AGL Response to the Independent Pricing and Regulatory Tribunal

Review of regulated retail prices and charges for electricity 2013 to 2016, Issues Paper

December 2012

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Executive Summary

This submission is in response to IPART's *Review of regulated retail prices and charges for electricity 2013 to 2016 - Issues Paper.*

General Comments

AGL believe that IPART's current determination has generally succeeded in facilitating competition in the NSW retail electricity market. IPART's challenge for this determination is to maintain high levels of competitive activity in an environment where future policy decisions which may have considerable impact on the cost of supplying electricity remain uncertain.

Form of Regulation

To encourage more customers to participate in the competitive market, IPART has proposed an opt-in model whereby the current regulated price would be unregulated in terms of price and customers would then be required to 'opt-in' to new regulated prices. On principle, any move toward deregulation should be encouraged. Continued regulation creates significant uncertainty for retailers. However, it is critical that the implementation of this opt-in approach be considered carefully.

AGL recommends no change to the regulation of green premiums or the weighted average price cap approach.

In relation to cost pass through, AGL encourages IPART to consider introducing a mechanism which will allow costs to be recovered in the same period as they occur rather than delayed until the next year.

When assessing retail completion, it is important that such analysis should be based on objective measures which take account of the conditions of the retail electricity market at the time. From a retailer's perspective, AGL does not consider that there are any substantial barriers to entry provided that regulated prices allow effective offers to be developed and promoted.

Energy Costs

AGL does not believe there is any compelling reason for IPART to move away from its current method for setting the energy cost allowance, that is, equal to the to greater of its estimates of the LRMC and market-based energy cost. This method would still comply with the new ToR as the selected energy cost allowance will always remain above the floor, as prescribed in the ToR.

AGL supports the 'standalone or greenfield' approach in calculating the LRMC of generation for the Standard Retailers. AGL notes that IPART has indicated the derivation of the Standard Retailers load forecasts will be made public unlike the regulated load forecasts for Standard Retailers in 2010. The calculation of the LRMC of generation to meet a particular load will be highly dependent on the input assumptions used. AGL is concerned that the approach proposed by IPART to develop a set of input assumptions specific for the determination will result in additional modelling complexity and uncertainty. AGL will be looking to understand from IPART and its consultants the specific details of these assumptions as part of the consultation process.

Deriving a realistic market based energy cost for Standard Retailers is of particular importance for this determination with it being a key part of setting the floor to the energy purchase cost. AGL has a number of concerns with the approach proposed by IPART and it's consultants to calculate a Standard Retailers market-based cost. AGL has provided a detailed discussion of these specific concerns in the submission.

AGL believes that in order to meet the requirement for a transparent and predictable methodology it is vital that all market-based cost modelling be made available to stakeholders for analysis and comment. This includes a detailed description of the methodology, the data used and the outputs derived.

This is especially important with regards to the regulated loads and input data for Frontier's LRMC modelling as these elements will be derived through new processes rather than the methodologies used in the 2010 determination.

Retail Costs and Margin

AGL considers that defining retail costs from the perspective of a Standard Retailer is inconsistent with the requirement to set prices to encourage competition. AGL anticipates that the introduction of the Clean Energy Act 2011 and the increase in churn have increased total retail operating costs. AGL has publicly reported a number of measures of operating costs per customer but on fully allocated basis, the cost is higher than the current benchmark.

As in previous submissions, AGL considers that the retail margin allowance of 5.4% which IPART has set in the 2010 Determination to be too low considering the risks of operating in the most volatile commodity in the world.

1. General Comments

AGL welcomes the opportunity to make this submission to the Independent Pricing and Regulatory Tribunal (IPART) in respect of the *Review of regulated retail prices and charges for electricity 2013 to 2016 - Issues Paper* (Issues Paper) released in November 2012.

AGL believe that IPART's current determination has generally succeeded in facilitating competition in the NSW retail electricity market. IPART's challenge for this determination is to maintain high levels of competitive activity in an environment where future policy decisions which may have considerable impact on the cost of supplying electricity remain uncertain.

AGL agrees with IPART that a well-functioning competitive market is in the long term interest of customers and that it would facilitate the removal of retail price regulation. On 18 December 2012, the South Australian Government announced the removal of price regulation of electricity and gas retail markets from 1 February 2013, joining Victoria which had been fully deregulated since 1 January 2009. AGL looks forward to the NSW Government's consideration of the recommendations of the AEMC review of competition in the NSW retail energy market when it is completed in 2013.

In this paper, AGL has responded to the Issues Paper in the following structure:

- Section 2 considers the terms of reference, policy and regulatory developments;
- Section 3 comments on retail competition in the NSW electricity market;
- Section 4 discusses the form of regulation;
- Section 5 considers the range of issues in establishing the energy cost allowance;
- Section 6 discusses the retail cost allowance including AGL's publicly reported costs; and
- Section 7 states AGL's view on retail margin.

An Annexure which discusses the components of the weighted average cost of capital is also included.

2. Terms of reference and other factors

IPART has been asked by the NSW Minister for Resources and Energy to review and determine regulated retail electricity for the period 1 July 2013 to 30 June 2016.

AGL recognises that:

- there are some significant differences with the terms of reference (ToR) for this determination compared with previous years; and
- potential policy, regulatory and market developments that have occurred since the 2010 determination also need to be considered.

These are discussed in greater detail below.

2.1. Terms of reference

The major changes to the ToR include:

- A floor to the energy cost allowance being set equal to 75 per cent of LRMC and 25 per cent of IPART's market based cost estimate;
- The determination only applying to small customers that consume less than 100 MWh per annum; and
- That IPART must transparently report on the total price impact of all the green schemes.

These will have various impacts on IPART's methodology in this determination.

Firstly, given the success of the current determination in facilitating competition in the NSW retail market, AGL does not believe there is any compelling reason for IPART to move away from its current method for setting the energy cost allowance, that is, equal to the to greater of its estimates of the LRMC and market-based energy cost. This method would still comply with the new ToR as the selected energy cost allowance will always remain above the floor, as prescribed in the ToR.

The importance of IPART deriving a realistic market based energy cost is of particular importance with it being an integral part of setting the floor to the energy purchase cost.

Secondly, the amended definition of small customers to those with consumption less than 100 MWh per annum changes the regulated load that will need to be considered in Frontier's modelling of LRMC and market-based energy cost.

AGL cannot effectively comment on how this can be best accomplished without seeing the actual load data that Frontier will be able to access. However, AGL submit that the regulated load profiles will need to be transparent and therefore based on the net system load profile (NSLP) in NSW.

It is also unclear how the two separate load forecasts, for customers consuming 0-40 MWh per annum and 0-100 MWh per annum, will be taken into account in both the Frontier modelling and the final construction of regulated retail tariffs.

2.2. Policy and regulatory developments

Uncertainty related to carbon pricing mechanism

AGL notes that a lack of bipartisan support for maintaining the carbon pricing provisions within the Clean Energy Act 2011 could have a significant impact on a number of components being considered as part of the determination. These include:

- Current futures market prices for electricity may not fully account for the costs of the carbon pricing mechanism on generators in future years. In theory as the contract period approaches, the level of uncertainty relating to the future of the carbon pricing mechanism should reduce and prices will better reflect the whether the carbon price will apply to generators during that period. However, if IPART uses current contract prices to set regulated tariffs this approach could risk not allowing for the full recovery of the carbon cost on retailers wholesale energy costs; and
- In 2015-16, the carbon pricing scheme will no longer be subject to a fixed permit price, instead a floating price will be introduced determined by market forces. IPART has clearly acknowledged the uncertainty resulting from this planned change in the scheme. AGL suggests that developing a suitable price to be used in the 2015-16 regulated retail price should be dealt with closer to that time. In the meantime, any estimates should be based on publicly available data such as Treasury modelling.

Network regulation

The N + R approach has to date ensured that network related cost changes are passed through to the customer through the regulated retail tariffs. There is considerable uncertainty regarding when the next network determination for charges from 1 July 2014 will be completed by the AER. It is quite possible that the timeframe for network price changes may not parallel IPART's annual setting of regulated retail tariffs. IPART will need to consider this possibility when setting its new determination so that the framework can accommodate changes to network prices that occur outside a 1 July date.

Gas market developments

AGL notes that since the development of the 2010-13 Determination, the east-coast wholesale gas market has changed considerably. In recent submissions to IPART for the proposed 2013-16 Voluntary Transitional Pricing Arrangement, none of the Standard Retailers provided retail gas prices for small customers beyond mid-2014 due to uncertainty in their wholesale gas supply arrangements. AGL highlights that this uncertainty should be acknowledged in the development of gas costs as part of this review and key assumptions worked through with stakeholders.

3. Assessing Retail Competition

3.1 Assessing current competition in the NSW market

IPART's approach to assessing retail market competition will involve:

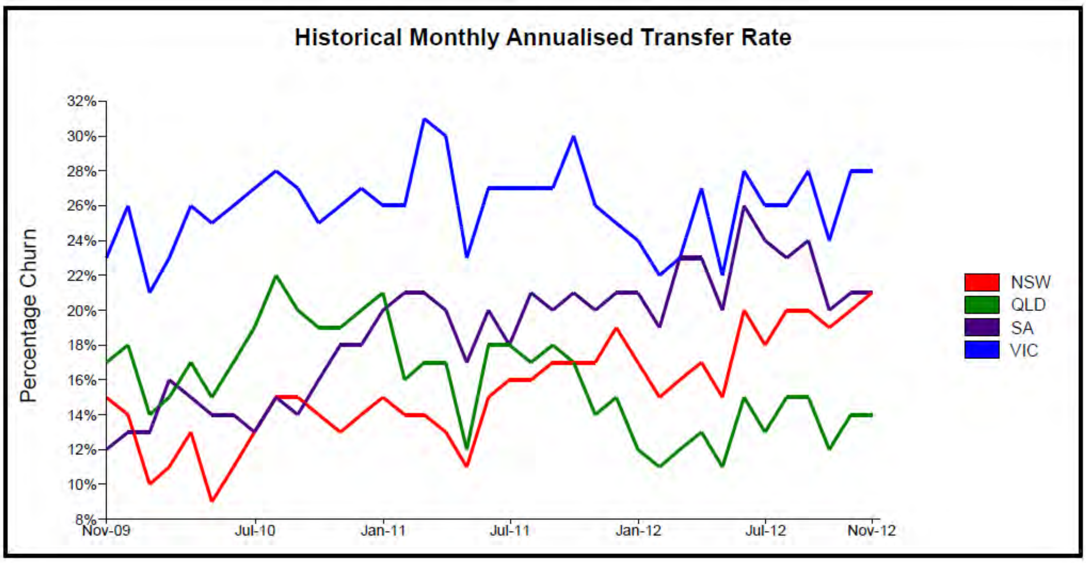
- defining the relevant market;
- considering the structural features of the market;
- assessing retailer and customer conduct in the market; and
- considering the outcomes for customers in the market.

AGL understands that this approach is similar to the approach that the AEMC used to examine retail energy market competition in other jurisdictions and is using in the current review in the NSW energy market. Accordingly, AGL considers that the proposed approach is appropriate.

IPART will be seeking to understand the experiences of customers who have been active in the market. It is important that such analysis should be based on objective measures which take account of the conditions in the retail electricity market at the time. A useful guide is the annualised churn rate which is produced by AEMO in the *National Electricity Market – Monthly Retail Transfers Statistics* and is closely monitored by retailers. The churn or switching rate is a measure used by international organisations such as VaasaETT which conduct studies on international utility customer switching trends and dynamics.

In Figure 1 below, the AEMO statistics show increasing churn rates in NSW up to November 2012. AGL considers the churn rate to be a simple but objective guide on the level of competitive activity in the market.

Figure 1: NEM churn rate up to November 2012



3.2 Facilitating retail market competition over 2013-16

IPART has noted the adoption of the National Energy Customer Framework (NECF) and the NSW Government' proposed ban on early termination fees. AGL's market retail contracts include a 'fair contracting promises' provision which already allows customers to avoid early termination fees. This provision allows customers to terminate their agreement without incurring early termination fees where customers are not prepared to accept variation to prices.

From a retailer's perspective, AGL does not consider that there are any substantial barriers to entry provided that regulated prices allow effective offers to be developed and promoted.

4. Form of Regulation

4.1 Consideration of an opt-in model

To encourage more customers to participate in the competitive market, IPART has proposed an opt-in model whereby the current regulated price would be unregulated in terms of price and customers would then be required to 'opt-in' to new regulated prices.

One of the reasons which IPART has put forward to support this opt-in approach is to directly reduce Country Energy's number of regulated prices and therefore remove a barrier to competition in the non-metropolitan market. In AGL's view, the number of regulated prices for Country Energy is no longer a barrier to competition as many of the prices have been rationalised as well as the implementation of online offers which could overcome the possible lower level of door-knocking activity.

On principle, any move toward deregulation should be encouraged. Continued regulation creates significant uncertainty for retailers.

However, it is critical that the implementation of this opt-in approach be considered carefully as the setting of a deadline will create a spike in customer calls which the retail energy market as a whole is unlikely to be resourced to manage. Should this model be introduced in the 2013 Determination period, some phasing in of this approach with a start date in the second year of the Determination period, that is, from 1 July 2014 is likely to be more workable. This will provide more time for information to be adequately communicated to affected customers and, if appropriate, could further support the recommendations of the AEMC review of competition.

4.2 Regulating green premiums

AGL supports the continuation of the current arrangement whereby any green premium component is unregulated. There is no imperative to introduce price regulation on this voluntary pricing component and it would be at odds with IPART's aim of moving towards price deregulation.

4.3 Using a WAPC approach

The WAPC provides retailers with flexibility to reset or re-balance individual regulated prices whilst allowing network charges to be fully passed through. Although the WAPC operates within the overall price level determined by IPART, there is a risk that some individual prices may be increased at significantly more than others. This risk is unlikely to occur if there is sufficient competition. Provided that the regulated prices are set at a level which continues to promote competition, AGL does not consider any changes are required and the WAPC approach should continue for the 2013-16 Determination.

IPART has referred to the Relative Price Movement methodology used in South Australia as an alternative approach. This methodology was used to determine the allowable change in regulated prices and is therefore not comparable with the WAPC which operates within the overall price level which has been already determined by IPART.

4.4 Threshold price increase test for Country Energy

As a general principle, prices should be cost reflective. It is likely that the limit on the allowable increase in individual Country Energy prices has continued to discourage competition as the price levels may not be sufficient to allow competitive offers to be developed. In AGL's view, the threshold price increase test should be removed. If this limit is retained, given the likely subdued changes in network charges for 2013-14, the 5% limit should be raised to at least 10%.

4.5 Cost pass-through mechanism

As noted by IPART, the cost pass-through mechanism has been triggered twice due to changes in the Renewable Energy Target scheme. As there is potential for further changes to the targets under this scheme and other policy and regulatory reviews, it is appropriate that this mechanism continue over the 2013 Determination period. This will be in addition to the more specific periodic review of the total energy cost allowance.

Currently, the cost pass-through is implemented in the following financial year. AGL encourages IPART to consider introducing a mechanism which will allow costs to be recovered in the same period as they occur rather than delayed until the next year.

5. The Energy Cost Allowance

The Issues Paper has proposed the method for estimating energy cost allowance is to be based on:

- forecasting the Standard Retailers' regulated load in each year of the determination period;
- estimating the long-run marginal cost (LRMC) of electricity generation;
- estimating the market-based cost of purchasing wholesale electricity;
- calculating the weighted average (75/25) of these two costs to establish the price floor; and
- determining an appropriate cost allowance for each Standard Retailer, subject to the price floor.

IPART has engaged Frontier Economics to provide advice on the estimated LRMC and the market-based cost as detailed in its Draft Methodology Paper.

AGL believes that in order to meet the requirement for a transparent and predictable methodology it is vital that all Frontier modelling be made available to stakeholders for analysis and comment. This includes a detailed description of the methodology, the data used and the outputs derived.

This is especially important with regards to the regulated loads and input data for Frontier's LRMC modelling as these elements will be derived through new processes rather than the methodologies used in the 2010 determination.

5.1. Demand

System load

Frontier describes the proposed approach to determining system demand forecasts for each NEM region which are required for their energy market modelling. AGL is concerned that the description of how Frontier proposes to "model a representation of the demand duration curve" does not provide sufficient detail for AGL to understand how this approach might impact on spot prices generated by the Frontier electricity market model. AGL's specific concerns include:

- How will Frontier select the 'representative demand points' i.e. how will they be weighted to ensure that the spread of half-hourly demand points are represented; and
- If the regulated loads for the Standard Retailers are modelled on a half-hourly basis, how does the model ensure that the pool price outcomes (based on a limited number of demand points) are sufficiently correlated to the retailers load?

Regulated load

The ToR requires two separate regulated load forecasts to be used:

- for customers who consume between 0 and 40 MWh per year and
- for customers who consume between 0 and 100 MWh per year.

AGL notes that IPART has indicated the derivation of these load forecasts will be made public unlike the regulated load forecasts for Standard Retailers in 2010.

Frontier will develop these regulated load profiles for each Standard Retailer and they will be developed based on the NSLP and CLP in consultation with the Standard Retailers. Frontier has also indicated the method used will be dependent on data derived from Standard Retailers. While Frontier has provided a reasonably detailed description of their approach, AGL has a specific query which we believe should be addressed to provide a better understanding of the approach:

- Frontier has described how they aim to capture trends in forecast load shape by relying on historical data. Whilst AGL supports an approach to capture the change in load shape over time, it is not clear to us how Frontier will adjust the load shape in practice. Frontier has provided by way of illustration a graph showing the change in load factor over time. However, this does not address how Frontier might in practice adjust the forecast regulated loads to match a forecast load factor. AGL requests that the basis for any manipulation of the forecast regulated load shape is clearly described so that stakeholders can provide feedback on this process.

<u>Preserving correlation between loads and spot prices</u>

AGL is in agreement with Frontier on the importance of the correlation between regulated load, system load and spot prices to capture the risks faced by the different standard retailers. Frontier describe how their proposed approach is designed to ensure that the system demand shape used under each POE case is correctly correlated with each Standard Retailer's load shape. Having said that, AGL does not expect correctly correlated load traces to necessarily demonstrate the same POE level because of diversity amongst Standard Retailer loads. While a POE level might be specified, say 10% POE NSW system load, the POE levels of correlated NSLP loads should be identified for AGL to assess the shape of these loads.

<u>Developing two regulated load forecasts</u>

AGL understands that if adequate actual data is not available to differentiate between the regulated loads then any differences between the separate regulated loads will have to manufactured by Frontier. AGL has concerns with this process but it is not clear from the Issues Paper how the separate loads will impact on Frontier's modelling and more importantly, what part these separate loads will play in the setting of regulated retail tariffs.

5.2. Long run marginal cost

AGL supports IPART's previous approach (based on the 2010-13 ToR) which sets the energy purchase cost allowance as the higher of LRMC or market-based energy cost. The use of the LRMC in the calculation ensures that electricity tariffs at least cover the costs of the LRMC of generation and that any needed investment in new plant will be encouraged in NSW.

The objective of the LRMC analysis should be to develop a simple and transparent methodology which captures the theoretical cost a generator will seek to recover from supplying electricity to small customers. As such, AGL supports modelling LRMC on a stand-alone (greenfields) basis, assuming the generation plant will be built to supply the volume and shape of the regulated loads for small customers in each distribution area. This is important as the generation plant required to meet a peaky load is very different to that of a flat load.

The calculation of the LRMC of generation to meet a particular load is highly dependent on the input assumptions used. AGL has provided a detailed discussion of the approach to setting the input assumptions and the industry implications of setting the EPC lower than the long run cost of supply later in this submission.

5.3. Market-based energy purchase cost

The importance of IPART deriving a realistic market based energy cost is of particular importance with it being an integral part of setting the floor to the energy purchase cost.

The market-based cost should be aligned to the costs a prudent retailer incurs to manage the supply of electricity to its regulated customer base and to manage its risks.

Wholesale energy costs incurred by retailers include a combination of the hedge contract prices paid to generators (swap, cap and other derivative costs) and the pool price for energy purchases not covered by hedge contracts. These prices reflect the costs and returns for existing generating assets, the supply/demand balance, the peakiness of the load in a particular market and the volatility of demand. Hedge contract prices inevitably include a risk premium attributable to such volatility. A retailer servicing a regulated load determines the amount of hedge and derivative contract cover based on the load and shape of the NSLP.

Accordingly, the key inputs are:

- a forecast of the load for the relevant period;
- spot market outcomes matched to demand for each half hour of the day; and
- forward hedge contract prices.

Market-based energy purchase cost modelling

Frontier determines a conservative hedging position based on the interaction of its forecasts of spot price, future contract prices and regulated load. If any of these forecasts is unbalanced then the derived hedging position will be unrealistic and the estimate of energy purchase cost will not represent a reasonable estimate of the Standard Retailers energy purchase cost.

It is therefore vital that all forecasts are transparent and can be analysed by stakeholders to ensure the validity of the outcomes.

Comments on the forecasting of these elements and the specific methodologies being considered by Frontier are outlined below.

<u>Spot price Forecasts</u>

AGL cautions that Frontier's spot price forecasts should be:

- properly constructed to align maximum demands in the regulated load forecasts;
- incorporate all recent information on future generation; and
- able to be compared with other time weighted price forecasts that have been published.

The spot price forecasts and their alignment with the regulated load forecast, maximum demands will drive the hedging position derived Frontier. If the forecast is not properly aligned, spot prices may occur at odd times such as public holidays or off-peak and these will have a significant impact on the derivation of Frontier's hedge contracting position and can lead to an unrealistic outcome.

Furthermore, AGL seeks confirmation that Frontier will include data on the changes to generation mix deriving its spot price forecasts. For example, the Northern Power Plant is only going to run for half of a year in summer while Tarong and Yallourn are mothballing generation units in Queensland and Victoria. In addition, Frontier should make clear what assumptions are made on how much wind generation is included in the mix to meet the LRET.

Finally, AGL expects Frontier's spot price forecasts to be compared with other available spot price forecasts produced in other recent determinations. AGL would highlight that many jurisdictions have released recent decision on retail energy prices or feed-in tariffs with accompanying spot price forecasts for coming years. These forecasts can vary considerably with the differences often left unexplained.

Conservative Hedging Position

Frontier proposes to take the most conservative risk position in determining its hedging strategy and claims that this would, if anything, over-estimate its estimated energy purchase cost.

Optimising the contracting strategy is dependent on having perfect foresight of the pool price and seeks to create a contracting strategy around this pool price. This contracting strategy would produce different results under various pool price outcomes and AGL considers this approach will likely understate the costs that would be incurred by a prudent retailer executing a contract strategy to hedge regulated demand.

Furthermore, based on the Issues Paper and accompanying Frontier Report, AGL understands that Frontier is planning to determine a single conservative contract strategy that is co-optimised based on the probability of three POE price/load scenarios occurring, that is, POE10, POE50 and POE90 loads and associated spot prices. This is inconsistent with methodology proposed in the Frontier Report (page 99, Appendix C – Strike), whereby the Strike Model '*determines the efficient mix of hedging products to meet **a particular load profile**.*'

If the hedging position is optimised across the three scenarios then the result will be that the single hedging position adopted by Frontier will not be the most conservative position for any of the modelled scenarios when considered independently.

Contract price data

AGL is of the view that IPART's methodology for assessing the market-based cost should rely on transparent, available market data. This includes using published forward hedge contract prices, from either AFMA or D-Cypha Trade, when the data is robust and derived from a liquid market.

The benefits of using AFMA or D-Cypha Trade data include that:

- the information can be found from public sources; and
- the outputs are more likely to reflect actual costs retailers might incur.

The choice of a contract price data source should be determined by considering which source provides the most accurate estimate of the cost which a Standard Retailer might be exposed to over the determination period. On this basis, where the data is unavailable, as is currently the case for future financial years of the determination period, or the lack of market liquidity makes the data unreliable the suitability of the data source should be reconsidered. AGL is concerned that futures prices for the latter years of the determination period might not fully reflect the cost that retailers will be exposed to due to the uncertainty related to the potential repeal of the carbon price legislation. Using an estimate of OTC prices plus a separate allowance for retailers carbon costs (based on the

AFMA carbon pass-through clause) could reduce the impact of any adjustments required to modelling the EPC in the future.

Point in time or rolling average basis

AGL believes that the appropriate methodology for assessing forward contract prices is to assume a prudent hedging strategy which is consistent with a 'rolling average' approach.

Assuming that a retailer gradually hedges its load over two to three years in advance of the period in question will more closely reflect the a retailer's hedging strategy and acknowledge the reality that retailers are exposed to the highs and lows of the market.

IPART seems to consider a 'point-in–time' approach appropriate because:

> *Contracts are financial instruments that can be traded, and therefore should be valued at current rates. For example, the appropriate way to value a share is the price that could be received today, not the value paid for it in the past.*

This is a misleading comparison. IPART should be attempting to estimate the cost that a retailer will incur to acquire sufficient cover to supply a non-discretionary regulated load. IPART should not be assessing the value of a retailer's book at a point in time as though it were an investment or a speculative position. Using IPART's approach has significant uncertainty as the market based costs will be dependent on what particular day is selected. It also does not reflect commercial reality as it assumes that the profit or loss of this revaluation is irrelevant.

A more apt comparison than the share market is to consider other futures markets in traded commodities or even currencies. In such markets, a producer or manufacturer may enter in futures contracts to cover its supply or demand for commodities on different occasions in order hedge its requirements. A point-in-time value of these financial positions is redundant because in the long-term, the positions are covered through physical supply or demand for the commodity. The cost or revenue from their contract positions has been set through a long-term hedging strategy as is the case in the forward contract market for electricity.

AGL is of the view that there is no fundamental support for use of a 'point-in-time' approach.

Input assumptions for LRMC and market-based energy purchase cost

<u>General comments</u>

In attempting to calculate the energy purchase costs for Standard Retailers to be applied for the three years of the determination the input assumptions used are a critical part of the modelling approach. In the Issues Paper IPART have proposed a significantly different approach to determining appropriate input assumptions compared to previous years. In summary these changes include:

- Changes to calculating system load and regulated load forecasts (discussed earlier);
- Development of assumptions for capital costs, operating and maintenance costs, fuel costs and technical parameters of generation plant generation specifically for the determination of NSW regulated electricity prices;
- Updating the input assumptions each year with reference only to the process for developing the input assumptions as established by IPART at the beginning of the price path.

In principle AGL is not opposed to IPART developing its own input assumptions for regulated pricing purposes. However, IPART should ensure that their process for developing these assumptions is open and transparent and reflects relevant stakeholder feedback. The published data sources that IPART has relied upon in the past have often been subject to industry review and participation i.e. AEMO planning assumptions. Due to the complex nature calculating appropriate input assumptions AGL requests that IPART ensure that stakeholders have sufficient opportunity to review the data and approaches used to determine the input assumptions. In addition, AGL requests that IPART clearly set out how will update the input assumptions as part of the annual review of the energy purchase cost and that this process will include stakeholder consultation.

<u>Existing and new generation plant</u>

Frontier has provided a general description of the methodology that they propose to employ in order to determine the costs and technical parameters of existing and new generation plant to be used in their LRMC and market modelling. Whilst the general approach appears sound, the efficacy of the approach can only be judged once the cost estimates have been made available and compared against industry-accepted benchmarks.

<u>Gas cost assumptions</u>

Frontier has proposed that gas costs for generation plant in the NEM be forecast using their proprietary gas market model, WHIRLYGAS to "estimate an incremental LRMC for the gas market". A key concern of the proposed approach is that the modelling of gas costs for generation facilities will not adequately reflect the impact on gas prices resulting from the development of LNG export facilities over coming years.

<u>Coal cost assumptions</u>

The development of an export thermal coal market from the east coast of Australia has seen a greater exposure for coal-fired generators to export-parity prices. As existing generators coal contracts are renegotiated the short-run marginal cost (SRMC) of generation for these plant will likely increase. On this basis, AGL is of the view that any coal cost forecast should adequately represent the exposure of existing and new generators to the price set in the thermal coal export market.

Weighted Average Cost of Capital

The discount rate used to calculate the stand-alone LRMC must reflect a reasonable estimate of the return on electricity generation assets that would be expected in the electricity industry.

AGL has provided a detailed discussion of the WACC parameters and issues presented in IPART's report: *Weighted average cost of capital. Incorporating a return on capital in the 2013 electricity determination. Electricity – Draft Methodology Paper, November 2012* in Annexure 1. The discussion focuses on WACC inputs for the electricity industry. AGL note that IPART's proposal of determining WACC inputs for a variety of industries (i.e. LNG facilities, gas transmission etc) will be a complex and resource-intensive process. AGL will seek to comment further on IPART's approach as more details are provided on how IPART treats the capital costs for these different industries.

<u>Post-tax WACC framework</u>

IPART has proposed changing the current approach of using a real pre-tax WACC to a real post-tax WACC. The real post-tax approach is used by IPART for determinations relevant for other industries. Moving to a real post-tax WACC would mean that the WACC should only be applied to after tax cash flows. Therefore, tax would need to be considered as part of the cash flows of the business in question.

AGL is concerned that estimating the tax liabilities, and related cash flow impacts, would result in additional modelling complexity due to the diversity amongst the businesses under consideration, in particular due to their capital structures. For example, the tax liabilities/cash flows of a company with high gearing levels would be significantly different to business with low gearing levels. Hence by applying a single post tax WACC to businesses which have differing gearing levels would not accurately reflect there true cost of capital.

Further, the formula outlined as the post tax WACC calculation needs to be clarified as it does not reflect the taxation component applicable to the cost of debt.

Choosing a point estimate within a range

AGL is satisfied with IPART's current approach of setting a range and then taking into account broader objectives and concerns raised by stakeholders in order to choose a single point within a range. AGL note that consistency in applying this approach will provide greater certainty to retailers and stakeholders alike.

Updating the WACC during the 2013 determination

As noted by IPART, AGL has expressed concerns that limiting the annual review of WACC components to solely market-based components can result in debt and equity cost estimates that do not align with prevailing market conditions. However, AGL does acknowledge that by expanding the scope of updating the input parameters that this could increase volatility of the cost of capital being considered.

On this basis, AGL considers that it is reasonable to update the risk free rate and MRP, on the basis that the MRP is reflective of short-term market conditions. It would also be appropriate to update debt margins to account for any changes in the market. AGL notes that as long as the gearing ratios are consistent with the credit ratings of the respective businesses, then we would expect minimal changes to occur in the equity beta, gamma and gearing ratios over the determination period.

Carbon Pricing Mechanism

The approach proposed by IPART to incorporate the carbon price into the 2013 determination is generally appropriate. AGL notes that uncertainty about the continuation of the carbon pricing scheme will have an impact on futures prices over the determination period. In the event that this has an impact on the market-based energy purchase cost, an allowance should be made to ensure that retailers are allowed to recover the full cost impact of the scheme on the futures price.

In regard to the carbon price for 2015/16, AGL supports delaying the choice of a final method to calculate the carbon permit price until greater certainty is available on the status of the carbon pricing scheme and likely permit price. In the meantime, any estimates should be based on publicly available data such as Treasury modelling.

Discretion in determining the EPC

IPART is considering whether it is in the long term interests of electricity customers for prices to include any further headroom in addition to the headroom that IPART considers is already built into prices with the 75% LRMC weighting in the floor when the LRMC exceeds the market-based cost.

In AGL's view holding prices below the long run cost of supply (i.e. LRMC) is not in the long term interests of consumers. A recent Working Paper by AGL's Chief Economist provided a detailed discussion on the effect of retail price regulation on industry investment.[1] In summary:

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[1] Simshauser, Paul. *When does retail electricity price regulation become distortionary?* AGL Applied Economic and Policy Research. Working Paper No. 33, July 2012. Available at : http://www.aglblog.com.au/wp-content/uploads/2012/08/No-33-Regulated-Pricing.pdf

- Investment flows into thermal and renewable capacity are facilitated by synthetic intra-firm or externally written long-dated Power Purchase Agreements (PPA).
- The use of short run dynamics has the effect of marking PPAs to market annually by a regulatory process reliant on imperfect information, rather than by competitive market forces. Consequently, the regulatory process produces disincentives to write long-dated PPAs. This is a highly problematic outcome because:
  - PPAs are the prime method of facilitating the flow of private sector investment into the electricity industry and by implication, security of supply, since at least 2004.
  - Crucially, PPAs need to be written by credit-rated entities. If short run dynamic price regulation was to become systemic across all regions, the stability of the NEM itself would be threatened, as integrated entities would risk losing their investment-grade credit ratings given past investment and PPA commitments. If integrated entities lost their credit ratings, they would be unable to write "bankable" PPAs.
  - At a minimum, this would lead to a generalised rise in the industry"s cost of capital, thereby increasing the cost of new thermal and renewable power plants (including those required to meet the 20% RET), and therefore final energy prices in all sectors of the economy.

As the regulated price acts as a price cap, it should be set in such a way as to ensure security of supply and offer sufficient incentive for retailers to enter the market and offer discounts off the price cap. When LRMC is higher than market-based costs, the change in the terms of reference would have diminished the headroom by 25% compared with the 2010 Determination. Therefore, the ability to discount will be reduced, thereby reducing the level of competitive activity.

For these reasons, AGL remains of the view that where the LRMC is greater than the market-based cost, the EPC allowance should be set based on 100% of LRMC.

5.4. Green scheme costs

LRET

AGL supports the use of a LRMC methodology for assessing the compliance costs associated with the LRET. AGL believes this is the most appropriate methodology given retailers of scale servicing a small customer load will invariably source a significant portion of their LGCs through long term PPAs with new entrant build renewable generation.

AGL is concerned that the using an incremental multi-year LRMC approach provides a result below what we would expect for the LRMC of meeting the LRET compliance requirement for a retailer. AGL believes that the most appropriate method of setting the LRMC allowance would be to use the current LRMC of a renewable energy generator (most likely to be deployed for LRET compliance) in the NEM and then deduct the expected black price' that the generator would receive over the period.

SRES

Calculating SRES compliance costs for retailers has been a difficult task for energy regulators over recent years. AGL supports IPART's proposed approach for dealing with the STP uncertainty through the use of a cost pass-through mechanism.

AGL broadly agrees with Frontier that calculating the cost of compliance with the SRES should be based on the binding and non-binding STP estimates and use of the $40 STC price. While acknowledging recent recommended changes to the STC Clearing House made by the Climate Change Authority, AGL does not support the use of historical market prices to set a future cost of scheme compliance for retailers. AGL notes that numerous changes in the market and other regulatory decisions have meant that fundamentals of the STC market have changed over time, and this could continue over the period of the determination.

ESS

AGL notes that IPART has proposed to "develop an approach and conduct our own analysis to estimate the costs of complying with the ESS." AGL suggests that the fundamental structure of the ESS market has not changed since 2012, and therefore the current approach for calculating the cost of compliance is appropriate. If IPART were to develop an approach for estimating a certificate price available for future years this would add an additional level of complexity into the process of determining the regulated retail price.

5.5. Annual energy review

The purpose of the annual WEC review is to remove the risk to retailers of being locked into a 3 year regulated price path which inadequately covers the costs and associated risks arising from a changing wholesale energy market.

As such, AGL broadly supports the methodology for annual reviews as used in the current determination.

However, experience from the current determination has shown that even when updating only an element of the decision, it is important to ensure that all variables that can impact on this component are updated in parallel. The difficulty in producing a realistic WACC in the recent annual review highlighted this issue. In that instance, the scope of variables to be updated when constructing a new WACC was restrictive and created significant concerns for IPART.

6. Retail cost allowance

6.1 Characterisation of a Standard Retailer

IPART's proposed definition of a Standard Retailer is a standalone retailer in NSW that:

- is not vertically integrated into electricity distribution;
- serves retail customers, including small retail customers, in NSW;
- has achieved economies of scale in retailing (ie, has efficient costs);
- can offer retail customers standard form and/or market customer supply contracts; and
- has an existing customer base to defend and seeks to acquire new customers.

This aligns with the 2010 Determination. In previous determinations, the historic retail cost data that IPART relied upon was derived from incumbent retailers that had stapled distribution businesses. The cost information was therefore unreliable or perhaps influenced by economies of scale as the reported costs were significantly lower than industry benchmarks as submitted by AGL and other retailers.

IPART's definition of a Standard Retailer in the Issues Paper is in contrast to the costs incurred by second tier retailers who have to acquire every customer and may not have the same economies of scale.

AGL considers that defining retail costs from the perspective of a Standard Retailer is inconsistent with the requirement to set prices to encourage competition.

True competition can only occur if new entrants are encouraged to participate. New retailers introduce a greater dynamism in the retail market than existing Standard Retailers as they seek to gain market share through discounting and new products.

In a competitive market, if regulated prices are set too high then discounting will act to remove any additional headroom so if IPART were to set retail operating cost based on second tier retailers' costs then it will encourage further competition.

6.2 Changes to retail operating costs and costs of acquiring and retaining customers since the 2010 determination

One significant change since the 2010 determination has been the introduction of the *Clean Energy Act 2011*. This has increased retail operating costs through the additional administration costs as well as the impact that carbon pricing has on bills and subsequently on bad debts.

In addition, the costs of acquiring and retaining customers are directly related to the level of competitive activity in the market. In the 2010 Determination, IPART assumed a churn rate of 13 per cent. In 2012, the churn rate has increased to over 20 per cent. This has a material impact on the total cost of acquiring customers.

Furthermore, the level of competitive activity has also had a significant impact on the unit cost of acquiring or retaining customers through various channels. For example, in its 2011-12 annual results, AGL has reported that the cost per lead sale has increased by 18 per cent.

6.3 Retail costs reported by publicly listed companies

Due to differences in corporate organisation and accounting treatment, it is difficult to compare the retail costs reported by publicly listed companies. It is often unclear if these costs include non-commodity energy products such as solar panels, costs of managing energy portfolio, range of customers or treatment of customer acquisition costs including goodwill from corporate acquisition.

Nevertheless, these costs provide a useful guide on the likely range of operating costs but it is highly unlikely that a collation of reported costs from publicly listed companies will provide agreement on a precise number. Therefore, some judgement is required in setting the operating cost allowance.

In Table 6.1 of the Issues Paper, IPART has referred to AGL's reported cost to serve per customer account of $63 to $66 above. This is one of three measures which AGL reports on operating costs.

In announcements to the market, AGL has published details of its financial performance in an ASX Appendix 4E report. For the financial year ended 30 June 2012, AGL has reported the following table in section 4.1.4.2 Cost to Serve Analysis:

Table 1: Cost to Serve Analysis

		Year ended 30 June 2012	Year ended 30 June 2011
Net operating costs	$million	321.7	290.8
Net operating cost per account	$	95.38	89.34
Cost to grow/retain	$million	108.0	75.9
Cost to grow per account acquired/retained	$	82.94	84.08
Cost to serve	$million	213.7	214.9
Cost to serve per account	$	63.36	66.01

These amounts represented costs which are directly related to the retail business and do not include operating costs related to Merchant Energy involved in managing the wholesale energy portfolio and Corporate Costs. They also do not fully reflect the direct cash outlays for customer acquisition incurred during the year as these costs are amortised.

In 2011-12, Corporate Costs or Centrally Managed Expenses which can be allocated to Retail Energy amounted to $55.8 million but there is a further $94.5 million which remained unallocated (section 4.5 of ASX Appendix 4E report). If the unallocated amount is re-distributed on the basis of the current allocation, Corporate Costs would represent about $33 per customer.

When operating costs related to Merchant Energy and Corporate (including a re-allocation of the unallocated amount), as well as the reversal of capitalised costs and amortisation of campaign costs, are considered, the cost per customer will be about $45 per customer higher for 2011-12. The adjusted cost to serve per customer for 2011-12 will be about $108 and the adjusted net operating cost per customer which includes acquisition and retention costs incurred during the year, would be about $140.

7. Retail margin

AGL notes that IPART has re-commissioned SFG to review the reasonable range of retail margin. As in previous submissions, AGL considers that the retail margin allowance of 5.4% which IPART has set in the 2010 Determination to be too low considering the risks of operating in the most volatile commodity in the world.

IPART has set the retail margin as a fixed percentage of the Standard Retailer' total costs including energy costs, retail costs allowance and network costs. As noted by IPART, as a consequence, the retail margin allowance (expressed as a dollar amount) increases whenever energy, retail and network costs increase. AGL considers that it is appropriate that retail margin continues to be set as a percentage of costs (or more usually, revenue). The retail margin accounts for retailers' risk (as well as return on investment) and this risk increases as costs increase.

8. Regulated retail charges

Late payment fees should be applied on a cost reflective basis and should be applied to those customers who have caused additional costs to be incurred by the retailer. Late payment fees are designed to encourage customers to meet their obligation to pay their accounts by the due date.

Currently, AGL charges $14 (GST inc) for those customers on electricity market contracts in NSW that make a late payment. This amount is cost reflective and AGL believes this is a fair and reasonable basis to recover the additional costs.

The dishonoured payment process generally requires manual intervention by the retailers and thus can result in considerable administration costs being incurred by the retailer. Therefore, the retailer should be able to recover these costs where payments are dishonoured by financial institutions in addition to any fee charged by external parties.

Annexure 1

Weighted Average Cost of Capital (WACC) – Determining a feasible WACC range

The following sections provide a discussion of each component used in the calculation of the WACC using the CAPM.

Nominal risk free rate

IPART has highlighted the need for maintaining consistency in the way in which inputs derived for use in the WACC, in particular for the nominal risk free rate and the market risk premium (MRP). AGL expressed concerns to IPART that because they used a significantly lower risk free rate in 2012 by comparison to long-run averages, while the equity beta and MRP remained constant, they implied a drop in the cost of equity. This drop in the cost of equity implied that a virtual wall of cheap equity capital market funding existed – when it is known in practice that exactly the opposite applied.

AGL remains of the view the risk free rate should reflect government debt instruments with a term to maturity consistent with the industry in question. In terms of electricity generation a 10 year term to maturity will more accurately reflect reflect the time value risk / volatility generation projects are exposed to.

Once IPART has established the source of data used to calculate the risk free rate it will need to consider over what time period the instruments should be sampled. AGL suggest the current averaging period approach is suitable, provided that a MRP is adopted that reflects current market conditions.

Inflation adjustment

IPART used an inflation adjustment of 2.8% in 2012/13. IPART derived the value from the 20-day average inflation swap market data. AGL agrees with this approach.

Market risk premium

IPART defined the market risk premium (MRP) as "the expected return over the risk free rate that investors would require for investing in a well diversified portfolio of risky assets".[2] As noted earlier, the MRP should be set so that the cost of equity represents a reasonable estimation of the expected return of investors. The SFG Report provided by AGL to IPART in May 2012 highlights that if the risk-free rate is updated so should the MRP such that it reflects the change in market conditions i.e. conditional MRP estimate. SFG suggested that an MRP estimate could be derived by establishing a reasonable MRP range and comparing recent values of three MRP conditioning variables (i.e. option implied volatility, debt yield spread and dividend yield) to their average value to determine the MRP value chosen within the range. Based on the value at May 2012 of the variables compared with their average SFG suggested that an appropriate estimate of the MRP is in excess of 7%.[3]

[2] IPART, Review of regulated retail tariffs and charges for electricity 2010-2013. Electricity – Final Report (March 2010). Page 241.

[3] SFG Consulting, The weighted-average cost of capital for electricity generation. Report for AGL. 10 May 2012. Page 20.

Equity beta

IPART describe the equity beta as the following:

> *The equity beta value is a business specific parameter that measures the extent to which the return of a particular security varies in line with the overall return of the market. It represents the systematic or market wide risk of an asset that cannot be avoided by holding it as part of a diversified portfolio. It is important to note that the equity beta does not take into account business specific or non-systematic risks.*[4]

AGL has argued previously that this equity beta range does not sufficiently represent the risks involved with electricity generation, and particularly based on the gearing levels assumed i.e. an increase in gearing results in more prior ranking debt, thereby increasing the risk of residual equity.[5] AGL previously proposed that an equity beta for an electricity generator should range from 0.9 – 1.4.[6] However, AGL note that in other WACC estimates for the electricity generation sector the equity beta of an independent power producer has been estimated as high as 1.75.[7] For an electricity retailer with a lower level of gearing their equity beta should be more consistent with the market i.e. ~1.

Gamma

In the CAPM, the value of the imputation tax credits for investors is represented by 'gamma'. IPART has proposed to use a gamma of 0.25 based upon recent regulatory precedent. AGL agree with this proposed approach.

Debt margin and debt raising costs

IPART used a debt margin range of 2.1% to 3.6% in 2012/13. This range is based upon the yields of a sample of Australian corporate bonds with a BBB/BBB+ credit rating and at least 2 years to maturity. The sample also includes the Bloomberg 7-year BBB fair value curve.

AGL has previously expressed concerns to IPART as to whether the assumption of that the debt margin should be calculated based upon a company with a BBB/BBB+ credit rating.[8] This credit rating is not considered representative of the range of companies currently developing and/or operating power generation plants in the NEM.

AGL is also concerned that the 2012/13 debt margin underestimates the costs likely to be experienced by both an 'Integrated Utility' and an 'Independent Power Producer' investing in a generation project which typically operate for 25 years because the corporate bonds sampled by IPART range in maturity from at least 2 years. AGL is of the view that the

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[4] IPART, Review of regulated retail tariffs and charges for electricity 2010-2013. Electricity – Final Report (March 2010). Page 237.

[5] AGL Energy, AGL Response to the Independent Pricing and Regulatory Tribunal, Changes in regulated electricity retail prices from 1 July 2011, Draft Report (Date: 13 May 2011). Page 9

[6] AGL Energy Ltd. AGL Response to the Independent Pricing and regulatory tribunal, review of regulated retail tariffs and charges for electricity 2010 -2013, Draft Determination (Date: 08 February 2010). Annexure C – Report by KPMG, Weighted Average Cost of Capital, IPART Review of regulated retail tariffs for Electricity – 1 July 2010 to 30 June 2013

[7] ACIL Tasman, Calculation of energy costs for the 2011-12 BRCI. Prepared for the Queensland Competition Authority. 30 May 2011. Page 23.

[8] AGL Energy, AGL Response to the Independent Pricing and Regulatory Tribunal, Changes in regulated electricity retail prices from 1 July 2011, Draft Report (Date: 13 May 2011). Page 9.

debt margin should be calculated to estimate the margin on longer-term debt instruments i.e. 10 years. If corporate bond data is not easily available then a useful proxy is the Bloomberg BBB 7-year fair value curve plus an adjustment to ensure this price is equivalent to a 10 year debt instrument.

Debt to total assets

The capital structure assumptions (i.e. gearing) used in the WACC calculation is intended to reflect the ratio of debt to equity in the financial structures operated by the business in question.

The WACC adopted previously by IPART for electricity generation assumes that:

- a power company finances the project by issuing corporate bonds;
- credit spreads for the bonds have been priced by IPART at investment-grade, that is, the bond spreads used by IPART are based on a credit rating of BBB/BBB+; and
- the power company has a capital structure of 50:50 bonds and equity.

AGL remains of the view that these assumptions are incompatible and in particular, the latter two assumptions simply cannot co-exist in theory, or in practice.

In order for an electricity generation firm to obtain an investment grade credit rating of BBB or BBB+ from the relevant ratings agencies (i.e. Standard & Poor's, Moody's, Fitch) the key financial metric or threshold that the power company would need to meet is:

- Funds From Operations (FFO) to Interest Expense (I).

Ratings agencies clearly require an FFO/I Ratio of at least 5x to provide an investment grade credit rating. Modelling of a benchmark stand-alone generator demonstrates that the feasibility of achieving a 5x FFO/I ratio is simply not possible unless unit prices are 'sustained' dramatically higher than the LRMC of the plant – which is of course an unreasonable proposition in a competitive market environment.

To provide some context, even vertically integrated merchant utilities such as Origin Energy and AGL Energy face at least a FFO/I Ratio of 5x when dealing with the ratings agencies on their respective BBB+/BBB credit ratings. Neither Origin Energy nor AGL Energy carry more than 30% debt in their capital structures, otherwise they would be in violation of one of the key metrics used in credit assessment (i.e. FFO/I at 5x or greater).

In order to address this error, AGL suggest that if the existing approach to issuing long-dated investment grade corporate bonds is retained, then the implied debt levels in the capital structure should reflect BBB/BBB+ credit metrics, which will have the effect of reducing debt levels down to at least 25-30%.