19 November 2020

Mr Mark Feather
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Dear Mr Feather

**Default Market Offer to apply from 1 July 2021 – Position Paper – October 2020**

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

We appreciate the opportunity to engage with the AER in setting the Default Market Offer (DMO) from 1 July 2021. In summary, our feedback on the AER's position paper is:

- we support continuation of the AER's indexation method, noting there is a need to balance the desirability of a light-handed approach against ensuring that material cost changes are appropriately accommodated in the DMO

- we have provided some data on 'step change' costs, noting that some items will need to be refreshed and updated closer to the AER making its final determination

- we support the AER exploring various issues affecting tariff calculations, including more detailed usage profiles and further assessment of costs arising from particular customers, including time of use (TOU) and solar customers

- we do not support the AER's proposed approach to estimating costs of complying with the Large-scale Renewable Energy Target (LRET) as it does not accurately reflect retailer costs. Our proposed alternative produces a more accurate estimate by recognising that the majority of certificates surrendered arise from long-term power purchasing agreements (PPAs), with the residual amount of certificates being purchased at 'observed' market prices.

If you would like to discuss this submission, please contact me on 03 8628 1655 or Lawrence.irlam@energyaustralia.com.au.

Regards

**Lawrence Irlam**
Regulatory Affairs Leader (acting)

### We support the AER's overall indexation approach with some qualifications

We support the DMO being set using a light-handed approach that avoids forensic examination of data and wasteful debate over concepts and measurement of efficiency, for example, as arises under the Victorian Government's Victorian Default Offer (VDO).

With this support, we caution against the AER being complacent in its task. For example, the AER considers that divergences between actual and forecast costs when setting the DMO should not be corrected for several reasons, including that the sum of variances may be small when calculated over several years, and that the DMO price is sufficiently high and should not affect retailers' ability to recover costs.[1]

The accurate tracking of the DMO against retailer cost trends is not necessarily important for retailer viability in the same way as the VDO. However, accuracy in the DMO is important to ensure reference price comparisons, including the presentation of any discounts, are not subject to material changes over time simply as a result of the AER's methods. Even though it is not based on efficient costs, changes in the DMO are regarded by many stakeholders as a reflection of 'true' cost trends, putting reputational and commercial pressure on retailers whose market offers do not keep in lock-step.

It also may be the case that the forecast errors listed by the AER[2] all offset one another, over time or for individual years, but it is not apparent the AER has actually determined this. Such a calculation would be of interest to all stakeholders in exploring the materiality of this issue.

While we do not suggest the AER develop a 'target' value of headroom in the DMO, this value is still important for customers and retailers in engaging in competition, including enticing customers from standing offers onto market offers. The AER should otherwise be mindful of short-term divergences between the DMO and costs as reflected in market offers in specific network regions, and the effect this might have on how certain retailers are perceived. The most prominent example of this is the AER's assessment of network price changes in July 2020, where its estimates for the DMO were materially different from the network tariffs it subsequently approved. This difference was much greater in some network regions where we have a larger customer base than other retailers. A further example is the AER changing methods in relation to the calculation of FCAS, which is likely to disproportionately affect the presentation of offers in South Australia.

In relation to 'retailer costs', we appreciate the intention of the AER in exploring use of a productivity factor but expect debates over the calculation of an appropriate amount will be counter-productive, and ultimately result in an imperceptible change to customer bills. In the first instance, the AER's position paper does not appear to recognise that this residual component includes retailer operating expenditure (opex), margins and depreciation, which raises questions about where efficiency gains can arise. To its credit, the AER notes that costs would need to be split into labour, operating and capital expenses, as well as fixed and variable costs.[3] There would already be considerable effort in validating the various datasets quoted in the AER's position paper, including reported results from AGL and Origin, and by the ACCC. This issue could be revisited in the future should the AER observe material and growing divergences between the DMO and what customers pay under market offers. However even in this instance, this would be a trigger for reconsidering more material elements of its calculations e.g. wholesale

[1] AER, *Position Paper Default Market Offer Prices 2021-22*, 20 October 2020, p. 25.
[2] ibid., pp 24-5.
[3] ibid., p. 40.

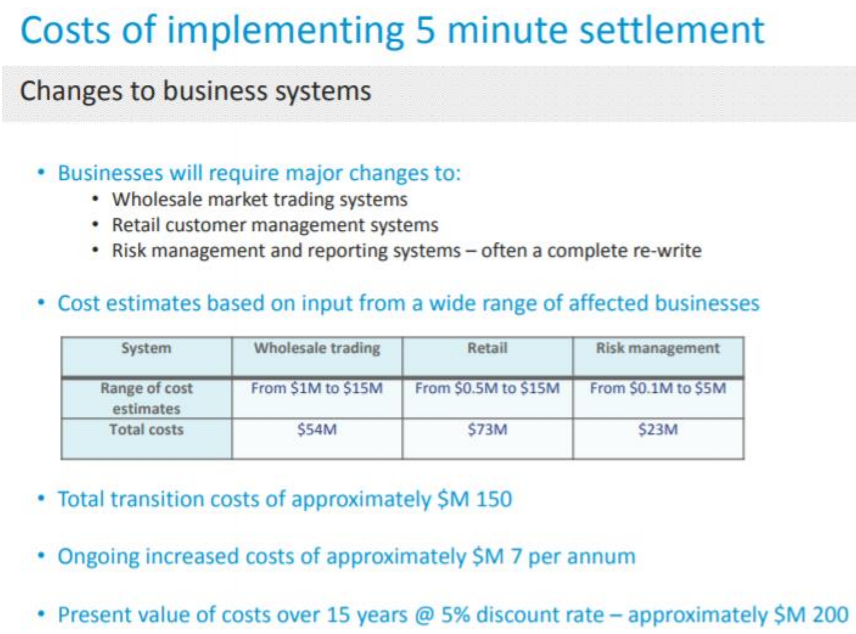
costs, or a more fulsome examination of retailer opex as part of the residual 'retailer cost' component of the DMO.

### COVID-19, 5-minute settlement (5MS) and Consumer Data Right (CDR)

Our further substantiation of EnergyAustralia's costs for implementing 5MS, CDR and dealing with COVID related costs, including items where costs decrease, is contained in confidential Appendix A of this submission.

The AER has noted it expects to seek further information on COVID-19 costs following its draft determination. Other cost items, particularly for CDR, will also become clearer over this time as rules are subject to finalisation.

On 5MS costs, there is published information suggesting the breakdown of industry-wide cost estimates. The following table was prepared by Russ Skelton and associates and presented at an AEMC public forum.[4] This suggests retailers would incur roughly half of the industry-wide costs of implementing 5MS.


Costs of implementing 5 minute settlement

Changes to business systems

- Businesses will require major changes to:
  - Wholesale market trading systems
  - Retail customer management systems
  - Risk management and reporting systems – often a complete re-write
- Cost estimates based on input from a wide range of affected businesses

| System | Wholesale trading | Retail | Risk management |
|---|---|---|---|
| Range of cost estimates | From $1M to $15M | From $0.5M to $15M | From $0.1M to $5M |
| Total costs | $54M | $73M | $23M |

- Total transition costs of approximately $M 150
- Ongoing increased costs of approximately $M 7 per annum
- Present value of costs over 15 years @ 5% discount rate – approximately $M 200

Source: Russ Skelton and Associates, 2017.

### Tariffs and other customer-specific cost items

We generally consider the AER's TOU usage profiles to be sound and support it exploring further refinements including weekends, seasonality, 30 minutes etc.

In relation to the costs of serving TOU customers, the AER considers that the total number of total customers on TOU standing offers is relatively small[5], however EnergyAustralia has a material base of standing offer customers that are not on flat tariffs, particularly in the Ausgrid distribution region. As noted above, the level of the DMO is potentially not as important for retailer cost recovery as it is in forming a

[4] https://www.aemc.gov.au/sites/default/files/content/52ce9f6e-8407-45e0-8fc8-34fec4ac8b29/12-Russ-Skelton-presentation-2.pdf
[5] AER, p. 50.

reference price for discounting and marketing. Demand tariffs are also growing in prevalence, again with different customer cost profiles, and should be monitored. The AER's approach and reference pricing requirements generally create challenges in retailers attempting to simplify their offers via a single, or at least a similar, discount for market offers per state, or even in a single distribution zone.

Costs associated with advanced metering are also worth exploring further as penetration continues to grow, including with new solar installations, and the AER's recent data request will inform this further.

We support the AER's proposal to estimate wholesale costs by splitting residential and small business load. In doing so the AER should have opportunity to re-examine 'shaping' costs in some jurisdictions, particularly South Australia.

We also support examination of likely profile and cost differences in regions where the number of solar customers is becoming increasingly important. Noting that the DMO Code does not allow a separate price for solar customers, any analysis conducted by the AER may be useful in considering eventual amendments to the Code where appropriate.

### Further substantiation of our approach to accurately estimating LRET costs

We have spoken to the AER at staff level about our proposed approach to estimating LRET costs. Essentially our method involves taking a weighted average of large-scale generation certificate (LGC) prices as per the AER's approach, and combining this with a long-run historical LGC price, reflecting the costs incurred by large retailers who have underwritten renewables projects via PPAs. Taking the AER's market-based approach as a given, two parameters must be determined to derive a weighted LGC price under our alternative:

- **The price of LGCs arising out of PPAs**. Our rough estimate is that PPAs struck over the past decade are likely to reflect LGC prices of between $40 to $50 per certificate. This can be validated through a sampling of retailer PPA contract materials. Other sources of information include environmental cost data submitted to the ACCC and the ESC under the VDO, which retailers should be readily able to produce if contract data are not available e.g. because of counter-party restrictions.

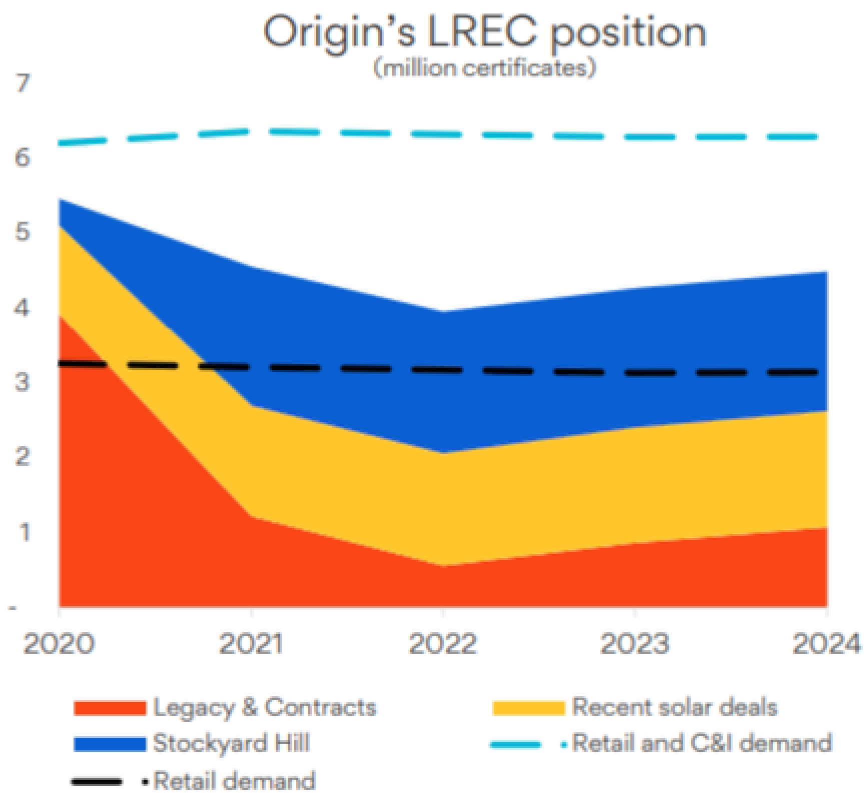
- **The volume of LGCs arising from PPAs, versus those procured from the market**

    - Retailers' holdings of LGCs, including from PPAs, can be easily read from periodic reports from market advisory services such as Green Energy Markets[6].

    - The AER's position paper suggests that forward and spot volumes of LGC trade equate to around half of those surrendered for 2019.[7] On face value this suggests that 50 percent of LGCs surrendered arise from PPAs, which, in our view, is sufficient evidence to invalidate the AER's approach as being representative of retailer costs. The AER should consider whether observed trades reflect individual certificates or are multiple trades of the

[6] http://greenmarkets.com.au/
[7] AER, p. 34.

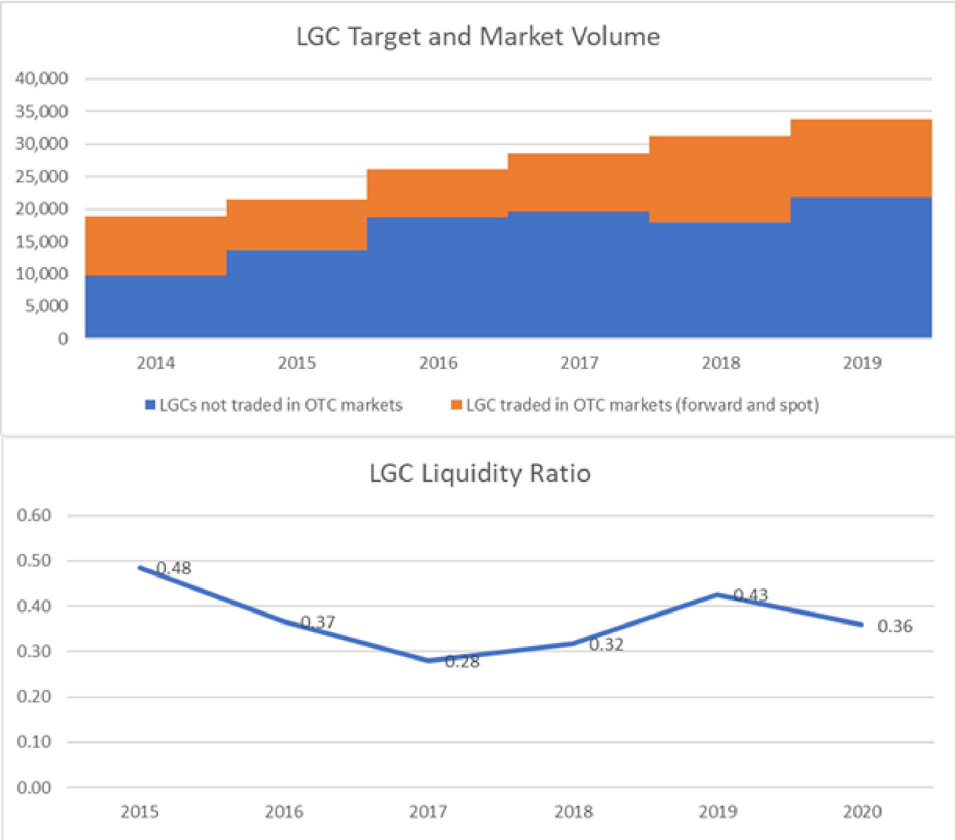
same certificate. Also, proper examination of these data should consider how retailers procure LGCs for the purposes of hedging their mass market requirements i.e. as it is relevant to the DMO. Some retailers have likely taken a position that ensures LGC volumes from PPAs match their mass market retail liabilities, with LGC liabilities for C&I load then taken from the market.




Source: Origin Energy 2020 Full Year Results, 20 August 2020.

In relation to traded LGC volumes, the AER's position paper states that "the broker data used in estimating LGC prices in this determination [sic] is robust and representative of the broader LGC market."[8] Our own examination of data for traded LGCs is not inconsistent with the figures quoted by the AER, however our conclusion is different. LGC liquidity ratios of around 0.4 compare to energy contract liquidity of up to 3 or 4 times the volume of output in some NEM regions. The AER has noted that South Australia has "poor" liquidity[9], even though energy trades here have twice the liquidity as LGC markets. The AER should reconcile its conclusions on these different data.

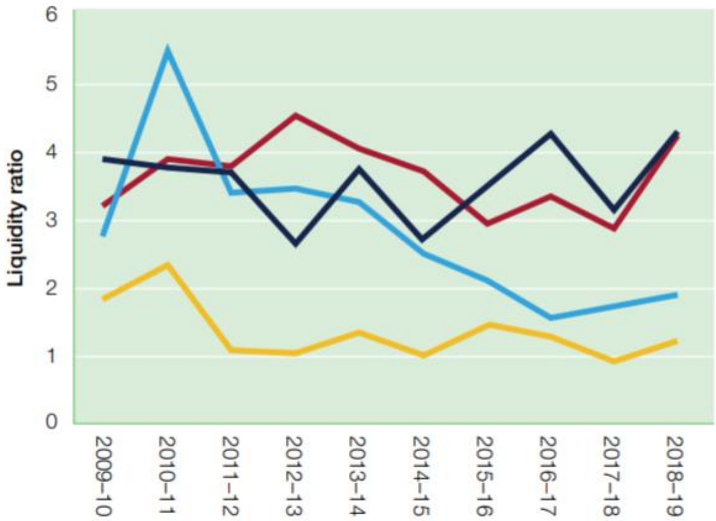
[8] Ibid.
[9] AER, *State of the Energy Market 2020*, p. 104.




Source: EnergyAustralia

Figure 2.31

**Liquidity ratio in NEM regions**




Source: AER State of the Energy Market 2020, p. 104

In summary, the AER's approach to estimating LRET costs is not reflective of retailer costs as it ignores the efficient, long-term costs retailers are incurring because of entering into PPAs. By assuming all retailers procure their entire LGC requirements from the market, and as the market price of LGCs continues to decline, retailers will be further undercompensated by the DMO. This must be addressed in accordance with sections 16(1)(b) and (4) of the DMO Code.