



Review of Electricity Pricing and Tariff Structures

AGL Submission to the Queensland Competition Authority
Date: 20 July 2009





1. Executive Summary

AGL supports the Government's direction to the QCA to conduct a review of the regulated *Electricity Pricing and Tariff Structures*. AGL agrees that, in the absence of a move to de-regulation, there is a need for a comprehensive review of the tariff structure and the pricing methodology as requested in the Ministerial Direction (**Direction**). There will be significant changes in the energy market over the next few years, with the most significant of this being the introduction of an emissions trading scheme. AGL is looking forward to working closely with the QCA, industry and consumers in order to develop a sensible, sustainable means of determining tariff structures and the price path for customers on regulated tariffs in the context of a changing market.

However, AGL is of the view that the policy objectives articulated in the Direction will be most effectively achieved over a longer timeframe, with the 2010/11 year being treated as a 'transitional year', with a view to establishing a 3 year price path commencing on 1 July 2011, whereby:

- the BRCI is amended so as to remove the network tariffs from the bundled tariff, and include them as a direct pass through (while ensuring the 'uniform tariff' policy can be maintained). Some initial balancing of tariffs can also be attempted in this period, with a comprehensive restructure being completed once the networks have conducted their own 'step change' restructure;
- the 'remainder' of the BRCI (i.e. that portion of the tariff that exists after the networks are excised) would be used to calculate the rate of change applicable to the tariffs (amended so as to allow the direct pass through of networks). The legislative framework would require relatively simple amendment to exclude the networks from the BRCI calculation. This would permit the QCA to use its current methodology to determine the rate of change in the WEC and the operating costs. While this is not the optimal result for retailers operating in the Energex patch, it seems the only means of ensuring a robust, consultative process capable of avoiding further controversy and uncertainty in the available time.

The QCA would then have the time necessary to properly consider:

- The appropriate methodology for determining the WEC in circumstances where the details of the CPRS will be known and can be more comprehensively dealt with. A three year price path commencing in 2011 (in the absence of a finding of effective competition) is less likely to require comprehensive overhaul, although it seems unavoidable that there will need to be flexibility around re-openers to account for a full market driven carbon price (currently anticipated to be introduced on 1 July 2012);
- a comprehensive restructure of the tariffs, considered in light of the network tariff structure (which will not be known until 30 May 2010);
- The most appropriate means of managing the customer impacts resulting from the move to cost reflectivity and demand management price signals. AGL suggests this part of the process will need to be the subject of intensive consultation between the QCA, industry, consumer groups and the government.



AGL believes that a transparent and considered process for the development of retail tariffs going forward will be a positive step to ensuring competition and investment thrives in Queensland.

Existing BRCI

AGL recognises the difficulties that the QCA and retailers have faced in the attempts to apply the current framework - the Benchmark Retail Cost Index (**BRCI**). The concept of an index applied to an existing tariff, rather than a 'cost stack' approach is one which AGL does believe has some merit. However, the BRCI is subject to significant structural issues, such that its application will not accurately determine the change in costs incurred by retailers operating in Queensland. The most significant structural issues with the BRCI as it currently exists are:

- the BRCI does not permit a direct pass through of network costs. The manner in which the BRCI currently accounts for changes in network costs has resulted in retailers operating in the Energex distribution area absorbing a significant amount of the Energex network tariff increases over the past 3 years;
- the BRCI requires the wholesale energy cost (**WEC**) be assessed with reference to the NEM Load (and in the case of the LRMC the entire Queensland load), which are larger, flatter loads than the regulated customer load. This means that the WEC calculated in accordance with the BRCI will automatically underestimate the cost a retailer incurs in procuring energy for the regulated load;
- a reference to LRMC as the primary determinant of wholesale energy cost. While AGL accepts that the LRMC provides a useful metric for the lowest cost a retailer would incur in supplying the relevant load, the change in the LRMC is not capable of capturing the changes in wholesale costs.

The structural framework of the BRCI, and the manner in which the QCA has administered the BRCI, has led to a clear and transparent degradation in retailer headroom since the sale of the government owned retail businesses.

Policy objectives best met through transitional process

AGL supports the policy objectives articulated in the Ministerial Direction, whereby the QCA has been directed to review the BRCI with a view to ensuring the tariffs:

- better reflect the costs of supplying electricity, including network costs and 'all state and Commonwealth Government environmental obligations', and
- assess in the long term management of peak electricity demand and provide an incentive for customers to use electricity more efficiently.

The Ministerial Direction also requires the QCA to ensure that the existing headroom is maintained at a relatively stable level.

The first step toward encouraging the efficient use of energy is to ensure that tariffs are cost reflective, and that the single greatest impediment to cost-reflectivity under the BRCI is the manner in which the networks tariffs are treated. As detailed further in the body of the submission, there can be no move toward achieving the policy objectives without first ensuring that the full rate of change in the network tariffs are passed through to the customer.



In order to conduct the review as required under the Direction, the QCA would need to:

- complete a review of the BRCI and the existing tariffs, develop a methodology capable of application for a three year period which will accurately and appropriately deal with the impacts of an expanded MRET and a possible carbon trading scheme, prior to the end of August 2009;
- provide direction and advice regarding the drafting of the necessary supporting legislation and regulation and ensure that the draft legislation and regulation has been appropriately tested so as to facilitate its immediate application. This would need to occur by the end of 2009;
- apply the new methodology and restructure tariffs in such a way as to meet the expectations of industry, consumers and the government. This would need to be completed within a 4-5 months period. AGL notes that a shift to fully cost-reflective tariffs for customers will entail some significant price adjustments for some customers, and will require careful management from industry, government and the QCA.

AGL further notes that:

- in respect of any restructure of tariffs, that the AER will make a determination on the next 5 year price path for both Energex and Ergon, with both determinations becoming effective on 1 July 2010. This is likely to entail a 'P-0' adjustment, and significant restructure of the network tariffs. The detail of the network tariffs will not be known until 30 May 2010. AGL suggests that any comprehensive restructure of retail tariffs is going to be achieved more efficiently and smoothly if the network tariff structures are known and relatively stable. While the network tariffs will not be completely stable during the 5 year price path, it can be assumed that the 'step change' will occur at the commencement of the period. It therefore seems sensible to conduct the overhaul of retail tariffs once this network tariff structure is known.
- there can be little prospect that the methodology, and the resulting retail price path, would not need to be 're-opened' and quite possibly reformulated after the detail of the eventual CPRS becomes known. There can be little prospect of any clarity on the CPRS emerging prior to Q2 2010, which means that any 3 year price path set before 1 July 2010 will need to be re-opened prior to 1 July 2011, creating considerable uncertainty for retailers and customers.
- it is also necessary to consider the impact time constraints have had in the past on the stability and credibility of the BRCI process. The development of the original BRCI framework and the subsequent applications of the BRCI by the QCA have, due to unavoidable circumstances, been subject to tight time frames and as a result limited consultation. AGL suggests that some of the complexity and controversy that has resulted can be at least partly be attributed to the operation of time constraints and may have been avoided if thorough consultation with industry was undertaken.

AGL looks forward to discussing the proposed transitional approach with the QCA in further detail.



2. Costs of supplying regulated customers

AGL suggests it is useful in the context of a review of electricity tariffs and the pricing methodology for the QCA to consider what the relevant cost structures are for a retailer servicing a large regulated load in south-east Queensland. This consideration is essential if the QCA are to meet the stated objectives in the direction of reflecting the costs of supplying electricity and providing price signals to ensure customers use electricity more efficiently.

The key costs of supplying electricity consist of three main components:

- Wholesale electricity purchase cost;
- Distribution and network costs; and
- Retail operating costs

Since 2007 three incumbent retailers have supplied electricity to retail customers in Queensland. Both AGL and Origin supply customers in the in the south-east of Queensland, where electricity is distributed through the Energex network. Ergon Energy (**Ergon**) supplies retail customers in the remainder of the State (**the Ergon region**), excluding the region supplied by Energex distribution (**the Energex region**).

It is important to note that the costs incurred by retailers supplying customers in each patch are very different, due to the different wholesale and network costs.

2.1. Wholesale Electricity Purchase Cost

The costs incurred by retailers in purchasing energy to supply customers in the Energex patch are higher than the costs incurred in the Ergon patch.

How retailers purchase energy for regulated customers in the wholesale market

Retailers purchase electricity from the National Electricity Market (**NEM**), sometimes referred to as the pool, on the basis of half hourly intervals. Electricity is sold in each half hourly interval at a price determined by the price at which the marginal generator in that half hour was dispatched. In short, what occurs is:

- Customers consume energy, with the physical supply directed from the network into the customer site. The customer's meter records the customer's actual consumption:
 - large customers tend to have interval meters which record what the customer consumed in which half hour, and so their consumption is referable to a particular half-hourly price;



- small customers (i.e. those subject to regulated tariffs) tend to have accumulation meters, which simply record the volume of electricity they have consumed in total. These meters are read every 2-3 month period.
- AEMO (formerly NEMMCO) calculates the energy each retailer is liable for in each half hour (by reference to each customer's meter number). The data gathered through interval meters provides an accurate estimate of each customer's half hourly consumption. However, the consumption of customers on accumulation meters has to be assumed. In order to provide an estimate of each small customer's consumption during each half hour, a usage profile is assumed – this profile is called the 'Net System Load Profile' (**NSLP**). In effect, the total consumption in a distribution patch is determined, and the interval metered consumption 'netted' off, to show the assumed consumption profile of all customers on accumulation meters.
- An NSLP has been developed for each distribution patch – ie Energex and Ergon areas have different NSLPs.
- AEMO then invoices the retailer on the basis of the interval metered consumption for each half hourly period, and the amount of energy the customers on accumulation meters are assumed to have consumed in that half hour in accordance with the NSLP.

A retailer's cost of wholesale energy

Wholesale energy costs incurred by retailers are a combination of the hedge contract prices paid to generators (swap, cap and other derivative costs) and the pool price for energy purchases not covered by hedge contracts including pool prices below the cap strike prices. These prices reflect the costs and returns for existing generating assets, the supply/demand balance, the peakiness of the load in a particular market and the volatility of demand. Hedge contract prices inevitably include a risk premium attributable to such volatility.

A retailer servicing a regulated load determines the amount of hedge and derivative contract cover based on the load and shape of the NSLP. The actual WEC incurred by a retailer is determined when the contracts and pool costs are settled out against the NSLP on a day.

The NSLP is therefore a key determinant of the cost of energy purchased for all small customers. In particular the shape of the NSLP has a significant impact on the value of the WEC given that the cost of wholesale energy differs significantly depending on whether it is purchased at peak or off-peak times.

In addition, retailers will purchase hedge cover on the basis of the historical NSLP. Where the NSLP is particularly sensitive to weather (for example where there is significant air-conditioning penetration) depending on the hedge strategy adopted, a retailer may find itself under hedged and therefore exposed to the pool at up-to \$10,000 MWh at times of extreme weather, or during unexpected mild weather over hedged and incurring high hedge and derivative contract costs. Either way, a NSLP which is highly sensitive to weather, results in a relatively higher WEC and risk to a retailer.

The Energex and Ergon NSLP

The historical NSLP's for each of Energex and Ergon differ significantly. The Energex NSLP has historically been peakier compared to Ergon's NSLP, and it appears that it is becoming even more peaky.

A way of measuring the peakiness of a load is through the calculation of the load factor. The load factor indicates the proportion of the total load below the average demand - the lower the load factor, the peakier the demand. The load factor for Energex is 42%, while Ergon's is 63%. This means that retailers would incur significantly higher wholesale energy costs in the Energex patch because they must buy more wholesale electricity at peak times.

Figure 1: Energex NSLP 07/08

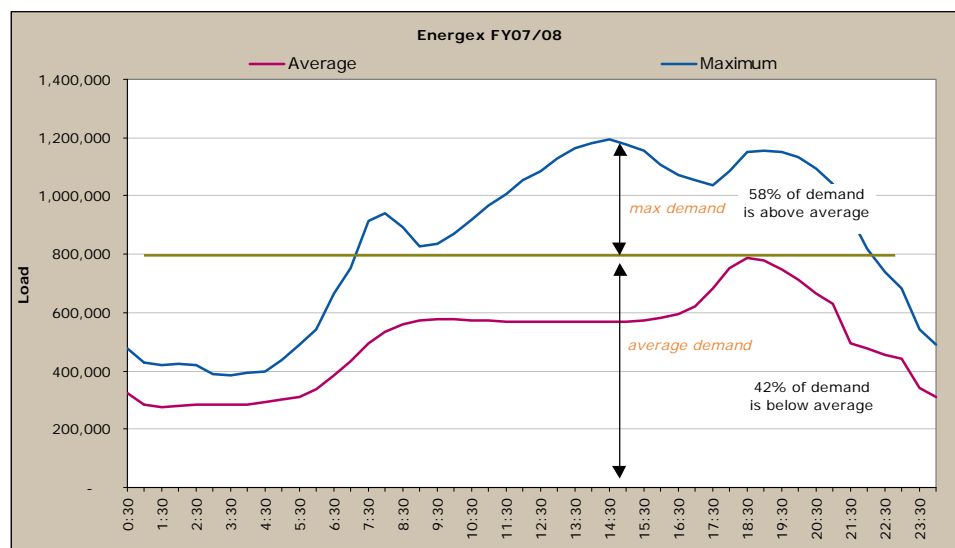
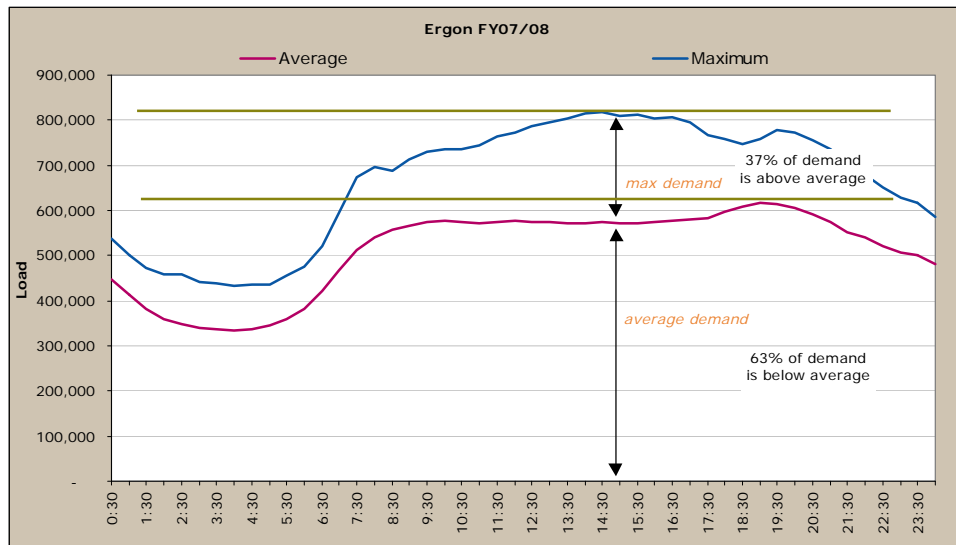


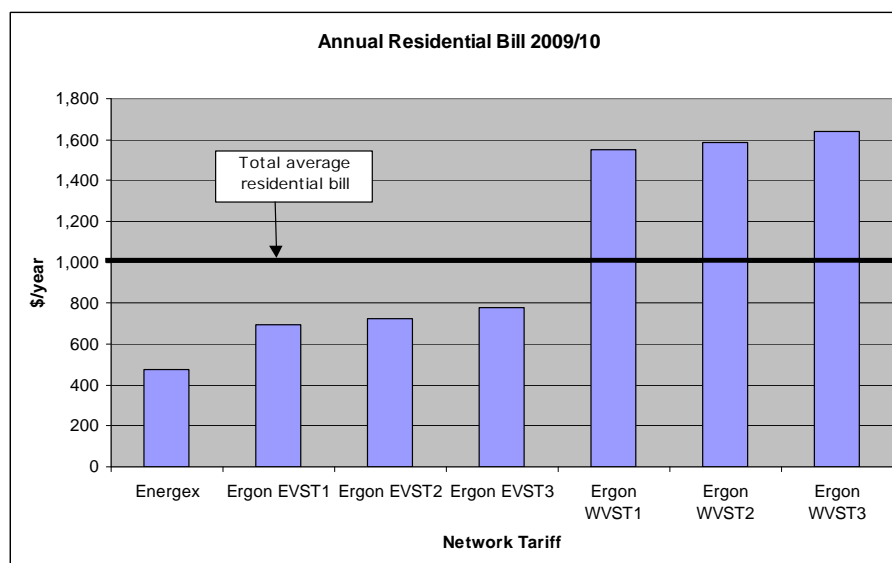
Figure 2: Ergon NSLP 07/08



2.2. Network Costs

The Energex and Ergon distribution businesses operate independently of each other, and apply different tariff structures in each of their regions. This, in combination with the different WEC structure, create some tensions in a policy objective of a transition to cost reflective tariffs and the application of a 'uniform tariff' policy.

In the way of an example, the graph below shows the costs of the network component of a residential customer's bill with a type 6 accumulation meter. As illustrated, the annual network cost to a customer consuming 5,500kWh/year differs significantly between Ergon and Energex, and between each of Ergon's tariff classes. Also shown on this graph is the average bill that applies uniformly to customers (on an accumulation meter) consuming 5,500kWh/year (this is a lower than average consumption for most tariffs). As shown, for some tariffs, Ergon is not able to cover the network component of an average customer's bill from the total retail tariff.



2.3. Retail Operating Costs

Retail operating costs are fixed or variable by nature:

- fixed costs are those that are incurred by a retailer on each customer, irrespective of the consumption of the customer;
- variable costs, being those which increase with the customer's consumption.

In general, an appropriate tariff structure is one whereby the retailer recovers its fixed costs in the standing charge (ie the flat supply charge) and the variable costs in the 'volume' component.

2.4. Retail margin

The margin earned by a business is, in effect, a return on the risk to its revenue/capital the business is required to undertake in its operations. In order for other energy retailing businesses to enter the market and compete, the margin available must be one which shareholders and debt and equity providers consider commercially acceptable to warrant the risk.

Ensuring the margin available is correlated with the risk faced by retailers is essential for the long term viability of retailers, which in turn is necessary for there to be ongoing investment in upstream supply. Historically, energy retailers have underwritten the majority of investment in upstream supply, either through direct investment or by way



of entering into the necessary 'foundation' supply contracts. Detailed in **Annexure 1** is a list of the upstream projects that AGL has effectively underwritten, and other major projects that have been underwritten by other retailers.

It is also important to note that benchmark retail margins exhibit an asymmetric risk. If the benchmark costs and margins are set below realistic levels then competition and investment are likely to be stifled. However, if margins are set above realistic levels then any benefit is likely to be competed away as other retailers seek to attract regulated customers.

In order for there to be effective competitive markets and ongoing security of supply, it is critical that the retail margin reflects a commercially realistic reward for the risks faced by retailers supplying electricity in the Queensland market in the market.



3. Current BRCI methodology and transitional approach

The QCA has requested stakeholder views on the current BRCI methodology and any preferred alternative methodology. AGL has outlined its comments in respect of the current methodology, and how the QCA should transition away from the BRCI to a different approach over the next few years. In short, AGL is suggesting that:

- the 2010/11 year be considered a 'transitional year' in a process toward achieving fully cost reflective tariffs, including appropriate arrangements for the pass through of network costs and costs incurred under any carbon trading scheme introduced;
- in 2010/11 the QCA should focus on removing the network component from the existing tariffs, and using the BRCI methodology (calculated with the networks component excluded) to determine the rate of change for the remaining component of the tariffs;
- the period through to 1 July 2011 be used to determine an appropriate pricing methodology and tariff structure. The pricing methodology would need to be one capable of adequately capturing the costs associated with the CPRS (which is more likely to have been finalised) to apply for the purposes of a 3 year price path (in the absence of de-regulation).

While the continued application of the BRCI to the WEC and the retail operating costs will continue to understate the change in retailer costs (due to the structural issues with the BRCI as articulated elsewhere), it seems unlikely in the extreme that the QCA will have sufficient time to consult on and develop an appropriate methodology. Further, any methodology developed will have been done so in the absence of any certainty as to the structure and emission targets under the eventual CPRS. This means that any methodology developed for 2010/11 is likely to require adjustment prior to 1 July 2011. AGL therefore concludes that a transitional approach will be the most likely to provide a well considered, reasonable outcome across the next 4 year period which will have the confidence of the industry, consumers and the government.

3.1. Calculation of WEC under BRCI

The calculation of wholesale energy costs under the existing BRCI legislation and regulation is not capable of fully capturing the rate of change in the costs incurred by a retailer supplying Energex regulated customers. This is primarily due to the fact that the the BRCI does not reference the costs to the NSLP, but rather refers to:

- the LRMC of the entire Queensland load; and



- the energy purchase costs of the NEM Load, being the entire Queensland load minus the very large, direct connect customers only.

In circumstances where the NSLP is becoming increasingly peaky (as demonstrated in section 2 above), the reference to the flatter NEM Load and entire Queensland loads in the calculation of the energy purchase costs means that retailers are likely to be precluded from recovering the full rate of change in their cost base.

Transitional year

There are adjustments that the QCA can make in its application of the BRCI in respect of the WEC which will improve the degree to which the change in costs is captured. AGL has previously raised serious concerns as to the credibility of any modelling process whereby we have not been presented with an opportunity to comment meaningfully on the modelling work conducted by consultants. A commitment to conduct a fully transparent and robust consultation process, whereby all data inputs and outputs are provided to stakeholders for analysis and comment, should be a fundamental principle on which all future price reviews are conducted.

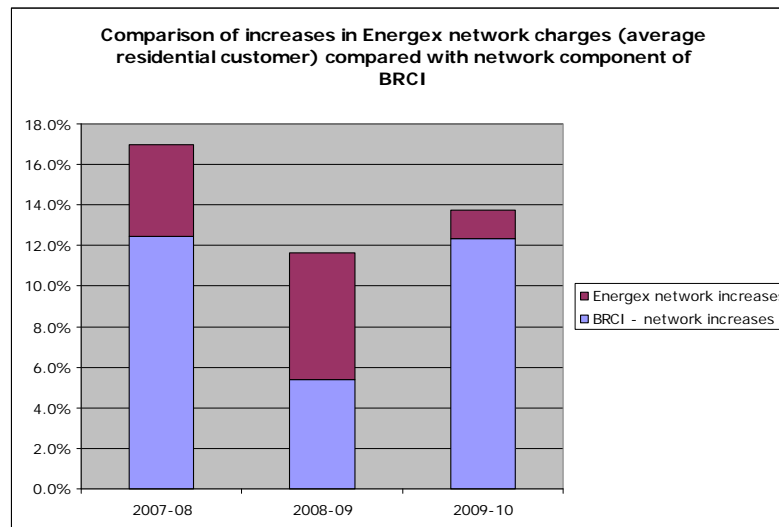
3.2. Calculation of network costs under BRCI

The manner in which the BRCI is presently structured does not permit a direct pass through of network costs, but only incorporates the 'average' of the Energex and Ergon AARR. The QCA's Information Paper does not make this point particularly clear, as it appears to suggest that network tariffs are passed through. In fact, the manner in which networks are dealt with in the BRCI has significantly eroded the headroom of retailers operating in south-east Queensland in two ways:

- The legislation provides that the average of the Energex AARR and the Ergon AARR determine the network increase permitted in the regulated tariffs. In 2007/08, 2008/09 and 2009/10 the Energex increase AARR was larger than the Ergon increase. This has meant that the average amount included in the BRCI does not capture the Energex AARR increase;
- Further, the Energex AARR does not determine the increase across all tariff classes. The AARR only governs the overall increase in revenue that the networks are able to recover. Energex is then able to 'rebalance' between tariffs.

Attached at **Annexure 2** is a table which shows the very marked increases in Energex network tariffs referable to regulated customers. **Figure 4** below illustrates how these costs have not been reflected in the BRCI Decisions – the 2007-08, 2008-09, and 2009-10 BRCI Decisions allowed significantly lower network cost increases to the retail entities than Energex's actual cost increase. This has led to retailers absorbing a significant loss – in effect retailers in Energex's patch have been subsidising Energex revenue.

Figure 4



3.3. Calculation of retailer operating costs under the BRCI

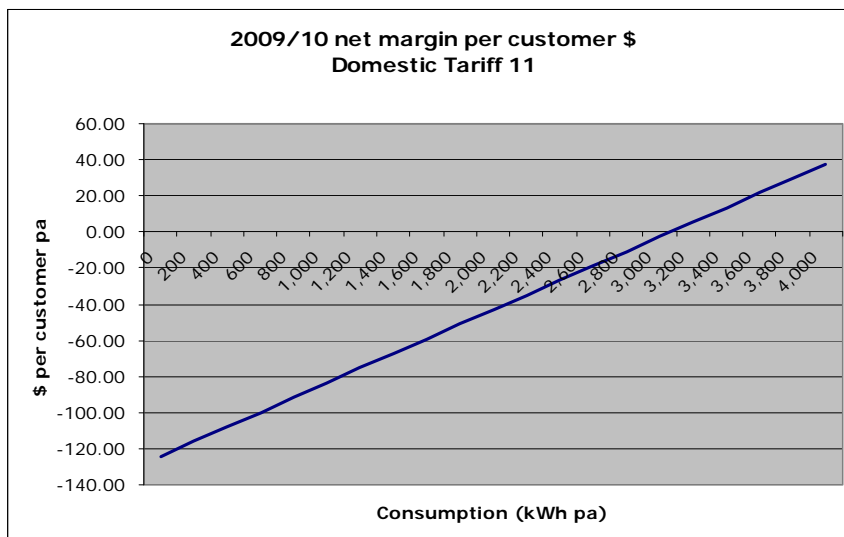
Operating costs under the current tariff structure

As noted above, in order for tariffs to be cost reflective, the supply charge should cover the fixed operating costs, and the volume element of the tariff should incorporate all variable operating costs. However, the existing tariffs for regulated customers in Queensland are not structured along these lines. In fact, the supply charge component in a number of existing tariffs not only falls short of a retailer's fixed costs, but in fact does not fully account for the supply charge levied by the networks. This means that

- retailers are subsidising the network's fixed charges, and not recovering any of their fixed costs against the supply charge;
- a portion of the variable charge is required to cover a retailer's fixed costs, which means the revenue earned from customers with low consumption does not cover the fixed costs associated with those customers.

Figure 5 below shows that, in respect of customers on Tariff 11 with lower than average consumption, retailers do not fully recover the costs of supplying electricity based on the benchmarks for wholesale energy and operating costs used in the BRCI.

Figure 5 Net margin (\$) per customer based on 2009-10 BRCI



Transitional year

The process of fully rebalancing the tariffs to achieve cost reflectivity and to drive behavioural change is a very complex one which requires extensive analysis of detailed data, and in respect of the appropriate level of operating costs for each tariff class, an analysis of the different costs attributable to servicing the different customer classes. As noted elsewhere in this submission, this analysis is not possible in the time permitted, and should be done in light of the network tariff structures which result from the 1 July 2010 'reset' by the networks. It should be recognised that any attempt to achieve this would necessitate a very large increase in the supply charge applied to residential customers.

For the purpose of the calculation of the 2010/11 tariffs, the QCA should focus on ensuring that the retail tariffs pass through the full amount of the network tariff increases. There are a number of ways in which this could be achieved. For example, the network component could be excised from the existing tariffs, leaving a residual supply charge and volume charge. This will result in some tariffs where there is a 'negative' supply charge (due to the network component being higher than the retail component). There are various ways in which this situation could be dealt with, and AGL would be happy to discuss this further with the QCA.

3.4. Requirement to maintain 'headroom' under BRCI

As AGL has noted in numerous previous submissions, the genesis of the requirement to 'ensure headroom remains relatively stable' was the statements made by the Government in selling its retail entities in 2007. Each year the headroom available to the retail businesses as they existed at that time has been eroded through:



- retailers being required to absorb a proportion of the network increases; and
- The WEC being calculated with reference to a larger, flatter load than that which defines a retailer's actual costs.

The trajectory of retailer headroom is attached at **Confidential Annexure 3**.

Transitional approach

The first step toward stemming the erosion of headroom available to retailers is to ensure the pass through of the full increase in network tariffs in 2010/11.

A more comprehensive analysis of how tariffs can be structured, the WEC appropriately calculated and headroom maintained should be undertaken over the course of the next 18 months.



4. Issues for Comment

4.1. Effectiveness of the current BRCI methodology in achieving cost reflective regulated retail electricity tariffs

- 4.1.1. Does the current BRCI framework produce regulated retail electricity prices that are reflective of the costs of supplying electricity in South East Queensland, including accounting for network costs and for all State and Commonwealth Government environmental obligations?
- 4.1.2. If not, would the BRCI methodology as it is currently applied be appropriate if existing retail tariffs were reviewed for cost reflectivity and the BRCI framework then applied to the revised tariffs?

As noted above, there are structural flaws in the BRCI which means it is not capable of accurately capturing the change in costs incurred by a retailer supplying customer in each different distribution patch. Even if tariffs were restructured so as to be completely cost reflective, the application of the BRCI as it is currently constructed would immediately distort the tariffs and preclude efficient cost recovery. However, AGL accepts that there may be merit in an indexation approach, and believes that further consideration could be given to an appropriately structured index in the future.

4.2. Assessment of alternative pricing methodologies for setting regulated retail electricity tariffs

Costs of Energy

- 4.2.1. What is the most appropriate method to estimate the cost of energy for the (future) tariff year(s) under review?

The most significant change that must be embraced for the purposes of calculating the WEC for the 2010/11 review, and indeed all subsequent reviews, is that the QCA must consult fully and openly, with all input data and all outputs of models being provided to participants and fully consulted on.



While AGL accepts that the time constraints on the QCA in respect of the Final Determination for 2009/10 were real, AGL does not accept that the lack of consultation was in any circumstances acceptable. This lack of consultation undermines industry and public confidence in the process, and must be addressed as an issue of primary concern.

Transitional year

As noted above, AGL is advocating the retention of the BRCI to the extent it governs the calculation of the WEC, including the MRET (although is advocating a methodological change to the means by which the rate of change is to be calculated).

In terms of the methodology which would be applied, AGL accepts it would be largely the same as that applied in respect of 2009/10:

- The LRMC for 2010/11 only would be calculated, and the rate of change assessed. AGL's comments in respect of the LRMC are detailed in section 4.2.2 below.
- The energy purchase costs would be calculated, and the rate of change assessed – see section 4.2.3 below.

Future methodology

In conducting its consultation on the future methodology, the QCA will need to consider the following principles:

- The WEC must be referable to the actual costs incurred by retailers in appropriately and prudently managing the high level of risk associated with supplying energy to the regulated load (ie referable to the NSLP);
- The methodology must appropriately account for the likely impacts of the introduction of a CPRS, in whatever form that CPRS eventually takes;
- The risks incurred by retailers acquiring and selling energy in a volatile market must be properly accounted for, with particular consideration given to:
 - volume risk, that is a retailer under or over hedges its load due to incorrect load forecasts and has to either buy or sell hedge contracts at the relevant market price. Load forecasts can prove to be incorrect due to churn being higher or lower than predicated;
 - liquidity risk, that is the WEC model assumes that a retailer is able to purchase its hedge cover in equal portions starting 2 years prior to the relevant period. However, it is possible that there will be insufficient liquidity in the market and the retailer can not purchase the load at the price assumed in the WEC model; and
 - extreme weather events. That is a retailer is left under hedged at times of extreme demand which usually equates to extreme pool and contract prices.



- There should be as little reliance on any 'black box' modelling as possible, and any forecasting or modelling exercise must be completely transparent – all inputs and outcomes of the modelling must be comprehensively provided. There is no valid reason any regulator or consultant should withhold any inputs or results of the modelling. Retailers cannot and should not be expected to accept the results of any modelling exercise without being provided with the comprehensive data sets to permit full, detailed and independent analysis;
- The methodology must recognise the increased risk that retailers will incur on the commencement of (and in the lead up to) any eventual CPRS;
- The LRMC of the generation build to meet the NSLP should provide the 'floor' to any regulated WEC, recognising that the LRMC can only be considered a proxy for the cost of hedges over the long term and in reference to that load a retailer is certain to be servicing. This is consistent with the approach being adopted in NSW for the determination of the 2010/11-12/13 regulated price path.

4.2.2. If the LRMC is included, how should it be estimated?

Transitional year

The rate of change in the LRMC will need to be calculated for the purpose of applying the BRCI to the WEC.

AGL has a number of concerns with the manner in which the LRMC was calculated in 2009/10, with the focus of these concerns being the QCA's reliance on the report from Concept Economics. AGL looks forward to discussing these matters with the QCA further in the consultation process.

Future methodology

AGL accepts that the LRMC of the generation build necessary to supply the relevant regulated customer load (namely the Energex NSLP) can be considered as a proxy for the cost a generator will seek to recover over the long term in the ordinary course of events. The LRMC does not capture the prices a generator will seek to achieve over the short term, nor in the event the generator perceives a threat to the life cycle of the plant. On this basis, the LRMC provides a useful metric for determining the appropriate 'floor' for the regulated WEC – it cannot be considered the determinant of the actual costs a retailer incurs in the market. AGL notes that this is the approach that has been accepted by the NSW Government in its recent Terms of Reference in respect of regulated electricity pricing 2010/10 – 2012/13.

4.2.3. If the cost of purchasing energy in the market is included, how should it be estimated?

Transitional year

The rate of change in the EPC should be calculated in accordance with the same methodology used in previous years. AGL notes that CRA is no longer available to conduct modelling work. However, AGL does not believe a change in consultants automatically necessitates a methodology change, as it notes that the QCA has engaged



different consultants to perform different sections of the calculation previously without considering such a change to constitute a methodology change. The following process could be followed:

- the NEM Load for 2010/11 would need to be forecast;
- the hedging strategy applied would be the same as previous years, using the actual market contract prices available for the year 2010/11 from 1 July 2008 through to the latest date available, and forecast from that date through to 30 June 2010;
- price and demand traces constructed. If this is to be done with reference to simulated models, AGL notes that there are models which will perform very similar processes to those patented by CRA. Comprehensive disclosure of the inputs used by, and outputs derived by, CRA, and appropriate consultation on the inputs used in, and outputs derived by, any subsequent process should address any concerns associated with a change in consultant.
- the hypothetical retailer's position is then 'settled out' against the price and demand traces, and an appropriate weighting applied.

4.2.4. If a mix of LRMC and purchase cost is to be adopted, as is the case at present, how should estimates of the two components be combined?

See comments above which state that the LRMC should be considered the 'floor' of the WEC.

4.2.5. How should the potential cost changes associated with environmental obligations such as the CPRS and the expanded RET be included?

Transitional Year - MRET

As AGL has noted in previous submissions to the QCA, the most appropriate measure of the cost to retailers of meeting their mandated renewable energy targets is by reference to the LRMC of renewable generation. This is the approach that has been used by IPART in its previous price review.

The open market for Renewable Energy Certificates (**RECs**) is thin and illiquid. The largest acquirers for RECs are retail companies subject to compliance targets under the MRET. Retailers of any significant size cannot rely on securing the volumes of RECs they are required to surrender on the open market – this does not present sufficient security of supply. Retailers therefore enter into contracts with renewable projects, long term Power Purchase Agreements (PPAs), to underwrite the development of renewable plant. The price at which the developer will commit to the development of the plant is the LRMC of that plant, and so this is the cost of RECs that is incurred by retailers.

Accordingly, in order for the QCA to determine the true retail cost of MRET, the long run marginal cost of renewable generation must be assessed.



Future Years – the CPRS

There is still enormous uncertainty around the targets, structure, compensation arrangements and timing of any CPRS which may emerge in the next few years. It does not seem possible to consider the appropriate means of assessing the costs incurred by retailers under a CPRS at this time.

AGL does not believe it sensible to seek to develop a new methodology in the hope that it will prove to be adaptable to the eventual CPRS. While AGL remains hopeful that the CPRS will be finalised by the first half of next year, this is by no means certain. In this context, AGL refers the QCA to the 'Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report', released by the AEMC. The AEMC recognises that the impacts of the eventual CPRS are going to be very difficult to predict, but will inevitably create increased risk for retailers – a risk which will be exacerbated by inadequate regulatory pricing flexibility.

AGL looks forward to a thorough and comprehensive consideration of the impact of the CPRS for the purpose of establishing a price path commencing 1 July 2011 once further detail of the CPRS is known.

Network costs

4.2.6. Should network costs be removed from retail tariffs and treated as a direct cost pass through to customers?

The full pass through of the actual increase in network costs incurred by retailers should be the QCA's focus for the transitional year. The 'averaging' of the Energex and Ergon network costs, with no allowance for the rebalancing of the networks between tariffs, is the single most distorting aspect of the BRCI. The first step in achieving the direction to progress toward cost reflective pricing is to excise network tariffs from retail tariffs.

It is also important to note that the 5 year price paths for Energex and Ergon are currently being determined, and AGL anticipates that both networks will seek to execute some significant structural change to their tariffs.

4.2.7. How should a direct cost pass-through be handled in the context of the Queensland Government's Uniform Tariff Policy?

As noted in section 2 above, the costs incurred by retailers operating in the different network regions are very different. The greatest divergence is that between the network tariffs applicable in each area, attributable to the greater distances the Ergon network is required to service. This divergence leads to obvious tensions between the policy objective of implementing cost reflective tariffs, and that of maintaining the uniform tariff policy across Queensland.



Transitional year

AGL is advocating a transition toward fully cost reflective tariffs, ensuring the smoothest adjustment possible for Queensland consumers. AGL suggests that in the transitional year, the QCA will need to base Ergon's tariffs on the lower Energex tariffs, and provide a direct and transparent subsidy to the Ergon retail business to account for the difference. This could be achieved through:

- removing the Energex network tariffs from the existing tariffs, which currently apply in both distribution patches;
- applying the BRCI to the surviving 'retail' component of the existing tariffs;
- allowing the direct pass through of the Energex network tariffs on each of those tariffs. This means that there is still one uniform set of tariffs that applies across Queensland;
- providing Ergon with a direct subsidy to account for the difference in the recovered revenue and the network tariffs imposed by the Ergon network business.

4.2.8. What would be the implications for the achievement of cost reflectivity and demand management if network costs were directly passed through?

The full pass through of network costs is an essential pre-condition of a move toward cost-reflectivity. Further, cost-reflectivity should be considered the first step toward providing appropriate price signals to customers, although it does need to be recognised that even a cost reflective 'all time tariff' provides a very blunt measure for driving management of peak demand.

In respect of a comprehensive review of tariff structure, with a view to driving more efficient management of peak demand, it needs to be recognised that as long as customers remain on accumulation (Type 6) meters, with their load profile referable only to the NSLP, it will be difficult to implement effective demand management initiatives. The costs and benefits of introducing smart metering technology will be an essential element of any further consultation on this topic.

Retail costs and the Retail Margin

4.2.9. What are the fixed and variable components of retail operating costs and how do these costs vary for customers in different tariff classes?

As a general comment, virtually all of the operating costs faced by retailers are fixed and do not vary based on consumption volume. Therefore unless tariffs are structured to ensure recovery those fixed costs from all customers, higher volume customers will continue to subsidise those customers who consume lower volumes of electricity.

The manner in which operating costs for each customer class will be reflected in the various tariffs will need to be a topic of consultation, as there are various issues to



consider in terms of cost reflectivity and the impact that would have on specific customer classes.

4.2.10. How should the retail margin for an efficient retailer operating or potentially operating in the south-east Queensland electricity market be determined?

As noted in previous submissions in relation to the BRCI, AGL does not accept that a retail margin of 5% appropriately represents a commercially sustainable return on the risk incurred in operating as a retailer in a volatile energy market.

Transitional year

On the basis that the BRCI as it currently applies is again applied to the WEC and the ROC only, a 5% return on the entire tariff (i.e. including networks) would need to be retained. There are a number of ways in which this could be achieved, which AGL would be happy to discuss further.

4.2.11. How should current level of headroom be determined and how should it be factored into regulated retail electricity tariffs to ensure that it remains relatively stable?

Transitional

The only means of ensuring that headroom is maintained at a relatively stable level, notwithstanding the structural flaws in the BRCI in relation to the calculation of the WEC, is to remove the network component from the BRCI and to permit the direct pass through of network tariffs based on the Energex tariffs.

Escalation of Regulated tariffs

4.2.12. The Authority seeks stakeholders' comments on whether to continue with a single escalation factor or to apply different escalation factors to different tariffs or tranches of tariffs?

Transitional year

Under the transitional approach being recommended, the network tariffs will escalate at different rates, while the WEC and opex component will be escalated at a generally uniform rate. AGL would also advocate some further flexibility to permit an adjustment on the supply charge on Tariff 11 to avoid the 'negative' retail supply charge.

Future years

In allowing a direct pass through of the networks, and perhaps some adjustment to the 'negative' retail supply charge, the QCA will have facilitated a step toward cost reflectivity. If there is to be further progress to cost reflectivity, and tariff structures



that will encourage efficient use of energy, there will need to be an unwinding of the cross-subsidies which currently exist between tariffs. This will entail proportionally greater increases for residential customers. Such a transition will require extensive consultation and careful management with consumers, industry and the government.

It should be assumed that all the relevant costs will continue to escalate at different rates. Once cost reflective tariffs are achieved, they will need to be escalated at different rates in order to maintain that cost reflectivity. There is a clear tension between the requirement to retain the uniform tariff policy, and the requirement to achieve cost reflective tariffs. Careful consideration will need to be given to how to reconcile these policy objectives over the next 18 months.

Achieving Price Certainty

4.2.13. What are the benefits and risks of moving to a longer regulatory period from the current annual indexation?

In the absence of deregulation, AGL is a very strong proponent of a 3 year price path as a general rule. A stable price path provides the industry, consumers and the government with a highly desirable level of certainty. However, as articulated above, AGL does not believe that any attempt to determine a 3 year price path at this time will lead to price certainty:

- any attempt to develop a methodology without clearer understanding of any carbon trading scheme will simply lock in a need to reconsider the methodology and the resulting price path prior to 2011/12 in any event;
- a methodology developed in haste will be prone to errors, complexity and controversy;
- the appropriate 'building block' for future tariffs is the restructured network tariffs, which will not be available in final form until 30 May 2010.

In short, AGL does not see any attempt to set a 3 year price path at this time as delivering any prospect of price certainty. In these circumstances, 2010/11 should be considered a transitional year, with a longer price path commencing on 1 July 2011 (in the absence of de-regulation).

4.2.14. If a longer period is adopted, how should prices be set for that longer period?

This question should be the matter of further consultation in developing the price path to commence from 1 July 2010.



Reopening Pricing Decisions in Special Circumstances

4.2.15. What events, if any, should trigger reopening of a retail pricing decision?

The circumstances in which the 3 year price path would need to be re-opened should be consulted on more fully over the next 18 months. Until the timing and the structure of the CPRS is determined, it is impractical to determine a 'base' methodology, let alone the triggers mechanism of a 're-opener'.

4.2.16. Should such a reopening be prospective only or also seek to recover losses incurred prior to the reopening?

This should be the topic of further consultation at the time of establishing the 3 year price path.

4.3. Assessment of existing tariffs

Current Tariffs and Tariff Structures

4.3.1. Are any of the current tariffs insufficient to recover the efficient cost of supplying electricity in south-east Queensland?

Under the current tariff structure, there is considerable disparity between residential and business tariffs. As noted, for tariffs to be efficiently structured and cost reflective, they should capture the fixed charges associated with customers in the supply charge, and the variable costs in the volume component.

As demonstrated in section 3 above, there are currently tariffs which, on some consumption bands, do not recover the efficient cost of supplying electricity in the Energex region due to the fact the retail supply charge is not sufficient to cover the network supply charge. It needs to be noted that addressing this will lead to significant customer impacts, which would need to be carefully managed manner.

4.3.2. Do the current tariff structures send appropriate price signals to customers to enable them to manage their use of electricity and if not, why not?

In respect of the capacity for the existing tariffs to send appropriate price signals to customers, AGL notes:



- where the application of a tariff to a customer of a particular consumption results in a loss being accrued by a retailer, it must be assumed that the customer is not receiving the appropriate price signal;
- 'anytime' tariffs such as Tariff 11 and Tariff 20, do not provide any real price signal, as all consumption is aggregated. The only 'blunt' signal that can be provided is that which means the customer is incurring a higher cost due to higher volume;
- peak and off-peak rates have the potential to promote a shift from peak to off-peak times. Controlled loads generally have a specific use (hot water) and therefore constrain significant shifts in usage pattern;

4.3.3. Do the current tariff structures facilitate effective retail competition and if not, why not?

Given that current tariffs do not reflect the cost of supplying electricity for low usage customers, retailers will focus retention and acquisition activities on high usage customers. Whilst current tariff structures remain there will not be effective retail competition or choice of retailers for low usage customers.

It is also relevant to note the further implications of having loss making, low volume customers, particularly where there are off-peak tariffs. Retailers entering the market will (where possible to do so) target the higher consumption customers. These customers yield the greatest amount of revenue (on peak tariffs) for a given energy usage. At the same time, customers on off peak tariffs other than those on controlled loads will be less attractive. This not only skews competition, but has the potential to drive perverse price signals, with retailers with these small volume customers on off-peak looking to increase off-peak rates rather than peak rates. In this way, the reliance on the NSLP for customers with basic meter may operate to reduce the imperative for retailers to promote demand management as it will reduce revenue without a corresponding decrease in wholesale energy costs unless the NSLP reflects this change.

Obsolete tariffs

4.3.4. Are there any tariff categories which no longer serve a customer need that cannot be accommodated in another tariff? If so, is it reasonable for those tariff categories to be retired?

4.3.5. Could any current tariff category be consolidated into another tariff category? Would such consolidation unfairly discriminate against any particular customer class?

4.3.6. Are there any tariff categories that provide perverse price signals?



AGL notes as a general principle, where tariffs are considered obsolete, any customers on those tariffs should be moved onto other tariffs. Otherwise, there is no reform utility in declaring those tariffs obsolete.

The comprehensive restructure of tariffs will present a number of options in respect of consolidation and removal of tariffs. AGL would need to understand the appetite of the QCA and the Government to commence this process in the transition year before commencing the necessary analysis and presenting recommendations. This process will have significant customer impacts, and the tariff restructure should be considered part of a larger project to execute a smooth transition of a large number of customers to different pricing arrangements.



Annexure 1

List of Generation Projects Underwritten by AGL

Queensland

- Yabula – 121 MW (50% dispatch rights)
- Oakey – 282 MW (100% dispatch rights)
- Moranbah – 12 MW

South Australia

- Torrens Island – 1,280 MW
- Hallet 1 – 94.5 MW (off-take)
- Hallet 2 – 71.4 (construction)
- Hallet 4 – 132 MW (construction)
- Wattle Point – 90.8 MW (off-take)
- Angaston – 49 MW (off-take)

Victoria

- Hydro – 583.3 MW
- Bogong / McKay Expansion – 150 MW (construction)
- Somerton – 150 MW
- Loy Yang A – 689 MW (32.5% equity)

NSW

- Hydro – 62.2 MW



Annexure 2

Table 3: Rate of Increase in Energen Network tariffs 2009 and 2010

	Network Tariff	Component		2007-08 to	2008-09 to
				2008-09	2009-10
8600	Business Medium	Fixed price	\$/day	4.8%	20.5%
		Energy price	c/kWh	9.2%	11.8%
8800	Business Medium	Fixed price	\$/day	4.4%	24.3%
	TOU	Peak energy price	c/kWh	10.4%	10.5%
		Off-peak energy price	c/kWh	10.7%	11.1%
8500	Business Small	Fixed price	\$/day	5.2%	17.8%
		Energy price	c/kWh	13.3%	12.8%
8700	Business Small	Fixed price	\$/day	10.2%	4.2%
	TOU	Peak energy price	c/kWh	10.4%	12.0%
		Off-peak energy price	c/kWh	10.6%	12.1%
8400	Domestic	Fixed price	\$/day	5.2%	17.8%
		Energy price	c/kWh	13.3%	12.8%
9000	Controlled Load 1	Fixed price	\$/day	3.8%	13.0%
	(Tariff 31)	Energy price	c/kWh	16.5%	18.7%
9100	Controlled Load 2	Fixed price	\$/day	3.5%	11.8%
	(Tariff 33)	Energy price	c/kWh	9.8%	18.6%