6 April 2023

Stephanie Jolly
General Manager, Market Performance
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Submitted by email: DMO@aer.gov.au

Dear Ms Jolly,

Default market offer prices 2023-24 – Draft Decision

Origin Energy Limited (Origin) welcomes the opportunity to provide comments on the Australian Energy Regulator's (AER) Default market offer (DMO) prices 2023-24 Draft Decision.

In keeping with the underlying objective, the DMO should be set at a level that allows retailers to recover efficient costs, while also facilitating competition, and ensuring that customers are protected from unreasonably high prices. We acknowledge that the AER faces a challenging task in balancing the DMO objective amid the recent significant increase in wholesale market volatility.

Origin agrees that managing the impact of higher energy prices and broader cost of living pressures, particularly for low-income households and vulnerable customers should be of the utmost priority. It is also crucial that this is primarily done through targeted programs such as concession schemes, customer hardship frameworks and direct bill subsidies.

With the above in mind, Origin considers there are some aspects of the Draft Determination that are consistent with the balancing of the DMO objective. The uplift in wholesale energy costs and increased volatility has a proportionate impact on the risks faced by retailers The decision in the draft determination is therefore appropriate, whereby the retail allowance continues to be set as a percentage of total costs, with the current level maintained.

The approach used in determining the Wholesale Energy Cost should be reviewed

We do, however, consider that there are material issues with the methodology used in determining the wholesale energy cost (WEC) component. The modelling used to guide the level of the WEC has produced a relatively narrow distribution of potential spot prices that a retailer could face, which are also lower than expected when considering: historical pricing outcomes; movements in the contract market; and actual spot prices to date. It appears this is due in large part to the decision to fix coal and gas fuel prices at $125/tonne and $12/GJ respectively across all simulations to align with price caps currently in place. This, however, ignores that gas powered generators (GPG) may also be reliant on gas bought at prices above $12/GJ, including from the facilitated markets (particularly at periods of high demand) that are not subject to the cap. Additionally, the gas cap expires at the end of 2023 and therefore does not cover the entirety of the DMO 5 period (FY2024).

To address these issues, variable gas prices should be modelled across different simulations to appropriately reflect the design of the temporary price cap and exposure of GPG to prices above $12/GJ. In future years where there are no regulated price caps, variable fuel prices should also be applied to ensure the impact of potential fuel price changes are reflected in the wholesale spot price modelling. The AER's modellers should also recalibrate its wholesale spot price modelling to ensure the median simulated price better aligns with contract market expectations; and the distribution of spot prices adequately reflects the potential variability that could occur (relative to the median) based on historical market outcomes. Given retailers are required to manage price variability and the potential for market volatility on an ongoing basis, this should be adequately reflected in the modelling.

Another aspect of the WEC that should be reviewed is the retailer hedging strategy, which is also an outworking of the modelling. In our view the hedging approach employed is not sufficiently aligned with that of a prudent retailer. The high proportion of cap contracts and low volume of baseload swaps results in the retailer having greater pool price exposure and consequently a riskier portfolio, including when compared to that used for DMO 4.

Our suggestion is that the principles guiding development of the hedging strategy should be expanded to account for the potential resilience to different market outcomes, with the objective being to determine a strategy that also minimises potential earnings at risk (EaR). This is appropriate given that remaining solvent and minimising possible losses is the foundation of a retailer's risk management framework and a primary consideration in determining a viable hedging strategy.

Retailer costs estimates can be improved by the AER sourcing the right data

The AER should improve the accuracy of the retailer costs calculation by accessing and utilising the appropriate data sets. In the case of retail operating costs and bad and doubtful debt (BDD), retailers already provide the relevant data to the ACCC as part of their ongoing market monitoring. In the absence of this data, the method used to estimate these costs in the Draft Determination is subject to inherent limitations, resulting in errors. We therefore suggest that the AER look to source the data from the ACCC or directly from retailers.

The removal of upfront costs from the metering allowance is well intentioned in that the aim is to prevent customers from paying twice and by extension some retailers from over-recovering. However, this also results in those retailers that do not charge an upfront fee from fully recovering their costs. This should be remedied for the Final Determination. It should also be noted that the AER's approach of including lagged costs creates a disincentive for retailers to proactively install smart meters. This impediment could be overcome with a working capital allowance.

Process changes and the path forward

A challenge with the existing process is that historically, underlying modelling inputs / assumptions and any key adjustments made to the DMO methodology are not known until the Draft Determination. Stakeholders are then provided with a relatively compressed timeframe in which to assess the methodology and its associated outputs, which is particularly apparent in the current process. The transparency of the process is also limited in some areas, with information relating to key inputs / outputs not published, or only published at the Final Determination stage.

Earlier visibility of modelling assumptions and outputs is ultimately needed to support a more informed assessment of the WEC methodology. Consistent with this, the Issues Paper should be accompanied with a workbook detailing core assumptions, data and parameters used to model the WECs. WEC modelling data sets should also be released at the Draft Determination stage and expanded to include simulated prices and the assumed retailer hedge portfolio on an hourly basis.

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 purpose of the DMO is to estimate the WEC from a retailer's perspective. We have material concerns with the WEC component of the draft determination. The WEC estimate is predicated on a hedging strategy that does not reflect the risk management practices of a prudent retailer; and modelled spot prices that do not align with contract market expectations or capture the full range of potential outcomes given historical events.

[2] It is crucial the framework is updated to remove any subjectivity around the determination of the hedging strategy. This can be achieved by requiring ACIL to test the potential resilience of any strategy to different market outcomes (e.g. a material increase in spot prices) with a view to minimising risk, rather than simply adopting the least cost strategy based on a narrow range of modelled spot prices.

1.1 Net system load profile

[3] As we have raised in previous submissions, the current net system load profile (NSLP) excludes the peakier and more variable load of solar PV customers, the penetration of which continues to grow. This creates an inherent bias toward underestimating hedging costs and by extension the WEC, given the lower (relative) cost of hedging flatter load profiles.

[4] Origin notes that in its recent draft determination for retail electricity prices in regional Queensland, the Queensland Competition Authority (QCA) and its modellers (ACIL Allen) incorporated smart meter data in combination with the NSLPs and controlled load profiles (CLPs), to estimate the WEC[1]. ACIL noted that the use of interval meter data in addition to the NSLP improves the estimation of the cost of supplying energy to small customers by better reflecting the shape of small customers' load.[2]

[5] We recognise that the use of smart meter data creates issues of transparency and validity given AEMO does not make interval meter load profile data publicly available, which means that it cannot be readily accessed by stakeholders for verification. Notwithstanding, as noted by ACIL in its advice to the AER, it is better to commence using the interval meter data in combination with the NSLP data sooner rather than later as it removes the risk of a step change in prices if the interval meter data is included all at once, when penetration is higher. This risk is particularly relevant if the aggregate load profile of customers on interval meters is different to that of customers on the NSLP.[3]

[6] For the reasons highlighted by ACIL in its advice to both the AER and the QCA, we strongly support the AER's proposal to review the use of the NSLP as soon as practicable to avoid potentially materially step changes to the WEC from any delay in incorporating aggregate load profile of customers on smart meters.

1.2 Wholesale spot price modelling

<u>Modelled spot prices do not adequately reflect the range of potential market outcomes</u>

[7] Spot price modelling is inherently challenging and contingent on iteratively running many statistical simulations with varying parameters. Under ACIL's approach, 561 different simulations

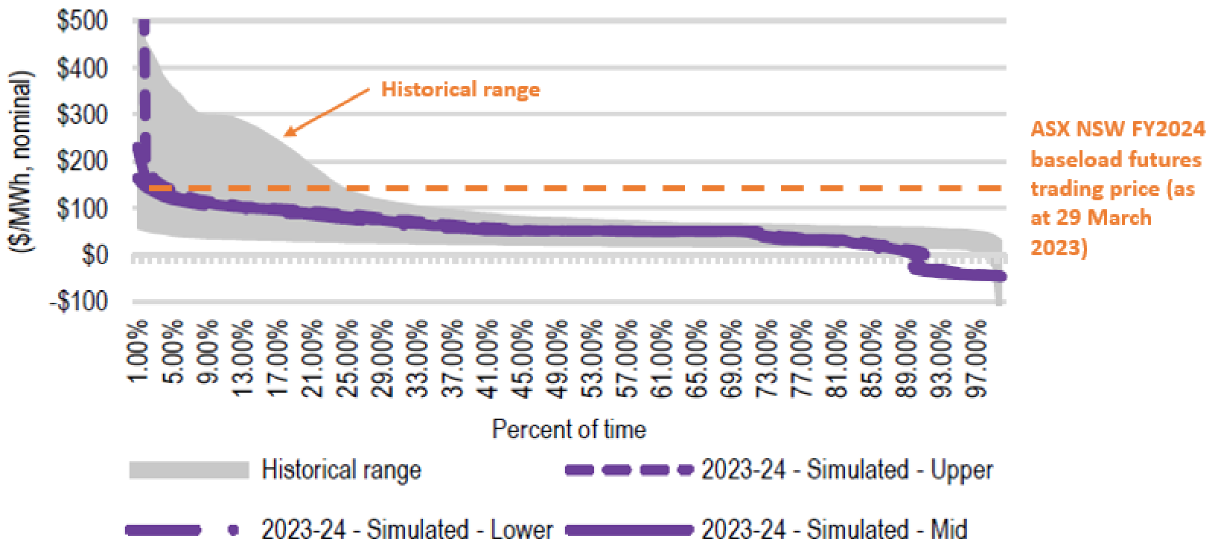
[1] Queensland Competition Authority, Draft determination, Regulated electricity prices in regional Queensland 2023-24, March 2023, pp. 25-26.
[2] ACIL Allen, Estimated energy costs, For use by the Queensland Competition Authority in its Draft Determination of 2023-24 retail electricity tariffs, 15 February 2023, p. 11
[3] ACIL Allen, p. 17.

Origin Energy Limited ABN 30 000 051 696 • Level 32, Tower 1, 100 Barangaroo Avenue, Barangaroo NSW 2000
GPO Box 5376, Barangaroo NSW 2000 • Telephone (02) 8345 5000 • Facsimile (02) 9252 9244 • www.originenergy.com.au

are developed by applying 11 different outage scenarios and 51 different demand and renewable energy traces, with coal and gas fuel prices fixed across all simulations. In both 2022-23 (FY2023) and 2023-24 (FY2024), ACIL has been satisfied the resultant simulations cover the range of expected price outcomes across all three regions in terms of annual averages and distributions.[4] However, comparison of simulated prices with actual spot / contract market prices demonstrates the modelling has *not* adequately reflected the range of potential market outcomes in practice.

[8] The Draft Determination provides a relatively narrow distribution of potential spot price outcomes. Chart 1 below shows there is very limited variation between the bottom, mid and upper simulated hourly price duration curves in the lower 99 per cent of modelled price outcomes. This is made even more apparent when compared to the historical range of prices. The distribution of modelled pool prices also does not reflect, (and appears to be inconsistent with), current contract market expectations. We estimate the 75th percentile of NSW time weighted pool prices modelled to be $93/MWh, which is $41/MWh below the ASX NSW FY2024 baseload contract trading price (of $134/MWh) as at 29 March 2023.

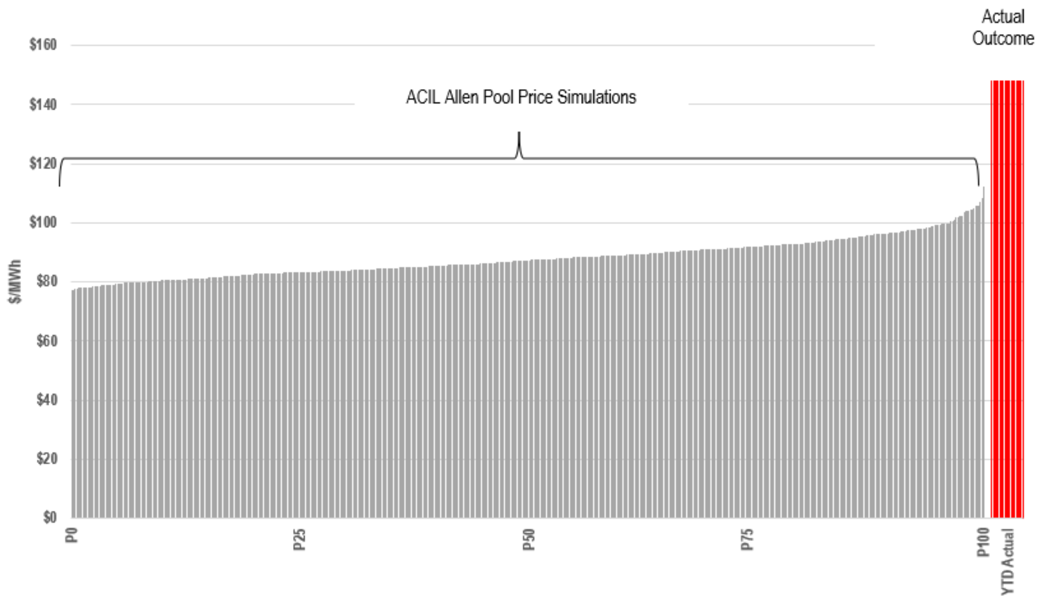
Chart 1: Comparison of simulated hourly price duration curves for New South Wales[5]



[9] Comparison of actual spot prices over FY2023 to date with the distribution of simulated prices for FY2023 also demonstrates that the modelled prices in DMO 4 did not capture the full range of potential spot market outcomes. As shown in Chart 2 below, the average FY2023 year to date pool price in NSW is $148/MWh, which is $56/MWh higher than the 75th percentile of modelled outcomes, and $35/MWh higher than the maximum simulated price in DMO 4. Consistent with our observation above, the range of modelled pool prices was also below contract market expectations, with the ASX NSW FY2023 baseload contract price trading at $146.50/MWh (at 13 May 2022, the DMO cut-off date).

[4] ACIL Allen, 'Default Market Offer 2022-23 – Wholesale energy and environment cost estimates for DMO 5 Final Determination, 23 February 2023, pg. 64; ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination, 23 February 2023, pg. 73.
[5] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination, 23 February 2023, pg. 69.

Chart 2: 2022-23 price simulations vs actual year to date outcomes (NSW)[6]



<u>Fuel price assumptions are likely a key driver of the relatively low spot price outcome and narrow price distribution</u>

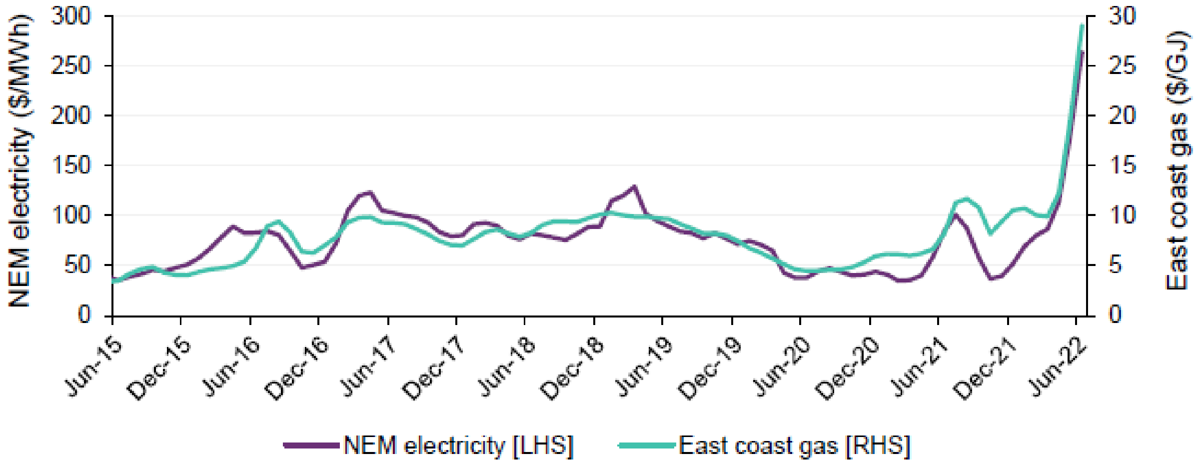
[10] The narrow range of modelled spot price outcomes may in large part be attributable to fuel prices being fixed across all simulations, which is an approach applied in previous WEC Determinations. Changes in fuel prices are a key driver of potential spot price volatility in the National Electricity Market (NEM). This relationship was acknowledged in the Australian Energy Market Operator's (AEMO) analysis of market dynamics in Q2 2022, with AEMO noting that '*changes in direct and opportunity costs of fuel are one principal driver of shifts observed in bidding behaviour from thermal generators… which then directly affect the level of wholesale electricity prices.*'[7]

[11] ACIL's model also caps gas fuel prices for GPG at $12/GJ over FY 2024 on the basis of the temporary price cap measure established under the *Competition and Consumer (Gas Market Emergency Price) Order 2022*. However, this assumption ignores GPG's ongoing exposure to fuel costs above that level, as the temporary cap does not apply to gas procured through the facilitated markets that are often relied on for fuel supply during high demand periods. The price cap is also due to expire in December 2023, and therefore only apply for the first half of the DMO 5 period. Given the strong correlation between movements in east coast gas market prices and NEM wholesale spot prices (shown in Chart 3 below), the fuel price assumptions are likely to materially impact the modelled prices. Taking a single view of fuel prices across all simulations is therefore not a prudent approach, as any variation between actual and assumed fuel prices could materially undermine the accuracy of the modelled spot prices, and by extension the WEC.

---

[6] Origin Energy analysis: Comparison of ACIL time-weighted spot price simulations over the 2022-23 period for DMO 4, with the time weighted average observed from 1 July 2022 to date in NSW.
[7] AEMO, 'Quarterly Energy Dynamics Q2 2022', July 2022, pg. 15-16.

Chart 3: NEM wholesale spot and electricity prices and east coast wholesale gas prices (rolling three-month averages)[8]



<u>The wholesale spot price modelling should be recalibrated to better reflect contract market expectations and potential spot price variability</u>

[12] ACIL has previously noted that it should not be assumed adjustments to the spot price modelling would change the WEC, since the main driver of the WEC is the trade weighted average contract price.[9] We agree with the premise that modelled pool prices should not be a key driver of the WEC. Rather, the purpose of the modelled prices should be to adequately reflect the range of wholesale price scenarios a retailer could potentially be exposed to. This should in turn inform the hedging strategy adopted in the modelling, as a prudent retailer must ultimately hedge exposure to a range of potential market outcomes, rather than a single modelled outcome that does not currently align with market expectations.

[13] As we discuss further in Section 1.3 below, this objective is not currently being achieved. The relatively low and narrow distribution of modelled prices has seemingly contributed to the adoption of a hedging strategy that isn't reflective of a prudent retailer. A further outworking of this is that the WEC is heavily influenced by modelled wholesale pool prices (rather than only the trade weighted average contract price) due to the hedging strategy creating increased exposure to those prices.

Recommendation(s)

- To support a more informed assessment and determination of hedging strategies, we recommend ACIL recalibrates its wholesale spot price modelling to ensure:
  - the median simulated price better aligns with contract market expectations; and
  - the distribution of spot prices adequately reflects the potential variability that could occur (relative to the median) based on historical market outcomes.
- For FY2024, variable gas fuel prices should be applied across different simulations to better reflect the design of the temporary price cap measure and exposure of GPG to prices above $12/GJ. For future years, both variable gas and coal prices should be applied across the

[8] AEMO, 'Quarterly Energy Dynamics Q2 2022', July 2022, pg. 16.
[9] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination, 23 February 2023, pg. 47

different simulations to ensure the impact of potential fuel price changes are reflected in the wholesale spot price modelling.

1.3 Hedging strategy

<u>The hedging strategy adopted does not reflect that of a prudent retailer</u>

[14] ACIL's approach to determining the hedging strategy is to test multiple portfolios by varying the mix of base / cap / peak contracts for each quarter and selecting one that is considered robust and plausible for each load profile and minimises the 95th percentile WEC. In the Draft Determination, ACIL has determined a revised hedging strategy that is predicated on a retailer adopting a lower base, and higher cap, contract position relative to DMO 4.[10] In Origin's view, this hedging strategy does not reflect the portfolio of a prudent and risk averse retailer.

[15] The change in strategy significantly reduces the level of hedge cover for the notional retailer. Table 1 below shows the estimated reduction in baseload contracts (which provide protection against high average energy prices) and increase in cap contracts (which provide protection against prices over $300/MWh) relative to DMO 4 for the Endeavour region in NSW. The key observation is that under the Draft Determination, a retailer is only hedging approximately 90 per cent of its average load with baseload contracts, compared with 116 per cent in DMO 4 (which is a more prudent approach to hedging).

Table 1: Change in the hedge portfolio FY2023 to FY2024 (Endeavour)[11]

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)	1.16	1.61	2.77
DMO 5 (FY2024)	0.91	1.86	2.77

[16] This ultimately increases the risk profile of the hedging strategy, with the retailer more exposed to high demand / price periods relative to the DMO 4 strategy. We estimate that for every $1/MWh increase in annual time weighted average prices, a notional retailers WEC under the Draft Determination would increase by $0.35/MWh, compared to $0.10/MWh under the DMO 4 strategy, which is a 339 per cent differential. This would expose a notional retailer to materially higher costs (relative to DMO 4) in the event of any significant increase in wholesale prices.[12] It also inherently means the WEC estimate is more heavily influenced by modelled wholesale spot prices (and associated assumptions) relative to DMO 4, which as we noted in Section 1.2, should not be the case.

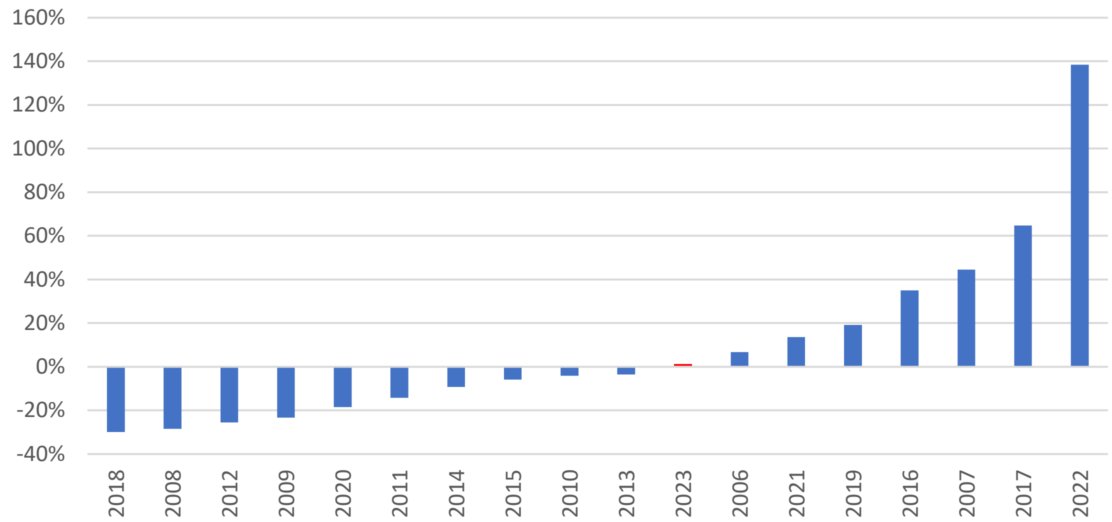
[17] While the strategy adopted may notionally facilitate the least cost WEC, this is predicated on the assumption that wholesale prices do not deviate from the *expected* low and narrow range

[10] Ibid, pg. 73.
[11] The above represents MWs of contracts purchased 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 patch in the DMO 4 Final Determination.
[12] This analysis is based on the Endeavour region, and assumes a $1/MWh increase in time-weighted prices increases a retailer's load-weighted cost by $1.26/MWh and the retailers hedge portfolio returns by $1.16/MWh in FY2023 and $0.91/MWh in FY2024, with FY2024 hedge returns being lower due to the lower amount of hedges in the assumed portfolio (I.e. $0.10/MWh = $1.26/MWh – $1.16/MWh and $0.35/MWh = $1.26/MWh - $0.91/MWh).

modelled. This approach to hedging is fundamentally inconsistent with the risk management practices of a prudent retailer.

[18] Wholesale spot prices can materially increase beyond expectations in some years. As shown in Chart 4 below, average NSW pool prices in FY2007, FY2017 and FY2022 were 45 per cent, 65 per cent and 138 per cent higher respectively than baseload contract market expectations prior to the commencement of the relevant financial year.

Chart 4: Percentage difference between the average NSW pool price for the FY, and the ASX NSW baseload contract price preceding the commencement of the FY[13]



[19] While these types of scenarios may be considered unlikely compared to the median / expected market outcome, it is clear they present a material risk for retailers and are within the bounds of scenarios that would be considered under the hedging strategy of a prudent retailer. This is because even limited exposure to higher pricing events can be detrimental to retailers, as evidenced by the seven retailer failures that occurred in 2022. A prudent retailer will therefore typically run stress tests like EaR to evaluate exposure to higher prices over different timeframes and seek to hedge that exposure in line with established risk limits.

Recommendation(s)

- Given the above factors, we consider 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, with the objective being to determine a strategy that also minimises potential EaR. This should be supported by:
  - modelling a broader range of wholesale spot price outcomes (as discussed in Section 1.2),
  - explicitly modelling the sensitivity of the WEC to an increase in pool prices given the assumed hedge position, to illustrate the likely losses a retailer would incur (and

[13] The contract price is taken as at around 13 May prior to the commencement of each FY (e.g. for FY2022, the price represents the NSW FY2022 baseload contract futures trading price at 13 May 2021).

therefore the effectiveness of the hedging strategy) if a one-in-ten year and one-in-twenty-year increase in pool prices occurred.

<u>The high level of modelled cap payouts</u>

[20] Modelled cap contract payouts have increased substantially from FY2023 in NSW. As shown in Table 2 below, the median capacity contract payout is $19/MWh higher in the Draft Determination relative to DMO 4 levels, leading to higher net capacity contract returns for the notional retailer.

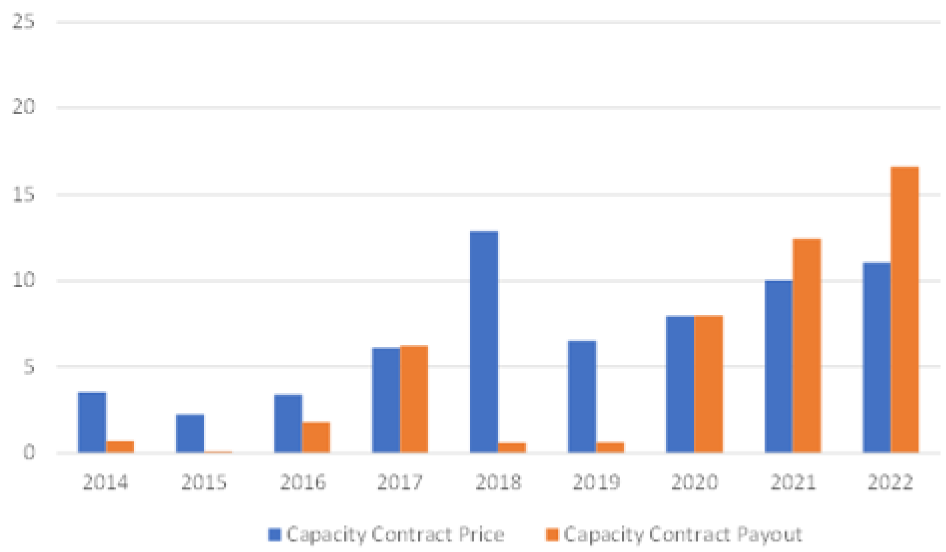
Table 2: Capacity contract assumptions – DMO 4 (FY2023) vs DMO 5 (FY 2024), NSW

Price ($/MWh)	FY2023	FY2024	Change
Trade-weighted capacity contract price[14]	16	26	10
Median cap contract payout[15]	11	30	19
Median net capacity contract return	-5	4	9

[21] The expectation of higher capacity contract payouts is inconsistent with historical experience. There is typically a premium associated with these contracts that results in prices paid exceeding the associated payouts received by contract holders. This is evidenced in Chart 5 below, which compares contract prices paid with associated payouts in NSW.

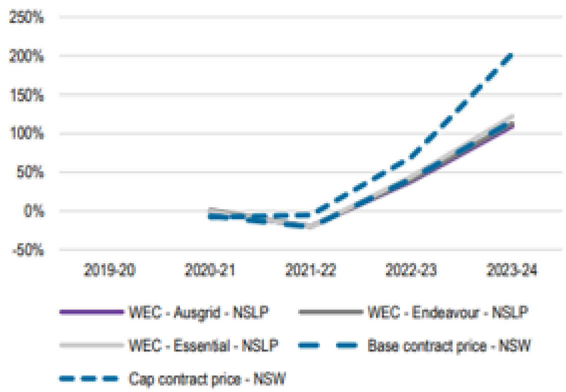
[14] For each respective FY, this is estimated based on the volume weighted average of quarterly capacity contract prices for NSW and Endeavour hedge portfolio capacity contract volumes. For FY2023, the price and volume information is as reported under Table 4.2 and Table 4.25 respectively in ACIL's DMO 4 Final Determination. For FY2024, the price and volume information is as reported in Table 4.2 and Figure 4.22 of ACIL's DMO 5 Draft Determination.
[15] For FY2023, this is the median contribution of spot prices above $300 to annual average spot price ($/MWh) for NSW reported in ACIL's cost of energy modelling data for 2022-23 Final Determination - 26 May 2022 spreadsheet. For FY2024, this is estimated from Figure 4.17 in ACIL's DMO 5 Draft Determination.

Chart 5: ASX capacity contract price and actual capacity contract payouts, NSW ($/MWh)[16]



[22] With the limited data provided it is difficult to quantify the drivers of the higher capacity contract payouts and resultant impact on the WEC. However, it is possible the 75th percentile WEC scenario has capacity contract payouts occurring when demand is lower than the peak annual demand. If this occurs, the capacity contract position pays out more than the increase in pool purchase costs for the retailer, potentially offsetting the impact of the increased capacity contract price on the WEC. This aligns with the dynamic show in Chart 6, below, where the WEC largely moves in line with changes in baseload contract prices, with the year-on-year increase in capacity contract pricing having minimal impact.

Chart 6: Annual change in WEC and trade weighted contract prices (%) – 2019-20 to 2023-24 (NSW)[17]



[16] The contract price is taken as at around 13 May prior to the commencement of each FY (e.g. for FY2022, the price represents the NSW FY2022 capacity contract futures trading price at 13 May 2021). The capacity contract payout has been estimated based analysis of trading intervals where pool prices exceeded $300 in the relevant FY.

[17] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination, 23 February 2023, pg. 83

Recommendation(s)

- A sensitivity of the WEC to the cap price payout assumptions should be tested. To support this, we recommend:
  - calibrating the assumed capacity contract payouts with historical market outcomes and contract market expectations; and
  - using historical measures of the risk of capacity contracts not paying out to determine a distribution of low cap price outcomes.

1.4 Transparency / timing of the WEC process

[23] A challenge with the existing process is that historically, underlying modelling inputs / assumptions and any key adjustments made to the DMO methodology (e.g. moving to the 75th percentile WEC estimate) are not known until the Draft Determination. Stakeholders are then provided with a relatively compressed timeframe in which to assess the methodology and its associated outputs, which is particularly apparent in the current DMO 5 process. The transparency of the process is also limited in some areas, with information relating to key inputs / outputs not published, or only published at the Final Determination stage.

Recommendation(s)

- Earlier visibility of modelling assumptions and outputs is necessary to support a more a more informed assessment of the WEC methodology.
- Consistent with this, we consider the Issues Paper should be accompanied with a workbook detailing core assumptions, data and parameters used to model the WECs, including:
  - scenarios / sensitives and risk limits (noting the framework changes we identified in Sections 1.2 and 1.3 above)
  - fuel price assumptions
  - renewable energy resource traces on an hourly basis
  - thermal plant outage scenarios / ranges
- WEC modelling data sets should be released at the Draft Determination stage, rather than only at the Final Determination stage (as was the case for DMO 4). Reported data sets should also be expanded to include simulated prices and the assumed retailer hedge portfolio on an hourly basis

2. Retail Costs and Allowance

[24] With retailers facing increased risk, retaining the retail margin at its current level is vital to preserving competition and to providing retailers with certainty to manage market offer discounts and further progress new service offerings.

[25] We consider the calculation of bad and doubtful debts, SME retail operating costs, and the metering allowance requires refinement.

2.1 Retail Allowance

[26] One of the key intentions of the retail allowance is to ensure the DMO remains a ‘fall back’ price that is above most market offers, to encourage competition and consumer engagement. The

intent is that retailers can offer discounts off the DMO and compete on price – ultimately leading to savings for consumers who switch to market offers and therefore an incentive for consumers to engage in the market.

[27] Given also, the heightened risks faced by retailers, which is also a function of higher wholesale prices and market volatility, Origin supports the retention of the retail allowance at current levels. We also agree that the AER's analysis adequately demonstrates that the current margin is not unreasonable.

2.2 Retail operating costs

[28] To derive the retail operating costs for SME customers, the AER converts the variable operating cost data published by the ACCC in its Inquiry report into a fixed retail operating cost so that it can be applied on a per customer basis. Origin is concerned that the approach used for this conversion has resulted in an underestimation of retail operating costs for SME customers.

[29] The AER approach involves deriving an average usage for a SME customer by dividing the amount of energy consumed by 'non-residential customers not on demand tariffs' (non-demand customers) by the number of customers on these tariff types. It sources this information from the networks' Regulatory Information Notices (RIN).[18] It then multiplies this value by the ACCC's average variable cost rate to determine its average cost for inclusion in its DMO cost stack.

[30] However, the SME customer data in the RINs are made up of both non-demand customers and 'non-residential low voltage demand tariff' (demand customers). This is an issue because the demand customer data includes both SME and C&I customers with no way of identifying or separating the SME from the C&I information. As a result, the AER has used non-demand customers as a proxy for SME customers.

[31] The problem with this approach is that there has been a significant reduction in both customer numbers and usage for non-demand customers. As a result, the AER's calculated average usage for a SME has also decreased significantly. When multiplied by the ACCC usage rates the outcome is a much lower allowance for operating costs in all jurisdictions despite an increase in the ACCC's reported costs in Queensland and South Australia.

[32] To highlight the impact of the AER's approach, Table 3 shows the percentage change in the ACCC's variable costs and the AER's derived average usage values. Despite the ACCC reporting an increase of about 10 per cent in retail costs for Queensland, the AER has determined that the average usage of a SME has decreased by about 28 per cent. This reduction when applied to the ACCC's c/kWh rate more than offsets the ACCC's increase resulting in a net reduction to the SME allowance in Queensland of about 16 per cent.

[18] AER, Default market offer prices 2023-24 – Cost assessment model, worksheet 'key inputs'.

Table 3: SME Retail Operating Costs – year-on-year movements

Jurisdiction	Change in ACCC[19] SME c/kWh costs	Change in AER SME[20] avg usage	Change in AER SME[21] costs 2023-24
NSW	(11.79%)	(9.49%)	(23.64%)
Queensland	10.45%	(28.37%)	(16.79%)
South Australia	3.63%	(9.26%)	(5.52%)

[33] The current approach therefore results in SME retail costs being understated. Furthermore, unless this issue is addressed, we expect the gap between the ACCC's costs and the AER's allowance to further widen as more SME customers transition from non-demand tariffs to demand tariff, largely because of network tariff re-assignments.

Recommendation(s)

- Given retailers provide the relevant data to the ACCC, which sets out operating costs on a dollar per customer basis for each jurisdiction, Origin urges the AER to obtain and incorporate this data in its calculation by either requesting the ACCC publish the data; or by obtaining it from the ACCC, or directly from retailers through issuance of a data request.

2.3 Bad and doubtful debt

[34] The AER derive its allowance for bad and doubtful debts (BDD) using the weighted average cost from the annual reports of 3 publicly listed retailers. The AER has derived Origin's BDD from table 6.1.4 of our 2022 Annual Report. Specifically, $58M divided by 4.5M customer accounts giving a BDD of $13.01.[22]

[35] This, however, understates the true BDD per customer because the figured taken from the Annual Report captures not only residential and SME electricity debt but also that of C&I customers. Furthermore, the customer numbers used include all of Origin's customer segments, including electricity, gas, LPG, C&I, Solar & Energy Solutions, and internet customers among other services. Electricity and gas accounts total 4.0M, and at a minimum this should be corrected.

[36] It should also be noted that there are differences between electricity and gas debt. Electricity is a higher bill service and therefore carries a greater BDD than gas, which means use of a combined number will likely understate/dilute the true value of BDD for electricity customers.

[37] In addition, the $58M reported in Origin's accounts include a $10m release of surplus COVID provision that solely relates to Origin's C&I customers.[23] This effectively means that the relevant BDD for gas and electricity SME and residential customers is $68M.

---

[19] Derived as the percentage difference between the retail operating costs reported in the ACCC Inquiry Report Appendix E table E4.8A November 2021 and the retail operating costs reported in the ACCC Inquiry Report, Appendix D tables 10.5 to 10.7, November 2022.
[20] Derived as the percentage difference in 'non-residential customers not on demand tariffs energy deliveries' reported in the network RINs cell reference DOPED0502 from 2021 to 2022.
[21] Derived as the percentage difference in the AER SME retail operating costs from the DMO Final Determination 2022-23, p.49, and the AER SME retail operating costs for DMO Draft Decision 2023-34, p. 38.
[22] Origin Energy Annual report 2022, Table 6.1.4, p. 32.
[23] Origin Energy Annual report 2022, Table 6.1.4, p. 32.

[38] What these points highlight is that the use of information from the Annual Report to determine the BDD allowance is not ideal and inherently flawed given it does not provide the appropriate data set.

Recommendation(s)

- A preferable outcome would be for the AER to again use the data provide by retailers to the ACCC. As part of its compliance obligations retailers provide the ACCC with BDDs allocated across customer types and by jurisdiction. Origin has included its BDD data as provided to the ACCC in a confidential Attachment 2 to this submission.
- For future decisions, we propose that the AER request the ACCC publish in its Inquiry reports retailer BDD at a jurisdiction level. Data presented at this level would not pose any issues of retailer identification and would not be considered sensitive.

2.4 Metering costs

[39] Origin suggests that the AER review two key aspects of its approach used in determining metering costs – the subtraction of upfront fees from the metering allowance; and the lag in the calculation of the allowance. As we explain further below both will result in under recovery for a subset of retailers.

[40] The AER has made an adjustment to its meter cost allowance by subtracting up-front/one off advanced meter costs, to prevent customers from overpaying and retailers that charge up-front fees over-recovering (i.e. they recover costs up-front and then through the metering allowance).

[41] We agree that retailers should not over-recover costs and nor should customers continue to pay for a service when they have already paid for it. Equally, those retailers that do not apply an upfront fee should not be prevented from recovering their metering costs over time.

[42] Under the AER’s approach, those retailers that have applied up-front fees will continue to recover metering charges through the metering allowance in the DMO. As a result, the AER’s approach will not have its intended result.

[43] Furthermore, those retailers that rely on an annual allowance will not be able to fully recover their costs because their actual costs have been reduced by the amount of upfront fees charged by other retailers.

[44] On the basis that the AER’s approach has not resolved its initial concern but instead has created an additional problem of cost under-recovery, we urge the AER to consider an alternative approach.

[45] Our second concern relates to the lag in the calculation of costs. The AER derive its allowance as the annual cost of a smart meter divided by the proportion of customers with a smart meter in each jurisdiction. To date this approach has been reasonably effective. However, as retailers proactively install greater numbers of meters and with the AEMC’s proposed mandatory rollout, we will see significantly more meters installed each year. This will result in the annual costs incurred by retailers being significantly higher than the allowance. While in subsequent years the allowance will capture the increasing number of installations, there will always be a one-year lag until 100 per cent penetration is achieved. This financial exposure of retailers will be significant.

[46] Requiring retailers to fund such levels of working capital could act as a disincentive to proactively install smart meters. To address this, the AER should consider a working capital allowance based

on forecast meter installations provided by retailers. Where actual installations were below the forecast, there could be a true up to the working capital allowance to avoid any over-recovery. This way retailers would be made whole for their total costs over time.

Recommendation(s)

- The Federal Department of Climate Change, Energy, the Environment and Water is currently consulting on the implementation of recommendations from its 2022 review of the Competition and Consumer (Industry Code – Electricity Retail) Regulation 2019 (the Code).[24] We believe this is an appropriate forum for the AER to seek amendments to the Code for the treatment of upfront fee to remove the issues as we have described.
- That the AER consider the inclusion of a working capital allowance to remove the disincentive for retailers to embark on a faster rollout of smart meters.

3. Other costs

3.1 Market suspension costs

[47] We support the AER's decision for known compensation costs to be included in future DMO decisions.

3.2 Network costs

[48] It is critical that network costs are passed through to retailers in full. The change in the publication date of the final DMO decision has largely resolved timing issues that had previously occurred. Notwithstanding this, to the extent there is any misalignment, a cost true-up should apply.

3.3 Environmental costs

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

[24] See https://consult.dcceew.gov.au/2022-default-market-offer-review-outcomes