12 April 2024

Daniel Harding
General Manager, Market Performance
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Submitted by email: DMO@aer.gov.au

Dear Mr Harding,

Default market offer prices 2024-25 – Draft Determination

Origin Energy Limited (Origin) welcomes the opportunity to provide comments on the Australian Energy Regulator's (AER) Default market offer (DMO) prices 2024-25 Draft Determination.

Origin recognises the significant challenges faced by the AER in balancing the inherent tensions between the DMO objectives including ensuring cost recovery for retailers and protecting customers from unreasonably high prices. Origin has offset price increases for customers on our hardship program since 1 July 2022, and we understand the AER's desire to put a higher weighting on affordability in this decision. However, it is also imperative the retail market remains competitive with many retailers offering a diverse range of market offers. We share a common objective of wanting to improve customer outcomes and to further develop an industry capable of navigating the energy transition.

On this basis, we do not support the decision to suspend the competition allowance, and do not consider it is in the long-term interest of energy consumers. The removal of the allowance also heightens the risk of under-recovery for retailers given there are several aspects of the DMO calculations that err on the side of conservatism with the rationale being that any under-recovery will be minimised by the headroom afforded by the competition allowance. This includes aspects of the wholesale cost methodology such as the approach used in determining the load profile where the error in the data set for the SAPN and Energex networks is only partially being addressed; and solar exports are to be excluded. It is not appropriate to adopt the level of conservatism seen throughout the DMO while also excluding the allowance.

Notwithstanding the decision for its exclusion, the Draft Determination notes that the AER has calculated a competition allowance of $66 per customer. However, there is no detail on how this was done. The lack of visibility around both the calculation of the allowance and the preconditions for its future reinstatement run the risk of undermining the DMO setting process.

We also note that for DMO 6, the moderating impact of lower wholesale prices was partially offset by higher network costs, given the high inflation and interest rate environment and the cost of jurisdictional schemes. Where this trend persists, it is not prudent or sustainable to seek the meeting of the DMO objectives by continually reducing elements of the cost stack that effectively compromise retailer cost recovery.

With the above in mind, we suggest the AER:

- Clearly set out the methodology used to determine the competition allowance. This will facilitate stakeholder feedback and provide visibility for retailers so that they can anticipate changes in the retail allowance and manage financial risk.

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- Rethink the decision to suspend the competition allowance for DMO 6. However, if this decision is upheld, the AER should confirm / reinforce that this can only reasonably be viewed as a temporary measure, and the criteria and decision-making framework for reintroducing the allowance should be made clear.

- Workshop more prudent and sustainable approaches in balancing the DMO objectives (particularly in a high-cost environment), including how any burden can be shared across the sector, as opposed to disproportionately on retailers.

Consistent with our feedback to prior DMO Determinations, there are some key aspects of the methodology used to estimate the wholesale energy cost (WEC) that we consider impractical that should be re-examined to ensure they adequately reflects the costs likely to be incurred by a prudent retailer.

We support the AER adopting a blended load profile based on a combination of net system load profile (NSLP), controlled load profile (CLP) and advanced meter data. However, we do not agree with the rationale for excluding solar exports as it is not consistent with realities of the market. The inclusion of solar exports will better reflect a typical retailer's small customer load and therefore support a more accurate calculation of the cost of supplying energy to those customers.

We recognise the challenge in developing demand forecasts for the SAPN and Energex networks given the 2021-22 net system load profile NSLP data set has been compromised following the transition to 5MS.We strongly support the solution put forward by the AER's consultants (ACIL Allen) to adjust the NSLP to address the error in the data set. The decision to take the midpoint of the both the adjusted NSLP and compromised data set seems arbitrary. We urge the AER to reconsider this approach, if not for DMO 6, but for any subsequent determinations, to the extent this issue is still relevant.

We retain the view that the hedging strategy adopted is not sufficiently aligned with that of a prudent retailer. The high proportion of cap contracts and low volume of baseload contracts is likely an outworking of the narrow range of spot prices modelled, and results in the notional retailer having heightened exposure to any increase in energy prices (i.e. sub $300/MWh prices), which could occur if fuel prices rise above expected levels. We recommend testing the potential resilience of the strategy to different market outcomes, including a sustained increase in pool prices and low cap contract payout scenarios.

Under the DMO Code, the AER is required to publish its annual DMO prices by 26 May each year. However, in a network revenue determination year (such as 2024), the AER will not receive proposed network prices until around 21 May. This timing makes its extremely challenging for the AER to assess and approve these prices for inclusion in the calculation of DMO 6.

We support that in the absence of approved network prices, the AER use prices submitted by the networks in their annual pricing proposals for 2024-25. These prices represent the best information available in that they should reflect the recently approved revenues and demand forecasts from the AER's revenue determination.

If you wish to discuss any aspect of this submission further, please contact Sean Greenup (sean.greenup@originenergy.com.au) or Shaun Cole (shaun.cole@originenergy.com.au).

Yours Sincerely,

Steve Reid
General Manager, Regulatory Policy

1. Wholesale Energy Cost

[1] The Draft Determination covered several important matters related to the calculation of the WEC, including the derivation of the customer load profile, issues with the NSLP datasets for SAPN and Energex, and approach to determining hedging costs in SA. We discuss these and other issues in further detail below.

1.1 Load profile assumptions

[2] We support the AER adopting a blended load profile based on a combination of net system load profile (NSLP), controlled load profile (CLP) and advanced meter data. However, we do not agree with the rationale for excluding solar exports as it is not consistent with realities of the market. The inclusion of solar exports will better reflect a typical retailer's small customer load and therefore support a more accurate calculation of the cost of supplying energy to those customers.

[3] We also support the decision to retain individual load profiles for each NSW network.

1.2 NSLP Datasets for SAPN and Energex

[4] We recognise the challenge for the AER in developing demand forecasts for DMO 6 given that the 2021-22 net system load profile (NSLP) data set has been compromised following the transition to 5MS.

[5] To resolve this error, it is important that the AER does not consider this issue in isolation. In the past the AER has relied on the fact that its retail allowance provided a sufficient buffer that it could exercise its judgment. However, that buffer no longer exists because the competition allowance as a percentage of the cost stack has been removed.

[6] The selection of a midpoint between the adjusted NSLP and the compromised data set seems arbitrary. To ensure the DMO obligation of cost recovery is met, the AER should adopt the solution that best allows retailers to recover their efficient costs.

[7] We strongly support the view put forward by the AER's consultants (ACIL Allen) that an adjusted NSLP is appropriate because it may better reflect an average retail load profile and it aligns more closely with AEMO's NSLP as published after the interim adjustment was removed in October 2023.

1.3 Wholesale spot price modelling

<u>Modelled spot prices do not adequately reflect the range of outcomes / risks a retailer must manage</u>

[8] A key objective of the spot price modelling is to reflect the range of wholesale price scenarios a retailer could be exposed to. This should in turn inform the hedging strategy adopted in the modelling, which acts to limit the retailer's financial risk across those scenarios. This approach of considering a range of potential market outcomes, rather than a single modelled view of the expected outcome, aligns with how a prudent retailer would operate.

[9] In Origin's view, this objective is not being adequately satisfied under the current approach. The spot price simulations notionally demonstrate a wide range of potential market outcomes. However, consistent with concerns we identified in the earlier Issues Paper, there is limited variation in energy prices. This is reflected in Table 1 below, which outlines the variation in prices above and below $300/MWh across all simulations for FY2023-24. While an equivalent data set is not available for the Draft Determination, this trend is consistent with our interpretation of Figures 4.16 and 4.17 in ACIL's Draft Determination which outline the simulated hourly price

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duration curves, and contribution of prices above $300/MWh to annual average prices respectively.

Table 1: Range of modelled spot price outcomes for FY2023 (NSW)[1]

	Minimum	Maximum	Range
Contribution of prices over $300 to annual average spot price	11	69	58
Contribution of prices under $300 to annual average spot price	74	81	7

[10] This lack of variability in energy prices is likely driven by the fixing of fuel prices across all simulations, as this assumption removes a key driver of spot price volatility and risk in the National Electricity Market (NEM). This is consistent with ACIL's statement that including a high and low fuel price scenario would increase variability in price outcomes below $300/MWh.[2] However, the Draft Determination further notes that such scenarios are likely to have little impact on the final WEC if the high and low scenarios are symmetrically located around the fuel prices currently applied.[3] In Origin's view, this would only be the case if the 50th percentile (i.e. the average) WEC was adopted rather than the 75th.

[11] ACIL's Draft Determination also notes that '*given the recent implementation of price caps on coal and gas, it is unlikely that any large fuel price increase in the near future would not attract further intervention*.'[4] We do not consider it appropriate or practical to assume an increase in fuel prices would be mitigated by government intervention, or that a retailer could rely on the prospect of government intervention to manage the risk of fuel price changes driver higher spot market outcomes. Any assumptions should be based on established policies / measures that will apply over the relevant period only.

[12] Related to this, we do not consider it appropriate to assume fuel prices for combined cycle gas plant (CCGT) are capped at $12/GJ over FY2025 given the Commonwealth Government's Gas Market Code. The reasonable pricing provision under the Gas Market Code only applies to regulated gas that is not subject to an exemption, with the Australian Competition and Consumer Commission (ACCC) advising that four conditional exemptions and around 50 small supplier exemptions have been provided to date.[5] The ACCC has also reported that prices offered by producers between February and August 2023 for 2024 supply averaged $14.60/GJ.[6] This demonstrates there is clear potential for CCGT fuel costs to exceed $12/GJ over FY2025.

[13] Given the above, we maintain scenarios should be developed that allow for the impact of variable coal and gas prices on modelled spot prices to be tested, as this is crucial to inform the selection of the appropriate hedging strategy. The $12/GJ fuel price cap applied to CCGT plant should also be removed to better reflect the design of the Gas Market Code. This would align with ACIL's

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[1] The contribution of prices under $300/MWh has been derived by subtracting the 'Contribution of spot prices above $300 to annual average spot price ($/MWh)' from the 'Annual regional time weighted spot price ($/MWh)' from the following resource: ACIL Allen, 'Default market offer prices 2023-24 (Final Determination) – Summary results of market simulation', 25 May 2023.
[2] ACIL Allen, 'Default Market Offer 2024-25 – Wholesale energy and environment cost estimates for DMO 6 Draft Determination', 13 March 2024, pg. 38.
[3] Ibid.
[4] Ibid.
[5] ACCC, 'Gas Inquiry 2017-2030 – Interim update on east coast gas supply-demand outlook for quarter 3 of 2024', March 2024, pg. 3.
[6] ACCC, 'Gas Inquiry 2017-2030 – Interim update on east coast gas market', December 2023, pg. 10.

approach for open cycle gas turbine (OCGT) plant, where it is assumed gas is purchased at prices above the cap (albeit on a short term basis).

1.4 Hedging methodology

<u>The hedging strategy should mitigate a retailer's financial exposure to key risks in the NEM</u>

[14] In the Draft Determination and recent DMO 5 Final Determination, ACIL has determined a hedging strategy that results in a retailer adopting a lower base, and higher cap, contract position relative to prior years (e.g. DMO 4). While this may notionally facilitate the least cost WEC, this is predicated on the assumption that wholesale prices align with the low and narrow range modelled. Consistent with Origin's feedback in response to DMO 5, this strategy does not reflect the portfolio of a prudent and risk averse retailer.

[15] Table 2 below illustrates the changes in the DMO hedging strategy between DMO 4 and DMO 5. The hedging strategy adopted in the DMO 5, which we interpret to be broadly similar to the Draft Determination given the contract volumes specified, would result in a notional retailer procuring approximately 0.9 MW of baseload contracts (which provide protection against high energy prices) and 1.9 MW of cap contracts (which provide protection against prices over $300/MWh) per MW of average demand. This compares with 1.2 MW and 1.6 MW respectively in DMO 4 for the Endeavour region in NSW. The lower level of baseload contract cover relative to DMO 4 means the retailer is only partially hedging its financial exposure to energy prices, which could be materially impacted by higher fuel costs, as was observed in winter 2022. This is not consistent with the risk management practices of a prudent retailer that will typically seek to hedge their exposure to high pool price scenarios that may be considered unlikely compared to the median / expected market outcome, but present a material financial risk. We expect a prudent retailer's hedge position to be closer to the level prescribed in DMO 4, as the risk retailers are hedging (i.e. their exposure to the load-weighted average price) tends to be approximately 1.2x the annual time-weighted average pool price.[7]

Table 2: Change in the hedge portfolio FY2023 to FY2024 (Endeavour)[8]

Period	MWs of baseload contracts per MW of average demand	MWs of cap contracts per MW of average demand	Total MWs of contracts per MW of average demand
DMO 4 (FY2023)	1.2	1.6	2.8
DMO 5 (FY2024)	0.9	1.9	2.8

[16] Moving the hedge portfolio toward a greater relative proportion of cap contracts has seemingly also been driven by the high level of modelled positive cap contract payouts, which put downward pressure on the WEC. Average cap contract payouts modelled for NSW have increased substantially from approximately $12/MWh in FY2023 (DMO 4) to $36/MWh in FY2024 (DMO 5) and $30/MWh in FY2025 (DMO 6).[9] This does not align with historical observations, where the

[7] For DMO4, ACIL modelled load-weighted average prices of 1.25-1.30x the time weighted average pool price in NSW.
[8] These values represent average MWs of contracts purchased across the year per MW of average demand on an annual basis. The values are determined by dividing the average MW volume of contracts shown in Figure 4.25 (ACIL, DMO 4 Final Determination) and 4.22 (ACIL, DMO 5 Draft Determination) by the average load assumed by ACIL for the Endeavour region.
[9] Contribution of spot prices above $300/MWh to the average annual trade weighted price has been used as a proxy for average cap contract payouts. For FY2023, pricing data was sourced from 'ACIL Allen cost of energy modelling data for 2022-23 Final Determination - 26 May 2022'. For FY2024, pricing data was sourced from 'ACIL Allen - Default market offer prices 2023-24 - Final determination - Summary results of market simulation – 25 May 2023'. For FY2025, pricing data was estimated from 'ACIL's DMO 6 Draft Determination – 13 March 2024 (Figure 4.17).'

premium associated with these contracts typically results in prices paid exceeding (or being close to) the associated payouts received by contract holders. Total cap payouts for FY2024 to date are around $8-10/MWh, which is well below the level assumed in both DMO 5 and DMO 6.[10]

[17] We maintain the principles guiding ACIL's determination of the hedging strategy should be expanded going forward to account for the potential resilience of the strategy to different market outcomes. To support this, for FY2025, the sensitivity of the WEC (using the hedging strategy outlined) to the following should be tested:

- a sustained high pool price scenario (e.g. modelled spot prices increase by 100 per cent).
- a low cap contract payout scenario (e.g. payouts are in the order of $5-10/MWh)

<u>Reliance on ASX trade data remains the most efficient approach to determining wholesale energy costs</u>

[18] We support the AER's decision to retain the current use of ASX Energy trade data and not incorporate a broader suite of bespoke products, including settlement residue auction (SRA) units. The benchmarking of ASX Energy trade prices with broker data for swaps / caps and other OTC contract data collected by the AER demonstrates the methodology remains appropriate, including for SA.

[19] We note the AER also requested ACIL derive alternate WEC estimates based on the long-run marginal cost (LRMC) of generation in SA for use as a comparative data point (i.e. to compare with the WEC derived for SA using ASX Energy trade data). There is a risk an LRMC-based approach could result in a WEC that is not representative of actual retailer costs, as evidenced by the AER's finding that the LRMC-based WEC's were lower than those resulting from the current methodology. Any reliance on this approach should therefore be for comparative purposes only.

1.5 Length of the book build

[20] We generally support the existing book build process which occurs over a two-to-three-year period.

1.6 Compensation costs

[21] We agree known AEMO and AEMC compensation costs should be passed through the DMO wholesale component.

1.7 Use of the 75th percentile

[22] Origin agrees it is important to balance the allocation of risk between retailers and consumers, and that this is a key driver for the AER retaining the 75th percentile approach. However, we remain of the view that it would be more prudent to utilise the 95th percentile. As noted by ACIL, adopting a higher percentile estimate such as the 95th percentile minimises the risk of underestimating the true value of the WEC, and recognises the varying degree of price uncertainty between the different regions and load profiles.[11] Given the transitional compromises that have been made with respect to developing a more accurate NSLP and issues identified above with respect to the hedging strategy, we consider there is an increased risk of underestimating the

[10] Estimated using NemSight data, which is sourced from AEMO.
[11] ACIL Allen, 'Default Market Offer 2024-25 – Wholesale energy and environment cost estimates for DMO 6 Draft Determination', 13 March 2024, pg. 37.

WEC. The impact of any underestimation would also be heightened in a scenario where the retail competition allowance (discussed further below) is also removed as proposed.

2. Retail Allowance

2.1 Separating the margin from the competition allowance

[23] Origin agrees that separating the retail allowance into a margin and a competition allowance will provide greater transparency regarding how these respective values are determined. However, transparency can only be achieved if the method used to calculate each allowance is clearly explained and well understood. Otherwise, a separation of the allowances will decrease transparency and create greater regulatory uncertainty. It is within this context we have we have framed our discussion on the retail allowance.

2.3 Approach to determining the competition allowance

[24] It is not clear how the proposed fixed competition allowance of $66 per customer was derived.

[25] We request that the AER explain its framework in a level of detail that will allow stakeholders to both understand how it has derived its value and have a meaningful opportunity to replicate it.

[26] This will also enable an understanding of how the AER has assessed the effectiveness of competition in the market and how it has made judgements regarding the market's resilience and the impact on discounting practices – of which active customers benefit from.

[27] Consulting on these details will allow stakeholders to scrutinise the framework, put forward refinements, and identify possible errors which will lead to a more accurate and robust method. It will also allow retailers to manage their financial risks including understanding and managing the likelihood of future adjustments.

2.4 The criteria for adjusting the competition allowance

[28] We understand the inherent tensions between the DMO objectives – a higher retail allowance in the DMO price incentivises competition and consumer engagement but also means a higher price for those least engaged. We agree it is in the long-term interests of customers that the retail market remains competitive with many retailers offering a diverse range of market offers.

[29] The decision to remove the allowance was underpinned by a greater weighting on increased inflation, cost of living pressures and electricity affordability. We understand the need to place a greater focus on these weightings. However, it is vital for any regulatory regime that stakeholders understand how and why decisions are made so that they confidence and an ability to anticipate possible changes to the calculation of the DMO price.

[30] The lack of visibility around both the calculation of the allowance and the preconditions for its future reinstatement run the risk of undermining the DMO setting process. We request that the AER specify how the competition allowance will be adjusted in future decisions. This should include the specific indicators and triggers that cover an assessment of both cost of living and the health of the market. We consider these metrics should be observable (such as CPI relative to the RBA target bands), targeted, and small in number so that decision making does not become overly complex. Importantly, how the AER sets triggers should be well explained and objective.

[31] To the extent discounting is examined as measure of market competitiveness, when considering the competition allowance, examining the variance in offers provides a more meaningful

representation of competition rather than solely looking at the depth of discounts on offer. This includes where there are offers above the DMO that could serve as a means of offsetting deeper discounts.

2.2 Approach to determining the retail margin

[32] The retail margin should reflect the level of risk that a retailer faces; the greater the risk the greater the retail margin that is required in order that capital invested in the business earns an appropriate return. We consider this is best captured when the margin is set as a percentage instead of a fixed dollar amount because risks scale with underlying costs.

[33] It is also important that the basis for the retail margin is consistent with other cost allowances. When considering a reasonable margin in relation to supplying electricity, we agree that the margin should not include risks that have been managed through components of the DMO cost stack. However, where the calculation of cost stack components increases the overall risk then this must be accounted for in the margin.

[34] We consider the AER has used a reasonable sample of approaches to estimate a range of retail margins. We agree that taking fixed rate market offers at a point in time and backing out DMO costs is a practical approach to approximate the price retailers are willing to charge and the margin retailers are willing to receive in a competitive market.

[35] However, these are backward looking measures and reflect an environment where a competition allowance was included in the DMO. This is no longer the case.

[36] These samples can only be truly reliable if they are applied on a consistent basis. The removal of the competition allowance has introduced a significant regulatory risk and is likely to influence the way retailers compete on margin going forward.

[37] Furthermore, in previous decisions, the AER has relied on the position that the 'DMO offers retailers with an allowance that can capture variations in costs'.[12] This implies a level of comfort in allowing a level of risk to be inherent in the calculation of cost stack components because this risk was offset by the higher allowance which applied as a percentage of the cost stack.

[38] This "buffer" no longer applies because of the removal of the competition allowance. However, there remains non-diversifiable risk in the cost stack such as the decision to adopt a midpoint in the NSLP as well as the overall regulatory uncertainty created by the decision to not only remove the competition allowance but to not have a clearly defined framework regarding when or if this allowance will be re-introduced.

[39] Considering the prevalence of and allocation of risk within the DMO cost stack, we consider the AER's decision to set the retail margin as a percentage of the DMO price and to adopt a value of 6% is prudent.

2.5 Differences in residential and small business retail allowances

[40] We support the AER's decision to continue to apply different margins to residential and small business customers. We agree that small businesses should attract a higher margin to reflect the relative higher risk of serving these customers and evidence from observed margins.

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[12] AER, Default market offer prices 2023-24 Final Determination, May 2023, pg. 35.

3. Retail Costs

3.1 Metering costs

Up-front fees

[41] We support the AER's decision to maintain up-front installation fees in the DMO smart meter allowance calculation. We believe this approach will allow retailers who do not charge up-front fees to recover their efficient costs as well as being consistent with the future intent of the AEMC metering reforms that will ban upfront fees in the future.

Metering costs

[42] We support the AER's decision to continue the current approach of using historic installation data until the legacy meter retirement plans are in place. We also support the decision to allow a working capital allowance to cover the shortfall between actual installation numbers and projected installations still to occur during the DMO 6 year. This will ensure customers are protected from the risk of forecasting errors while at the same time ensuring retailers are compensated for their funding costs for installations that exceed historic levels.

3.2 Bad and doubtful debts

[43] We support the AER's decision to continue to use actual data published in the ACCC's National Electricity Market Report. This approach reduces the cross subsidisation across regions that has happened in prior DMOs when an average is applied and provides for a more cost reflective allowance.

4. Network costs

[44] Networks costs represent the largest driver of cost increases in DMO 6. We expect that this trend is likely to continue as further increases in network expenditure occur to support the transition to a renewable economy.

[45] We believe this is a cost component that the AER needs to consider how best to manage rather than using retail cost levers to mitigate increases in network costs.

[46] We support the AER's proposal to rely on estimates for the purposes of this Draft Determination and to replace these with AER final approved network tariffs for the Final determination. Where this is not possible, the AER should use the network tariffs contained in the network pricing proposals submitted for approval by 21 May 2024.

5. Environmental costs

[47] Origin supports the current market-based approach to determining environmental costs.