Benchmark Retail Cost Index for Electricity: 2011-12 – Draft Decision

AGL submission to the Queensland Competition Authority

Date: 11 February 2011

1. Executive Summary

AGL welcomes the opportunity to provide feedback on the Benchmark Retail Cost Index for Electricity: 2011-12 – Draft Decision.

AGL continues to support the QCA's general approach to the BRCI, which is largely reflective of its approach in previous years. However, AGL does have some concerns with the manner in which particular elements of the BRCI for 2011 - 12 have been calculated. In particular:

- The LRMC is not based on the most recent public LRMC input data, namely that developed by ACIL for the DRET and AEMO as part of the consultation on the Energy White Paper.
- The allowance for the cost of SRES compliance is significantly below retailer's actual cost; and
- The calculation of the costs of compliance with the GEC liability appear flawed.

AGL is of the view that most of these issues would be most effectively explored by having a workshop with ACIL, stakeholders and the QCA.

LRMC Methodology

AGL is concerned that ACIL has not used the most recent public capital cost data in respect of the LRMC, with the most recent public data being that data prepared and published by ACIL as part of the work it did for AEMO and the Department of Resources and Tourism (***DRET***) in 2010 in respect of the Energy White Paper process. While the work involved the composition of several scenarios, the report prepared by ACIL[1] setting out the supply assumptions for each scenario (**ACIL 2010 Report**) clearly identified a 'central' set of capital cost data, against which all scenarios were compared. Further, Scenario 3 presents a set of 'average' assumptions in respect of other input data, which AGL believes present a more robust and credible data set than those developed by ACIL for the sole purpose of the BRCI. AGL has referred in this submission to the central capital costs and other Scenario 3 inputs as the ***ACIL 2010 Data***. This data was also used in the preparation of the National Transmission Network Development Plan 2010 by the Australian Energy Market Operator (***AEMO***) and would be an appropriate up-dated data set to be used in the QCA's LRMC model.

ACIL has acknowledged that it is appropriate to update the input data from that used in the 2010 – 11 BRCI, but instead of using the ACIL 2010 data, ACIL has instead sought to develop a different set of data. While the data being used is based on the ACIL 2009 Data[2], it has been adjusted in a manner that AGL does not understand, and in a manner that appears to be inconsistent with the ACIL 2010 Data.

AGL's detailed comments in respect of some apparent anomalies in the LRMC data are outlined below. AGL remains firmly of the view that the most appropriate data set is the publicly available, and widely accepted, ACIL 2010 Data, and seeks clarification from ACIL

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[1] Preparation of energy market modelling data for the Energy White Paper, Supply Assumptions Report, (Prepared for AEMO/DRET - 13 September 2010)

[2] ACIL Tasman, Fuel resource, new entry and generation costs in the NEM - Final Report. Prepared for the Inter-Regional Planning Committee, April 2009.

as to why the most recent data has not considered in preparing the LRMC for the Draft Decision.

Energy Purchase Cost Methodology

AGL remains broadly satisfied with the approach used to calculate energy purchase costs (***EPC***).

AGL notes that the impact of a lower average pool price will depend upon the assumed hedging strategy. AGL believes that it would also be useful to discuss at the workshop the potential impact of the change to the pool price trace.

Enhanced RET Scheme - SRES

The manner in which the cost of compliance with the SRES under the amended Renewable Energy Target scheme (***RET***) has been calculated does not fully account for a retailer's costs, and therefore does not accord with the legislative requirement that the costs allowed reflect the likely total costs to be incurred in purchasing energy to supply the relevant customers. AGL notes in this respect that:

- Retailers are incurring the costs from 1 January 2011 onwards, while the current approach only captures those costs incurred from 1 July 2011 onwards;
- The methodology has not captured the full amount of costs incurred from 1 July 2011. The ACIL estimate of the 2012 STP which is being used for the purpose of the BRCI is the lowest estimate prepared by ACIL for the Office of Renewable Energy Regulator (**ORER**), rather than the estimate referred to by ACIL as the 'Best Estimate'. In addition, the estimation of small-scale technology certificate (**STC**) creation volume in 2012 does not appear to be on the same basis as the 2011 STP estimate accepted by ORER. AGL does not believe the ACIL approach to estimating the 2012 STP is appropriate, nor that there is sufficient explanation provided as to its reasons for adopting this estimate.

AGL is of the view that in order for the QCA to comply with its legislative requirements it needs to address these issues and ensure that the costs of compliance are appropriately allowed for in the BRCI.

Enhanced RET Scheme - LRET

The Draft Decision calculates the LRET compliance cost with reference to the market price only, rather than accepting AGL's submission that the cost of compliance should be calculated with reference to the LRMC of renewable generation. AGL remains of the view that for the compliance cost of LRET to be fully captured, it should be based on the LRMC of renewable generation.

In relation to the market approach used in the Draft Decision:

- Using the information presented in the Draft Decision AGL is unable to replicate the calculation of the 2011-12 LGC price. AGL requests that the QCA provide further information on the methodology used by ACIL to determine the 2011-12 LGC price;
- AGL is unclear as to the source of the LRET RPP for 2011 of 5.08%. ORER have published the final 2011 LRET RPP as 5.62%; and
- AGL does not agree that ACIL's forecast for the 2012 LRET RPP is the most likely outcome in the circumstances. AGL is of the view that a more likely 2012 LRET RPP is 8.66%.

Queensland Gas Scheme

AGL is surprised to note that the QCA have changed their methodology in respect of calculating the costs of compliance with the Queensland Gas Scheme. ACIL and the QCA have not adequately addressed the issue of liquidity in the GEC market, which as they note, is a significant reason the penalty price has been considered the appropriate reference in previous BRCI processes.

Network Costs

AGL understands the constraints imposed by the BRCI legislative provisions. AGL remains concerned that:

- In using the average Energex and Ergon aggregate annual revenue requirement (AARR), the BRCI will not accurately capture the changes incurred in Energex's patch over the period; and
- The BRCI makes no allowance for the ability of Energex to re-balance its tariffs with the AARR increase.

Retail Costs

AGL continues to support a 'benchmarking' approach to calculate retail costs. AGL is of the view that a retail margin of 5%, as used in the BRCI 2010-11, is too low to cover the associated costs and risks of being an electricity retailer in Queensland with an obligation to supply regulated customers.

2. General Comments

AGL welcomes the opportunity to provide feedback on the *Benchmark Retail Cost Index for Electricity: 2011-12 – Draft Decision*.

AGL looks forward to continuing to work closely with the QCA through this year's BRCI process to ensure that the views of stakeholders are addressed as part of the process. To that end, AGL suggests that it would be appropriate for the QCA to convene a stakeholder workshop for electricity retailers and other relevant stakeholders to provide their views to the QCA in regards to the issues raised in this and other stakeholder submissions.

3. Cost of Energy

3.1. Long Run Marginal Cost Methodology

AGL supports the continued use of the LRMC in setting the wholesale energy cost component of the regulated tariff in all jurisdictions. AGL does however have some concerns with the manner in which ACIL Tasman has approached the LRMC calculation, as described in *Calculation of energy costs for the 2011 – 12 BRCI, Draft Report of 16 December 2010* (***ACIL's 2011-12 BRCI Report***), for the purpose of the Draft Decision, and these concerns are outlined below.

3.1.1. LRMC Input Data

Failure to use ACIL's 2010 Input Data

AGL understands the QCA's LRMC draft decision is based on ACIL's capital cost projections from its 2009 report to the then National Electricity Market Management Company[3] (***ACIL 2009 Data***). AGL is concerned to note that ACIL has chosen to use the ACIL 2009 Data as the basis for its LRMC calculation, rather than use the more recent capital cost data it prepared in 2010 as part of the Energy White Paper process. AGL notes that while the work involved the composition of several scenarios, the report prepared by ACIL[4] setting out the supply assumptions for each scenario (**ACIL 2010 Report**) clearly identified a 'central' set of capital cost data that forms a base case, and an 'average' scenario which identifies the 'base case' for other input data (***ACIL 2010 Data***). AGL notes that this ACIL 2010 Data has been used in the preparation of the National Transmission Network Development Plan 2010 by the Australian Energy Market Operator (***AEMO***), and that AEMO supported the use of this data in the context of the South Australian regulated price review[5]

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[3] ACIL Tasman, Fuel resource, new entry and generation costs in the NEM - Final Report. Prepared for the Inter-Regional Planning Committee, April 2009.

[4] Preparation of energy market modelling data for the Energy White Paper, Supply Assumptions Report, (Prepared for AEMO/DRET - 13 September 2010)

[5] AEMO: "ESCOSA Standing Contract Price Review", 20th August 2010, p.10. AGL notes that the ACIL 2010 Report was not publicly available at the time ESCOSA made its Final Determination.

ACIL 2010 Data most appropriate input data

In regards to the ACIL 2010 Data, AGL notes that:

- The Energy White Paper process was conducted by the AEMO/Commonwealth Government Department of Resources, Energy and Tourism (***DRET***), and ACIL spent a significant amount of time consulting on capital costs for generation, working in conjunction with the Electric Power Research Institute (***EPRI***) and receiving significant feedback from a diverse Stakeholder Reference Group (***SRG***) during the consultation period.
- The work focussed on developing several scenarios, and identifying the appropriate LRMC input data for each scenario. In the ACIL 2010 Report, ACIL details the various scenarios. AGL observes from this report that:
    - There is a 'central' set of capital cost assumptions, which form the basis of the capital cost analysis. These capital costs, referred to in the ACIL 2010 Report as the 'central estimates', are based on the EPRI data adjusted in line with the feedback from the SRG. These provide the reference point for all of the scenarios; and
    - Scenario 3 appears to be the scenario which captures the 'average' or 'medium' ground on the input parameters, with the other scenarios designed to reference to the 'average'. AGL is of the view this suggests the input data used in Scenario 3 would be appropriate for the purpose of the BRCI analysis.
- AGL understands that the findings in the report are generally supported by industry. The ACIL 2010 Data has been on AEMO's website for some time, and AEMO published a summary of the ACIL 2010 Data.

<u>Capital Costs – clearly articulated 'central' case</u>

- The consultation process resulted in robust cost assumptions for a complete range of generation technologies for Australian conditions. As is clear from the ACIL 2010 Report, the EPRI capital cost data, as adjusted in consultation with the SRG, forms the basis of the ACIL 2010 Report.

    > *The capital costs of each technology covered in the study are derived from the data provided by EPRI with amendments as agreed by the Stakeholder Reference Group on 23 December 2009 and 30 April 2009*

- As noted above, the ACIL 2010 Report refers to a number of 'scenarios', with the central case for capital costs is that articulated in Table 18 at page 24 of the ACIL 2010 Report, titled 'Assumed Capital Costs – central estimates'. These capital cost are referred to as the 'average' capital costs, and the different capital cost scenarios are defined with reference to deviations from this 'average'.
- On this basis, AGL believes it is clear that the 'central' or 'average' capital costs articulated in Table 18 of the ACIL 2010 Report is the most appropriate capital cost data to be used for the purpose of the Draft Decision. AGL would ask for a detailed explanation from ACIL as to why these 'central estimates' of capital costs are not appropriate in the event ACIL does not use these capital costs.

<u>Other input data – Scenario 3 data presents more robust basis for 'base case'</u>

- AGL observes from Tables 12, 13 and 14 on pages 18-20 of the ACIL 2010 Report, that Scenario 3 appears to be premised on a set of inputs that are described as ‘average’ and/or ‘medium’, thereby suggesting this presents a scenario analogous to a ‘base case’.

- While AGL accepts that the ACIL 2010 Report does not identify a ‘base case’, AGL is of the view that the input data used in Scenario 3 must present a more reasonable basis on which to proceed than the development by ACIL, without any consultation, of a set of input costs solely for the purpose of the Draft Decision.
- In the event ACIL remains of the view that it is appropriate to develop a separate set of input data solely for the purpose of the BRCI, then AGL would ask ACIL to clearly explain why the input data from Scenario 3 is not appropriate, and why it believes the data it has developed for the BRCI should be considered to be more robust and credible than that presented in the ACIL 2010 Report.

ACIL’s updated data for the BRCI is not preferable to the 2010 ACIL Data

ACIL has conducted a review of the ACIL 2009 Data for the purpose of the 2011 – 12 BRCI Draft Decision, and it appears that they have provided an ‘update’ on some of the data and this up-date does not align with the ACIL 2010 data. Therefore, while ACIL and the QCA have accepted that it is necessary to use ‘updated’ data, thus implying that the ACIL 2009 Data is no longer appropriate, they have not accepted the ACIL 2010 Data, despite it being public and compiled with reference to robust methodologies.

AGL does not believe that an analysis performed by ACIL, solely for the purpose of the 2011 - 12 BRCI should be considered an appropriate substitute for the analysis underpinning the ACIL 2010 Data. AGL is further concerned by the opaque nature of the assumptions which appear to underpin these data points. AGL has outlined its concerns with these assumptions below, and notes that all of these issues would become irrelevant if the ACIL 2010 Data were used as suggested.

AGL does not understand why ACIL has used data which does not accord with the ‘average’ and ‘central’ data set identified in its ACIL 2010 Data (AGL’s comment on the data used by ACIL in the Draft Decision is outlined below). At present, ACIL has provided no explanation for the divergence, and has not even referred to the ACIL 2010 Data in the Draft Decision. If ACIL believes the data used in BRCI analysis is to be preferred, then this must be adequately and clearly explained.

AGL is of the view that this issue should be discussed at a workshop.

Forecast methodology for fuel costs

<u>Methodology not consistent across fuels</u>

AGL is concerned there is an inconsistency in approach in how ACIL has adjusted the fuel costs from the ACIL 2009 Data.

Section 2.3.6 of ACIL’s 2011-12 BRCI Report describes the basis for the coal and natural gas cost forecasts used in the LRMC modelling. Natural gas price projections are derived from ACIL’s proprietary gas market model – *GasMark*. From the description of the modelling process and the prices for natural gas provided it appears that the new entrant gas price represents the marginal cost of gas production based upon a range of supply assumptions for “existing and known, but undeveloped field developments and an assessment of undiscovered conventional and yet-to-be certified CSG resources”[6].

AGL supports the modelling of fuel costs for LRMC modelling based upon the marginal cost of fuel supply over the relevant time period for the modelling i.e. fuel costs in this report should represent the long term marginal cost of fuel production.

[6] p16. ACIL Tasman, Calculation of energy costs for the 2011 – 12 BRCI. Prepared for the Queensland Competition Authority, Draft Report of 16 December 2010).

AGL is concerned that coal prices used in the LRMC modelling have not been considered on a consistent basis, and appear to have been determined with reference to prices under existing coal supply contracts. ACIL's 2011-12 BRCI Report states:

> *In arriving at black coal costs in NSW and Queensland for use in the LRMC we have averaged the coal prices into existing stations. This has been done on the assumption that the existing coal supply sources will be available to the new build coal stations in the calculation of the LRMC.*[7]

AGL is not persuaded that this approach will adequately represent the long term cost of securing a coal supply for a new entrant power station. Whilst many of these fuel sources will continue to be operational as these new entrant power stations are commissioned AGL believe it is unreasonable to consider that new entrants will negotiate an average of existing fuel costs. AGL suggests that if ACIL continues to use 'adjusted' data from the ACIL 2009 Data, rather than using the ACIL 2010 Data, then the coal costs should be modelled on a marginal cost basis within the relevant regions of QLD and NSW to better represent the cost to new entrant power stations.

<u>Possible calculation error</u>

AGL seeks clarification on how the "Coal price used in LRMC modelling", shown in Table 10 of ACIL's 2011-12 BRCI report, was calculated (Table 10 – Coal prices into Queensland power stations (A$/GJ, 2011-12 prices)). The corresponding "Coal price used in LRMC modelling" shown in Table 9 is the arithmetic mean of the coal prices for existing stations. The "Coal price used in LRMC modelling" in Table 10 appears to be calculated using a different method.

Unit sizes used in LRMC calculation

It would appear from the ACIL Tasman LRMC Results (shown in Table 13 – ACIL 2011 – 12 BRCI Report) that *Plant capacity (MW)* has been calculated using a 'relaxed integer' approach i.e. calculating system capacity on an incremental per MW basis. AGL acknowledges that in the context of the BRCI, if this approach is used consistently from year to year then it should capture the rate of change of the LRMC of total capacity required to meet system requirements. However, in developing a cost stack of elements within the BRCI then not accounting for specific unit sizes in the *Plant Capacity (MW)* calculation then this will underestimate the LRMC of the system.

AGL requests that the QCA provide clarification on whether specific unit sizes were assumed in the calculation of the LRMC, or whether a 'relexaed integer' approach has been adopted.

3.1.2. SRMC calculation methodology

Notwithstanding the issues in relation to the input data used, AGL is concerned that there may be an issue in respect of the calculation of the SRMC of CCGT. Table 2 below summarises AGL's analysis of the SRMC calculations, which are then used to calculate the LRMC:

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[7] p14. Ibid.

Table 2 – SRMC Calculation Summary

	Fuel price	HHV	-	VOM	SRMC	SRMC in 2011-12 Draft Decision
	$/GJ	(sent-out)	GJ/MWh	$/MWh	$/MWh	$/MWh
SC Black	1.26	40%	9	1.29	12.63	12.61
CCGT	4.46	50%	7.2	1.13	**33.24**	**28.36**
OCGT	5.57	31%	11.6129	8.08	72.76	72.76

AGL understand that the difference is likely due to a discount on the CCGT SRMC related to GEC revenue. AGL would welcome the opportunity to discuss this matter further with ACIL and the QCA in order to understand this approach.

3.1.3. WACC for new entrants

In calculating the LRMC of electricity generation, assumptions relating to the cost of capital can significantly affect the wholesale energy costs of an electricity retailer. AGL is broadly satisfied with the approach adopted by ACIL to estimate the weighted average cost of capital (WACC) and its use in calculating the LRMC. However, there are a number of assumptions with the calculation of the WACC which AGL believes does not accurately represent the WACC for electricity generators in a 'greenfields' context.

Debt margin premium

ACIL has used a debt basis premium of 300 points to calculate the WACC. ACIL note that this is the same as that used in the 2010-11 BRCI. AGL is of the view that this debt margin does not adequately represent the level of debt margin experienced by developers of electricity generation projects, and therefore underestimates the WACC relevant in calculating the LRMC of electricity generation in Queensland.

The level at which debt margin is set depends upon a number of factors:

- The business and financial profile of the entity seeking debt funding. This is often represented as a credit rating;
- Type of financing i.e. bonds, private debt placement, bank debt etc; and
- Financial market conditions

In a range of recent regulatory submissions[8] AGL has argued that taking a 'one-size fits all' approach to estimating debt margin and using it to estimate the cost of debt for an electricity generation project does not adequately reflect the level of risk for an electricity generation project.

ACIL uses reference to a recent IPART paper, *IPART's Weighted Average Cost of Capital, Final Decision (April 2010)*, to confirm the 300 points debt basis premium. ACIL states:

"IPART indicate a debt basis premium of about 280."

[8] AGL Response to the Independent Pricing and Regulatory Tribunal, Developing the approach to estimating debt margin. Other industries – Discussion Paper (November 2010)

This debt basis premium appears to be interpreted from a graph showing the debt margin for a set of securities (i.e. 'Traditional universe of securities') from January 2008 to April 2010. This sample of securities includes three BBB to BBB+ credit rated companies (i.e. Santos, Snowy Hydro and General Property Trust) and the Bloomberg BBB value yield (7 years).

AGL is of the view that comparing this debt basis premium to debt funding likely to be available to electricity generation developers is not realistic. Any comparison should be made to companies currently developing electricity assets.

Table 3 provides a summary of the recent credit ratings of a number of electricity sector businesses.

Table 3 – Credit ratings of Australian electricity sector participants

Business	Type	S&P Credit Rating	Status
Snowy Hydro	Generator	BBB+	Stable
Origin Energy	Vertically integrated retailer	BBB+	Positive
AGL Energy	Vertically integrated retailer	BBB	Stable
Loy Vic & IPM Australia ("Loy Yang B")	Generator	BBB-	Negative
Redbank	Generator	CCC-	Negative

Source: KPMG, Advice on Weighted Average Cost of Capital, October 2010.

Table 1 highlights the spread of credit ratings in the electricity sector, in particular the difference in credit ratings between merchant generators and retailers.

AGL also notes that there is no mention of using project financing as a source of data for debt basis premium. In the electricity sector, project financing has become a common feature in the financing of electricity generation projects. Margins on project finance transactions are generally higher than those for on-balance sheet transactions due to the higher level of gearing and increased risk due to the lower level of security (i.e. only the asset itself is available as security).

AGL is therefore of the view that in order for the debt basis premium to be appropriately assessed for the calculation of the LRMC, the cost of debt using project financing should be considered by QCA.

A selection of recent electricity sector project finance transactions is shown in Table 4.

Table 4 – Recent project finance transactions in the electricity sector

Project	Date	Amount	Tenor	Credit margin
Loy Yang A	Sep-10	A$490m	5 yrs	4.50% over BBSY
Collgar Wind	Mar-10	A$270m	5 yrs	3.50% over BBSY
Waubra Wind	Feb-10	A$338m	5 yrs	3.25 – 3.40% over BBSY
Hazelwood	Jan-10	A$740m	2.5 yrs	4.00% over BBSY

Source: KPMG, Advice on Weighted Average Cost of Capital, October 2010.

The project finance transactions listed in Table 4 indicate a debt margin of 3.25% to 4.50%; however this does not include upfront fees, financing risk (from short term nature of loans) and inclusion of facilities that were not up for renewal. It should be noted that in AGL's view the tenor of these transactions does not represent the average time to maturity for debt funding in the electricity generation sector. For most projects developers seek longer term financing to avoid the risks of refinancing. The project finance transactions in Table 4 have shorter tenor due to the higher levels of risk for electricity generation and correspondingly higher credit margins. The flow-on effect of this is that the gearing ratio needs to be adjusted to reduce the risk exposure to short tenor-high margin debt and increase equity requirements.

Project finance transactions are subject to upfront fees which are typically driven by the size and complexity of the transaction and the tenor of funding provided. The Hazelwood project finance transaction described in Table 4 incurred a 2% establishment fee i.e. 0.8% p.a. above the margin. AGL would highlight that these additional costs for other types of debt transactions should be reflected in the overall WACC.

AGL also notes that these recent transactions have a shorter tenor than historically is considered desirable in the electricity industry. For long term assets such as power stations project sponsors will typically seek debt to match the life cycle of the asset so as to minimise requirements for other more expensive sources of funding such as equity capital. This trend is largely due to conditions over the last 2-3 years referred to as the 'Global Financial Crisis' (GFC). The GFC resulted in a decline in capital market liquidity and the level of investors risk appetite. These factors combined to restrict the availability of financing, and hence increase the cost of long term debt.

Gearing Ratio

In Table 12 of the ACIL's 2011-12 BRCI Report the debt to equity gearing ratio of 60% debt & 40% equity has been applied. AGL is of the view that this gearing ratio is inconsistent with the debt basis premium applied for the financing of an electricity generation project.

The two financing options available are: on-balance sheet and project financing. On-balance sheet financing implies that the asset should be funded with the same debt to equity mix as the project sponsor's balance sheet to avoid potential deterioration in credit rating. This approach will generally involve a lower level of debt, however at a lower premium than a project financing approach. Project financing involves lending against specific assets and cash flows and is generally non-recourse to the project sponsor. These transactions usually employ higher levels of debt, and therefore due to the higher level of risk, they incur higher debt premiums.

In ACIL's 2011-12 BRCI Report if the current debt to equity ratio is maintained then AGL suggest that the debt basis premium should be increased (as discussed in the previous Section) to recognise the level of risk associated with this funding approach. However, if the current debt basis premium is maintained then the implied level of risk (i.e. on-balance sheet approach) should be reflected by adjusting the debt to equity ratio such that a greater proportion of equity is included.

3.2. Energy Purchase Cost Methodology

AGL remains broadly satisfied with the approach used to calculate energy purchase costs (***EPC***).

AGL notes that the impact of a lower average pool price will depend upon the assumed hedging strategy. AGL believes that it would also be useful to discuss at the workshop the potential impact of the change to the pool price trace.

3.3. Enhanced RET Scheme

AGL is concerned the Draft Decision does not appear to appropriately account for the costs of complying with the Enhanced RET Scheme.

From 1 January 2011, the Commonwealth Government's Renewable Energy Target (***RET***) scheme was split into 2 schemes - the Small-scale Renewable Energy Scheme (***SRES***) and the Large-scale Renewable Energy Target (***LRET***). As recognised by the QCA in its Draft Decision "*the introduction of the restructured scheme will need to be reflected in the calculation of the RET costs for 2011-12*" (page 9).

However, the QCA's Draft Decision does not fully account for the compliance costs incurred by retailers under the SRES and LRET. In fact, due to the following issues with the methodology adopted by the QCA in preparing the Draft Decision, the costs permitted in the Draft Decision fall significantly short of the costs a retailer will incur in complying with the amended RET scheme:

Small-scale Renewable Energy Scheme

1. The Draft Decision does not adequately address the costs associated with the changes to the RET scheme that have been incurred by retailers from 1 January 2011. The Draft Decision notes that the BRCI will adjust for the future impact of the scheme, however the proposed approach will embed a significant loss to retailers as they are not able to recover their costs for the SRES from 1 January 2011 through to 30 June 2011.

2. In forecasting SRES costs from 1 January 2012, the QCA applies ACIL's lowest estimate of certificate creation, with no explanation or justification of this approach. The adoption of this lowest estimate could result in a material underestimation of the actual number of certificates created in 2012 and therefore the cost incurred by retailers over the period. In addition, there is no mention in the Draft Decision of whether the QCA will consider ORER's non-binding estimate of the small-scale technology percentage (***STP***) for 2012 which is due to be released before 31 March 2011.

Large-scale Renewable Energy Target

1. As noted in AGL's previous submission, the split of current eligible RET activities between SRES and LRET means that historical renewable energy certificate (***REC***) prices do not provide an appropriate indication of future large-scale generation certificates (***LGC***) prices. Neither ACIL nor the QCA have addressed the issue that stems from seeking to use historical REC prices (based on a different set of regulations and eligible technologies) as a proxy for the long term price of LGC prices. AGL believes the LGC should be based on the LRMC of renewable generation.

2. The Draft Decision does not adequately describe the methodology used to calculate the 2011 and 2012 LGC price. Whilst AGL is of the view that the market approach does not properly represent the portfolio cost of a retailer, AGL requests that the QCA publish on its website the data and calculation methodology used by ACIL.

3. In AGL's view, the LRET compliance cost allowance has been underestimated as ACIL's 2011-12 BRCI Report refers to the penalty price being used to determine the LRMC. This appears to suggest that two different REC prices are being used by ACIL in its Energy Purchase Cost calculations.

4. The LRET renewable power percentage (***RPP***) for 2011 does not appear to be in line with the actual RPP for 2011 published in the *Renewable Energy (Electricity) Regulations 2001*, which took effect on 14th December 2011 and the calculation of the RPP for 2012 appears to underestimate the cost to liable entities.

Each of these issues is dealt with below.

3.3.1. SRES

Scheme Commencement on 1 January 2011

AGL is disappointed the Draft Decision doesn't make any allowance for the recovery of SRES costs from 1 January 2011.

As noted in AGL's earlier submission, the only way in which a retailer's costs could be covered is for a price change to take effect on 1 January 2011, or the price change from 1 July 2011 to include the costs incurred by retailers from 1 January 2011. AGL acknowledges that the QCA is bound by the legislative provisions that govern the BRCI which appear to preclude an out of cycle price change. However, AGL remains of the view that if the QCA wishes to maintain cost reflective pricing within the BRCI then the cost incurred by retailers should be acknowledged in the 2011-12 BRCI.

The QCA has indicated in the Draft Decision that it does not interpret the 2011- 12 BRCI to permit the inclusion of costs from 1 January 2011. The QCA's current approach to assessing the costs of compliance for 2011 - 12 is to identify the STP for the 'financial year' - taking the arithmetic mean of the relevant calendar year STPs, where the first year is known and the second year is 'forecast'. Forecasting the STP for 2012 is an extremely difficult task, and considerably more difficult than forecasting the LRET RPP, as the large scale RET scheme incorporates a target. The small scale scheme is uncapped, and therefore forecasting the trajectory of certificate creation is extremely complex.

An alternative approach which would avoid the need to forecast, and would more accurately reflect a retailers cost of compliance, would be to apply the published calendar year STP to the subsequent financial year i.e. apply 2011 STP (14.8%) in 2011-12. Whilst AGL acknowledge that the STC liability cost is accrued by retailers as the electricity is sold, this approach would represent a pragmatic solution which could be applied consistently into the future years of the BRCI, and would represent the rate of change of SRES costs borne by retailers.

2012 STP forecast

The forecast for the 2012 STP is based on analysis performed by ACIL for the Office of Renewable Energy Regulation (***ORER***) in November 2010. The report is titled *Small-scale Technology Certificates Data Modelling: Projected take-up of small-scale renewable technologies over calendar years 2011 to 2013* (***ACIL ORER Report***).

In setting the STP ORER is required to consider:

- The STC's that will be created in the relevant year. This is stated as a MWh value; and
- The total amount of 'relevant acquisitions' in the relevant year – i.e. how much electricity retailers will acquire, and the 'partial exemptions' expected to be claimed for the year.

AGL is of the view that ACIL has not used the most likely certificate creation scenario, and that the most appropriate 2012 STP is 12.57%, as set out in Table 5 below.

Table 5 – Estimation of 2012 STP

Likely Certificate Creation (STCs)	23,000,000
Forecast 2012 Load (MWh)	235,665,020
Partial Exemption (MWh)	52,757,183
STP 2012	**12.57%**

Further detail on the calculation of the Forecast 2012 Load (MWh) and the Partial Exemption (MWh) is provided in Annexure 1.

Likely certificate creation

AGL does not believe that the STC creation forecast for 2012 used by ACIL is the most likely scenario in the circumstances.

- *ACIL most conservative of all ORER modelling*

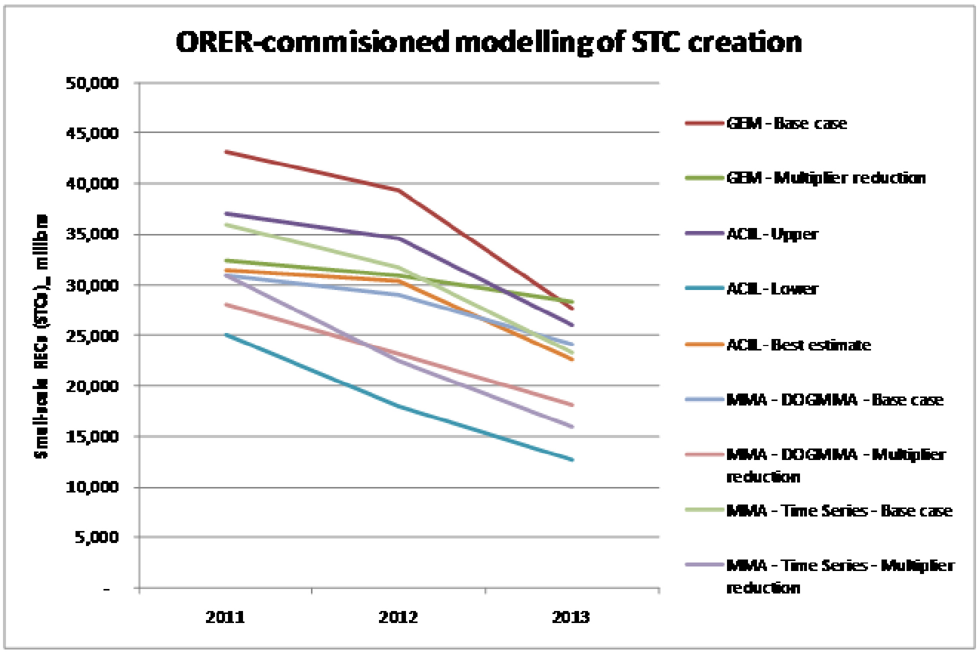
In determining the 2012 STP ORER commissioned three consultants[9] to model the STC creation for the years 2011, 2012 and 2013 with each consultant modelling three different scenarios. ACIL was one of these consultants.

ACIL referred to these three scenarios as the 'Upper', 'Low' and 'Best Estimate'. ACIL submitted these scenarios and its assumptions in the form of a report to ORER titled *Small-scale Technology Certificates Data Modelling: Projected take-up of small-scale renewable technologies over calendar years 2011 to 2013* (***ACIL ORER Report***).

A summary of the results of the modelling performed by the three consultants is set out in Figure 1 below. Figure 1 highlights that there is a significant range of estimates for the amount of STCs expected to be created from 2011-13.

[9] The three consultants engaged by ORER to provide forward estimates of the number of STCs likely to be created in the 2011, 2012 and 2013 calendar years were Green Energy Markets Pty Ltd, SKM-MMA and ACIL Tasman Pty Ltd.

Figure 1 – ORER commissioned modelling of STC creation



AGL also notes in this respect that the *ACIL-Low scenario* is predicated on a range of changes to state-based complimentary policies. For example, the *ACIL-Low scenario* assumes that Queensland and Western Australia will close their feed-in tariff schemes at some point during the projection period. AGL is of the view that this is an overly conservative assumption, and renders the *ACIL-Low scenario* inappropriate for use in the BRCI forecast. Current policy settings should be used as the premise of any forecast, unless there is a high probability that the policy settings will change. AGL does not understand this to be the case, and would seek clarification from ACIL if they believe there is a probability of change.

- *ACIL forecast inconsistent with 2011 STP*

In establishing the 2011 STP, ORER assumed that 28 million STCs would be created during the year. As can be seen in Figure 1 this estimate is closest to the '*MMA – DOGMMA – Multiplier reduction*' scenario i.e. 28,079,000 STCs in 2011.

AGL notes that the *ACIL - Low* scenario results in the lowest STC amount of all scenarios modelled, and the 2011 STC creation in the *ACIL-Low scenario* is significantly lower than the STC amount adopted by ORER. ACIL state that there is "significant uncertainty regarding the number of STCs created over this period (as highlighted by the size of the range) due to potential changes in rebates and feed-in tariffs over the period"[10], however AGL note that no explanation is provided as to why the assumptions used for 2012 have apparently changed so significantly from 2011.

AGL suggest that using a 2012 STC volume in line with the '*MMA – DOGMMA – Multiplier reduction*' scenario would more closely reflect the assumptions adopted by ORER in

[10] p 43 – 44. ACIL Tasman, Calculation of energy costs for the 2011 – 12 BRCI. Prepared for the Queensland Competition Authority, Draft Report of 16 December 2010).

determining the 2011 STP, and more closely reflect the actual, and therefore most likely relevant, policy settings.

Relevant acquisitions and partial exemptions

In publishing the STP, ORER do not provide any information as to the amount of electricity acquired for the year and the amount of partial exemptions expected to be claimed. It is necessary to form a view on these matters in order to forecast future STPs. AGL has therefore conducted an analysis, which is detailed in Annexure 1.

ORER 2012 STP Upper and Lower Bound Estimates

AGL also note that ORER will be releasing its non-binding upper and lower bound of STP for 2012 and 2013 by 31 March 2011. AGL is of the view that the QCA's forecast for 2012 should be the mid-point of this upper and lower band. AGL requests that the QCA provide further detail on how this ORER data might be used as part of the final decision.

3.3.2. Large-scale Renewable Energy Target

Changes to the RET and impact on LGC price

The Draft Decision calculates the LRET compliance cost with reference to the market price only, rather than accepting AGL's submission that the cost of compliance should be calculated with reference to the LRMC of renewable generation.

While AGL notes that ACIL have outlined reasons for this, AGL is disappointed to note that ACIL has not addressed one of the primary reasons suggested by AGL for the need to change, namely the impact that the separation of the RET into the SRES and LRET will have on the trajectory of the REC price.

AGL remains of the view that for the compliance cost of LRET to be fully captured, it must be based on the LRMC of renewable generation. This is most appropriate under the new split scheme as the LRET, by its very nature, is there to encourage investment in large scale renewable generation. Retailers, such as AGL, will invest in renewable plant with the expectation that the additional cost of this plant will be recovered through the LRET scheme, over and above that earned in the black energy market. AGL notes in this respect that ESCOSA accepted this methodology in determining the South Australian 2010 retail electricity price[11].

Calculation methodology for 2011-12 LGC Price

Notwithstanding AGL's view that the LRMC is the most appropriate means of assessing the likely cost of RECs due to the change to the RET scheme, AGL is concerned that the methodology being used by ACIL to determine the 2011-12 LGC price is not able to be replicated based on information available in ACIL's 2011-12 BRCI Report.

In ACIL's 2011-12 BRCI Report the calculation of the LGC prices from "AFMA data" is described as "using the averaging methodology set out in the CRA Report" with a reference to page 111 of *Calculation of the Benchmark Retail Cost Index 2009-10 (1 December 2009)*. In the CRA Report page 111 describes the following:

> *Based on AFMA data published from when it was first published (17 January 2007 for 2009 and 16 January 2008 for 2010) up to the cut off data for data for this report being 15 October 2008, the average REC price is $45.85 for 2009 and $58.32 for 2010.*

[11] 2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report & Final Price Determination, December 2010.

AGL has not been able to repeat the ACIL calculation. AGL request that the QCA clarify the following aspects of the averaging methodology:

- Confirm which statistical data from the weekly AFMA market survey is used to calculate the weekly price i.e. does ACIL us median of bid & offer mid points (excluding outliers) to determine average LGC prices; and
- Confirm the data period over which the weekly AFMA data is averaged to get the LGC price.

AGL requests that the QCA publish on its website the data and calculation methodology used by ACIL. In the absence of this information, stakeholders do not have an appropriate opportunity to analyse and comment on this aspect of the Draft Decision.

LGC price - Possible inconsistency in assumptions

AGL notes in this respect the comment on page 24 of ACIL's 2011 – 12 BRCI Report, where it refers to assumptions being made in its LRMC calculation. It states that:

> *The effects of the LRET scheme are included with the REC price fixed at the penalty. We assume the LRET scheme is satisfied at the recently adjusted targets and the REC price is taken off the LRMC of the renewable plant in all regions.*

This comment suggests that ACIL is assuming a higher REC price is assumed when determining the LRMC of the generation build for the purpose of the LRMC calculation, and a lower REC price is assumed when determining the cost of compliance. This would suggest that retailers will incur the scheme penalty, but only be able to recover the market price. AGL seek clarification from the QCA on the basis for this approach.

LRET RPP for 2011

AGL is unclear as to the source of the LRET RPP for 2011 of 5.08% presented in Table 22 of ACIL's 2011 – 12 BRCI Report. AGL assumes that the final 2011 RPP of 5.62%[12] was not published at the time of drafting ACIL's 2011 – 12 BRCI Report. AGL seek confirmation from the QCA that ACIL will use the final 2011 RPP to calculate the 2011-12 LRET cost.

LRET RPP for 2012

AGL does not agree that ACIL's forecast for the 2012 LRET RPP is the most likely outcome in the circumstances. AGL is of the view that a more likely 2012 LRET RPP is 8.66%

In seeking to form a view as to the most likely RPP, AGL has applied the methodology set out in section 39 the *Renewable Energy (Electricity) Act 2000*, which set out regulations for the calculation of the RPP, if it has not been specified by the regulator. For further detail on this proposed methodology please refer to Annexure 2.

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[12] The 2011 LRET Renewable Power Percentage is available at http://www.orer.gov.au/rpp/index.html

3.4. Queensland Gas Scheme

AGL is surprised to note that the QCA have changed their methodology in respect of calculating the costs of compliance with the Queensland Gas Scheme. AGL emphasises that the previous methodology of using the penalty rate only delivers a change of CPI to the GEC component– it does not result in the absolute value of the penalty rate being realised in the tariffs.

ACIL and the QCA have not adequately addressed the issue of liquidity in the GEC market, which as they note, is a significant reason the penalty price has been considered the appropriate reference in all previous BRCI processes.

AGL remains of the view that:

- There is little to no liquidity in the GEC market, such that any analysis conducted on the basis of available data cannot be considered a robust analysis. In previous BRCI Decisions a lack of liquidity in the GEC market has been identified as a reason why market prices were not considered an accurate indicator of a retailer's compliance scheme cost. AGL does not understand ACIL or the QCA to be asserting any increase in liquidity;
- The small number of Cal 2011 and Cal 2012 trades conducted on the open market cannot be considered to provide a reasonable basis on which to assess a retailer's cost of compliance. The total lack of liquidity provides evidence that retailers are not sourcing their compliance requirements through the market, but instead have entered into bilateral, long term arrangements for the acquisition of GECs. The contract price of these GECs must be assumed to be higher than the current market price, as the market price is reflective of the GECs that are not subject to long term contract;
- As such, the most appropriate methodology is that used by the QCA since the 2007/08 BRCI, which is referenced to the GEC penalty rate. AGL notes that the absolute value of the penalty rate is not relevant, but only the rate of change between the years. The rate of change under this methodology is CPI, which presents a robust and reasonable assumption as to the likely annual increases in long term contracts; and
- In the event the QCA is not willing to accept that the CPI increase on the penalty rate remains the appropriate methodology, AGL suggests that a more reasonable proxy for the movement of the GEC price in a long term agreement is the long term GEC market movement – ie an average over a period of 4 years, rather than 2 years.

3.4.1. No liquidity in market price to support the change

<u>Consistent lack of liquidity in the GEC market</u>

The lack of liquidity in the GEC market has been accepted in the previous BRCI processes as a key reason for the need to use a methodology premised on the shortfall (or penalty) rate. In December 2008, in the Draft Decision for the 2009 - 10 BRCI, the QCA's consultants CRA noted that:

> *When we then calculated the BRCI for 2008-09, and also at the same time needed to re-calculate the BRCI for 2007-08, we considered whether we should continue to estimate the prices of GECs based on penalty prices, or alternatively whether we should start to base the pricing of GECs on prices for trades which have been published by AFMA. At that time, if we have used quoted prices, we would have had only a small number of data points on which to base the GEC price for 2007-08,* ***and this would therefore not have been a robust basis on which to estimate the cost of compliance with the Queensland 13% Gas Scheme in***

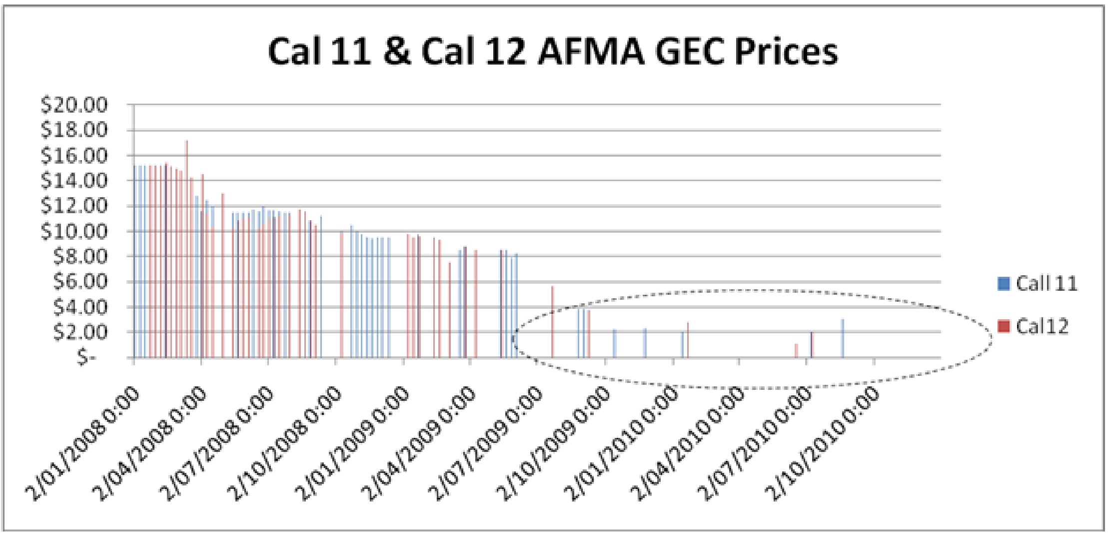
__2008-09__. We needed to have consistent approach for calculating the GEC prices for the two tariff years 2007-08 and 2008-09, and therefore we estimated the prices of GECs based on penalty prices rather than on AFMA-quoted prices for both 2007-08 and 2008-09.

AGL does not believe there has been any improvement in liquidity, and in fact notes that as demonstrated by the graph below, the liquidity in the GEC market remains at extremely low levels. For example:

- AFMA have only published 11 data points for Cal 11 from 1 July 2009 through to 31 December 2010. This means that in only 11 weeks of the 18 months, were AFMA able to solicit quotes from market participants; and
- AFMA have only published 5 data points for Cal 12 in that same 18 month period.

Figure 2 provides a summary of AFMA survey responses for Cal11 and Cal12 GEC contract prices from 2008 – 2010.

Figure 2 – Cal11 & Cal12 AFMA GEC Prices



The number of data points provided by AFMA during the relevant time period is not such as to provide a representative sample of market activity over the period, and any analysis based on this amount of data cannot be considered sufficiently robust to support a change in methodology.

<u>Nextgen data not relevant to the question of liquidity</u>

In ACIL's 2011 – 12 BRCI Report Nextgen data appears to be referenced as a 'confirmation' of the AFMA data. The concerns with the AFMA data in this context are not that the AFMA data is unreliable per se, but rather that there is not sufficient liquidity in the GEC market , and therefore the AFMA data does not provide a sufficient basis on which to assess the likely cost to retailers of complying with their GEC liability.

AGL does not believe that the analysis of the Nextgen data 'validates' the use of AFMA data to determine a representative compliance cost for the following reasons:

- AGL does not understand from the Draft Decision that ACIL is of the view there is more liquidity evidenced in the Nextgen data than is evidenced in the AFMA data - retailers are not procuring Cal11 and Cal12 GECs through the OTC market. In fact, AGL has contacted Nextgen and received confirmation that there were 'very few trades' after July 2010 for Cal 2011 or Cal 2012, and no GEC trades of any vintage from September 2010 through to early January 2011.

- On the basis that Nextgen data does not evidence, and is not based on, any additional trades in the GEC market, AGL does not understand that ACIL's reference to Nextgen data is relevant to the key issue, which is whether reference to the 'market price' is appropriate when seeking to assess the likely cost to retailers of complying with their GEC liability.

AGL does not believe that the reference to the Nextgen data provides any support for a change to the current methodology. AGL would welcome any comment from ACIL, AFMA or Nextgen on whether they believe the thinly traded GEC market does provide a reasonable basis on which to assess the cost of GECs to retailers with substantial compliance targets.

<u>Lack of liquidity evidence that retailers satisfy compliance targets through bi-lateral contracts</u>

The AFMA data and Nextgen information makes clear that retailers operating in the Queensland are not seeking to satisfy their GEC liability through purchases on the open market. Rather, the number of trades is very clear evidence that retailers acquire their GEC requirements through long term bi-lateral arrangements with generators. AGL is of the view that the GECs being traded on the market are the very small number of GECs created by generators that are not subject to a long term purchase agreement.

Therefore, an analysis of the thinly traded GEC market cannot be considered the most appropriate means of assessing the likely cost to retailers of satisfying their GEC liability targets.

AGL notes that as the 'penalty price' methodology in fact allows an increase of CPI on the GEC component only – the absolute value of the penalty price is not captured, but only the rate of change. AGL suggests that it is reasonable to assume that a CPI rate of change is a valid proxy for a benchmark retailer's increase in costs under long term GEC off-take arrangements.

In the event the QCA remains of the view (not supported by AGL) that a move to a market based methodology is warranted, AGL suggests that the movement in the GEC price under long term agreements is better represented by a longer term view of the market price – particularly given the illiquid nature of the market. For example, an average over 4 years may represent a better proxy for the cost of GECs under a long term agreement.

3.4.2. Lack of transparency around methodology

While AGL remains of the view that the most appropriate methodological approach is that used in previous BRCI processes, AGL also has concerns around the manner in which ACIL have applied the new methodology.

AGL has not been able to replicate the results calculated by ACIL, and the information provided by ACIL is not sufficiently detailed to permit an understanding of the exact methodology used.

AGL suggests that it is necessary in order for all stakeholders to have confidence in the process followed by ACIL, and the QCA's Draft Decision, that the QCA publish on its website as soon as possible the exact data and methodology used to calculate the GEC values for the Draft Decision.

3.4.3. Possible inconsistency in assumptions

AGL notes in this respect the comment on page 24 of ACIL's 2011 – 12 BRCI Report, where it refers to assumptions being made in its LRMC calculation, where it states that:

> *The modelling assumes the Queensland Gas Electricity Certificate (GEC) Scheme continues with GEC prices fixed at the penalty and the GEC target set at 15% for 2011/12. PowerMark LT subtracts the GEC price from the LRMC of gas-fired plant in Queensland – this deduction increases the attractiveness of these plant which results in more CCGT/OCGT being included in the optimal mix of Queensland. However, if there is an oversupply of GECs then only the proportion of GECs able to be sold is included in the revenue streams*

This comment suggests that ACIL is assuming a higher GEC price when determining the LRMC of the generation build for the purpose of the LRMC calculation, and a lower GEC price is assumed when determining the cost of compliance for retailers i.e. retailers will incur the scheme penalty but are only be able to recover the market price. AGL seek clarification from the QCA on the basis for this approach.

4. Network Costs

AGL acknowledges the constraints imposed on the QCA by the legislative provisions which govern the application of the BRCI. AGL notes that in the BRCI 2010 – 2011 network costs contributed 8.21% to the change in the BRCI (i.e. 61% of the total increase). Due to the significant contribution of the network component to the calculation of the BRCI AGL remains concerned that:

- In using the average Energex and Ergon aggregate annual revenue requirement (AARR), the BCRI will not accurately capture the changes incurred in Energex's patch over the period. Whilst AGL acknowledge that this approach is a requirement of the Electricity Act 1994 and the Certificate of Delegation, it still remains that this approach will not provide the most cost-reflective outcome for retailers and consumers.

- The BRCI makes no allowance for the ability of Energex to re-balance its tariffs with the AARR increase

5. Retail Costs

5.1. Benchmark costs

AGL continues to support a 'benchmarking' approach to calculate retail costs. AGL note that in March 2010 IPART determined a retail margin of 5.4%. This figure was determined as the mid-point of three methodologies used to estimate the margin. The benchmarking approach used in this review estimated a 6.7% retail margin. AGL believe that an appropriate regulated retail margin should be in excess of 6%, which is consistent with the range put forward by IPART.

AGL remains of the view that a retail margin of 5%, as used in the BRCI 2011-12, is too low to cover the associated costs and risks of being an electricity retailer in Queensland with an obligation to supply regulated customers.

5.2. Customer Acquisition and Retention Costs

Since 2007-08, the QCA has estimated the costs of switching and transferring a customer and multiplied by the forecast number of switches and transfers to obtain an overall CARC estimate for the year. In the Draft Decision, the QCA has proposed to incorporate costs associated with customer acquisition and retention within retail operating costs, rather than a separately calculated cost item. By combining the operating costs and CARC on a per customer basis used in its 2010-11 BRCI Final Decision as the opening value for the 2011-12 Draft Decision, the QCA has fixed the proportion of switches and transfers to that assumed in its 2010-11 BRCI Final Decision.

The methodology for forecasting the number of switches and transfers has not been consistent over the last few years. AGL understands the reason for latest proposed change is based on the "current state of competition". AGL notes that by proposing this change, QCA considers the level of churn in 2010-11 will be an ongoing feature in the Queensland market, implying the market has matured and is fully competitive.

6. NEM Load

The QCA notes that it proposes to adopt the same approach to determining the NEM load as it adopted in calculating the 2010-11 BRCI. This means that for the Draft Decision the QCA will rely on actual load data for the first three quarters of 2010 and a forecast for the December quarter 2010 load. The December quarter 2010 data will then be replaced by actual data for the Final Decision.

AGL is of the view that the process used for the 2010-11 forecast of the NEM load was appropriate. Any forecast loads should be in line with the findings of the AEMO Electricity Statement of Opportunities (SOO) 2010. AGL request that the QCA's data on load forecasts used for the purposes of the BRCI be made available to electricity retailers through the BRCI consultation process.

Annexure 1

Relevant acquisitions and partial exemptions calculation methodology

In publishing the 2011 STP, ORER has not provided any information as to the amount of electricity acquired for the year or the amount of partial exemptions expected to be claimed. It is necessary to form a view on these matters in order to forecast future STPs. AGL has therefore completed the following analysis:

- Estimate 2012 relevant acquisitions

  Using the 2010 actual load data (see Table 6 below) and an assumed load growth of 2.1% p.a[13], AGL has estimated the 2012 relevant acquisitions to be **235,665 GWh**;

Table 6 – Estimation of 2012 Relevant Acquisitions

System	Demand (MWh)
NEM (2010 Demand)	204,366,289
SWIS (2010 Demand)	18,012,147
Intermittent generation 2010	3,691,932
TOTAL 2010 Load	226,070,368
Assumed load growth	*2.1% p.a.*
TOTAL 2012 Load	**235,665,020**

- Estimate 2012 partial exemptions

  In order to estimate the 2012 partial exemptions, AGL has first derived the 2011 partial exemptions. This is done by:
  - Identifying the 'relevant acquisitions less partial exemptions' for 2011, by using the published 2011 RPP (5.62%) and LRET target (10,600 GWh); and
  - Using the forecast 2011 relevant acquisitions forecast the 2011 partial exemptions amount can be estimated at 42,205,746 MWh.

  AGL has then used the increase identified by ACIL in Section 4.1.2 of the report, where it states:

  > *RPP estimate includes a 25% increase in the amount of partial exemption certificates for energy intensive trade exposed (EITE) customers*

  Assuming a 25% increase to the 2011 partial exemption, the 2012 partial exemption amount is **52,757,183 MWh**.

[13] AEMO – 2010 Electricity Statement of Opportunities, Table 4-4—NEM-wide energy projections (GWh), Medium growth scenario.

- Estimate 2012 STP

  Using the projected likely STC creation, in line with the *SKM-MMA – DOGMMA – Multiplier reduction' scenario*, Table 7 shows the estimation of 2012 STP:

Table 7 – Estimation of 2012 STP

Likely Certificate Creation (STCs)	23,000,000
Forecast 2012 Load (MWh)	235,665,020
Partial Exemption (MWh)	52,757,183
STP 2012	**12.57%**

Annexure 2 – Calculation of LRET RPP

ACIL 2011 – 12 BRCI Methodology

ACIL have forecast the 2012 RPP at 7.97%. In ACIL's 2011 – 2012 BRCI Report the process used to estimate the 2012 RPP includes:

- Projection of the amount of RECs in excess of the 34.5 million REC cap set by ORER. ACIL predicts that there would be a 7.7 million REC excess, which requires the 2012 and 2013 targets to be increased to 16,150 GWh and 18,050 GWh respectively; and
- Estimating the amount of exempted load from emissions intensive trade-exposed (EITE) industries. As noted above, ACIL estimate a 25% increase in the amount of partial exemption certificates for EITE customers.

A number of elements in this approach require either updating with correct/further information or further explanation.

<u>LRET Target Adjustments</u>

The LRET target adjustments for 2012 and 2013 should be updated so as to align with the ORER adjustments published in January 2011, namely LRET targets of:

- 16,338 GWh for 2012; and
- 18,238 GWh for 2013.

<u>Energy Intensive Trade Exposed partial exemption</u>

ACIL have not clearly articulated the approach taken in estimating the EITE for 2012, and in fact ACIL have not referred at all to the 'relevant acquisitions' which together with the EITE are a key element of the RPP.

AGL Proposed Methodology

AGL is of the view that in the absence of the published 2012 RPP then a transparent approach, based on published legislation is preferable to the approach used in ACIL's 2011 – 12 BRCI Report.

Section 39 of *Renewable Energy (Electricity) Act 2000* states:

Regulations to specify renewable power percentage.

> *(2) If the regulations do not specify a percentage for a year, the percentage for the year is:*
>
> *(a) for the year commencing on 1 January 2001—0.24%; and*
>
> *(b) for any later year—the rate worked out using the formula:*

$$\text{Renewable power percentage for the previous year} \times \frac{\text{Required GWh of renewable source electricity for the year}}{\text{Required GWh of renewable source electricity for the previous year}}$$

Using the published 2011 RPP of 5.62%, the published 2012 LRET Target of 16,338 GWh and the adjusted 2011 LRET Target of 10,600 GWh, the resulting 2012 RPP is 8.66%.