrated in Figure 1.1.

Figure 1.1: Cost Components in the Supply of Electricity 2009-10



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.

On 16 March 2007, the Minister wrote to the Authority advising that he had delegated this responsibility to the Authority, subject to certain conditions (Original Delegation).

On 3 June 2009, the Minister provided the Authority with a revised certificate of delegation in relation to the 2009-10 BRCI Decision (Current Delegation). The Current Delegation, which is at Appendix 1, is the basis upon which this Draft Decision has been prepared. The delegation requires the Authority to:

(a) calculate the BRCI; and

(b) apply the change in the BRCI to the schedule of notified prices.

While the Current Delegation specifies a deadline for the previous 2009-10 Final Decision, it does not specify a deadline for making the 2010-11 Decision. The requirements of section 96(1) of the Electricity Act therefore apply, which requires that notified tariffs be gazetted at least one month prior to the beginning of the relevant tariff year. Therefore, for the 2010-11 tariff year, the Authority must gazette the new notified prices by 1 June 2010.

The Current Delegation requires the Authority to consider certain policy objectives of the Queensland Government, including that:

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

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

1.4 Calculation of the BRCI for 2010-11

On 23 October 2009, the Authority released an Interim Consultation Notice advising interested parties of the process for calculating the BRCI for 2010-11 and seeking comment from them. The Authority's Interim Consultation Notice proposed to adopt the same methodology in calculating the BRCI for 2010-11 as that used in 2009-10.

Nine submissions were received by the Authority – as listed in Appendix 2. A copy of the Interim Consultation Notice and the submissions received can be obtained from the Authority's website (www.qca.org.au).

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on the cost of energy to be included in the BRCI for 2010-11. ACIL's report can also be obtained from the Authority's website.

1.5 Timetable for determining the BRCI for 2010-11

• Draft Decision released	18 December 2009
• Submissions on Draft Decision close	12 February 2010
• Final Decision released and prices for 2010-11 published	26 May 2010

1.6 Submissions on the Draft Decision

Submissions on this Draft Decision must be received by the Authority by the close of business 12 February 2010. The Authority will consider those submissions received by the due date in preparing its Final Decision.

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 NEM load 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 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 adopted 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. The method used here is the same as that used in the 2009-10 BRCI Final Decision.

To maintain consistency between 2009-10 and its current estimates for 2010-11, the Authority has applied a modelling factor to estimates produced by its consultant in order to account for differences between the proprietary model used in 2009-10 and that being used in 2010-11. 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%.

In establishing the total cost-of-energy component of the 2010-11BRCI, the Authority has taken into account the impact of the 13% 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 and the penalty cost to retailers for not surrendering sufficient Gas Electricity Certificates.

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 components described above, the estimated total cost of energy component of the BRCI is $2,497 million in 2010-11, an increase of 10.69% from the $2,255 million estimated in 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 long run cost of purchasing additional units of electricity will tend to reflect the cost of replacing outdated generating capacity. 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 is required to take into account the effect 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 Draft 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, but is calculated based on the lowest cost combination of generating plant to meet the projected load from a base year;

(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:

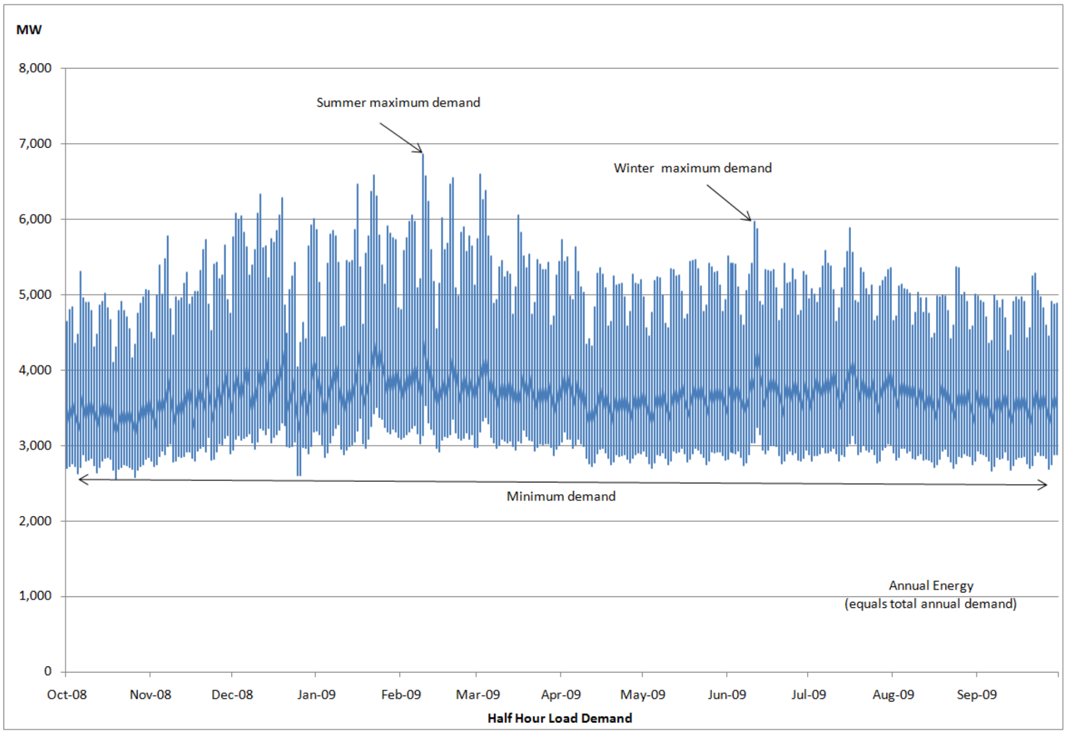
(a) a forecast of the total demand for electricity (annual energy);

(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 October 2008 to 30 September 2009



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 data from AEMO from 1 October 2008 to 30 September 2009. 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: the Australian Energy Market Operator's (AEMO, formerly NEMMCO) Statement of Opportunities (SOO) publication and Powerlink's Annual Planning Report (APR).

The SOO 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 SOO 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 SOO 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 Estimating cost of energy for 2010-11

In its Interim Consultation Notice for 2010-11, 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.

As noted in the Interim Consultation Notice, the Authority engaged ACIL Tasman (ACIL) to provide advice on the calculation of the cost of energy components of the BRCI for 2010-11. While ACIL were responsible for developing the required load traces for the 2009-10 BRCI, the Authority's previous consultant CRA International (CRA) provided advice on the calculation of other elements of the cost of energy for the 2009-10 BRCI.

Given the change of consultant, it is an unfortunate fact that the proprietary models used by the two consultants to estimate the LRMC and energy purchase cost components are unlikely to produce identical results despite implementing the same framework. The Authority has addressed this issue by calibrating the output of the two models in relation to 2009-10 estimates and then applying an adjustment factor to ACIL's 2010-11 modelling.

2.4 Submissions from stakeholders

While many submissions did not specifically comment on the costs of energy calculation, there was broad support for the proposal to continue using the same methodology for the 2010-11 BRCI as established by the Authority in the 2009-10 BRCI Final Decision.

Provision of input modelling data

Several stakeholders requested that the Authority release all LRMC and energy purchase cost modelling input data as part of the consultation process. In particular, AGL made a detailed request for the Authority to provide all the inputs and results of the load modelling, spot price forecasting and detailed workings of the BRCI calculations.

Authority comment

The Authority is conscious of its obligations to consult under the Electricity Regulations. As always, the Authority is committed to a consultation process that will ensure its decisions are made on a fully informed basis. In the Authority's view, the critical issue is that stakeholders understand the methodology and reasoning for the decision. The obligation to consult does not require it to provide information to the level of detail and volume as requested by AGL and some other stakeholders.

The annual BRCI calculation involves tight time frames where modelling data is refined and updated regularly during the process. The Authority understands that some stakeholders may wish to duplicate the modelling internally but it is not practical from the Authority's perspective to manage the consultation or decision making process on the basis that it will provide stakeholders with underlying modelling input data throughout the process.

Nevertheless, the Authority will release as much of the data and information it has relied upon in arriving at its decision as it reasonably can at the same time (or soon thereafter) as it releases this Draft Decision.

LRMC

Both Origin Energy and AGL believed that the capital costs of generation used in the LRMC calculation should be revisited as they considered the Authority's decision to rely on generation cost input data provided by the Authority's consultant, Concept Economics, for the 2009-10 BRCI was unsatisfactory.

Origin Energy stated that the Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) capital cost estimations used in the 2009-10 BRCI were too low. Similarly, AGL reiterated its view from the 2009-10 BRCI that, contrary to the findings in the Concept Economics report, there has been a structural break in the capital costs of generation plant implying a step change in the LRMC input costs. To support its position, AGL provided additional econometric analysis as evidence that there was a step change in coal and gas plant capital costs. On this basis, AGL argued that the Concept Economics data set should not be used for the 2010-11 LRMC calculation and instead preferred the use of more recent data produced by ACIL for the Inter-Regional Planning Committee in April 2009.[1]

AGL stated that it had significant concerns with the approach taken by Concept Economics, noting that it was not aware that the Authority had commissioned this report prior to its use by the Authority in the 2009-10 BRCI Final Decision.

AGL also commented on a number of other issues in relation to the LRMC calculation, including:

(a) proposing a move away from the previous BRCI approach of modelling the LRMC on a 'greenfields', stand-alone basis where the relevant load was modelled over a nine year period to moving to a one to three year LRMC modelling period. To support this move AGL noted that this modelling period is being adopted in New South Wales by the Independent Pricing and Regulatory Tribunal (IPART) and its consultant, Frontier Economics for the 2010-2013 retail pricing determination;

(b) the tax treatment of interest during construction and the WACC. AGL was of the view that the WACC used in the LRMC calculation should not assume any benefit from a tax shield prior to a positive taxable income and suggested that the timing of the tax shield benefit be modelled in each project's cash flow such that the assumption of a standalone new build is correctly incorporated; and

(c) the treatment of interest during construction for determination of fixed costs. AGL stated that in order to be consistent with standard industry practice for project-financed standalone projects, the estimation of generation fixed costs for use in the modelling of LRMC should treat interest during construction as fully capitalised and thus subsequently included in the determination of the average cost of new plant.

Authority comment

The choice of capital input costs is discussed further in section 2.5. For 2010-11 the Authority has accepted ACIL's advice and used capital and fuel input costs provided by ACIL in its report to AEMO's Inter-Regional Planning Committee in April 2009. This report is publicly available.

AGL was the only stakeholder to suggest moving away from the nine year LRMC modelling period used in previous BRCI.

This issue has been considered in previous BRCI decisions. For example, in 2008 CRA noted that generating plants are built to last periods of up to 30 years and more and, as a result, the most cost-efficient mix of plant to service the load of a particular year may not be the most efficient when considered over a longer period of time.[2] The nine year LRMC horizon also matches the demand growth projections provided by AEMO in their annual SOO forecasts which are only available over a nine year horizon. These forecasts serve as the benchmark planning time horizon for the industry and are the base for the selection of an optimal generation system in the LRMC calculation.

Moving to a three year LRMC modelling period would be more indicative of short run Marginal costs (SRMC) than LRMC.

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

2 See Appendix A of CRA's Addendum Report, *Calculation of the Benchmark Retail Cost Index for 2007-08 and 2008-09*, 28 May 2008, available at http://www.qca.org.au/files/ER-NEP0809-FinalDecCRA-Addendum0508.pdf

In support of its suggestion to move to a shorter timeframe for LRMC modelling, AGL claimed that this modelling period is being adopted in New South Wales by IPART and its consultant, Frontier Economics (Frontier) for the 2010-2013 retail pricing determination. However, according to Frontier's report to IPART on the modelling methodology and assumptions for the 2010-2013 retail pricing determination, it proposes to conduct the LRMC modelling over a ten year period "…in order to ensure that the investment and output outcomes during the period from 2010-11 to 2012-13 reflect the fact that investment decisions are long term decisions."[3]

In light of the above, the Authority will continue to model LRMC over the longer nine year period.

ACIL has commented on the treatment of interest during construction in its report to the Authority. ACIL notes that its new entrant LRMC model uses an Officer WACC which has allowance for financing activities incorporated and is an after tax model.[4] ACIL's treatment of the cash flows in the modelling is consistent with the Officer approach and if it were to make a specific allowance for interest during construction, as suggested by AGL, then there would be double counting of this component.

ACIL's model is set up as a discounted cash flow model that applies the discounting factor (the WACC in this case) from year zero, which is the commencement of construction. This means that negative cash flows during the construction period are increased by the weighted average of the industry return on equity and interest rate. Interest incurred during the construction period has being taken into account through this mechanism. In effect all costs during this period, including the return on capital and interest costs, are being capitalised in ACIL's model as they contribute to accumulated negative cash flow against which future positive cash flows will be offset.

On this basis, the Authority is satisfied that ACIL's treatment of interest during construction, as part of its LRMC modelling, is appropriate.

Energy Purchase Cost

In response to the Authority's proposal to use the same approach to estimating energy purchase cost as it had done in its 2009-10 BRCI Final Decision, AGL reiterated its views in respect of the NEM Load forecasts developed by ACIL for the 2009-10 BRCI Final Decision. AGL again submitted a brief report prepared by its consultant, Creative Energy Solutions (CES), which it suggested showed that the methodology used by ACIL resulted in a NEM load forecast that is 'flattening' and therefore does not accord with the historical evidence that demonstrates that the NEM Load has become peakier over the relevant period. AGL claimed that, as a consequence, ACIL's methodology resulted in a NEM Load forecast that was inconsistent with the load trajectory observed in AEMO's SOO forecast and Powerlink's APR.

AGL also raised a number of issues in relation to energy purchase cost modelling that it believed were unclear in the previous modelling approach adopted by. Briefly, these included:

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3 Frontier Economics, *Modelling methodology and assumptions*, A report for IPART, August 2009, pp17-18, available at http://www.ipart.nsw.gov.au/investigation_content.asp?industry=2&sector=3&inquiry=196&doctype=5&doccategory=1&docgroup=1

4 The Officer approach is a form of WACC that estimates post-tax (cash) return on assets that the company needs to generate. ACIL utilises a post-tax real Officer WACC within its new entrant model and applies it to un-geared cash flows. The post-tax nominal Officer WACC is then adjusted into real terms by ACIL using the Fischer equation. The Officer WACC is applied to cash flows that do not include the effects of the interest tax shield and dividend imputation credits. That is, cash flows are un-geared and defined simply as:

$$Cash\ Flows_{(Officer)} = X \times (1 - T)$$

Where X is the project cash flow and T is the statutory corporate tax rate.

(a) the high degree of correlation between incidents of high price and high demand. AGL highlighted that this degree of correlation should be present in any spot price forecasts produced by ACIL;

(b) the calibration process previously undertaken by CRA. AGL sought clarification on whether the pool price forecast will be calibrated to achieve a weighted average price by an adjustment in the number of incidences of high prices or whether by reference to underlying prices; and

(c) application of marginal loss factors (MLF). AGL was concerned that CRA had previously applied the MLF after the forecast load was determined. AGL believed that the appropriate manner in which to determine hedging costs for the hypothetical retailer would be to apply the MLF to the forecast load prior to the 'acquisition' of hedges.

Authority comment

The Authority engaged ACIL to prepare the load traces for 2009-10. The approach proposed by ACIL was the same as it had outlined to the Court in the judicial review hearing.

The Authority considered the report from CES report during its consultation on ACIL's methodology for developing the NEM load traces for the 2008-09 Remade Decision and the 2009-10 Final Decision. The Authority noted in its 2009-10 Final Decision, that ACIL had considered all the technical issues raised in submissions (including having reviewed the CES report) and, having had regard to ACIL's advice on these issues, the Authority was satisfied that ACIL's methodology was an appropriate basis for determining the NEM load traces.

The Authority has again sought ACIL's expert view on the issues raised in the CES report. Given that the CES report has already been reviewed by the Authority and ACIL previously as part of the 2009-10 BRCI Decision, the Authority on this occasion was inclined to dismiss AGL's concerns on ACIL's load trace methodology. However, in order to ensure that the Authority is making a fully informed decision, it once again sought ACIL's advice in relation to AGL's assertions and the issues raised in CES's report. Based on ACIL's assessment of the matters raised by CES (see Appendix 3), the Authority remains satisfied that the methodology used by ACIL to forecast the NEM load is appropriate and is consistent with the judicial interpretation of the load to be used to forecast energy purchase costs.

Regarding AGL's comments on the application of marginal loss factors, the Authority notes that in previous BRCI decisions, including the 2009-10 BRCI Final Decision, the energy purchase cost was calculated using an Average Loss Factor (ALF) for Queensland, as calculated by Powerlink in its APR, not a MLF.

The alternative of using a MLF had been canvassed during preparation of the 2009-10 BRCI decision. However, this was not pursued following comments from stakeholders including AGL.

Regardless, the Authority sought ACIL's expert advice in relation to the impact of applying loss factors as suggested by AGL. ACIL has advised the Authority that the application of the loss factors to the input load trace, rather than applying it at the end, results in the same cost of energy estimate.

Based on the above, the Authority is satisfied that no change in the approach to applying ALF is warranted for the calculation of energy purchase costs for 2010-11.

Weighting of LRMC and Energy Purchase Cost

A number of submissions, such as those from TRUenergy, EnergyAustralia and Origin Energy, appeared to advocate a move away from the equal weighting of the LRMC and Energy Purchase Cost. These submissions suggested that the cost of energy should be more heavily weighted towards Energy Purchase Cost, with LRMC setting a floor to reduce risk exposure in underwriting generation sector investment (consistent with IPART's current approach for 2010-2013 retail price determination).

Authority comment

This issue has been extensively canvassed in previous BRCI decisions. There are arguments that could be made for both weighting the balance in either direction. In the past, as is again the case here, retailers have generally argued for the balance to be more heavily weighted in favour of energy purchase costs while consumer representatives have generally favoured a heavier weighting toward LRMC. The 50/50 weighting adopted by the Authority in the past reflects this balance of views and also recognises the emphasis in the legislation on LRMC as the basis for determining energy costs.

As there is no new or compelling argument to support a change in that view, the Authority will continue to weight LRMC and energy purchase costs equally in calculating the energy cost component of the 2010-11 BRCI.

Carbon Pollution Reduction Scheme (CPRS) and LRMC

Origin Energy suggested that, since introduction of CPRS is now more assured than at the time of the 2009-10 BRCI, the LRMC should be modelled on some credible CPRS scenarios and, if it is clear before the Authority's Final Decision what the actual CPRS will be, then it can be incorporated into the 2010-11 LRMC in the Final Decision. AGL supported excluding any consideration of the CPRS in calculating the 2010-11 LRMC.

Authority comment

In its 2009-10 BRCI Final Decision, the Authority decided not to include any costs associated with the future introduction of a CPRS due to the uncertainty surrounding the timing of introduction of the scheme as well as the detail of the scheme itself. Since then, the Commonwealth Government delayed the planned introduction of the CPRS until 1 July 2011 and flagged other changes to ameliorate its impact.

More importantly, recent events have seen the CPRS legislation defeated in the Senate and the future of the scheme is now entirely uncertain.

For these reasons, the Authority has again not included any specific recognition of potential future carbon costs. To the extent that some costs may already be reflected in market prices due to the uncertainty surrounding carbon costs if nothing else, these will be captured in the prices used for estimating energy purchase costs.

Other energy costs

The Authority did not receive any specific comments from stakeholders other than Origin Energy and AGL on other energy costs that must be taken into account in determining the overall cost of energy component for the BRCI.

Origin Energy supported the continued use of the approach adopted by the Authority in its 2009-10 BRCI Final Decision to accounting for the costs associated with retailers acquiring sufficient Gas Electricity Certificates (GECs) and Renewable Energy Certificates (RECs) to meeting their legislative obligations under the Queensland Gas Scheme (under the Electricity Act) and the MRET scheme (under the Renewable Energy Act), respectively.

AGL on the other hand was concerned that recent changes to the MRET scheme following the legislative change to expand the RET have led to a significant degree of uncertainty as to the Renewable Power Percentage (RPP) and REC prices. AGL noted that the regulations and policies that provide certainty on the RET obligations of participants have not been finalised, and may not be finalised before March 2010. The areas of uncertainty noted by AGL include:

(a) the final form of the 20% RET contains an additional component for the inclusion of eligible waste coal mine generation. AGL observed that in modelling the REC cost, this additional target and cost will need to be included;

(b) the electricity loads that are liable (for RECs) given the partial exemption for trade exposed industries from the expanded target;

(c) the appropriate RPP for each retailer; and

(d) the partial assistance offered to trade exposed industries for costs incurred above $40/MWh for the original MRET component of the 20% RET.

In relation to the cost of RECs, AGL was of the view that RET compliance costs should be determined with reference to the LRMC of generation for assets that are eligible to create RECs because any retailer with a significant REC liability will need to enter into long term power purchase agreements (PPAs) in order to fulfil their liability.

Authority comment

In its report to the Authority, ACIL have advised that they have attempted to calculate the RET cost component in the same way as it was calculated for the 2009-10 BRCI by CRA. ACIL have used the same source for the cost of RECs and made a reasonable estimate of the RPP based on the targets under the expanded RET scheme. However, ACIL have acknowledged that there are some uncertainties in projecting RET costs, as suggested by AGL, and that these are unlikely to be resolved before March 2010 when the RPPs for 2010 become known. ACIL are of the view that the historical approach to calculating RET costs should be maintained until there are clear and detailed announcements from the Commonwealth Government on how the expanded RET scheme is to be administered.

With respect to AGL's suggestion that RET compliance costs should be determined with reference to the LRMC of generation for assets that are eligible to create RECs, ACIL have interpreted this as suggesting that the price of RECs should be projected using typical industry methodology for projecting REC prices into the future rather than using the most recent Australian Financial Markets Association (AFMA) data as has been done in previous BRCI decisions. ACIL were of the view that, since REC prices for the BRCI are only needed over a one year forecast period, a change in methodology from using actual market data to long term forecasting of REC prices was not justified and would serve no useful purpose.

After considering ACIL's advice on issues raised in relation to RPP, the Authority agrees that the cost of REC's cannot be settled until the RPPs are known for 2010 in March 2010. These could then be considered in the Authority's Final Decision.

In relation to RET compliance costs, there does not appear to be a strong argument to change the method of estimating compliance costs that has been used in the past and accepted by most stakeholders in that context.

2.5 Estimating cost of energy for 2010-11

Model calibration based on 2009-10

In order to assess any potential modelling difference between that used by ACIL and that used in 2009-10 by CRA, the Authority asked ACIL to use their model to calculate the LRMC and energy purchase costs for 2009-10 using the same input data and same theoretical framework as was used in 2009-10 and compare their results with those provided previously by CRA.

Replication of 2009-10 LRMC calculation using ACIL's model

In modelling the 2009-10 LRMC, ACIL used a similar approach to that used by CRA for the 2009-10 BRCI Final Decision. Consistent with CRA's modelling approach, ACIL's modelling involved:

(a) developing forecasts of fuel, capital and operating and maintenance costs for the range of power stations in use in Australia;

(b) taking into account State and Commonwealth programs that add or subtract to energy costs, such as the GEC and MRET schemes;

(c) using these inputs in a least cost supply model which minimizes both short run and long run marginal costs in meeting future market demand.

ACIL used their proprietary least cost optimising model to calculate the LRMC for the Queensland region of the NEM. For the 2009-10 LRMC calculation, ACIL used the same data inputs and sources as CRA used in their calculation, including the data from the Concept Economics report on the review of capital and fuel inputs costs.

ACIL also used actual half-hourly demands for calendar year 2008 from the AEMO's website. The demand included electricity delivered from the transmission system to the distribution system in Queensland as well as demand of end-users directly connected to the transmission system, consistent with the demand load used by CRA. ACIL's model utilised a sample of 50 regional demands from the set of half-hourly demands to represent the entire year. This sample set was selected to best represent the distribution of demands in each region on an annual basis as well as to best represent the relationship between demands across the regions. ACIL believe that this appears to be similar to the approach taken by CRA. While CRA used a sample of 40 regional demands instead of 50, ACIL did not consider this difference to be material but merely a reflection of the way the two different models are set up.

A potential modelling difference identified by ACIL relates to the effect of the Queensland Gas Scheme. ACIL's LRMC model was calibrated to subtract the GEC price from the LRMC of gas-fired plant in Queensland, which increases the attractiveness of these plants and results in more CCGT/OCGTs being included in the optimal plant mix of Queensland. However, in the ACIL model, if there is an oversupply of GECs, then only the proportion of GECs able to be sold is included in the revenue streams. ACIL have noted in their report that this has the effect of decreasing the amount deducted from the LRMC due to the GECs. An example given by ACIL is that if there are twice as many GECs as required, then ACIL's model will only reduce the LRMC of the CCGTs/OCGTs by 50% of the GEC penalty.

While ACIL's LRMC model assumes the gas scheme continues with GEC prices fixed at the penalty rate and the GEC target as published in the CRA report, ACIL were not able to clearly ascertain whether CRA's LRMC model took into account any oversupply of GECs in the CCGT/OCGT revenue streams. However, based on CRA's reports, ACIL believe that CRA took a similar approach.

A description of how ACIL's propriety model operates including its treatment of all other modelling parameters compared to CRA's modelling approach is provided in ACIL's report, which is available on the Authority's website.

Table 2.1 below compares ACIL's 2009-10 LRMC estimate with that produced by CRA for the 2009-10 BRCI Final Decision.

Table 2.1: Comparison of the 2009-10 LRMC estimates by CRA and ACIL

Cost Component	*2009-10 CRA estimate[1]*	*2009-10 ACIL estimate*	*Difference*	*ACIL's implied LRMC modelling difference*
	$/MWh	*$/MWh*	*$/MWh*	*%*
LRMC	53.28	53.63	-0.35	-0.65

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

As can be seen from Table 2.1, the LRMC estimate produced by ACIL is only marginally different to that produced by CRA, by $0.35 per MWh or 0.65% above that produced by CRA.

Replication of 2009-10 Energy Purchase Cost calculation using ACIL's model

ACIL also estimated 2009-10 energy purchase costs using the same methodology as that used by CRA for the 2009-10 BRCI Final Decision. ACIL used the same data inputs as CRA, with the exception of the NEM pool prices for which it used prices from its own electricity market simulation modelling.

The volume of hedge contracts was determined by ACIL based on the criteria detailed by CRA in its Final Report on the 2009-10 BRCI, 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.

The half hourly load data used for constructing the hedging strategy represented an estimate of the 50% probability of exceedance (POE) of the NEM load of Queensland which excluded the load associated with directly connected customers. The NEM load used by ACIL was the same load forecast used by CRA which was itself prepared by ACIL for the Authority for use in the 2009-10 BRCI Final Decision.

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

Using these inputs, ACIL were able to match the cost of contracts with those estimated by CRA for the 2009-10 BRCI Final Decision.

Settlement of these contracts was modelled for three load scenarios (10%POE, 50%POE and 90%POE) similar to CRA's approach. These load forecasts were in fact estimated by ACIL for the Authority and used by CRA in its modelling for the 2009-10 BRCI Final Decision.

The only material difference in the input data was the half hourly NEM pool prices used to calculate the energy purchase cost under the three load scenarios. As ACIL would have to generate the NEM pool prices for 2010-11 it seemed appropriate to compare the results using the same approach that would be required for 2010-11. ACIL therefore generated its own NEM pool prices for 2009-10 using its proprietary electricity market simulation model based on the 10%POE, 50%POE and the 90%POE load scenarios.

Table 2.2 below compares ACIL's 2009-10 energy purchase cost estimate with that produced by CRA for the 2009-10 BRCI Final Decision.

Table 2.2: Comparison of the 2009-10 Energy Purchase Cost estimates by CRA and ACIL

Cost Component	*2009-10 CRA estimate*[1]	*2009-10 ACIL estimate*[2]	*Difference*	*ACIL's implied energy purchase cost modelling difference*
	$/MWh	*$/MWh*	*$/MWh*	*%*
Energy Purchase Cost	57.70	54.83	2.88	5.25

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

ACIL's modelling resulted in an energy purchase cost estimate that is $2.88/MWh (5.25%) lower than CRA's model. ACIL noted that its spot price forecast for the 50%POE were generally lower than those of CRA and ACIL's 10%POE prices show greater volatility on average than CRA's forecast. While this difference could potentially be attributed to the use of different NEM Pool prices, ACIL noted that it is difficult to identify any one specific reason to account for the resulting differences as projecting the NEM pool prices requires a large number of inputs and the models themselves would invariably use different proprietary methods to simulate spot prices.

Long Run Marginal Cost

ACIL has applied the same approach to calculating the 2010-11 LRMC component of the cost of energy as that described above for 2009-10. The treatment of specific issues relevant to the 2010-11 calculation, including the availability of final data, are discussed below.

Load Demand Profile

The Electricity Regulation requires the LRMC to be calculated to meet the demand profile formed over each half-hour for the previous calendar year. Therefore, the LRMC for 2010-11 is calculated on the basis of the generation required to meet demand in calendar year 2009. For this Draft Decision, the actual load data for the 2009 calendar year was only available for the period from 1 January to 30 September 2009, with the remainder estimated by ACIL.

Actual load data for the full 2009 calendar year will become available in time for use in the Final Decision.

Energy Generation Costs

In making its 2009-10 BRCI decision, the Authority undertook an extensive review of capital and fuel input costs of various generation plant types for calculating the LRMC. At the time, some retailers argued strongly that the LRMC did not take sufficient account of an apparent change in energy generation costs over recent times. Retailers were also of the view that the apparent cost increases constituted a permanent change in costs (a step-change) rather than a temporary shift from a long-run cost path.

In response to this issue, for the 2009-10 BRCI Draft Decision, the Authority engaged ACIL to provide it with advice on whether there had been a step-change in energy generation costs and how rising costs might best be reflected in the LRMC of energy calculation. ACIL provided its report to the Authority in October 2008.

To consider this matter further in preparing its 2009-10 Final Decision, the Authority engaged Concept Economics to provide an independent review of ACIL's earlier LRMC input cost forecasts and to also consider how the rapidly changing global economic environment might impact on the assessment of the step-change claims made by the retailers.

In its Final Report in May 2009, Concept Economics noted that ACIL's October 2008 proposition that a step-change in capital cost had occurred was driven mainly by a change in steel prices and, to a lesser extent, labour. While Concept Economics accepted that steel prices rose steeply over the two or three years prior to October 2008 and that capital costs appeared to increase concurrently, these prices had dropped substantially since that time.

Compared to ACIL, Concept Economics had the benefit of being able to observe the later events driven by the rapid deterioration in global economic conditions. However, Concept Economics did find that statistical tests based on historical data from 1997 to October 2008 (which had been the latest data available to ACIL at the time) did support the hypothesis of a structural break in the data series for CCGT plants. For coal plants, Concept Economics were of the view that the statistical results were inconclusive.

Concept Economics also had some concerns about the selection of data used by ACIL. Concept Economics noted that, because ACIL did not consider that a regression approach for forecasting the LRMC was appropriate (because of the apparent step-change in costs), ACIL instead projected capital costs by combining steel and labour price indexes and aligning this new index to capital cost indexes for CCGT and Black Coal plants.

Concept Economics therefore constructed a new series of input cost estimates which were more in keeping with more recent economic conditions and offered a more appropriate (but not substantially different) basis for assessing the LRMC of energy.

For its 2009-10 BRCI Final Decision, the Authority used the Concept Economics input costs in calculating the LRMC.

Given the concerns expressed by retailers and the significant changes in world markets that have continued since the 2009-10 Final Decision was made, the Authority asked ACIL to review the choice of input costs most appropriate for use in the 2010-11 BRCI decision.

ACIL is of the view that its April 2009 report to AEMO's Inter-Regional Planning Committee report provides a more comprehensive estimate taking into account not only recent developments in capital input costs but also significant changes in energy fuel costs since April 2009, particularly due to exchange rate fluctuations that should also be taken into account.

ACIL therefore recommended using data from their April 2009 report, as suggested by AGL, as the basis for the capital and energy fuel price projections in the LRMC calculation with an update to the coal prices to take into account significant changes in exchange rates which have an effect on domestic prices into power stations.

Based on this set of input costs, ACIL found that the capital costs used were very similar to the capital cost projections put forward by Concept Economics, except for gas fuel costs, which were about 25% higher, and coal costs, which were about 10% lower.

Given the differences in energy fuel costs between the Concept Economics forecasts and ACIL's later data, the Authority has opted to use the more recent data available from ACIL rather than use the, now somewhat dated, forward forecasts provided by Concept Economics in its report for the 2009-10 BRCI Final Decision.

LRMC estimate for 2010-11

On this basis, ACIL estimated the LRMC for 2010-11 to be $58.51 per MWh.

Application of LRMC modelling factor to 2010-11

As demonstrated above, there are some inherent differences in the models used by ACIL and CRA to calculate the LRMC. To maintain consistency between the LRMC modelling results for 2009-10 and those produced now for 2010-11, the Authority considers it appropriate to account for this difference by applying a modelling factor to adjust ACIL's 2010-11 LRMC estimate. The modelling factor reflects the difference in the modelling of LRMC between ACIL and CRA for 2009-10 as previously discussed. The application of this modelling factor should ensure that the estimate derived by ACIL is consistent with CRA's estimate for 2009-10, against which the BRCI change will be measured.

Based on the difference identified in the 2009-10 LRMC estimates for ACIL and CRA in Table 2.2 above, the Authority has adjusted ACIL's 2010-11 LRMC estimate by -0.65% to arrive at its Draft Decision estimate of the LRMC for 2010-11 of $58.13 per MWh as shown in Table 2.3 below.

This adjustment is only required in measuring the change in the BRCI for 2010-11. Should the Authority be required to adjust notified prices for a further year (2011-12) using the BRCI approach, and ACIL is again engaged to provide advice on the cost of energy, the relevant comparison point from 2010-11 would be $58.51/MWh and not the slightly lower $58.13/MWh derived by applying the modelling factor. This is because, in any subsequent year, there would be no modelling difference to adjust for, so long as ACIL's model continued to be used.

Table 2.3: LRMC estimate for 2010-11 BRCI

Cost component	*2009-10*[1]	*2010-11 forecast by ACIL*[2]	*Modelling factor*	*Adjusted LRMC estimate for 2010-11*	*Change between 2009-10 and 2010-11*
	$/MWh	*$/MWh*	*%*	*$/MWh*	*%*
LRMC	53.28	58.51	-0.65%	58.13	9.10

1. See the Authority's 2009-10 BRCI Final Decision.
2. ACIL Tasman, The Calculation of Energy Costs in the BRCI for 2010-11, Draft Report 14 December 2009.

Energy Purchase Costs

As discussed above in relation to replicating the 2009-10 energy purchase costs, ACIL has applied the same approach to calculating the energy purchase costs for 2010-11. The key inputs used by ACIL to estimate the energy purchase cost component are as follows:

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

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

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

Detailed discussion of ACIL's approach to forecasting energy purchase cost is contained in its report which is available from the Authority's website. Table 2.4 below summarises ACIL's energy purchase costs for 2010-11 for each of the three probability three scenarios which are weighted to arrive at an overall estimate.

Table 2.4: 2010-11 Scenario weighted energy purchase cost estimates

	Scenario Weighting	***2010-11***
	%	*$/MWh*
Energy purchase cost 10%POE	30.40	58.82
Energy purchase cost 50%POE	39.20	58.61
Energy purchase cost 90%POE	30.40	58.76
Energy purchase cost weighted	**100.00**	**58.72**

Source: ACIL Tasman, The Calculation of Energy Costs in the BRCI for 2010-11, Draft Report 14 December 2009.

Application of Energy Purchase Cost modelling factor to 2010-11 estimate

The Authority is of the view that ACIL's approach to calculating energy purchase cost is consistent with that used in the 2009-10 Final Decision. However, as demonstrated above, there are some inherent differences in the models used by ACIL and CRA to calculate energy purchase costs. To maintain consistency between the energy purchase cost modelling results for 2009-10 and those produced now for 2010-11, it has applied a modelling factor to adjust ACIL's 2010-11 energy purchase cost estimate. The modelling factor reflects the difference in the modelling of energy purchase costs between ACIL and CRA for 2009-10 as previously discussed. The application of this modelling factor should ensure that the estimate derived by ACIL is consistent with CRA's estimate for 2009-10, against which the BRCI change will be measured.

Based on the difference identified in the 2009-10 energy purchase cost estimates for ACIL and CRA in Table 2.2 above, the Authority has increased ACIL's 2010-11 energy purchase cost estimate by 5.25% to arrive at its Draft Decision estimate of the energy purchase cost for 2010-11 of $61.80 per MWh, as shown in Table 2.5 below.

As was noted in relation to LRMC, this adjustment is only required in measuring the change in the BRCI for 2010-11. Should the Authority be required to adjust notified prices for a further year (2011-12) using the BRCI approach (and engaged ACIL to again provide advice on the cost of energy), the relevant comparison point from 2010-11 would be $58.72/MWh and not the slightly higher $61.80/MWh derived by applying the modelling factor.

Table 2.5: Energy purchase cost estimate for 2010-11 BRCI

Cost component	*2009-10*[1]	*2010-11 forecast by ACIL*[2]	*Modelling factor adjustment*	*Overall energy purchase cost estimate for 2010-11*	*Change between 2009-10 and 2010-11*
	$/MWh	*$/MWh*	*%*	*$/MWh*	*%*
Energy purchase cost	57.7	58.72	5.25	61.80	7.10

1. *See the Authority's 2009-10 BRCI Final Decision.*
2. *ACIL Tasman, The Calculation of Energy Costs in the BRCI for 2010-11, Draft Report 14 December 2009.*

Other energy costs

In establishing the cost of energy component of the BRCI, the Electricity Act requires the Authority to consider the impact of the 13% Queensland Gas Scheme under the Electricity Act and the MRET scheme established under the Renewable Energy Act.

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

To determine likely changes in the cost of these components in 2010-11, the Authority asked ACIL to also estimate these costs consistent with the methodology used previously by CRA.

The Queensland Gas Scheme

The costs to retailers of complying with the Queensland Gas Scheme are based on the penalty price to retailers for not surrendering sufficient GECs. Based on current data, ACIL estimated the cost for 2010-11 to be $2.80/MWh or, in total, $105 million, an increase of 9.46% from 2009-10.

Mandatory Renewable Energy Target (MRET)

To determine the costs to retailers of complying with the MRET scheme, ACIL used weekly market prices for RECs published by AFMA. Based on this approach and the currently available data up to the week of 25 November 2009, ACIL estimated the cost of complying with the MRET scheme to be $3.02/MWh in 2010-11 and in total $113.2 million, an increase of 24.54% from 2009-10. This significant cost increase is related to the new higher MRET target under the expanded RET scheme.

NEM participant fees and ancillary services

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

For 2010-11, ACIL estimated the cost of 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's website. On this basis, the Authority expects the total cost of NEM fees to be $13.9 million in 2010-11, an increase of 13.78% from 2009-10.

The cost of ancillary services provided by AEMO has also been estimated by ACIL. Based on the average cost over the preceding 52 weeks of currently available ancillary services cost data, it is estimated that the cost of ancillary services will be $0.45/MWh in 2010-11, or in total $16.9 million, an increase of around 11.35% from 2009-10.

2.6 The Authority's Position

In total, the Authority estimates that the cost of energy will rise from $2,255 million in 2009-10 to $2,497 million in 2010-11, an increase of 10.69%. In $/MWh terms, the total cost of energy is expected to increase from $61.20/MWh in 2009-10 to $66.60/MWh in 2010-11, as shown in Table 2.6 below.

Table 2.6: Cost of energy components, 2009-10 to 2010-11 – Draft Decision

Cost Component	***2009-10[1]***		***2010-11***		***Change***
	$/MWh		*$/MWh*		*%*
LRMC *(50% weighting)*	53.28	*26.64*	58.13	*29.06*	9.10
Energy purchase cost *(50% weighting)*	57.70	*28.85*	61.80	*30.90*	7.10
Cost of Energy		55.49		59.96	8.06
20% MRET		2.43		3.02	24.54
Queensland Gas Scheme		2.56		2.80	9.46
NEM fees		0.33		0.37	13.78
Ancillary services		0.40		0.45	11.35
Total: $/MWh		**61.20**		**66.60**	**8.82**
$million		**2,255.4**		**2,496.6**	**10.69**

1. 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 revenue requirements of transmission and distribution network service providers in Queensland.

The Authority has based its assessment of transmission network costs on the AER's revised Powerlink Final Decision and the transmission related costs that the distributors pass through to customers.

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 AER will determine the revenue requirements for both distributors for the following regulatory period. For this Draft Decision, the network costs for 2010-11 are based on the AER's recent Draft Determination. These figures will be updated in the Authority's Final Decision to reflect the AER's Final Determination.

On this basis, the Authority has estimated the relevant network costs to be $2,861 million for 2010-11, an increase of 20.1% 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 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 must reflect the Authority's view of the likely total revenue requirements for transmission and distribution networks in Queensland.

3.3 Estimating network costs to be used in the 2010-11 BRCI

Transmission costs

The costs which are included in the BRCI for the transmission component of the total network costs are an estimate of the amount that Queensland's main transmission entity (Powerlink) is expected to charge Queensland's electricity distributors (Energex and Ergon Energy) for using its services and other transmission-related costs.

Powerlink's transmission use of system (TUOS) charges are by far the largest component of the charges Energex and Ergon Energy incur for using Powerlink's services. However, there are a number of other minor transmission-related costs incurred by distributors, including avoided TUOS payments made to embedded generators, and other payments to Powerlink or to other distributors for transmission-like network services.

At the date of this Draft Decision, Powerlink charges and other transmission charges for 2010-11 were not available. Therefore, as in the 2009-10 Draft Decision, the Authority has estimated these charges by calculating the proportion of Powerlink's maximum allowable revenue (MAR) in the previous year (2009-10) that accounted for the total transmission charges levied on distributors. This proportion of Powerlink's MAR was then applied to its 2010-11 MAR, as calculated by the AER in its *Final Decision on Powerlink Queensland transmission network revenue cap for 2007-08 to 2011-12 (June 2007),* revised on 8 July 2008 to account for Powerlink's South Pine to Sandgate contingent project (AER's revised Powerlink Final Decision).

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

These estimates will be updated for the Authority's Final Decision following better estimates becoming available in the distributors' 2010-11 Pricing Proposals. The Pricing Proposals contain individual estimates of Powerlink's TUOS charges as well as specific estimates of the other transmission-related costs to be incurred by the distributors.

While the AER has inherited the task of approving distributors' annual Pricing Proposals as part of its assumed responsibilities as the economic regulator of distribution network service providers in the NEM, the Authority will request a copy of the 2010-11 Pricing Proposals from Energex and Ergon Energy when these are finalised.

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

Distribution costs

For 2009-10 and previous years, estimated distribution costs were derived from the revenue caps of the Queensland distributors Energex and Ergon Energy, specified by the Authority's 2005 Distribution Final Determination. These revenue caps were amended to reflect a number of adjustments which were subsequently made by the Authority, including several cost pass-through decisions and adjustments to account for the exclusion of non-DUOS services from the distributors' revenue caps. Details of adjustments to distributors' revenue caps and the treatment of under- or over-recovery of revenue are provided in the Authority's 2009-10 BRCI Final Decision.

However, as of 1 January 2008, the AER assumed responsibility for the economic regulation of distribution network service providers in the NEM. Accordingly, from the commencement of the next five-year regulatory period on 1 July 2010, at which time the Authority's 2005 Final Determination expires; the AER will set the annual revenue caps for the Queensland distributors rather than the Authority. The Authority's estimates of Energex and Ergon Energy's regulated revenue for 2010-11 are therefore based on the revenue caps derived by the AER.

The AER has yet to release its Final Decision in relation to Energex and Ergon Energy for the regulatory period commencing 1 July 2010. As a result, the regulated revenue estimates for 2010-11 have been taken from the AER's *Queensland Draft Distribution Determination 2010-11 to 2014-15* (November 2009). These revenue forecasts exclude any adjustments for the annual under- or over-recovery of revenue.

3.4 Submissions from stakeholders

In its submission to the Interim Consultation Paper, Origin Energy noted that the BRCI methodology utilises the network cost of the whole of Queensland as it uses an average of the network costs faced by Energex customers in South East Queensland with those faced by Ergon

Energy customers in regional Queensland. Origin Energy submitted the averaging of network charges has been a significant issue to date and may be an even greater issue for the 2010-11 BRCI given both Ergon and Energex are in the midst of new revenue determinations by the AER. Origin Energy acknowledged, however, that the Authority is unable to specifically address this issue given the constraints of the current legislative framework.

AGL also noted that the shortcomings of the current legislative framework exposes retailers to a significant risk that the network component permitted in the bundled tariff that results from the application of the BRCI will be lower than the actual network tariff imposed by Energex. AGL also acknowledged that the Authority is bound to apply the existing legislative framework.

EnergyAustralia suggested that the distribution and transmission costs used to calculate the BRCI should reflect the final regulatory decisions of the AER. EnergyAustralia stated that any other value potentially leaves retailers even more exposed to the shortcomings of the BRCI around network costs than would otherwise be the case.

3.5 The Authority's Position

The Authority has adopted the same approach to calculating network costs for use in the 2010-11 BRCI as was used in 209-10.

Transmission costs

The Authority has determined its Draft Decision estimate of the total transmission charges that Powerlink is expected to levy on Energex and Ergon Energy in 2010-11, by applying the percentage share of Powerlink's 2009-10 MAR accounted for by these charges to the 2010-11 MAR determined in AER's revised Powerlink Final Decision.

As shown in Table 3.1 below, the total transmission charges levied by Powerlink upon the distributors in 2009-10 was $514.0 million, which was approximately 77.7% of Powerlink's MAR for 2009-10, of $661.4 million.

This same proportion (77.7%) has been applied to Powerlink's MAR for 2010-11 of $734.2 million, as determined by the AER in its revised Powerlink Final Decision, to derive an estimate of Powerlink charges to be levied in 2010-11.

In addition to Powerlink charges, the distributors incur other transmission-related costs, including avoided TUOS payments to embedded generators and payments to other distribution network service providers for transmission-like network services which are included in the estimates of network costs. As these charges for 2010-11 are not yet available, the Authority has estimated other transmission-related costs by applying the proportional increase in Powerlink charges from 2009-10 to 2010-11 to the cost of these other services in 2009-10.

On this basis, the Authority has estimated total transmission costs to be passed through to customers by Energex and Ergon Energy for 2010-11 to be $583.4 million.

As indicated, these estimates will be updated for the Final Decision following better estimates becoming available in the distributors' 2010-11 Pricing Proposals.

Distribution costs

Based on the AER's Draft Determination for Energex and Ergon Energy, the Authority has estimated the regulated revenues for Energex and Ergon Energy to be $1,181 million and $1,097 million respectively. These estimates will be revised for the 2010-11 BRCI Final Decision, following release of the AER's Final Decision on the revenue requirements for Energex and Ergon Energy. It is anticipated that this will be released in late March 2010.

3.6 Network Costs

The following table provides the Authority's view of transmission and distribution network costs for use in the 2010-11 BRCI.

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

Network cost	***2009-10[1]*** ***$m***	***2010-11*** ***$m***	***Change*** ***%***
Transmission			
Maximum allowable revenue[2]	*661.4*	*734.2*	
Powerlink charges	514.0	570.5	11.00
Avoided TUOS payments	3.5	3.9	11.00
Unregulated Powerlink charges	5.9	6.5	11.00
Other Charges	2.2	2.4	11.00
Total transmission costs	**525.5**	**583.4**	**11.00**
Distribution			
Energex	**1,000.3**	**1,180.6**	**18.02**
Ergon Energy	**855.8**	**1,096.6**	**28.14**
Total Network Costs	**2,381.6**	**2,860.6**	**20.11**

1. *See the Authority's 2009-10 BRCI Final Decision.*
2. *Source: AER revised Powerlink Final Decision (July 2008).*

As shown in Table 3.1, and in contrast to previous years, the increase in Ergon Energy's network revenue for 2010-11 is substantially higher than that of Energex. The BRCI methodology uses the average distribution costs faced by Energex and Ergon Energy despite the majority of competition occurring in the south-east corner of the State served by Energex. In past years, retailers have criticised this approach on the basis that they considered that it understated the rate of increase they were actually experiencing in the areas they served. This year that effect will be reversed.

4. RETAIL COSTS AND MARGINS

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 previous approach, 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 churn. In total, retail costs (including customer acquisition and retention costs) are expected to increase by 21.2% in 2010-11

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.

Based on projected total customer numbers, total retail costs, including the retail margin, are expected to increase by 18.3% from $472.6 million in 2009-10 to $559.0 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 costs.

Retail operating costs include customer administration (including call centres), billing and revenue collection, IT systems and regulatory compliance and may 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 are related to acquiring new customers, retaining existing customers and transferring existing non-market customers onto market contracts. These costs include: marketing, advertising, sales overheads, door-to-door/commission/agent costs and telesales.

The retail margin is the amount that a retailer earns from its activities net of 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 operating costs, while the (smaller) net 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 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.

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. Specifically, the Delegation requires that:

(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 (FRC) 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.

4.3 Submissions from stakeholders

Submissions received in response to the Interim Consultation Notice generally supported the continued application of the approach used in 2009-10 to estimate retail costs. For example, submissions such as those of AGL and Origin Energy expressed support for continuing the approach to estimating retail operating costs, whereby benchmarked retail operating costs are escalated over time to account for inflation.

Submissions from consumer organisations drew attention to their concern that the focus of previous BRCI decisions was on the sufficiency of the margins of electricity retailers and did not include a separate and comprehensive consideration of consumer impacts, in particular whether the notified prices allowed for the provision of a basic level of non-discretionary essential energy at an affordable price.

However, the Authority notes that the method for calculating the BRCI is closely scripted in the legislation and provides no scope for the Authority to address such issues. It is always open to the Government to implement whatever steps it considers appropriate, as it has done in the past, to provide some offset to rising electricity prices for vulnerable groups within the community.

Electricity retailers considered that there was scope for improving upon the previous approach to estimating customer acquisition costs. For example, the submissions of AGL and TRUenergy suggested that customer churn should be calculated having regard to the experiences in other jurisdictions where functioning competitive markets were more established, such as in Victoria or South Australia.

With respect to the retail margin, retailers were almost unanimously of the view that the retail margin had been set too low in previous BRCI decisions. Several submissions, such as those of EnergyAustralia and Origin Energy referred to the preliminary findings in Stage 1 of the Authority's review of the tariff structures in Queensland, that there are a number of flaws in the BRCI which could have impacted on retailer headroom over time. TRUenergy suggested that a specific allowance should be included to compensate retailers for the alleged erosion of margins over the past three determinations.

Other submissions, such as that of Integral Energy, suggested that, irrespective of past movements in the level of margin, a continuation of the previous BRCI methodology on this occasion would see retailer headroom erode further in 2010-11, unless the retail margin was increased. TRUenergy also suggested the retail margin should be increased to drive market outcomes such as increasing the level of competition.

However, notwithstanding the concerns expressed about the adequacy of the retail margin, no stakeholder provided evidence as to what the appropriate level was.

AGL also queried whether the escalation process described in the 2009-10 BRCI, to account for the impact of price inflation and wages growth, was conducted properly. It suggested that a 60/40 weighting of Wage Price Index (WPI) and Consumer Price Index (CPI) over the relevant period should produce an escalation factor of 3.04%, rather than the 2.8% applied in the 2009-10 BRCI.

4.4 Estimating retail costs to be used in the 2010-11 BRCI

Customer numbers

For previous BRCI decisions, the Authority has 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. For 2010-11, this information will not be available internally as responsibility for setting prices in 2010-11 has transferred to the AER.

For this Draft Decision, the Authority has escalated customer numbers for 2009-10 (1,978,965) based on the rate of growth in customer numbers over the previous two years. On this basis, the Authority has arrived at an estimate of customer numbers in 2010-11 of 2,030,624.

For the Final 2010-11 BRCI Decision, the Authority expects to be able to update these numbers using the distributors own estimates of customer numbers as contained in their 2010-11 annual pricing proposals to the AER. The Authority expects to receive these estimates from the distributors in March 2010.

Inflation escalation factors

In previous BRCI decisions, the Authority has used a weighted average of WPI (60%) and CPI (40%) to account for the impact of price inflation and wages growth on benchmarked retail operating costs and the costs of customer acquisition and retention.

The Authority has based its current 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. For the 12 months to 30 June 2011, the Authority has used an estimate of WPI of 3.3% and for CPI of 2.25%. These estimates are likely to be updated in the Authority's Final Decision as more recent estimates will be available at that time.

Based on the 60/40 weighting of WPI and CPI, the cost escalation factor for the 12 months to 30 June 2011 is 2.88%.'

In its submission, AGL questioned the calculation of the escalation factor in the 2009-10 BRCI Final Decision. This comment appears to reflect some confusion over how the Authority arrives at its best estimate of these measures for the year in prospect. The approach the Authority has adopted is not to simply add a further year's data to past estimates but rather to take the latest available data for the relevant period. Based on the latest ANZ and RBA data, the escalation factors to apply since 2007 are shown in Table 4.1. So, for example, to escalate retail operating costs (as discussed in the following section) to arrive at the Authority's best estimate of the 2010-11 value of retail operating costs originally benchmarked in 2006-07, the original cost is escalated for each of the intervening years according to the factors shown in Table 4.1.

Table 4.1: Inflation escalation factors

Period	***WPI***	***CPI***	***60/40 weighted average of WPI and CPI***
12 months to Jun 08 (Actual)	4.21%	5.12%	4.58%
12 months to Jun 09 (Actual)	3.71%	2.02%	3.03%
12 months to Jun 10 (Forecast)	2.90%	2.50%	2.74%
12 months to Jun 11 (Forecast)	3.30%	2.25%	2.88%

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 6 November 2009. Actual WPI figures based on ABS Labour Price Index – Australia, CAT NO: 6345. Quarterly Index; forecast WPI figures based on ANZ Markets Weekly – 5 November 2009.

These latest estimates are not used to recalculate the cost estimate for the previous year (2009-10 in this case) as that value (and all values in that Decision) remain unchanged. However, the Authority's best estimate for the year in prospect (2010-11) is based on the latest available information as shown in Table 4.1.

Retail operating costs

In calculating retail operating costs for 2010-11, the Authority has continued with the benchmarking approach adopted since the 2007-08 BRCI.

This approach has been broadly supported in previous Decisions and many of the submissions received in response to the Interim Consultation Notice have expressed support for this approach to be continued.

The original benchmarked cost estimate of $75.00 in 2006-07 has been escalated for inflation over the intervening period, using the escalation factors described above.

On this basis, the Authority has estimated 2010-11 retail operating costs to be $85.42 per customer, representing a 2.7% increase on the 2009-10 figure ($83.19 per customer) reported in the Authority's 2009-10 Final Decision.

Customer acquisition costs

Customer acquisition and retention costs relate to the costs incurred by a retailer operating in a competitive market, such as the costs of marketing, advertising and other strategies designed to win new customers and retain existing customers.

As was done in previous BRCI Decisions, the Authority has followed a two-step approach to estimating customer acquisition and retention costs. The two steps involve:

(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 from a non-market contract to a market contract with the same retailer; and

(b) estimating the likely number of customers transferring and switching.

To establish the costs of customers switching and transferring, the Authority has 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. Similar to the escalation of retail operating costs, the 2010-11 values for switching and transfers are based on the 60/40 weighted average of WPI and CPI over the intervening period. This approach is consistent with the approach taken by the Authority in the 2009-10 BRCI.

On this basis, the Authority estimates customer acquisition costs in 2010-11 be $186.69 per customer switching retailer (equivalent to $42.41 per customer spread across all customers) and $108.90 per customer transferring to a market contract with the same retailer (equivalent to $1.79 per customer spread across all customers).

Determining the most appropriate rates of transfers and switches is more difficult. In the 2009-10 BRCI Decision, the Authority noted the difficulties involved in analysing the Market Settlement and Transfer Solution (MSATS) statistics produced by AEMO (then known as NEMMCO), with the aim of separating the numbers of customers switching between retailers from those customers staying with their retailer but transferring to a market contract. In particular, there were circumstances specific to Queensland which made it difficult to exclude paper transfers resulting from customers being transferred between subsidiaries of the same retailer from actual transfers.

Due to these difficulties, the Authority used the same customer switching and transfer numbers for calculating customer acquisition and retention costs in the 2009-10 BRCI Decision as it had used in the 2008-09 Decision. Those figures indicated that 11% of customers switched from one retailer to another while 6.2% of customers moved to a market contract with their same retailer.

In its 2009-10 Final Decision, the Authority indicated it would investigate this matter further in future BRCI decisions. In submissions received in response to the Interim Consultation Notice, retailers suggested the Authority could improve on the previous approach.

Following discussions with AEMO and consideration of other data sources, the Authority has used all available data on customer churn in Queensland and in other jurisdictions, to arrive at its best estimate of the likely numbers of customers switching and transferring in 2010-11.

Switching between retailers

Figure 4.2 below shows the available AEMO market transfer data.

While AEMO has improved the quality of its MSATS data, the Authority considers that the more volatile data relating to the first 12 to 18 months of FRC should not be used in estimating customer switching behaviour up to 18 months from now. Rather, the Authority considers that more recent data should form the basis of such projections.

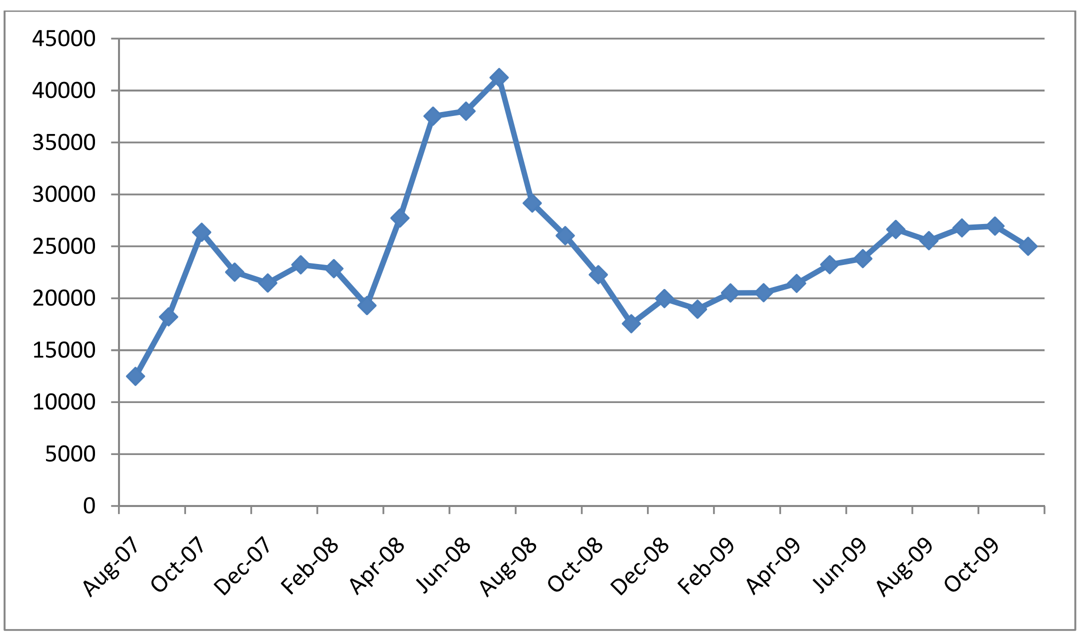
In the absence of a better method of making the necessary forecasts given the limited data available, the Authority has decided to base its forecasts on a 12 month rolling average of the monthly increase in the number of customers switching retailers.

In this regard, based on the average monthly rate of growth in the number of customers switching retailers over the last 12 months of 3.2%, the Authority has estimated that 22.7% (some 461,000) of total customers will switch retailer in 2010-11.

The Authority accepts that this is a fairly simplistic basis for forecasting customer switching patterns. In addition, further data will become available before the Final Decision is made and it is proposed to use the most recent 12 months' data available at that time for the purposes of estimating customers switching retailers. This could, however, lead to a significant movement in these forecasts, depending of the rate of switching over the next few months.

Given the limited data and the potential sensitivity of the proposed approach to variations in data, the Authority will be interested to receive stakeholder views on this approach to forecasting customer switching.

Figure 4.2 – AEMO monthly MSATS transfers statistics for Queensland



Source:AEMO website www.aemo.com.au; MSATS transfers for Queensland, November 2009 report

This represents a significant increase in the estimated number of switches compared to 2009-10. In large part, this reflects the Authority's decision to continue using old data in its 2009-10 Decision due to the deficiencies in the data available at that time. With the improved data now available from AEMO, it is clear that the number of customers switching retailers was continuing to grow and that the rate of growth has been accelerating.

The estimated rate of switching for 2010-11 of 22.7% is not dissimilar to the rates of switching experienced in other jurisdictions. In 2006-07, the fourth year after FRC was introduced in South Australia, the annualised average switch rate was approximately 24%. In Victoria, following full deregulation, the annualised average switching rates have generally ranged between 20% and 30%. However, as a proportion of customers in South East Queensland, where the majority of competition is occurring, the switching rate is closer to 35.5%. 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.

Transferring to market contract with the same retailer

The Authority has also estimated the number of customers likely to remain with the same retailer, but transfer onto market contracts, in 2010-11.

The Authority has based its estimate on the market customer numbers reported to it on a quarterly basis under of the Electricity Industry Code (the Code). Clause 8.5.5 of the Code requires distributors to provide the Authority with the number of large and small National Metering Identifier (NMI) premises in their distribution area at the end of each quarter.

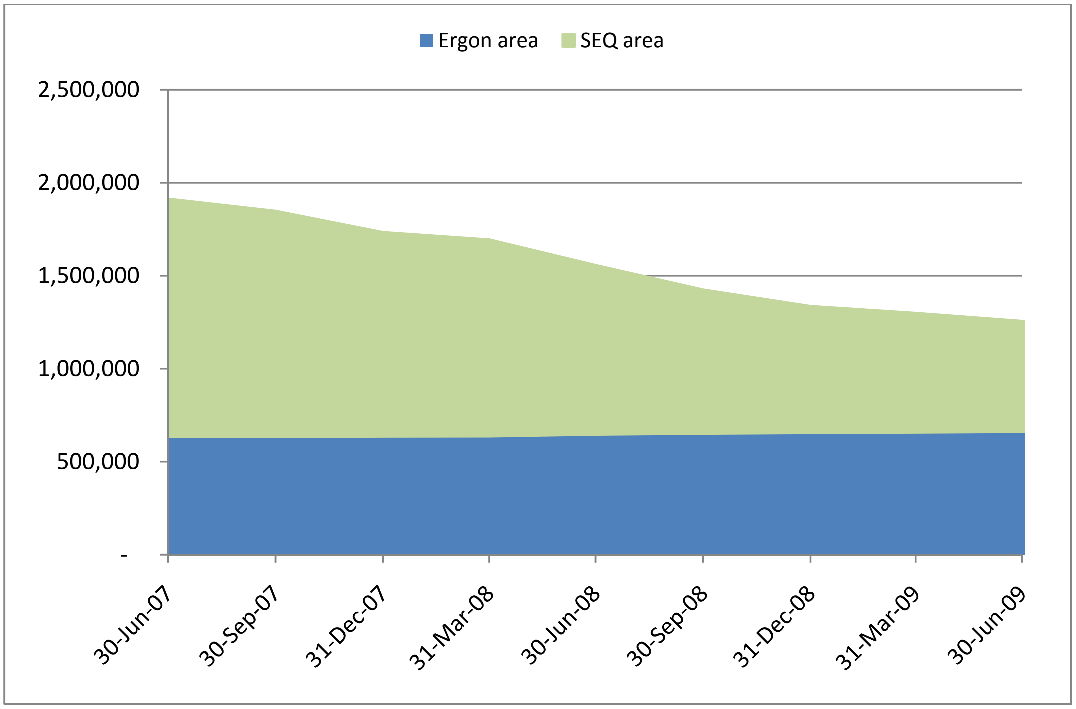
Retailers have a similar obligation, under clause 8.5.2 of the Code, to provide the Authority with quarterly data on the number of NMI premises to which they were providing retail electricity services under a negotiated (market) contract at the end of the quarter.

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

As at 30 June 2009, 35.8% of all Queensland customers had moved to a market contract. Of those remaining on non-market contracts, 52.4% of customers 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 47.6% (around 600,000) 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 4.3 shows the number of customers on non-market contracts, based on the total NMI premises data provided by distributors and the market NMI data provided by retailers.

Figure 4.3: Non-market customer numbers in Queensland



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.

Of the customers remaining on non-market contracts, a portion are likely to move to a market contract with a new retailer (measured above in the estimate of switches) and a portion are likely to move to a market contract with their current retailer (transfers). It is also to be expected that there will be a residual group of customers who choose to remain on non-market contracts indefinitely. There is also an option for small customers to revert to notified prices with their current retailer should they so desire.

As noted above in relation to forecasting the number of customers switching retailer, the short period of time since the commencement of FRC means that there is limited data upon which to base estimates of customer transfers.

The NMI data reported to the Authority by distributors and retailers provides a source of information for estimating the number of customers moving from a non-market contract to a market contract. However, this data is somewhat volatile, particularly that relating to the first year of FRC but is showing a clear downward trend as would be expected.

However, it has also become apparent during this process that AGL has incorrectly reported market NMI data since June 2008 when it incorrectly included a large number of customers in its reported NMI data. While some adjustments have been made in order to address this problem for this Draft Decision, further data revisions will be required prior to the Final Decision, once AGL provides accurate NMI data.

Given the limited options for estimating future transfers, the Authority has decided to derive its estimates by first calculating the number of customers moving each quarter from a non-market contract to a market contract using the most recent 12 month average of the percentage change in the number of such customers 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 estimates that the total number of transfers in 2010-11 will be some 33,000. In total, this implies that 1.6% of total customers will transfer onto a market contract with their current retailer in 2010-11. In terms of the smaller number of customers in South East Queensland, the implied rate of transfers would be 2.6%.

As with the earlier estimates of customer switching, the Authority accepts that this is a relatively simplistic basis for forecasting customer transfers. Also, data for at least one more quarter (and further revisions from AGL) will become available before the Final Decision is made. The Authority proposes to use the most recent 12 month's data available at that time for the purposes of estimating customer transfers in its Final Decision. However, this could lead to a significant movement in these forecasts, depending of the rate of transfers over the next few months.

As with customer switches, given the limited data and the potential sensitivity of the proposed approach to variations in data, the Authority will be interested to receive stakeholder views on this approach to forecasting customer transfers.

Combining switches and transfers gives a total churn rate for 2010-11 of 24.37% or 38.1% for South East Queensland.

Based on the above estimates of costs and numbers of customers moving, total customer acquisition and retention costs are estimated to be $89.8 million in 2010-11, comprised of some 461,000 switches at $186.69 per switch and 33,000 transfers at $108.90 per transfer.

Retail Margin

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

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

As noted above, most retailers suggested the retail margin should be higher.

Several submissions referred to the Authority's view, in its review of tariff structures and pricing, that the BRCI methodology has a number of flaws as support for increasing the retail margin. However, the flaws identified by the Authority in that context apply to specific aspects of the calculation of cost components required by the legislation (which are unavoidable) or to headroom which is a measure of return above and beyond normal costs and returns. None of these provide reasons to arbitrarily increase the retail margin.

There were also suggestions that setting the retail margin higher would encourage further competition. However, as the Authority noted in its review of tariff structures and prices and has noted in previous BRCI Decisions, setting notified prices above the costs of supplying electricity would stimulate more competition in South East Queensland but leave customers in much of the rest of the State paying higher prices with no option to move to a competitive market contract.

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 dollar value of the retail margin has increased from $255.5 million in 2009-10 to $295.8 million in 2010-11, an increase of 15.79%.

Other Issues

In arriving at its estimate of the increase in the BRCI for 2010-11, the Authority has not taken explicit account of the requirement in the Current Delegation to maintain the 'headroom' of incumbent retailers. As the Authority has noted in previous BRCI Decisions, it does not have access to reliable information on the actual retail margin of either Origin Energy or AGL nor is it able to discern the headroom that may have existed in the retail prices at the time retail competition was introduced. However, as the Authority has accounted for all other sources of cost increase in the terms required in the legislation, it is of the view that it has met the obligation that the existing headroom (whatever it might be) should be broadly maintained.

The Authority acknowledged in its Review of Tariff Structures and Prices that the averaging of network costs in the BRCI has in the past most likely eaten into the headroom available to retailers. As noted in the network costs chapter, that situation has reversed in 2010-11 with Ergon Energy's network costs growing more rapidly than those of Energex. As a consequence, in this year, the averaging of network costs will actually add to the available headroom rather than detract from it.

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

4.5 The Authority's position

A summary of the Authority's assessment for this Draft Decision of the costs of providing retail services in is provided in Table 4.4.

Table 4.4: Changes in Retail Cost Components ($m) 2009-10 to 2010 - Draft Decision

Retail Cost Component	*2009-10*[1] *$m*	*2010-11* *$m*	*Change* *%*
Retail costs (including customer acquisition and retention)	217.1	263.2	21.22%
Retail margin (5%)	255.5	295.8	15.79%
Total Retail Costs	**472.6**	**559.0**	**18.28%**

1. See the Authority's 2009-10 BRCI Final Decision.
Note: Totals may not add due to rounding.

In total, retail costs are estimated to increase by 18.28% from $472.6 million in 2009-10 to $559.0 million in 2010-11.

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 this case) in order to determine the unit cost of supplying electricity, expressed in c/kWh.

Given the timing of this Draft Decision, part of the NEM load for 2009 must be forecast. Load data for the full 2009 calendar year will be available for inclusion in the Final Decision to be released in May 2010.

The Authority has estimated the 2009 NEM load to be 37,483 GWh, an increase of 1.7% on that used in calculating the 2009-10 BRCI.

5.1 Background

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

5.2 Legislative requirements

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

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

5.3 Estimating the NEM load for 2009

For the 2010-11 tariff year, the relevant NEM load is that for the 2009 calendar year.

The Authority has obtained half-hourly load data for each Transmission Network Identifier (TNI) from AEMO. This data includes the loads of customers directly connected to the transmission network, loads supplied by registered embedded generators and loads supplied to 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.

Given the timing of this Draft Decision, only load data for the first three quarters of 2009 (1 January – 30 September 2009) was available from AEMO. Load data for the December quarter of 2009 has been forecast by ACIL by applying an average ratio of the total load for the December quarters in the last four calendar years (2005-2008) to the total load of the first three quarters of the last four calendar years (2005-2008). The ratio was then applied to the actual load data for the first three quarters of 2009 to arrive at the State NEM load. To arrive at the NEM load for 2009, the Authority has made the following adjustments to the data supplied by AEMO.

Loads of directly connected customers

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

Loads of registered embedded generators

Data supplied by AEMO also included loads supplied by registered embedded generators participating in the NEM but excluded loads supplied by unregistered embedded generators[5]. As in previous years, only the loads met by registered generators embedded within the networks of Energex and Ergon Energy that are connected to the NEM have been included, while loads of unregistered embedded generators have been excluded from the calculation of the NEM load.

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

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.

5.4 Submissions from stakeholders

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

5.5 The Authority's position

The 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.

Given the timing of this Draft Decision, part of the load for the 2009 calendar year is not available and has been forecast. For this Draft Decision, load data for the first three quarters of 2009 is based on actual data obtained from AEMO. The load for the last quarter of the year has been forecast by ACIL. Actual load data for the full 2009 calendar year will be available for inclusion in the Final Decision and the NEM load will be updated at that time.

The data provided by AEMO for 2009 included five new TNIs that were not present in 2008 and excluded two TNIs that are no longer present but had been during 2008. With assistance from Powerlink, the Authority has been able to classify these new TNIs as either connected to the networks of Energex or Ergon Energy (in which case the load passing through the TNI has been included in the NEM load calculation) or as directly connected to Powerlink's network (in which case the load has been excluded from the calculation of the NEM load for 2009).

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

The Authority estimates that the NEM load for 2009, to be used as the denominator in calculating the 2010-11 BRCI, is 37,483 GWh, an increase of 1.7% from the 2008 NEM load used in calculating the BRCI for 2009-10. Table 5.1 provides the components of this estimate.

Table 5.1: 2008 and 2009 NEM load

	2008[1]	***2009***[2]	***Change***
	GWh	*GWh*	*%*
Total State NEM load	47,367	48,001	1.34
Less loads of directly connected customers and portions of loads connected to the NSW network	10,517	10,518	0.02
NEM Load	**36,851**	**37,483**	**1.72**

Sources, AEMO and Powerlink.
1. See the Authority's 2009-10 BRCI Final Decision.
2. The load for December quarter 2009 has been forecast.

6. DRAFT DECISION – 2010-11 BRCI

The Authority estimates the BRCI to be 15.78 cents per kWh in 2010-11 compared to 13.87 cents per kWh in 2009-10. This represents an expected increase of 13.83% in the BRCI between 2009-10 and 2010-11.

The cost of energy is expected to increase by 10.69% in 2010-11 while total network costs are estimated to rise by 20.11% over the year. Retail costs are expected to be 18.28% higher in 2010-11.

The 2009 NEM load for this Draft Decision is estimated to be 37,483GWh, which is 1.72% more than that for 2008. This estimate will also be updated using actual data for the Final Decision once the full calendar year's data becomes available.

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 - Draft Decision

	2009-10	*2010-11*	*Change (%)*
Cost of energy ($m)	2,255.4	2,496.6	10.69
Network costs ($m)	2,381.6	2,860.6	20.11
Retail costs ($m)	472.6	559.0	18.28
NEM load of Queensland (GWh)	36,851	37,483	1.72

Note: Totals may not add due to rounding.

Based on the figures contained in Table 6.1, the Authority has calculated that the BRCI will increase by an expected 13.83% in 2010-11, as shown in Table 6.2.

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

BRCI cost component	***2009-10***	***2010-11***	***Change***	***Share of total costs 2009-10***	***Change in BRCI***
	c/kWh	*c/kWh*	*%*	*%*	*%*
Cost of energy	**6.12**	**6.66**	**8.82**	**44.14**	**3.90**
LRMC of energy	*5.33*	*5.81*	*9.10*	*38.43*	*3.50*
Purchase cost of energy	*5.77*	*6.18*	*7.10*	*41.61*	*2.96*
Other energy costs	*0.57*	*0.66*	*16.24*	*4.12*	*0.67*
Network costs	**6.46**	**7.63**	**18.09**	**46.61**	**8.43**
Distribution	*5.04*	*6.08*	*20.62*	*36.33*	*7.49*
Transmission	*1.43*	*1.56*	*9.15*	*10.28*	*0.94*
Retail costs	**1.28**	**1.49**	**16.29**	**9.25**	**1.51**
Operating costs (including customer acquisition and retention costs)	*0.59*	*0.70*	*19.18*	*4.25*	*0.81*
Margin	*0.69*	*0.79*	*13.83*	*5.00*	*0.69*
Total	**13.87**	**15.78**	**13.83**	**100.00**	**13.83**

Note: Totals may not add due to rounding.

APPENDIX 1 – CURRENT DELEGATION

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):

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 network cost component of the 2008-09 BRCI, and future tariff years, the QCA must apply the Annual Aggregate Revenue Requirement (AARR) determined for each year of Ergon Energy's current access arrangement (covering the period 2005-06 to 2009-10), and any changes to the AARR for any approved cost pass through made subsequent to the finalisation of the current access arrangement, without undertaking any re-smoothing of these AARR amounts;

4. The QCA must complete the delegated activities for the 2009-10 tariff year no later than 12 June 2009;

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

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

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

This delegation revokes my delegation of 29 May 2009.

[redacted]

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

Dated: 3rd June 2009

APPENDIX 2 – LIST OF STAKEHOLDERS

Table A1: Submissions to Interim Consultation Notice

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

APPENDIX 3 – REVIEW OF ACIL'S NEM LOAD TRACE METHODOLOGY

AGL provided a report "Review of Forecast Load Traces" dated 22 May 2009 prepared by Creative Energy Solutions (CES) as part of the consultation process for development of the 2009-10 BRCI. The CES report commented on load traces prepared by ACIL Tasman (ACIL) for use by the Authority's previous consultant, CRA International, in calculating energy purchase costs as part of the calculation of the BRCI for 2009-10.

AGL again submitted this report as part of its submission in response to the 2010-11 Interim Consultation Notice. The following discusses the CES critique of ACIL's methodology as well as ACIL's responses.

Forecast of NEM load

The CES report is critical of ACIL's approach where the forecast growth in the Directly Connected (DC) load trace was based on the Powerlink forecast DC demand at the time of state peak. Given the very flat load profile for the DC load (around 94% load factor), ACIL considered it reasonable to apply the Powerlink forecast of MW growth in coincident demand for the DC customers to each half hour in the DC customer load trace. Furthermore, ACIL believed that approach ensured that the forecast of DC load was consistent with the overall Powerlink forecast for Queensland.

On this matter CES had concluded that a better approach may be to derive the forecast of DC energy by forecasting energy for the NEM load and deducting this from the forecast for the state to arrive at an annual energy figure for the DC load.

ACIL was of the view that the approach they had adopted was better than that suggested by CES. ACIL observed that the DC load is quite flat and Powerlink provides a forecast of the change in the contribution to demand of DC customers which is consistent with the overall Powerlink forecast. As Powerlink does not produce a forecast of the NEM load (small load), ACIL was required to construct this forecast to be consistent with the Powerlink forecast of state load. ACIL believed that it would be a very difficult task to undertake such an independent forecast and guarantee its consistency with the Powerlink forecast for the entire state load.

On this basis, ACIL believes that its method of subtracting its forecast of the flat DC load from the Powerlink forecast of the state load is a simpler and more precise approach to forecasting the NEM load than that suggested by CES.

Quarterly energy balance

CES in its report observed that the distribution of energy by quarter from ACIL's forecast load traces was different to that observed in the previous actual year, namely that energy in Q2 and Q3 (winter quarters) was lower in ACIL's load trace forecast than that in the previous year's historical data and that Q4 and Q1 (summer quarters) in ACIL's load trace forecast were above the level suggested by previous year's historical data.

ACIL highlighted that in order to compare the previous year's historical load data with ACIL's forecast, CES derived the "adjusted historical" energy for each quarter by simply multiplying the quarterly energy by the ratio of forecast annual energy to actual annual energy. ACIL believes that CES's approach implies that it expects the energy in each quarter to grow by exactly the same (average annual) rate within a given year. ACIL observed that the basis of CES's criticism therefore appeared to be an expectation of equal quarterly growth.

ACIL suggested that the differential growth rates in quarterly energy resulting from its approach are not unexpected and in fact, are consistent with historical growth patterns. ACIL noted that the load traces are governed by the Powerlink forecasts of summer and winter peaks and annual energy, which have noticeably stronger growth in summer peak demand than in annual energy or winter peak demand. These differences in growth rates are therefore reflected in ACIL's forecast load trace. On this basis, ACIL were satisfied that their load trace program had appropriately adjusted the historical load trace to fit the forecast parameters.

ACIL also noted that the CES report itself demonstrated that historically, the actual energy growth rates are typically higher for summer (Q4 and Q1) than winter (Q2 and Q3) – which supports the results of ACIL's forecast methodology (given the differential in the Powerlink forecast growth rates of summer and winter peaks).

Distribution of the winter load profile

ACIL observe that the lower volatility in the forecast winter months, as demonstrated by CES, is almost entirely due to the low winter peak demand forecast. ACIL believe that if the annual minimum load was lower, the winter demand spread would increase but this would only have a relatively small effect.

According to ACIL, the minimum load is an important element in their load trace program, particularly where the forecast growth rates for the key elements are somewhat different, as they are in the Powerlink forecast. ACIL's load trace program therefore avoids the minimum load incorrectly reducing to allow the energy to match the forecast when the peak demands have higher growth than energy.

Accordingly, ACIL are satisfied that its treatment of winter load profile is appropriate compared to the apparent underlying assumption of the CES critique that the winter and summer energy should be growing at the same rate.

Annual demand envelopes

ACIL noted that CES was satisfied that the annual demand envelope of its forecasts were reasonable. ACIL highlighted the comparison in Figures 2 to 4 in the CES report as support for this.

Monthly load traces

ACIL noted that the CES findings on the monthly load traces were as they would expect given that the comparisons are with the normalised history for average demand. ACIL's load trace forecast has a noticeably lower demand growth in winter and a higher growth in summer. On this basis, ACIL stated that they would expect lower growth winter month demands to be lower than the normalised history and the higher growth summer month demands to be higher than normalised history.

ACIL highlighted that Figures 5 to 8 in the CES report demonstrate the expected effects of the variations in forecast winter and summer demand growths.

Evaluation of 10POE and 90POE scenarios

ACIL noted that their choice of the 400 half-hour demands was on the basis that these higher demands are likely to pose the greatest risk to a retailer. ACIL's methodology does not specifically target the summer demands for adjustment but the result that all of these periods occur in summer in Queensland when pool and hedge prices are at their highest provides support for this approach. For example, ACIL noted that to have 10%POE demands occurring in both winter and summer is likely to occur with a much lower frequency than 1 in 10 as it implies the occurrence of both an unusually hot summer and cold winter within the same year.

On this basis ACIL were satisfied that adjusting the top 400 half hourly demands, regardless of when they occur, adequately covered the risk of a 10POE year.

Spot price forecast

ACIL agree with CES that the half hourly spot price forecast must be entirely consistent with the half hourly load forecast. ACIL have ensured that this will be the case for development of the 2010-11 EPC forecast.