9 April 2026

EnergyAustralia
LIGHT THE WAY

Paul Harrigan
Executive Director,
DMO and Consumers Branch
Australian Energy Regulator
By email: DMO@aer.gov.au

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 19
Two Melbourne Quarter
697 Collins Street
Docklands Victoria 3008

Phone +61 3 9060 0000
Facsimile +61 3 9060 0006

enq@energyaustralia.com.au
energyaustralia.com.au

Submitted electronically: DMO@aer.gov.au

AER DMO prices 2026-27 - Draft Determination – PUBLIC version

EnergyAustralia is one of Australia's largest energy companies with around 2.2 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

EnergyAustralia welcomes the opportunity to make this submission on the AER's Draft Determination for the Default Market Offer for 2026–27 (DMO8). This is the first determination in which the Default Market Offer reflects the new objective of providing a fair, trusted and reasonably priced electricity option. This determination also marks the introduction of the Solar Sharer offer - a significant reform that will be available to residential customers with a smart meter from 1 July 2026. This sits alongside broader consumer-focused industry changes taking effect at the same time. We remain concerned that this concentration of reforms is unprecedented in recent DMO processes and amplifies the risk of unforeseen knock-on effects for both retailers and customers. We continue to emphasise that adjustments to aspects of the DMO methodology to reflect the new DMO objective should be made with a clear understanding of their cumulative impact on customers, retailers, and the broader energy market, and with a recognition of the added risk that uncertainty brings.

A neutral and even-handed application of the new DMO framework is key

EnergyAustralia supports the new DMO objective. However, achieving it requires a methodology that is reasonable, consistent and grounded in the costs retailers face. As we noted in our issues paper submission, the shift to an efficient tariff cap approach is a material change to the DMO framework. It is important that the AER's interpretation reflects competitive neutrality across retailers of every scale — DMO settings that reflect only certain retailer cost structures risk undermining the viability of others at a time when retailers are already absorbing rising network costs and supporting significant investment in the energy transition. It is equally important that the methodology avoids

unintended consequences for customers: a price cap set without full regard to efficient costs can compress the difference between offers, reduce incentives for retailers to innovate, and ultimately deliver worse outcomes for the customers the DMO exists to protect.

Our submission explores key issues where we consider refinements to the draft determination would better deliver on the new DMO objective. Across these, we encourage the AER to apply its methodology consistently and, where the draft determination seeks to depart from cost-reflective starting positions, such as the possible re-allocation of fixed and variable costs, to do so with a clearly stated rationale.

We reserve our comments on the DMO guideline, Solar Sharer offer developments, and expansion to embedded network customers for future consultations and the DMO9 price setting.

Our full submission with responses to key issues is in the **Attachment**.

If you have any questions in relation to this submission, please contact me (maria.ducusin@energyaustralia.com.au or 03 9060 0934).

Yours sincerely,

Maria Ducusin
Regulatory Policy Manager

1. Network cost methodology

1.1. The network tariff approach for the flat rate DMO cap requires consideration

EnergyAustralia does not have strong initial concerns with the AER's approach for the DMO time of use (TOU) tariff cap applying the corresponding TOU network tariff, or for non-regulated tariffs, applying the TOU network tariff, reflecting that these products require a smart meter and incur cost-reflective network charges.

Our submission focuses on one aspect of the methodology where we consider the draft determination requires further consideration - the network tariff used to determine the flat rate DMO cap.

The AER has determined that it will:

> *apply the lowest applicable network tariff for the DMO flat rate retail tariff and comparison price because retailers can use either a flat rate or time of use network tariff for flat rate tariffs.*[1]

In Essential Energy, Energex and SA Power Networks, this produces TOU network costs in the flat rate DMO cap — on the basis that, in those regions, TOU network costs are lower than flat rate network costs, and that 'retailers can arrange for installations' of smart meter to access the lower tariff.[2]

Our concern is that the AER's reasoning rests on a premise - that retailers can act on the incentive to install smart meters and access the lower tariff, which does not hold in practice.

1.2. Applying the lowest applicable network tariff results in an unavoidable gap

A material proportion of customers across the DMO regions remain on basic meters. These customers cannot be assigned to a TOU network tariff, and retailers are therefore billed the flat rate network tariff for them. The draft determination sets the flat rate cap using TOU network costs for some regions, but the actual network cost retailers incur for those customers is the flat rate tariff. The difference is an unrecovered cost with no recovery mechanism in the DMO.

1.2.1. The smart meter roll out is already operating at full regulatory capacity

The AER acknowledges that not all customers in DMO regions currently have smart meters installed, but reasons that retailers can arrange for installations and are required to do so for all small customers by 2030.[3] The issue is whether retailers can materially accelerate installations above the current rate, such that the assumption underlying the methodology is achievable in practice. We consider it cannot. EnergyAustralia's Legacy Meter Replacement Program (LMRP) is already operating at full regulatory capacity. The binding constraint is not retailer willingness.

---

1 AER, *Default market offer prices 2026-27: Draft determination*, p 56.
2 AER, *Default market offer prices 2026-27: Draft determination*, p 60.
3 AER, *Default market offer prices 2026-27: Draft determination*, p 60.

The LMRP involves tens of thousands of installation *attempts* annually, not completions, because customer refusals, access difficulties, site defects and remediation requirements mean a proportion of scheduled exchanges cannot proceed.

The full costs of running the LMRP are also beginning to crystallise at a scale the AER has not addressed. One-in-All-In (OIAI) distributor fees — charges passed to retailers under the regulations when a distributor attends a site as part of a smart meter exchange — are material and were flagged as unquantified risks at the time EnergyAustralia's LMRP investment was approved.
CONFIDENTIAL:

. The full cost picture across all DMO regions is therefore materially higher than this figure alone suggests.

The AER cannot credibly assume that retailers will respond to the perceived DMO incentive and close the gap when the programme is already operating at regulatory capacity. Setting a price based on a cost structure that requires infrastructure a material segment of customers do not yet have and providing no recovery mechanism for the shortfall in the interim, is not an inefficiency, it is a structural under-recovery that will persist for as long as the roll-out constraint persists. This approach to the flat rate DMO cap does not eliminate these costs - it displaces them. An approach that displaces unrecovered costs outside the DMO framework - where they will ultimately be passed on to customers - sits in tension with the DMO's objective of providing a fair and reasonable price for customers.

1.2.2. AER-approved distributor plans schedule the smart meter roll-out pace

Distribution network service providers (DNSPS) are required to develop LMRPs, setting out how many meters will be replaced, in which areas, across which periods - and have submitted those plans and subsequently been approved by the AER. Retailers are then responsible for implementing the LMRPs by arranging installations in line with the published schedules. The pace is not a variable retailers can unilaterally accelerate — it is set by an AER-approved schedule that coordinates the roll-out, if it is to be increased, this needs to be in consultation and fully aligned by the individual DNSPs and Metering coordinators The schedule itself confirms that a material proportion of customers will remain on flat rate network tariffs for several years to come.

1.2.3. The 2030 roll-out obligation already provides the incentive, the DMO gap adds cost

The AER frames its approach as providing an incentive for retailers to have the lowest cost applicable network tariffs assigned, with the TOU tariff becoming applicable once a smart meter is installed.[4] We do not consider this framing is appropriate. The incentive to install smart meters already exists through the AEMC's regulatory obligation to complete roll-out by 2030, reinforced by civil penalties for non-compliance.[5] The DMO gap adds a financial cost on top of an obligation that does not require further sharpening through price under-recovery. Adding a compounding cost on top of an existing regulatory obligation, is not an additional incentive. It is an uncompensated impost on the sector that is already doing what the rules require.

[4] AER, *Default market offer prices 2026-27: Draft determination*, p 60.
[5] AER, *Default market offer prices 2026-27: Draft determination*, p 60.

1.2.4. The AER's approach is difficult to reconcile with its approved network revenue outcomes

We also consider the AER's DMO flat cap network approach needs further consideration in light of its own network revenue determinations. Through those determinations, the AER has approved revenue increases for distribution businesses across the DMO regions — guaranteed outcomes that those networks are entitled to recover through network charges. Through its DMO flat cap approach for some regions, the AER at the same time suggests that retailers can achieve reductions in those same network costs through migrating customers on TOU and installing smart meters in the same regulatory period.

If distribution businesses are guaranteed to recover their approved revenue, it is difficult to reconcile how retailers can collectively pay less to those same networks — the approved revenue must be recovered from somewhere. An approach that assumes retailers will pay less to networks than the AER has approved those networks to recover is not realistic and does not, in our view, reflect efficient costs.

1.2.5. The AER's Ausgrid and Endeavour approach raises inconsistency questions

The most direct challenge to the AER's position appears to come from its own reasoning. In Ausgrid and Endeavour Energy, the AER uses flat rate network costs in the flat rate DMO cap — because 'retailers cannot assign a time of use retail customer to a flat rate network tariff once a smart meter is installed'.[6]

We consider the same logic applies equally to flat rate customers without smart meters in Essential Energy, Energex and SA Power Networks. For those customers today, the flat rate network tariff is equally the only *applicable* network tariff currently available — not because of a network rule, but because the smart meter that would unlock TOU access has not yet been installed. The impact is identical in effect: the TOU network tariff is not accessible to those customers.

The AER appears to apply cost correspondence when it produces a lower outcome in Ausgrid and Endeavour Energy but abandons it when consistent application would require a higher outcome in the other regions. That is not a principled distinction — it appears to be an asymmetric application of the same principle which should be reconsidered.

1.3. The AER should apply the same cost correspondence principle it uses for Ausgrid and Endeavour Energy

For the reasons set out above at 1.2 to 1.2.5, we suggest the AER:

- apply the flat rate network tariff to the flat rate DMO cap, consistent with the cost correspondence principle it already applies in the Ausgrid and Endeavour Energy regions.

This reflects the network cost retailers are billed for customers who remain on flat rate network tariffs. Getting this right matters: a network approach that embeds a structural under-recovery in the DMO flat cap produces prices that neither reflect efficient costs nor provide a sustainable basis for serving customers.

[6] AER, *Default market offer prices 2026-27: Draft determination*, p 61.

2. Wholesale energy cost (WEC) methodology

EnergyAustralia supports the AER's commitment to transparency in its wholesale cost methodology and welcomes the publication of ACIL Allen's supplementary back-cast analysis.

We maintain that the percentile estimate used to set the WEC should adequately reflect the asymmetric nature of wholesale cost risk — where the consequences of under-recovery are far more severe than those of overestimation.

2.1. Questions remain about the basis for moving to the 50th percentile

The AER has justified the move to the 50th percentile in selecting the WEC stating:

> The choice of percentile estimate is ultimately a decision about the extent to which consumers or retailers should bear the risk that actual wholesale cost outcomes may differ from that forecast. We consider this forecast risk should be allocated evenly, which is achieved through adopting the median forecast estimate – the 50th percentile.[7]

We consider this reasoning does not adequately account for the asymmetric consequences of error in each direction. Where the WEC is overestimated, consumers pay modestly more than efficient cost in that year - a diffuse financial impact spread across a large customer base that is recoverable over time. Where the WEC is underestimated, retailers face under-recovery that can, in severe instances, become a solvency risk rather than a manageable cost variance. The consequences are concentrated, potentially irreversible, and fall on the competitive structure of the market itself. A risk-sharing framework that treats these outcomes as equivalent is not genuinely neutral — it systematically underweights the asymmetric consequences of being wrong in one direction versus the other.

The regulations require the AER to have regard to the long-term interests of consumers, which depend on sustained retail competition. **A percentile estimate that adequately reflects this asymmetry, such as the 75th percentile, should be retained as it better satisfies that requirement.**

The rest of our response focuses on the volatility allowance — specifically whether the amount determined for DMO 8 appears sufficient.

2.2. We suggest the volatility allowance be empirically tested

The AER has set the volatility allowance by multiplying the spread between the 100th and 50th percentile WECs by a weighted average cost of capital (WACC). We question whether the P100–P50 spread is an appropriate basis for the allowance. The spread reflects variation across modelled simulations with fixed contract prices — it does not capture the risk of contract prices moving materially after the determination date. ACIL Allen's analysis shows that post-determination price movements have been asymmetric, with prices rising more than they have fallen and in some years by over $20/MWh.[8] A symmetric spread measure applied to an asymmetric real-world risk does not appear to provide an adequate basis for calibrating the volatility allowance.

Further, the volatility allowance does not appear to have been back tested against actual under-recovery instances in the way the percentile decision was tested.

---

7 AER, *Default market offer prices 2026-27: Draft determination*, p 44.

8 ACIL Allen, *Wholesale energy and environment cost estimates for DMO 8 Draft Determination*, 17 March 2026, p. 35

We understand the back-cast analysis examined 25 data points (five years across five distribution areas) and tested whether the P75 and P50 estimates would have covered actual wholesale costs. The AER does not appear to have demonstrated, using the same historical data, that the allowance would have been sufficient to cover the shortfalls observed in practice. We consider this to be a material gap. The percentile decision to move from the 75th percentile to 50th percentile appeared largely grounded on this back cast analysis, so we suggest the AER test the adequacy of the volatility allowance quantum on a similar basis.

If back-testing demonstrates the volatility allowance is materially insufficient to cover observed under-recovery instances, the AER should recalibrate the allowance upward before the final determination.

2.3. The Queensland back-cast results raise questions about the adequacy of the accumulation argument

ACIL Allen's back-cast analysis shows that for south-east Queensland at the 75th percentile WEC appears on average across the five years analysed, to have been insufficient to recover actual costs — with the actual WEC running approximately 8 percent above the 75th percentile estimate once post-determination contract price movements are accounted for.[9]

Critically, this under-recovery does not appear to have been a one-off event: the back-cast data indicates Energex experienced under-recovery in 3 years of the five years analysed, [10] compared with four instances of underestimation across all 25 data points.

The AER's response to under-recovery concerns is that the volatility allowance will accumulate over time, such that over-recovery in good years compensates retailers for under-recovery in bad years.[11] We consider this reasoning does not hold for several reasons.

- First, the volatility allowance appears primarily framed as compensating retailers for the cost of holding capital reserves - it may not fully address the consequences of severe under-recovery, which in some circumstances could present a solvency risk rather than a manageable cost variance. A shortfall of the scale observed in 2022–23 may not be manageable through capital reserves alone, particularly for retailers without the balance sheet depth to absorb it.

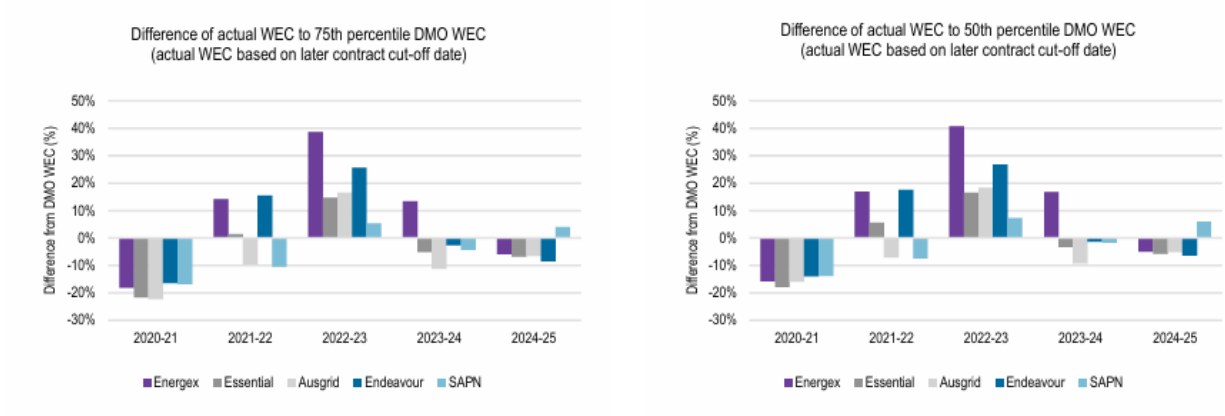
- Second, the accumulation argument appears to assume retailers can cross-subsidise across years - that a bad year will eventually be offset by a good one. There is no guarantee that under-recovery years will be followed by over-recovery years in a predictable sequence, and the financial consequences of a loss year followed by a profit year may differ materially from breaking even in both. A retailer that does not survive a bad year cannot benefit from any subsequent recovery.

- Third, using the AER's published figures from the cost assessment model, the Energex volatility allowance of $0.989/MWh generates approximately $1.2 million per year across the Energex customer base. The 2022–23 shortfall appears to represent a gap many times that amount - that annual accrual appears to cover only a small fraction of a shortfall of that scale. When Queensland under-recovered at P75, it

[9] ACIL Allen, *Wholesale energy and environment cost estimates for DMO 8 Draft Determination*, 17 March 2026, p. 36. Figure 2.12.
[10] ACIL Allen, *Wholesale energy and environment cost estimates for DMO 8 Draft Determination*, 17 March 2026, Figure 2.11.
[11] AER, *Default market offer prices 2026-27: Draft determination*, p 46.

appears to have done so by a substantial margin — the 2022–23 shortfall appears to be close to 40 percent above the P75 WEC (Figure 2.11 left panel) [12]

Figure 2.11 Comparison of actual WEC to DMO WEC – when accounting for contract price movements post determination



Source: ACIL Allen

Importantly, under the proposed methodology the starting estimate is lower (50th percentile rather than 75th percentile). The 8 percent Energex under-recovery observed against the 75th percentile estimate therefore appears to represent a floor for the risk exposure under the revised approach - not a ceiling. A volatility allowance that has not been shown to cover observed under-recovery risk — set against a lower 50th percentile estimate - risks undermining the competitive conditions on which the DMO protection ultimately depends.

3. Retailer costs – bad debt methodology

EnergyAustralia supports the AER's approach to allocate bad debt as a fixed cost component of the DMO. This is consistent with our submission to the issues paper.

However, we have strong concerns about the AER's decision to use actual written-off amounts only,[13] rather than the established industry standard measure of bad and doubtful debt expense being write-offs plus movement in doubtful debt provisions.

3.1. The write-off metric understates current bad debt costs

The industry standard measure of bad and doubtful debt expense is write-offs plus movement in doubtful debt provisions. This reflects how bad debt risk actually accrues to a retail business.

The key issue is timing. Debt is rarely written off in the year it was incurred. Retailers are required to exhaust all reasonable recovery avenues - including payment plans, hardship programs and collections processes - before an account is finalised and a debt written off. This process can take a number of years from when the debt first arose.

As a result, the debt written off in any given year largely relates to revenue from prior years. To the extent electricity tariffs have generally increased over time, using write-offs as the sole measure of bad debt systematically **understates** current bad debt costs — the debt being written off today was incurred at lower tariff levels than those in force

[12] ACIL Allen, *Wholesale energy and environment cost estimates for DMO 8 Draft Determination*, 17 March 2026, Figure 2.11.

[13] AER, *Default market offer prices 2026-27: Draft determination*, p 68.

now. Conversely, in a period of falling tariffs, write-offs alone would **overstate** current bad debt costs. Either way, the metric is a lagged and distorted proxy for the actual risk retailers are bearing in the year the DMO price is being set.

3.2. The "full lagged recovery" argument does not hold at the annual benchmark level

The AER contends that 'using the actual expensed written-off debt allows retailers the full (albeit lagged) recovery of bad debt risk for future DMOs' [14] We do not consider this an appropriate approach for two reasons.

- First, the DMO retail cost benchmark should reflect the efficient costs a retailer is bearing in the year in question.
- Second, the "lagged recovery" argument assumes the DMO framework continues indefinitely and that tariff relativities remain broadly stable over time. Neither assumption is guaranteed. A retailer that exits the market, or that operates in a period of structural tariff change, may never recover the gap. The working capital cost of carrying unrealised bad debt for multiple years is also real and uncompensated under the AER's approach.

3.3. Bad debt provisioning reflects current risk, not speculative forecasting

The AER's concern about over-recovery appears to stem from the view that provisions are estimates subject to management judgment, whereas write-offs are hard, audited figures. Movement in doubtful debt provisions is not speculative forecasting, as suggested by the AER.[15] It is a measure of credit risk in the active customer book, calculated against actual current debt balances. Under standard industry practice, doubtful debt provisioning is calibrated to recent arrears history and updated regularly. It captures the risk sitting in live accounts that have not yet been resolved — risk the retailer is actively bearing today.

3.4. Hardship obligations increase the importance of debt provisioning

Hardship obligations retailers carry under the National Energy Customer Framework (NECF) increase the importance of debt provisioning. Retailers are required to maintain hardship programs, offer payment plans and exhaust support options before disconnecting customers in financial difficulty. These obligations deliberately extend the lifecycle of at-risk accounts and defer write-offs further. Customers accumulating debt while on hardship programs represent active, current credit risk that are not reflected under a write-offs-only approach until the account is finalised.

A methodology that obscures current risk does not serve the DMO objective of a fair, trusted and reasonable price. **In our view, the best indicator of current bad debt costs incurred by a retail business is bad and doubtful debt expense, calculated as write-offs plus movement in doubtful debt provisions. We strongly recommend the AER adopt this measure for the DMO8 final determination.**

4. Apportionment of fixed and variable costs

We support the AER's proposed approach of allocating fixed costs to the daily supply charge and variable costs to usage charges. We consider this is an appropriate starting point – it reflects how retailers incur costs and is consistent with approaches used by the QCA and ESC.

---

[14] AER, *Default market offer prices 2026-27: Draft determination*, p 80.

[15] AER states: 'using written-off debt amounts would protect consumers from over-recovery of bad debt and prevent retailers under-recovering bad debt, both of which inherently arise in forecasting', *Default market offer prices 2026-27: Draft determination*, p 80.

Before settling on any departure from this methodology, however, we encourage the AER to be explicit about what the three options in section 9.3.3 are intended to achieve. The DMO objective provides the overarching framework, but it does not resolve the distributional question embedded in this design choice – namely, which customer group should be prioritised, and on what basis. That is an implicit value judgement about fairness, and it sits underneath each of the three options the AER has proposed, whether or not it is stated. Bringing it to the surface is not a technical matter; it is a precondition for the determination to be fair, reasonable and efficient in a durable sense.

4.1. Usage and vulnerability do not reliably align

EnergyAustralia's recent engagement with consumer groups suggests customers and advocates broadly acknowledge that:

- the DMO is not necessarily the cheapest offer available and that separate mechanisms exist to support customers – including other offers in the market and separate protections for customers experiencing vulnerability or financial hardship.

- Low-usage customers are not necessarily vulnerable, and vulnerable customers are not necessarily low-usage.

The AER's own analysis in the draft determination is instructive here: hardship and payment plan customers have median usage around 76 percent and 58 percent higher respectively than the median across all customers.[16] A reallocation that shifts fixed costs to the usage charge – with the intention of benefiting low-usage customers – could in practice increase costs for many of the customers the change is meant to help. Hardship programs, concession schemes and targeted financial assistance are better instruments for protecting specific vulnerable cohorts than adjustments to the DMO cost allocation made without a stated objective.

4.2. The fixed cost problem may be getting structurally worse

Network costs are largely fixed – they are incurred to maintain the grid regardless of how much energy flows through it. As more customers install solar and batteries and reduce their grid consumption, those fixed costs are spread across a shrinking volume of usage. A methodology that shifts fixed cost recovery into the usage charge therefore places a growing burden on customers who consume more grid energy – who are increasingly those without the means or the tenure to invest in solar and batteries. This can create a regressive dynamic over time.

The customers least likely to have solar and batteries are renters, low-income households, and those in apartments or social housing.[17] They are therefore likely to be higher grid-usage customers not always by circumstance of high usage, but by circumstance of limited choice. Shifting fixed costs to usage charges in this environment is not neutral – it may progressively concentrate the burden of shared grid infrastructure on the customers least able to reduce their exposure to it. This is a structural dynamic that can intensify as the energy transition progresses, and it is a further reason why any departure from cost-reflective allocation requires a clearly stated and durable objective rather than a year-by-year response to advocacy pressure.

4.3. Clarity of purpose is a precondition for sound methodology

Allocating fixed costs to the daily supply charge and variable costs to usage charges reflects how retailers incur costs. It can be deemed fair because customers contribute in proportion to the costs they generate. It can be deemed efficient because it does not

[16] AER, *Default market offer prices 2026-27: Draft determination*, p 109; AER analysis of ACCC July 2025 report, appendix E Supplementary table A3.18.

[17] See for example, ECA, *Understanding the energy divide*, Explainer, December 2023, p 6.

distort cost signals. It also can be deemed reasonable because it is consistent with approaches used by other regulators. Departing from that principle is not inherently wrong, but it involves trade-offs that should be made explicitly.

There is no allocation that is neutral across all customer groups. Shifting fixed costs to the usage charge reduces daily supply charges for low-usage customers but increases costs for high-usage customers – some of whom, as noted above, are among the most vulnerable. The AER is therefore making an implicit choice about whose interests to prioritise. That choice should be stated openly, with a clear objective, rather than embedded in a technical methodology decision. Without that, adjustments to the fixed/variable split risk varying from year to year in response to whichever cohort attracts advocacy attention at the time – introducing regulatory uncertainty for retailers and delivering inconsistent outcomes for customers.

4.4. If a change is pursued, transition design matters

If the AER determines that a reallocation is warranted, the design of any change matters as much as the decision to proceed.

For future DMO decisions, we suggest the AER:

- articulate a specific and explicit objective for any reallocation options, distinct from the DMO's overarching objective, before proceeding with any reallocation, and that any change should be designed transparently against that objective
- ensure that any reallocation applies equitably across customer groups and does not implicitly prioritise one group over another without acknowledgement.

5. Small business retail margin

We do not oppose the AER's approach to a uniform retail margin for residential and small business customers as a long-term objective. We support the AER's decision to maintain the retail margin as a percentage of total DMO costs. This approach is simple to apply and appropriately reflects that retailer risk scales with the underlying cost base — as wholesale, network or other underlying costs move, so does the exposure retailers are managing.

However, we suggest that the proposed immediate reduction from 11% to 6% for small business customers be implemented through a glide path across DMO 8 and DMO 9, rather than as a single-year step change.

We propose the AER:

- adopt an interim small business margin of 8.5% for DMO8
- transition to 6% for DMO 9.

The proposed reduction translates to a decrease of between $247.67 and $390.32 per small business customer in a single year. This is not a modest recalibration — it is a structural repricing of the small business segment.

The AER has previously recognised that large, abrupt margin changes are undesirable. In DMO 4, when initial margins varied significantly across regions the AER introduced a glide path expressly to 'minimise potential impacts of a sudden change on retailers and customers'.[18]

Regulatory decisions of this kind shape the investment and operational decisions retailers make across multi-year planning cycles. Retailers commit to system investments, staffing models and pricing structures based on the margin environment they reasonably expect the AER to maintain. The AER indicate that margins should not

[18] AER, Default market offer prices 2022–23: Final determination, May 2022, p1.

be set so low as to cause retailer exit.[19] We submit that a single-year step change of this magnitude tests that threshold in a way that a phased transition would not.

5.1. Margin funds service capacity for a more complex customer segment

The AER's analysis appears to treat the question of efficient margin primarily as a financial question about compensating non-diversifiable risk.[20] Margin also plays a functional role in funding the capacity of retailers to serve the small business segment effectively.

Small business customers present greater operational complexity than residential customers. They typically have higher consumption, more variable load profiles, greater metering complexity (particularly with the accelerated smart meter rollout) and more demanding billing and account management requirements. While small businesses may have lower compliance obligations in some respects (for example, no hardship programs), this does not mean they are cheaper or simpler to serve — the cost to serve figures in Table 7.1 confirm that small business costs to serve are materially higher than residential costs.

Compressing the small business margin by five percentage points in a single year creates pressure to reduce service investment in this segment. Retailers operating under tighter margins have less capacity to invest in the quality and responsiveness of service for customers who are not protected by hardship frameworks. This is not in the long-term interests of small business customers or the broader market.

A phased transition to a lower margin level, rather than an immediate step change — would allow retailers to adjust their operating models in a way that protects service quality throughout the transition.

6. Other detailed issues

As part of our engagement on the DMO draft determination, EnergyAustralia raised a number of detailed technical questions with the AER prior to this submission. These included:

- the Endeavour Energy SME flat rate tariff cap and its two-block network tariff structure
- an apparent error in the controlled load supply charge calculations for CL1 and CL2 tariff caps across the NSW distribution businesses
- rounding methodology for comparison prices, and the risk that a standard ROUND function produces a compliant tariff cap but a non-compliant comparison price
- the AER's approach to time of use, where we identified a discrepancy between the AER's profile assumptions and the published pattern of supply. The AER has confirmed it will revise its approach for the final determination.

We appreciate the AER's responsiveness during this process.

In reviewing the draft legislative instrument, we have also identified what appears to be omissions in the tariff period descriptions in the tariff cap tables. For example, the residential time of use tariff cap for Ausgrid does not stipulate that peak periods apply Monday to Friday, and the small business time of use tariff cap for Endeavour Energy similarly omits this qualification — whereas the equivalent Energex entry includes it.

We request the AER review all tables and information in the legislative instrument for accuracy and consistency before the final determination is made.

---

[19] AER, *Default market offer prices 2026-27: Draft determination*, p 69.

[20] AER, *Default market offer prices 2026-27: Draft determination*, p 89.

The other detailed issues below were not raised through our most recent exchange so have been included for the AER's consideration in the final determination.

6.1. Broken Hill and the Essential Energy local time standard

The draft determination sets the solar sharer offer free usage period for Essential Energy at 11 am to 2 pm "local time".[21] However, Broken Hill sits within the Essential Energy distribution area while observing South Australian time — ACST/ACDT — not NSW time.

We suggest the AER:

- insert a footnote in the relevant instrument to make clear that some postcodes covered in the Essential Energy distribution zone may face different local times.

Without this, the instrument is ambiguous on its face for these customers, exposing retailers to compliance risk for an expectation that is not clearly stated.

6.2. Demand tariffs and the comparison price

The comparison price for non-regulated tariffs, including demand tariffs — is calculated using standard annual usage amounts. However, demand tariffs include a variable demand charge that depends on a customer's peak demand in a billing period, not just total consumption. A retailer cannot calculate a meaningful annual comparison price for a demand tariff standing offer without making assumptions about a customer's demand profile — assumptions the instrument does not prescribe.

Without any guidance, retailers must develop their own assumptions with no defined standard to test against. A retailer acting in good faith, using a reasonable approach, could still be found non-compliant at some later time, against a standard that is never articulated.

We suggest the AER:

- insert a footnote in the relevant instrument to make clear retailers should make a representative estimated demand profile that is reasonable.

[21] Section 10 of legislative instrument, AER, *Default market offer prices 2026-27: Draft determination* p 152