



Review of Electricity Pricing and Tariff Structures

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1. Executive Summary

AGL welcomes the release by the Queensland Competition Authority (QCA) of the Draft Report – Stage 1 of its Review of Electricity Pricing and Tariff Structures (Draft Report) on 18 August 2009. AGL supports the Draft Report’s acknowledgement that:

- The current BRCI methodology is flawed and does not deliver cost reflective prices; and
- Under an alternative methodology networks costs are to be passed through.

However, AGL is concerned that the process for achieving a cost reflective structure under a new pricing methodology is complex and cannot be achieved in the timeframes proposed by the QCA. AGL has attempted to respond to all points raised in the Draft Report, however it has not been possible in the time provided.

AGL remains of the view that the policy objectives articulated in the Ministerial Direction would be most effectively achieved over a longer timeframe, with the 2010-11 year being treated as a ‘transitional year’, and the establishment of a three year price path commencing on 1 July 2011. AGL previously proposed¹ a legislative approach that would allow a “transitional year”, prior to moving to a three year price path and still considers it to be a very constructive approach that should be closely considered.

AGL is concerned about a number of aspects set out in the Draft Report, in particular:

- Circumstances for re-opening the retail tariffs are likely to prevent prices from moving to fully cost reflective levels;
- The need for a “floor price” for energy purchase costs to provide the required stability in the retail price trajectory that will encourage the retail sector to continue to underpin investment in new generation capacity;
- The proposal to pass through network costs for 2010-11 based on the Australian Energy Regulator (AER) draft decision rather than final decision²;
- The material costs of implementing the proposed disclosure of network charges on customer bills;
- The proposed exclusion of a specific allowance for customer acquisition and retention costs, despite the objective of ensuring cost reflective tariffs and the promotion of competition;
- The availability of regulated tariffs to large customers consuming more than 100MWh per year; and
- The absence of “merits review” of pricing decisions.

AGL looks forward to working through the details of an alternative methodology; however our view is that this should occur in an appropriate timeframe that allows for robust consultation, consideration of all relevant issues and ensure transparency of all methodologies and assumptions. This will be particularly important in Stage 2 and for the price review process for 2010-11.

Reopening of price path

Reopening of prices should be primarily concerned with upwards movement in prices as a means of ensuring the viability of the market. In circumstances where costs decrease during the price path, increased retailer activity and the market should be allowed to operate to compete away any excess margin that might exist. This view is supported by the increased customer churn experienced in South East Queensland (SEQ) in July 2009 following the re-made BRCI Decision for 2009-10.

¹ In AGL’s Further Submission to QCA Request for Comments Paper, dated 4 August 2009

² The AER is currently reviewing network revenue requirements for Energex and Ergon Energy, to apply from 1 July 2010

Reopening decisions after the introduction of Carbon Pollution Reduction Scheme (CPRS) or other environmental obligations should be 'event driven' and at the retailers' request. This should be considered necessary to protect smaller, less well capitalised retailers in respect of situations of extreme price volatility. In the event that no reviews are requested by retailers, reviews should be conducted by the QCA annually rather than six monthly.

Wholesale Energy Cost (WEC)

AGL supports the move towards a market-based energy purchase cost as it allows retail tariffs to capture sharp rises in wholesale market prices, albeit with a lag, in the event of annual reviews of the WEC. However, AGL notes that critical details regarding assumptions and methodology are yet to be addressed. It is AGL's view that maintenance of Long Run Marginal Cost (LRMC) as a "floor price" for energy purchase costs, as is currently the case in the New South Wales Terms of Reference to IPART³, is critical to ensure the retail sector retains confidence to continue to underwrite investment in new generation capacity, either through power purchase agreements or direct investment. If the generation, retail and finance sectors do not have confidence in the underlying stability of retail prices, the ongoing viability of new generation will be at risk, thereby putting at risk security of supply.

Network costs

Regulated retail tariffs for 2010-11 and onwards must be based on the Final Decision of the Australian Energy Regulator (AER) and not its Draft Decision. This would comply with the requirement in the Ministerial Direction for tariffs to fully reflect the costs of supplying customers in (SEQ). This would also preclude the need for reopening for differences between final and draft decisions. Any network cost pass through events approved by the AER outside of the price determination should be treated as an automatic pass through for retailers.

AGL notes with some concern the QCA's comments that, even where network costs are fully passed through, it will be necessary to provide a mechanism (through re-opening events) that ensures price stability as well as enabling cost pass-through. This would seem to indicate that retailers will continue to be required to absorb costs to facilitate such stability, and AGL is understandably opposed to any suggestion that retailers would have to do so.

Disclosure of network costs on customer bill

Whilst AGL supports the notion of greater transparency for customers, the QCA's proposal to separately disclose network costs on customer bills must be considered in light of the material cost of such a change to billing systems. AGL has recently completed the implementation of a national billing system to improve efficiency through standardisation of billing processes. The proposed disclosure of network costs would introduce a material variation from the practice of other jurisdictions and undermine the efficiency of billing processes. Best practice regulation should require a proper assessment of the costs and benefits of such a proposal with opportunity and time for retailers to properly assess the likely impact and have the opportunity to ensure it is an informed consideration. In the event that a net benefit can be demonstrated, retailers should be entitled to fully recover all associated costs.

Customer acquisition and retention costs

AGL is of the view that in addition to Retail Operating Costs (ROC), a specific allowance for customer acquisition and retention costs must be included in retail tariffs, as retailers should be entitled to recover all costs. Customer retention and acquisition activities are both material and fundamental to encouraging and maintaining effective market competition. Using a regulatory approach recently adopted from the substantially smaller ACT market and applying the same logic to Queensland, as the second largest energy region in the NEM is not reasonable. Furthermore, the ACT market was opened to full retail competition (FRC) from 1 July 2003, a full four years ahead of FRC in Queensland.

Merits review

³ As requested by the Minister for Water and Energy in July 2009 for the review of regulated retail tariffs 2010-13

AGL has previously raised⁴ the need for a review and appeals process and proposed a draft framework based on the South Australian model. AGL believes that to provide regulatory certainty to all stakeholders an alternative regulatory framework must include provision for merits review and appeal.

2. Price regulation - best practice

Best practice principles

It is critical that the development and application of an alternative price regulation methodology is based on "best practice" principles. Geoff Swier, AER member, presented the AER's views on principles of best practice regulation at a seminar at the Australian National University in 2006. The following principles set out in Table 1 were highlighted as providing the basis for effective regulation.

Principle	Features
Communication	Information to stakeholders on a timely and accessible basis.
Consultation	Participation of stakeholders in meetings.
Consistency	Across market participants and over time.
Predictability	Reputation that facilitates planning by suppliers and customers
Independence	Autonomy – free from undue political interference
Flexibility	Using appropriate instruments in response to changing market conditions and experience Regulation must be feasible in the light of the stage of development of the market.
Effectiveness and Efficiency	Efficient and timely regulatory decision making Cost effectiveness emphasised in data collection and policies.
Accountability	Clearly defined process and rationales for decisions with the ability for appropriate review This aims to ensure that the regulator adopts objective and fair decision making.
Transparency	Decision making based on accurate information. Openness of the process

Table 1: Principles of Best Practice Utility Regulation

Source: The AER and Best Practice Utility Regulation, Geoff Swier, AER Member, Acore Seminar Series, 2006

AGL has some key concerns given the complexity involved in the pricing methodology and tariff reform process and the importance of the outcome for all stakeholders. In this regard:

- The time available to consider the Draft Report has been limited with the result that AGL's ability to respond to the issues in detail has been constrained. AGL notes the truncated timeframe (two weeks) provided for stakeholder response in Stage 2. As a result of the time constraints, thorough consultation on all aspects will not be possible.
- AGL also notes the only stakeholder workshop proposed by the QCA was subsequently cancelled, which represents an unusual departure from best regulatory practice outlined above.
- Aside from the substantial amount of work required to establish the details of the new pricing methodology and rebuild the tariff structures, the significant lead time to implement changes to retailers' system must be taken into account.
- Proposals must weigh up the associated costs against the likely benefits. Stakeholders must also have adequate time to properly assess the costs and benefits of such proposals. For example, the time provided to respond to the Draft Report has constrained AGL's ability to properly assess likely impact of the proposed separate disclosure of network costs on bills. This proposal requires a full cost/benefit analysis.
- Regulatory frameworks should require regulators to be accountable for their decisions through the provision of a mechanism for review and appeals to ensure the application

⁴ AGL Further Submission dated 4 August 2009 to the QCA Request for Comments Paper – Review of Electricity Pricing and Tariff Structures

of the regulations is fair and objective. Attached as **Annexure 2** is the proposed framework based on the South Australian model that was previously provided by AGL.

Objectives of price regulation

It is AGL's view that in developing an alternative pricing methodology, the establishment of the following objectives is critical to deliver an effective regulatory pricing framework:

- Protection of the long term viability of the retail market (against exposure to non controllable costs and material spikes in other costs); and
- Provision of a maximum "safety net" price for small customers.

An effective regulatory pricing framework, in the context of Full Retail Competition, should not attempt to replace the role and proper functioning of the competitive market. AGL would argue that best practice regulation should intervene in a competitive market only where there is a risk of market failure and otherwise leave the market to compete and determine its own level when underlying costs fall. This is a key point in considering the circumstances in which a three-year price path should be reopened given the asymmetric nature of price regulation in competitive markets.

In the event that a methodology seeks to define and set a so-called efficient regulated 'competitive market price' in the world's most volatile commodity market, determinations will inevitably fail from time to time. Regulation of price in a competitive electricity market should not aim to be a reasonable proxy for an efficient market because if the regulated maximum price is set too low, it will impede market activity and competition. And the nature of price regulation is that if a regulator mis-calculates and prices are set too low, cumulative losses will not be recouped in subsequent price setting events. Conversely, if price is set too high any excess margin will inevitably be competed away.

The QCA seems to suggest that an efficient price should be determined on the basis that some customers do not have access to the competitive market (i.e. non SEQ customers). In such instances, if a regulated price is set too low in the Ergon region, it merely exacerbates an already overweight Community Service Obligation (CSO). Conversely, a higher regulated price will merely reduce the fiscal burden on future QLD State Government budgets, since the cost of supply in the Ergon region is likely to remain materially higher than a reasonable safety-net notified price in any event, particularly given that current CSO payments in Queensland are expected to exceed \$450 million.

In light of this asymmetry, AGL believes that prices should be set as a safety net, and should only be reopened where there is a risk to the viability of the market, requiring pass through of network costs and material changes in anticipated wholesale costs.

3. Alternative pricing methodology

WAPC and N + R cost built up approach

The WAPC approach and the N+R cost built up approach considered by the QCA have in common the pass-through of network charges. It is the treatment of the retail or R component which differs. AGL supports the underlying principle of network pass-through and either of these approaches will be a significant step toward the development of cost reflective tariffs.

The N+R approach has the advantage of establishing cost reflective prices in the first instance whilst the WAPC approach allows rebalancing of the retail components to cost reflective levels.

AGL notes the QCA's preference for the N+R approach and the possible transition required if the difference between notified prices and efficient costs is significant. Whilst AGL supports a N+R approach in principle, it is only on the basis that full cost reflectivity is allowed for each individual tariff and the ability to re-balance the retail component of tariffs is provided.

Circumstances for re-opening

The Draft Report proposes a number of reopeners to deal with uncertainty if a three year price path is set. The key circumstances for reopening include:

- An annual review of wholesale energy cost with a reset if it exceeds a predetermined band (+ or -10%);

- An automatic review on introduction CPRS and six monthly reviews thereafter while costs remain volatile; and
- An automatic review if the AER Final Decision on network review is materially different from the Draft Decision.

As pointed out earlier in this submission, it is AGL's view that regulated tariffs should provide a 'safety net' that provides price protection to customers whilst also ensuring viability of retailers through potential reopening if costs increase unexpectedly or materially. In this regard, it is AGL's view that:

- A year-to-year 'threshold' approach for allowance of cost increases is not supported as it exposes retailers to cumulative cost increases that may not, in any one year, exceed the predetermined threshold. It is quite feasible that in the first year, a retailer's costs increase but remain below the tolerance threshold. If, in the second year, the costs increase again but still increase at a lower rate than the tolerance threshold, the retailer is exposed to a cumulative effect at the end of year 2 that exceeds the annual tolerance threshold.
- At a minimum, any threshold should be set on a cumulative basis with the reference point set at the commencement of the price path. It should also be noted that as energy costs comprise about 40-45% of the retail price, a 10% increase could reduce retail margin by around 80%. A 9.5% increase (that would not be recoverable under the QCA's proposal) would still reduce retail margin by a material amount.
- Re-opening tariffs should not occur for underlying cost decreases as increased retailer activity will compete away any 'excess' margin in a relatively short space of time. Further, the costs of regulatory reviews are significant and likely to outweigh any possible excess margin that may arise for a transitory period. This is supported by Figure 1 below which shows the increased churn activity in July 2009 following the price increase arising from the remade BRCI decision for 2009-10.

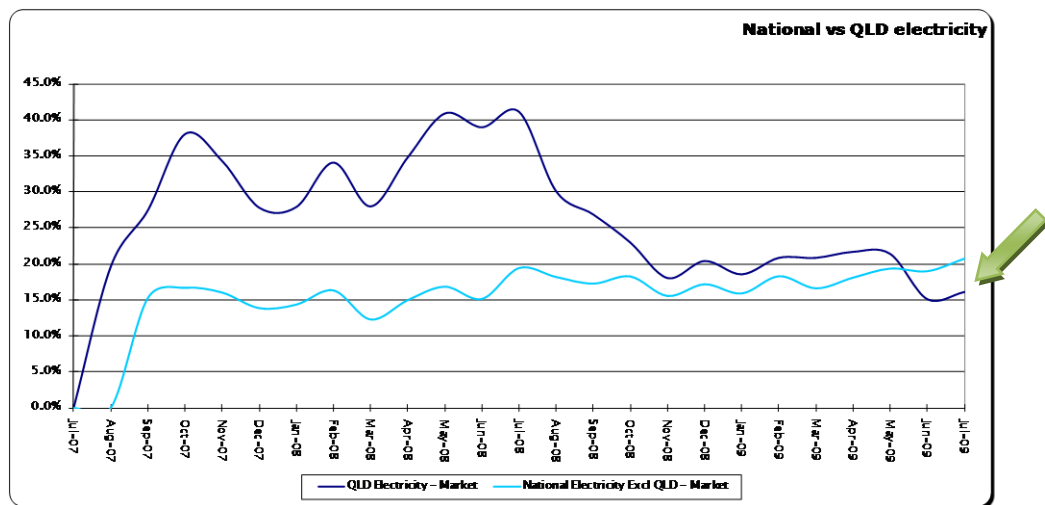


Figure 1: Queensland electricity v National electricity churn

- Re-opening for the review of CPRS or other environment obligations following its introduction should be 'event driven' rather than at a set review period, such as six monthly intervals. Whilst AGL may be able to bear increased costs associated with extreme price volatility and transient price increases in a post-carbon market, it is likely that small retailers would be unable to sustain such a position that spans a period of up to six months. Regardless, neither AGL nor small retailer shareholders would find it acceptable to bear material adverse financial impacts for a period as long as 6 months. Accordingly, a review should be conducted at the reasonable request of retailers. Assuming that retailers do not request a review, any review by the QCA should occur annually rather than six monthly to reduce transaction costs associated with price regulation.
- Passing through the final approved network tariffs. There is no need to reopen for network costs. Final approved network charges have been passed through when re-setting retail tariffs in a number of jurisdictions for many years.

Transitional measures

AGL notes that although the Draft Report proposes a “bottom up review of tariffs and prices with a new tariff structure and prices to be implemented from 1 July 2010”⁵, it also proposes the “*consideration of transitional measures once the extent of any likely price change becomes clearer.*”

The absence of any details regarding options for transition leaves stakeholders with increased levels of uncertainty and risk. The QCA must engage closely with all stakeholders to ensure analysis of the likely impact of any transitional measures with a view to moving to fully cost reflective tariffs from 1 July 2011.

South East Queensland market

AGL supports the QCA’s view that the objective of achieving cost reflectivity in South East Queensland (SEQ) is more critical to the development of a competitive energy market than the distribution pricing signals that may be provided to customers on Ergon Energy’s network. Accordingly, the considerations in this submission assume that the development of the alternative methodology and setting of regulated retail tariffs will be based on the costs incurred in the Energex distribution region with respect to network charges and the NSLP for WEC. The Queensland uniform tariff policy can be maintained by setting retail prices for the Ergon Energy region based on SEQ prices.

4. Network costs

Network pass-through

The pass-through of network charges is a central element in reforming the current methodology. AGL notes with concern the QCA’s comments that, even where network costs are fully passed through, it will be necessary to provide a mechanism (through reopening events) that ensures price stability as well as enabling cost pass-through. This appears to suggest that retailers will continue to be required to absorb costs, which is not in accordance with the Ministerial Direction’s requirements for cost-reflective tariffs. AGL is opposed to any suggestion that retailers will continue to absorb network costs.

AGL is concerned that the current lack of alignment between the structure of regulated retail tariffs and network tariffs creates difficulties when implementing the full pass through of network charges.

Without network and retail tariff alignment, developing retail tariffs from bottom up with an N+R approach will result in significant duplication of the existing set of notified prices due to multiple network tariffs which can be matched to a particular retail tariff.

For non-demand metered customers in the Energex distribution region, there are separate network tariffs depending on whether the customer uses less than or more than 25,000 kWh a year. There is no similar distinction in the notified prices.

In addition, demand based retail tariffs have minimum chargeable demands which are significantly different from the nearest corresponding network tariffs.

AGL recommends that a detailed analysis of the application of the N+R approach on the development of individual regulated retail tariffs and the resulting impact on customers be undertaken with full consultation with all stakeholders. While Stage 2 will commence shortly, preliminary analysis of the issues associated with restructure of retail tariffs to align with network tariffs is attached at **Annexure 3**.

Pricing signals

The application of NSLP has tended to dampen the ability for retailers to create price signals which reflect seasonal and intra-daily pool prices. This is because customers with accumulations meters (Type 6 meters) are attributed with energy costs based on the NSLP and not on their actual usage. This issue can be resolved by the installation of interval meters (Type 5 meters) and the development of tariffs which can better target the time of use. Until then, there is limited ability for retailers to provide appropriate pricing signals with respect to energy costs.

On the other hand, pricing signals in relation to demand management, which is important for network utilisation and investment, can be conveyed to customers on Type 6 meters if

⁵ At page iii of QCA Draft Report Review of Electricity Pricing and Tariff Structures – Stage 1

appropriate network tariff structures are aligned with those of retail tariffs. It is important that retail tariffs do not distort this pricing signal.

Separate disclosure of network costs

The Draft Report proposes that the disclosure of network cost as a separate line item on a retail bill to allow the customer to clearly identify the network cost component and make transparent any network price signal.⁶

AGL opposes this proposed change primarily because:

- Best practice regulation requires that the costs of a regulatory proposal are outweighed by the benefits, and at this point no such quantitative assessment has been undertaken. In November 2008, AGL completed the implementation of a single national billing system for its mass market customers with a standardised billing presentation that complies with the requirements of all jurisdictions. AGL understands that costs associated with a change to its billing systems (which are unique to Queensland customers) would be in the order of several million dollars and will take well in excess of 1 year to implement. The proposed changes are fundamental to the pricing structure of the system. Re-configuration would be required to provide for all distribution tariffs and a redesign of the bill would be required. The magnitude of the work would delay several other proposed system changes designed to improve efficiency and customer service.
- Retailers seek convergence of regulation between jurisdictions and AGL considers it would be a backward step to introduce further variations from the regulatory practices of other jurisdictions. Currently, no jurisdiction in Australia requires separate disclosure of network costs on invoices for small customers.
- The disclosure of network costs does not of itself provide an adequate price signal to end users with respect to demand management. Network charges comprise less than half of the customer's bill. A total (bundled) retail tariff can provide the appropriate price signal if structured correctly and aligned with the relevant network tariff.
- The risk of billing error is likely to increase along with increased complexity of the billing process. This risk will be exacerbated with the proposed timeframe for implementation.

Customers can be informed of network cost components through, for example, separate disclosure of the network charges in published retail tariffs and at other times, such as communication of price increases. Refer the extract of South Australian Electricity Standing Prices at Figure 2 below.

Figure 2 – Extract of SA Standing Electricity Prices⁷

Tariff Categories	Retailer Tariffs	Prescribed Distribution Service Tariffs	Standing & Default Contract Prices	Standing & Default Contract Prices
	GST Exclusive		GST Exclusive	GST Inclusive
Domestic Light/Power 110 <i>From 1 Jan - 31 Mar</i>				
First 3.2877 kWh/day (c/kWh)	11.2069	6.7231	17.93	19.723
Next 7.6712 kWh/day (c/kWh)	13.4269	6.7231	20.15	22.165
Next 16.4384 kWh/day (c/kWh)	13.4586	9.8614	23.32	25.652
Next 27.3973 kWh/day (c/kWh)	13.4832	10.1968	23.68	26.048
Thereafter (c/kWh)	13.4832	10.1968	23.68	26.048
Supply Charge (c/day)	14.6948	26.2652	40.96	45.056

Introduction of new network tariffs

The AER is currently in the process of determining the network revenue requirements for Energex and Ergon Energy, with the next five year price path effective from 1 July 2010.

⁶ At page 43

⁷ Published on AGL website at www.agl.com.au

This is likely to entail a significant 'P₀' adjustment, possible restructure of the network tariffs and introduction of new tariffs such as kVA tariffs.

These changes are likely to provide challenges in the setting of retail tariffs, not least because the full details of the network tariffs may not be known prior to the finalisation of the 2010-11 retail tariffs.

5. Transition

Transitional pricing for 2010/11

Given the timeframe and range of issues to be resolved by early 2010, AGL recommends that transitional pricing be set for 2010/11 to allow sufficient time and due process to develop the reforms that the Ministerial Direction has required. AGL notes that an option in the 'transitional' year might be:

- Full pass-through of approved Energex network charges from 1 July 2010;
- Allowance of a CPI increase of the retail component of each tariff (calculated as the difference between the notified prices and Energex network from 1 July 2010); and
- Where a retail component is negative for 2009-10, it will be reset to zero as a transition to cost reflective retail tariffs.

AGL is aware that there are issues with this simplified approach especially due to the mismatch of network and retail tariffs as outlined in Section 4 above. As this would only be a transitional matter, AGL believes that these issues can be managed. This approach to transitional pricing should be viewed in the context of the likely significant price increases with the introduction of CPRS.

Regulation threshold

The Draft Report⁸ discusses the appropriateness of large business customers in Queensland being afforded the protection of regulated retail tariffs. This situation is quite different to that in NSW, ACT and South Australia where all customers above 160MWh are required to negotiate market based contracts. Whilst the electricity market is fully deregulated in Victoria, the Victorian Government has reserve powers to regulate retail prices for electricity customers consuming less than 160MWh/year.

Large and commercial customers can and do negotiate most of the costs they incur in operating their businesses. However, in SEQ many large customers remain on regulated retail tariffs. Retailers are required to assume significant hedging risk in relation to these large (un-contracted) loads that could churn out as the market evolves over time.

Similarly, retailers are also exposed to re-balancing of network tariffs on these customers as there is a misalignment between the network and retail tariffs, particularly where a customer's volume exceeds 100MWh per annum and they can be assigned a new network tariff. This can and frequently does expose retailers to increased network charges that may be over or under-recovered due to the fact that, for each network tariff, there is not a "matching" retail tariff. The misalignment of network and retail tariffs occurs not only in relation to the allocation between fixed and variable components but also in relation to the consumption threshold and minimum chargeable demand thresholds for network tariffs as compared with retail tariffs.

AGL supports the notion of a "sunset clause" but considers a 3-5 year transition period excessive given the risks to which retailers are exposed in relation to large customers. AGL also considers that, for the period these customers are able to remain on regulated tariffs, a specific allowance for the increased hedging risk needs to be incorporated into the Wholesale Energy Cost (WEC).

AGL recommends transition of these customers to cost reflective market based contracts over a 1-3 year period.

⁸ At pages 27 and 28

6. Wholesale Energy Cost

As a general principle, any methodology for determining the wholesale energy cost must reflect how a prudent retailer actually hedges rather than focusing on spot and forward prices at a point in time. The calculation methodology must reflect the fact that retailers typically hedge 2-3 years out and undertake longer-dated transactions (such as 10 and 15 year PPAs) and therefore a retailer's wholesale energy costs will not fully reflect what is happening in the market at a given moment in time.

Long Run Marginal Cost as floor price for WEC

AGL supports the move to a market based approach for determining the Wholesale Energy Cost (WEC) – with the additional application of a “floor”, equivalent to the Long Run Marginal Cost (LRMC), under any market-based costing.

The Draft Report states⁹ that the LRMC is unlikely to be a useful indication of the “floor” for derived market prices as at any point in time actual prices could be above or below the LRMC.

Nevertheless, AGL contends that it is imperative that a “floor price”, equal to the LRMC, is provided for the WEC. This is due to the fact it is the retail sector that underwrites much of the investment in new electricity generation plant.

It is critical that power project investors, financiers and most critically, counterparty off-takers have confidence that the regulated retail price will not fall below the cost of new investment in generation capacity as otherwise there is a risk that they will be unwilling to enter into the longer term power purchase agreements (PPAs) that are necessary to underwrite new investment in generation capacity. Nor will the retail sector be willing to directly invest in new generation if it is not clear that the retail price will support the necessary wholesale price to justify the investment. A list of power development projects underwritten by AGL is attached as **Annexure 1**.

This issue was recognised by the NSW Government in June 2009 in setting the Terms of Reference for the determination of the 2010-13 regulated electricity price path in that State.¹⁰

In academic literature on energy economics, “resource adequacy” is used to describe the potential for insufficient generating capacity relative to aggregate power system demand¹¹. The issue is primarily one of timing – will new plant capacity arrive in a timely manner? The common thematic amongst these analyses is that wholesale prices in energy-only markets are inherently unstable. As a result, consumers face the risk that power project proponents will mis-time investments, leading to transient price shocks and load shedding during the period spanning the lag in investment.

Electricity reforms in England & Wales, Europe and the US were primarily undertaken during the 1990s in response to a common problem; a vast oversupply of generating capacity built-up during the pre-reform monopoly era. Australia was no different. Structural reforms and market deregulation was carried out during the 1990s in response to an oversupply of generating plant. For example, in the six years between 1979 and 1986, aggregate generating capacity in the NEM States of Queensland, New South Wales and Victoria increased by 65% from 13,500MW to 22,250MW, with the value of capacity stocks more than doubling, from \$5.5 billion to \$12.6 billion.

⁹ At page 38

¹⁰ The NSW government's Terms of Reference to IPART for the 2010-13 review of regulated tariffs states “The Energy Purchase Cost Allowance for each year must not be lower than the least cost mix of generating plant (based on those plants earning an economic rate of return on their market value), including any plant that would be required to meet any regulatory obligation, (using generation technology that is available in the NEM for the relevant year/period), to efficiently meet each Standard Retail Supplier's forecast regulated load.”

<http://www.ipart.nsw.gov.au/files/Terms%20of%20Reference%20-%20Regulated%20electricity%20retail%20tariffs%20and%20charges%20for%20small%20customers%202010-2013%20-%2026%20June%202009%20-%20WEBSITE%20DOCUMENT.PDF>

¹¹ Besser et al. (2002); Oren, (2003); Peluchon, (2003); Bidwell et al. (2004); Neuhoff et al. (2004); Wen et al. (2004); Bushnell, (2005); Roques et al. (2005); Simshauser, (2008)

Peluchon (2003) noted in the case of Europe, and Roques et al. (2005) noted in the case of England & Wales, that resource adequacy is a relatively new problem because deregulated energy-only markets have historically thrived on their inheritance of generation capacity oversupply built up by the public monopolies that previously existed. Australia's NEM was no exception. But importantly, Roques et al. (2005) noted quite accurately that there has been insufficient experience with deregulated energy-only markets to conclude that investment will be timely and adequate given the starting blocks these newly formed markets inherited. And further, Roques et al. (2005) noted that the world's electricity markets are only just beginning to approach their first major 'investment cycle' – as surplus capacity from the pre-reform era is finally being absorbed. Once again, Australia's NEM is a case in point. Table 2 below sets out the NEM plant stock in 2008 against system optimal conditions. (This analysis was performed based on dynamic partial equilibrium modelling of the power system.)

Operating Duty (Peak load: 35,700MW)	Optimal (MW)	Actual (MW)	Imbalance (MW)	Weighting
Base Load Plant	25,000	26,700	1,700	overweight
Intermediate Plant	3,600	5,900	2,300	overweight
Peak Load Plant	11,600	9,900	-1,700	underweight
Renewables	1,700	1,700	0	Balanced
Embedded Generation	1,000	1,000	0	Balanced
Aggregate Supply	42,900	45,300	2,400	oversupplied
Capital stock (\$M)	\$38,817.0	\$41,570.5	\$2,753.5	overcapitalised

Table 2: Optimal plant mix in the NEM in 2009

When comparing actual NEM supply with optimal, we can see the NEM system is now oversupplied by just 2400MW with aggregate supply of 45,300MW representing an 18% reserve plant margin over peak demand of 35,700MW.. To put the magnitude of this diminishing oversupply in some context, the peak load in the NEM increased by 2400MW during the 2008-09 financial year alone.

One of the interesting characteristics of the literature on resource adequacy has been the focus on market design as the source of the problem. Arguments generally draw on Bushnell's (2005) much cited 'missing money theory' – that is, given the political economy of electricity prices with artificially low market price caps and a reliability of supply constraint, equilibria in energy-only markets do not cover average costs of the power station fleet under conditions of intense competition. In fact, as Bidwell and Henny (2004) observed, competitive energy-only markets are only remunerative if the power grid is virtually on the edge of collapse.¹²

Roques et al. (2005) noted that raising funds had become a material obstacle to building new generating plant in the England and Wales market, with "*bankers extremely reluctant to engage in merchant power projects*". As Peluchon (2003, p.2)¹³ noted:

"...Peak capacity investment, especially, seems quite problematic. An investment in base generation plant is a decision that requires forecasting base future prices. An investment in peak generation plant is a decision that requires much more information as peak prices depend on base prices as well as from the future investments in every other kind of generation capacity. The revenue generated by peak plant is therefore much more hazardous than base plant, since it produces only when every other plant produces at full capacity or cannot produce. In the same way an option is said to be 'out-of-the-money', peak plant has a value that may change drastically with any change in the way the supply-demand balance evolves..."

The NEM has had a similar experience with peaking plant. Table 3 below demonstrates that between 1998 and 2009 only 25.8% of proposed peaking power development projects in the National Electricity Market (NEM) have been completed¹⁴.

¹² This of course violates the reliability of supply constraint in any event.

¹³ "Is investment in peak generation assets efficient in a deregulated electricity sector?", Research Symposium: European Electricity Markets, The Hague, September 2003

¹⁴ Source: AGL and Electricity Supply Association of Australia (ESAA)

Table 3: Hit-Rate of power projects in the NEM between 1998-2009 by technology

Project Technology	Proposed (US\$M)	Completed (US\$M)	Proposed (MW)	Completed (MW)	Project Hit-Rate
Coal	17,049	6,301	9,687	3,580	37.0%
CCGT	9,174	3,236	7,645	2,697	35.3%
OCGT	11,669	3,015	14,733	3,806	25.8%
Renewable	14,540	4,333	7,270	2,166	29.8%
NEM Total	52,433	16,885	39,335	12,249	31.1%

It can be seen from the above that getting a power development project to completion is a considerable achievement. Solutions in resource adequacy literature on both sides of the Atlantic and Australia have tended to focus on changes to market rules or a reversal of retail contestability in order to reduce cash flow volatility, thus enhancing the bankability of new plant. It seems clear to AGL that the potential impact of allowing the implied WEC to drop below LRMC would certainly not meet these seemingly fundamental criteria for resource adequacy in the Queensland region of the NEM.¹⁵

What makes a power project 'bankable', in the absence of sponsorship by a Government Owned Corporation or funding agency, is likely stability in the forward cash flows of the project. The historic stability in the trajectory of retail price paths in the NEM has been fundamental to achieving this. It is likely that if the regulated WEC in Queensland was able to drop below the LRMC, it would import the same level of price volatility of the wholesale market into the retail market, and in turn would represent a break in retail price stability and almost certainly put at risk the timely investment in peaking plant to meet forecast annual average growth in 50PoE peak demand of 5.0% per annum over the next 5 years in the combined Moreton and Gold Coast sub regions (which closely correspond to the Energex distribution region).¹⁶

AGL would be pleased to discuss this issue in more detail as it is a critical factor for ensuring ongoing investment in generation capacity and thus the security and reliability of electricity supply.

Estimating the LRMC

In light of the above discussion, AGL is concerned to ensure consistency and transparency of assumptions used in modelling the LRMC to ensure stakeholders can have confidence in the outcome.

Any robust LRMC modelling process must include estimates of the following parameters.

- **Estimation of the appropriate load shape**, using a robust and transparent process – AGL contends that the load shape for use in the context of regulated retail pricing is the Net System Load Profile (this is discussed further below).
- **Selection of the appropriate range of available generation technologies** – incorporating details of minimum and maximum unit size, availability and reliability. Only proven and available technologies should be used in any analysis of LRMC.
- **Fuel costs** – both fixed and variable fuel costs must be included. Care must be taken when considering the cost structure of relatively low capacity factor gas-fired generators that fixed gas transportation costs are allocated correctly. The average per-gigajoule gas cost can vary significantly based on assumptions of such a unit's annual capacity factor.
- **Operations and Maintenance expenses** – including fixed and variable components
- **Capital costs** – as noted in **Annexure 4**, AGL encourages development of a transparent and quantitative process for identifying "step changes" in the capital costs of new plant. However we believe that the approach recently used by Concept Economics (in response to an engagement from the QCA) has actually revealed a step change in the capital costs of a range of technologies. We therefore remain opposed to a "trending" approach based on fifteen or more year of data.

¹⁵ See for example Bidwell and Henney (2004), Bidwell (2005) and especially de Vries (2003), Neuhooff and de Vries (2004), Roques, Newbery and Nuttall (2005).

¹⁶ –Powerlink Annual Planning Report 2009, chapter 3, table 3.18,

- **Financing costs** – includes application of the appropriate discount rate for use in modelling the least-cost mix of plant to meet the selected load shape, and must include interest costs incurred during the construction phase of new plant.
- **Environmental compliance costs** – costs of complying with liabilities under any emissions trading scheme, such as the Carbon Pollution Reduction Scheme.

Relevant load for WEC – Net System Load Profile:

As discussed in Section 5 above, AGL urges a transition away from the regulated tariff for large customers (i.e. those with consumption greater than 100MWh per annum). As a consequence, when formulating a view of market-based wholesale electricity costs for the regulated small-customer remainder, the load shape used for the analysis should as closely as possible represent the actual load shape of that remainder.

The best available public data source to use as the basis for projecting the load shape of the small-customer base is the Net System Load Profile (NSLP), published by the Australian Energy Market Operator (AEMO).¹⁷ This load profile essentially represents the half-hourly sum of all non-interval meters within a distribution area, and as such will be a close fit to the loads remaining after larger customers have transited away from regulated tariffs.

Accurate load forecasting is an integral part of AGL's business and we would welcome the opportunity to contribute to discussions on how to develop robust projections based upon publicly available NSLP data.

Usage of the NSLP as the basis for projecting a market-based WEC is also appropriate during any period of any large-customer transition away from regulated tariffs. It is a reasonable assumption that any large customers affected by this approach who may have a flatter (and thus lower-cost) load shape will have the means and motivation to enter into new retail contracts appropriate to their circumstances. Of course, the implication of this is that Queensland retailers with such customers on their books face an increased hedging risk – not faced by retailers in other jurisdictions – due to the large quantum of load that could churn away at any time. Therefore, an allowance should be incorporated into the WEC to account for this increased hedging risk.

AGL therefore reiterates its previously-stated support for the use of the NSLP in calculating any market-based wholesale electricity cost. This approach would satisfy the criterion of being reflective of the costs faced by retailers, and would be based upon publicly-available data, thus being transparent.

As previously pointed out, net market-based wholesale energy costs incurred by retailers are a combination of the:

- Hedge contract prices paid to generators and other counterparties (typically comprising a combination of swaps and caps, PPA's and other derivative costs); and
- Pool price for energy purchases not covered by hedge contracts.

These prices reflect the costs and returns for existing generating assets, the supply/demand balance, peakiness of the load in a particular market and the volatility of demand. Additionally, hedge contract prices will inevitably include a risk premium required by generators to compensate them for the asymmetric risk they face due to risk of plant failure.

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.

Mandatory Renewable Energy Target

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 (MRET) is by reference to the LRMC of renewable generation. This is the approach that has been used by IPART in its 2007 electricity price review.

¹⁷ "The NSLP is calculated by aggregating the wholesale [distribution area] boundary energy and subtracting off all the non-wholesale boundary interval energy. *Understanding Load Profiles Published from MSATS*, Australian Energy Market Operator, p6, <http://www.aemo.com.au/electricityops/0700-0016.pdf>

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 energy projects and long term PPAs to underwrite the development of renewable plant. The price at which the developer will commit to the development of the plant is the LPMC 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 LPMC of renewable generation must be assessed.

AGL supports the comments made by TRUenergy in its last submission¹⁸, that the MRET scheme experienced high prices in the early phase of the scheme, responding to high start up costs for qualifying generators. However when REC prices subsequently fell regulators failed to recognise the longer term position held by retailers and created a funding shortfall through an insufficient REC allowance in the retail cost-stack. If REC costs are priced using market prices, but with LPMC as the “floor price” such a funding shortfall will be prevented from recurring. This is clearly analogous with an LPMC floor price for the determination of the WEC.

Retailers and market participants will optimise their portfolios to minimise costs. In this context, it should be noted that the expanded Renewable Energy Target allows for banking of RECs. A retailer may actually face higher costs than the marginal renewable generation project in any particular year if overall costs are minimised by investing in additional projects so that additional certificates can be ‘banked’ into later years.

Modelling and assumptions

AGL reiterates the following points made in earlier submissions:

- 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 and any other relevant risks.

7. Retail Operating Costs

Customer acquisition and retention costs (CARC)

It is AGL’s view that retailers should be entitled to recover all their costs. This also accords with the Ministerial Direction regarding the requirement for tariffs to reflect costs of supply.

The Draft Report points to the recent decision of the Independent Competition and Regulatory Commission (ICRC) in the ACT to exclude any consideration of CARC on the basis that (in the view of the ICRC) the ACT market was unlikely to experience any further growth in competition¹⁹. The Draft Report questions the need to include any specific estimate of customer acquisition costs in establishing the retail cost component and considers that normal marketing expenses should be able to capture CARC. AGL notes this would represent a departure from the existing practices in QLD, SA and NSW, and previous practice in Victoria prior to de-regulation.

AGL does not agree with the reasoning expressed in the Draft Report as:

- The ACT market has approximately 160,000 electricity customers compared with the SEQ market, which has approximately 1.2 million customers;

¹⁸ Dated 16 July 2009

¹⁹ At page 40

- The incumbent retailer in the ACT is a unique multi-utility offering water, sewerage and telecommunications products in addition to electricity and gas. This is not comparable to electricity retailing in SEQ;
- Even if competition reaches an acceptable level, churn will still continue, requiring retailers to maintain acquisition and retention activities; and
- CARC incurred by retailers are the costs associated with running direct campaigns through a variety of channels that include door knocking, telemarketing and so on. The quantum of CARC is generally multiples of the normal marketing and advertising expenses that a retailer incurs in brand and advertising each year. Retailers should be allowed to recover all marketing and CARC costs.

It is inconceivable in any competitive retail market that CARC could be shaved off without any resultant impact on competition levels in the market.

Fixed v variable costs

As noted in AGL's earlier submission, most of a retailer's operating costs are fixed and do not vary with a customer's consumption. AGL reiterates that to achieve cost reflective tariffs retail operating costs will need to be passed through in the fixed component of regulated retail tariffs to ensure that costs are recovered without significant cross-subsidisation between customers and tariffs.

8. Retail Margin

AGL considers that the retail margin should reflect the risks of participating in the competitive section of the electricity market in Queensland i.e. in SEQ.

When setting an appropriate retail margin, it is not sufficient to adopt the benchmarks used in other jurisdictions without reflecting the unique characteristics of the Queensland market and increased risks arising from environmental and policy changes. The particular risks in Queensland are:

- All customers can remain on regulated tariffs regardless of size. This exposes retailers to materially increased hedging risk as these loads can potentially churn out at short notice and also to increased risk from reassignment of network tariffs;
- Due to the current mismatch of retail and network tariffs, retailers are not able to pass through changes from the re-balancing of network tariffs and re-assignment of customers to different network tariffs; and
- The regulatory risk faced by retailers in Queensland is extremely high compared to that present in other jurisdictions – AGL notes particularly a tendency²⁰ to introduce variations rather than convergence with other jurisdictions. Further, a lack of consultation on the development of the BRCI, the truncated timeframe allowed for this review and very limited stakeholder consultation points to a higher regulatory risk than faced in any other jurisdiction. This risk is further elevated by the increasingly uncertain nature of future regulatory frameworks both in Queensland and Federally.

Until the details of the pricing methodology have been fully developed and retail pricing has transitioned to full cost reflectivity, retailers will continue to be exposed to the above risks.

The QCA has proposed to investigate further options for setting retail margins other than a benchmarking approach by specifically measuring the actual risks for which a retailer would be compensated. AGL has reservations about how actual risks can be properly measured and assuming these can be measured in the first instance, how to reconcile the divergent risk profiles of various retailers.

When the above risks are combined with the increased risks faced by retailers in relation to MRET and CPRS, a complete re-assessment of the adequacy of historical benchmarks will be required. At best, historical benchmarks should be the minimum starting point in determining retail margin.

²⁰ Eg proposed separate disclosure of network costs and proposal to adopt ACT approach of customer acquisition costs rather than that of most jurisdictions

It is AGL's view that current benchmarks for retail margin do not adequately reflect the complex and high risk electricity market where, for example, a retailer's price is capped and yet it is exposed to a maximum price in the market of \$10,000/MWh.

9. Headroom

The Draft Report has defined retail headroom as:

" a 'premium' above the required (efficient) retail margin that provides an additional return to encourage competitive retail electricity market activity and attract competitive retailers to enter the market"²¹.

AGL does not consider that there is a material difference between retail margin and headroom and has used these terms interchangeably.

AGL notes the comments in the Draft Report²² that:

"in setting headroom it is necessary to recognise that not all customers on notified prices have access to alternate market contracts." For this reason, the inclusion of headroom in notified prices in Queensland is likely to be a more contentious issue than it may be in some other jurisdictions where active competition is more pervasive. Careful consideration needs to be given to what is a reasonable level of headroom to encourage further activity in the competitive section of the market while not imposing undue cost on customers who have no choice but to pay notified prices.."

These comments are concerning as the entire SEQ market is open to competition and even incumbent retailers offer market based contracts. Ergon remains the only area where customers may not have access to market based pricing. It is AGL's view that headroom/margin should be determined for retailers in SEQ. The inclusion of headroom/margin in Ergon tariffs should reduce the amount of the CSO to be paid to Ergon by the Government. The argument that prices to customers must remain low until competition is effective is unsound and circular, as competition will only be attractive to new entrants when the reward for entry is adequate.

The Draft Report points out it will seek evidence of headroom that existed at FRC and that exists today. This assumes that retailers distinguish between retail margin and "headroom" as defined in the Draft Report.

The "representative retailer"

The definition of representative retailer, as currently defined, is not a reasonable definition moving forward and neither is the legislative requirement to assume an electricity consumption profile that is representative of a cross section of the customers that exist throughout Queensland. For the reasons outlined at Section 6 above, AGL reiterates that the only appropriate profile to be used in calculating the WEC is the NSLP of the Energex region (i.e. a specific and localised subset of Queensland customers, with usage patterns that differ markedly from the pattern of the overall State load.)

²¹ At page 41

²² At page 41

List of Generation Projects Underwritten by AGL

Queensland

- Yabulu – 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

Merits review process

The provisions proposed below are based on the review process established in the analogous South Australian legislation and regulatory provisions.

Reviews and appeals

1—Review by Commission

- (1) An application may be made to the Commission—
 - (a) by the QCA or by a regulated entity to which the determination applies, for a review of a price determination; or
 - (b) by a person of whom a requirement has been made by written notice under Part 5 for a review of the decision of the QCA to make that requirement; or
 - (c) by a person who has been given written notice under Part 5 of the proposed disclosure of information that the person claimed to be confidential information for a review of the decision of the Commission to disclose the information.
- (2) An application for a review must—
 - (a) be in writing; and
 - (b) set out the price determination or part of the price determination, or the decision, to which the application relates; and
 - (c) set out in detail the grounds on which the applicant seeks review and the decision sought on the review; and
 - (d) be accompanied by any information that the applicant considers should be taken into account by the Commission on the review; and
 - (e) be lodged with the Commission within 20 working days after the price determination is published or after receipt of the written notice referred to in subsection (1) (as the case requires).
- (3) If an application is made for a review of a price determination—
 - (a) the Commission must give a copy of the application to each other person who could also have applied for review of the determination; and
 - (b) invite each such person to join as a party to the review and make submissions on the matter the subject of the review in a manner and within a period specified by the Commission.
- (4) The price determination or decision to which the application relates operates until the review under this part is completed.
- (5) A review must be decided within 20 working days of the application being lodged with the Commission.
- (6) If a review is not decided within that period, the Commission is to be taken to have confirmed the price determination or decision.
- (7) After considering the application, the Commission may confirm, vary or substitute the price determination or decision.
- (8) The Commission must give the applicant and any other person who joins as a party to the review written notice of the Commission's decision, and comprehensive reasons for the decision, on the review.
- (9) If the Commission decides on a review of a price determination to vary or substitute the determination, the Commission must vary or substitute the determination by a further determination in accordance with Part 3 but that further determination may not be made the subject of an application for a review under this section.

2—Appeal

- (1) The applicant for a review under this Part, or any other party to the review who made submissions on the review, who is dissatisfied with the price determination or decision as confirmed, varied or substituted by the Commission on the review may appeal to the Commercial List Supreme Court Judge (the Court) against the determination or decision.
- (2) The Court must sit with experts selected in accordance with Schedule 1.
- (3) An appeal must be made—
 - (a) within 20 working days after receipt of the written notice of the decision on the review; or
 - (b) if the Commission failed to make a decision on the review within the allowed period, within 10 working days after the end of that period, which period can only be extended where the Court is of the view that such an extension is warranted in the circumstances.
- (4) If an appeal is made under this section, any other party to the review who made submissions on the review must be given notice of the appeal and may, on application, be joined as a party to the appeal.
- (5) If an appeal is made under this section, the price determination to which the appeal relates operates until the appeal is determined
- (6) On an appeal the Court may consider information
 - a) on which the Commission based the price determination or decision that was the subject of the review and any information put before the Commission on the review
 - b) and any additional information.
- (7) The Court may, on an appeal—
 - (a) affirm the decision appealed against; or
 - (b) remit the matter to the Commission for consideration or further consideration in accordance with any directions of the Court.
 - (c) substitute the QCA decision with its own decision
- (8) An appeal will lie against a decision of the Court under this section on a question of law and on questions of fact and reasoning.

Schedule 1—Appointment and selection of experts for Court

- (1) The Minister must establish a panel of experts who may sit as assessors with the Court consisting of persons with knowledge of, or experience in, a regulated industry or in the fields of commerce or economics.
- (2) A member of a panel is to be appointed by the Minister for a term of office not exceeding 3 years and on conditions determined by the Minister and specified in the instrument of appointment.
- (3) A member of a panel is, on the expiration of a term of office, eligible for reappointment.
- (4) Subject to subclause (5) and except in the case of an appeal limited to a question of law, a judicial officer of the Court must select 2 members from the panel to sit with the Court on an appeal. The panel must consist of:
 - a) one panel member experienced in economics or commerce; and
 - b) one panel member experienced in the electricity industry
- (5) A member of a panel who has a direct or indirect pecuniary or other interest in a matter before the Court is disqualified from participating in the hearing of the matter.

- (6) Subclause (5) does not apply if the interest is as a result of the supply of goods or services that are available to members of the public on the same terms and conditions.
- (7) If a member of a panel sitting with the Court dies or is for any reason unable to continue with any proceedings, the Court constituted of the judicial officer who is presiding at the proceedings and the other member of the panel sitting with the Court may, if the judicial officer so determines, continue and complete the proceedings.
- (8) If proceedings are reheard, the Court may have regard to any record of proceedings made in the earlier proceedings (including a record of evidence taken in those proceedings).

Tariff Restructure – Preliminary Analysis

Matching of retail and network tariffs

The following analysis assumes that Queensland regulated retail tariffs will be developed with respect to network costs in the Energex region.

Below is a desktop assessment to match regulated retail tariffs to Energex network tariffs based on 2009-10 schedules (AGL is aware that there are exceptions to the match below):

<i>Retail tariffs</i>	<i>Energex network tariffs</i>
Tariff 11	NTC 8400 (<25 MWh/year) NTC 8600 (>25 MWh/year)
Tariff 20	NTC 8500 (<25 MWh/year) NTC 8600 (>25 MWh/year)
Tariff 21	NTC 8500 (<25 MWh/year) NTC 8600 (>25 MWh/year)
Tariff 22	NTC 8700 (<25 MWh/year) NTC 8800 (<25 MWh/year)
Tariff 31	NTC 9000
Tariff 33	NTC 9100
Tariff 37	NTC 8500 (<25 MWh/year) NTC 8600 (<25 MWh/year) (no direct match to pricing periods)
Tariff 41	NTC 8200 (minimum demand 120 kW) NTC 8300 (minimum demand 20 kW)
Tariff 43	NTC 8100
Tariff 53	NTC 8000
Tariff 62	NTC 8700 (<25 MWh/year) NTC 8800 (>25 MWh/year)
Tariff 63	NTC 8700 (<25 MWh/year) NTC 8800 (>25 MWh/year)
Tariff 64	NTC 8500-8800 (no direct match to pricing periods)
Tariff 65	NTC 8500-8800 (no direct match to pricing periods)
Tariff 66	NTC 8200 (minimum demand 120 kW) NTC 8300 (minimum demand 20 kW)
Tariff 67	NTC 8500-8800

Simplification of tariffs

For customers using up to 100 MWh/year, regulated retail tariffs for customers on accumulation meters (Type 6) might possibly be simplified into three categories given the 2009-10 Energex tariffs:

- Flat tariffs - Tariff 11 or 20.
- Time of use tariffs – Tariff 22: TOU tariffs are structured with higher charges during peak times. Peak time is 7am to 9 pm Mondays to Fridays.
- Controlled load tariffs - Tariffs 31 and 33.

All tariffs currently reflecting declining block structure (Tariffs 21, 62 & 63) could be removed by transferring these customers to other tariffs:

Customers on	Transfer to
Tariff 21	Tariff 20
Tariffs 62 and 63	Tariff 22

A number of retail tariffs remain problematic:

- Non-domestic heating Tariff 37 has pricing periods (4.30pm to 10.30pm) which do not correspond to any network tariff.
- Irrigation Tariffs 64 and 65 have fixed 12-hour daily pricing periods which also do not correspond to any network tariff. To simplify initially, customers on Irrigation Tariff 64 could be transferred to Tariff 65.
- Farm Tariff 67 is applicable only to customers supplied under the Rural Subsidy Scheme (noting that for some customers, this tariff is more costly than Tariff 20).
- These tariffs – Tariffs 37, 64, 65 and 67 - may be consolidated into Tariff 20.

Possible tariff restructure

For non-demand customers:

- As a minimum, the pass through of network charges should include the full recovery of network fixed charges, particularly for Tariffs 11, 31 and 33.
- The fixed charge for Tariff 11 under-recovers the network fixed charge by over \$14 a year (excluding GST) for 2009/10. This charge should be increased to recover not only all of the network fixed charge but also the retail operating costs.
- For controlled loads - Tariffs 31 and 33, there is only a minimum payment each month whilst the corresponding network charges are structured with fixed daily charges. The minimum monthly payments under Tariffs 31 and 33 should be replaced by a fixed charge at least equal to the network fixed charge.
- Due to the structure of network tariffs, another set of regulated retail prices duplicating Tariffs 11, 20 and 22 might need to be constructed to reflect the 25,000 kWh/year threshold.
- Changes to the tariff structure for network charges for usage such as inclining block structures should be implemented as a pass-through.

For demand customers:

- For Tariff 41 there are two network tariffs – small demand and medium demand – which are applicable so an additional tariff might need to be created to properly reflect the network tariffs.
- Tariffs 41 and 53 have minimum chargeable demands which are significantly different from the nearest corresponding network tariffs so that these minimum levels may need to be aligned.

Overview of a quantitative approach to assessing step changes in capital costs – a response to Concept Economics

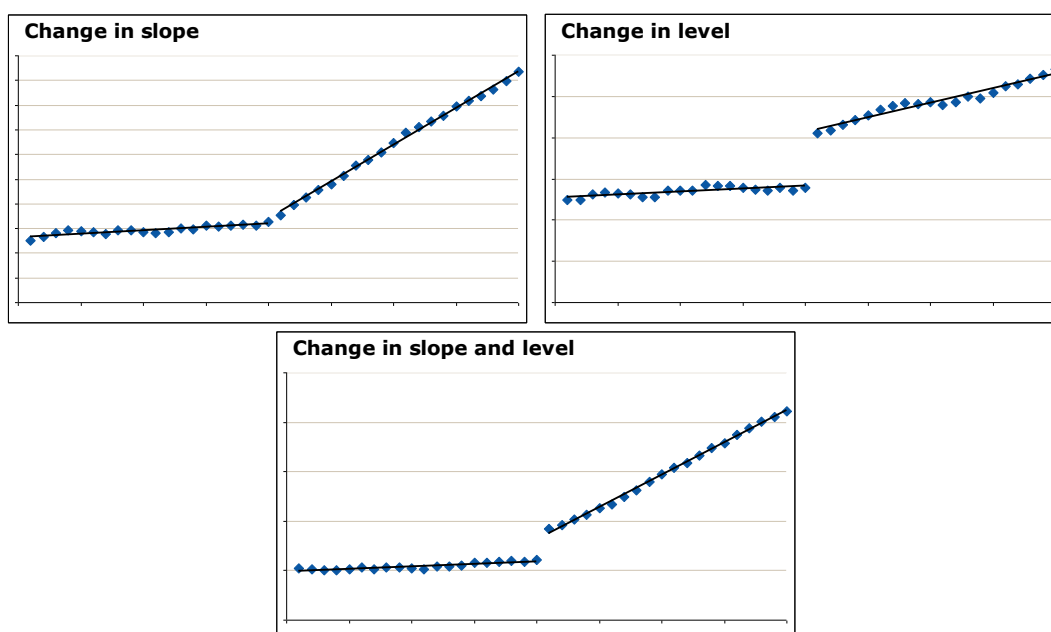
Background

In the determination of the 2009/2010 BRCI, there was considerable debate as to whether or not there had been a 'step change' in the capital costs of building power plants in Australia. In both their 2008 and 2009 reports on capital and fuel costs in the NEM, ACIL Tasman contested that there had been a recent step change in the costs of building coal and gas plants. They hypothesised that this step change was due to the rapid increase in commodity costs over the previous few years along with an increase in demand for generating equipment worldwide. ACIL Tasman's arguments in favour of a step change were qualitative in nature and hence were not accepted by the QCA.

In 2009, the QCA engaged Concept Economics²³ to assess whether or not there had been a step change in the capital costs of plants. Concept Economics took a more quantitative approach to the problem by using statistical tests to quantitatively assess if there was evidence of a 'structural break' (the statistical term for 'step change') in ACIL Tasman's data. Concept concluded that there was evidence of a structural change in ACIL series of gas plants but that there was not a step change in coal plants.

Structural changes

A statistical structural change refers to a point in time when there is enough evidence to prove that the underlying distribution of the data series has changed and hence the historical parameters of a model are no longer appropriate from that point onwards. The main types of structural changes are "a change in slope," "a change in level" or a combination of the two. These changes can best be illustrated by the charts below:



Typically, structural changes are associated with significant historical events such as: the stock market crash of 1929 (change in level to US GDP), the oil price shock in 1973 (change in slope of G7 GDP), World War I (change in level to UK GDP), World War II (change in level and slope European nations' GDP), etc.

The presence or absence of structural breaks in a time series has an extremely large impact on the quality of forecasts and inferences made from a model and hence there has

²³ Concept Economics' report has been published on the QCA's website. See <http://www.qca.org.au/files/ER-NEP0910-Final-ConEcon-ConsRep-0609.PDF>

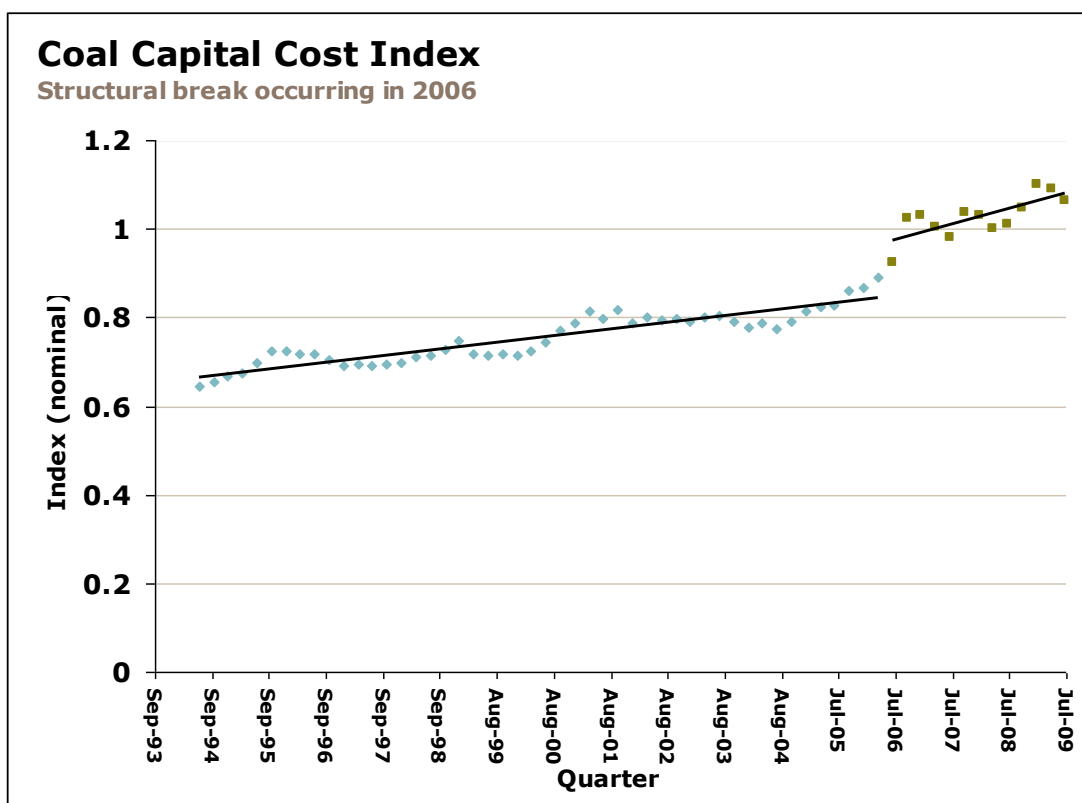
been a tremendous amount of research into the estimation and testing of structural breaks in the statistical literature for over 50 years now. An excellent summary of methods and issues can be found in Perron (2005).

Structural changes in power plant capital costs

AGL is pleased that quantitative methods are now being used to assess if there has been step changes in plant capital costs as it adds a degree of rigour and transparency to the argument around appropriate capital cost projections. AGL also welcomes Concept Economics’ independent provision of a new transparent source of data that can be used to project future capital costs of plants.

AGL however has found that not only has there been a step change in ACIL Tasman’s coal and gas series, but there has also been a structural break in Concept Economics’ series. The structural break occurs around 2006 and is a break in level and slope. The evidence of a break is supported by multiple statistical tests (for which AGL will gladly provide detailed calculations) on both the coal and gas series.

The structural break in the black coal series is shown below:



The implications of the structural break are that the nominal series post 2006 is growing at an accelerated rate of 4.4% p.a. and not at 3.1% p.a. which is the average growth rate over the period 1994 to 2009. Hence, AGL believes that Concept’s numbers should be updated to reflect the fact that there has been a structural change in the capital costs of plants within the recent past.

References:

Perron, P. (2005), “Dealing with Structural Breaks”, Forthcoming in Vol 1 Handbook of Econometrics: Econometric Theory. (available at: <http://people.bu.edu/perron/papers/dealing.pdf>)