AGL Energy Limited
ABN: 74 115 061 375
Level 24, 200 George St
Sydney NSW 2000
Locked Bag 1837
St Leonards NSW 2065
t: 02 9921 2999
f: 02 9921 2552
agl.com.au

Mr Mark Feather
General Manager, Policy and Performance
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

By email: DMO@aer.gov.au

18 October 2019

Dear Mr Feather,

Position Paper – Default Market Offer Price 2020-21

AGL welcomes the opportunity to provide comments to the Australian Energy Regulator (AER) in relation to the Position Paper on the Default Market Offer Price for 2020-21 which was published in September 2019.

The introduction of the DMO is a fundamental change in the regulatory framework and represents a return to the partial regulation of retail electricity prices. When the DMO was implemented on 1 July 2019, no existing AGL customers faced price increases as standing prices were reduced to match the DMO.

AGL agrees that it is not appropriate to apply the top-down approach used to establish the 2019-20 DMO for future periods as it will not meet the policy objectives. AGL supports the AER's preferred option to set the 2020-21 DMO price by adjusting the current 2019-20 DMO price for forecast cost changes.

However, the AER's proposed approach in assessing environmental costs should be re-considered because the market prices of LGCs are not representative of retailers' costs and the non-binding STPs have been highly unreliable.

In relation to forecasting network cost changes, AGL believes the best available forecast, where available, is the networks' annual pricing proposals which should be submitted to the AER by 1 April each year. They are usually approved with no amendments and are much more credible than using the price paths outlined in the regulated revenue determinations. As the approving body, the AER is in the best position to set the DMO price using these network tariff proposals.

More detailed comments are attached in response to the issues raised in the Position Paper.

If you have any questions in relation to this submission, please contact Meng Goh, Senior Manager Regulatory Strategy, on mgoh@agl.com.au or (02) 9921 2221.

Yours sincerely

Elizabeth Molyneux
General Manager Energy Market Regulation

Attachment: AGL's Comments on the Position Paper

Approaches to setting the DMO annual price

AGL supports the policy objectives of:

- preventing unjustifiably high standing offers,
- allowing retailers to recover efficient costs including a reasonable retail margin and CARC, and
- not dis-incentivising innovation, competition and market participation by customers and retailers.

To determine the 2019-20 DMO (DMO1), the AER used a top-down approach which assessed the DMO price as the mid-point of the median standing offer and median market offer. This was based on generally available prices in October 2018 with no other adjustments after considering forecast cost changes of key inputs such as wholesale and network costs for 2019-20. AGL agrees with the AER's view that this approach is not appropriate for future DMOs as the range of standing offers and market offers have significantly reduced following the implementation of DMO1.

The AER has identified three general pricing approaches for setting the 2020-21 DMO (DMO2) and beyond.

Option 1 is to take the DMO1 price and update it for forecast cost changes. This is the AER's preferred option which AGL also supports. With DMO1 price set at a level which meets the policy objectives, the focus is on the change in cost rather than the absolute level of costs. However, there should be some flexibility to adjust costs where they have been set inappropriately previously.

Option 2 is to use observed market offer prices and for instance, set the DMO price at a set percentage above the median market price. AGL agrees that this creates significant risk to retailers by causing market distortions and gaming the offer spread in response to this methodology. There could be greater volatility in the price re-set and the premium to establish above median market price will be the subject of considerable debate.

Option 3 is to adopt the traditional cost build up approach. In AGL's experience, there is a range of views on the appropriate levels of the cost stack components, in particular, wholesale energy costs, environmental costs, retail costs and retail margin. Often, subjective judgement is required to determine each of the cost stack components because a suitable benchmark is not available or there is a range of possible values. Where modelling is involved, different inputs, assumptions and methodologies will produce different outcome. In addition, due to different operating model, there are different retailer cost structures.

One factor which could also be relevant to consider is that retailers including AGL have fixed price offers, which could be up to 2 years. While these offers provide certainty to customers over the contract period, there is considerable risk to retailers if the DMO price reset is uncertain.

Forecasting changes in the retailer's cost of supply

AGL notes that the representative retailer is defined as an efficient, prudent and risk adverse retailer with an established customer load. This allows a portfolio hedging approach to be adopted, involving a layering of swaps and caps over a period of time. However, there is no allowance for volume risk resulting from customer churn. Whilst this definition may be appropriate for the larger retailers, the resulting wholesale energy costs may not be sufficient to account for all the risks of retailers operating in a competitive environment.

In relation to using a simplified forecast methodology, ACIL Allen has provided a study using a portfolio contract price index approach which showed that the movement in contract prices is a strong predictor of the change in Wholesale Electricity Cost (WEC), accounting for 98% to 99% of the variation from 2013-14 to 2019-20 in the Queensland market. However, the approach does not provide a perfect fit so that in some years the estimated changes can be 5% higher or lower than the full model approach. Combined with the changes in the full model WEC of 10%, these differences using the index approach could create additional risk of prices being set too low. As ACIL Allen has considered this variation as a "not inconsequential error" and the fact that the extent of variation may differ by jurisdiction, further assessment of this approach will be necessary, including the consideration of an adjustment to compensate for this error.

Wholesale electricity costs

Retailers are likely to hedge according to their own customers' load profile. However, as each retailer will have a different profile, the Net System Load Profile (NSLP) and Controlled Load Profile will be a useful proxy to model a representative load profile. The use of NSLP and CLP is particularly relevant when retailers are seeking to acquire customers where their consumption profile is unknown.

The use of a market based hedging approach is also reasonable. As with any modelling, however, the outputs of the model will depend on the inputs and assumptions. They should reflect recent changes in wholesale market conditions such as the closure of Hazelwood Power Station in 2017 and more supply from renewable energy resources. Due to the rapid penetration of rooftop solar, the correlation of weather and demand in the past may not be suitable for the future.

It should be also noted that corporate risk management policies could define the hedging strategy by establishing minimum levels of hedge cover. In addition, while retailers will seek to minimise costs, taking a view on future spot and contract prices to determine when to hedge is better treated as a wholesale trading activity rather than a hedging function.

In addition, there are other wholesale related costs. AEMO has invited Expressions of Interests for the Short and Medium Notice RERT for 2020. AGL believes an allowance should be made for these costs in the DMO, as well as the cost of directions especially in South Australia.

Environmental costs

Large scale renewable energy target (LRET)

In the *Residential Electricity Price Trends – Wholesale Market Costs Modelling 2018* produced for the AEMC, EY made a number of observations:

- Only a small percentage of LGCs are traded on the spot market, with most large scale renewable projects entering into PPAs with retailers.
- The LGC spot price is subject to many different drivers that are completely de-coupled from the commercial drivers of LGC contract prices.
- Due to the long term nature of PPAs, the average LGC price received by renewable developers is likely to be higher than that of the marginal new entrant.

The LRET scheme was designed to encourage investment in generation. As the LGC market is thinly traded, it is questionable whether it is appropriate to use a market-based approach to assess LGC prices for pricing purposes. An "efficient, prudent and risk adverse retailer with an established customer load" is more likely to meet its LRET obligations largely through PPAs so that its LGC costs do not vary with market prices. In addition, for various reasons, some retailers have opted to pay the shortfall charge. AGL suggests that a reasonable approach for estimating LGC costs should reflect the long term industry costs by considering the range of historical PPA prices.

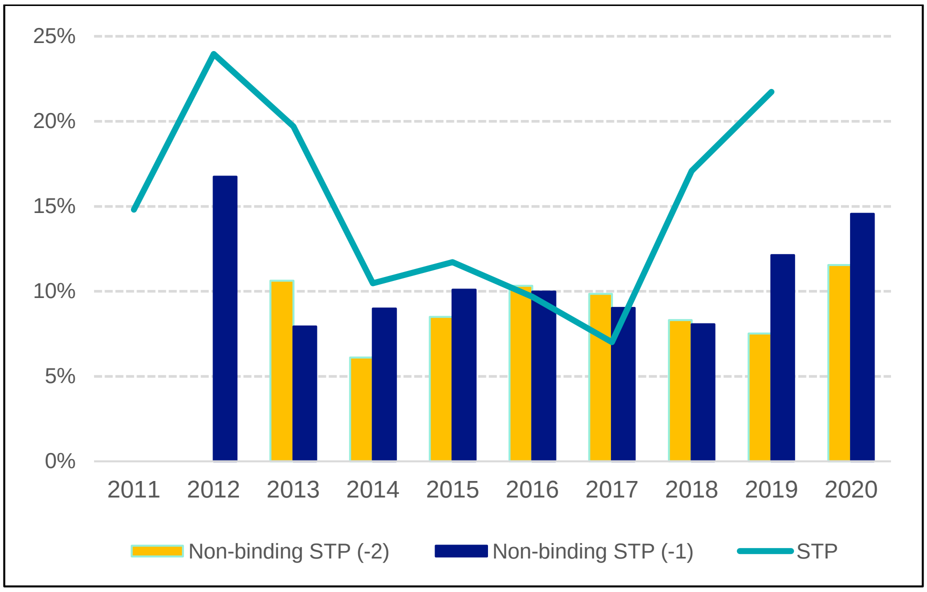
Small scale renewable energy scheme (SRES)

The cost of compliance with the SRES is derived by applying the STP value to the STC price. AGL supports the use of the STC clearing house price of $40 per STC.

ACIL Allen proposes to estimate the STP by using the binding and non-binding STPs published by the Clean Energy Regulator (CER). The CER publishes non-binding STPs one and two years in advance. AGL has concerns with the use of the non-binding STPs as they have significantly underestimated the final binding

STPs over the past 9 years and particularly, more recently, in 2018 and 2019. This is illustrated in the graph below:

Figure 1 Comparison of binding and non-binding STPs



Note: This graph is based on data published by the Clean Energy Regulator.

In AGL's view, the published non-binding STPs for 2020 and 2021 of 14.56% and 12.88%, respectively, are highly unreliable. AGL has assessed the 2020 STP to be higher than the current 2019 STP of 21.73%. In the final determination in April 2020, AGL anticipates that the AER will take account of the final binding 2020 STP which should be set by 31 March 2020. In relation to the 2021 STP, the AER (and ACIL Allen) should consider if there are more robust estimates than the non-binding target.

Network costs

The network tariffs outline in Table 3 of the Position Paper are the flat or non-TOU tariffs. AGL agree that these are the appropriate network tariffs for assessing network cost changes. However, it is relevant to review this from time to time as the network distribution businesses consider alternative pricing approaches.

The AER has noted that due to timing of annual network tariff approvals, particularly for the distribution networks undergoing a revenue reset, the AER's cost assessment may not be able to incorporate the actual changes in annual tariffs, as the AER is required to make their DMO determination by 1 May of each year. The AER also considers that the best available forecast is the annual change in revenue provided in the network revenue determinations.

In AGL's view, the forecast network cost changes for DMO1 has been unsatisfactory, particularly given that the AER was both approving the network tariffs and also setting the DMO price using the network tariffs. The forecast network cost changes for 2019-20 were generally below the actual changes in the final approved tariffs.

The issue can be highlighted with the determination of DMO1 price for South Australia. In SA, the AER assessed SAPN's 2019/20 prices to increase by 3.2% based on SAPN's 2015-20 revenue determination. However, due to lower demand, final SAPN's 2019-20 prices were 11.3% higher for a residential customer on the flat tariff using 4,000 kWh a year (8.9% higher for a small business customer using 20,000 kWh a year). Therefore, the DMO1 price for SA was significantly below what it should have been if there had been proper adjustment for the actual network cost changes for 2019-20.

AGL has observed that the revenue X-factors in the network determinations are unreliable and seldom eventuate as the price change in the final network tariffs. This is due particularly to the wash-up to account for the variation in demand as well as tariff re-balancing and adjustments under the various incentive schemes. In AGL's view, the best available forecast, where available, is the networks' annual pricing proposals which should be submitted to the AER by 1 April each year. In most cases, these pricing proposals are approved by the AER with no amendments and are much more credible than using the price paths outlined in the regulated revenue determinations. As the approving body, the AER is in the best position to set the DMO price using these network tariff proposals.

Where annual pricing proposals are unavailable, for instance, due to the regulatory reset of the five year revenue determination, AGL suggests that the AER consults with network businesses to provide forecast network charges. This will significantly reduce the risks of mis-pricing.

In addition, AGL recommends that adjustments be made to the DMO1 price, particularly in relation to SA, to correct for the under-statement of actual tariff changes for 2019-20 before considering the network changes for 2020-21.

Residual costs

Residual costs referred to by the AER are the cost component remaining after accounting for wholesale energy costs and network charges. They comprise of retail costs, acquisition and retention costs, and retail margin.

The AER has asserted that is generally accepted that representative retail costs do not vary significantly over time, unless there is a significant change required in a retailer's business operations or in customer service requirements. The AER has proposed to index the residual costs by CPI.

There has been a significant number of regulatory changes in recent times in the wholesale and retail markets with rule changes proposed by Federal and State Governments. In addition, in a highly competitive environment, AGL has continued to improve the services which we offer to customers and has implemented projects such as the Customer Experience Transformation program to increase digitalisation and improve operating efficiency. On balance, AGL agrees that it is reasonable to assume a CPI increase in the baseline residual costs

Step change framework for material changes in retailer costs

In addition to the cost to serve and cost to acquire and retain, the AER has proposed a step change framework to assess changes to the external operating environment which could impact on retail costs. This include regulatory initiatives such as five minute settlement and the consumer data right.

For 2020-21, the AER considers that all the regulatory initiatives that will lead retailers to incur costs over the DMO2 time period can be absorbed by the existing costs to serve and are not material enough to need specific adjustments through a step change.

In AGL's view, this framework is reasonable for significant market and regulatory developments where specific projects are established, and costs can be separately tracked.

Model annual usage

The model annual usages for residential customers outlined in Table 4 in the Position Paper are appropriate and it is important that these usages are consistent from one year to another for comparative purposes. However, based on AGL's customer base, the model usage for small business of 20,000 kWh a year is too high A more representative annual usage for small business customers is about 10,000 kWh a year.

Time of use

We note the AER's position to use the flat rate DMO annual usage and price for residential TOU tariffs and that the AER is not required to set a DMO price or usage for small business customers on flexible tariffs.

AGL notes the AER's justifications for using the flat rate DMO price for TOU tariffs i.e. the annual bill for TOU customers is similar to the annual bill or flat rate customers, and there are a comparatively small number of customers on TOU standing offers. However, these should be monitored regularly. Following the introduction of metering competition, with customer-led and retailer-led rollouts of digital meters, there will be a higher take-up of time-of-use pricing with distribution network businesses establishing mandatory assignment of time-of-use tariffs. In addition, over time, the level of TOU prices could diverge materially from flat rates.

Solar

AGL agrees with the AER's proposed approach to apply the DMO price for customers who have installed solar PV. It is appropriate that the standing offer prices which have set in line with the DMO price are available to customers regardless of whether they have a solar PV installation.

.