QUEENSLAND
COMPETITION
AUTHORITY

Final Decision

Benchmark Retail Cost Index for Electricity: 2011-12

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PREAMBLE

The Queensland Competition Authority has been delegated the responsibility for determining annual adjustments to notified (regulated) electricity prices, under the Benchmark Retail Cost Index (BRCI) methodology, to ensure that notified prices reflect the change in the costs of producing, transporting and retailing electricity. The Authority is required by legislation (the *Electricity Act 1994* and the *Electricity Regulation 2006*) to estimate the increase in the BRCI annually and to apply that increase to existing notified prices.

In its Final Decision on the BRCI for 2011-12, the Authority estimates the BRCI will increase by 6.6% between 2010-11 and 2011-12, compared to an estimated increase of 5.83% at the time of its Draft Decision. The 6.6% increase in the BRCI is made up of:

(a) a 10.62% increase in the network cost component ($/MWh), largely reflecting the ongoing investment in Queensland's distribution networks approved by the Australian Energy Regulator (AER) for the 2010-11 to 2014-15 regulatory period and a 2.13% reduction in load. As network costs account for around 49% of total costs, the 10.62% increase contributed 5.24 percentage points to the change in the BRCI (79% of the total increase).

(b) a 1.66% increase in the energy cost component ($/MWh), reflecting an increase in the long run marginal cost (LRMC) of energy offset by a reduction in the purchase cost of energy plus some changes in other energy costs, including an increase in the cost of the Federal Government's Expanded Renewable Energy Target and a reduction in the cost of complying with the Queensland Gas Scheme, as well as the 2.13% reduction in load. As energy costs account for around 41% of total costs, the 1.66% increase contributed 0.69 percentage points to the change in the BRCI (10% of the total increase).

(c) a 7.24% increase in the retail cost component ($/MWh), reflecting increased operating costs due to wage and price inflation, an increase in customer numbers, the inclusion of regulatory fees and a 2.13% reduction in load. As retail costs account for around 9% of total costs, the 7.24% increase contributed 0.68 percentage points to the change in the BRCI (10% of the total increase).

A key influence underlying the change in the BRCI was the change in the relevant load between the two years. For the purposes of calculating the BRCI, total costs are divided by the relevant load. Between 2009 and 2010 the load decreased by 2.13%, reflecting the more benign temperatures during the latter months of 2010. As costs increased while the load decreased, the BRCI was pushed higher than it would have been had the load remained relatively constant.

The increase in the BRCI would have been higher than 6.60% had it not been for a decision by the Queensland Government to limit the amount of additional revenue it would allow Energex and Ergon Energy to collect in 2011-12 as a result of a decision by the Australian Competition Tribunal. Had the Government not made this decision, which reduced network costs by $93.2 million, the change in the BRCI, and hence notified electricity prices, would have been 8.31%.

Given the change in the BRCI, all existing notified electricity prices will increase by 6.6% with effect from 1 July 2011.

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1. INTRODUCTION

The Electricity Act 1994 (the Electricity Act) requires that notified electricity prices be adjusted each year by the rate of change in the BRCI.

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

Following the release of an Interim Consultation Notice on 23 September 2010 and a Draft Decision on 17 December 2010, the Authority is now releasing its Final Decision on the 2011-12 BRCI.

1.1 Background

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

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

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

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

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

1.2 Scope of this Final Decision

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

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

1.3 Overview of the BRCI

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

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

(a) the cost of energy;

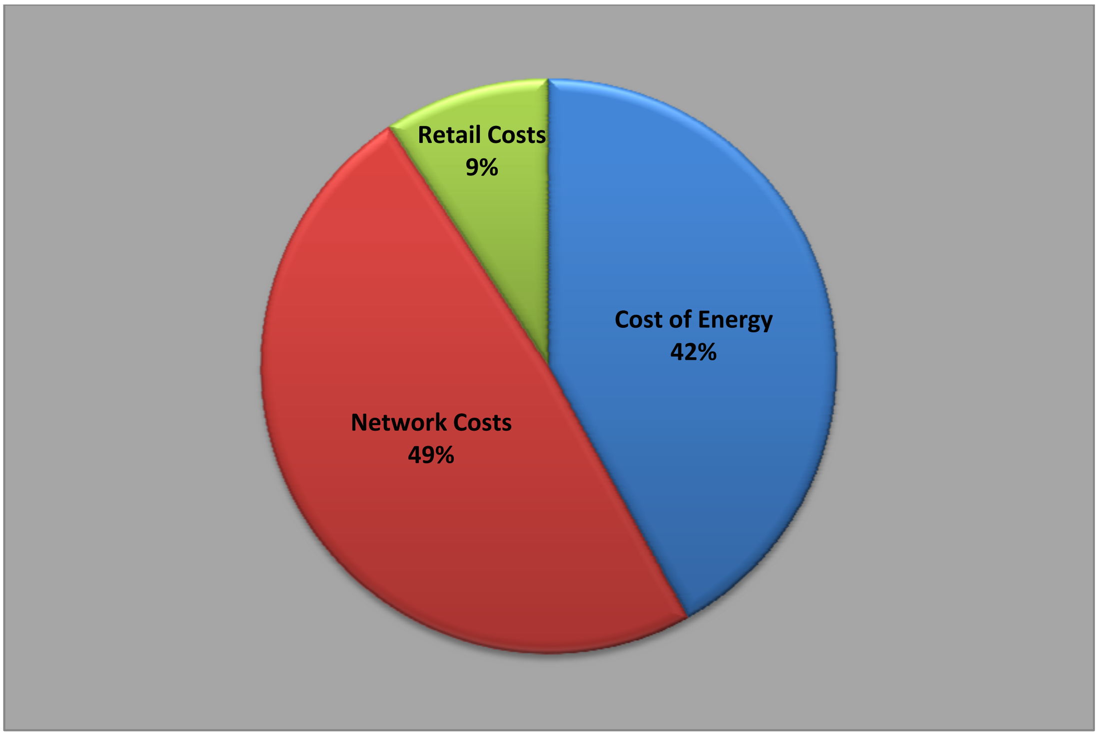
(b) network costs;

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

(d) any other costs considered relevant.

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

Figure 1.1: BRCI cost components in 2010-11



Source: QCA

The impact on notified prices of a change in any component of the BRCI will reflect both the size of the change in the component as well as the weighting of the component in the overall BRCI.

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

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

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

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

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

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

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

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

1.4 Calculation of the BRCI for 2011-12

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

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

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on the calculation of the cost of energy to be included in the BRCI for 2011-12.

The Authority released a Draft Decision on 17 December 2010, along with reports from ACIL and several data files relating to the modelling of energy costs. The Draft Decision addressed issues raised in submissions received in response to the Interim Consultation Notice.

In response to the Draft Decision, the Authority received nine submissions (see **Appendix 2**). The Draft Decision and submissions received in response can also be accessed from the Authority's website.

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

2. COST OF ENERGY

The Electricity Act requires that the cost of energy component of the BRCI in a particular year reflects the Authority's view of the likely total cost of purchasing energy to supply all of the National Electricity Market (NEM) load (see Chapter 5) for that year. The Authority is required to base its view on its most recent estimate of the LRMC of energy in that part of Queensland connected to the national grid and to take account of the actual cost of purchasing energy to meet the NEM load.

In estimating the cost of energy component for the 2011-12 BRCI, the Authority has estimated the LRMC of energy and the purchase cost of energy and then calculated an equally weighted average of these two costs. This is the same approach as was followed in the 2010-11 BRCI Final Decision.

The estimate of the LRMC of energy is required by the Electricity Act to take into account the most efficient combination of generating plant to supply all of the NEM load of Queensland for the relevant tariff year. In arriving at its estimate of the change in LRMC for 2011-12 of 9.98%, the Authority has used updated input costs as suggested by a number of stakeholders and recommended by ACIL.

As in previous years, the purchase cost of energy was estimated based on a combination of contract and spot market energy prices that a prudent and efficient retailer could be expected to purchase over a two-year period in order to meet the NEM load. This is the same method as used in the 2010-11 BRCI Final Decision. On this basis, energy purchase costs are estimated to have declined by 20.53%

As required, and consistent with recent BRCI decisions, in establishing the total cost of energy component of the 2011-12 BRCI, the Authority has taken into account the impact of the Queensland Gas Scheme and the Federal Government's re-structured Renewable Energy Target (RET) scheme. As in its Draft Decision, the Authority has used a market data based approach to estimating the cost of Gas Electricity Certificates (GECs) rather than the penalty price approach used in previous years. The Authority has also estimated the cost of the re-structured RET scheme using publicly available prices for Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs).

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

Summing each of the cost of energy elements, the total cost of energy component of the BRCI is estimated to be $2,394.9 million in 2011-12, a decrease of 0.5% from the $2406.9 million estimated for 2010-11. However, once the reduction in the load is taken into account (see Chapter 5), energy costs in $ per MWh terms actually increase by 1.66%

2.1 Background

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

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

2.2 Legislative Requirements

The Electricity Act requires that the cost of energy component of the BRCI in a particular year reflects the Authority's view of the likely total cost of purchasing energy to supply the NEM load for that year.

The judgment on the judicial review of the 2008-09 BRCI 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.

In forming its view, the Authority is required to take account of its most recent 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 that year.

This view must also take account of the Queensland Gas Scheme under the Electricity Act and the RET scheme under the Federal Government's *Renewable Energy (Electricity) Act 2000 (Cwlth)* (the Renewable Energy Act) and the accompanying *Renewable Energy (Electricity) Regulations 2001* and *Renewable Energy (Electricity) Amendment (Transitional Provisions) Regulations* (2009 and 2010).

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 the NEM load of the State for the relevant tariff year. The Electricity Regulation states 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) results in 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) does not double count the costs of the Queensland Gas Scheme and the RET scheme; and

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

Having established a method for estimating the LRMC of energy, 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 the Authority:

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

(b) has, under section 99, published a draft decision explaining the reason for the change.

2.3 Method for estimating cost of energy

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

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

LRMC

The Authority's approach to calculating the LRMC of energy is driven by the legislative requirement to adopt a "greenfields" approach. As outlined in the Authority's Final Decision for the 2010-11 BRCI, the LRMC calculation has the following features:

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

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

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

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

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

Energy Purchase Cost

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Queensland Gas Scheme

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

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

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

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

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

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

Renewable Energy Target (RET) Scheme

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

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

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

From 1 January 2011, the RET scheme was split into two schemes – the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET) scheme.

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

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

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

The introduction of the ERET scheme has been reflected in the calculation of energy costs for 2011-12.

Market Participation Costs

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

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

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

2.4 Provision of input modelling data

Draft Decision

The Authority released a number of data files and other information it relied upon in arriving at its 2011-12 BRCI Draft Decision at the time of its release.

Submissions in response to the Draft Decision

AGL requested that load and LRET data used by the Authority to calculate the BRCI be made available to retailers through the BRCI consultation process. Origin Energy requested that load shape and spot price data be made available as has been the case with the release of previous decisions.

Authority Comment

The Authority is conscious of its obligations to consult under the Electricity Regulation and, as always, is committed to a consultation process that will ensure its decisions are made on a fully informed basis. However, it is not practical for the Authority to release data earlier, as requested by AGL, given the tight timeframes involved in the annual BRCI calculation, where modelling data is refined and updated regularly during the process. 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 stakeholders with underlying modelling input data throughout the process.

The Authority's Final Decision

As it has done in previous years, the Authority will release a number of data files and other information it has relied upon in arriving at its decision, at the same time (or soon thereafter) as it releases this Final Decision.

2.5 LRMC

Draft Decision

In estimating the LRMC in its Draft Decision, the Authority considered suggestions by AGL and Origin Energy to use more up-to-date data on capital and fuel costs to calculate the 2011-12 LRMC.

The Authority used coal and gas prices updated by ACIL to reflect recent price levels and industry developments. ACIL also reviewed the components of the weighted average cost of capital (WACC) to make sure they remained current and considered the impact of the significant appreciation of the Australian dollar against the US dollar in recent months.

On this basis, the Authority was satisfied that ACIL's update of the capital and fuel cost parameters in its LRMC modelling was appropriate and accepted ACIL's estimate that the LRMC for 2011-12 would be $61.51/MWh.

Submissions in response to the Draft Decision

Origin Energy and the Queensland Government supported the Authority's approach to calculating the cost of energy component of the BRCI, including the LRMC. However, a number of submissions questioned specific aspects of the LRMC calculation.

AGL, Origin Energy and TRUenergy queried ACIL's decision to use revised 2009 capital and fuel cost input data instead of more recent data prepared in 2010 for AEMO and the Department of Resources, Energy and Tourism (DRET[1]) for use in the National Transmission Network Development Plan (NTNDP). AGL suggested that Scenario 3 of the NTNDP represented a 'central' case and that the associated cost input data was therefore appropriate for calculating the LRMC in the BRCI context.

Both QCOSS and the Queensland Government suggested that the $A/$US exchange rate used by ACIL was below forecasts of the exchange rate from a range of other sources.

CCIQ noted the views of Queensland businesses that coal prices were a contributing factor to ongoing electricity price rises and that the proposed Mineral Resource Rent Tax (MRRT) would put further pressure on the cost of electricity generation.

Origin Energy suggested that ACIL's coal price forecasts did not account for price impacts following the expiry of existing coal contracts with those mines with export quality coal which may be looking to take advantage of higher value in export markets. Origin Energy also suggested that higher crude oil prices and Queensland LNG exports would increase domestic gas prices beyond 2014 to a level above that forecast by ACIL.

AGL raised a number of detailed issues concerning aspects of ACIL's modelling, including:

(a) coal prices appeared to have been determined with reference to prices under existing coal supply contracts. AGL suggested that it was unreasonable to expect that a new entrant could negotiate an average of existing coal costs;

(b) AGL was unable to arrive at the same average Queensland coal prices as those in Table 10 of ACIL's draft report;

(c) the debt margin used by ACIL to estimate the WACC was too low and did not reflect the increased level of risk associated with higher levels of project financing in the electricity generation sector;

(d) whether generating plant capacity had been calculated on an incremental per megawatt basis without accounting for specific generating unit sizes in developing the generation stack, as this would underestimate the LRMC; and

(e) how the short run marginal cost (SRMC) of combined cycle gas turbine (CCGT) generation had been calculated as AGL's own calculations differed slightly from those of ACIL.

Both AGL and TRUenergy suggested that ACIL had used the penalty price of surrendering GECs in its LRMC calculation, but the market price of GECs in determining energy purchase costs. TRUenergy suggested this would lead to an unrealistically low estimate of LRMC. AGL raised similar concerns with ACIL's approach to using different REC values in calculating LRMC and energy purchase costs.

Authority Comment

In its final report to the Authority, ACIL has responded to all issues raised in submissions concerning its LRMC modelling and calculation.

ACIL noted that, at the time its Draft Report was prepared, AEMO had not released its 2010 NTNDP and the associated cost input data. ACIL was therefore unable to utilise this data in preparing its advice to the Authority at that time. Since the Draft Decision was released,

[1] ACIL Tasman, *Preparation of energy market modelling data for the Energy White Paper, Supply assumptions report*, 13 September 2010.

AEMO has released the 2010 NTNDP and its more recent data. In its Final Report to the Authority, ACIL has utilised that more recent data in its LRMC modelling, as suggested by a number of retailers. Like AGL, ACIL considered that Scenario 3 of the NTNDP represented a likely future scenario and therefore used this data as the basis for calculating the LRMC.

ACIL also noted that, while AEMO has also released cost input data for the 2011 NTNDP, this data was still the subject of consultation and had not been formally adopted by AEMO for the 2011 NTNDP. ACIL therefore considered that, at this time, it would not be appropriate to use the 2011 NTNDP cost input data in calculating the LRMC for the 2011-12 BRCI.

While ACIL accepted that there will be short term impacts on generation costs as a result of the significant appreciation of the Australian dollar against the US dollar in the past 12 months, ACIL did not adjust its exchange rate assumption used for modelling the LRMC on the basis that the LRMC is a long term analysis and ACIL considered that the historic average exchange rate provides a sound long term outlook for the exchange rate.

Contrary to the suggestion by CCIQ, ACIL considered that the MRRT will have a negligible effect on the price of coal used by domestic power stations because the tax would not affect the price of export coal (which influences the price of coal for power stations supplied by mines with an export option) and because mines that supply only local power stations are (relatively) low profit and therefore unlikely to incur the tax.

In relation to the more technical issues raised by AGL and Origin Energy, ACIL has provided detailed responses in its Final Report. However, ACIL was not persuaded by the arguments raised to change its modelling approach. Several issues that were raised have been addressed by the inclusion of more recent data that is now available, as suggested by AGL.

Of the other specific issues mentioned above, ACIL noted that:

(a) contrary to suggestions by Origin Energy, ACIL confirmed that its coal price forecasts do take into account the expiry of existing coal supply contracts and their replacement with contracts in which coal is priced relative to coal export prices and that it has based its revised gas price and volume forecasts on those from the 2010 NTNDP, which includes updated assumptions about gas exports from Gladstone;

(b) in response to AGL's query, ACIL confirmed that the coal prices used in its LRMC modelling are the average of coal price forecasts for existing stations. ACIL argued that this approach provided a more realistic estimate of coal prices for use in a greenfield LRMC model than the extreme prices produced by other possible approaches;

(c) ACIL clarified that the apparent discrepancy in average coal prices in ACIL's draft report, suggested by AGL, was due to the removal of prices for coal supplied to Swanbank B, Collinsville and Tarong power stations from the average Queensland price, on the basis that these stations have largely exhausted their existing supply sources;

(d) based on its industry experience and recent regulatory decisions, ACIL decided to retain a debt margin of 300 basis points and a gearing ratio of 60/40 despite AGL's concerns about these parameters;

(e) regarding modelling of plant capacity, ACIL advised that its model adds generation capacity in a continuous manner (referred to as the relaxed integer approach) and agreed with AGL that consistent use of the relaxed integer approach from year to year would capture the rate of change in the LRMC and is suitable for the purpose of the BRCI calculation; and

(f) ACIL confirmed that its estimate of the SRMC of CCGT included a deduction to account for the Queensland GEC scheme and provided further description of its approach.

Finally, ACIL argued that using the penalty prices for GECs and RECs in calculating LRMC was consistent with the required greenfields approach, in which the LRMC modelling reflected hypothetical conditions, as opposed to using current (short run) market prices that reflect existing real world conditions. ACIL noted that this approach was consistent with the approach adopted for previous BRCI calculations.

The Authority's Final Decision

In its Final Report for the 2011-12 BRCI cost of energy estimates, ACIL has estimated the 2011-12 LRMC based on the generation required to meet the total State load for Queensland in the calendar year 2010. Consistent with past practice, the load shape used for modelling the LRMC for 2011-12 was developed by ACIL on the basis of the half-hourly load for the previous calendar year (2010). This load shape includes the loads of customers directly connected to the transmission network.

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

As noted above, for this Final Decision, ACIL has used 2010 NTNDP data as the basis for input costs for estimating LRMC for 2011-12. Relative to input costs used in the Draft Decision, the key input costs that have changed are as follows:

(a) capital costs for coal-fired generation plant are higher than those used in the Draft Decision, which were based on the cost of coal plant installed over the past decade;

(b) capital costs for gas-fired generation plant are similar to those used in the Draft Decision in the initial years of the forecast period but higher in later years;

(c) coal prices are the same as those in the Draft Decision and are similar to those in the 2010 NTNDP data;

(d) gas prices are higher than those used in the Draft Decision and reflect a more refined approach by ACIL to modelling gas prices and volumes, based on gas price and volume forecasts consistent with the 2010 NTNDP data;

(e) operating and maintenance costs for coal-fired plant are higher than in the Draft Decision; and

(f) operating and maintenance costs for gas-fired plant are lower than in the Draft Decision.

For this Final Decision on the 2011-12 BRCI, the Authority has accepted ACIL's final advice on the generation input costs to be used in the LRMC calculation. The input costs used for modelling the LRMC for 2011-12 are discussed in more detail in chapter 2 of ACIL's Final Report to the Authority.

The Authority has considered other issues raised in submissions in relation to LRMC and is satisfied that the assumptions used by ACIL are consistent with the BRCI framework for calculating the LRMC for greenfield generation projects.

Final LRMC Estimate for 2011-12

Consistent with the above discussion and reflecting the use of more recent data, the Authority estimates that the LRMC for 2011-12 is $64.44/MWh, which is 4.8% higher than its estimate of $61.51/MWh presented in the Draft Decision.

2.6 Energy Purchase Cost

Draft Decision

There was general support from stakeholders in response to the Interim Consultation Notice for the Authority to continue with the same approach to estimating energy purchase costs as it had used in the 2010-11 BRCI Final Decision.

The Authority considered the Queensland Government's view that significant decreases in energy prices should be reflected in the energy purchase cost estimate for 2011-12. While the Authority acknowledged there had been recent declines in energy prices, it noted that BRCI energy purchase costs were not simply a function of historical spot market prices and current forward contract market prices, but were more complex, reflecting wholesale prices expected in the forthcoming year, historical forward contract prices, and the NEM load of the previous year. Nevertheless, the Authority agreed that falling prices would progressively influence the cost of purchasing energy as those lower prices filtered through to forward contract prices for future years.

For the Draft Decision, the Authority accepted ACIL's energy purchase cost estimate for 2011-12 of $49.23/MWh.

Submissions in response to the Draft Decision

AGL, Origin Energy and the Queensland Government supported the Authority's decision to maintain the same approach to estimating energy purchase costs as it had used in the 2010-11

The Queensland Government observed that the price of peak and flat energy contracts had continued to fall since the Draft Decision was finalised and that, if this trend continued, the energy purchase cost should be lower in the 2011-12 BRCI Final Decision. The Government also suggested that the forward market for energy contracts reflected an expectation that increased energy supply capacity would place downward pressure on wholesale electricity prices in 2010-11 and 2011-12, despite forecast strong demand growth.

In its submission, APG suggested that hedging products are not equally accessible to all retailers, as implicitly assumed by the Authority, and that the diversity of retailers now operating in Queensland warranted a review of the BRCI method for assessing energy purchase costs. However, APG acknowledged the Authority's limited capacity to do so.

APG and TRUenergy suggested that adverse environmental conditions, such as the Queensland flood, would have an impact on the level of risk and costs faced by retailers and that the Authority needed to consider these impacts in calculating energy purchase costs.

Authority Comment

In its Final Report to the Authority, ACIL provided updated data that confirmed the price of peak and flat energy contracts has continued to decline since the Draft Decision. ACIL noted that lower energy contract prices was one reason why energy purchase costs were lower than in 2010-11, along with several other reasons, including:

(a) significantly lower pool prices;

(b) a higher proportion of load being covered by flat energy contracts relative to more expensive peak energy contracts; and

(c) larger payments to retailers associated with swap hedge contracts.

In response to APG's comments, the Authority acknowledges that each retailer will have a different capacity to obtain various forms of hedging cover. However, for the BRCI, the Authority is required to consider the position of a representative retailer which has significant market share, provides services to a cross section of customers and earns a reasonable retail margin, rather than to attempt to simulate the outcome for an actual retailer.

As for costs associated with adverse environmental factors, all costs that the Authority is aware of have been taken into account in estimating the energy purchase cost, and the BRCI more broadly. The impact of recent floods and cyclones are more likely to impact network costs than the cost of purchasing energy, but to date there has been no request or decision to pass-through any associated costs.

The Authority's Final Decision

In its Final Report to the Authority, ACIL has updated its pool price forecasts for 2011-12 by including the latest NEM load data up to the end of the first quarter 2011. The final pool prices forecast by ACIL for 2010-11 are shown in Table 2.1.

Table 2.1: Queensland quarterly pool prices projected by ACIL Tasman for 2011-12 ($/MWh)

	10%POE	*50%POE*	*90%POE*
Quarter 3 2011	$57.60	$44.31	$39.17
Quarter 4 2011	$23.95	$23.72	$23.70
Quarter 1 2012	$59.11	$39.30	$26.33
Quarter 2 2012	$32.64	$29.83	$29.57
Annual average	$43.27	$34.28	$29.71

Source: ACIL Tasman Calculation of energy costs for the 2011-12 BRCI, Final Report to the Authority, May 2011.

Due to the inclusion of more recent load data, the final pool prices forecast by ACIL are significantly lower than those included in its Draft Report. In its Draft Report, ACIL used the NEM load traces for the year to 30 September 2010, whereas its final projections use NEM load traces for the year to 31 March 2011.

Applying the more recent load traces removed the effects of warm weather conditions that occurred in Quarter 4 2009 and replaced them with load associated with the cooler weather conditions that occurred in Quarter 4 2010. As a result, forecast pool prices in Quarter 4 of 2011 are now significantly lower than those forecast in ACIL's Draft Report.

Contracting Strategy and Contract Prices

In estimating energy purchase costs for 2011-12, ACIL has applied the same contracting strategy as had been used in its Draft Report and the 2010-11 BRCI Final Decision, namely:

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

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

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

ACIL used the 2011-12 half-hourly NEM load trace forecast for Queensland (which excludes the load of directly connected customers) to construct the hedging strategy. The NEM load forecast was developed by ACIL using the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50%POE, 10%POE and 90%POE based on AEMO's 2010 ESOO and Powerlink's 2010 APR.

The cost of swap and cap contracts were estimated by ACIL using the same assumptions as used in the 2010-11 BRCI Final Decision – that the hypothetical retailer spreads its purchases of contracts evenly over 24 months up to the start of the tariff year (2011-12). ACIL also used the d-cyphaTrade data for the same period (up to 31 March 2011) to estimate the cost of electricity swap and cap contracts following the 2010-11 BRCI methodology of averaging daily settled prices.

Table 2.2 below summarises ACIL's final estimates of the quarterly flat, peak and cap contract volumes purchased by an efficient retailer for 2011-12 under this strategy.

Table 2.2: Contract volumes and prices estimated by ACIL Tasman for 2011-12

	Flat contract volume	***Flat contract price***	***Peak contract volume***	***Peak contract price***	***Cap contract volume***	***Cap contract price***
	MW	*$/MW*	*MW*	*$/MW*	*MW*	*$/MW*
Quarter 3 2011	4,570	$30.88	1,181	$44.56	1,022	$3.98
Quarter 4 2011	4,514	$36.16	1,374	$56.66	1,391	$9.16
Quarter 1 2012	4,867	$50.62	1,755	$90.30	1,762	$17.86
Quarter 2 2012	4,634	$33.83	1,289	$46.91	938	$3.13

Source: ACIL Tasman, The calculation of energy costs in the BRCI for 2011-12, Final Report to the Authority, May 2011.

Consistent with the approach adopted for the 2010-11 BRCI Final Decision, ACIL has used the half-hourly NEM load and the contracting prices and quantities for each half hour of the 2011 12 year to provide an estimate of the cost of purchasing energy in 2011-12. ACIL then applied an average loss factor of 3.7% (sourced from Powerlink's 2010 APR) to the settled pricing outcomes.

Table 2.3 shows ACIL's 2011-12 energy purchase cost estimates for the three demand scenarios (10%POE, 50%POE and 90%POE)

Table 2.3: Energy purchase cost estimates for 2011-12 by ACIL Tasman

	Scenario weighting	***ACIL Tasman final estimate for 2010-11***
	%	*$/MWh*
Energy purchase costs 10%POE	30.40	45.75
Energy purchase costs 50%POE	39.20	46.42
Energy purchase costs 90%POE	30.40	47.35
Total energy purchase costs (weighted)	**100**	**46.50**

Source: ACIL Tasman, The calculation of energy costs in the BRCI for 2011-12, Final Report to the Authority, May 2011.

The Authority has accepted ACIL's advice on energy purchase costs which it estimates to be $46.50/MWh in 2011-12.

2.7 Weighting of LRMC and Energy Purchase Cost

Draft Decision

In its Draft Decision, the Authority considered a suggestion by EnergyAustralia to move away from the equal weighting of the LRMC and energy purchase cost towards a heavier weighting on the market-based energy purchase cost, with LRMC setting a price "floor".

The Authority noted that the 50/50 weighting it had adopted in the past reflected the balance of arguments that could be made for a greater weighting either way, as well as recognising the emphasis in the BRCI legislation on LRMC as the basis for determining the cost of energy.

As there were no new or compelling arguments provided to support a change in this view, the Authority decided to continue with the equal weighting of LRMC and the energy purchase cost in calculating the cost of energy component of the 2011-12 BRCI.

Submissions in response to the Draft Decision

EnergyAustralia and TRUenergy again suggested that energy costs should be based on the higher of energy purchase costs and LRMC, rather than a hybrid of the two.

EnergyAustralia suggested that using the LRMC as a floor price would allow the Authority to meet its obligation to take into account the LRMC of energy in calculating the cost of energy component of the BRCI.

Authority Comment

The issue of the weighting to be given to the LRMC and energy purchase cost has been extensively canvassed in previous BRCI decisions. While there are arguments that could be made for a greater weighting either way, the 50/50 weighting adopted by the Authority in the past reflects this balance of arguments.

The Authority disagrees with EnergyAustralia's suggestion that using the LRMC as a floor price would allow the Authority to meet its legislative obligations because, in those years when the energy purchase cost exceeded the LRMC and hence, under the EnergyAustralia approach only the energy purchase cost would be applied, the Authority would not be meeting its legislative obligation to base the cost of energy component of the BRCI on the LRMC, as required under the Electricity Act.

The Authority's Final Decision

In the absence of new or compelling arguments to change the current approach, the Authority is not persuaded to move away from the equal weighting of LRMC and energy purchase costs in calculating the cost of energy component of the 2011-12 BRCI.

2.8 Queensland Gas Scheme

Draft Decision

In establishing the overall cost of energy component for the 2011-12 BRCI Draft Decision, the Authority considered the impact of the Queensland Gas Scheme on energy costs, as required.

In response to comments from stakeholders, the Authority considered whether market data on the price of GECs could be used (instead of the penalty price for not surrendering sufficient GECs) to reliably estimate the change in Queensland Gas Scheme costs for retailers. ACIL advised that annual movements in the cost of complying with the scheme would be better reflected by year-on-year changes in the market price of GECs (rather than the penalty price) if market prices could be obtained from a reliable and consistent source each year.

ACIL considered market data available from NextGen and AFMA. The Authority accepted ACIL's advice that the AFMA data would provide a reasonable basis for estimating GEC costs for Queensland retailers.

Based on AFMA market data available at 30 October 2010, and assuming that retailers would need to obtain GECs for 15% of their load in 2011-12, ACIL estimated that the average cost to a retailer of complying with the Queensland Gas Scheme in 2011-12 would be $0.56/MWh.

In order to ensure consistency in the BRCI framework, the Queensland Gas Scheme cost for 2010-11 was also re-estimated using AFMA data that was available at the time of the previous BRCI Final Decision. The re-calculated 2010-11 estimate of $1.20/MWh was some 57.7% lower than the estimate used in the 2010-11 Final Decision.

In the Draft Decision, the estimated cost of the Queensland Gas Scheme declined by a further 53% from $1.20/MWh in 2010-11 to $0.56/MWh in 2011-12 using the market data based approach.

Submissions in response to the Draft Decision – Queensland Gas Scheme

The Queensland Government and QCOSS supported the Authority's decision to apply a market data based approach to estimating the cost of GECs to value the impact of the Queensland Gas Scheme on energy costs for 2011-12.

The Queensland Government noted that, in the 2009 compliance year, only 0.3% of the total GEC liability was transacted by organisations paying the penalty price, and that a market data based approach would be more representative of the GEC market and its actual cost of supply.

TRUenergy indirectly supported the move to the new approach by suggesting that the LRMC should be calculated using the market based approach to be consistent with the approach adopted by the Authority in calculating the cost of complying with the Queensland Gas Scheme.

Conversely, Origin Energy and AGL argued that a market data based approach was inconsistent with the way in which retailers acquire GECs. Both retailers suggested that GECs are usually sourced via bilateral, long-term arrangements between retailers and eligible generators.

Origin Energy and AGL also had concerns about the use of market data reported by AFMA and NextGen as a basis on which to assess GEC costs due to the lack of liquidity in the GEC market, and suggested that this situation had not changed since previous BRCI decision. Origin Energy sought clarification on the percentage of GEC liability covered by the data used by ACIL in the modelling of the 2010-11 and 2011-12 GEC cost estimates that attracted a market price.

However, Origin Energy acknowledged the difficulty in determining the appropriate method of estimating GEC costs and suggested that neither the market data nor penalty price approach provided a true reflection of the change in costs. AGL suggested that, should the Authority maintain the approach adopted in its Draft Decision, the movement in GEC costs would be better represented by a longer term view of market prices as it would better reflect the long term contracting behaviour of retailers. Specifically, AGL suggested that a retailer would contract four years in advance rather than two years.

While QCOSS supported the Authority's move to a market data based approach, it argued that the judgment in the AGL/Origin Energy case suggested that the Authority need not recalculate the base year if not doing so maintained the integrity and object of the index.

As noted in relation to LRMC, both AGL and TRUenergy noted that, while ACIL had used the penalty price of surrendering GECs in its LRMC calculation, it had used the market price of GECs in determining energy purchase costs.

AGL considered that information provided by ACIL was not sufficiently detailed to permit understanding of the exact methodology used to calculate GEC costs.

Authority Comment – Queensland Gas Scheme

The general conclusion to be drawn from the comments in submissions, as acknowledged by Origin Energy, is that neither the market data based approach (given the data currently available) nor the penalty price approach provides a true reflection of the change in retailers' costs of complying with the Queensland Gas Scheme. However, in the absence of information from retailers about their actual GEC costs, the Authority has no feasible alternative but to adopt one of these approaches.

The Authority agrees with the Government's view that using the penalty price as a proxy for GEC prices would currently result in inflated price estimates for GECs, given that the penalty price is typically escalated by CPI year on year while, in recent years, GEC prices have been declining due to the growing supply of gas-fired generation and associated GECs. As a result, using market data should provide a better, if still imperfect, indication of the change in GEC costs incurred by retailers from year to year than does the penalty price.

The Authority acknowledges the suggestion by AGL that the movement in GEC prices would be better represented by a longer term view of market prices to reflect the long term contracting behaviour of retailers. However, there is limited reliable data available on market prices. In its Final Report, ACIL has used data from 1 July 2007 which includes an additional six months' of data compared to that used in the Draft Decision. ACIL considered that it was not possible to extend the period back further due to a lack of sufficiently robust historical data. The length of the analysis period could be increased in future years as more data becomes available.

By incorporating more data into the analysis period, ACIL's estimate of GEC costs in 2010-11 has changed from that reported in the Draft Decision. ACIL now estimates GEC costs of

$1.29/MWh in 2010-11, up from $1.20/MWh in the Draft Decision and $0.65/MWh in 2011-12 compared to $0.56/MWh estimated in the Draft Decision. .

As for the suggestion by QCOSS that it was not necessary to recalculate the scheme cost in the 2010-11 base year, the Authority considers that QCOSS has incorrectly attributed general comments made by McMurdo J in the AGL/Origin Energy case about the use of updated data to the situation when there is a change in the framework. McMurdo J was clearly of the view that the Authority is required to recalculate the base year when there is a change in framework. This view has been confirmed by the Authority's legal advisors.

The Authority's Final Decision – Queensland Gas Scheme

For its Final Decision, the Authority has retained the market data based approach to estimating GEC costs proposed in its Draft Decision.

Using this approach, incorporating the latest available data and assuming GECs will account for 15% of retail load, the Authority estimates the average cost to a retailer of complying with the Queensland Gas Scheme in 2011-12 to be $0.65/MWh (and $1.29/MWh in 2010-11).

2.9 Enhanced Renewable Energy Target (ERET) Scheme

Draft Decision

In the Draft Decision, the Authority considered the impact of the Federal Government's RET scheme under the Renewable Energy Act, as required. From 1 January 2011, the RET scheme was split into two schemes – the LRET scheme and the SRES.

To determine the costs to retailers of complying with the LRET scheme, ACIL used weekly market prices for RECs published by AFMA, a Renewable Power Percentage (RPP) of 5.08% and annual LRET targets set by the Office of the Renewable Energy Regulator (ORER). Based on this approach, ACIL estimated the cost of complying with the LRET scheme to be $2.80/MWh in 2011-12.

To determine the costs to retailers of complying with SRES, ACIL used the fixed price of STCs of $40/MWh, the published Small-scale Technology Percentage (STP) for 2011 of 14.8% and the number of STCs expected to be created in 2012. Based on this approach, ACIL estimated the cost of complying with the SRES to be $4.73/MWh in 2011-12.

From this, ACIL estimated the combined cost of the LRET and SRES schemes to be $7.53/MWh in 2011-12, a 147% increase from the RET scheme cost of $3.05/MWh estimated in the 2010-11 BRCI Final Decision.

Submissions in response to the Draft Decision – ERET Scheme

Origin Energy, the Queensland Government and QCOSS broadly supported the Authority's decision to use a market based approach for estimating RET costs. However, AGL, Origin Energy and TRUenergy did not support the assumptions used by ACIL to underpin the market based approach.

LRET Costs

AGL, Origin Energy and TRUenergy suggested that ACIL's estimation of 2011-12 LRET costs was undervalued and contrary to recent LGC market prices which had increased by up to 25% since the scheme commenced on 1 January 2011. AGL observed that the intent of the restructured RET scheme was to increase the cost of LGCs to improve investment in renewable energy.

AGL and Origin Energy sought a more detailed explanation of ACIL's method for calculating LGC prices and questioned the period on which the calculation of the average LGC prices for 2011 and 2012 were based. AGL requested that the calculation method and data be made available to enable retailers to replicate ACIL's calculations.

In addition, AGL, the Queensland Government and Origin Energy suggested that ACIL may not have used the most up-to-date forecast of the RPP in the Draft Decision. The Queensland Government noted that ACIL used an RPP of 5.08% when the published RPP (for the 2011 compliance year) was 5.62%. AGL further suggested that the forecast RPP was too low, and that it believed an RPP of 8.66% was more appropriate.

AGL, Origin Energy and TRUenergy suggested an alternative approach of using the LRMC of renewable generation, instead of a market based approach, to determine LRET costs.

Authority Comment – LRET

In response to comments by Origin Energy and TRUenergy, the Authority notes ACIL's comment that retailers would have acquired many LGCs prior to January 2011 at prices lower than those available since then and that the cost of these earlier purchases needs to be reflected in LRET costs.

As requested by AGL and Origin Energy, ACIL provided further explanation of its method for calculating LGC prices and specified the period of prices on which LGC prices for 2011 and 2012 were based in its Final Report.

In relation to stakeholder comments regarding ACIL's forecast RPP, ACIL, in its Final Report, has used:

(a) the revised RPP for 2011 of 5.62%;

(b) the adjusted LRET target for 2012 of 16,338 GWh (as published by ORER on 28 January 2011); and

(c) its own estimate of total liable energy of 185,672GWh for 2012 to arrive at the estimated RPP of 8.8% for that year (ACIL has addressed in detail how it estimated total liable energy using data on STCs in 2012 published by ORER).

In its Draft Decision, the Authority rejected the suggestion by retailers to use the LRMC of renewable generation rather than a market-based approach to determine LRET costs. ACIL identified a number of concerns with the proposal and recommended the continued the use of market-based data instead of proxy measures. The Authority accepted ACIL's advice on the basis that it also preferred to rely on market data when it was available rather than proxies. Submissions in response to the Draft Decision did not include any information to persuade the Authority to change its decision on this issue.

SRES Costs

AGL, Energy Australia, Origin Energy and TRUenergy disagreed with the STC forecast used by ACIL to estimate SRES costs in the Draft Decision. The retailers argued that ACIL had not provided a justification for the basis of its STC scenarios and that ACIL did not provide its reasons for choosing the low case scenario as the likely outcome. AGL, Energy Australia and Origin Energy suggested that a medium or high case scenario was a more likely outcome. Further, Origin Energy suggested that ACIL's estimate of a large decrease in 2012 SRES costs compared to 2011 was unreasonable, given that strong incentives to install small-scale technologies still exist.

The Queensland Government supported the reduction in the STP for 2012 from 14.8% to 8.87%. However, AGL and Energy Australia argued that this was too low and suggested estimates of 12.57% and 16.0% respectively. AGL and TRUenergy suggested that, in its Final Decision, the Authority rely on the revised ORER estimates for the 2012 STP due to be released by 31 March 2011. AGL further suggested that the forecast of the 2012 STP should be the mid-point of ORER's non-binding upper and lower bound of STP for 2012 and 2013.

TRUenergy requested that the Authority consider developing an approach for the 2011-12 BRCI that ensures that retailers and Queensland consumers are not subject to windfall gains and losses when the STP for 2012 is finalised.

AGL and Origin Energy proposed that, alternatively, to avoid any forecast error, rather than forecasting the STP for 2012, the published calendar year STP for 2011 could be assumed to apply to the 2011-12 financial year. AGL and Origin Energy suggested that this approach would represent a pragmatic approach which could be applied consistently into the future and that it would provide the rate of change of SRES costs borne by retailers.

AGL and Energy Australia also considered that, in ACIL's calculation of the STP for 2012, there was a lack of transparency in relation to the relevant electricity acquisitions and the partial exemption certificates (PECS) estimate used.

Authority Comment – SRES

Since the Draft Decision, ORER has published a final STP of 14.8% for 2011. This is the same value as used by ACIL in its Draft Report.

ORER has also published a non-binding STP estimate for 2012 of 16.75%. However, the Federal Government subsequently announced (on 5 May 2011) that it would be reducing the solar credits multiplier from four to three from 1 July 2011 and then from three to two from 1 July 2012. As a result, it seems likely that this estimate will be reduced significantly when ORER finalises the STP for 2012, in March next year.

ACIL considered that the lower multipliers announced by the Federal Government will directly influence the number of STCs created and also reduce the number of small scale technology installations because the lower multipliers will reduce the returns available to owners of solar photovoltaic systems. On this basis ACIL estimated a 2012 STP of 9%.

On 13 May 2011, the New South Wales Government announced that its solar feed-in tariff scheme would be closed to new applicants from 28 April 2011. As the New South Wales scheme had previously been particularly generous, it had contributed to the strong increase in the number of solar photovoltaic systems in New South Wales and the creation of STCs in Australia. The changes to the New South Wales scheme is likely to significantly reduce the quantum of STCs created from the second half of 2011 onwards.

Similarly, on 19 May 2011, the Western Australian Government reduced its feed-in tariff for new applicants from 1 July 2011. While the size of the reduction in the Western Australian feed-in tariff is less than for New South Wales, it will still have some impact on the number of STCs created in Australia. Both these policy changes suggest there is a trend away from overly generous subsidies to small-scale renewable generation across Australia and that, as a result, the level of STCs in 2012 is likely to be lower than the current ORER estimate.

As for the alternate proposal by AGL and Origin Energy to address STP forecast error by using old, but actual, data, the Authority notes that it is required to estimate costs in the coming tariff year. The legislation does not allow the Authority to simply use historical values in place of forecasts (unless no better basis for the forecasts is available) or to provide a 'true-up' between actual and forecast costs in subsequent years. The BRCI is meant to be a self-correcting index and any forecast errors should be compensated for in subsequent years.

Finally, ACIL has provided a more detailed explanation of its calculation of the STP for 2012 in its Final Report which now better explains its estimate of the total liable energy for 2012 to address the issue of relevant electricity acquisitions and PECS.

Other Issues

QCOSS supported the Authority's decision not to include a catch-up cost allowance for ERET costs for the period 1 January to 30 June 2011. However, AGL, Origin Energy and TRUenergy argued against this approach, highlighting that it would result in a significant loss to retailers since they were not able to recover SRES costs for this period. Origin Energy suggested that the costs for the first six months of the scheme in 2011 should be included in the 2011-12 retail tariffs as a cost pass through. Origin Energy noted that this would be in line with the cost pass through applications currently being considered by the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales and encouraged the Authority to explore this approach for the Final Decision.

In response to the Draft Decision, CCIQ argued that ERET costs should not be factored into the 2011 12 BRCI because retailers were already recouping those costs by increasing electricity rates from 1 January 2011 (for market customers). CCIQ argued that the energy sector should accept a proportion of the business risk associated with the RET scheme rather than simply pass on the full costs to the consumer.

Authority Comment – Other Issues

In its Draft Decision, the Authority noted that the BRCI is an index, not a cost build-up and, as such, it is intended to measure the rate of change in costs between two years rather than provide retailers with a full recovery of the costs they actually incur. It was also noted that section 91G(1) of the Electricity Act requires the Authority to determine the BRCI for the relevant tariff year (2011-12) by estimating the total costs of supplying customers in that year, which, unlike the arrangements applying in New South Wales, would preclude making an allowance for the pass-through of costs incurred in supplying customers in some previous year.

The Authority's Final Decision – Enhanced Renewable Energy Target

Based on the consideration of issues outlined in the preceding sections, the Authority has retained a market-based approach to estimating ERET costs as proposed in its Draft Decision. On this basis, the Authority estimates the cost of complying with the LRET scheme at $2.96/MWh and the cost of complying with the SRES scheme at $4.76/MWh, to arrive at a total ERET cost of $7.72/MWh in 2011-12, as outlined in detail in ACIL's report.

2.10 Market Participation Costs

Draft Decision

As it has done previously, the Authority took into account NEM participant fees and ancillary services charges paid by retailers in reaching its Draft Decision on the overall cost of energy.

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

ACIL also estimated the cost of ancillary services provided by AEMO. Based on the average cost over the preceding 52 weeks of available ancillary services cost data up to 30 October

2010, ACIL estimated that the cost of ancillary services would be $0.43/MWh in 2011-12, an increase of 9.3% from 2010-11.

Submissions in response to the Draft Decision – Market Participation Costs

No comments were received from stakeholders on this issue.

The Authority's Final Decision – Market Participation Costs

The Authority has followed the same approach to estimating NEM participant fees and ancillary service charges for this Final Decision on the 2011-12 BRCI as it had proposed in the Draft Decision.

Based on advice from ACIL, the Authority estimates NEM fees to be $0.39/MWh in 2011-12, and the cost of ancillary services to be $0.45/MWh in 2011-12, based on the ancillary services costs data up to 31 March 2011.

2.11 Final Decision on Cost of Energy for 2011-12 BRCI

In total, the Authority estimates that the total cost of energy will decrease from $2,406.9 million in 2010 11 to $2,394.9 million in 2011-12, a decrease of 0.5%. However, despite energy costs declining slightly in total dollar terms, once the reduction in the load between 2009 and 2010 is taken into account (see Chapter 5), the cost of energy in $ per MWh terms increases by 1.66%. The break-up of energy costs is shown Table 2.4.

Table 2.4: Cost of energy components, 2010-11 to 2011-12 – Final Decision

Cost Component	*2010- 11*[1]	*2011 12*[2]	*Change*
Energy Costs	*$/MWh*	*$/MWh*	*%*
LRMC	58.59	64.44	
LRMC (50% weighting)	29.30	32.22	9.98%
Energy purchase cost	58.51	46.50	
Energy purchase cost (50% weighting)	29.26	23.25	-20.53%
Weighted Cost of Energy	**58.55**	**55.47**	**-5.26%**
RET Scheme Costs			
Small-scale Renewable Energy Scheme	0.00	4.76	-
Large scale Renewable Energy Scheme	0.00	2.96	-
Total RET Scheme Costs	**3.05**	**7.72**	**153.11%**
Queensland Gas Scheme Costs	**1.29**[3]	**0.65**	**-49.61%**
Market Participation Costs			
NEM fees	0.34	0.39	15.96%
Ancillary services	0.39	0.45	14.41%
Total Market Participation Costs	**0.73**	**0.84**	**15.12**
Total Cost of Energy:$/MWh	**63.62**	**64.68**	**1.66%**
$million	**2,406.9**	**2,394.9**	**-0.50%**

1. See the Authority's 2010-11 BRCI Final Decision.
2. See ACIL Tasman, Calculation of Energy Costs in the BRCI for 2011-12, Final Report, 24 May 2010.
3. Recalculated with market data from 1 July 2007 to 31 March 2010.
Note: Totals may not add due to rounding.

3. NETWORK COSTS

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

The Authority has based its assessment of transmission network costs on the latest Powerlink and other transmission-related charges that the distributors are expected to pass through to customers in 2011-12.

The distribution network costs for 2011-12 are based on the maximum allowable revenue (MAR) approved by the Australian Energy Regulator (AER) for Energex and Ergon Energy. The MAR for Energex and Ergon Energy incorporates adjustments required following the review of the AER's original determination by the Australian Competition Tribunal (the Tribunal) which the AER indicated would increase distribution costs by $541 million over the current regulatory period.

Following the Tribunal Decision, the Authority was advised by the Minister that the Government had decided to limit the amount of additional revenue to be raised by both Energex and Ergon Energy as a result of the Tribunal decision. To implement this decision, the Minister has directed Energex and Ergon Energy to reduce their network prices so as to target annual revenue in 2011-12 $52.3 million and $40.9 million less, respectively, than that initially approved by the AER following the Tribunal's decision. The Minister noted that the Government had taken this decision in order to reduce the financial burden on Queensland consumers due to increases in the cost of living.

Accordingly, the Authority has reduced its estimate of distribution network costs by $93.2 million.

On this basis, the Authority has estimated the network costs for this Final Decision to be $3,108.7 million in 2011-12, an increase of 8.26% from the previous year.

3.1 Background

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

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

As regulated monopoly businesses, the revenues to be raised via charges by Powerlink, Energex and Ergon Energy are set by the AER.

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

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

3.2 Legislative Requirements

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

3.3 Draft Decision

Transmission Costs

As actual data was not available for the Draft Decision, the Authority estimated the TUOS charges Powerlink would apply to the distributors in 2011-12 by calculating the proportion of Powerlink's MAR in the previous year (2010-11) that was accounted for by the total TUOS charges levied on distributors. This proportion of Powerlink's MAR was then applied to its 2011-12 MAR, as approved by the AER in its *Final Decision on Powerlink Queensland transmission network revenue cap for 2007-08 to 2011-12*.

Other transmission costs expected to be incurred by the distributors were estimated by escalating the 2010-11 cost by the proportional change in the Powerlink charges between 2010-11 and 2011-12.

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

In its Draft Decision, the Authority indicated that these estimates would be updated in the Final Decision once better estimates were available from the distributors' 2011-12 Pricing Proposals to the AER.

Distribution Costs

As in previous years, the estimate of the distribution component of total network costs was based on the AER approved annual revenue requirements for both Energex and Ergon Energy as set out in its *Queensland Final Distribution Determination – 2010-11 to 2014-15*.

At the time of the Draft Decision, the AER determinations for both Energex and Ergon Energy were being reviewed by the Tribunal in response to appeals by the two distributors. At that time, the Authority expected that the result of the reviews would be known in time for inclusion in its Final Decision and indicated that any necessary adjustment would be made at that time along with any other routine annual adjustments made by the AER.

As required by the BRCI methodology, the Authority removed Mt Isa network revenue from Ergon Energy's annual revenue requirement. The Authority noted that, as the AER's Final Decision did not separately identify revenue associated with the Mt Isa network, the Authority would rely on information from Ergon Energy's 2011-12 Pricing Proposal to the AER in order to remove Mt Isa revenue for the 2011-12 BRCI Final Decision. For the Draft Decision, the Authority estimated the Mt Isa network revenue to be deducted for 2011-12 by assuming the Mt Isa network revenue would grow at the same rate as Ergon Energy's total revenue.

3.4 Submissions in response to the Draft Decision

The Queensland Government and Energy Australia considered that the Authority had calculated the network cost component of the BRCI according to legislative requirements.

While acknowledging the constraints that these legislative requirements place on the Authority's network cost calculation, AGL, Energy Australia and Origin Energy all questioned the appropriateness of the legislative requirement to include both the Energex and Ergon Energy annual revenue requirements in estimating the distribution costs, when competition is generally confined to that part of the State covered by the Energex network. AGL and Energy Australia also expressed concern that the BRCI methodology makes no allowance for the ability of network service providers to re-balance their tariffs.

The CCIQ was critical of the calculation of distribution costs for the BRCI without some link to the distributors' performance.

The Queensland Government noted that network costs in the Final Decision may differ from those in the Draft Decision as a result of the Tribunal's review of the AER's determinations for Energex and Ergon Energy. TRUenergy suggested that the Authority should capture the outcome of the review in its Final Decision.

Origin Energy and TRUenergy suggested that costs associated with recent floods and cyclones in Queensland had the potential to raise network charges for 2011-12 and that the BRCI should allow for any such impacts.

3.5 The Authority's Final Decision

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

Transmission Costs

In the Draft Decision, the Authority noted that its estimate of the TUOS charges Powerlink was expected to levy on Energex and Ergon Energy during 2011-12 and other transmission charges likely to be incurred by Energex and Ergon Energy would be updated in the Final Decision to reflect better estimates that would become available from the distributors.

Based on information provided by Energex and Ergon Energy from their Pricing Proposals to the AER, estimated transmission network costs are $707.0 million, which is (1.8%) higher than the $694.3 million estimated at the time of the Draft Decision and 13.04% higher than in 2010-11.

Distribution Costs

At the time of the Draft Decision, Energex and Ergon Energy had sought review by the Tribunal of certain aspects of the AER's *Queensland Final Distribution Determination – 2010-11 to 2014-15* which set the revenue requirements for both distributors. The matters subject to review by the Tribunal included the setting of the WACC parameter 'gamma' for both distributors and a number of other issues only affecting Ergon Energy, including the amounts allowed by the AER for non-system capital expenditure, street lighting, customer service costs and the appropriate inflation measure to be used in calculating wage escalation.

Since the release of the Authority's Draft Decision, the Tribunal has made its decisions in relation to each of the matters appealed by Energex and Ergon Energy. The AER has indicated that the effect of the Tribunal's decision would be to increase distribution network costs by $541 million over the current five year regulatory period.

The AER has also made a number of routine annual adjustments to the MARs for Energex and Ergon Energy to reflect a range of factors, such as the latest CPI forecast and variations in capital contributions. Overall, these annual adjustments reduced distribution revenue by $21.9 million in 2011-12.

The Authority also received updated estimates of the amount of revenue associated with the Mt Isa network to be deducted from Ergon Energy's MAR.

Based on the updated information provided by the AER and Ergon Energy, the Authority estimated distribution network costs to be $2,494.9 million in 2011-12 (11.1% higher than in 2010-11).

On 27 May 2011, the Authority received advice from the Minister that the Queensland Government had decided to limit the amount of additional revenue to be raised by Energex and Ergon Energy as a result of the Tribunal's decision. To implement this decision, the Minister has issued Directions to both Energex and Ergon Energy to adjust their network prices so as to raise $52.3 million and $40.9 million less revenue respectively than would have otherwise been allowed by the AER (see **Appendix 3**).

While an unusual step, it is open to shareholders to make such decisions. From a business perspective, the effect of this decision will be to reduce the bottom line of both Energex and Ergon Energy by equivalent amounts in 2011-12.

For the BRCI, the effect of this decision will be to reduce the previously estimated increase in distribution network costs by $93.2 million and hence reduce the change in the BRCI which would otherwise have been passed onto customers in notified prices.

As a result, the Authority's final estimate of distribution network costs is $2,401.7 million in 2011-12, which is 6.9% higher than in 2010-11 but slightly less than the $2,452.5 million estimated at the time of the Draft Decision.

Other Network Costs

Several submissions noted the potential impact of recent floods and cyclones on network costs and hence the BRCI. While the cost of repairs following the recent floods and cyclones in Queensland may impact future network costs, at the time of preparing this Final Decision, neither Energex nor Ergon Energy had lodged a cost pass-through application for flood or cyclone costs with the AER.

On 25 May 2011, the Queensland Government announced[2] that it had directed Energex and Ergon Energy not to pass on to customers costs related to the floods and cyclones during the summer of 2010-11. However, any costs which might result from these events will not impact 2011-12 distribution charges as, under the National Electricity Rules, the AER cannot amend distribution prices mid-year. Therefore, any costs associated with these events could only impact network prices from 2012-13 at the earliest.

As in past years, a number of submissions commented on perceived shortcomings of the current legislated approach to calculating network costs. However, such issues are beyond the scope of the Authority's discretion. For this Final Decision, network costs have been calculated in line with the legislation and mirror the approach adopted in the 2010-11 BRCI Final Decision.

[2] DEEDI media release – *Electricity regulator's decision will not push up power prices for Queenslanders*, 25 May 2011

Total Network Costs

For this Final Decision, the Authority estimates total network costs to be $3,108.7 million in 2011-12, an increase of 8.26% from 2010-11. This compares with an estimate of $3,146.8 million at the time of the Draft Decision.

Table 3.1 provides Authority's estimate of the various components transmission and distribution network cost for use in the 2011-12 BRCI Final Decision.

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

Network cost	***2010-11[1] $m***	***2011-12 Final Decision $m***	***Change %***
Transmission			
Powerlink charges	611.5	691.3	13.05
Avoided TUOS payments	5.7	4.8	-16.72
Unregulated Powerlink charges	6.0	6.1	1.74
Other Charges	2.2	4.8	119.04
Total transmission costs	**625.5**	**707.0**	**13.04**
Distribution			
Energex	1,135.1	1,272.7	12.12
Ergon Energy	1,110.9[2]	1,222.2[3]	10.03
Government decision	0	-93.2	na
Total distribution costs	**2,246.0**	**2,401.7**	**6.93%**
Total Network Costs	**2,871.4**	**3,108.7**	**8.26%**

Note: Totals may not add due to rounding.
Source: QCA 2010-11 BRCI Final Decision, AER revised Powerlink Final Decision (July 2008), AER Queensland Distribution Determination 2010-11 to 2014-15 Final Decision (May 2010), as amended by the AER in May 2011, and information from Energex and Ergon Energy's Pricing Proposals for 2011-12 to the AER.
1. *See the Authority's 2010-11 BRCI Final Decision.*
2. *Excludes $12.2 million for network revenue associated with Mt Isa.*
3. *Excludes $13.1 million for network revenue associated with Mt Isa.*

4. RETAIL COSTS AND MARGIN

The retail cost component of the BRCI comprises retail operating costs and a retail margin. The retail costs component must reflect the Authority's view of the likely cost of providing customer retail services to Queensland customers connected to the national grid, based on an efficient representative retailer (rather than an actual retailer) which is carrying on an electricity retail business separately from any other business, has a significant share of the Queensland electricity retail market and has a cross-section of customers in the same proportions as the customer mix for Queensland as a whole.

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

As permitted under the QCA Act, the Authority recently imposed fees on retailers to meet the Authority's cost of performing regulatory functions in respect of the retail electricity industry (and all other regulated industries). The cost of these fees has been recognised in the 2011-12 retail operating cost estimate.

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

In total, retail costs are expected to increase by 4.96% from $545.6 million in 2010-11 to $572.6 million in 2011-12.

4.1 Background

The retail cost component of the BRCI relates to the services provided by an electricity retailer to its customers, excluding those costs over which it has limited or no control (energy costs and network costs). There are two broad categories of retail costs that are incurred by a retailer – customer acquisition and retention costs (CARC) and other retail operating costs. A retailer will also seek to earn a margin above its costs as a return on its investment.

CARC includes marketing, advertising, sales overheads, door-to-door/commission/agent costs and telesales.

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

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

4.2 Legislative Requirements

The Electricity Act requires that retail costs must reflect the Authority's view of the likely cost of providing customer retail services to Queensland customers connected to the national grid, based on an efficient entity carrying on an electricity retail business that meets all of the following criteria:

(a) it is carried on separately from any other business (that is, the business is a stand-alone Queensland electricity retailer);

(b) it has a significant share of Queensland's electricity retail market;

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

(d) it earns a reasonable retail margin.

In addition, the Electricity Regulation requires that the Authority must consider the following cost categories for the provision of customer retail services:

(a) billing;

(b) customer call centres;

(c) credit management;

(d) energy trading activities;

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

(f) information technology systems; and

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

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

4.3 Retail Operating Costs

Draft Decision

In its Draft Decision, the Authority continued with the escalated benchmark approach to calculating retail operating costs that it had applied since the 2007-08 BRCI decision. This approach involved escalating the Authority's 2006-07 estimate of retail operating costs (which were determined by benchmarking against other regulatory decisions at the time) to account for wages growth and price inflation over the intervening period.

However, the Authority changed its approach to CARC. While these costs were previously treated as a separately calculated retail cost item, the Authority considered that, given the current state of competition in the Queensland retail market, these should be treated in the same manner as other retail operating costs. As a result, the Authority established a new operating cost base for 2010-11 by combining the 2010-11 estimate of retail operating costs per customer and the 2010-11 allowance for CARC per customer. This was then escalated forward to 2011-12 using the same escalation factor.

The Authority also incorporated the additional costs associated with the Authority's decision to impose regulatory fees on retailers in its estimate of retail operating costs. The allowance for regulatory fees in 2011-12 was based on the Authority's estimate of the annualised actual cost of performing its functions over the five-year period from 1 July 2010 to 30 June 2015.

Customer Acquisition and Retention Costs

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

The Authority had calculated CARC as a separate (retail) cost item since the first BRCI Decision following the commencement of full retail competition (FRC) on 1 July 2007. At that time, there were only two substantial incumbent retailers in the market and the Authority determined that it was appropriate to recognise the customer acquisition costs likely to be incurred by a new entrant trying to gain market share and customer retention costs likely to be incurred by incumbents trying to defend their market share. Linking these costs to the rate of market churn was a means of recognising the scale of these costs and encouraging the development of competition in the market.

In the Draft Decision, the Authority noted that, while this had been an appropriate approach during the early years of full retail competition (FRC), the level of competition had expanded rapidly since then. Accordingly, the Authority proposed to adopt an alternative approach more attuned to the current level of competition in the Queensland retail market. This approach involved de-linking the growth in CARC from the rate of change in market churn and treating CARC in the same manner as other retail operating costs.

However, to do so it was necessary to estimate an appropriate 'baseline' CARC allowance per customer for inclusion with other retail costs which would then be escalated forward. As there were a number of difficulties associated with estimating an appropriate 'baseline', the Authority opted to include the same CARC allowance per customer (in real terms) as had been calculated for the 2010-11 BRCI.

In the 2010-11 BRCI Final Decision, the Authority estimated 2010-11 retail operating costs at \$85.89 per customer and CARC at \$40.52 per customer – a combined cost of \$126.41 per customer.

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

The Authority considered that this approach offered a pragmatic and prudent solution to compensating retailers for their marketing expenditure while recognising the need for customers to share in the benefits of a competitive market.

Escalation Factors

As in previous BRCI decisions, the Authority used a 60/40 weighted average of the Wage Price Index (WPI) and CPI to escalate the retail operating cost base.

The Authority based its forecast estimates of:

(a) WPI on the ANZ *Australian Economics Toolbox* of 5 November 2010 (now known as the *Australian Economics Weekly*); and

(b) CPI on the Reserve Bank of Australia (RBA) *Statement on Monetary Policy* of November 2010.

Using this approach, the Authority arrived at an escalation factor for the 12 months to 30 June 2012 of 3.56% (the WPI estimate was 4.1% and the CPI estimate was 2.75%). The Authority also noted that it would use the most recently available forecasts of WPI and CPI for the Final Decision.

Additional Regulatory Costs (Regulatory Fees)

For its Draft Decision, the Authority included a new cost within retail operating costs to recognise the imposition by the Authority of regulatory fees on retailers. These fees are intended to recover the Authority's costs of performing regulatory functions in respect of the retail electricity industry.

The Authority had calculated the regulatory fees to be paid by electricity retailers (in aggregate) based on its estimate of the annualised actual cost of performing its functions over the five-year period from 1 July 2010 to 30 June 2015. On this basis, the annual fee to be paid by retailers was set at $2.795 million in 2010-11 and $2.957 million in 2011-12.

As the fee was not known at the time of the 2010-11 BRCI Final Decision and was a new cost placed on retailers in addition to all existing costs, the retail cost base for 2010-11 was not recalculated to include this fee.

Customer Numbers

The Authority required an estimate of customer numbers to transform retail operating costs per customer into total retail operating costs for input into the BRCI Draft Decision calculation.

Consistent with the approach used in previous BRCI Draft Decisions, the Authority escalated the 2010-11 customer numbers (2,012,602) using the annualised customer growth rate reported in the previous three years (2008-09 to 2010-11) of 1.43% to arrive at an estimate of 2,041,401 customers for 2011-12. The Authority noted that, as in previous years, it would use updated estimates of customer numbers from Energex and Ergon Energy for the Final Decision.

4.4 Submissions in response to the Draft Decision

Customer Acquisition and Retention Costs

The Queensland Government, Origin Energy, the Queensland Consumers Association and the QCOSS all supported the Authority's proposed approach to delink the growth in CARC from market churn rates. Origin Energy considered that the cost allowance for customer acquisitions was now appropriate for a mature competitive market and that the continued use of a method based on market activity would be inappropriate. The Queensland Government argued that notified electricity prices should not be sensitive to the rate of customer churn and that CARC for an efficient electricity retailer with significant market share should be relatively stable.

However, some submissions questioned the application of the new approach. The Queensland Consumers Association questioned the size of the allowance included in the new 2010-11 retail operating cost base (given that it was derived from estimates based on the previous approach) and urged the Authority to ensure that it was suitable and accurate. QCOSS questioned the accuracy of the AEMO data used in establishing the 2010-11 allowance, suggesting the Authority confirm the data was a true reflection of customer changes between retailers and did not include any changes between Participant IDs of the same organisation or any Market Settlement and Transfer Solution (MSATS) transaction that merely reversed a previous transaction. QCOSS also considered that a downward adjustment to the switching data may be appropriate to account for switching that resulted from inappropriate marketing tactics.

While supportive of the Authority's approach to CARC, the Government also reiterated its long held view that CARC should be incorporated into market contract rates rather than being recovered through regulated tariffs.

APG did not support the Authority's proposed approach. APG noted that the Authority had decided to reduce the CARC allowance on the basis of increased competition. However, it argued that the allowance had dropped to $40.52 in the Draft Decision (compared to $187.66 and $109.47 per switch and transfer, respectively, in the 2010-11 Final Decision) which it considered was a gross underestimate of the cost of services.

Authority Comment

The issue of AEMO data quality has been considered in previous BRCI decisions. While there appeared to be some anomalies in the data in the early years of the BRCI, the Authority noted in its 2010-11 BRCI Decision that AEMO had made some changes to the data, including removing customer movements within the same retail entity and estimating transfers based on the change in financially responsible market participant (FRMP) rather than simply any change to a customer's account status (meaning that transfers between different Participant IDs of the same organisation are not counted). AEMO also advised that it expected any overstatement of numbers due to the reversal of previous transactions to be minimal, with no significant impact on the overall numbers.

The Authority concluded previously that the AEMO data is the best independent source of information available for assessing customer switching rates and that any attempts to alter or cleanse the data (including to account for switches resulting from inappropriate marketing tactics) would be highly subjective. Given the change in approach to assessing CARC, the quality of AEMO transfer data is not a factor in estimating the 2011-12 retail operating costs (other than via its impact on previous years estimates) and will not be relevant in any future BRCI decisions. The Authority notes that in NSW, IPART also relies on AEMO MSATS data to forecast customer switching rates.

While supporting the Authority's revised approach to handling CARC, the Government questioned whether CARC should even be a factor in setting notified prices which apply only to non-market customers. However, s94(1) of the Electricity Act requires that the Authority consider retail costs in the context of a representative retailer (rather than an actual retailer) that has a significant market share and cross-section of customers. It cannot solely consider the costs of servicing customers on notified prices. While the change in the BRCI is used to adjust notified prices (which only apply to non-market customer) the change in costs the Authority is required to measure in calculating the BRCI is not restricted to the cost of servicing non-market customers.

In its comment, APG appears to have misinterpreted how the Authority calculated the CARC allowance. In establishing a new baseline CARC for 2010-11, the Authority multiplied the number of switches by the cost per switch ($187.66) and the number of transfers by the cost per transfer ($109.47). The resulting two figures were then added together to obtain a total allowance for CARC. This allowance was then divided by the total number of customers (rather than just the number of customers switching and transferring) to arrive at an allowance of $40.52 per customer. Therefore, contrary to the claim by APG, the value of CARC calculated for 2010-11 has been preserved and in future will grow at the same rate as other retail operating costs.

Additional Regulatory Costs (Regulatory Fees)

Origin Energy, Energy Australia and APG supported the inclusion of regulatory fees as an additional retail cost item. However, APG also suggested that the 2010-11 base should be adjusted (because regulatory fees were also payable in that year) and that the 2010-11 fee should be escalated and incorporated in the 2011-12 BRCI.

QCOSS did not support the inclusion of regulatory fees in the 2011-12 BRCI and suggested that regulatory fees were implicitly included in the original benchmark since other jurisdictions also charge regulatory fees to retailers. QCOSS also argued that giving specific recognition to regulatory fees would be inconsistent with the treatment of other costs for which the Authority had not made explicit allowances in the BRCI (such as administration costs associated with the Home Energy Emergency Assistance Scheme and the Queensland Government Solar Bonus Scheme). Finally, QCOSS questioned whether due process had been followed because it appeared the Authority had decided its approach on regulatory fees outside the BRCI process.

Authority Comment

In its 2008-09 BRCI Final Decision, when reviewing the options for estimating retail operating costs, the Authority decided to continue with the benchmarking approach for that year but was also of the view that, where appropriate and possible, the benchmarking approach could be supplemented by more detailed analysis of some individual components.

The Authority considered that regulatory fees were a new cost for retailers (though (lesser) fees had previously been charged to distributors and hence were reflected in network costs) and the impact of this new cost should be recognised in establishing the new retail cost for 2011-12.

The Authority did not add regulatory fees into the 2010-11 base as the imposition of regulatory fees had not been considered at the time the 2010-11 decision was completed and were considered by the Authority to represent a new and additional retail cost which needed to be recognised. In the context of the BRCI, to add these into the 2010-11 base would have effectively denied retailers any recognition of this new cost other than for the small change between 2010-11 and 2011-12. The alternative suggestion by APG may be an appropriate comment were the Authority setting a bottom-up retail cost rather than the BRCI process which is focussed on assessing the change in costs from year to year.

While QCOSS claimed that regulatory fees would have been captured in establishing the original benchmark operating cost, it provided no evidence to support this view. Retailers in Queensland were certainly not paying regulatory fees at that time. IPART did not (and still does not) charge regulatory fees. While the benchmark cost adopted by the Authority was not based solely on IPART, it was the same as the IPART retail operating cost allowance and was towards the bottom of the range of results from other jurisdictions. It would therefore appear unlikely that regulatory fees would have been a factor in the original benchmark cost.

The Authority also notes that costs associated with the Home Energy Emergency Assistance Scheme and the Queensland Government Solar Bonus Scheme (along with several other Queensland Government policy initiatives) were not specifically included in retail operating costs, because the Authority considered that the administration and cost recovery for such initiatives was a matter for the Government to determine, not because the Authority considered it inappropriate to adjust its original benchmark cost.

Finally, the Authority rejects the suggestion that due process had not been followed in deciding the treatment of regulatory fees. The release of the Draft Decision provided the opportunity for all interested parties to comment on the approach to be adopted by the Authority. Correspondence from the Authority to retailers merely noted that the small impact on costs resulting from the introduction of fees would be recognised in the BRCI process.

General Comments

The CCIQ argued that, where it was within the Authority's jurisdiction to do so, full retail costs should only be included in the retail cost allowance for businesses that can demonstrate service improvements to customers.

Authority Comment

The legislation does not provide for the Authority to tie the inclusion of any cost components of the BRCI to demonstrated service quality improvements, as proposed by CCIQ.

4.5 The Authority's Position

In line with the comments above, the Authority has decided to maintain the approach it proposed in the Draft Decision for estimating retail operating costs. Where appropriate, the Authority has updated its calculations to include the most recently available data.

Customer Acquisition and Retention Costs

As per the Draft Decision, combining retail operating costs and CARC from the 2010-11 BRCI of $85.89 per customer and $40.52 per customer produces a new retail operating cost base for 2010-11 of $126.41 per customer. This was then escalated forward to 2011-12 values.

Escalation Factors

As per the Draft Decision, the Authority has retained the 60% WPI and 40% CPI weighting for the escalation factor to be applied to the new 2010-11 retail operating cost base (excluding regulatory fees – see below). However, it has updated its forecasts based on most recently available data for the 12 months to 30 June 2012.

The WPI forecast of 4.05% was sourced from the ANZ *Australian Economics Weekly* (6 May 2011) and the CPI forecast of 2.5% was sourced from the RBA's *Statement on Monetary Policy* (6 May 2011). Applying the 60%/40% weighting, the escalation factor for 2011-12 is 3.43%.

Additional Regulatory Costs (Regulatory Fees)

Regulatory fees are set at $2.358 million for 2011-12. This is slightly lower than reported in the Draft Decision due to revised estimates of regulatory costs. This slightly lower fee translates into $1.16 per customer (compared to $1.45 per customer in the Draft Decision).

Despite the fee being payable in both 2010-11 and 2011-12, the Authority has not adjusted the 2010-11 base for this year's BRCI calculation.

Customer numbers

The Authority has obtained updated customer numbers from Energex and Ergon Energy for 2011-12. The distributors provided the Authority with the forecast customer numbers they included in their annual pricing proposals to the AER for 2011-12.

Based on the information reported by the distributors, the Authority has estimated 2011-12 customer numbers to be 2,038,158 (compared to 2,041,401 in the Draft Decision). This represents an increase of 1.27% in the total customer base relative to 2010-11. This latest estimate of customer numbers is used to determine the overall BRCI retail operating costs for 2011-12.

Summary – Retail Operating Costs

Escalating the new 2010-11 retail operating cost base of $126.41 per customer by the escalation factor (3.43%) produces an estimate of $130.74 per customer for 2011-12. Adding regulatory fees of $1.16 per customer produces an estimated retail operating cost for 2011-12 of $131.90 per customer, which is 4.35% higher than 2010-11. This is slightly lower than estimated in the Draft Decision due to the slightly lower escalation rate and lower regulatory fees.

The Authority therefore estimates total retail operating costs for 2011-12 to be $268.8 million ($131.90 per customer multiplied by 2,038,158 customers), which is 5.67% higher than 2010-11.

4.6 Retail Margin

Draft Decision

As in previous BRCI Decisions, the Authority proposed to use a retail margin of 5% of total BRCI costs (excluding retail margin). After applying the 5% margin in the Draft Decision, the dollar value of the retail margin increased from $291.0 million in 2010-11[3] to $307.8 million in 2011-12, an increase of 5.77%.

Submissions in response to the Draft Decision

Retailers generally claimed that the retail margin was too low to cover their costs and risks. TRUenergy argued that the retail margin should be well above 5%, AGL suggested that it should be in excess of 6% and Energy Australia considered that it should be at the upper end of the range of margins accepted by regulators in other jurisdictions. TRUenergy noted that IPART provided a retail margin of 5.4% in NSW. It argued that, since IPART had defined cost pass-through provisions for certain regulatory and tax change events (such as the introduction of the SRES) regulatory risk was lower in NSW than in Queensland, suggesting that a higher retail margin is warranted. TRUenergy also argued that by applying the same percentage increase across all tariffs and customer classes (with no consideration of underlying cost structures and changes) the BRCI creates risks for retailers.

The Queensland Government was of the view that the margin was appropriate and that there was no justification for an increase.

The Queensland Consumers Association argued that the margin was too high because it resulted in an excessively large dollar increase when other costs are increasing. CCIQ also claimed that the margin was too high and argued that a revenue and profit discount factor should be applied to align returns of retailers with other businesses given state-wide economic conditions.

Authority Comment

To justify an increase in the retail margin, it would be necessary to establish that the risk profile of the representative retailer has changed. No evidence has been provided by retailers to suggest that the risks of retailing electricity in Queensland will be higher in 2011-12 than it has been in 2010-11. Neither have any retailers provided detailed financial information to the

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

Authority to establish what their actual retail margins are. While the BRCI approach does not allow for the catch-up of SRES costs incurred in the first half of 2011, the potential for divergence between actual and forecast costs has always been a feature of the BRCI framework. While the retail margin has been held constant since 2007-08, there continue to be many discounts to notified prices on offer in the market, suggesting that, at least, overall notified prices are not too low.

The Authority is also not convinced by the arguments of the Queensland Consumers Association and CCIQ that the retail margin is too high. The Authority considers that it is appropriate to calculate the margin as a percentage of total costs. This recognises that a retailer is exposed to changes in each component of the costs of supplying energy to customers. That the dollar value of the margin will vary from year to year has no impact on the BRCI while ever the retail margin remains constant in percentage terms.

Similarly, regarding the suggestion from CCIQ to align returns with current economic conditions, the 5% margin was determined by the Authority to provide a reasonable return to a representative retailer operating efficiently. The margin has not been varied in the past despite fluctuating general economic conditions and to do so now would introduce a degree of uncertainty which might of itself suggest the margin should be higher. Adopting this suggestion would also be a double edged sword as the same logic would require that the retail margin be increased when economic conditions are strong.

The Authority's Position

No evidence was provided to indicate that the risk profile of retailers had changed since prices were last set.

The Authority has therefore maintained the retail margin at 5% of the total BRCI. As a result, the dollar value of the retail margin has increased from $291.2 million in 2010-11 (as recalculated in this Final Decision following changes to the calculation of GEC costs) to $303.8 million in 2011-12, an increase of 4.33%.

4.7 Other Issues

In arriving at its estimate of the increase in the BRCI for 2011-12, the Authority has not taken explicit account of the requirement in the Current Delegation to maintain the 'headroom' in the tariffs in place immediately prior to the commencement of full retail competition. Origin Energy and Energy Australia both argued that the level of headroom had eroded as a result of shortcomings in the BRCI (for example, due to the averaging of the network cost component across both distributors and the introduction of the SRES).

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 (the only two competitive retailers in existence prior to the introduction of full retail competition), 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 have been broadly maintained.

Further, as noted previously, retail market contracts continue to offer discounts to customers relative to notified prices, new entrants continue to be attracted to the Queensland market and there continues to be a high degree of market activity as retailers compete for customers, all of which suggests that headroom has not been eroded.

Finally, the certificate of delegation requires that the Authority ensures 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 Final Decision. Notified prices have been increased in line with rising costs and market contracts generally match or offer a discount to the notified prices. Therefore, the Authority considers it unlikely that any of the limited number of customers who have (or may in the future) revert to notified prices would impose a financial loss on their retailer.

4.8 The Authority's Final Decision

A summary of the Authority's Final Decision on the costs of providing retail services is provided in Table 4.1.

Table 4.1: Changes in Retail Cost Components, 2010-11 to 2011-12 - Final Decision

Retail Cost Component	*2010-11*[1]	*2011-12*	*Change*
	$m	*$m*	*%*
Retail costs	254.4	268.8	5.67
Retail margin (5%)	291.2[2]	303.8	4.33%
Total Retail Costs	**545.6**	**572.6**	**4.96%**

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

In total, retail costs are estimated to increase by 4.96% from $545.6 million in 2010-11 to $572.6 million in 2011-12.

5. NEM LOAD

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

For this Final Decision, the Authority has determined that the 2010 NEM load was 37,027 GWh, a decrease of 2.13% from that used in calculating the 2010-11 BRCI and, reflecting the inclusion of final data, a decrease of 2.08% on the 37,812 GWh NEM load estimated at the time of the Authority's Draft Decision on the 2011-12 BRCI.

While not a separately identified cost component in the BRCI, changes in the load impact the final c/kWh cost of supplying electricity and hence the BRCI.

5.1 Background

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

5.2 Legislative Requirements

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

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

5.3 Draft Decision

The Authority's 2011-12 Draft Decision included an estimate of the 2010 NEM load because, at that time, the actual load data for the entire year was not available. The Authority noted that full year data for 2010 would become available from AEMO in time for the 2011-12 Final Decision and that it would use that actual data in preparing its Final Decision.

For the purposes of its 2011-12 BRCI Draft Decision, the Authority estimated the 2010 NEM load to be 37,812 GWh based on actual load data for the first three quarters of 2010 and a forecast for the December quarter 2010 prepared by ACIL.

5.4 Submissions in response to the Draft Decision

AGL considered that the process used by the Authority to forecast the NEM load for the 2010-11 BRCI was appropriate to use for the 2011-12 BRCI. AGL also requested that, as in previous years, the Authority make the load data used in calculating the BRCI available to electricity retailers.

5.5 The Authority's Final Decision

Estimating the NEM load for 2010

As required by the legislation, for the 2011-12 tariff year, the relevant NEM load is that for the 2010 calendar year. The Authority has followed the same approach to calculating the NEM load for 2010 as was used to calculate the 2009 NEM load used in the 2010-11 BRCI Final Decision.

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

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

Loads of directly connected customers

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

Loads of registered embedded generators

Data supplied by AEMO included loads supplied by registered embedded generators participating in the NEM but excluded loads supplied by unregistered embedded generators[4].

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 could have sourced annual load data for unregistered embedded generators from Energex and Ergon Energy, it was not able to source a matching load profile. Therefore the Authority has not made any adjustment to the data supplied by AEMO to include the loads of unregistered embedded generators when calculating the 2010 NEM load. This is the same approach that was used in calculating the 2009 NEM load for the BRCI for 2010-11.

Other exclusions

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

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

2010 NEM Load

Based on the load data obtained from AEMO, the Authority estimates that the 2010 total State NEM load decreased by 0.83%, compared to growth observed over the previous four years of around 1% per annum. However, the directly connected load (including load connected to the NSW network) for 2010 increased by 3.78%.

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

On this basis, the Authority estimates that the NEM load for 2010, to be used as the denominator in calculating the 2011-12 BRCI, is 37,027 GWh, which is 2.13% less than the 2009 NEM load used in calculating the BRCI for 2010-11. The Authority's final 2010 NEM load estimate is 2.08% lower than that used in the Draft Decision. This change reflects the lower than forecast energy consumption over the December 2010 quarter due to the relatively mild temperatures experienced in that quarter. Table 5.1 provides the components of the 2010 NEM load estimate.

Table 5.1: 2009 and 2010 NEM load

	2009[1]	***2010***	***Change***
	GWh	*GWh*	*%*
Total State NEM load	48,451	48,047	-0.83%
Less loads of directly connected customers and loads connected to the NSW network	10,619	11,020	3.78%
NEM Load	**37,832**	**37,027**	**-2.13%**

Sources: AEMO and Powerlink.
1. See the Authority's 2010-11 BRCI Final Decision.

6. FINAL DECISION – 2011-12 BRCI

The Authority estimates the increase in the BRCI will be 6.6% between 2010-11 and 2011-12.

In dollar terms, the Authority estimates that the cost of energy will decrease by 0.50% in 2011-12, while network costs and retail costs will rise by 8.26% and 4.96% respectively.

The 2010 NEM load (denominator) decreased by 2.13% from the 2009 NEM load used in calculating the 2010-11 BRCI. This reduction in load will increase the BRCI (which is calculated in cents per kWh) as higher costs in 2011-12 are now spread over less load.

After converting the total dollar costs to cents per kWh, the Authority estimates that the cost of energy (despite falling slightly in dollar terms) will increase by 1.66% in 2011-12, while network costs and retail costs will rise by 10.62% and 7.24% respectively.

As a result, the Authority estimates the total BRCI to be 16.41 cents per kWh in 2011-12 compared to the 15.39 cents per kWh in 2010-11. This represents an increase in the BRCI of 6.6% between 2010-11 and 2011-12.

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

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

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

	2010-11	*2011-12*	*Change (%)*
Cost of energy ($m)	2,406.9	2,394.9	-0.50%
Network costs ($m)	2,871.4	3,108.7	8.26%
Retail costs ($m)	545.6	572.6	4.96%
NEM load of Queensland (GWh)	37,832	37,027	-2.13%

Note: Totals may not add due to rounding.

Based on the total costs and load presented in Table 6.1, the Authority has calculated that the BRCI will increase by an expected 6.6% in 2011-12, as shown in Table 6.2.

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

BRCI cost component	*2010-11*	*2011-12*	*Change*	*Share of total costs 2010-11*	*Change in BRCI*
	c/kWh	*c/kWh*	*%*	*%*	*%*
Cost of energy	**6.36**	**6.47**	**1.66%**	**41.33%**	**0.69%**
LRMC of energy	2.93	3.22	9.98%	19.03%	1.90%
Energy purchase costs	2.93	2.33	-20.53%	19.01%	-3.90%
Other energy costs	0.51	0.92	81.67%	3.29%	2.69%
Network costs	**7.59**	**8.40**	**10.62%**	**49.30%**	**5.24%**
Distribution	5.94	6.49	9.26%	38.56%	3.57%
Transmission	1.65	1.91	15.49%	10.74%	1.66%
Retail costs	**1.44**	**1.55**	**7.24%**	**9.37%**	**0.68%**
Operating costs	0.67	0.73	7.97%	4.37%	0.35%
Margin	0.77	0.82	6.60%	5.00%	0.33%
Total	**15.39**	**16.41**	**6.60%**	**100.00%**	**6.60%**

Note: Totals may not add due to rounding.

As required by the Certificate of Delegation and section 90(5) of the Electricity Act, all existing notified prices will be increased by 6.6% with effect from 1 July 2011.

APPENDIX 1: CURRENT BRCI DELEGATION (SEPTEMBER 2010)

CERTIFICATE OF DELEGATION

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

Delegation

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

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

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

Conditions of delegation

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

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

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

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

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

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

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

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

[redacted]

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

Dated: 21 September 2010

APPENDIX 2: STAKEHOLDER SUBMISSIONS

Table A1: Submissions in response to the Draft Decision

	Organisation/Individual
1.	AGL
2.	Australian Power and Gas
3.	Chamber of Commerce and Industry Queensland
4.	Energy Australia
5.	Origin Energy
6.	Queensland Consumers' Association
7.	Queensland Council of Social Service
8.	Queensland Government
9.	TRUenergy

Table A2: Submissions in response to the Interim Consultation Notice

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

APPENDIX 3: MINISTERIAL DIRECTIONS ENERGEX AND ERGON ENERGY

Queensland Government

Hon Stephen Robertson MP
Member for Stretton

Minister for Energy and Water Utilities

MBN4730

30 MAY 2011

Mr B Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001

Dear Mr Parmenter

As you are aware, both ENERGEX Ltd (ENERGEX) and Ergon Energy Corporation Limited (Ergon Energy) made application to the Australian Competition Tribunal (the Tribunal), under the provisions of the National Electricity Law, for a review of the value of gamma applied by the Australian Energy Regulator (AER) in its Final Distribution Determinations for 2010-15.

The Tribunal has recently concluded that a revised gamma value of 0.25 would be applied to the AER Final Determination (revised down from 0.65). This decision increases the total revenue that can be recovered by ENERGEX and Ergon Energy during the 2010-15 regulatory period. As a result, both ENERGEX and Ergon Energy have submitted revised pricing proposals for 2011-12 to the AER.

This Government remains concerned about the continuing increases in the cost of living, including rising electricity costs, and the financial burden this is placing on consumers, particularly those recovering from the recent natural disasters in Queensland. The Tribunal's decision in relation to gamma places further upward pressure on electricity prices.

In light of this, the Queensland Government has determined that $93.2 million of the increased revenue available to the distributors as a result of the Tribunal's decision will not be raised by the distributors in 2011-12. To this end, and to ensure these extra charges are not passed onto consumers in higher electricity prices, the shareholding Ministers for Energex and Ergon will issue direction notices to both entities requiring them to exclude $93.2 million from their network prices in 2011-12. The foregone revenue is not to be recovered in future network tariffs.

We note the Queensland Competition Authority (QCA) is required to release its Final Benchmark Retail Cost Index (BRCI) Decision on electricity prices for 2011-12 by 31 May 2011. Under section 93 of the *Electricity Act 1994*, the network cost component of the BRCI must reflect the QCA's view of the likely total revenue requirements for the relevant tariff year for transmission entities and distribution entities in the State.

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To reflect this decision and ensure the forecast revenue to be recovered by the distributors is not overestimated in the BRCI calculation, the QCA is requested not to include $93.2 million in additional combined revenue resulting from the Tribunal decision, in estimating the total revenue requirement for ENERGEX and Ergon Energy when calculating the network cost component of the 2011-12 BRCI.

If you have any questions about my advice to you, Ms Kathie Standen, A/General Manager, Energy Industry Policy of the Department of Employment, Economic Development and Innovation will be pleased to assist you and can be contacted on telephone 322 58256.

Yours sincerely

[redacted]

STEPHEN ROBERTSON MP

GOVERNMENT OWNED CORPORATIONS ACT 1993

SECTION 108(4)

DIRECTION BY MINISTERS

We, the shareholding Ministers of Ergon Energy Corporation Limited, hereby direct the board of Ergon Energy Corporation Limited to modify the draft 2011-12 Statement of Corporate Intent submitted to us by letter dated 25 March 2011 to:

- include a statement that Ergon Energy Corporation Limited will:
  - not seek to recover $40.9 million in increased revenues from its Standard Control Services in 2011-12 (foregone revenue) arising from the Australian Competition Tribunal Determination of 19 May 2011 in Australian Competition Tribunal File No 3 of 2010; by either:
    - developing an amended pricing proposal for 2011-12, consistent with that undertaking; and seeking approval of that amended pricing proposal from the Australian Energy Regulator in accordance with National Electricity Rule 6.18.8; or
    - varying or adjusting the tariff that was the subject of the amended pricing proposal dated 20 May 2011, as contemplated by National Electricity Rule 6.18.2(b)(5);
  - publish the relevant tariff classes and tariffs, and charging parameters, in accordance with National Electricity Rule 6.18.9;
- include a statement that Ergon Energy Corporation Limited will not seek to recover the foregone revenue in any future period beyond 30 June 2012;
- amend the financial forecasts contained in the Statement of Corporate Intent to reflect this action; and
- include a statement quantifying the revenue foregone by Ergon Energy Corporation Limited in implementing this direction.

[redacted]	[redacted]
The Honourable Rachel Nolan MP	**The Honourable Stephen Robertson MP**
Minister for Finance and The Arts	**Minister for Energy and Water Utilities**
30 / 5 /2011	30 / 5 /2011

GOVERNMENT OWNED CORPORATIONS ACT 1993

SECTION 108(4)

DIRECTION BY MINISTERS

We, the shareholding Ministers of ENERGEX Limited, hereby direct the board of ENERGEX Limited to modify the draft 2011-12 Statement of Corporate Intent submitted to us by letter dated 31 March 2011 to:

- include a statement that ENERGEX Limited will:
  - not seek to recover $52.3 million in increased revenues from its Standard Control Services in 2011-12 (foregone revenue) and $2.5 million in increased revenues from its Alternate Control Services (street lighting) in 2011-12 (foregone revenue) arising from the Australian Competition Tribunal Determination of 19 May 2011 in Australian Competition Tribunal File No 2 of 2010; by either:
    - developing an amended pricing proposal for 2011-12, consistent with that undertaking; and seeking approval of that amended pricing proposal from the Australian Energy Regulator in accordance with National Electricity Rule 6.18.8; or
    - varying or adjusting the tariff that was the subject of the amended pricing proposal dated 24 May 2011, as contemplated by National Electricity Rule 6.18.2(b)(5);
  - publish the relevant tariff classes and tariffs, and charging parameters, in accordance with National Electricity Rule 6.18.9;
- include a statement that ENERGEX Limited will not seek to recover the foregone revenue in any future period beyond 30 June 2012;
- amend the financial forecasts contained in the Statement of Corporate Intent to reflect this action; and
- include a statement quantifying the revenue foregone by ENERGEX Limited in implementing this direction.

[redacted]

The Honourable Rachel Nolan MP
Minister for Finance and The Arts

30/5/2011

[redacted]

The Honourable Stephen Robertson MP
Minister for Energy and Water Utilities

30/5/2011