Mr Gary Henry
Queensland Competition Authority
L19 12 Creek St
Brisbane QLD 4000
SENT BY EMAIL

Dear Mr Henry

***Re: Regulated Retail Electricity Prices 2013-14***
***Cost Components and Other Issues Consultation Paper***

This is Qenergy Limited's (QEnergy's) response to the Queensland Competition Authority's (the Authority's) Consultation Paper December 2012 (the Paper) regarding regulated retail electricity price cost components for setting the 2013-14 notified prices.

QEnergy is an established national electricity retailer with 11,000 customers in Queensland, South Australia, New South Wales and the Northern Territory, specialising in providing retail electricity to small businesses.

First, QEnergy is grateful for the opportunity to respond to this paper and in particular to add our perspective on ACIL Tasman's (ACIL's) approach to estimating energy costs for use in setting 2013-14 notified prices. This submission includes confidential pricing information in support of our perspective, however a redacted version is provided along with the unredacted version in order to allow publication as the Authority requests.

This letter is structured to answer questions as posed within the Paper upon which QEnergy feels we can make a genuine and useful comment or bring a perspective that may shed light on a methodology. For this reason, not all questions have been explicitly answered within this letter.

*Section 2.3 The Authority seeks stakeholders' views on how best to maintain alignment between network and retail tariffs.*

The Delegation to the Authority under section 90(5)(a) of the Electricity Act explicitly requires that the Authority consider 'the actual costs of making, producing or supplying the goods or services' in setting notified prices. Given that network costs are passed through to customers under the N+R methodology (albeit not costlessly, as noted by the Authority itself), then any change to the level of N which is not reflected in the Draft Determination because of the time when network prices are reset, should be cause for a reset of the level of notified prices.

QEnergy is cognisant of the legislative and regulatory difficulties in undertaking this course of action, but considers that the Authority, in consultation with the Minister and Department, should work diligently to achieve an outcome so consistent with the wording of the Delegation.

*Section 3.3 Is ACIL's proposed method for estimating wholesale energy costs reasonable given the requirements of the Electricity Act and the Delegation? What other approach should the Authority consider? What factors should ACIL take into account when determining modelling inputs such as customer load forecasts, plant outage scenarios, hedging strategies and spot price forecasts?*

QEnergy believes that over the long-run, LRMC pricing will be delivered by the Queensland electricity market since this is the rational approach to electricity generation pricing. As noted by IPART (*Changes in Regulated Electricity Retail Prices from 1 July 2011 – draft April 2011 p.31*):

> *The market-based cost is sensitive to the supply-demand balance and can move significantly from year to year. As a result for some years the market price can be significantly above the LRMC of generation, for example, during the tightening of the supply-demand balance … Over the longer term we would expect the market price to reflect the LRMC of generation.*

QEnergy therefore does not support the adoption of a solely market-based approach to estimating energy costs, chiefly because this will significantly add to year-on-year volatility for customers. The volatility will in some periods be beneficial for customers, and in some periods punitive, but will always make forward budgeting uncertain and more complex.

However, given that ACIL have ruled out using LRMC, we turn to a critique of their methodology which in our view falls well short of an acceptable approach to estimating electricity costs.

ACIL commence their discussion by articulating that their intent is to '*provide the QCA, our best estimate of wholesale energy costs that will be incurred by a retailer to supply customers on notified prices for 2013-14'*. QEnergy considers this to be an appropriate interpretation of the Delegation both to and from the Authority, but does not consider that ACIL outworks this intent with sufficient sophistication to merit it being the basis for setting notified prices.

The core of QEnergy's concern is that ACIL's understanding of the risk management processes used by retailers as articulated in section 2.2 of their paper '*Estimated energy costs for use in 2013-14 electricity retail tariffs*' (ACIL's Paper) is not actually reflected in the modelling methodology which they subsequently outline in section 5.1.

For modelling purposes, ACIL restricts the instruments used by their modelled retailer to those fungible through d-Cypha Trade, which is not the way retailers hedge their entire load. ACIL further states that a retailer's rationale for entering into more complex hedging arrangements is because '*such arrangements would result in lower overall energy costs than the estimates from the simplified contract model – otherwise the retailer would be expected to prefer the simplified contract model*'.'

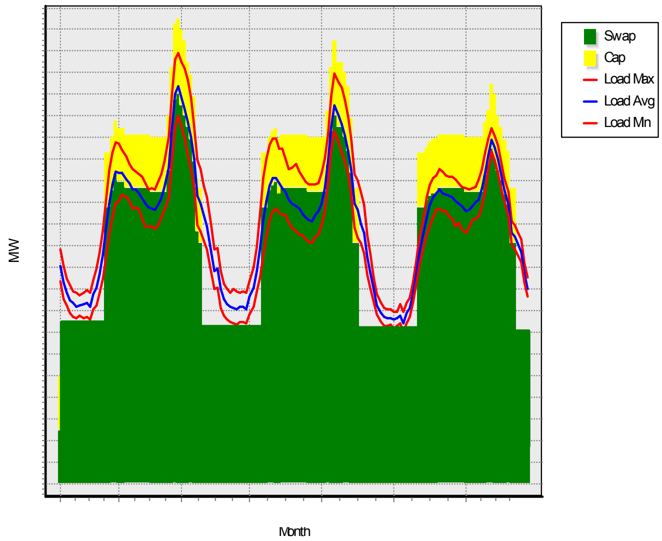
This statement is entirely incorrect, because the simplified contract model operates in an *ex post* world with data that has actually been outworked, whilst the overriding purpose of hedging is to protect the retailer against the risk of an event which has the potential to occur. For this reason, retailers (incumbent or otherwise) will always pursue a hedging arrangement which reduces risk but which might cost more on the basis that it ensures the sustainability of the company.

QEnergy recognises that the prices associated with structured hedges are often confidential and sourcing them is therefore not easy to achieve. Whilst core Flat, Peak and Offpeak swap and cap prices – such as those used by ACIL from d-Cypha Trade – are readily available for the Queensland market, these do not reflect the actual cost of hedging as noted by the Authority.

If ACIL's portfolio based on visible market instruments and prices is adopted as a base point, then a variety of risk premia must be added to these prices in order to achieve true cost reflectivity. The other risk premia not included in visible market prices include:

- *Time risk.* Because retailers traditionally hedge over time – a fact which has been acknowledged and accepted by ACIL – a premium needs to be added to allow for price volatility. In the 2012-13 report ACIL estimated this premium at a 0.5% uplift per six months of weighted forward contracting, which QEnergy considers reasonable. However this methodology does not appear to be replicated in the 2013-14 report and QEnergy advocates that it be so applied.
- *Shape risk.* The cost of an NSLP shaped hedge is higher than a combination of Peak and Offpeak prices because of the fact that Peak load shapes are higher in the SuperPeak periods (mornings and evenings) and lower in the middle of the day, particularly now given the penetration of solar panels in South-East Queensland. There is also a significant month-on-month difference between even average levels within quarters because demand levels and profiles evolve through the year over shorter timeframes than the quarter, and are generally hedged monthly.

  These two impacts in combination mean that retailers seek to match their cover in shape as much as possible against the load, generally by using fungible flat and Peak products to cover the bulk of their hedging, but then supplementing them with more structured products to cover peakier load. An example of the severity of this impact for QEnergy's ENERGEX NSLP book is given below for three consecutive winter monthly periods during the 2012 year:




Over these three months, if ACIL's methodology had been used to hedge the load, then depending on the month, the morning Peaks would have been 40 - 70% **over**hedged relative to QEnergy's cover strategy as per the chart; the midday Peaks would have been around 60% **over**hedged; the all-important evening Peaks (where price excursions commonly occur and where most of the demand excursions did in fact occur) would have been around 5% **under**hedged; and the Offpeak periods (where much of the pool price increase has occurred after the introduction of carbon on 1 July 2012) would have been around 5% **under**hedged.

It should be clear from this analysis that the complexity in determining a simplistic hedging strategy given the variety of variables in a typical retailer's load, is the reason why retailers do actually resort to the use of the structured products that ACIL dismissed in their analysis. By way of an example of these structured products, ACIL cites contracts with predetermined load profiles or the use of retailers' own generation.

QEnergy submitted a Supplementary Submission to the 2012-13 Draft Determination which went straight to these issues and provided actual prices in support of claims that the ACIL methodology underestimated costs, but which was unfortunately not referenced in the 2012-13 Final Determination. To demonstrate the real unaccounted for cost of using these products, QEnergy makes these points once again below.

QEnergy has an arrangement with our trading provider which delivers shaped contracts suitable for the ENERGEX load trace or NSLP at a fixed multiple of [redacted] times the flat price. This product is a fair representation of a prudent retailer's hedging strategy, reflecting the costs of the peaky shape of the NSLP and ensuring that margins are locked in rather than positions established. The multiple has been built using historical pool and settlements data to take account of the risks of price excursions over different parts of the demand cycle.

To demonstrate that the ACIL methodology does underestimate prices, last year's wholesale price ex carbon under the Draft Determination was struck at $41.60 / MWh for 2012/13. Even based on market contract data, QEnergy at the time of the supplementary submission did not consider that the levels proposed by the QCA were dealable, since when applied to 2012 /13 contracts current at the time of $34.75 / MWh, the product would be priced at [redacted] / MWh. Further, contract prices at the time were particularly low historically, since over the previous six months they had traded down from approximately $36.50 / MWh. At that higher level, the sculpted product would have been priced at [redacted] / MWh.

These are not the only types of products retailers use to deal with the variability in forecast load shape – other products include Power Purchase Agreements struck against specific profiles, and flexible Power Purchase Agreements underpinning generation. It is for this reason that ACIL should include structured products in their analysis, or at the very least an estimate of the risk premium arising from the way that retailers deal with these risks.

- *Load risk* – ACIL should be applying a premium for load variability to reflect the risk that customer volumes increase exactly at the time of price excursions. This increases prices in an asymmetrical manner because of the correlation between the two event likelihoods.

On balance, none of these pricing elements are easily observable, so if the Authority is to pursue the approach of using visible market prices rather than the LRMC, it would be preferable to ask for retailer confidential feedback on their specific bilateral costs, then compare them to the observable market to determine appropriate premia and make a qualitative determination of costings from that point. This step could easily be incorporated into ACIL's process for 2013-14.

On the issue of asking for retailer confidential feedback, it appears to QEnergy that the Authority has the power to demand this information under Section 90(A) of the Electricity Act 1994:

*Section 90(A) Obtaining information for price determination*

*(1) A pricing entity may, in writing, ask a retail entity for relevant information the pricing entity requires to make a price determination for the retail entity.*
*(2) The retail entity must, within the reasonable period stated in the request, give the relevant information to the pricing entity.*

This section would appear to apply to any retailer who supplies a customer under notified prices – which could be most retailers because of the Financially Responsible Market Participant model in use in Queensland whereby retailers must supply customers at the end of their Market Contract under Standard Contracts if the customer so desires. Whilst QEnergy is not an incumbent, by virtue of the passage of time we do have some of these customers and so would be caught under these rules.

If the Authority continues not to exercise this right, then they should at the very least direct ACIL to consider genuine pricing data provided to them from the market. QEnergy has attempted to provide our own confidential data in the analysis above, and encourages other retailers to supply the same to the Authority to allow the development of a fully informed '*best estimate of wholesale energy costs that will be incurred by a retailer to supply customers on notified prices for 2013-14*'.

QEnergy does acknowledge that ACIL has recommended attempting to deal with these risk premia through using the 95th percentile of price outcomes rather than last year's 50th percentile, which was unbearably low. Whilst QEnergy supports this improvement, the methodology is not transparent and does not in fact reflect the way that retailers hedge and hence the actual costs of supplying energy to customers.

Consequently QEnergy's preference would be for the Authority to direct ACIL to use actual retailer data garnered as suggested. Note that there is precedent for the use of confidential retailer data in setting notified prices in the ESCOSA collar methodology, so the Authority would not be unreasonable in using this as a basis upon which to move forward.

On a further issue relating to wholesale energy costs as well as to Retail Operating Costs, QEnergy noted in its submission of 2012-13 that it did not consider that the QCA addressed the costs of providing prudential capital to operate in the NEM, nor indeed acknowledge the increases on 1 July 2012 as a result of the expected impact of carbon. These costs are therefore explored again further below to reinforce their importance to retailers in terms of both wholesale energy costs and retail margin.

To participate in the electricity markets, retailers must provide prudential capital to the Australian Energy Markets Operator (AEMO), as well as to hedge counterparties for swap hedging and to Network Service Providers for network collections.

An electricity retailer – like any market trader – therefore requires two different types of capital:

- *Business capital*, to fund establishment and growth of the business as well as customer payment delays. This capital is risky by nature and represents the investors' equity in the business.
- *Prudential capital*, bank guarantees which provide surety to market counterparties that the retailer will be able to deliver on its market obligations.

According to the Authority, the retail margin represents the reward to investors for committing capital to a business and for accepting risks associated with providing retail electricity services. The type of capital to which the Authority is referring is business capital and is covered by the retail margin.

However, the second type of capital required by the electricity retailer is prudential capital, and the volume of this prudential capital required in the Australian electricity market is a barrier to entry for retailers.

For a non-vertically integrated incumbent retailer of the type identified as the model retailer within the Authority's 2012-13 Determination, most of the prudential capital required by AEMO is managed through the acquisition of either reallocation hedges, or straight hedges with separately purchased reallocation credits available through a traded market. Under a reallocation hedge – or through a reallocation certificate – the guarantee requirement is passed to another party, say a generator.

One of the core reasons for a retailer to acquire their own generation or reallocated Power Purchase Agreements is to access reallocation certificates. For most retailers, accessing bank guarantees to cover their entire load with AEMO (and note that the NEM is a gross market rather than a net market) is both prohibitively expensive and prohibitively leveraging. Therefore, most retailers either hedge their full load using straight hedge cover with reallocation credits purchased against all of it, or use reallocation hedges of the type dismissed by ACIL.

In 2012-13 the Authority argued that the cost of prudentials was a national retail cost which was implicitly included in the IPART benchmark which formed the basis of the estimate of Retail Operating Cost. However, this did not take into account the fact that IPART – by virtue of their having LRMC as a floor at the time – assumed a vertically integrated model retailer. In the Authority's case, neither of these assumptions are correct.

Therefore the cost of reallocation certificates – currently around $0.75 / MWh – should be applied to the wholesale energy cost as an unrecognised cost of electricity retailing.

*Section 3.3 How could appropriate time of use signals be included in energy cost estimates under the current metering and settlement arrangements?*

In Queensland, network Peak and Offpeak price ratios have actually converged over time, despite a general view that load factor is deteriorating and that this is one of the reasons for spiralling network costs (in the words of the Productivity Commission). There is currently significant load-shifting potential latent in simple Time of Use accumulation meters, without the requirement to worry about the installation of smart meters. But for this potential to be realised, customers with Time of Use accumulation meters require a significant financial incentive to shift out of Peak pricing periods and into Offpeak.

Under the current structure of the network tariffs – and hence notified prices – there is limited rationale to shift and so the opportunity to potentially increase the network's load factor and defer network augmentation is lost, increasing permanently the cost to the customer base. In this case, QEnergy would support the Authority in encouraging the distribution businesses to ensure that Peak and Offpeak pricing signals are appropriate to shift behaviour, and institute a consultation and education campaign designed to take the consumer on that journey.

QEnergy would also support the application of wholesale market Peak and Offpeak prices to the wholesale energy cost component of notified prices, further reinforcing these incentives. In this way, significant mileage can be made through better usage of existing assets without the requirement to spend money on new technologies.

*Section 3.4.2 Could ACIL's approach to estimating carbon costs be improved?*

QEnergy is not clear why ACIL is required to estimate the costs of carbon given that carbon pricing is now a law, and seems likely to remain so until the end of the 2013-14 period. Admittedly, this will be a more difficult question for the 2014-15 Determination.

*Section 3.4.2 How should the Authority estimate retailers' costs of complying with the ERET scheme? What factors should be considered in forecasting the REC costs likely to be incurred by retailers in the SRES and LRET markets? Do stakeholders agree with using clearing house prices in estimating SRES costs, or would market prices be more appropriate? How can the proportion of STCs sold through the clearing house be calculated? Do stakeholders agree with using non-binding STP targets for 2014 and future years? Are there any better forecasts that the Authority could use? How should the Authority deal with variations from the STP targets used in determining 2013-14 prices? Are there any other issues that should be considered in estimating this cost component?*

QEnergy does not support the unaltered use of market contract data to estimate the costs of LRECs, because the issues associated with using market data for 'black' energy costs also apply to environmental markets. If the Authority chooses to use observable market contract data as the basis for pricing LRECs, then a premium for price volatility should be applied as per wholesale market energy costs, which can be estimated using historical data on contract price volatility over an annual term. QEnergy supports ACIL's view that the clearing house price of $40 should be used to price SRECs.

A further important issue is the history of forecast error associated with the non-binding estimates of the STP published by the Clean Energy Regulator.

When the 2011-12 Determination was made, the SRES percentage for 2012 was published by ORER (now part of the Clean Energy Regulator) at 16.75%, which was downwardly revised by ACIL to 9% in their calculations on the basis that the scheme was changing. Announcements as to STP are given below:

| Publication Date | 31/03 | 29/07 | 16/12 | Final |
|---|---|---|---|---|
| **2012 SRES Percentage** | 16.75 | 20.87 | 23.95 | 23.96 |

At 1.43 times the original estimate, this is a forecast error of 43% from the non-binding STP in place at the time of the final determination, and a forecast error of 167% from the estimate used by ACIL. Extraordinarily, there was no makegood to the final figure of 23.96%.

A similar issue has now occurred in the 2012-13 Determination. At the time when the Determination was made, the SRES percentage for 2013 was published by ORER at 7.94%. Announcements as to STP are given below:

| Publication Date | 30/03 | 19/10 | Final |
|---|---|---|---|
| **2012 SRES Percentage** | 7.94 | 18.76 | 18.76 |

At 2.36 times the original estimate, this is a forecast error of 136% from the non-binding STP in place at the time of the final determination. Again, there has been no makegood to the final figure of 18.76% – in both of the last two years electricity retailers rather than customers have been paying the Federal Government for compliance with these schemes.

Given the history of significant underforecasting of STPs for the second half of the Authority's Determination period, QEnergy suggests applying an uplift to the non-binding STP in place at the time. Given no makegood has been made on this element of either of the last two years' STP forecasts, it appears reasonable to apply last year's underforecast of 136% to the current target of 7.69%, giving an allocation of 18.15%.

*Section 3.4.3 How should the Authority estimate NEM participation fees and ancillary services charges incurred by retailer?*

QEnergy supports the Authority's proposed approach in dealing with NEM participation fees and ancillary services charges.

*Section 3.5 How should the Authority take account of energy losses that occur between the regional reference node and the retail customer?*

QEnergy supports the Authority's proposed approach in dealing with the application of energy losses.

*Section 4.2 Is the Authority's 2012-13 approach to determining the retail operating cost allowances appropriate to use for 2013-14? If not, what is an appropriate alternative approach and why would this be superior? Have there been any recent developments that would suggest a significant change in current costs has occurred?*

As noted above, QEnergy considered in its 2012-13 submission that the major flaw in the methodology underpinning the estimation of Retail Operating Costs was that in QEnergy's view, the Authority did not address the costs of providing prudential capital to operate in the NEM, nor indeed acknowledge the expected increase on 1 July 2012 as a result of the impact of the introduction of carbon.

To recap, AEMO, generators and distributions businesses all require bank guarantees in return for extending credit to the retailer. QEnergy concedes that the cost of provision of guarantees to distribution businesses could be considered to be implicit within IPART's operating costs since it is independent of whether or not the underlying retailer is vertically integrated, but this is absolutely not the case with guarantees required by AEMO or by hedge providers such as generators.

In the discussion above, QEnergy also dealt with the bulk of prudential provision to AEMO through the costs of reallocation certificates. However, the cost of providing residual prudentials to AEMO as well as to generators has not yet been considered. In 2012-13, the Authority dismissed these concerns on the basis that this cost was a national retail cost which was implicitly included in the IPART benchmark which formed the basis of the estimate of Retail Operating Cost. Again, however, this did not take into account the fact that IPART – by virtue of their having LRMC as a floor at the time – assumed a vertically integrated model retailer. In the Authority's case, neither of these assumptions are correct.

QEnergy strongly considers that the Authority should take account of the cost of prudentials to the Authority's non-vertically-integrated model retailer, as they are clearly not included in the underlying IPART benchmark.

The costs of prudential capital are a function of the actual amount of capital required by providers, and the cost of capital to the retailer. Both of these elements are significantly determined by the credit rating of the retailer, a point on which the Authority has been is silent. Given that, out of the three incumbents across Australia – TRUEnergy, AGL and Origin Energy – two have sub-investment grade and one an investment grade rating, QEnergy considers that modelling the retailer as having a sub-investment grade (BBB) rating and consequently funding costs, prudential requirements and expected returns is appropriate.

However, QEnergy recognises that setting the funding costs based on market participants rather than benchmarking may be difficult. At the very least, though, comparisons should be drawn between the allowable rate of return for regulated monopolies relative to the amount allowed for retailers. Retail risks are significantly higher than those of a regulated monopoly:

- retailers are subject to competition and can lose customers easily;
- retailers have much higher uncertainty around price inputs – the Australian electricity market is the most volatile commodity market in the world;
- the Authority's determination period is shorter than that of AER for distributors (one versus five years);
- retailers have a much greater challenge in raising funds because of the less securitisable nature of the assets on retailer balance sheets (customer cashflows versus hard assets such as transformers or generators).

QEnergy considers that the cost of or return on capital allowed by the Authority in calculating the cost of prudential capital should reflect returns appropriate to a sub-investment grade entity. However, if this is not possible, they should be on a par with that of the regulated distribution businesses operating in Queensland, ENERGEX and Ergon Energy. This was determined by the Australian Energy Regulator to be 9.72% in the most recent Distribution Determinations, and is the figure that has been used for calculation throughout.

The indicative costs of providing prudential capital to allow operation in the market for the non-vertically integrated incumbent model retailer are given below. QEnergy considers that the Authority should include an explicit allowance for these costs in Retail Operating Costs.

### *Cost of prudential provision to AEMO*

Support for AEMO prudentials is calculated by AEMO on a quarterly basis with the method published on the AEMO website. Most retailers use the reduced trading limit methodology which in gross terms requires a guarantee to support only the time period between consumption of the energy and the payment to AEMO, approximately four weeks.

As noted above, non-vertically-integrated retailers partially offset the guarantee requirement by purchasing a reallocated hedge. However, this is only a partial offset as seven days and the GST portion of the energy cost cannot be covered by the reallocation transaction.

Unusually, in AEMO's case the guarantee is required to be one hour callable, thus incurring additional cost and substantially increasing barriers to access.

The cost of funding the residual unreallocated load can be calculated as follows:

{(ave daily load x regional reference price x volatility factor x loss factor + GST) x credit time period} – {(ave daily reallocated load at the node x regional reference price x volatility factor) x (credit time period – reaction time period)} x (cost of capital + cost of guarantee)/365

Following the introduction of a carbon price on 1 July 2012, Queensland pool prices increased from this average of $29.07 / MWh (2011-12) to $56.18 / MWh (2012 / 13). This is a 93% increase, which is accompanied by an increase in the prudential requirements to AEMO of the same magnitude. QEnergy calculates the AEMO residual prudentials cost for the 2012-13 financial year as follows:

{(1MWh * $56.18 * 1.5 * 1.05) * 1.1) * 42} – {(1.05MWh * $56.18 * 1.5) * (42-7)} * (0.0972+0.025) / 365

= $0.33179 /MWh

Note that average daily load is at the meter and therefore the calculation specifically includes a grossup for loss factors. On the other hand, reallocated load volume is at the node and consequently needs to be grossed up for loss factors.

Regional reference prices and volatility factors are based on current levels as published by AEMO.

Cost of funding is assumed to be at the level allocated to ENERGEX and Ergon Energy in the last distribution determination (9.72%).

Banks are currently charging 2.5% administrative charges for the provision of a bank guarantee against cash (the capital assumed to be priced at 9.72%).

This cost should be added on to the variable notified prices as part of Retail Operating Costs.

### *Cost of prudential provision to hedge providers*

Hedge providers require bank guarantees to cover the potential future credit exposure for the hedges they provide. This is calculated by summing the notional hedge amount (volume by price) for each hedge and then applying the 10% for the hedges maturing in the next 12 months and 12% for hedges maturing beyond 12 months.

For each MWh hedged this is calculated as:

(volume in MWh x price in MWh x 10% for first 12 months x 12% for remainder of hedge) x (cost of capital + cost of guarantee)

Using the hedge costs (including carbon) for the 2012-13 Determination, this result is:

(1MWh x $61.49 / MWh x average 11%) x (0.0972 + 0.025) = $0.8266 / MWh

This cost should be added on to the variable notified prices as part of Retail Operating Costs.

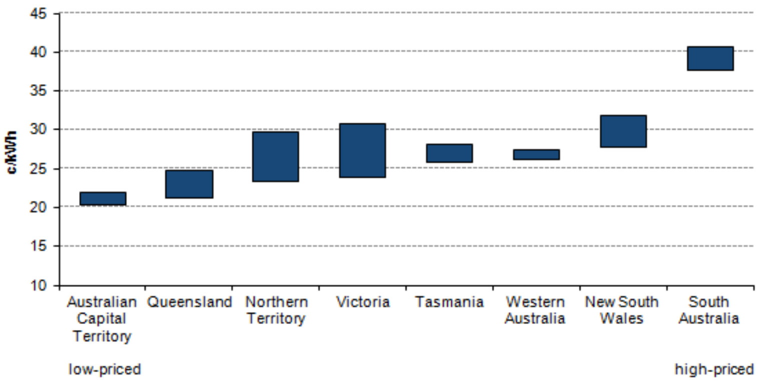
### *Other cost elements*

With respect to the retail component of costs, the 2012-13 Determination is predicated on costs appropriate for a retailer of scale, and so should be recognised as being set at low levels as scale benefits have already been accessed. From this perspective, QEnergy does not understand why the Authority should have articulated that it considers Customer Acquisition and Retention Costs (CARC) to be generous at $43.27 / customer. This is well below dealable levels in the market, since outsourced or broked customers are costing [redacted] / customer.

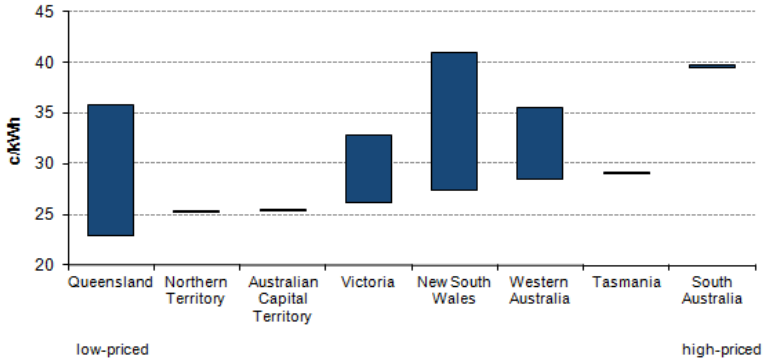
*Section 5.1 What matters should the Authority take into account to assess the effectiveness of competition in SEQ? What information could assist the authority in this task? What impact has the level of headroom had on competition in SEQ? Are there other factors impacting on competition in SEQ? How could these be addressed? What else should the Authority take into account in determing the appropriate level of headroom?*

Under the current regulatory structure, notified prices are the benchmark for small customer products because customers must be offered the option of returning to them. If the level of these prices is set too low, then the fuel for competitive discounts will not exist.

This is the case in Queensland, which according to the Office of the Tasmanian Economic Regulator has the second lowest level of notified price in Australia, above only the Australian Capital Territory where competition is effectively non-existent:




South-East Queensland also has the lowest level of business customer prices in Australia (these are represented by the bottom of the bar below, but the comparison is somewhat confounded by the transition of large customers in the Ergon Energy area off tariff onto market contracts who are represented by the top of the bar):




Comparative pricing should be used therefore as a sense-check on notified prices in support of competition.

The Queensland Government's Interdepartmental Working Committee has also been looking at switching levels, questioning why Queensland's switching rates – another indicator of competition – have fallen over the last two years.  QEnergy considers that when the QCA commenced its methodology review process in 2009, the Queensland market became one fraught with regulatory risk because the level of the notified price determines the competitive prospects for competition and so competition effectively became at risk.  This risk has been borne out in Queensland with significant price falls for small business, which left no headroom for competition within the Queensland market.

Subsequently both QEnergy and AGL have publicly stated that we have withdrawn from active marketing within the region, as have other retailers in closed fora.  This heightened regulatory risk, and removal of active marketing by retailers, is the reason for the fall in Queensland's rate of customer switching.

The regulatory stance mitigating against competition in Queensland was further exacerbated by the Government's freeze on Tariff 11 prices, and retrospective introduction of Terms and Conditions relating to exit fees within contracts.  All of these factors, as well as an opening up of competition in Victoria (which is fully deregulated and highly effective) and NSW in particular, meant that other markets became more interesting for retailers to focus their sales teams.

These elements suggest that to counteract these negative impacts on competition, headroom should be increased within the Authority's determination above the current levels.

With respect to this level of headroom, in the 2012-13 Determination the Authority based its decision to set headroom at 5% on an analysis of what it perceived to be available headroom in the original Benchmark Retail Cost Index (albeit predicated on a flawed assessment of wholesale energy costs).  The Authority found it to be 6% for Tariff 11 customers and between 12% and 23% for other customers.

Even given that the Authority dismissed the idea of using the higher levels of headroom on the basis that most customers are domestic, the impact on competition outlined above would suggest that headroom should have been set in 2012-13 at the very least at the 6% defined by the Authority in its historical analysis.  QEnergy advocates at least this modest increase in headroom levels.

*Section 5.2 The Authority seeks stakeholders' views on whether the Authority should include a catch-up mechanism if it is able to do so and what events this should be applied to?*

As noted above, regulatory events have occurred, particularly associated with environmental schemes, which have adversely impacted retailer margins during a Determination year, and which have not been passed through.

QEnergy considers that the maintenance of a price reopening mechanism in the price setting framework is imperative. Changes to law and regulatory disruption should form the triggers for this mechanism. These changes might include any changes to the percentage allocations of any renewable energy schemes, which have an extremely material impact on the costs for retailers in providing supply to customers, or a price reopening Determination for the ENERGEX network business.

QEnergy hopes that this input is of use in the Authority's deliberations. As is the case for all matters, QEnergy remains open to discuss or clarify any matter relating to this request. I look forward to future dealings as we work towards a regime that rewards diversity, choice and customer service over time.

Yours sincerely

[redacted]

Kate Farrar
Managing Director