

Ergon Energy Queensland Pty Ltd

**Interim Consultation Notice
Calculation of the 2007-08 Benchmark Retail
Cost Index**

**Queensland Competition Authority
10 April 2007**

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INTRODUCTION

Ergon Energy Queensland Pty Ltd ('Ergon Energy') welcomes the opportunity to provide comment to the Queensland Competition Authority ('Authority') on the calculation of the Benchmark Retail Cost Index ('BRCI').

This submission provides Ergon Energy's views on the questions raised in the Consultation Notice upon which we have comment to make at this time. The issues are addressed in the order raised in Consultation Notice

Ergon Energy looks forward to participation in the Authority's workshop on the subject, and would be pleased to discuss this submission or to provide further details about any specific concerns.

COST OF ENERGY

1. How should the LRMC of energy be defined? What methods could be used to measure the LRMC of energy? Should a different method be used for different fuel sources, such as coal, gas, renewable energy, etc?

Ergon Energy understands the difficulties involved in formulating a theoretical model of the LRMC of energy. We consider that the approach adopted by the Authority in calculating the cost of energy should be one that achieves the aim stated in section 92 of the *Electricity and Other Legislation Amendment Act 2006*, namely:

"The cost of energy must reflect the pricing entity's view of the likely total of costs to be incurred during the relevant tariff year to purchase energy to supply all of the NEM load of the State for the relevant tariff year".

Importantly, in meeting this aim, the Authority should take care not to adopt a theoretical approach which attempts to identify the LRMC of generation rather than the "costs ... to purchase energy". When considering the approach to be adopted, we also note the comments of the Hon Geoff Wilson MP in the letter to the Bidders in the Queensland Retail Asset Sale Process that *"the actual level of the components (of the BRCI calculation) are less critical than the change in the components"*.

Ergon Energy therefore proposes the adoption of a market-based approach that reflects the actual costs of purchasing, and will capture the change in those actual costs over time, thereby influencing the BRCI in the manner intended. The proposal is the establishment of an average market electricity benchmark price. The benchmark would reflect the market cost of a retailer purchasing energy in Queensland for a future demand load profile.

The proposed benchmark would be calculated by applying an equal weighting to three current independent market indexes:

- (1) Sydney Futures Exchange (SFE) is a benchmark determined by taking the average of the close of business "settle" prices of each day. This benchmark captures the price that was actually paid in the market.
- (2) Over The Counter (OTC) broker screens is a benchmark determined by taking the average of daily midpoints between the highest "bid" and lowest "offer" on each trading day. This benchmark captures the price that participants value in the market.

- (3) Australian Financial Markets Association (AFMA) electricity forward curve is a benchmark determined by participants submitting to AFMA their expectation of particular contract prices in the future. This benchmark captures the price that participants expect to see in the market.

Each index would be separately calculated, and then averaged (equally) to form a single market benchmark price. The benefits of this methodology of determining the costs to be incurred during the relevant tariff year to purchase energy are as follows:

- (a) The benchmark follows economic demand/supply equilibrium theory to determine a market price in each period;
- (b) The benchmark is based on market prices, which are already in \$/MWh units;
- (c) Each benchmark has within it peak/off-peak/flat components weighted accordingly to match demand load profiles;
- (d) The contract market is separate to the regulatory schemes market, and as such will not account for them;
- (e) A premium above the average Queensland market contract price can easily be applied to ensure ancillary service charges are stacked into the final "benchmark" price; and
- (f) Price movements in the wholesale market due to adverse conditions (i.e. environmental conditions) will be appropriately captured in the BRCI as it will be retailers who will wear these costs immediately.

The result would be a cost component in the BRCI which, when combined with additional costs such as renewable energy costs (ie purchase of certificates), addresses the concerns raised by the Authority in the calculation of LRM.

Attachment B to the Authority's Letter of Delegation explains that "*in principle marginal cost pricing means that the market over the long run will cause a commodity to be sold at its long run marginal cost of production*". As such, the simplest methodology for achieving an indicative LRM is to identify the market price at which energy is actually sold. Due to the critical nature of the change in LRM, as opposed to the actual level of LRM, the proposed market-based approach of determining a change in LRM by determining a change in purchasing costs is considered to be reasonable having regard to the purpose of the BRCI calculation.

Support for such an approach can be found in a report by the Independent Pricing and Regulatory Tribunal ("IPART") titled *Promoting retail competition and investment in the NSW electricity industry*, which outlines an assessment conducted by Frontier Economics of the appropriate application of the long-run marginal cost of generation in determining a retail tariff. Their assessment led them to investigate the merits between the application of a long-run marginal cost of generation approach and market-based purchasing costs approach. Their conclusion favours a market-based purchasing cost approach for the following reasons:

- The market-based approach directly addresses the costs of purchasing a load profile for regulated customers and ensures cost reflectivity. It also addressed peak, shoulder, and off-peak costs more realistically than a long-run marginal cost approach;
- It was strongly supported by stakeholder submissions, as the approach was much less theoretical than the alternative long-run marginal cost assessment. They found the market based approach to be practical, pragmatic, and feasible; and

- In a perfectly competitive market, the long-run marginal cost and market-based costs for each retailer would be expected to be the same. Even in the absence of perfect competition, the market-based costs are similar to, but slightly higher than, the long-run marginal cost.

2. Is there any evidence or argument to suggest that the LRMC of energy may change between 2006-07 and 2007-08?

Use of a market benchmark as proposed would capture any changes to the cost of energy during 2006-07 and 2007-08.

3. What is the efficient combination of generating plant to meet the Queensland load?

The most efficient combination of generating plant to meet Queensland load is the generation which is dispatched by the National Electricity Market Management Company ('NEMMCO') on the basis of the generator bid stack. The cost of energy produced by that combination of generating plant is reflected in wholesale market prices.

4. How should the impact of the 13% Gas Scheme be measured in the LRMC of energy?

The cost of the 13% Gas Scheme should be measured by valuing the cost of Gas Electricity Certificates ('GECs') at the visible forward market price at which participants are willing to trade, and adding that value to the cost of energy. A similar methodology should be adopted for calculating the impact of the Mandatory Renewable Energy Target ('MRET').

5. What level and mix of renewable generation should be assumed in the long run?

Adoption of the market-based purchasing cost approach would avoid the need to address this question. However, if the Authority determines to adopt a theoretical approach which seeks to identify the LRMC of generation, then reference can be made to the MRET Scheme, and the mandated target used as a proxy. For 2006, the MRET was set at 4500 additional GWh of generation above year 2000 levels, equating to approximately 2.17% of total national load for 2006. Assuming no change to total national load during 2007, the target will increase to 2.70%, and in subsequent years 3.28% (2008), 3.91% (2009), and 4.58% in the long run (2010-20) in line with the increasing targets set under the MRET.

6. Which ancillary services should be included in the determination of the LRMC of energy? How should the LRMC of these ancillary services be measured? How can double counting of ancillary services be avoided, especially if these costs are recovered directly from customers?

The allowance for ancillary charges is a relatively small component of retailers' total costs. Ancillary service costs are somewhat difficult to estimate as these costs are likely to vary over time. However, if the Authority determines to include an ancillary services cost component, it may be most appropriate to reflect the change one year in arrears.

That is, in determining the ancillary services component of the 2007-08 BRCI, the change in ancillary service costs between 2005-06 and 2006-07 (March to March) could be adopted.

Ancillary services are a separately charged item that is not bundled with any other costs. It is unlikely that this cost would be double counted as it is clearly visible.

NETWORK COSTS

7. Are there any issues that the Authority should consider in measuring either distribution or transmission costs? For example, how should adjustments for under and over-recovery be treated? Should pass-through amounts be re-smoothed or included in the same year that the pass-through amount was incorporated into prices?

It is Ergon Energy's view that distribution and transmission components of the BRCI should be reflective of the Network Service Providers' (NSP) actual allowable prices. Therefore, in addition to the respective annual aggregate revenue requirement ('AARR') determined by the Authority (for distribution – Ergon Energy & Energex) and the AER (for transmission - Powerlink), any other allowable revenues – e.g. cost pass-throughs and unders/overs – should be taken into account in the year they are given effect in the relevant NSPs prices, and not subjected to any smoothing. Generally the determination (by the Authority and AER) of such network service provider ('NSP') pass-throughs and under/overs have already taken into account price-shock impacts. Therefore, for the purposes of determining the BRCI, there should not be further 'smoothing'.

The effect of the approach advocated by Ergon Energy is that the network component of Notified Prices will be more closely aligned to any movements in network prices passed through to market customers. This approach will promote stability for retailers since small customers will be dissuaded from attempting to move, perhaps annually, between market contract prices and Notified Prices.

If the Authority was to adopt a BRCI smoothing approach to AARR adjustments (e.g. cost pass-throughs and unders/overs), retailers would experience the adverse effect of having a misalignment of costs to revenue because they would be charged NSPs allowable network charges, while the increase in Notified Prices would not be reflective of the increased network charges. For example, if NSPs network charges have increased at a rate significantly higher than the Notified Prices, it is likely that the Notified Prices will increase in the later years to compensate retailers for the increased costs incurred. However if a retailer loses a customer, while the retailer was effectively exposed to the higher NSP charges in an earlier year, they are unable to recover the full amount of the increase spread over later years because the customer has churned.

8. Are there any implications stemming from the required treatment of Ergon Energy's AARR for Energex?

Ergon Energy understands that the proposed treatment of Ergon Energy's AARR for 2005-10 in the BRCI calculation is to re-smooth 5 years' allowable revenue to achieve a

consistent movement to the network component of Notified Prices for the 2007-08, 2008-09 and 2009-10 years¹.

Ergon Energy is not aware of any implications for Energex in this approach.

9. In the absence of a Final Decision by the AER regarding Powerlink’s 2007-08 revenue requirement, what would be a reasonable approach to estimating this cost?

Ergon Energy proposes that the Authority use the AER’s Draft Determination for Powerlink as a reasonable estimate of the transmission network cost component. When a final decision is published, any movement between the draft and the final should be taken into account using the same approach suggested in our response to Question 7 for the treatment of cost pass-throughs and unders/overs (i.e. not smoothed, but instead applied in the year the NSP is permitted to collect/refund the price movement).

RETAIL COSTS

10. What is the existing retail margin? What constitutes a relatively stable retail margin?

Ergon Energy is unable to provide an indication of the retail margin or headroom which currently exists for the incumbents in South East Queensland. The following provides an indication of what other jurisdictional regulators consider to be a relatively stable net retail margin:

	Existing Retail Margin	Source
ACT	3% of Sales	Investigation into Retail Prices for Non-Commercial Electricity Customers in the ACT – Final Determination, May 2003 http://www.icrc.act.gov.au/__data/assets/pdf_file/16681/finaldeterminationreport5of2003cw.pdf
VIC	5% - 8% of Sales	CRA Report used as the basis of the DOI’s decision at: http://www.doi.vic.gov.au/doi/doielect.nsf/2a6bd98dee287482ca256915001cff0c/491259c987464272ca256e050016a845/\$FILE/CRA%20Report%20Electricity%20and%20Gas%20Standing%20Offers%20and%20Deemed%20Contracts%20(2004-2007).pdf
TAS	3% of Sales	Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices, September 2003. http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/R_ElectPriceInvest_FinalReport.pdf/\$file/R_ElectPriceInvest_FinalReport.pdf

¹As per the Minister’s Certificate of Delegation, Attachment A.



SA	5% of Total Costs	Inquiry into Retail Electricity Price Path – Final Report, March 2005 http://www.escosa.sa.gov.au/webdata/resources/files/050318-R-InquiryElecPricePath_FinalReport.pdf
NSW	5% of EBITDA	Promoting retail competition and investment in the NSW electricity industry: Regulated electricity retail tariffs and charges for small customers 2007 to 2010 http://www.ipart.nsw.gov.au/files/Draft%20report%20and%20draft%20determination%20-%20electricity%20retail%20review%20-%20April%202007.PDF

Subject to the provision of data from the incumbents in South East Queensland, it is therefore arguable that an appropriate margin would lie between 3% and 8% of total revenue received. Taking into account the fact that Queensland's energy customer base is far more disparate and geographically dispersed than any other region it would be reasonable to assume a stable retail margin in Queensland should be no less than 5 - 8% of total revenue.

11. Under what circumstances would a customer reverting to prices result in a retailer making a loss? Is this likely? How can this be avoided?

In simple terms, this will occur when a retailer's Cost to Serve is greater than the difference between the total Customer Revenue and the Energy Costs, Other Market Costs, and Network & Transmission Costs.

This event could occur if a retailer acquires a customer and supplies them on the Notified Prices where the Notified Prices are not sufficient to meet the customer's current or potential future cost. This may happen for customers in South East Queensland if the total retailing costs increase at a greater rate than the Notified Prices.

It should also be noted that such events may occur as a result of circumstances which are (or should be) within a retailer's control. For example, a customer may be acquired by mistake (ie incorrectly calculating current profitability) or as part of a strategic business approach, to achieve:

- a. Greater economies of scale;
- b. Energy trading benefit;
- c. Other sales stream benefits (eg. energy related products); and/or
- d. Sales targets or other internal KPIs.

A further key risk that should be considered is the event of a significant increase in the future cost of energy. A key aspect of the BRCI is that tariff movements should reflect changes in the LRMC between periods. This highlights the importance of adopting a methodology which captures the change in wholesale energy costs. A theoretical model which reflects LRMC, without consideration of actual wholesale energy costs, risks failing to appropriately capture cost increases in determining the level of Notified Prices increases (or decreases). The potential result is a misalignment between the movement of tariff revenue and the underlying cost of purchasing energy to supply retail customers.

12. Would the retail functions of an efficient hypothetical retailer differ from the incumbent retailers, Origin and AGL? What costs could an efficient hypothetical retailer expect to recover directly and what costs are compensated for through the retail margin.

AGL Energy is Australia's largest gas and electricity retailer and serves about 3.6 million customers. Origin Energy serves about two million customers in Australia, New Zealand and the Pacific². It could be expected that AGL and Origin energy are efficient retailers, both of which have dual fuel offerings. However, their customer bases do not reflect the requirements of the hypothetical retailer as outlined in section 110 of the Draft Electricity Regulation.

An efficient hypothetical retailer should expect to directly recover all costs. In this regard it is important to distinguish between a cost recovery and a retail margin. A retail margin should represent the return that a mass market new entrant requires in order to attract the capital needed to provide a retailing service. An appropriate retail margin should be determined from the difference between the price that a retailer requires in order to earn a sufficient return and all of the costs that a retailer incurs. The calculation should take into account the principal that businesses should be compensated for the systematic risk to which they are exposed. While the margin may reflect a direct shareholder return, retailers may choose to invest a portion of their retail margin in mechanisms, systems or approaches with a view to such goals as expansion or the creation of future efficiency gains. A sufficient margin will allow retailers flexibility in operating businesses in a changing environment while not completely absorbing their return.

13. Should additional retail costs be included in the BRCI for 2007-08 given the introduction of FRC on 1 July 2007?

Allowance for additional retail costs required to participate in the Queensland FRC market should be included in the BRCI for 2007-08. Costs include system changes required to participate in the Queensland market (eg to allow the application of Queensland tariffs) as well as training costs, additional call centre and communication costs and costs of ensuring compliance with Queensland rules.

QUEENSLAND LOAD

14. Are there any issues the Authority should consider in calculating Queensland Load? For example, how should embedded generators be treated in calculating the NEM load?

When calculating the Queensland load the Authority should take into account load from all Market Generators in Queensland. Such data is readily available from NEMMCO and captures all significant generation dispatched in the State. Such an approach uses data readily available from NEMMCO and avoids the need to separately source load data for small non-market generation such as on-site generation and residential solar systems, which would have an immaterial impact on load calculations.

² <http://www.theage.com.au/news/business/origin-and-agl-in-merger-talks/2007/02/05/1170524018439.html>