DRAFT DETERMINATION

Default Market Offer Prices 2021-22

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AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

Shortened form	Extended form
ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CARC	Customer acquisition and retention costs
CER	Clean Energy Regulator
CL	Controlled load
CLP	Controlled load profile
COAG Energy Council	Council of Australian Governments Energy Council
CPI	Consumer Price Index
DMO	Default market offer
DMO 1	Default market offer determination for 2019-20
DMO 2	Default market offer determination for 2020-21
DMO 3	Default market offer determination for 2021-22
DMO 4	Default market offer determination for 2022-23
DUOS	Distribution use of system
ECA	Energy Consumers Australia
EME	Energy Made Easy
ESCV	Essential Services Commission Victoria
EWOSA	Energy and Water Ombudsman South Australia
FiT	Feed-in tariff
ICRC	Independent Competition and Regulatory Commission
kW	Kilowatts
kWh	Kilowatt hours
kVa	Kilovolt amperes

Shortened form	Extended form
LAR	Local area retailer
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
MMO	Median market offer
MO	Market offer
MSO	Median standing offer
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NUOS	Network use of system
NSLP	Net System Load Profile
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic system / solar power system
QCA	Queensland Competition Authority
QCOSS	Queensland Council of Social Service
REPI	Retail Electricity Pricing Inquiry
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RPP	Renewable power percentage
SAPN	SA Power Network
SBS	Solar Bonus Scheme (Queensland)
SME	Small and medium-sized business customers (enterprises)
SO	Standing offer
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates

Shortened form	Extended form
STP	Small-scale technology percentage
TOU	Time of use
TUOS	Transmission use of system
UTP	(Queensland) Uniform tariff policy
VDO	Victorian Default Offer

1 Summary

1.1 The DMO price cap and its objectives

This is our Draft Determination for retail electricity default market offer (DMO) prices to apply from 1 July 2021 to 30 June 2022.

The Default Market Offer (DMO) is the maximum price an electricity retailer can charge a standing offer customer each year. A customer might be on a standing offer if they have never switched to a retailer's market offer, or for a range of other reasons.

The objectives of the DMO price cap are to:

- prevent retailers charging unjustifiably high standing offer prices
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin
- not reduce incentives for competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

Our first DMO determination, for 2019-20 (DMO 1), resulted in annual reductions of $118 to $181 to the median standing offer price for residential customers.

For our 2020-21 determination (DMO 2), we maintained the balance we achieved in the initial DMO by:

- adjusting the environmental, wholesale and network components of the retail bill 'cost stack' to take into account the forecast changes for the 2020-21 period
- adjusting residual costs (including retail costs) in line with changes to the cost of inflation.

We referred to this as an indexation approach.

Compared to DMO 1, our DMO 2 determination saw prices:

- for residential customers reduce by a further $109 in SAPN's region and $62 in Energex, while remaining flat in New South Wales regions
- for business customers reduce by a further $815 in SAPN's region, $265 in Energex, and between $4 to $131 in the New South Wales regions.

1.2 Draft DMO 2021-22 prices

Our use of the indexation approach has resulted in Draft 2021-22 (DMO 3) prices that are lower for customers in all regions compared to last year.

Compared to 2020-21, Draft DMO 3 prices for residential customers without Controlled Load will be:

- $90-$136 lower in New South Wales (depending on the distribution region)
- $69 lower in South East Queensland

- $117 lower in South Australia.

For small business customers, Draft DMO prices will be:

- $499-$577 lower in New South Wales (depending on distribution region)
- $317 lower in South East Queensland
- $342 lower in South Australia.

The main factors driving these decreases are:

- forecast wholesale energy cost reductions of 13 to 21 per cent compared to 2020-21, due to lower forward contract prices and the changing shape of load profiles due to continued strong investments in renewable generation. As wholesale costs account for around 22 to 41 per cent of the DMO annual price, these decreases have been the greatest driver of lower DMO prices
- forecast cost reductions of 3 to 5 per cent for retailers to comply with government environmental regulations, including the Large-scale Renewable Energy Target and the Small-scale Renewable Energy Scheme, compared to last year. We call these environmental costs.

In relation to wholesale forecasts, we note in December the Australian Energy Market Commission (AEMC) released its Retail Price Trends 2020 report[1], which includes wholesale cost forecasts for 2021-22. The forecasts for South Australia, south east Queensland and New South Wales are lower than our DMO forecasts, and in the case of South Australia they are significantly lower.

We have identified a number of key differences in our respective approaches that cause the forecasting differences. In particular:

- The AEMC uses an assumed contract book profile (an 'exponential' profile), as well as spot price modelling to estimate contract prices. The exponential profile gives more weighting to recent (and forecast) lower contract prices. In contrast, we only use observed contract prices and trade volumes up to January. In South Australia, we estimate these differences account for around $32/MWh of the forecast DMO wholesale cost.
- The AEMC excludes certain costs from its wholesale forecasts that we include, including prudential costs and Reliability and Emergency Reserve Trader (RERT) costs. Prudential costs account for $2-4/MWh of the DMO wholesale cost (depending on region). The Draft DMO price does not include any RERT costs as it has not been activated in the past year.

If actual contracts continue to be traded at volumes observed in previous years, and contract prices decrease further, we would expect DMO wholesale costs to be lower for the Final Determination.

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1 See https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2020

Network costs decreased in some areas but increased slightly in others.

We have also applied the Reserve Bank of Australia's (RBA) November Consumer Price Index 2021-22 forecast of 1.25 per cent to the DMO retail cost component.

Figures 1 and 2 illustrate the change in DMO price components between DMO 2 and DMO 3 for residential customers without Controlled Load (CL) and small business customers. Appendix F contains the full set of these figures for each customer type.

Figure 1: DMO 2 to DMO 3 cost component changes, residential flat rate

Figure 2: DMO 2 to DMO 3 cost component changes, small business

In addition to maintaining the reductions in standing offer prices we achieved in DMO 1 and DMO 2, these prices continue to balance the other DMO policy objectives.

- We consider the median market offer price is a reasonable indication of retailers' efficient costs to serve customers in each region. Draft DMO 3 prices remain well above median market offer prices for residential and small business customers. These margins indicate retailers can recover costs for serving customers, while also having incentives to compete on price and offer discounts.
- The significant margin between the Draft DMO 3 prices and the lowest market offer prices in each area indicates there are strong financial incentives for DMO customers to shop around for a market deal.

1.3 DMO 3 approach

Having considered stakeholders' feedback, we have determined to adopt a largely unchanged approach to determining DMO 3 prices from our DMO 2 determination.

This remains the approach best suited to achieving the DMO policy objectives, while also providing consistency and stability for stakeholders.

Consideration of stakeholder feedback

While our DMO 3 Position Paper in October 2020 set out our proposal to continue using the indexation approach, we sought stakeholder views on a number of possible refinements. These included amendments to our wholesale forecasting assumptions and the introduction of a productivity adjustment to the retail cost component of the DMO price.

We received 15 submissions to the Position Paper.[2] We also held a public forum on 29 October 2020 to discuss the matters raised in the Position Paper. This was attended by approximately 55 stakeholders.[3]

We have had regard to submissions we received in response to the Position Paper, as well as other feedback provided from stakeholders, in formulating this Draft Determination.[4]

We have not changed key assumptions underpinning the wholesale forecasting methodology. This includes the time period over which our assumed retailer buys contracts to hedge its wholesale market risk, or our Consultant's use of the 95th percentile of modelled prices. Overall, retailer and consumer stakeholders did not support us changing these assumptions.

We have not set an end point for our use of the indexation approach, but acknowledge it is important to ensure our approach remains appropriate in future. We consider a holistic review of the DMO methodology and underlying assumptions, such as those underpinning our wholesale cost forecasts, will be an appropriate way to ensure that our approach continues to meet the policy objectives. We are considering the timing of such a review.

While there was some support for us developing separate residential and small business forecasts, our analysis indicates there are challenges in using Australian Energy Market Operator (AEMO) interval meter data as a basis for developing separate profiles. As a result, we have not changed our current approach.

Alongside this paper, we have also published a report by ACIL Allen Consulting on the approach to forecasting the wholesale and environment costs for 2021-22.

Stakeholders supported updating the TOU profiles, as well as the development of a TOU profile for the new SAPN TOU CL network tariff. We have made these changes, introducing profiles based on current interval meter data, setting out usage in 30-minute blocks.

Most retailers supported our making an allowance for increased costs due to the impact of the COVID-19 pandemic. While we recognise that retailers' bad debt costs have increased, the available information indicates these cost increases are not significant enough to warrant an adjustment to the DMO price under our retail cost step change framework.

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2 A list of submitters to the Position Paper is included in Appendix A.

3 AER, *Position Paper, Default Market Offer Prices 2020-21,* 20 October 2020: https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2021-22

4 Our consultation documents and all public submissions to our process are available on our website at: https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2021-22

We investigated data sources that may enable us to quantify a productivity adjustment to the DMO price that is consistent with our overall approach of not identifying specific retail costs. These included public information about retailer costs, as well as Australian Bureau of Statistics (ABS) productivity information.

While we considered the ABS's Multifactor Productivity was potentially an approach that fit our objectives, our analysis suggests that electricity retail productivity has not increased at a rate materially above the overall economy.

We have assessed retailer information about advanced meter costs, including information about advanced meter penetration and tariff types provided by retailers, and found no specific adjustment to the DMO price is warranted to account for these costs.

Structure of this Draft Determination

Chapter 2 outlines the background and policy objectives for implementing DMO prices and the legislative framework

Chapter 3 sets out our Draft Determination for DMO prices

Chapter 4 sets out our model annual usage determination, covering the annual usage amount and the timing and pattern of supply for TOU and solar customers, and costs to supply TOU customers

Appendix A – List of submitters to the DMO 3 Position Paper

Appendix B – Market offer analysis for each distribution region

Appendix C – Comparing the DMO to the Median Market offer

Appendix D – Matters we have had regard to in determining DMO prices

Appendix E – Draft legislative instrument

Appendix F – DMO 2 to DMO 3 price movements

2 Background

The AER is the independent regulator for Australia's national energy market.

Our functions include regulating electricity networks and covered gas pipelines, in all jurisdictions except Western Australia. We enforce the laws for the National Electricity Market (NEM) and spot gas markets in southern and eastern Australia. We monitor and report on the conduct of market participants and the effectiveness of competition.

We protect the interests of household and small business consumers by enforcing the National Energy Retail Law (NERL). Our retail energy market functions cover New South Wales, South Australia, Tasmania, the ACT and Queensland.

Our goals include effectively regulating competitive markets, and protecting vulnerable consumers while enabling consumers to participate in energy markets.

This is our Draft Determination for retail electricity default market offer (DMO) prices that will apply from 1 July 2021 to 30 June 2022 in network distribution regions where there is no retail price regulation. We have made this Draft Determination in accordance with the requirements under Part 3 of the Regulations.

2.1 Policy context for the Default Market Offer

The DMO was introduced by the Commonwealth Government and commenced on 1 July 2019 following the recommendation by the ACCC's Retail Electricity Pricing Inquiry. [5] The purpose of the DMO was to cap the price of standing offers, which were previously used by retailers as a high priced benchmark from which their advertised market offers were derived, causing financial harm to consumers. The AER was given the power to set the maximum price for the default offer in each jurisdiction.[6]

The legislative framework for determining DMO prices is contained in the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).[7]

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5 ACCC, *Restoring electricity affordability and Australia's competitive advantage. Retail electricity pricing inquiry – final report*, June 2018, p. v, xi–xii: https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf

6 ACCC, *Restoring electricity affordability and Australia's competitive advantage. Retail electricity pricing inquiry – final report*, June 2018. See recommendations 30, 32, 49 and 50 and related discussion.

7 *Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019:* https://www.legislation.gov.au/Details/F2019L00530

The policy intent of the DMO, as set out by the ACCC in its recommendations, is to act as a fall-back option for those not engaged in the market, and should not be a low-priced alternative to a market offer.[8] To achieve this it should:

- reduce unjustifiably high standing offer prices
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and customer acquisition and retention costs (CARC)
- not dis-incentivise competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

We balanced these objectives in our DMO 1 determination by adopting a 'top-down' approach, based on retailers' observed standing and market offer prices, rather than the cost-based 'bottom-up' approach conventionally applied in retail price regulation.

We set the DMO at a price where standing offer customers saw price reductions, but where retailers still have incentives to compete on price, invest and innovate with their market offers.

In each distribution region this was the mid-point (50th percentile) in the range between the median standing and median market offer.[9]

For our DMO 2 determination, we maintained this balance by adjusting retailers' main costs (purchasing wholesale electricity, network, and costs to comply with government environment schemes) to reflect forecast changes. We applied CPI to the remaining retail cost 'residual'. We referred to this approach as 'indexation'.

Balancing the policy objectives remains our primary consideration in determining DMO 3 prices.

Customers on standing offers

The majority of standing offer customers are customers of the 'Tier One' retailers─AGL, EnergyAustralia and Origin Energy.[10] The Tier One retailers are otherwise referred to as Local Area Retailers (LARs), who acquired the customer base of a particular region at the time of retail market privatisation.[11]

The AEMC and ACCC have identified customers on standing offers are those who:

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8 ACCC, *AER Default market Offer, Submissions to the Draft Determination*, 20 March, p. 1–2: https://www.aer.gov.au/system/files/ACCC%20-%20AER%20Default%20Market%20Offer%20-%20Submission%20to%20Draft%20Determination%20-%2020%20March%202019.PDF

9 AER, *Final Determination, Default market offer prices 2019-20*, April 2019, p. 30.

10 See AER market performance data: https://www.aer.gov.au/retail-markets/performance-reporting/retail-energymarket-performance-update-for-quarter-4-2018-19. See also AER, *State of the Energy Market Report*, November 2019, p. 29–34.

11 AEMC, *Advice to COAG Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, p. 14–15. We note that while AGL and Origin acquired the Energex customer base, Origin is the formally designated LAR under the NERL.

- have not taken up a market offer since the introduction of retail competition in that jurisdiction
- are supplied under a retailer's 'obligation to supply' obligations (for example, if a poor credit history means other retailers will not supply them)[12]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to make contact with the retailer[13]
- have defaulted to a standing offer following the expiry of a market contract.[14]

Table 1 sets out the number and proportions of standing offer customers for DMO areas in the first quarter of 2020-21.

We note the proportion of small business standing offer customer numbers in DMO areas has slightly increased in some areas after a period of steady decline.

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12 Unlike other retailers, under s. 22 of the NERL LARs cannot refuse to supply customers.

13 AEMC, *Advice to COAG Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, p. 15.

14 Section 10 of the Regulations makes clear the DMO price only applies to customers on an electricity retailer's standing offer. It does not apply to customers who are on 'evergreen' ongoing market contracts where discounts have expired, and who in practice are paying a retailer's standing offer prices.

Table 1: Standing offer customers in DMO areas

	Residential standing offer customers (Number and %)		Small business standing offer customers (Number and %)	
	Q3 2019-20	Q1 2020-21	Q3 2019-20	Q1 2020-21
New South Wales	390,153 (11.9%)	379,840 (11.5%)	71,228 (21.5%)	73,620 (22.1%)
South-east Queensland Figures extrapolated from all Queensland by excluding Ergon customers. We note other retailers have customers in regional Queensland so figure is approximate	172,300 (12.1%)	166,413 (11.6%)	25,338 (23.1%)	24,771 (22.5%)
South Australia	65,002 (8.3%)	63,834 (8%)	13,445 (15.3%)	13,662 (15.5%)
Total standing offer customers	**627,455 (11.3%)**	**610,087 (11%)**	**110,011 (20.8%)**	**112,053 (21.1%)**

Source: AER Retail Market Performance update, Quarter 1 2020-21

2.2 DMO regulatory framework

The legislative framework for implementing DMO prices and the reference bill mechanism are contained in the Regulations.

Part 3 of the Regulations confers price setting functions on the AER. Specifically, we are required to determine:

- how much electricity a broadly-representative small customer of a particular type in a particular distribution region would consume in a year and the pattern of that consumption[15] (the model annual usage)[16]
- a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region (the DMO price).[17]

15 The AER is not required to determine the pattern of consumption in the case of small business customers.

16 Regulations, s. 16(1)(a).

17 Regulations, s. 16(1)(b).

The DMO price cap applies to residential and small business customers on standing offers in distribution regions that are not subject to retail price regulation.[18] These regions are:

- New South Wales – Ausgrid, Essential Energy and Endeavour Energy network distribution regions
- South Australia – South Australian Power Networks (SAPN) region
- South-East Queensland – Energex region.

The Regulations set out that we must determine DMO prices for ‘small customers’ of certain types. These types are:

- *Residential customers* – customers on flat rate or time of use tariffs who use electricity mainly for personal, household or domestic use, and whose prices do not include a controlled load (CL) tariff. A CL tariff applies to a separately metered part of a customer’s load, for appliances such as electric hot water storage systems or underfloor heating.
- *Residential customers with CL* – customers on flat rate or time of use tariffs who use electricity mainly for personal, household or domestic use, and whose prices include a CL tariff.
- *Small business customers* – customers on flat rate tariffs with no CL, and who use less than 100 MWh per year.

Each category includes customers with solar tariffs.

We are not currently required to determine an annual price and usage for other tariff types, such as:

- tariffs with a demand charge
- small business CL and TOU tariffs
- tariffs offered to customers in embedded networks.

The Regulations require us to have regard to a range of specific factors in determining a reasonable annual price. These include wholesale electricity, network and retail costs, the principle a retailer should be able to make a profit, and other matters we consider relevant.[19] Our previous determinations have set out how we have had regard to these factors in setting the DMO price.[20]

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18 Section 8 of the Regulations specifies that the instrument would not apply in a distribution region if any standing offer prices, or maximum standing office prices, for supplying electricity in the year in the region to a small customer are set by or under a law of a State or Territory.

19 Regulations, s. 16(4).

20 AER, *Final determination, default market offer prices 2019-20*, p. 27–29; AER, *Final determination, default market offer prices 2020-21*, p. 75–77.

The DMO price also functions as a reference price for retailers' advertised offers. Reference price provisions are set out in Part 2 of the Regulations and administered by the ACCC.[21]

2.3 Our consultation process

In making our Draft Determination we have undertaken a consultation process consistent with section 17(1) of the Regulations.

- On 20 October 2020 we published a Position Paper and received 15 submissions. A list of submitters is included at Appendix A.
- On 29 October 2020 we held an online public forum attended by about 55 stakeholders. Presentations from the forum, as well as Q&A from the forum, were published on our website.
- We published our consultant, ACIL Allen's methodology report.

2.4 Default Market Offer – market observations for 2021-22

While the Regulations do not directly affect what retailers can charge for market offers, the DMO price cap and reference price may have indirect impacts on retailers' market offer pricing over time.

As in previous DMO documents, we have analysed retail market offer prices for the DMO regions, tracking changes over time since October 2018 (prior to the announcement of the DMO policy) to the current period. The purpose of this analysis is to provide a snapshot of how retail electricity prices have changed following the DMO's introduction.

We note that a range of factors influence retailers' market offer pricing, and that specific price trends should not be attributed to the introduction of the DMO. Factors currently influencing market offer prices are likely to include:

- lower wholesale electricity purchase costs, due to a combination of lower forward contract prices and continued investment in renewable generation
- changes in network businesses' charges
- individual retailer pricing strategy and market positioning.

Changes in market offer prices observed in December 2020 are likely to be a result of some combination of these factors. Detailed analysis of market offer prices is included in Appendix B. We highlight key observations from this analysis below.

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21 Regulations ss. 10, 12, 14.

Standing offer prices

The Regulations require that retailers' standing offer prices must not exceed the DMO price for the relevant distribution area and customer type.

As expected, from July 2019 we have seen standing offers reduce to the DMO level.

Market offer prices

The Regulations do not restrict what retailers are able to charge for market offers.

However, while retailers are free to set market offers above the DMO level, under the Regulations' reference price provisions they would have to show this in any advertising or marketing material.

In July 2019 we observed the highest priced market offers in each DMO area reduce to the level of the DMO or below, for all customer types. However, since August 2020[22] we have observed a few market offers substantially above the DMO, which continued to 31 December 2020. These may be legacy offers that were priced at or close to the previous DMO price that have not been discontinued by retailers.

We consider the median market offer price in each region is a reasonable indicator of the efficient costs of supplying a customer in each region.

In the Position Paper, we highlighted that between March and August 2020, median market offers had decreased further than the DMO. This trend appeared to be driven by some small retailers offering very low priced offers.

Based on our updated analysis for December, we observed for the period August 2020 to December 2020 median market offers further decreased in all distribution regions for all customer types:

- the median residential market offer decreased by between 1.6 per cent (Endeavour region) and 4.5 per cent (SAPN).
- the median small business market offer price reduced in all areas between 2 per cent (Essential) and 6.7 per cent (SAPN)
- the lowest priced residential offer decreased by 6.5 per cent in Ausgrid, 5.3 per cent in Energex, 3.7 per cent in Essential, and 0.7 per cent in SAPN's regions, with no change in Endeavour's region
- the lowest priced small business offer decreased by 1.7 per cent Endeavour, 6.4 per cent in Essential and 9.4 per cent in SAPN's regions with no change in Ausgrid or Energex's regions.

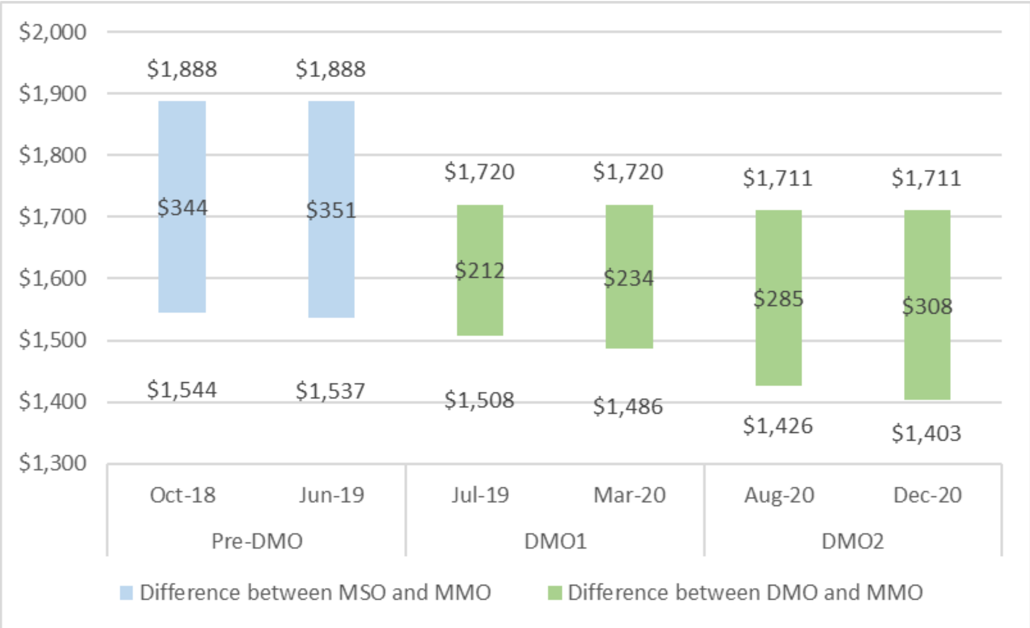
22 Our analysis considered offers available on 3 August 2020, as before this date some retailers had not updated their offers to reflect the DMO 2 price that came into effect on 1 July 2020.

At December 2020, the margin between the median market offer and the DMO 2020-21 price was between:

- $227 and $352 for residential customers on a flat rate tariff (depending on region)
- $287 and $420 for residential customers on a flat rate tariff with CL
- $879 and $1,593 for small business customers on a flat rate tariff.

This margin has increased since the introduction of the DMO in July 2019. For example, Figure 3 shows that in Endeavour region (representative of all regions) the margin has increased steadily. Charts illustrating the margin over time for all regions are included in Appendix C.

Figure 3: DMO/Median market offer margin since July 2019, Endeavour residential



This margin suggests retailers can recover their efficient costs to serve customers, while having additional ‘headroom’ for price competition. The larger margins observed in the August and December 2020 coincide with a period of low wholesale prices. As we noted in the Position Paper, low-price offers from a number of small retailers appear to be contributing to the lower median prices.

The margin between the lowest market offer and DMO 2 price was between:

- $432 and $561 for residential customers on a flat rate tariff (depending on region)
- $487 and $639 for residential customers on a flat rate tariff with CL
- $1,682 and $2,896 for small business customers on a flat rate tariff.

These significant margins, similar to the levels reported in the Position Paper, indicate there are strong incentives for customers on the DMO to shop around for cheaper options.

ACCC Inquiry into the National Electricity Market 2020 report

In September 2020, the ACCC published the *2020 Inquiry into the National Electricity Market* report. The report used a new dataset collected from retailers encompassing over 8.5 million electricity bills for 1.5 million customers, to assess the early effects of the DMO and VDO by considering outcomes for different residential and small business customers between Q3 2018 and Q3 2019.[23]

To determine customer outcomes the report focused on changes in the median effective price, which also takes account of customer usage. The report found:

- the DMO (and VDO) are working effectively to protect standing offer customers from paying excessive prices. Median effective prices for standing offer customers (across the DMO regions and Victoria) decreased by 4.4 per cent for residential customers and 7.5 per cent for small business customers between 2018 and 2019, though standing offer customers paid 6 per cent more in 2018 and 5.5 percent more in 2019 than market offer customers.[24]
- the DMO does not appear to have had adverse effects on market offer prices.[25] The median effective price paid by market offer customers in DMO regions decreased by 1.4 per cent to 7.6 per cent for residential customers. Market offer price reductions for small business customers ranged between 1 per cent and 3.7 per cent.[26] The report also noted the decrease in the median market offer effective price was greater than the decrease achieved by other likely contributing factors, including reductions in network, wholesale and environmental costs and other factors.[27]
- the difference in prices paid by standing and market offer customers highlights the potential savings to be achieved by shopping around. The median effective price paid by residential market offer customers across the DMO regions and Victoria was 17 per cent lower than for standing offer customers, and for small business customers it was 25 per cent lower.[28]
- however, market offer customers of the local area retailers paid higher prices than market offer customers of other retailers. Residential customers of these retailers paid between 0.4 per cent to 7.7 per cent more, and small business

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23 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020: https://www.accc.gov.au/publications/inquiry-into-the-national-electricity-market-september-2020-report. Prices are given in $2019 and are GST exclusive.

24 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 4, 10, 19–20.

25 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 5.

26 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 11.

27 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 21.

28 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 12.

customers paid between 0.3 per cent to 4.3 per cent more, depending on the region.[29]

- the median effective price paid by customers with solar systems was around 24 per cent lower than non-solar customers in DMO regions and Victoria.[30]
- a larger proportion of customers chose market offers over standing offers in 2019 which indicates greater customer engagement.[31]

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29 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 15.

30 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 6.

31 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 5.

3 DMO 2021-22 draft price determination

This chapter sets out our pricing methodology and reasoning for our draft DMO 3 price determination. It provides an overview of the DMO 3 pricing methodology, including our consideration of forecast changes in key cost components for 2021-22.

DMO prices for 2021-22 for each customer type in each distribution region are set out in Table 2 below.

The draft DMO prices are nominal, and based on the most recent forecast data available at the time of publication (early February 2021). The draft prices are likely to change in our Final Determination to be released in April 2021, as we include market data and forecasts that become available between February and April.

Also, the draft DMO prices are indicative prices based on a set model annual usage, and are not a 'maximum bill'. Individual customers' bills will vary depending on how much electricity they use, their distribution region, and how their retailer has set the fixed and variable charges on their standing offer.

The rest of this chapter covers the following matters:

- the matters under the Regulations that we are required to have regard to in determining DMO prices
- observations about market offer prices
- detailed discussion of our DMO pricing approach. This includes:
    - our consideration of forecast changes in input costs
    - our consideration of retail costs, including our 'step change' framework.

Table 2: Draft DMO prices – 1 July 2021 (GST inclusive, nominal)

Distribution region		Residential without CL	Residential with CL	Small Business without CL
Ausgrid	DMO 3 Price	$1,372	$1,886	$6,663
	for annual usage of	3,900 kWh	General usage 4,800 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 2	-$90 (-6.2%)	-$138 (-6.8%)	-$577 (-8%)
Endeavour	DMO 3 Price	$1,575	$1,969	$5,652
	for annual usage of	4,900 kWh	General usage 5,200 kWh + CL 2,200 kWh	20,000 kWh
	Difference to DMO 2	-$136 (-7.9%)	-$196 (-9.1%)	-$525 (-8.5%)
Essential	DMO 3 Price	$1,849	$2,212	$7,542
	for annual usage of	4,600 kWh	General usage 4,600 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 2	-$111 (-5.7%)	-$144 (-6.1%)	-$499 (-6.2%)
Energex	DMO 3 Price	$1,439	$1,717	$5,443
	for annual usage of	4,600 kWh	General usage 4,400 kWh + CL 1,900 kWh	20,000 kWh
	Difference to DMO 2	-$69 (-4.6%)	-$95 (-5.2%)	-$317 (-5.5%)
SAPN	DMO 3 Price	$1,715	$2,086	$7,963
	for annual usage of	4,000 kWh	General usage 4,200 kWh + CL 1,800 kWh	20,000 kWh
	Difference to DMO 2	-$117 (-6.4%)	-$158 (-7%)	-$342 (-4.1%)

In accordance with the Regulations, we have specified DMO prices as annual prices, based on the model annual usage (which incorporates annual usage and the timing and pattern of supply).[32] Under the Regulations, retailers must structure their tariffs to not exceed the DMO annual price for the model annual usage.[33]

3.1 Requirements under the Regulations

In making our DMO price determination, we must have regard to the matters under section 16(4) of the Regulations and have used the relevant model annual usage amounts set out in Chapter 4.

We have also had regard to submissions made in response to our Position Paper and stakeholder feedback from our public forum.

Appendix D summarises how we have considered each of the matters under section 16(4) in determining total annual prices.

3.2 Pricing methodology for DMO 2020-21

This section outlines our draft pricing methodology for determining DMO 3 prices.

Position Paper position

Our proposed pricing methodology in the Position Paper was to retain the indexation approach adopted for DMO 2.

Underlying this approach was our view that the DMO 1 and 2 prices had appropriately balanced the DMO policy objectives and are an appropriate starting point for setting DMO 3 prices.

In the Position Paper, we also sought stakeholder feedback on our proposal to not make any adjustments or 'true-ups' to the DMO 3 price to reflect variances between our forecast costs and assumptions for 2020-21 and actual costs.[34]

We noted that while the indexation approach will remain fit for purpose for future determinations, it may be appropriate to review our methodology and assumptions in the future.

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32 Regulations, s. 16(1).

33 The ACCC is responsible for compliance and enforcement under the Regulations.

34 AER, *Position Paper, Default Market Offer Prices 2020-21,* 20 October 2020, p. 25.

Stakeholder submissions

Indexation approach

Overall, retailers were broadly supportive of us continuing the indexation approach for DMO 3, while the majority of consumer representatives continued to support pricing methodologies based on identifying retailers' efficient costs.[35]

Origin Energy, Alinta Energy, Red Energy/Lumo Energy and AGL were among retailers to note that continuing the same approach as previous years provided consistency. Red Energy/Lumo Energy, for instance, noted a consistent methodology reassures retailers they will be able to recover reasonable costs over time, thereby supporting competition.[36]

While supporting the approach, the Australian Energy Council (AEC) considered the AER should publish a clear set of objectives for annual indexing. It suggested this was important to give industry confidence the DMO will continue to meet its policy objectives. The DMO's role is to provide a fall back option to protect disengaged consumers from unjustifiably high prices.[37]

Among consumer representatives, Etrog Consulting (submitting on behalf 13 Queensland community sector organisations) reiterated its views from our DMO 2 consultation that it was not possible to assess whether the DMO price was achieving the objective of protecting standing offer customers from excessive prices if we did not identify a benchmark level of efficient costs. To do so, Etrog Consulting considered we should adopt a bottom-up approach to price-setting. It also considered that we should exclude customer acquisition and retention costs from our calculations as there is no need to actively recruit and retain customers to a default offer.[38]

PIAC supported the role of default pricing to improve outcomes for consumers, but considered this price should be based on retailers' efficient costs. It submitted that an efficient price would be more effective in maintaining competition in the interests of consumers. PIAC considered the experience of the DMO to date demonstrates a focus on efficiency to deliver even better outcomes for consumers and the market.[39]

PIAC submitted that consumers benefitted from standing offer prices remaining at or below the level of the DMO, and median market offer prices decreasing across all distribution regions and customer types. It noted the spread of market prices decreased, indicating less 'subsidy' between consumers. PIAC cited findings from New South Wales Independent Pricing and Regulatory Tribunal's (IPART) recent monitoring

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35 Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1. Red Energy/Lumo Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1. EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1. MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 2.

36 Red Energy/Lumo Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

37 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1–2.

38 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 11–12.

39 PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 1.

report regarding the impact of the DMO on retailer competition in New South Wales. The report highlighted the entry of new retailers and the market share of smaller retailers increasing (and conversely decreasing for the three largest retailers). It also observed an increase in the number of customers on market offers and an increase in product differentiation and other competition not exclusively based on price.[40]

Energy Consumers Australia (ECA) was broadly supportive of the indexation approach. It submitted that it is observing positive market impacts of the DMO for consumers–specifically, lower standing offer prices, fewer conditional discounts on market offers, and the removal of many market offers that were priced above the DMO. ECA noted the recent decreases in wholesale and most network costs have been passed onto consumers. It suggested the DMO 3 price determination provides an opportunity to build on this foundation.[41]

Retrospective adjustments

Retailers generally supported the proposed position to not make adjustments, or 'true ups', to the DMO 3 price to retrospectively address variance between our DMO 2 forecasts and actual costs, though many were silent on the subject.[42]

ActewAGL commented that the DMO is intended to be a forward-looking instrument, facilitating the comparison of offers from different retailers by consumers, and that the AER should use the most accurate information at the time of the final decision.[43] AGL agreed the closing index value for the previous DMO prices should be the opening index value for the 2021-22 DMO prices, provided there were no changes in approach or methodology in setting the cost components. If there were any fundamental changes to the indexation methodology, AGL considered we should recalculate DMO 1 cost components using the new assumptions, then re-index these to derive a new DMO 3 price.[44]

Red Energy/Lumo Energy considered the approach is reasonable, but highlighted the need for a 'conservative' approach to setting the DMO price, to ensure it was high enough to facilitate competition.[45]

Conversely, Alinta Energy and Origin Energy considered it was unreasonable for us not to make retrospective adjustments to account for some types of costs. Both submitted that our under-estimation of DMO 2 networks charges should be accounted for in the indexation approach applied for DMO 3.[46]

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[40] PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 1–2.

[41] ECA, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 1–2.

[42] ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 2. AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1. MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

[43] ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 2.

[44] AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

[45] Red Energy/Lumo Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

[46] Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2. Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1–3.

Origin Energy considered that the principle of not retrospectively adjusting is generally appropriate in the case of costs within its control (such as wholesale costs), as retailers have a degree of control over these costs via the use of business and risk mitigation strategies.

However, it considers it is unreasonable for retailers to bear any cost burden (or receive a cost benefit) associated with costs beyond its control (such as network costs and COVID-19 debt-related costs). Origin Energy noted that this was inconsistent with the principle that retailers should be allowed to recover an efficient cost allowance.[47]

In relation to uncontrollable costs where forecasts were subject to significant uncertainty, such as future costs associated with COVID-19, Origin Energy suggested an approach similar to the United Kingdom's energy regulator Ofgem's recent default tariff cap decision covering the period of 1 April 2021 to 30 September 2021.[48] This would involve the AER making an initial forward estimate of costs, then adjusting the next year's DMO determination prices based on ex-post analysis of retailers' actual costs.

Other issues

Etrog Consulting suggested we have not considered affordability in setting the DMO. It noted that more customers are currently financially vulnerable (due to economic conditions related to COVID-19) and should not be charged an additional amount for recovery of bad debts.[49]

ReAmped submitted that the Retail Pricing Information Guidelines should have regard to fees and discounts. While this matter is outside the scope of our DMO price setting role, we have provided this feedback to the AER Guideline team.[50]

Draft Determination approach

Our draft position is to continue to use the indexation methodology to determine DMO 3 prices.

Retailers and some consumer representatives support the approach as being fit for purpose, flexible and providing consistent outcomes. We note PIAC and Etrog Consulting's preferences for an approach based on identifying efficient prices. The decision to set the DMO price above the level of efficient costs is consistent with the policy objectives of the Regulations and the REPI report. In its submission to the DMO 1 Draft Determination, the ACCC repeated this intention for the DMO to be set above efficient costs, noting the DMO price should not aim to be the lowest priced offer

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47 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p.

48 Ofgem, *Decision on the potential impact of COVID-19 on the default tariff cap*, February 2021 https://www.ofgem.gov.uk/system/files/docs/2021/02/decision_on_the_potential_impact_of_covid-19_on_the_default_tariff_cap.pdf.

49 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 7–8.

50 ReAmped, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

or be set at the efficient level, but rather act as a 'reasonable fall-back position for those not engaged in the market for whatever reason or for those that require its additional protections'.[51]

Additionally, we do not intend to make any adjustments to the DMO 3 price to reflect the difference in between the indicative New South Wales tariffs we used for the DMO 2 determination and the final approved network tariffs. Our reasons remain the same as we set out in the Position Paper:

- the DMO price is not intended to be an accurate reflection of retailers' efficient costs. Making adjustments in this way suggests there is a 'correct' DMO price in circumstances where the AER has not adopted a detailed 'bottom up' cost build-up methodology to determining the DMO
- the DMO is a forward-looking instrument, based on the best information available at the time. This approach is transparent and conceptually simple. If we were to adjust the price for one component of the DMO cost stack, it follows that we would have to adjust all components. This would decrease year-on-year comparability, and reduce stakeholder certainty in the DMO pricing outcomes
- the nature of our DMO approach means that while variance between forecast and actual costs may disadvantage retailers in some years, it will benefit them in others. In a scenario where our forecasts were higher than actual costs, we would not seek to adjust the DMO price to reflect this. The DMO price is sufficiently high that an under-estimation of costs should not impact the DMO achieving the policy objectives.

For similar reasons, we do not propose to use Origin Energy's suggestion to use a backward-looking mechanism to account for COVID-19 or other uncertain forward costs. We discuss this matter further in section 3.3.4.

In relation to Network Costs, our view is that aligning the DMO and network tariff timing is a longer term solution that would mitigate the risk of us relying on indicative network tariffs. We discuss this further in section 3.3.3.

With regard Etrog Consulting's concerns about affordability, one of the objectives of the DMO is to reduce unjustifiably high standing offer prices. As we have discussed, our DMO 1 and subsequent determinations have achieved this goal. To the extent that the previously high standing offer prices were unaffordable for many vulnerable customers, the DMO has made electricity more affordable for these customers.

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51 ACCC, *AER Default Market Offer, Submission to the Draft Determination*, 20 March 2019, p. 1–2: https://www.aer.gov.au/system/files/ACCC%20-%20AER%20Default%20Market%20Offer%20-%20Submission%20to%20Draft%20Determination%20-%2020%20March%202019.PDF

3.2.1 Future DMO methodology review

In developing the DMO ‘indexation’ methodology, we did not set out a specific end-date or ‘reset’ point.

In the Position Paper, we noted it would be important to understand whether variance between actual costs and forecasts, under our indexation approach, was impacting whether the DMO price continued to balance the policy objectives over time.

This Draft Determination further sets out a number of issues which, because they were fundamental to our calculation of the DMO 1 price components, would be impractical to change and create uncertainty for stakeholders. These include issues such as the hedging approach of our assumed retailer. To retain the consistency of our indexation approach, changing the methodology would require us to recalculate the DMO 1 components, then re-index these for DMO 2 and DMO 3. This would reduce comparability between years, and decrease certainty for stakeholders.

Other stakeholders have raised issues such as the need to review the accuracy of annual usage amounts for residential and small business customers, which may change over time.

Given the issues above, our view is that it will be necessary to review our methodology and assumptions in future, to ensure they remain appropriate to the DMO objectives. It will be important to address and consult on these issues together, as part of a holistic review of the DMO assumptions and methodology.

As we have noted, the Department of Industry, Science, Environment and Resources (DISER) has committed to a review of the Regulations. This review may lead to changes to the Regulations, which we would be required to take into account in subsequent decisions.

DISER has advised that it expects to commence its review in the second half of 2021, with resulting amendments to the Regulations intended to be in place for DMO 4 (July 2022).

In light of this timing, we have commenced discussions with DISER with the aim coordinating on the scope and timing of our respective reviews.

We expect to have determined the timeframes for our review and be in a position to discuss these in the DMO 3 Final Determination.

3.3 Forecast changes in cost inputs in 2021-22

Our forecasts of changes to the cost components between 2020-21 and 2021-22 and the relevant impact on retail prices in each of the distribution regions are set out in Table 3 below.

A detailed assessment of the wholesale and environmental cost forecasts, including inputs provided by the Consultant and issues raised by submissions, is provided in the Consultant’s report.

Table 3: Forecast changes in cost components and DMO bill impact – 2020-21 to 2021–22 (incl GST, nominal)

Description	Network cost	Wholesale cost	Environ-mental cost	Overall price impact from DMO 2020–21 (%, $)		DMO 2021-22
Residential without CL						
Ausgrid	+1.9%	-21.6%	-3.0%	**-6.2%**	*-$90*	**$1,372**
Endeavour	-1.1%	-21.8%	-3.0%	**-7.9%**	*-$136*	**$1,575**
Essential	-0.5%	-20.9%	-3.0%	**-5.7%**	*-$111*	**$1,849**
Energex	+2.4%	-18.2%	-5.0%	**-4.6%**	*-$69*	**$1,439**
SAPN	+1.2%	-18.6%	-4.3%	**-6.4%**	*-$117*	**$1,715**
Residential with CL						
Ausgrid	+1.7%	-20.3%	-3.0%	**-6.8%**	*-$138*	**$1,886**
Endeavour	-1.0%	-21.3%	-3.0%	**-9.1%**	*-$196*	**$1,969**
Essential	-0.4%	-19.8%	-3.0%	**-6.1%**	*-$144*	**$2,212**
Energex	+2.1%	-18.5%	-5.0%	**-5.2%**	*-$95*	**$1,717**
SAPN	-0.2%	-17.2%	-4.3%	**-7.0%**	*-$158*	**$2,086**
Small business without CL						
Ausgrid	-3.0%	-21.6%	-3.0%	**-8.0%**	*-$577*	**$6,663**
Endeavour	+0.5%	-21.8%	-3.0%	**-8.5%**	*-$525*	**$5,652**
Essential	-1.0%	-20.9%	-3.0%	**-6.2%**	*-$499*	**$7,542**
Energex	+2.3%	-18.2%	-5.0%	**-5.5%**	*-$317*	**$5,443**
SAPN	+9.3%	-18.6%	-4.3%	**-4.1%**	*-$342*	**$7,963**

Note: Overall price impact includes residual cost adjusted for CPI (1.25%) in 2021-22

The key drivers for these changes are:

- Wholesale costs comprises **wholesale energy costs** associated with hedging and spot market costs, as well **as other energy costs** incurred in participating in the NEM wholesale market.[52] The overall impact of the forecast changes in **wholesale energy costs** and **other energy costs** is presented above.

The key drivers of change in **wholesale energy costs** are the substantial reductions observed in forward contract prices and the change in the shape of load profiles, leading to significant reductions in wholesale energy costs for all DMO regions.

Our Consultant noted that, compared with 2020-21, futures-based contract prices for 2021-22, on an annualised and trade weighted basis to date have:

- decreased by about $12.60/MWh for Queensland
- decreased by about $13.00/MWh for New South Wales
- decreased by about $20.30/MWh for South Australia.

There are two main drivers for this:

- the continued strong increase in renewable investment coming on-line between 2020-21 and 2021-22, with about 4,000 MW of renewable investment entering the NEM over the next 12-18 months
- the continuation of lower gas prices for gas fired generation. Spot prices across the east coast gas market have maintained their lower levels over the past 12 months.

Other energy costs are forecast to decrease across most distribution regions between 2020-21 and 2021-22. The most significant change in other energy costs are the costs associated with ancillary services, which declined across all regions and tariff types in response to an increase in supply of new entrant capacity able to participate in this relatively small market.

- **Environmental costs** are forecast to fall slightly across all regions and for all customer and tariff types. The decline is primarily driven by a projected decline in the cost of the LRET between 2020-21 and 2021-22, of about 20 per cent (or $0.98/MWh) as a result of declining LGC forward prices. We have however, observed strong demand for LGCs in recent quarters driven by shortfall charge refund[53] and voluntary surrenders, leading to an uptick in recently traded LGC prices. The cost of SRES is projected to increase by 3 per cent, with the expectation that small-scale installations (rooftop solar and solar water heaters) will increase slightly in 2022. The cost variations by region mainly result from differences in jurisdictional energy efficiency schemes.

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52 Other energy costs includes costs for services such as the Australian Energy Market Operator (AEMO) charges and ancillary service charges for services to manage power system safety, security and reliability.

53 Retailers pay a shortfall charge ($65/LGC) if they do not surrender the required number of LGC's in a given year but receive a refund if they make up the shortfall within three years. If the price of the LGC's used to make up the shortfall is lower than in the original year, the retailer makes a saving. Some retailers use this mechanism to manage price risk.

- **Network costs** vary across the regions by customer and tariff type. As all regions are within a regulatory control period, the approved distribution revenues are smoothed across the period. This allows for relatively predictable network price movements. Changes to yearly revenue of the distribution and transmission businesses also occur as a result of under- or over-recovery in previous years, annual incentive rewards/penalties, approved pass through amounts and changes in the annual return on debt. Changes to the mix of the daily charge and usage tariffs can also affect the network costs. For residential customers, the forecast change to network costs is a 1.1 per cent decrease in the Endeavour region to a 2.4 per cent increase in Energex region in 2021-22. For small business customers the forecast change is a 3.0 per cent decrease in Ausgrid region to a 9.3 per cent increase in SAPN region.
- **Residual costs** increased by 1.25 per cent across all regions based on the RBA's November 2020 Consumer Price Index inflation forecast for the 2021-22 period. Our analysis and consideration of submissions has not identified any increase or decrease in retail costs that would warrant a step change. We considered introducing a productivity factor to residual costs, though have decided not to apply it for this determination.

The detailed description and formulas on the approach to forecast the changes in network, wholesale and environmental costs is published in our DMO 2 Final Determination.[54] We also publish the index model for the DMO 2 determination.

3.3.1 Wholesale energy costs

Overview

Under the methodology used by our consultant ACIL Allen Consulting (the Consultant), forecast wholesale energy costs are a function of projected energy supply and demand forecasts, hedging strategy and any residual exposure to forecast spot market prices.

The demand-side forecast is a function of AEMO's Electricity Statement of Opportunities (ESOO) central scenario[55], estimated uptake of rooftop solar photovoltaic (PV) and weather simulations in respect to their impact on demand and availability of renewable resources.

The supply-side forecast, which is broadly aligned with AEMO's Integrated System Plan, takes into consideration announced new investments, retirements, fuel costs and simulated thermal power generation availability. Our Consultant takes the above demand-side and supply-side forecasts to produce a distribution of around 500 simulated spot market price outcomes, representative of volatility in the spot market.

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[54] AER, *Final Determination, Default Market Offer Prices 2019-20,* April 2019, Appendix D, p 71–74.

[55] AEMO, 2020 Electricity Statement of Opportunities, August 2020: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2

Distribution Loss Factors (DLF) for each network area and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the WEC estimates to incorporate any losses.

Other energy costs include hedging costs, AEMO NEM management fees, Reliability and Emergency Reserve Trader (RERT) costs and ancillary services charges for services to manage power system safety, security and reliability.

Details of the Consultant's wholesale cost forecasting methodology and resulting wholesale and energy costs forecasts are set out in its *Default Market Offer 2021-22 draft determination technical report*.

Position Paper position

We sought stakeholders' views on various matters relating to the wholesale cost forecasting methodology and assumptions, and whether these remained appropriate given the DMO policy objectives.

Assumed hedge book build period

Our assumed retailers' hedging strategy uses all trades back to the first trade recorded by ASX Energy for a given contract product. Observable trades recorded by ASX Energy generally commence 36 months prior to the start of the relevant period, although the large majority of trades (typically around 98 per cent) occur in the 24 months prior to the start of a period.

In our DMO 3 Position Paper, we sought stakeholders' views as to whether our current book build assumption of a risk-averse retailer remains reasonable, or whether a shorter book build period would be a more appropriate contracting strategy, given the DMO objectives.

Setting wholesale energy costs

As part of the wholesale cost forecast process, our Consultant makes use of demand-side and supply-side forecasts to produce a distribution of 550 simulated spot market price outcomes. The 95th percentile value of the distribution of simulated spot market price outcomes, combined with the optimal contracting costs, form the wholesale energy costs used in the DMO.

The Position Paper noted this approach may create a risk of over-estimating wholesale costs, and sought stakeholder feedback on the appropriateness of using the 95th percentile and whether any alternative percentiles could be reasonably applied.

Separating residential and small business load profiles

The level and shape of the load profile is a key determinant of the efficient mix of futures contracts and the forecast exposure to the spot market, which drives the wholesale cost forecast. In the DMO 2 Final Determination, our Consultant used the distribution region Network System Load Profile (NSLP) and Controlled Load Profile (CLP) as indicators of the level and shape of load profiles, as they provided good indicators of typical loads for the customer types relevant to the DMO. However some stakeholders noted developing separate profiles may increase accuracy.

Our DMO 3 Position Paper sought stakeholder views on the implications of differentiating between residential and small business load profiles to forecast wholesale costs. We noted we had requested residential and small business aggregated interval load data from AEMO for the DMO jurisdictions to assist our consideration of this issue.

Allocation of ancillary services charges

Ancillary services charges are estimated using weekly aggregated settlements data published by AEMO. These charges vary year-on-year, dictated by market conditions and demand for Frequency Control Ancillary Services (FCAS).

For our DMO 2 Final Determination, the forecast ancillary services charges for all distribution regions were based on average NEM FCAS costs published by AEMO over the 52 weeks preceding 25 March 2020. In the DMO 3 Position Paper, we noted that this averaging approach may not be reflective of actual charges incurred by retailers in a particular DMO jurisdiction, as these charges are impacted by NEM region specific events.

Therefore for DMO 3, we proposed in the Position Paper to forecast ancillary services charges separately for each NEM region, and sought stakeholder feedback on this approach.

5 minute settlement and cap contract availability

We noted the issue relating to the availability of cap contracts after Q3 2021—that is, currently there are no cap contract products available for trade on ASX Energy for Q4 2021 and Q1/2 2022, due to the implementation of 5 minute settlement from Q3 2021. An update on the treatment of this issue is provided under the Draft Determination approach heading below.

Stakeholder submissions

Retailer and consumer stakeholder submissions supported retaining the current market-based wholesale cost forecasting methodology for DMO 3, noting it maintained consistency[56] and captured the impacts of COVID-19 on the wholesale market.[57]

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56 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3; AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4; Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2; Australian Energy Council, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 22; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

57 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4.

Assumed hedge book build period

The majority of stakeholders, including one consumer stakeholder, supported retaining the current approach of building the hedge book from the time of the first contract trade for DMO 3.[58]

The AEC noted that the current book build approach is prudent and means retailers are not unduly penalised for managing their expected load in advance.[59] Alinta Energy further submitted that maintaining the longer book-build approach more appropriately reflects how a risk-averse retailer would behave.[60] AGL submitted that the longer book build approach would reduce the volatility of estimating wholesale energy costs.[61]

Etrog Consulting supported the current approach on the basis that it was preferable to maintain stability for this aspect of the methodology.[62] Similar views were expressed in submissions from AGL, Alinta Energy, and Origin Energy.

Alinta Energy submitted that it did not support an 18-month book build period.[63]

Setting wholesale energy costs

Retailer and consumer submissions on this matter supported retaining the setting of wholesale energy costs at the 95th percentile of distributed outcomes for DMO 3.[64] Stakeholders noted maintaining consistency, meeting the DMO objectives and adequately accounting for risks as key reasons.

Etrog Consulting was the only consumer representative to comment on this issue. It submitted that hedging to the 95th percentile is a feasible strategy for a retailer to manage its wholesale energy purchasing.[65] Origin Energy also noted that the use of the 95th percentile of the simulated wholesale energy costs represents an appropriate approach to assessing risk.[66]

No stakeholders responded to our consultation question about whether potential alternative approaches were more appropriate.

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58 Australian Energy Council, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 20; MEA Group, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6

59 Australian Energy Council, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

60 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

61 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

62 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 20.

63 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

64 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 2; AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2; Australian Energy Council, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

65 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21.

66 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

Separating residential and small business load profiles

Stakeholders had mixed views about developing separate residential and small business load profiles for wholesale cost forecasting. ActewAGL supported retaining the current approach of using the NSLP and CLP.[67] It noted that combining wholesale costs for residential and small business customers is a reasonable approach and achieves the objectives of the DMO.

The AEC, EnergyAustralia and Red Energy/Lumo Energy supported separating residential and small business profiles, noting such an approach would provide more accurate wholesale cost forecasts for each customer segment.[68] Origin Energy also supported the approach, provided that robust and representative load profile data is available.[69]

AGL and Etrog Consulting noted that accumulation/basic meters are still prevalent in DMO jurisdictions, for which the NSLP continues to represent the best reflection of energy usage and is best for NEM settlement purposes.[70] AGL further noted that until there is a large penetration of advanced meters, having separate residential and small business profiles could result in a misalignment of wholesale costs for market settlement, which is done on the basis of the NSLP for the majority of customers.[71]

Nevertheless, AGL and Etrog Consulting flagged support for the AER to investigate whether the differences between the NSLP and separate residential and small business profiles are significant enough to warrant changing the wholesale cost forecast methodology.

Allocation of ancillary services charges

All stakeholder submissions on this matter either supported or provided conditional support for the assignment of ancillary services charges at a jurisdictional level for DMO 3, including ActewAGL, AGL, Etrog Consulting and Origin Energy.[72] Generally, submissions noted that a jurisdictional-level allocation of ancillary services charges would be more cost reflective, as opposed to the previous approach of having the NEM-wide average cost applied to the DMO jurisdictions.

Etrog Consulting submitted that the AER should check with AEMO on how ancillary services charges are recovered from retailers, as information on AEMO's website

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67 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

68 Australian Energy Council, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4; Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5.

69 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 7.

70 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21–22.

71 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4.

72 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 2; AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

indicates that ‘for the purpose of FCAS payments and recovery, the market is treated globally. Hence, for the purpose of recovery, participants are treated equally, regardless of region.’[73]

AEMO energy directions

Under the National Electricity Rules (NER) AEMO can take action to maintain security and reliability of the power system by directing a participant to undertake an action, such as directing a generator to operate even though the spot price in the NEM is less than that generator’s operating cash costs.

In such instances, compensation may be payable to the participant. This compensation needs to be recovered from other market participants.

AGL’s Position Paper submission noted AEMO continued to issue directions to gas-powered generators in South Australia, resulting in material costs to retailers in the region. AGL considered that we should consider the impact of AEMO directions in our DMO determination.[74]

Draft Determination approach

Having considered stakeholder submissions, we propose to preserve our current approach to the wholesale cost forecasting methodology, with amendments to how we allocate ancillary services costs.

Assumed hedge book build period

Having considered the submissions, our Draft Determination position is to continue with the same hedge book build assumptions as in previous determinations. Stakeholders, including some consumer representatives, supported the stability and consistency of retaining the current approach.

We note that a change to the assumed hedging strategy would require us to recalculate the DMO 1 wholesale component, then index this forward to DMO 2 and DMO 3. This would complicate comparisons between DMO years, and result in a retrospective adjustment to the index. We consider that this would be inconsistent with our approach of not making retrospective adjustments.

In light of the above, we consider it appropriate to revisit this matter as part of the future DMO methodology review discussed previously.

Setting wholesale energy costs

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73 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21.

74 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4.

In response to stakeholder preferences for maintaining consistency of approach, we will retain our approach to setting wholesale energy costs at the 95th percentile of the range of simulated price outcomes for DMO 3.

Similar to the hedging strategy, the 95th percentile estimate is a fundamental assumption in our forecasting methodology, and changing it would require recalculating the DMO 1 wholesale component, and the DMO 2 index.

For this reason, we consider it appropriate to revisit this matter as part of the future DMO methodology review.

Separating residential and small business load profiles

In the Position Paper, we undertook to make an initial assessment about whether the differences between the NSLP and individual residential and small business load profiles across the distribution regions are significant enough to warrant changing the forecasting methodology (which we noted is transparent and uses public information).

Having analysed the interval meter data provided by AEMO[75], we have determined not to develop separate residential and small business load profiles.

From the AEMO interval data provided, the shape of residential aggregated load profile tracks the NSLP closely, though exhibiting less peakiness, with an observable reduction in demand during the evening peaks and an uptick around midnight. The small business aggregated load profile showed a marked difference from the NSLP, with peak demand occurring around midday as opposed to late afternoon and evening.

However we were concerned this data on its own is not suitable for use due to uncertainty about the amount of solar customers captured[76], which reduces its representativeness of the broader population on accumulation meters.

Weighted profiles

To reduce the uncertainties and limitations introduced from relying purely on the aggregate load data from AEMO to forecast wholesale costs, and to create a more representative profile for the majority of customers on accumulation meters, we developed weighted profiles.

The weighted profiles combined interval load data provided by AEMO and the NSLP and CLP to develop separate small business and residential load profiles. These profiles were weighted by demand, so that the low number of interval meters, and thus demand compared to the broad majority on accumulation meters, had a proportionally small impact on the overall profile.

Overall, the weighted profiles showed only marginal differences from the NSLP. This was somewhat expected, as small business customers, for which the load profiles

75 We requested advanced meter aggregated load data from AEMO for the DMO jurisdictions. Interval and advanced meter load data are recorded on a net basis in AEMO's Market Settlement and Transfer Solutions (MSATS) database, for three years up to the end of February 2020.

76 The MSATS database is unable to separately identify all interval meters containing solar.

differ materially from the NSLP, only make up a small proportion of the overall demand. Overall, comparing the weighted profiles against the NSLP, we observed only a minor variation in the form of reduced peakiness of demand.

Noting the mix of stakeholder views on the matter, the general preference for a consistent methodology, and the small and immaterial variance observed between the weighted profile and the NSLP and CLP, our view is that there is no compelling reason to change this aspect of our wholesale forecast methodology at this time.

Therefore, we will continue the approach adopted in our DMO 2 Final Determination of using the NSLP and CLP for our wholesale energy cost forecasts. Due to the current prevalence of accumulation meters in DMO jurisdictions, these continue to represent the best reflection of broader residential and small business energy usage patterns.

We note advanced meter penetration is gradually increasing. It is anticipated that the Regulations governing the DMO and assumptions and methodology used to set the DMO would be reviewed in due course. This, along with data improvements (such as the move to 5 minute settlement) may remove practical challenges, and would provide us with another opportunity to review and re-investigate this matter.

Allocation of ancillary services charges

We investigated the matter raised by Etrog Consulting[77] on how cost recovery takes place for FCAS. AEMO's Settlements Guide to Ancillary Services Payment and Recovery[78] states, 'FCAS payments for services enabled to meet a Local Requirement are recovered from specified categories of Market Participants in the region(s) in which the relevant FCAS constraint was binding'. Conversely, 'FCAS payments for Global Requirements are recovered from specified categories of Market Participants across the entire NEM'.[79]

Therefore, ancillary services charges vary year-to-year, dictated by market conditions and demand for FCAS either at a local or global level. In the DMO 2 period where cost data was used to create forecast ancillary services charges, there was an increase in FCAS costs in specific NEM regions due to events such as the South Australian islanding in November 2019[80] and the Heywood interconnector outage in January 2020.[81] For DMO 1, ancillary services costs across the DMO jurisdictions were generally equivalent.

Noting the above, and in response to stakeholder comments, for DMO 3, we will move to a NEM regional-based allocation of ancillary services charges while also accounting

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77 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 21.

78 AEMO, Settlements Guide to Ancillary Services Payment and Recovery February 2020: https://aemo.com.au/-/media/files/electricity/nem/data/ancillary_services/2020/settlements-guide-to-ancillary-services-payment-and-recovery.pdf?la=en

79 AEMO, Settlements Guide to Ancillary Services Payment and Recovery February 2020, p. 9.

80 AEMO, *December 2019, Preliminary Report Non-Credible Separation Event South Australia – Victoria on 16 November 2019.*

81 AEMO, April 2020, *Preliminary Report – Victoria and South Australia Separation Event*, 31 January 2020.

for global recoveries. Such an approach would more closely reflect the actual manner in which ancillary services costs are incurred by retailers.

Availability of cap contracts

As the market-based approach relies on derivatives data from ASX Energy, we are aware that with the introduction of 5 minute settlement in the NEM, cap contracts have been delisted from 1 October 2021. That is, cap contracts are currently unavailable for Q4 2021 and Q1/2 2022.

The adopted approach, suggested by our Consultant, for determining wholesale costs in this Draft Determination is equivalent to that of the Essential Services Commission's Victorian Default Offer 2021 Final Decision.[82] The approach estimated cap contract prices based on the percentage change in base contract prices between 2020-21 and 2021-22. See the *Default Market Offer 2021-22 draft determination technical report* for more information.

However, the above approach is envisaged to only apply to this Draft Determination. The Consultant expects there to be cap contract data available on ASX Energy in time for our DMO 3 Final Determination, on which the wholesale cost forecasts will be based.[83]

If no cap contract data is available for the Final Determination, our Consultant will change the mix of contracts used in the hedge model by limiting the amount of caps available to the algorithm when searching for the optimal mix of hedges to produce representative wholesale cost forecasts. This matter is discussed in section 4.2 of the technical report.[84]

AEMO electricity directions cost

We have considered AGL's submission and have determined not to include AEMO directions costs in our Draft Determination.

As we have not previously included AEMO directions costs in the DMO price, accounting for this cost at this stage would have implications for our indexing approach. Given the DMO 1 price excluded this cost, to maintain the consistency of the index we would need to re-calculate the DMO 1 price, then re-calculate DMO 2 and DMO 3 prices from this revised starting point. In our view, this would reduce comparability across years, and decrease certainty for stakeholders.

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82 Essential Services Commission, Victorian Default Offer 2021 Final Decision 25 November 2020: https://www.esc.vic.gov.au/sites/default/files/documents/FD%20-%20%202021%20VDO%20-%20Final%20decision%20-%2020201125.pdf

83 ASX Energy on 3 February issued a press release on its intention to list the Australian Base Load Electricity 5 Minute Cap Futures Contract on 22 March 2021: https://www.asxenergy.com.au/newsroom/industry_news/intent-to-list-asx-australian

84 ACIL Allen Consulting, Default Market Offer 2021-22 draft determination technical report, p. 48.

The appropriate point to consider changes that affect the DMO index will be as part of the holistic review of DMO methodology and assumptions discussed previously in this paper.

We also note the installation of four synchronous condensers by ElectraNet, the South Australian transmission network owner, by mid-2021. The AEMC has noted these devices improve system reliability, and hence reduce the need for AEMO interventions going forward.[85]

Wholesale cost inputs

For comparison, the wholesale cost inputs provided by the Consultant for the 2021-22 period are given in Table 4, together with inputs for the 2020-21 period used in the DMO 2 Final Determination.

Table 4: Wholesale costs for 2020-21 and 2021-22, $/MWh (excl GST, - nominal).

Distribution region	Tariff	2020-21	2021-22
Ausgrid	Flat rate	111.06	**87.06**
	CL1	74.02	**62.26**
	CL2	72.11	**60.95**
Endeavour	Flat rate	112.27	**87.80**
	CL1	103.92	**83.04**
	CL2	103.92	**83.04**
Essential	Flat rate	103.50	**81.88**
	CL1	87.90	**73.11**
	CL2	87.90	**73.11**
Energex	Flat rate	91.49	**74.86**
	CL1	72.29	**57.07**
	CL2	74.06	**60.05**
SAPN	Flat rate	154.12	**125.38**
	CL1	93.15	**82.35**

Source: Default Market Offer 2021-22 draft determination technical report

[85] AEMC, *Investigation into intervention mechanisms in the NEM Final Report*, 15 August 2019, p. 3.

3.3.2 Environmental costs

Overview

Environmental schemes at both Commonwealth and State level require retailers to procure electricity supply from renewable sources and improve customer energy efficiency. The costs of these schemes are incurred by retailers and are included as a cost component of the retail price. Environmental costs broadly fall into two main categories—national schemes or the Renewable Energy Target (RET), and jurisdictional green schemes.

The majority of environmental costs relate to complying with the RET. Retailers have an obligation to purchase renewable energy certificates and surrender them to the Government in proportion to the overall amount of energy consumed by their customers.

The RET is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). LRET costs are incurred by retailers to acquire the necessary amount of Large-scale Generation Certificates (LGCs). Required LGC surrender for each retailer is determined by the electricity consumed by a retailer's customers in that year, multiplied by the Renewable Power Percentage (RPP) set annually for a calendar year.[86]

Similar to the LRET, under the SRES, Small-scale Technology Certificates (STCs) are required to be surrendered by retailers based on the Small-scale Technology Percentage (STP)[87] set annually for a calendar year, and the amount of electricity consumed by a retailer's customers in that year. Retailers have the option to either purchase STCs on the market or from the STC Clearing House at a set price.

In addition to the RET costs, a retailer also incurs a small amount of jurisdictional green scheme costs, which are passed onto their customers. These include the New South Wales Energy Savings Scheme (ESS) and South Australian Retailer Energy Efficiency Scheme (REES).

Position Paper position

Our Position Paper position was to continue to use our market-based approach adopted in the DMO 2 Final Determination to forecast environmental costs. The approach provides consistency between environmental and wholesale cost forecasting.

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86 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage, viewed 21 December 2020.

87 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage, viewed 21 December 2020.

Approach to forecasting the components of environmental costs:

1. **LRET cost** – is a function of LGC prices and the RPP. As part of our market-based approach, the LGC price would be set at the trade-weighted average of LGC forward prices for 2021 and 2022, from when they commenced trading. LGC trade data is provided by broker TFS Green Australia. The RPP for 2021 will be determined by the Clean Energy Regulator (CER) by 31 March, with the RPP for 2022 estimated by our Consultant based on mandated LRET targets and liable acquisitions.
2. **SRES cost** – is a function of STC prices and the STP. The STC price is set at the STC Clearing House price of $40 per certificate (excluding GST). The CER will publish binding 2021 STP by 31 March, as well as a non-binding STP for the following two years. While the non-binding STP published by the CER is intended to give an indication of what the STP will be in those years, our Consultant may use a different STP for 2022 based on estimates of STC creation and liable acquisitions.
3. **Jurisdictional green scheme costs –** our Consultant estimates the ESS cost by considering IPART's ESS Target and energy conversion factor, and Energy Savings Certificate forward prices for 2021 and 2022 from broker TFS Green Australia. REES cost is derived from the AEMC's Residential Electricity Price Trends report data. For 2021-22, the AEMC Residential Electricity Price Trends 2020 report data estimated the REES cost to be $2.5/MWh.[88]

In forecasting environmental costs based on the above components, Distribution Loss Factors (DLF) and Marginal Loss Factors (MLF) are applied.

In our DMO 3 Position Paper, we sought stakeholder views on whether the above approach remains appropriate for DMO 3.

Stakeholder submissions

Stakeholder views were varied in relation to our proposed approach to forecasting environmental costs. A number of stakeholders supported retaining the environmental cost forecasting methodology adopted in the DMO 2 Final Determination for DMO 3, including ActewAGL, Etrog Consulting and Origin Energy.[89] Origin Energy supported using our Consultant's own STP estimates where CER's non-binding STP estimates do not take into account the growth trend in solar installations.[90]

While maintaining concerns with our approach to estimating LGC prices, AGL recognised the difficulties in using Power Purchase Agreement (PPA) prices to

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88 See AEMC website: https://www.aemc.gov.au/news-centre/data-portal/price-trends-2020/trends-sa-supply-chain-components, viewed 21 December 2020.

89 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3; Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 22; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 7.

90 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 7.

estimate the cost of complying with the LRET.[91] AGL expressed concern for large fluctuations in LGC prices due to thin trading volumes and the potential commercially damaging price outcomes this could cause. To mitigate this risk, AGL suggested setting an LGC floor price, tying the price of LGCs to those of Australian Carbon Credit Units (ACCUs) by converting MWh renewable generation represented by LGCs to tCO_2-e using the NEM emissions intensity factor.

EnergyAustralia proposed an alternative approach to estimating LRET costs that takes into account the cost and volume of LGCs derived from PPAs in combination with the AER's market-based approach.

EnergyAustralia submitted its estimated PPA derived LGC cost is between $40 and $50 per certificate, and that volume of LGCs derived from PPAs for retailers could be gathered from Green Energy Markets. It considered the estimated volume of on-market LGC trades, equating to roughly 50 per cent of required LGC surrender amount, indicates a market-based approach would not be representative of costs incurred by retailers.[92]

Draft Determination approach

STP setting

On the application of the STP, noting Origin Energy's submission and consistent with our approach adopted in the DMO 2 Final Determination, we will assess both CER's non-binding STP estimates and our Consultant's estimates. We will determine the appropriate STP based on the latest available information, such as forecast growth in solar PV uptake and any impact on demand due to the COVID-19 pandemic.

For this Draft Determination, we have used our Consultant's estimated STP of 23.94 per cent for calendar years 2021 and 2022. We note the binding STP for 2021 will be published prior to the release of our DMO 3 Final Determination. This will be used to forecast the SRES cost in the Final Determination. The 2022 STP used in the Final Determination will be selected based on the assessed merits of CER's non-binding STP estimate and our Consultant's estimate.

LGC floor price

A benefit of adopting a market-based forecasting approach is its ability to account for fluctuating price outcomes that reflects market sentiments and microeconomic conditions of supply and demand. Conceptually, setting a LGC floor price through the application of the NEM's emissions intensity factor may be of limited benefit to mitigate the fluctuating price risk identified by AGL. As more renewable generation comes online, the NEM's emissions intensity factor would decrease. Holding the price of ACCUs constant, the LGC floor price would drop due to a lower emissions intensity factor in line with any expected decrease in market LGC prices through increased supply.

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91 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5.

92 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–6.

The concept of a carbon exchange rate for LGC that combines LGC to ACCU as proposed by AGL, was also considered as part of the King Review on the future of Australia's renewable energy policy.[93] The Government's response to the King Review recommendation was to 'undertake further work to assess the best approach to account for the implicit carbon content in an LGC, including the most appropriate methodology for determining a conversion factor. The proposed convention would provide additional information to assist buyers and sellers in voluntary markets to understand the carbon content of LGCs'.[94] Noting the Government's ongoing work in this area, it would not be prudent for the AER to independently introduce a framework for tying the LGC price to ACCU price.

The September 2020 Quarterly Carbon Market Report[95] published by the CER also showed robust demand for LGCs from a variety of sources outside of legislated demand, such as shortfall charge refunds, GreenPower and the Australian Capital Territory Government scheme. Further, demand from the Climate Active Carbon Neutral Standard is starting to appear, with 2019 demand for 54,000 LGCs compared to zero in 2018.[96] All this contributes to rising forward LGC prices since September 2019. Calendar year 2021 and 2022 prices, which are relevant for DMO 3, are all significantly above AGL's proposed floor price.

Noting the above, a floor price or framework for a floor price will not be introduced for DMO 3. We will continue to monitor the work undertaken by the Government on LGC carbon exchange and the price of market traded LGCs.

LRET cost forecasting

The weighted average approach to forecasting LRET costs proposed by EnergyAustralia in its submission made use of PPA derived LGC costs in conjunction with the market-based approach proposed in the DMO 3 Position Paper, as EnergyAustralia considered a market-based approach alone does not sufficiently account for retailers' costs.

A salient requirement of EnergyAustralia's proposal is to know the true/net cost of LGC's derived from PPAs. PPAs are private contracts between electricity retailers and renewable energy project owners. They include contracted LGC and wholesale prices and various non-price terms. Aside from the private nature of PPAs, there is significant complexity and difficulty in using PPAs, as AGL recognised in its submission. PPAs

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93 *Report of the Expert Panel examining additional sources of low cost abatement*,14 February 2020: https://www.industry.gov.au/sites/default/files/2020-05/expert-panel-report-examining-additional-sources-of-low-cost-abatement.pdf.

94 Australian Government response to the Final Report of the Expert Panel examining additional sources of low-cost abatement ('the King Review'): https://www.industry.gov.au/sites/default/files/2020-05/government-response-to-the-expert-panel-report-examining-additional-sources-of-low-cost-abatement.pdf.

95 See CER website: http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/Quarterly-Carbon-Market-Report-%E2%80%93-Quarter-3-September-2020.aspx, viewed 21 December 2020.

96 See CER website: http://www.cleanenergyregulator.gov.au/About/Pages/Accountability%20and%20reporting/Administrative%20Reports/The%20Renewable%20Energy%20Target%202019%20Administrative%20Report/Voluntary-large-scale-generation-certificate-demand-grows.aspx, viewed 21 December 2020.

have various forms, durations, and commercial drivers that create challenges to estimate a weighted average LRET price for a specific regulatory period.

We note that our market-based approach to estimating LRET costs is also adopted by other Regulators, including the QCA and ESCV. The ESCV in its VDO Final Decision[97] observed that a combined benchmark for its wholesale and LGC costs sits comfortably within the range of retailers' submitted actual costs. This may mean the higher LGC costs are offset by lower wholesale electricity costs derived from those PPAs. As there is limited visibility on this matter due to the private nature of PPAs, we could not satisfy the salient requirement of EnergyAustralia's proposed approach, of determining the true/net LGC costs derived from PPAs.

In addition, we consider there are significant challenges in reconciling an approach using historical LCG prices from PPAs with a forward-looking DMO approach. Also, as we have not adopted a specific cost build-up approach for other elements of the DMO, such as wholesale costs, it would be inconsistent for us to do this for PPAs with respect to environmental costs.

As we noted in our DMO 2 Final Determination, LGCs trade reasonably well in the market. For example, LGC market trades during calendar year 2019 amounted to over 69 million LGCs, or over two times the mandated LRET target for 2019. Compared with 2019, the number of trades in TFS-brokered forward contracts to date have increased by 45 per cent and 81 per cent for the 2021 and 2022 surrender years respectively.

Therefore, we maintain the view that market-traded LGC prices are transparent, publicly available and a function of market conditions, and are the best available proxy for the cost of acquiring LGCs.

Noting the above, and that the majority of stakeholders supported our market-based approach to forecasting LRET costs adopted in the DMO 2 Final Determination, we will retain this approach for DMO 3.

Environmental cost inputs

The environmental cost inputs provided by the Consultant for the 2021-22 period are given below, along with inputs for the 2020-21 period as used in the DMO 2 Final Determination for comparison.

Jurisdictional scheme costs and network losses vary between distribution regions. As a result, total forecast environmental costs ($/MWh) vary across regions as indicated in Table 5.

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97 Essential Services Commission, Victorian Default Offer 2021 Final Decision 25 November 2020, p. 23: https://www.esc.vic.gov.au/sites/default/files/documents/FD%20-%20%202021%20VDO%20-%20Final%20decision%20-%2020201125.pdf

Table 5: Environmental costs for 2020-21 and 2021-22, $/MWh (excl GST, nominal).

Distribution region	Tariff	2020-21	2021-22
Ausgrid	Flat rate	17.17	**16.65**
	CL1	17.22	**16.70**
	CL2	17.22	**16.70**
Endeavour	Flat rate	17.36	**16.84**
	CL1	17.36	**16.84**
	CL2	17.36	**16.84**
Essential	Flat rate	17.25	**16.73**
	CL1	17.25	**16.73**
	CL2	17.25	**16.73**
Energex	Flat rate	15.10	**14.35**
	CL1	15.10	**14.35**
	CL2	15.10	**14.35**
SAPN	Flat rate	18.57	**17.78**
	CL1	18.57	**17.78**

Source: Default Market Offer 2021-22 draft determination technical report

3.3.3 Network costs

Overview

Network costs in a retail electricity bill represent the cost of transporting electricity through transmission and distribution networks.

Under the National Electricity Rules (NER), the AER regulates network charges, approving network tariffs the distribution network businesses annually set for customer use of the network. Network tariffs are typically constituted of two components.

- Network Use of System (NUOS) charges largely recover the costs of providing transmission and distribution of electricity through network infrastructure. These include the costs of jurisdiction-specific schemes recovered across the entire customer base.
- metering charges relating to the distribution network businesses' installation and maintenance of type 5 manually-read interval meters and type 6 accumulation meters.

The AER approves network charges in annual pricing reviews. For the review, distributors submit proposed tariffs for the next financial year on 30 March each year. The changes in tariffs are based on the annual change in revenue set in the relevant determination, as well as other factors.

The Regulations require us to determine DMO prices by 1 May each year.[98] We have no discretion to extend this timeline and accordingly, in the absence of approved network tariffs, must use our judgement as to the most accurate source of network prices in our DMO calculations.

For DMO 3, this task is somewhat more straightforward as no network distribution businesses are undergoing a revenue reset.[99] This means that under the timelines set out under the National Energy Rules, all network businesses should have submitted their 2021-22 pricing proposals by 30 March 2021.[100] However, it is possible the AER will not have formally approved network tariffs by the time we finalise DMO prices, around late April. This may be due to delays in receiving the complete annual pricing proposals or because we require a detailed assessment of changes in parameters from the previous year or Tariff Structure Statement. We may require this, for example, if there were a proposed unexpected change in demand or a new tariff was proposed or delayed.

This section discusses our proposed approach should the AER have not formally approved network tariffs.

Position Paper position

To assess the change in network costs in 2021-22, we proposed to consider the network tariffs proposed by the network businesses in their 2021-22 pricing proposals. Network businesses must submit these by 30 March each year.

If the AER has approved proposed prices at the time of finalising the DMO calculations in late April, it will be straightforward to use the final published prices.

If the AER has not approved the prices, we proposed to use the submitted network pricing proposals, noting these may change before they are finally approved. We considered submitted prices are a reasonable substitute as they are unlikely to change significantly before being approved.

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98 Regulations, s. 17(2)(c).

99 The timing of approved initial prices for the regulatory control period may vary depending on the circumstances. The earliest available initial pricing would be late May. Economic uncertainty resulted the delay of the South Australian and Queensland 2020-25 distribution determinations and the initial pricing was approved late June 2020.
The AER is expected to publish the distribution determination by 30 April which is 2 months prior to the start of the regulatory period [NER 6.11.2]. The distribution business has 15 business days to submit the initial pricing proposal after the publication of the distribution determination [NER 6.18.2(a)(1)]. The AER must approve the initial pricing as soon as practical [NER 6.18.8(c2)].

100 NER 6.18.2(a)(2)

If there are more significant delays in finalising prices, for example, if network businesses delay submitting their pricing proposals for some reason, or submitted prices require more detailed assessment, there is a greater chance of some final prices varying more substantially from submitted prices. In this case, we would adopt the latest available indicative network tariffs.

In assessing the network costs, we proposed to continue the approach used in DMO 2. The approach considered the representative retailer will pass through the applicable network tariffs to the customer. In determining the changes in network costs, we intended to pass through changes in the applicable network tariffs outlined in Table 6.

To calculate draft DMO prices, we used indicative network tariffs for 2021-22 submitted as part of the 2020-21 pricing proposals as the best available information.

Table 6: Network tariffs (with network codes) to assess the change in network costs

Distribution region	Residential flat rate	Residential CL	Small business flat rate
Ausgrid	Residential Non TOU - EA010	EA030 – Controlled load 1 EA040 – Controlled load 2	EA050 Small business non-TOU
Endeavour	Residential Energy (anytime) N70	Controlled Load 1 N50 Controlled Load 2 N54	General Supply N90
Energex	Residential Flat NTC8400	Super Economy NTC9000 Economy NTC9100	Business Flat NTC8500
Essential	Residential Anytime BLNN2AU	Energy Saver 1 BLNC1AU Energy Saver 2 BLNC2AU	Small Business Anytime BLNN1AU
SAPN	Residential Single Rate RSR (SR)	Residential Single Rate RSR (CL)	Business Single Rate BSR

Stakeholder submissions

Submissions on DMO 3 network tariffs

Regarding determining which network tariffs to use for DMO 3:

- AGL agreed with using the network tariff proposals if they have not been approved in time for the DMO determination.[101] Ausgrid agreed with using the submitted pricing proposals rather than the indicative pricing from the previous

[101] AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4.

year.[102] Etrog Consulting accepted our proposal is suitable, given the circumstances[103]

- ActewAGL supported the use of final approved network tariffs only.[104]

MEA Group proposed amending the dates for submitting network pricing proposals to bring forward network pricing approvals to ensure they are available for the DMO 3 determination.[105] ActewAGL proposed we seek more time if required.[106]

AGL considered that in future we will need to allow for the default network tariffs for new customers and customers receiving advanced meters (TOU tariffs).[107]

DMO 2 network tariffs

Approved network tariffs were not available for the distribution regions at the time we published the DMO 2 Final Determination. Instead, we used the latest available indicative network tariffs to forecast the changes in network costs for DMO 2.

- In the Energex and SAPN regions, final network tariffs were not available due to ongoing network revenue resets. We used indicative tariffs for 2020-21 from the revised regulatory pricing proposal submitted by the network businesses as part of the 2020-25 revenue resets.
- In New South Wales, network businesses delayed submitting pricing proposals as they considered COVID-19 impacts on their forecasts. For Essential Energy we used tariffs from its 2020-21 pricing proposal. The proposals submitted by Ausgrid and Endeavour Energy were being assessed when the DMO 2 Final Determination was published. We used the indicative tariffs for 2020-21 (from the 2019-20 pricing proposals) for these regions.

The use of indicative tariffs in our DMO 2 calculations resulted in a smaller network component for those regions than if we had used the subsequently approved final network prices. This resulted in a lower DMO price (generally by less than 2 per cent).

Several submissions focused on DMO 2 network charges:

- ActewAGL supported the use of final approved network tariffs only, due to the risk of understating network charges if we used submitted prices.[108] The AEC pointed out the indicative network prices used in DMO 2 resulted in an under-recovery of network costs.[109]

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102 Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1–2.

103 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 14–15.

104 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

105 MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

106 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

107 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4.

108 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

109 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

- Alinta submitted the shortfall in DMO 2 network charges should be accounted for in DMO 3.[110]
- As discussed in section 3.1, Origin Energy considered we should adjust the DMO price to address any under- or over-recovery of network costs.[111]

Draft Determination approach

If the AER has approved the 2020-21 pricing proposals at the time of finalising the DMO calculations in late April, it will be straightforward to use the final published prices.

If the AER has not approved the prices, we will use the submitted network prices, noting these may change before they are finally approved. We still consider this is the best alternative to approved tariffs.

If the pricing proposals are delayed by the network businesses, or they are undergoing AER assessment at the time of the DMO 3 Final Determination, we would have regard to the latest available indicative network tariffs.

To calculate DMO prices for this Draft Determination, we have used indicative network tariffs for 2021-22 submitted as part of the 2020-21 pricing proposals, as the best available information at the time of publication of this Draft Determination. Refer to Table 6 above.

Timing of network tariffs

While network tariffs are a known cost for retailers, the timing of the DMO final determination each year means that in some cases the AER will not have approved these, and we will have to rely on another information source in our DMO calculations.

The AER is undertaking work to consider how the timing of network pricing proposals can be better aligned with the DMO process in the longer term, including the timing of network regulatory proposals (every 5 years) and the annual updating of cost of debt which flows into the annual pricing proposals.

We note the AEC is also considering this matter.

3.3.4 Residual costs and the step change framework

Overview

We identify other costs that make up the DMO price, apart from wholesale, environmental and network costs, as retail residual costs. While we do not specify individual costs, the retail residual component of the DMO price includes costs that are incurred by retailers to acquire, service and retain customers, meet regulatory obligations, as well as a nominal profit margin.

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110 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

111 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 8.

Under our indexation approach, we index the residual component we calculated from our DMO 1 determination by the change in the forecast Consumer Price Index (CPI).

Our indexation methodology also incorporates a step change framework. This enables us to adjust the DMO price to account for changes in retail costs that, in exceptional circumstances, are not accurately reflected by applying a general rate of change adjustment.

For us to consider an adjustment under the step change framework any cost must:

- be due to an exogenous change in a retailer's operating environment that is mandatory and would be incurred by an efficient and prudent retailer within the relevant DMO determination period
- not be compensated in other parts of our forecast or other DMO cost elements
- lead to a material overall change in the retail costs of an efficient and prudent retailer.

Given the DMO 1 residual component is assumed to include some costs to meet regulatory obligations, our starting position in considering any step change is that only exceptional circumstances are likely to require explicit compensation under the framework.

This also applies to our consideration of COVID-19 related debt costs, as the DMO 1 residual is assumed to include some costs for bad and doubtful debt.

While we have not defined 'materiality', our view is that incremental cost changes due to new regulatory requirements, for instance, would generally be compensated by the residual CPI indexation.

Additionally, the DMO price is sufficiently high that minor cost increases can be accommodated without impacting retailers' abilities to recover their costs to service standing offer customers.

Adjustments or allowances made under the step change framework are separate to the residual cost component, and not subject to indexation. Any step change adjustment or allowance would apply for one DMO period only.

Where a step change spans multiple DMO periods, retailers would need to demonstrate the cost changes remain material for the subsequent period.

We sought stakeholders' views on the possible impact on retailers' costs from COVID-19, the implementation of the Consumer Data Right and other matters.

COVID-19 costs

Overview

COVID-19 and measures to restrict its transmission have had impacts on the Australian economy, including businesses and households. Submissions to our DMO 2 COVID-19 consultation[112] considered the major categories of retail costs that would likely increase are:

- bad debt—debt a retailer 'writes off' as never recovering
- doubtful debts as a result of more customers experiencing financial vulnerability. This includes additional short-term debt carrying costs due to more customers accessing hardship programs and extended payment plans
- cost to serve as a result of requirements for staff to work from home, closure of international call centres, which have required some retailers to bolster onshore capabilities, and increases in the volume and complexity of communication with customers, due to an increase in calls about payment difficulty, hardship and/or broken payment plans.

Position Paper position

We proposed to consider any impacts of COVID-19 under the step change framework, which includes a materiality threshold.

In the Position Paper we asked retailers to demonstrate how COVID-19 could lead to cost changes for retailers, and to provide evidence of the likely size of these costs, to establish if these costs meet the materiality threshold.

Stakeholder submissions

Nearly all retailer submissions supported an allowance for COVID-19.

Retailers expected their costs to increase as a result of increased rates of bad debt in the DMO 3 period.

ActewAGL's view was that bad debt write-offs will increase during 2021/22 when collection activities resume.[113] The AEC and Red Energy/Lumo Energy noted that customer debts are increasing, requiring retailers to make increased provisions for bad debts. They recommended we consider publicly listed retailers' expected bad debt impacts in the 2021-22 financial year, as required under recent changes to accounting standards.[114]

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112 AER, *submissions to impact of COVID-19 on the determination of the Default Market Offer*, April 2020: https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2020-21/draft-decision.

113 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4.

114 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4.

Alinta Energy recommended we consider the likely impact of COVID-19 on retailer operating costs, particularly in relation to bad and doubtful debt, once retailers have provided cost data.[115] EnergyAustralia also anticipated COVID-19 related costs.[116] MEA Group considered bad debt write-offs are likely to increase if support measures, such as the JobKeeper wage subsidy, cease in March 2021.[117] Simply Energy considered an increase in unemployment from 5 per cent to 8 per cent as a result of COVID-19 will see a commensurate increase in retailer bad debt expenses of approximately 50 per cent.[118]

Most retailers did not provide forecast increases in costs due to COVID-19, but indicated they may be able to provide forecasts in coming months as more information becomes available. However, some retailers provided information on increased provisioning for increased bad and doubtful debt due to COVID-19.

- Origin Energy's submission considered bad and doubtful debts will present a significant cost in 2021-22, noting it has made a provision of $38 million for bad and doubtful debts as a result of COVID-19 for the period up to 30 June 2020.[119]
- AGL provided a forecast cost of around $10 per customer due to increased bad debt in 2020/21.[120]
- Red Energy/Lumo Energy note its expected credit losses have increased by $11.8 million for the year ended June 2020, including a $5 million provision for the effects of COVID-19.[121]
- EnergyAustralia provided confidential information about its expected COVID-19 costs in 2020.[122]

Some retailers also noted that the AER's statement of expectations, which encouraged a temporary cessation of disconnections and debt collection activities, has limited their abilities to mitigate increases in customer debt.[123] In its presentation at the DMO 3 stakeholder forum, Red Energy/Lumo Energy noted customers are more likely to contact their retailer once they receive a notice of disconnection. It has observed higher rates of customer engagement among those that have received disconnection notices.[124]

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115 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1–2.
116 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p.3.
117 MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 2.
118 Simply Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p.23
119 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5.
120 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.
121 Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4; Snowy Hydro, *Annual Report 2019-20*, p. 41.
122 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, Confidential Appendix p. 7–8.
123 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.
124 Red/Lumo Energy's presentation at AER's DMO 3 Position Paper stakeholder forum, 29 October 2020: https://www.aer.gov.au/system/files/Red-Lumo%20-%20DMO%202021-22%20-%2029%20October%202020%20Public%20Forum%20-%20Presentation.pdf

Some retailers suggested COVID-19 could introduce additional costs to retailers above those incurred due to increased rates of bad and doubtful debts. AGL and Red Energy/Lumo Energy noted increased costs of investing in infrastructure to allow staff to work flexibly and from home during the pandemic.[125] EnergyAustralia also provided evidence of costs additional to increases in bad and doubtful debts.

Submissions from consumer groups do not support an additional allowance for COVID-19 during the DMO 3 period.

ECA noted that in instances where businesses provide confidential evidence of cost impacts due to the pandemic (or other causes), there is an information asymmetry between businesses, market bodies and interested stakeholders. This leaves stakeholders such as ECA unable to substantiate the accuracy of costs given the lack of publicly available transparent data.[126]

Etrog Consulting did not support an allowance for COVID-19 costs during the DMO 3 period, arguing this would adversely affect vulnerable households impacted by COVID-19, contrary to the AER's Statement of Expectations, which includes supporting the needs of customers in vulnerable circumstances. Etrog Consulting noted it is likely that customers on standing offers include a high proportion of vulnerable households with the least capacity to pay.[127] It also considered there is enough headroom present in the residual component to allow for any additional retail costs.[128]

PIAC contended the impacts of COVID-19 do not meet the requirements of the step change framework and recommended an allowance for COVID-19 is not included in DMO 3. PIAC's submission considered there has not been a material increase in customers with debt of 90 days or over and that initial evidence from retailers indicates increases in costs are not a material proportion of revenue.[129]

Origin Energy noted the UK Energy Regulator Ofgem's decision to consider COVID-19 costs in its next default tariff cap as a 'float' that will be subject to a true-up or adjustment at a later period, based on actual costs.[130] Origin supported a similar approach for DMO 3, with a price adjustment ('true-up') occurring in a future determination, arguing this would address concerns about uncertainty in forecasting the impact of COVID-19.

125 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

126 ECA, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

127 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 7–8.

128 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 13.

129 PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4.

130 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–5; Ofgem, *Reviewing the potential impact of COVID-19 on the default tariff cap: November 2020 consultation* p.19–20.

Debt analysis and trends

We have been closely following the weekly updates from retailers on debt and other metrics as part of COVID-19 Dashboard reporting.[131] Our analysis below, while using the same data, excludes non-DMO regions, whereas the analysis published on AER website considers debt reporting metrics across the jurisdictions covered by the National Energy Retail Law, and includes additional retailers such as Ergon Energy, Aurora Energy and ActewAGL.

We have been following the average debt as smeared across the relevant customer base. This provides a normalised measure of debt for each retailer and gives an indication of the significance of debt for retailers as a proportion of overall costs on a per customer basis.

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131 See, AER, Weekly retail market dashboards - COVID-19: https://www.aer.gov.au/retail-markets/performance-reporting/weekly-retail-market-dashboards-covid-19. From May 2020 retailers have provided additional data on a voluntary basis to enable the AER to have visibility of the effect of COVID-19 on the retail energy market. This additional data is a subset of that already provided by retailers as part of the normal quarterly reporting cycle, but on a more frequent basis and provides a high-level summary of changes in the retail market, published on a weekly basis.

Figure 4: Residential electricity debt per customer base, DMO regions

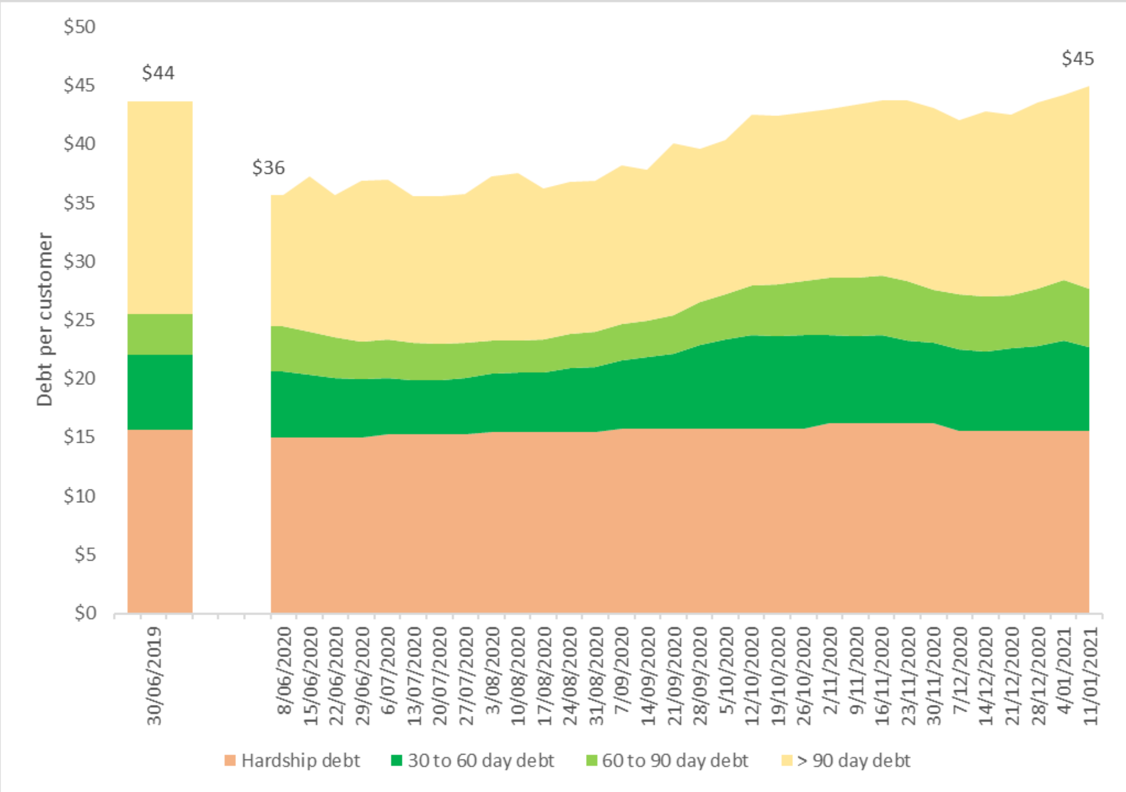
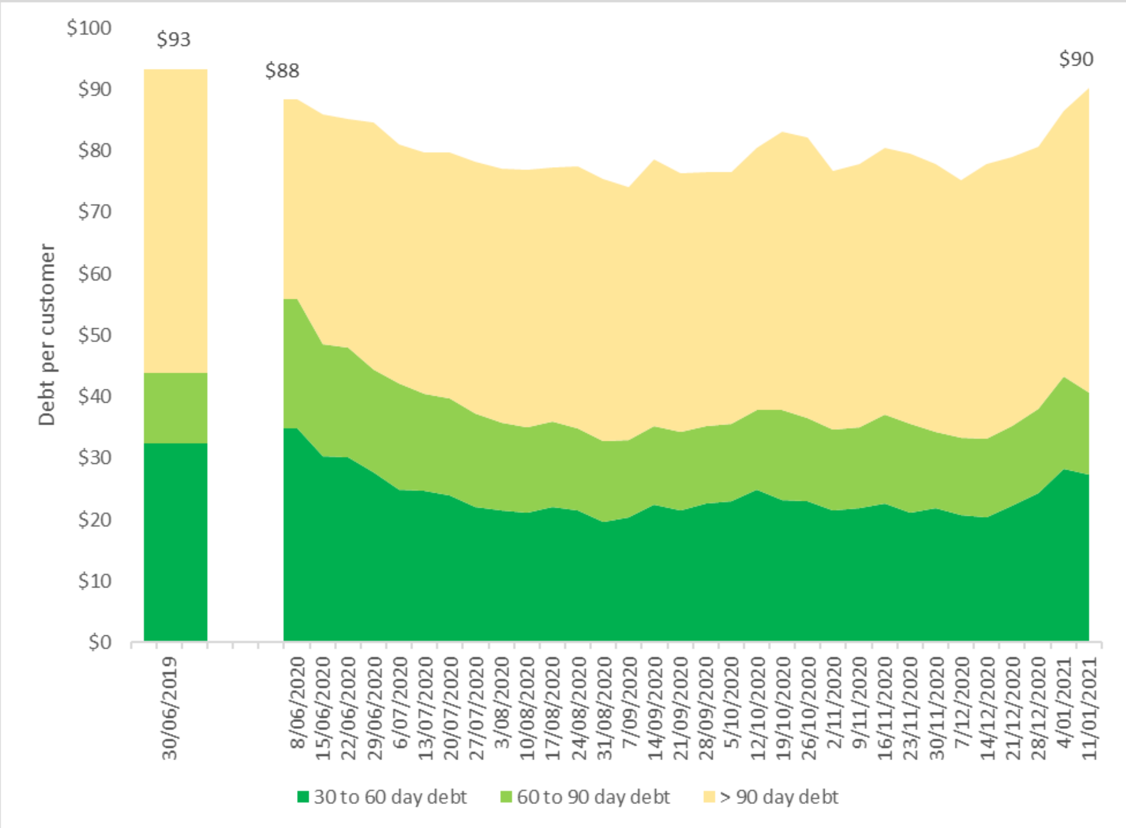


Figure 5: Small business electricity debt per customer base, DMO regions



Figures 4 and 5 suggest that while debt per customer has started to increase during COVID-19, it is still comparable to historic levels, including Q2 2018-19 when the DMO residual was calculated as the mid-point between the median standing and market offers.

As retailers have noted, future debt levels and bad debt costs will be impacted by any changes to the JobKeeper and JobSeeker support payments, the AER Statement of Expectations and the broader macroeconomic outlook. We will continue to monitor these trends as retailers provide updated weekly debt data.

Draft Determination approach

Having considered stakeholder submissions and the available information, our view is that bad debt cost increases due to COVID-19 will not be sufficiently material to warrant adjustment under our step change framework.

Bad debt costs

Based on the publicly available information provided, estimated bad debt increases range from around $4 to $10 per customer for the current year.

We have also considered other public information, including ESCV’s 2021 Victorian Default Market Offer decision and the 2019-20 annual financial reports of AGL, Origin, and Snowy Hydro (the parent company of Red Energy/Lumo Energy).

In its final decision for the 2021 VDO, published November 2020, the ESCV included a $6 per customer allowance for COVID-19 impacts to take into account forecasted increases in bad and doubtful debts.[132]

When comparing our DMO 3 Draft Determination to ESCV's 2021 VDO decision, it is important to note that:

- the VDO is a 'bottom up' cost stack that estimates the efficient costs and margin for retailers. The VDO methodology aims to account for all efficient costs faced by retailers and pass through these costs, including minor costs
- the DMO has a different policy objective and uses a different methodology that includes a residual component to ensure customers on standing offers are not being charged unjustifiably high prices, while allowing retailers to cover their costs. Because the DMO 3 is well above efficient costs, we have a high threshold for passing through additional costs

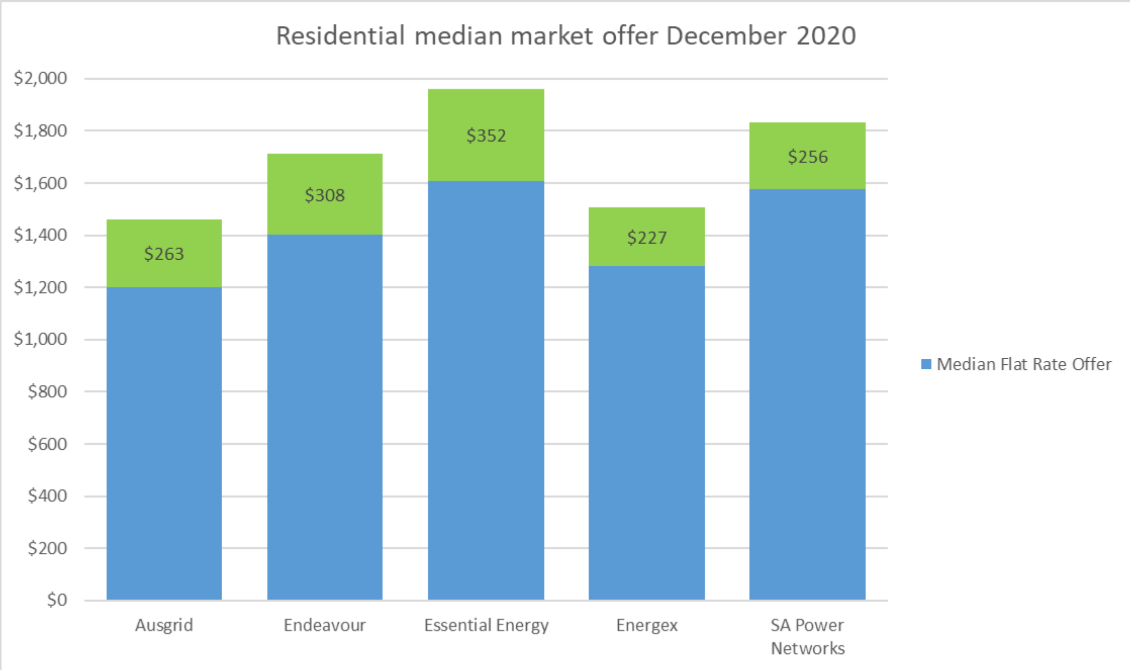
The ESCV's allowance of $6 per customer was based on the average increase in provisioning for bad and doubtful debt in publicly available 2019-20 annual reports of publicly listed retailers (AGL, Origin Energy and Red Energy/Lumo Energy).

While we recognise the increases in bad debt costs may be higher than the CPI rate of change adjustment, we are satisfied the DMO price is sufficiently above retailers' efficient costs, that the DMO policy objectives will continue to be met without us making an adjustment for COVID-19.

For example, Figure 6 shows the difference between the median market offer as at 31 December 2020 and the DMO 2020-21 determination is between $227 and $352 for residential customers on a flat rate tariff, which is much greater than ESCV's allowance and the estimated per customer costs discussed above.

[132] Essential Services Commission, *Victorian Default Offer 2021: Final Decision*, November 2020, p. 5.

Figure 6: Flat rate median market offers compared to DMO 2 prices



Other COVID-19 related costs

Retailers did not provide information to demonstrate an increase in other retailer costs due to COVID-19, such as increased staffing or investment in infrastructure to facilitate flexible work arrangements during the DMO 3 period.

We also note that a report prepared by Ernst & Young for the ESCV 2021 VDO found it unlikely that other potential COVID-19 related costs such as increased staffing to meet increased call centre volumes or investment in infrastructure to facilitate flexible work arrangements would be significant during 2021.[133]

We note that while retailers have made provisions for 2019-20, they have not made specific forecasts of COVID-19 costs for the DMO 3 period. Only AGL has made forecasts for 2020-21 in forward guidance for the 2021 financial year.

We do not propose to introduce a true-up mechanism similar to Ofgem's approach in its next default tariff cap, as suggested by Origin Energy in its submission.

We acknowledge there is uncertainty at present in estimating COVID-19 impacts on retailers during the DMO 3 period.

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133 Ernst and Young, *Impact of COVID-19 on the efficient costs for retailers to supply electricity,* November 2020, p. 30, 32.

However, there would be a range of practical challenges in determining the actual impact of COVID-19 on retail costs and applying a true-up to a subsequent determination, as there will be a potential lag between that determination and when the actual costs are known.[134]

Origin Energy recognises these challenges in its submissions. While Origin Energy suggests these could be managed, we remain of the view that as with network and other costs, our approach is not to make retrospective adjustments to the DMO price, for the reasons discussed in section 3.2. In particular, the DMO price is not an accurate reflection of retailers' efficient costs, and the DMO is a forward-looking instrument, based on the best information available at the time.

We acknowledge there is inherent uncertainty in forecasting the extent of COVID-19 impact during the DMO 3 determination period. Our analysis of COVID-19 dashboard data suggests that debt levels can move erratically, and it is difficult to extrapolate into the future with any degree of certainty.

Some of the key factors that will have an impact on employment forecasts, such as the rate of economic recovery as well as government support for businesses during the DMO 3 period, are not currently known.

We expect there will be more information and greater clarity in coming months as retailers release public mid-year reports, and as a clearer picture emerges of the macroeconomic outlook and the extent of State and Commonwealth Government assistance provided to households and small businesses during the DMO 3 period.

Given the current uncertainty, we are open to considering further information about cost impacts as they become available.

Consumer Data Right

Position Paper position

The Consumer Data Right (CDR) reforms are being rolled out to consumers in the electricity sector, facilitating easier consumer access to their metering and other data.

Key elements of the rollout to the energy sector are AEMO developing a data 'gateway' system that will facilitate access to its central database of metering data. Retailers will need to develop and maintain systems that ensure they can comply with the new requirements.

We expect the new CDR obligations[135] for the energy sector will come into effect during the DMO 3 period. Additional rules to support the subsequent technical builds by stakeholders are also likely to be made in the first half of 2021.

[134] Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5.

[135] *Consumer Data Right (Energy Sector) Designation 2020*.

In our Position Paper, we requested relevant cost information to assist with estimating cost changes associated with CDR and the basis for estimating any cost impacts.

Stakeholder submissions

Many retailers submitted that the cost to implement CDR would be significant.

The AEC listed CDR as one of the changes to retailers' costs to serve.[136] Alinta Energy considered the cost will be material during the DMO 3 period and likely in DMO 4 period.[137]

Origin Energy expected the costs associated with CDR to be significant and material.[138]

However, AGL and ActewAGL noted it was too early for them to provide accurate estimates of the costs due to the uncertain scope of the final rules.[139]

EnergyAustralia submitted that CDR costs will also become clearer over this time as the rules are finalised. It also provided information about its implementation costs for CDR in a confidential submission.

Origin Energy noted the difficulty in accurately determining costs associated with CDR and other regulatory reforms due to current uncertainty in the scope of the project. It suggested Ofgem's approach to deal with uncertain COVID-19 costs discussed above, could also be applied to other regulatory costs. For example, we could identify a reasonable estimate of CDR costs expected to be incurred in 2021-22 and true-up in subsequent DMO calculations once actual data is received.[140]

Some retailers suggested they could provide further information about CDR costs later in the DMO determination process.[141]

Among consumer representatives, PIAC considered the implementation of the CDR does not meets the criteria for a step change adjustment. It submitted that all estimates indicate that CDR will not have a material impact on business costs compared to the significant headroom afforded by the current DMO setting.[142] ECA highlighted the difficulty of consumer groups providing meaningful commentary on this matter because these costs are likely to remain confidential giving rise to information asymmetry.[143]

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136 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4.

137 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

138 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9.

139 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6–7. ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4.

140 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9.

141 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6. Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2. EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

142 PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

143 ECA, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

Draft Determination approach

While we acknowledge that the costs associated with CDR are unavoidable and an exogenous change in a retailer's operating environment, we have not received information that would enable us to estimate retailers' costs for CDR in 2021-22.

We will assess any additional evidence provided prior to the Final Determination. Such evidence would need to demonstrate that costs are incurred during the DMO 3 period.

In addition, we do not support the Ofgem true-up approach for CDR for the same reasons discussed above in relation to COVID-19 related costs.

5 Minute Settlement and other regulatory changes

Position Paper position

In our Position Paper, we questioned whether there are other regulatory or operating environment changes that are likely to materially increase or decrease retailers' costs to serve customers in 2021-22.

Stakeholder submissions

Retailers have listed reforms and regulatory changes affecting their cost to serve:

- 5 minute settlement arrangements[144]
- Global settlements[145]
- Wholesale demand response mechanism[146]
- Customer switching rule changes[147]
- National Energy Retail Amendment (bill contents and billing requirements) rule[148]
- Post-2025 NEM market design work being undertaken by the Energy Security Board.[149]

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144 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4. AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4. AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6-7. Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2. EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3. MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

145 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4. AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4. Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2. MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

146 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4. Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2. MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

147 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4–5.

148 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 4–5.

149 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

While consumer representatives did not specifically list these reforms, they have indicated their position on step changes. PIAC noted the threshold for costs to be considered must be high.[150] ECA noted that because costs are often provided on a confidential basis, there are information asymmetries and other stakeholders are unable to assess and consider the accuracy of these costs.[151] Etrog Consulting will review any cost estimates and refers to ongoing productivity improvements.[152] These positions are discussed in more detail in relation to the discussion on COVID-19 costs and CDR.

AGL suggested 5 minute settlement will impact most of a retailer's business processes, including customer billing, metering, pricing, forecasting, bidding and settlements. It considered the cost of 5 minute settlement should also be included as a step change in the 2021-22 DMO prices. It considered the cost of introducing 5 minute settlement was underestimated by AEMO when it estimated the costs over a 15 year period to be $250 million, including system change costs of $150 million.[153]

EnergyAustralia provided the Russ Skelton and associates' assessment of the 5 minute settlement transition costs of $150 million, as presented at an AEMC forum.[154] It also substantiated its costs of implementing 5 minute settlement in its confidential submission.[155]

Stakeholders have not submitted details regarding wholesale demand response mechanisms, customer switching rule changes, national Energy Retail Amendment (bill contents and billing requirements) rule and post-2025 NEM market design work being undertaken by the Energy Security Board.

Draft Determination approach

We have considered the reforms and regulatory changes affecting retailer's cost to serve, in particular 5 minute settlement. Retailers have not demonstrated these costs are significant enough to warrant inclusion as a step change. We did not make a step change in DMO 2 for 5 minute settlement or any other market reforms.[156] We consider the majority of 5 minute settlement costs will be incurred prior to the DMO 3 period as these system changes need to be in place in preparation for 1 October 2021.[157]

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150 PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

151 ECA, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

152 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 18–19.

153 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6–7.

154 AEMC rule change: https://www.aemc.gov.au/rule-changes/five-minute-settlement
Public forum transcript: https://www.aemc.gov.au/sites/default/files/content/87b6f18a-adfb-48bf-b29c-5f2651be6516/ERC0201-Five-minute-settlements-public-forum-transcript-FINAL.pdf
Russ Skelton presentation: https://www.aemc.gov.au/sites/default/files/content/52ce9f6e-8407-45e0-8fc8-34fec4ac8b29/12-Russ-Skelton-presentation-2.pdf

155 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

156 AER, *Default Market Offer Prices 2020-21*, Final Determination, p. 48.

157 Essential Services Commission Victoria, *Default Offer 2021 Final Decision*, 27 November 2020, p. 33.

We will assess any further evidence provided by retailers prior to the Final Determination. Such evidence would need to demonstrate that the costs are incurred during the DMO 3 period.

Productivity adjustment

Overview

Productivity is a function of and measures how much output can be produced using a given quantity of inputs. In the retail electricity market, this relates to the cost of serving, acquiring and retaining customers, as well as other costs.

During the DMO 2 consultation, consumer representatives[158] disagreed with the application of CPI to forecast changes in residual costs, considering that it does not reflect efficiency and productivity improvements.

Various regulators[159] and rule making authorities[160] have considered or applied a productivity factor when making pricing determinations or rules. However, no Australian energy regulators currently apply productivity adjustments in their retail price determinations. We note the ESCV in its recent Victorian Default Offer 2021 Final Decision[161] did not include a productivity factor for the 2021 VDO due to the uncertainty associated with COVID-19.

Position Paper position

In our Position Paper we stated that we would review information available to us to consider whether it is appropriate to include a productivity improvement factor in our DMO price setting to account for efficiency improvements.

Additionally we sought stakeholder submissions on whether to apply a productivity factor and what form this should take, consistent with the DMO approach to not individually identify cost components. We also asked for feedback on the available sources of information to determine an appropriate factor to apply, including examples from comparable sectors or jurisdictions.

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158 Energy Consumers Australia (ECA), *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 3; Queensland Council of Social Service Inc (QCOSS), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2–3; Etrog consulting (on behalf of Queensland Council of Social Service Inc), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 12–15.

159 See Independent Pricing and Regulatory Tribunal New South Wales, *Review of regulated retail prices and charges for electricity From 1 July 2013 to 30 June 2016*; Queensland Competition Authority, *Regulated retail electricity prices for 2016–17*; Australian Energy Regulator, *Forecasting productivity growth for electricity distributors.*

160 Australian Energy Market Commission, *Review into the use of total factor productivity for the determination of prices and revenues*

161 Essential Services Commission Victoria, *Default Offer 2021 Final Decision*, 27 November 2020, p. 34.

Stakeholder submissions

Retailers and the AEC[162] were generally against the inclusion of a productivity factor for the DMO, stating the following:

- inclusion of a productivity factor implies a level of specificity regarding costs that is inconsistent with the current top-down methodology of the DMO[163]
- a productivity factor is at odds with the policy objectives of the DMO[164]
- there is considerable uncertainty regarding retail costs. An adjustment should occur when there is less uncertainty in the operating environment.[165]

Consumer representatives however held a different view, arguing a productivity factor should be included in the DMO 3 determination.

PIAC stated, 'where the AER persists with the current approach, PIAC supports the application of a productivity factor to the DMO. The current approach intentionally sets the DMO well above any estimation of efficient cost to serve (including retail margin), and indexes in line with the CPI'.[166]

ECA was also in favour of a productivity factor, 'even if inconsistent with top-down DMO'.[167]

Etrog Consulting considered the DMO calculation should take into account the efficiency improvements that would be expected from an efficient retailer. It noted, 'if an indexing approach is to be used, then it is imperative that a downward adjustment should be made to reflect increased productivity'.[168]

Draft Determination approach

We investigated data sources that may enable us to quantify a productivity adjustment to the DMO price that is consistent with our overall approach of not identifying specific costs.

We agree with stakeholders who noted that determining a productivity factor from an examination of how individual retailers' retail costs have changed over time would imply a level of specificity in the DMO that is not consistent with the DMO's top-down methodology.

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162 AEC, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

163 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2, AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–5, Simply Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1–2.

164 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2, Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–5, AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–5, MEA Group, *Submission to DMO 3 Position Paper*, 20 November 2020, p. 3.

165 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 8.

166 PIAC, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

167 ECA, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 3.

168 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 3.

Considering the above, we investigated three data sources to determine if they could be used to estimate a productivity factor that is consistent with DMO methodology and transparent:

- ACCC published retail cost data
- Publicly available retailer annual reports
- ABS productivity statistics.

ACCC cost stack reporting data

Each year the ACCC's Electricity Monitoring Inquiry publishes information about retailers' costs. We considered whether these reports provided information that would enable us to determine a productivity factor suited to the DMO methodology.

In 2019 the ACCC noted retail and other costs (in real price) for residential customers had been relatively stable between 2013-14 and 2018-19.[169]

The supporting publicly available data shows that in New South Wales, real per-customer costs fell by $35 in 2014-15 (at the time of price deregulation), and have since been relatively flat. In South Australia, real per-customer costs dropped by $8 in 2016-17 and were relatively constant before and after. In south-east Queensland, real per-customer costs peaked in 2017-18 before falling by $18 in 2018-19.

However, we do not have ready access to the disaggregated cost stack data. We cannot measure capital costs and total costs associated with electricity retail operation. While publicly available cost data is specific to electricity retailing, there may be potential cost allocation issues as retailers generally provide multiple energy services, and some are vertically integrated into generation.

Due to the above data limitations we are unable to conclusively determine whether retailers have become more productive over time based on ACCC published data. The available data suggests that retail and other costs have been relatively stable over time.

Retailer annual reports

We considered data available in both AGL and Origin Energy's annual reports. Both retailers realised substantial reductions in operating costs between 2017-18 and 2019-20, with forecast reductions in the following years.

In its submission to the Position Paper, AGL pointed out its net operating costs do not include all the costs that a retailer would incur.[170] We agree with AGL that this makes it problematic to gauge the extent of total retail cost changes achieved. There is evidence, including the increase to AGL's centrally managed expenses, which

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169 ACCC, *Inquiry into the National Electricity Market*, November 2019, p. 7.

170 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4–5

suggests AGL's total costs for its retail business in 2019-20 may not have reduced to the same extent as operating costs.

Origin Energy argued that cost savings since 2017-18 appear substantial because of a significant cost increase from the previous financial year (2016-17). It suggested this is due to Commonwealth policy interventions and a mixture of mandated and voluntary measures'. [171] Like AGL, there is evidence Origin Energy's total retail costs may not have reduced to the same extent as its operating costs, for example, its corporate capital expenditure rose by $159m in 2019-20.

While from the two annual reports we were able to find evidence to suggest that operating costs have decreased there is also evidence that other cost categories may have remained stable or increased.

Additionally, this does not provide an indication of how costs have changed across all retailers. Efficiencies may have been found to reduce operating costs by the major retailers that are not available to smaller retailers.

We were not able to determine from this data source whether retailers were becoming more productive and could therefore not determine an estimated productivity factor.

ABS productivity statistics

The ABS publishes annual estimates for industry multi-factor productivity (MFP) for the 16 industries comprising the market sector since 1994-95.[172]

MFP is an index that takes into account various economic factors, such as output, capital and labour inputs, in order to measure how productivity in the economy is changing over time.

We initially considered that MFP was conceptually well-suited to considering productivity for the DMO residual as it applies at an industry-wide level, is publicly available, and transparent. The ABS measures MFP for the overall economy, as well as 16 specific market sector industries. Electricity retailing is not specifically defined as one of the market sector industries.

We therefore considered whether any of the existing market sector industries were similar enough to electricity retailing to be a reasonable substitute.

One sector is the 'electricity, gas, water and waste services' (EGGWS) category. While clearly covering electricity retail, it encompasses a broad range of industries from retail and infrastructure sectors, and electricity retailing makes up a very small proportion. Given this range of activities we considered it was not a suitable proxy for the electricity retail sector.

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171 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 8.

172 See https://www.abs.gov.au/statistics/industry/industry-overview/estimates-industry-multifactor-productivity/latest-release

Our analysis suggests the 'retail trade' ABS sector is the sector most analogous to energy retail for the following reasons:

- electricity retailing is essentially a margin business (like retail trade) rather than production and/or transportation businesses
- as a margin business, a retailer charges a mark-up over the 'cost of goods sold' to it. It incurs operating expenses to run the business such as labour, rent, marketing and sales, and administration, and earns a net profit margin
- the retail trade sector has experienced structural changes and heightened competition since the early 2000s like electricity retailing. Similarly, the sector has been particularly affected by disruptive technologies such as online shopping, aggressive price discounting, as well as branding and bundling
- similarly to how to energy retailers can be vertically integrated with generators, retailers have sought to offset the declining margins by vertically integrating supply chains, adjusting product mixes and reducing operating expenses.

Applying a MFP-based productivity factor would see us adjust our current CPI escalation to take into account any productivity improvements in the retail trade sector.

CPI already takes into account productivity changes for the entire economy. It is a measure of how prices in the overall economy change over time, with any inflationary factors pushing prices and therefore CPI up, while any productivity improvements made will push costs, prices, and therefore CPI down.

To understand if we need to make a productivity adjustment to CPI, we need to understand whether the retail trade sector has higher or lower productivity growth than the overall economy.

MFP statistics for the retail sector show multifactor productivity changes that are similar to the overall economy, over the most recent productivity cycle[173]:

- MFP for the cycle, on an hours worked basis, was 1.07 per cent, compared to 0.84 per cent for the overall economy.

This was because both experienced materially similar output, labour and capital input growth. For example:

- Output Gross value added grew by 2.64 for retail over the cycle, compared to 2.63 for the overall economy

[173] The ABS considers that examining MFP movements over growth cycles is a common approach for interpreting productivity performance over time, due to the short-term volatility of annual estimates. The most recent growth cycle for the market sector was identified for 2011-12 to 2017-18, which had an annual average MFP growth at 0.84 per cent (on hours worked basis).

- Labor input – hours worked basis grew by 1.05 per cent for retail, compared to 0.93 for the economy
- Capital services input rose by 2.87 per cent for retail, compared to 2.88 for the economy

Overall these metrics indicate retail trade has not experienced materially different changes from the overall economy in relation to productivity growth.

Conclusion

Having considered the available information, we have not included a productivity adjustment in the DMO price.

Published ACCC data and retailer annual reports suggest that some retail costs are falling. However, these data sources did not provide enough detail about capital and other costs we would need in order to understand whether these reflected productivity increases. This level of retail cost analysis would be inconsistent with our top-down methodology.

The ABS productivity data for retail trade, our closest proxy to the electricity retail sector, shows productivity does increase slightly over time. However, given that the sector is not materially different from the overall economy in relation to productivity growth, we considered a productivity factor based on this data would be zero, that is, it would have no effect on the DMO price.

Our review of the DMO methodology and assumptions will be an appropriate time to further consider significant methodological changes to the DMO. If we were to adopt a methodology where we considered retail costs, for instance, this may allow us to address some of the issues raised above.

4 Model annual usage determination and TOU customers

Under Part 3 of the Regulations, we are required to determine 'broadly representative' annual supply amounts for residential and small business customers in each distribution region, from which a DMO price and reference price can be calculated. In this document we refer to annual supply as annual 'usage'.

We must also determine the timing and pattern of supply to residential customers.[174] The Regulations refer to these elements in combination as the 'model annual usage'.

This chapter sets out our methodology for determining the DMO model annual usage for 2021-22, including how we have considered time of use (TOU) and solar tariff customers under the single DMO price.

4.1 Model annual usage

Position Paper position

Our Position Paper position was to continue to use the annual usage amounts from our DMO 2 Determination for residential (flat rate, TOU and solar), and small business customers (flat rate and solar).

We acknowledged the 20 000 kWh annual usage figure for small business customers may not represent the electricity usage of many small businesses, but proposed to retain it because:

- it continued to meet the criteria of being 'broadly representative' of customer usage
- there was no readily available alternative figure
- changing the figure would require us to recalculate the DMO 1 and DMO 2 prices with the new usage amount to determine DMO 3 prices
- there was no clear benefit to customers from doing so.

We sought stakeholders' views on whether there were benefits in changing the amount. We also proposed to retain the overall timing and pattern of supply from the DMO 2 determination.

For DMO 3 we also proposed to update the TOU daily usage profiles using interval meter data obtained from AEMO, reflecting current usage patterns in each region.

This detailed data would enable us to specify profiles in various ways (for instance, with daily usage patterns for different seasons and days of the week), we sought

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174 Regulations, s. 16(1)(a)(i).

stakeholder views on whether a more complex profile would be desirable, given it would also be more complex for retailers to implement.

We also noted we were considering how to accommodate a newly introduced TOU CL tariff in South Australia.

Stakeholder submissions

Stakeholders generally supported retaining DMO 1 annual usage amounts for DMO 3.[175]

Ausgrid agreed retaining the same usage figures would aid consistency, simplicity and comparability, and noted actual usage during 2020 in the Ausgrid distribution region is very similar to the DMO 2 annual usage amounts.[176]

In regards to small business usage, AGL suggested it would be better to reduce the annual usage amount for small business customers from 20,000 kWh (used for DMO 2) to 10,000 kWh, to be more representative of an average small business.[177]

On the other hand, Alinta Energy considered 20,000 kWh for small business customers is reasonable, given the diverse nature and usage requirements of small business users that makes it difficult to arrive at an accurate figure.[178]

Etrog Consulting questioned the residential annual usage figure for the Energex distribution region, indicating difficulties in verifying the figures used.[179] In particular, it observed our annual usage amount for residential customers with CL in this region differs from the average annual usage identified in the AER's 2017 and 2020 Energy Consumption Benchmarks reports, and suggested we check our annual usage estimates across all network businesses for accuracy.[180] It also suggested the annual usage amounts are out of date because of changed consumption requirements during COVID-19.[181]

In relation to the TOU usage profile, stakeholders widely supported our continuing to use a simple, single day usage profile.

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175 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 2; Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2; Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9; Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

176 Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

177 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9.

178 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

179 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 18.

180 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 14; Etrog Consulting, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 15–16.

181 Etrog Consulting also refers to its submission to the DMO 2 Draft determination: Etrog Consultation on behalf of QCOSS, *Submission to the DMO 2 Draft Determination*, 9 March 2020.

ActewAGL suggested a single day profile best meets the requirement that it broadly represent customer usage.[182] Alinta Energy noted a more complex profile is not necessary because the transition to advanced meters in DMO jurisdictions is slow.[183] AGL suggested a two-day profile may be workable, but an eight day profile was overly complex with minimal benefit or relevance because few customers are on seasonal TOU tariffs.[184]

Simply Energy supported updating the profiles with more recent data while retaining a single day profile, noting a more granular profile would be more complex to apply and is unlikely to assist customers to better compare offers.[185] Ausgrid preferred a single day profile because a multiday one would add complexity with marginal increases in accuracy.[186] Red Energy/Lumo Energy supported a single day usage profile because it was easiest to implement.[187]

EnergyAustralia was the only stakeholder in favour of a more detailed profile to provide greater certainty for season tariffs in different distribution regions.[188]

Etrog Consulting agreed that in determining whether to increase the level of detail in the profile, we should weigh up the benefits against the costs of increasing the complexity of the profile.[189]

Red Energy/Lumo Energy suggested the AER should take account of changed consumption patterns during COVID-19 in developing the usage profile.[190]

Of those supporting a single day usage profile, Ausgrid preferred usage specified at one hour intervals, noting more detail would only marginally improve accuracy.[191] Red Energy/Lumo Energy supported specifying usage for 30 minute intervals as being more consistent with some tariff structures.[192]

Draft Determination approach

Our Draft Determination is to retain the annual usage amounts for residential and small business customers from DMO 2.

- For all customers, to assume the same usage amount every day (with no variation for weekday, weekend or season)

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182 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 5.

183 Alinta Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2–3.

184 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9.

185 Simply Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3

186 Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2, 5.

187 Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5–6.

188 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3; EnergyAustralia, *Submission to DMO 2 Draft Determination,* 13 March 2020, p. 9.

189 Etrog Consulting, Submission to DMO 3 Position Paper, 23 November 2020, p. 23.

190 Red/Lumo, Submission to DMO 3 Position Paper, 19 November 2020, p. 6.

191 Ausgrid, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 2.

192 Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 6.

- For residential customers with CL, to apply the same proportional allocations of annual CL usage across multiple CLs as in previous determinations.
- For TOU tariff customers, to assume the usage across each day follows a set pattern, expressed in the form of a simple 24-hour profile.

We note Etrog Consulting's concern about annual usage amounts for the Energex region.[193] We have compared the usage amounts used to determine the DMO 1 benchmarks with the latest network usage forecasts for residential customers with flat rate and CL usage.[194] The difference in usage is minor—there is approximately a 5 per cent increase or decrease across the distribution regions since DMO 1. Given this, we remain of the view that our annual usage amounts are broadly representative of customer usage, and intend to retain them for DMO 3.

In relation to Etrog Consulting's comment about changed consumption during COVID-19, we acknowledge usage amounts have changed during COVID-19.[195] However, given the recency of COVID-19 impacts in the DMO jurisdictions, changes in annual consumption are not yet known. It is also unclear whether any changes will continue through 2021-22. If longer term changes in usage are observed in the approved annual prices, we may consider changing the annual usage amounts in future determinations. However we would need to be satisfied the changes are sufficiently large that the usage amounts adopted for the DMO are no longer broadly representative of customer usage. Also, we would need to ensure the benefits to customers of changing the usage amounts outweigh the benefits of being able to compare offers year-to-year from retaining the same usage amounts.

In relation to small business usage, since we published the Position Paper, the ACCC released its *Inquiry into the National Electricity Market - September 2020 report.* The report summarised small business usage, based on analysis of customer bill information provided by retailers. The report found the median usage amount for small business market offer customers is around 8 000 kWh.[196]

While this supports AGL's suggestion that a lower small business annual usage figure is more representative of small business annual usage, the report also notes small business annual usage is diverse and extends above 20 000 kWh.

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193 For a detailed description refer to the AER, *Draft Determination, Default Market Offer Price*, February 2019, p. 66–67; AER, *Final Determination, Default Market Offer Prices 2019-20,* April 2019, p 63-64.

194 Network usage forecasts are contained in network pricing proposal models distributors provide to the AER annually.

195 For example, AEMO estimated COVID-19 contributed to a reduction of 2.1 per cent in NEM operational demand in Q2 2020, and a reduction of 1.4 per cent in NEM operational demand in Q3 2020 across all NEM regions on average. AEMO, *Quarterly Energy Dynamics*, Q2 2020, p. 7; AEMO, *Quarterly Energy Dynamics*, Q3 2020, p 6.

196 ACCC, *Inquiry into the National Electricity Market September 2020 report*, 21 September 2020, p. 40–41: https://www.accc.gov.au/publications/inquiry-into-the-national-electricity-market-september-2020-report

Given this, we consider 20 000 kWh remains a reasonable estimate of small business energy usage and is ‘broadly representative’ of small business usage for the purposes of the Regulations.

Our view therefore remains there is no compelling reason for changing the small business annual usage at this time.

We acknowledge customer usage may change over time and that the DMO usage figures we initially determined in 2018 will need to be reviewed at some future time to ensure they remain representative. The proposed review of the DMO methodology discussed in section 3, would be a logical point to review our usage assumptions.

The ACCC’s bill data analysis is likely to be an authoritative source of information about small business electricity usage that we would consider in that review.

Table 7 sets out the draft model annual usage amounts for DMO 3.

Table 7: Annual usage determinations 2021-22

Distribution Region	Residential Annual Usage – no CL#	Residential Annual Usage – CL ++		Small Business Annual Usage ^
		General Usage	Controlled Load Usage	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	20,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	20,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	20,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	20,000 kWh
SAPN	4,000 kWh	4,200 kWh	1,800 kWh	20,000 kWh

Source: Network distribution businesses’ 2019-20 annual pricing proposals

++ Source: Network distribution businesses’ 2019-20 annual pricing proposals, with CL assumptions based on the AER’s 2017 Energy Consumption Benchmarks

^ Source: Energy Consumers Australia, SME Retail tariff tracker

Our Draft Determination for timing and pattern of supply is to:

- assume the same usage amount every day (with no variation for weekday, weekend or season), as in previous determinations
- use the same proportional allocations of annual CL usage across multiple CLs
- retain a single 24-hour profile for residential TOU customers, and:
  - update these using the current AEMO interval meter data for each region

    - specify usage at 30-minute intervals (rather than hourly intervals)
- develop a new profile for the SAPN TOU CL tariff.

For TOU tariffs, we have updated the single day usage profile, and have specified usage for every 30 minute interval over a 24 hour period (See Appendix E).

Stakeholders overwhelmingly supported updating the profile with more recent data, while retaining a simple single day format. Generally it was considered a more detailed profile (for example, incorporating separate seasonal and/or weekday/weekend patterns) would be more complex to implement for little resulting benefit.

While retaining a single day usage profile similarly to DMO 2, the profile we have developed for DMO 3 represents a significant improvement on the DMO 2 profile.

- The daily usage profile has been updated and is based on three years of meter data to February 2020.
- By deriving the profile from three years of data we removed anomalies relating to any one year, better representing typical usage patterns.
- While we previously specified usage at one hour intervals, the DMO 3 profile specifies usage at 30 minute intervals. We agree with Red Energy/Lumo Energy this may assist retailers calculate usage for TOU tariffs with periods that start/end on the half-hour, and does not add complexity.

While Etrog Consulting suggested that changed customer consumption since COVID-19 should be accounted for in DMO 3, in developing the TOU profiles we opted to only include data up to February 2020. While we acknowledge it is likely COVID-19 had an effect on electricity consumption patterns during 2020, the recency of this impact means there is limited data available at present demonstrating the impact on customer consumption. Basing the profiles on a shorter dataset would mean it would be more susceptible to seasonal and annual variations, and cause greater variability in the usage profile from year-to-year. Given the function of the usage profile to provide a basis for comparing TOU offers, we consider it unlikely a variable profile year-to-year would benefit customers because it may limit their ability to compare offers between years.

It is also unclear whether any changes in consumption patterns due to COVID-19 will continue into 2021-22, and therefore whether it is appropriate to take account of changed consumption patterns due to COVID-19 for DMO 3.

To obtain more reliable and stable usage estimates we based usage profiles on more typical consumption patterns by averaging over the past three years of usage data. This method provides greater consistency and predictability in the usage profiles year-to-year.

If recent changes in consumption patterns remain over the longer term we will be able to reflect these changes in future usage profiles to ensure they remain broadly representative of customer usage.

In relation to SAPN's TOU CL tariff, the AEMO interval meter data did not include separate CL consumption data for the subset of customers that are on the TOU CL tariff that would enable us to develop a profile based on observed usage. This is because this tariff was introduced recently on 1 July 2020, during the COVID-19 pandemic and outside of the time period for the interval meter data we requested from AEMO.

We have requested the initial observed CL usage information for residential customers on the TOU CL tariff from SAPN to examine any differences in consumption patterns between the TOU CL and legacy CL tariff. However, as the TOU tariff was only introduced recently, usage information for a full year will only become available from July 2021.

In the absence of observed usage data, we have developed a usage profile based on highly simplified assumptions. For consistency with the non-CL profiles, we specified usage at half-hourly intervals over a 24-hour period.

The TOU CL usage profile allocates 50 per cent of the daily CL usage to the overnight off-peak period (11.30pm to 6.30am), and 50 per cent to the daytime 'solar sponge' period (10am to 3pm). No usage is allocated to the peak period.[197]

While we acknowledge this allocation is somewhat arbitrary, we consider it is reasonable given the policy objective for the solar sponge tariff is to encourage consumers to use CL-linked appliances during the peak solar generation hours.

We consider this option is likely to be the most representative of other arbitrary allocations we considered. For instance, we consider it unlikely that 100 per cent of usage would fall within the solar sponge period.

As stakeholders have not previously had an opportunity to comment on this matter, we would welcome stakeholder feedback, including any information that supports an alternative allocation.

The TOU daily usage profiles for each distribution region, and for the South Australian TOU CL tariff, as well as usage allocations for CL are specified in Appendix E.

4.2 Costs to serve TOU and solar customers

The Regulations do not enable us to determine different DMO prices for customers of the same 'type'. Therefore, for solar and TOU customers, we need to consider any additional costs retailers may incur to supply customers on either of these tariff types in the residential DMO price.

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[197] The timing of the off-peak periods in the legacy CL network tariff (10 am to 3 pm and 11 pm to 7 am) differ slightly from the solar sponge (9:30 am to 3:30 pm) and off-peak (11:30 pm to 6:30 am) periods in the TOU CL network tariff. As we can only chose one consumption pattern per customer type, we have allocated controlled load consumption to the lower priced intervals common to both tariffs, to avoid assigning any controlled load usage to a peak period in either tariff.

Position Paper position

During our DMO 2 determination process some stakeholders highlighted the increasing penetration of advanced meters in DMO jurisdictions, and suggested the DMO price should be adjusted to reflect higher metering costs incurred by retailers for advanced meters. Our DMO 2 Final Determination therefore considered how we should take into account any differences in costs to serve TOU customers in the single DMO price.

Our position was that while acknowledging retailers faced higher fixed costs to serve TOU customers in some regions, we would not adjust the DMO price to account for these because:

- the DMO price is sufficient to enable recovery of efficient costs for TOU customers, being above the median TOU market offer, our proxy for a retailer's efficient costs
- the relatively small number of customers on TOU standing offer tariffs (around 38,000 in DMO jurisdictions) would mean any cost differences, where they exist, would have limited impact on retailers' revenues.

Our consideration of advance meter costs included:

- the average annual cost of an advanced meter is higher than a conventional meter. The QCA final report found a typical residential advanced meter costs approximately $118 per meter per annum in South East Queensland, though actual costs vary by retailer.[198] It suggested an accumulation meter costs around $36 per year
- retailers recover the costs of advanced meters in different ways. The QCA noted most retailers do not currently charge customers individually for their particular metering costs. Due to the relatively small number of advanced meters installed, retailers either absorb the costs, or spread them across all customers
- retailers avoid some costs when a customer has an advanced meter installed. These include meter reading costs (as most advanced meters can be read remotely) and the costs that would have been incurred had an accumulation meter been installed.

Based on the above considerations, we determined not to make any adjustment to the DMO price to account for additional costs retailers face for TOU and/or advanced meter customers.

198 AER, *Default Market Offer prices 2020-21, Final Determination*, April 2020, p. 54; QCA, *Ministerial advice: Benefits of advanced digital metering*, September 2019, p. 3; ACIL Allen, *Report to the Queensland Competition Authority, Advanced digital meters, estimating the potential net benefits final report*, 2 September 2019, p. 16.

The Position Paper noted that in the absence of new information to suggest the DMO policy objectives are not met for customers on TOU tariff types, we proposed no change to our DMO approach.

We sought stakeholders' feedback on:

- whether this approach remained appropriate
- any evidence that advanced meters costs were affecting retailers' abilities to recover costs under the DMO cap
- whether it was reasonable for flat rate standing offer customers to pay a higher price to cross-subsidise TOU customers.

In addition, to inform our understanding of retailers' advanced meter costs, we requested retailers provide information on the number of standing offer customers with advanced meters (type 4 meters). We discuss this data below.

Stakeholder submissions

In relation to the appropriateness of our approach, stakeholders provided similar comments to those received in relation to DMO 2. Retailer comments fell broadly into two categories:

- those concerned about revenue impact and cost recovery for standing offer customers with advanced meters
- those suggesting advanced meter costs should be taken into account, for example, to allow more room for retailers to offer discounts and compete on price.

Of those suggesting retailers should be able to recover advanced meter costs for standing offer customers, ActewAGL noted that accounting for metering costs is consistent with the approach taken by the Independent Competition and Regulatory Commission in regulating electricity prices in the ACT.[199]

Origin Energy considered not making a particular allowance for TOU customer costs, including advanced meter costs, creates 'adverse revenue risk to retailers'.[200] It said while it is unlikely a DMO customer would request a advanced meter, DMO customers will continue to shift to advanced meters as older meters fail.[201] For this reason it considers the AER should provide an allowance for advanced meters.

Origin Energy also noted that if we retain the view that the DMO price is at a high enough level to cover the cost of advanced meters, we should specify a threshold number of DMO customers with advanced meters that would trigger the inclusion of a specific allowance for advanced meter costs in the DMO price.

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199 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 5–6.

200 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p.9.

201 Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 10.

Simply Energy similarly argued there are various reasons why customers acquire advanced meters, for example, to accommodate solar and because of meter failure. On this basis it considers a specific allowance for advanced meter costs should be made in the DMO price.

On the other hand, EnergyAustralia and Red Energy/Lumo Energy focused on concerns about the competitiveness of market offers if the DMO does not include an allowance for advanced meter costs.

EnergyAustralia considered the impact of the DMO on discounting and marketing practises for market offers is more important than its price cap function.[202] It suggested a lower DMO price impacts retailers' abilities to offer competitive market offer prices. For example, the lower the DMO price, the lower the discount and the less competitive market offers appear compared to standing offers.

Red Energy/Lumo Energy similarly considered the DMO price is a price cap and reference price for market offers, and that because retailers absorb the cost of advanced meters, these offers can't be priced as competitively.[203] Noting our preference to not make subsequent adjustments to DMO prices for actual changes in costs, Red Energy/Lumo Energy suggested we should adopt a more conservative approach to setting DMO prices to ensure retailers are able to recover costs. It said the consequence of not doing so is that retailers may not offer their most competitive offers to specific customer segments or encourage customer uptake of advanced meters. This may have the effect of undermining the DMO policy objective to facilitate retailer competition and customer participation in the energy market.

EnergyAustralia further suggested the AER consider any cost (and usage) differences to supply solar customers, which would be helpful in determining a separate DMO price if the Regulations are amended in the future to provide for a solar DMO price.[204]

Meter provider Vector offered a third viewpoint, noting advanced meter costs should be taken into account in the DMO price to encourage greater take up of advanced meters by compensating retailers for advanced meter costs.[205]

Not all retailers considered we should adjust the DMO price to account for advanced meter costs. AGL considered it was not necessary to include an allowance for advanced metering in the DMO 3 price, but that an allowance will be needed in future DMO prices when advanced meter take-up increases. AGL expected this is likely to occur because tariff assignment policies will increase the rate of transition from flat to cost reflective tariffs (TOU and demand tariffs), which will require more customers to transition to advanced meters.[206]

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202 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3–4.

203 Red/Lumo, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 1.

204 EnergyAustralia, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 4.

205 Vector, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 5.

206 AGL, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 9–10.

In response to the consultation request for evidence of any cost impacts from serving advanced meter customers, Origin Energy was the only retailer to respond. It noted it incurs a cost of over $1 million for DMO customers on advanced meters.

The Position Paper also asked stakeholders whether it was reasonable to increase the DMO price for flat rate customers to allow retailers to recover costs for TOU customers.

Simply Energy noted advanced meter customers may be on flexible (including TOU) or flat tariffs.[207] It suggested retailers should be able to recover advanced meter costs for all customers noting, 'it is not appropriate that retailers are expected to solely recover the costs of advanced meters from the subset of customers with advanced meters that have chosen non-flat tariffs.'

Similarly, ActewAGL considered metering is an essential part of supplying all customers with energy, and retailers should be able to recover the associated costs (capital, operating, maintenance) regardless of customer or meter type. [208]

Representing the views of 13 community organisations, Etrog Consulting suggested that rather than adopt the median market offer price as a proxy for efficient costs, we should quantify retailer costs and develop a benchmark approach to calculating DMO prices. In this case it would not be necessary to provide a specific allowance for advanced meter costs.

Etrog Consulting considered however, that if we retain the current indexation methodology the margin we have allowed above the median market offer price is sufficient for retailers to recover advanced meter costs and any additional costs retailers may incur to supply solar customers. Etrog Consulting also observed advanced meters are intended to lower costs to customers overall, and it is not appropriate for customers to incur additional costs for advanced meters.[209]

Advanced meter information request

During the DMO 2 consultation, stakeholders noted while advanced meter numbers were relatively low, the increasing rollout of advanced meters would be a factor contributing to increased retailer costs. We acknowledged the Power of Choice reforms will result in a growing proportion of advanced meters in the future, and we undertook to monitor our approach to ensure it remains appropriate in future DMO determinations.

To inform our understanding of retailers' advanced meter costs, and the extent to which retailers were exposed to standing offer customers with these meters, we requested the 10 retailers with the highest customer numbers to provide information on

207 Simply Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p. 3.

208 ActewAGL, *Submission to DMO 3 Position Paper*, 18 November 2020, p. 5–6.

209 Etrog Consulting, *Submission to DMO 3 Position Paper*, 23 November 2020, p. 23.

the number of customers with advanced meters.[210] These retailers account for over 95 per cent of market share in DMO regions.

For each distribution region, we requested they specify[211]:

- the number of residential and small business standing and market offer customers with advanced meters
- for residential customers, whether they were on a TOU or flat rate tariff. We asked retailers to exclude customers with demand tariffs from the count, as these are not covered by the DMO cap.

Key findings included:

- across all DMO regions, 18 per cent of residential standing offer customers and 10 per cent of small business standing offer customers have advanced meters. In individual regions, this proportion ranges from around 10 per cent (in Ausgrid's region) to 28 per cent (in SAPN's region)
- of all residential customers with advanced meters around 80 per cent are on flat rate and 20 per cent on TOU tariffs
- in Ausgrid's and Energex's regions, over two-thirds of TOU customers do not have advanced meters. This indicates our previous assumption that advanced meter customers are closely correlated with TOU customers is not accurate for all regions.

Figures 7, 8 and 9 below show these proportions.

[210] When referring to advanced meters we mean type 4 and 4A interval meters. Type 4A are the same as type 4 meters, except the remote reading capability has been disabled.

[211] The data request was for data as at 30 September 2020.

Figure 7: Residential standing offer customers by tariff and meter type

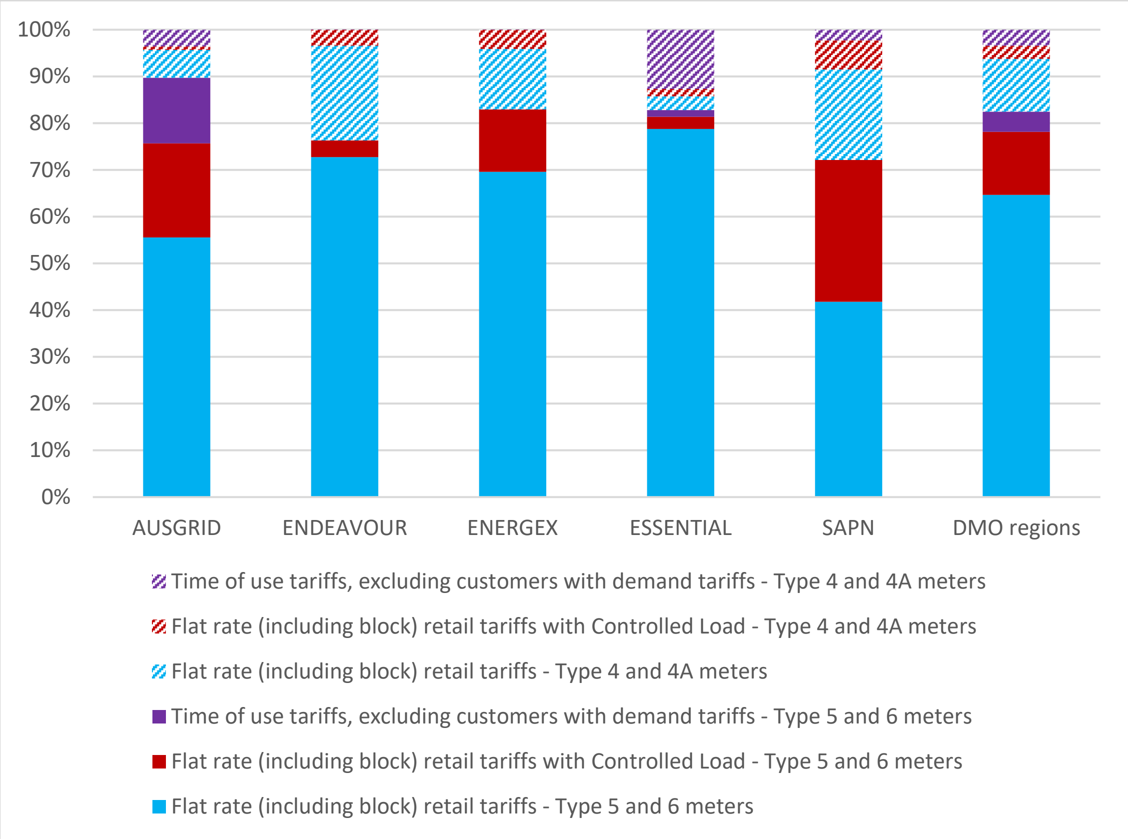


Figure 8: Small business standing offer flat rate customers by meter type

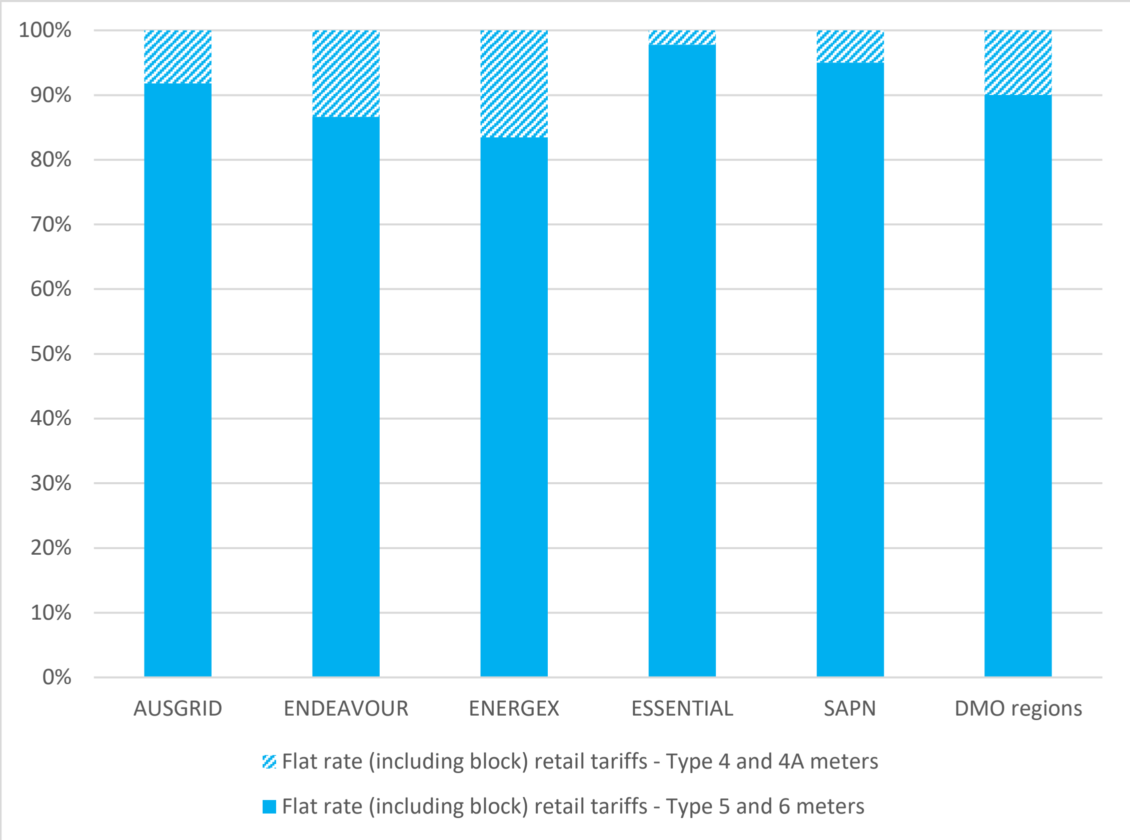
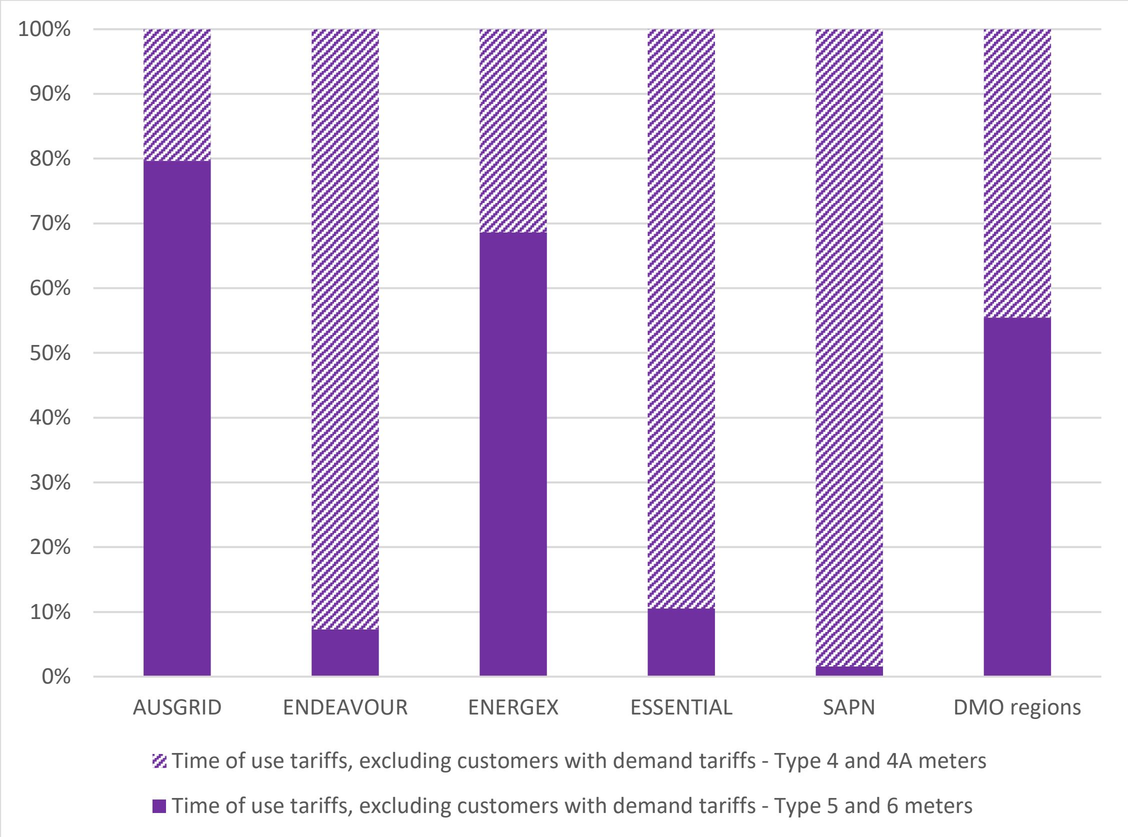


Figure 9: Residential standing offer TOU customers by meter type



Draft Determination approach

Having considered stakeholder submissions and the meter number data provided by retailers, our Draft Determination position is to not adjust the DMO price to take into account costs relating to advanced meters.

Overall, our reasons for this view are substantively the same as for DMO 2.

Our analysis of the meter information provided by retailers confirms that while the proportion of customers on type 4 meters is not negligible, it is low compared to the number of customers with accumulation meters.

The data also highlights that were we to account for advanced meter costs in the DMO price, 80 to 90 per cent of standing offer customers would face higher DMO prices to compensate retailers for costs not related to them. In our view, this would not be an equitable outcome.

We also note that retailers have a range of options to recover costs for type 4 meter customers, either spreading them across all customers through supply and usage charges, or via up-front and/or recurring fees.

Regarding Origin Energy's request we define a threshold number of meter installations above which we will make an allowance for advanced meters in the DMO price, we have determined not to do so because our consideration of advanced meter costs relies on a number of factors in addition to numbers of customers with advanced meters. This includes consideration of TOU offer prices compared with flat rate offer prices and DMO prices, and whether retailers are able to recover the efficient costs incurred to supply customers.

We will continue to assess the available information as part of future determination processes in relation to advanced meter costs.

In relation to EnergyAustralia's and Red Energy/Lumo Energy's points about possible effects on retailers' abilities to offer competitive market offers, we consider our determination not to provide an additional allowance for advanced meters in this determination does not impact the DMO policy objectives.

Our analysis, conducted in January 2021, indicates there is a significant margin between the median TOU market offer (our proxy for retailers' efficient costs) and the DMO price enabling retailers to recover any additional costs they may incur to supply customers on advanced meters.

While we acknowledge advanced meters and associated costs will be higher than for accumulation meters, based on our assessment of QCA's analysis, Origin Energy's cost estimate and the customer numbers data, we are satisfied the DMO price is at a high enough level above retailers' efficient costs for retailers to recover costs to serve customers with advanced meters.

Comparing the relative cost of supplying TOU and flat rate customers in January 2021, Figure 10 shows the margin between the median TOU market offer and the DMO price remains at a similar or greater level than for flat rate offers, suggesting the margin for competition is not impacted for these customers.

Figure 10: TOU and Flat rate median market offers compared to DMO 2 prices

We note comments from AGL and other stakeholders suggesting the increasing uptake of advanced meters means the associated costs will become increasingly significant for retailers, and that we continue to monitor this.

We recognise the Power of Choice reforms will result in a growing proportion of advanced meters in the future. We will continue to monitor our approach to ensure it remains appropriate in future DMO determinations.

Appendices

Appendix A – List of submitters to AER Position Paper

Appendix B – Market offer analysis for each distribution region

Appendix C – Comparing the DMO to the Median Market offer

Appendix D – Matters we have had regard to in determining DMO prices

Appendix E – Draft legislative instrument

Appendix F – DMO 2 to DMO 3 price movements

A List of submitters to AER Position Paper

1. ActewAGL
2. Australian Energy Council (AEC)
3. AGL Energy
4. Alinta Energy
5. Ausgrid
6. Energy Consumers Australia (ECA)
7. EnergyAustralia
8. Etrog Consulting on behalf of 13 Queensland community sector organisations – Caxton Legal Centre; Council on the Aging (COTA) Queensland, Energetic Communities Association Inc; Good Shepherd; Kildonan & Lentara Cluster; Laidley Community Centre, Laidley; Multilink Community Services Inc; Queensland Consumers Association; Queensland Council of Social Service (QCOSS); St Vincent de Paul; Uniting Care; Uniting Church; Youth and Family Service (YFS), Logan
9. MEA Group
10. Origin Energy
11. Public Interest Advocacy Centre (PIAC)
12. ReAmped Energy
13. Red Energy/Lumo Energy
14. Simply Energy
15. Vector

B Market offer analysis for each distribution region

	Headroom
Difference between lowest market offer and DMO 2	DMO 2 prices remain well above the median market offer price in each region. The difference between the DMO 2 price and the lowest market offer ranged between: • $432 and $561 for residential customers on a flat rate tariff • $487 and $639 for residential customers on a flat rate tariff with CL • $1682 and $2896 for small business customers on a flat rate tariff.
Difference between median market offer and DMO 2	The DMO 2 price remains higher than most market offers, with significant margin between the lowest market offer and the DMO indicating there are strong incentives for customers to shop around and switch. The difference between the DMO 2 price and the median market offer ranged between: • $227 and $352 for residential customers on a flat rate tariff • $287 and $420 for residential customers on a flat rate tariff with CL • $879 and $1593 for small business customers on a flat rate tariff.

As the agency responsible for determining DMO prices each year, we consider it necessary to understand any DMO-related impacts so they can inform our future DMO price determinations. The purpose of this analysis is to provide a snapshot of how the market has moved immediately following the DMO's introduction.

This section looks at changes to highest, lowest and median market offer prices before and after the introduction of the DMO on 1 July 2019. It shows these changes at six points in time:

October 2018 – the same data that informed our DMO Final determination. The offers in this dataset preceded the announcement of our DMO

- June 2019 – immediately before the introduction of the DMO
- 31 December 2019 – six months after the introduction of the DMO
- March 2020 – nine months after the introduction of the DMO
- August 2020 – capturing offers after the second DMO came into effect

- 31 December 2020 – six months after the second DMO came into effect.

Figures B.1 to B.15 below show these movements in graph form. These fifteen graphs show the offers from Energy Made Easy (EME) for the three customer types and five distribution regions. To calculate the annual bill amounts from EME data, we used assumptions to allow direct comparison of generally available offers. The list of annual bill calculation assumptions is published in our DMO 2 Final Determination.[212]

[212] AER, *Final Determination, Default Market Offer Prices 2019-20,* April 2019, Appendix C, p 69–70.

Changes in market offer prices in Ausgrid's region

Figure B1: Residential flat rate tariff

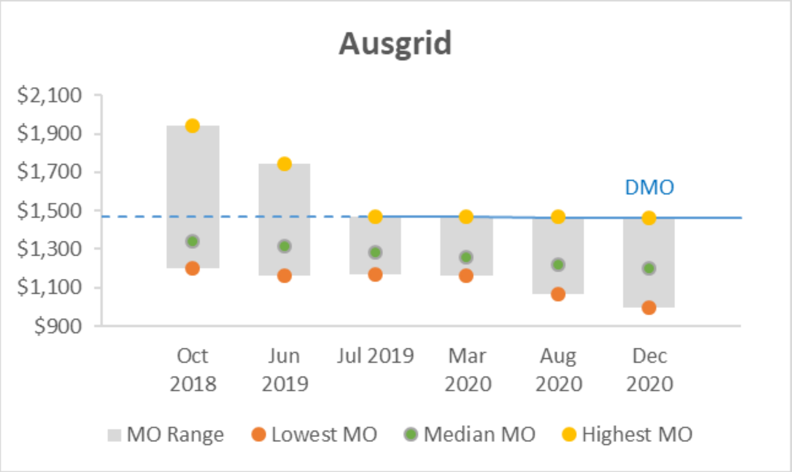


Figure B2: Residential flat rate tariff with controlled load

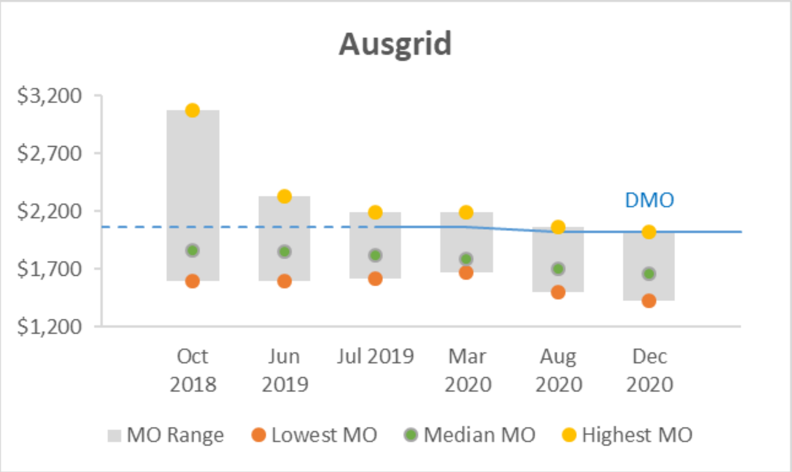
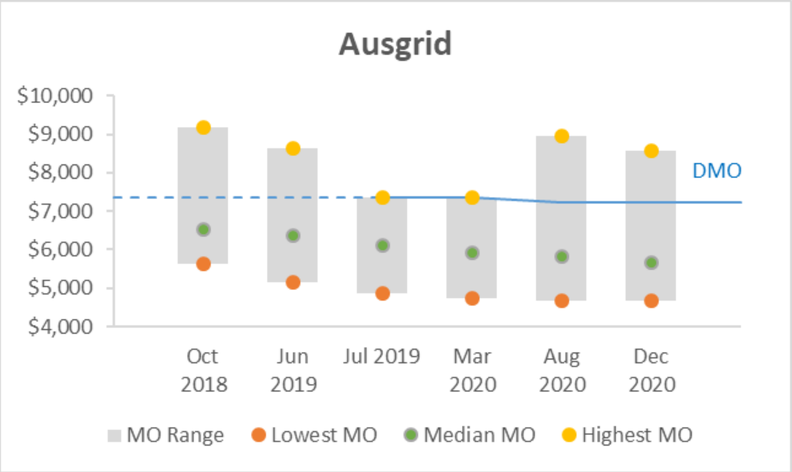


Figure B3: Small business flat rate tariff



Changes in market offer prices in Endeavour's region

Figure B4: Residential flat rate tariff

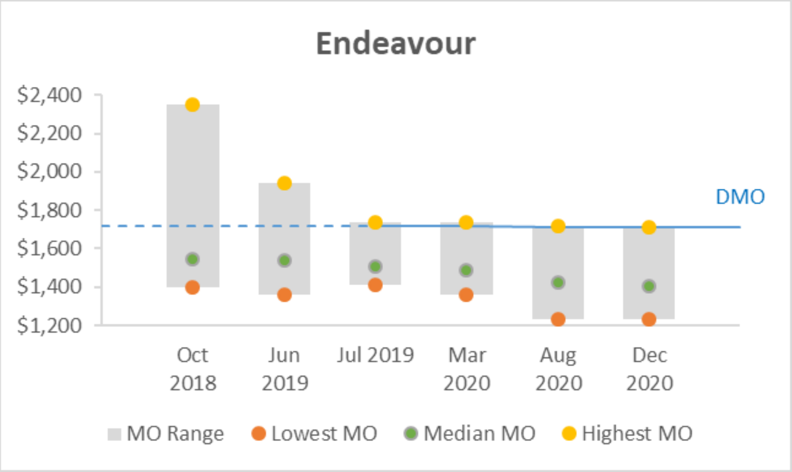


Figure B5: Residential flat rate tariff with controlled load

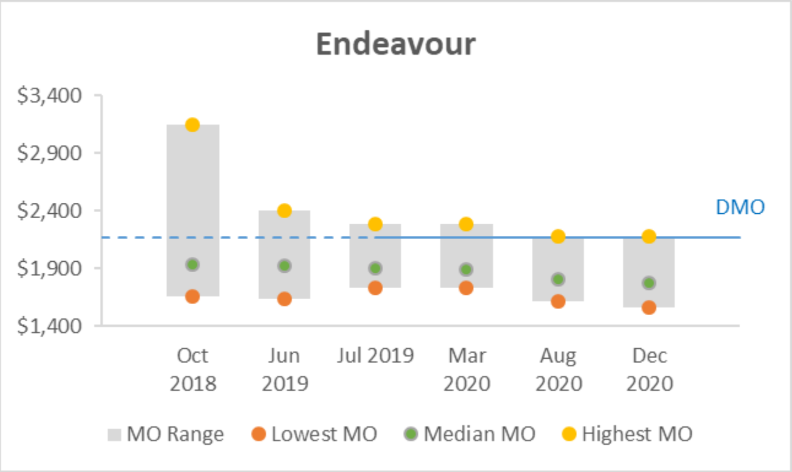
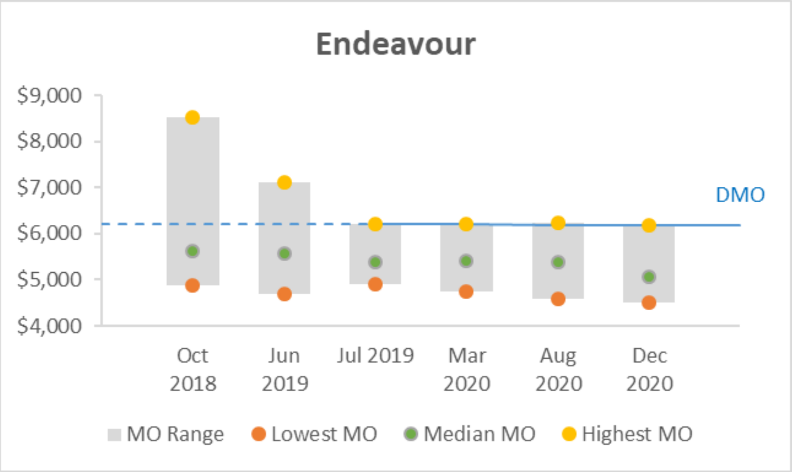


Figure B6: Small business flat rate tariff



Changes in market offer prices in Essential Energy's region

Figure B7: Residential flat rate tariff

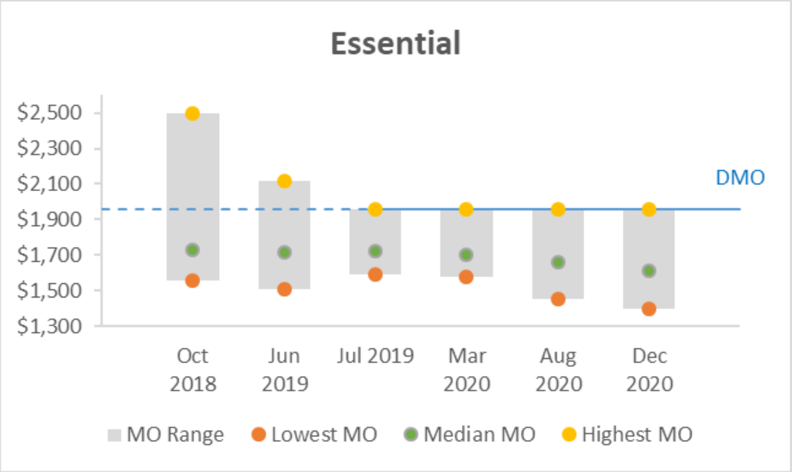


Figure B8: Residential flat rate tariff with controlled load

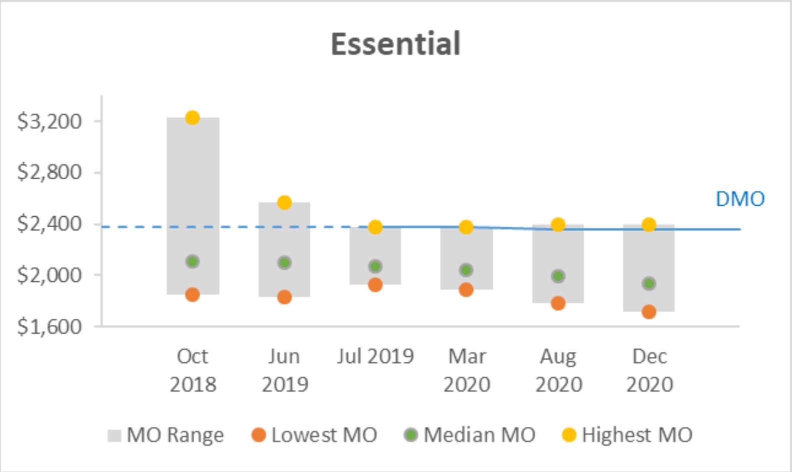
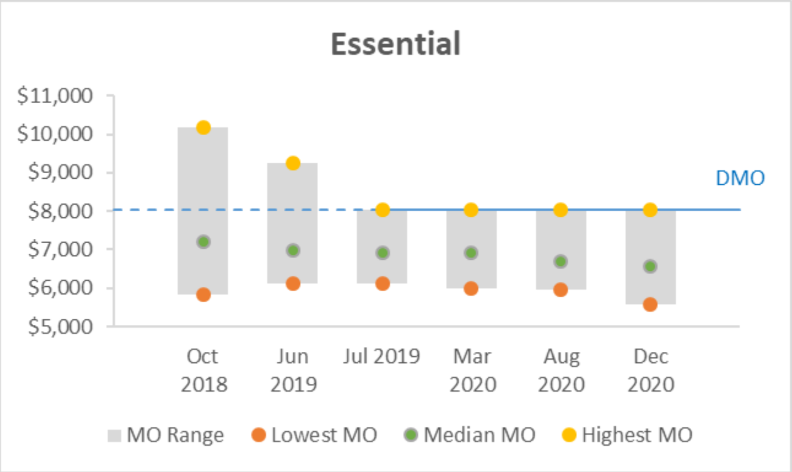


Figure B9: Small business flat rate tariff



Changes in market offer prices in Energex's region

Figure B10: Residential flat rate tariff

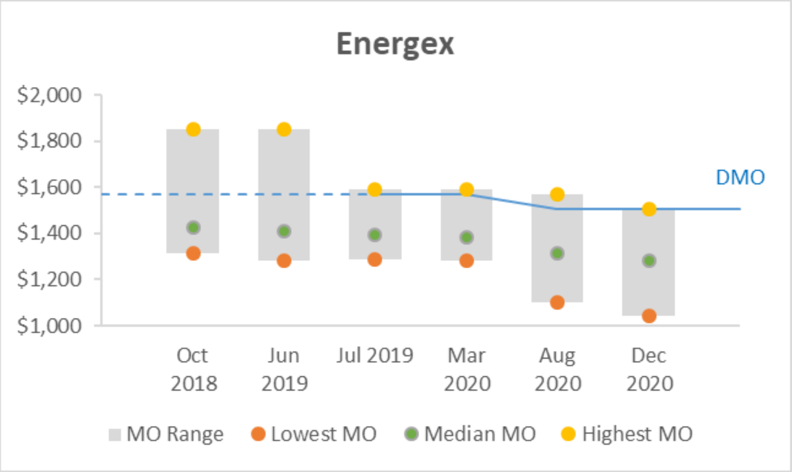


Figure B11: Residential flat rate tariff with controlled load

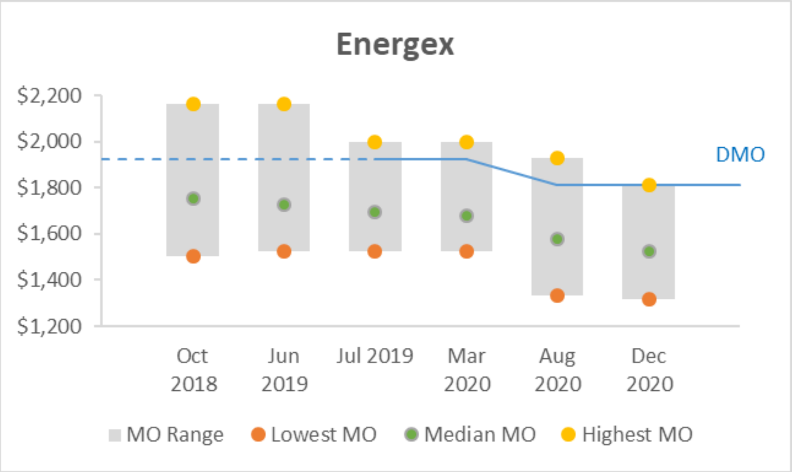
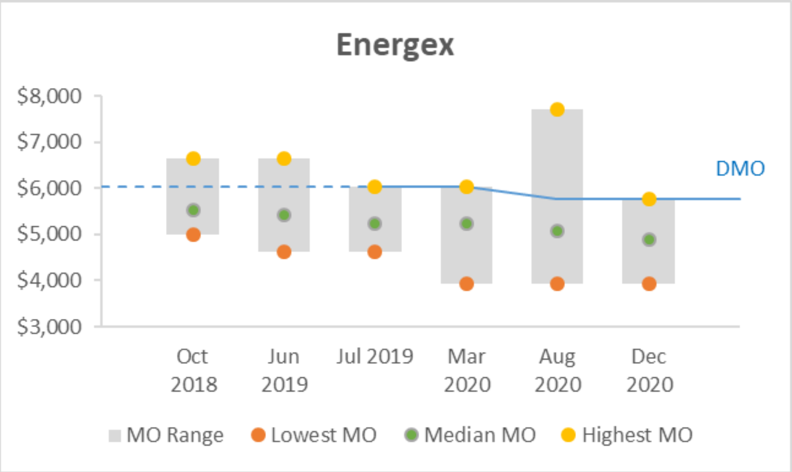


Figure B12: Small business flat rate tariff



Changes in market offer prices in SAPN's region

Figure B13: Residential flat rate tariff

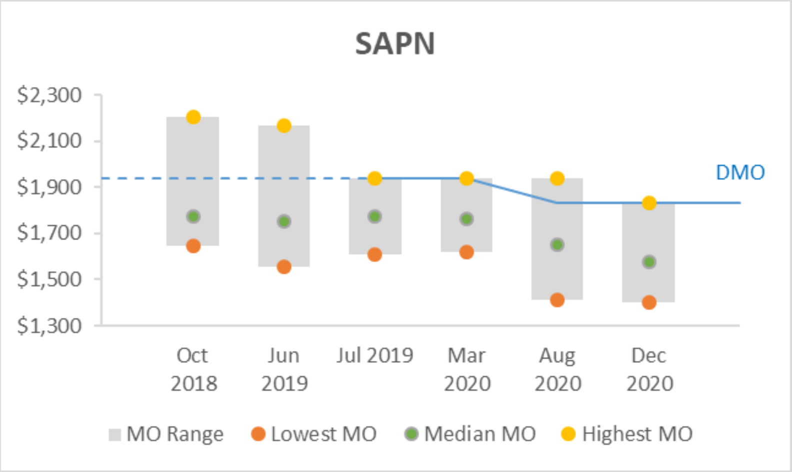


Figure B14: Residential flat rate tariff with controlled load

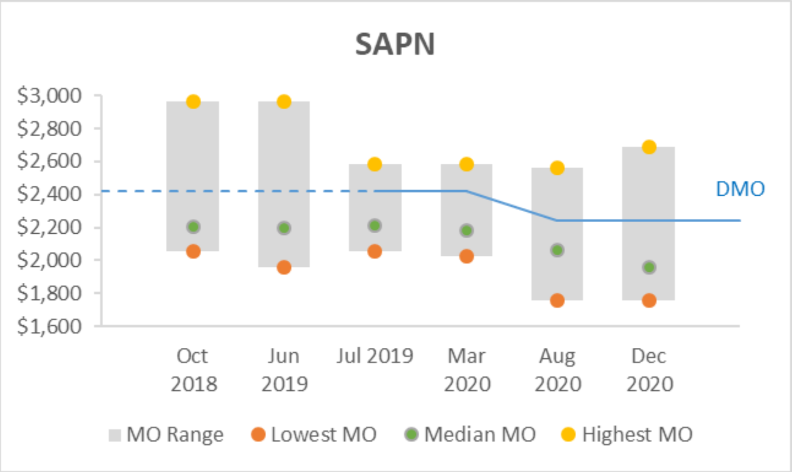
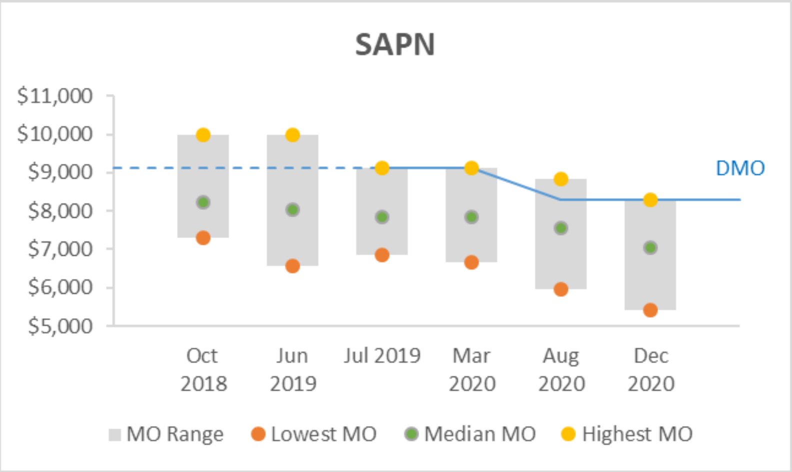


Figure B15: Small business flat rate tariff



From August 2020 to December 2020, the median market offers decreased in all distribution regions for all customer types. These reductions followed similar decreases from March 2020 to August 2020. For residential customers the median market offer reduced between 1.6 (Endeavour) and 4.5 per cent (SAPN), and between 1.7 (Endeavour) and 5.2 per cent (SAPN) for customers with CL. The median market offers for small business customers reduced between 2.0 (Essential) and 6.7 per cent (SAPN).

These reductions in median market offer prices have generally been larger than the change from DMO 1 to DMO 2, when there were either smaller decreases or marginal increases, depending on the region and customer type. This has had the result of increasing the margin between the DMO and the median market offer.

Across this same time period, the lowest market offers decreased for all customer types in all regions, with the exception of residential customers in Endeavour's region and small business customers in Energex's and Ausgrid's regions, which had no price movement. We observed some significant decreases for all customer types in some regions. For residential customers, the lowest market offer reduced between 0.7 (SAPN) and 6.5 per cent (Ausgrid) and between and 0.1 (SAPN) and 5.4 per cent (Ausgrid) for customers with CL. The lowest market offers for small business customers reduced between 1.7 (Essential) and 9.4 per cent (SAPN).

These large decreases in the lowest market offers are part of a trend where small retailers, some of which are new entrants, have aggressively priced their market offers. These retailers may have greater exposure to wholesale spot prices and could currently be in a position to price offers lower than retailers that hedged their wholesale prices in advance. However, we also observed some instances where a larger retailer offered the lowest market price (Endeavour residential fixed rate with CL and small business fixed rate). These lower offers, coupled with the small number of offers in some regions above the DMO price cap, have led to a larger spread in the range of offers, similar in breadth to June 2019, prior to the introduction of DMO.

C Comparing the DMO to the Median Market offer

The following figures provide a time series of the difference between the DMO price and the median market offer (MMO) for Residential Flat Rate and Small Business tariffs in each DMO region. The figures also show the difference between the median standing offer (MSO) and the MMO for time periods before the DMO was introduced.

The figures depict the:

- DMO price (top of each green column) for July 2019 to December 2020
- Median Market Offer price (bottom of each column) for October 2018 to December 2020
- Median Standing Offer price (top of each blue column) for October 2018 and June 2019
- the difference between the DMO and the MMO (height of each green column) for July 2019 to December 2020
- the difference between the MSO and the MMO (height of each blue column) for October 2018 and June 2019.

Comparing the DMO to median market offer prices in Ausgrid's region

Figure C1: Residential flat rate tariff

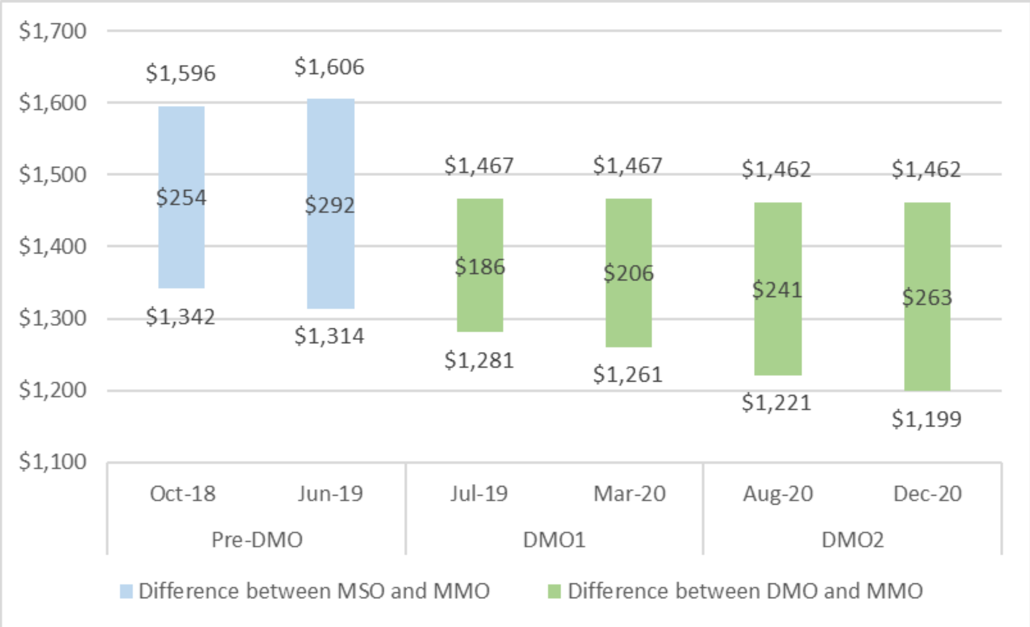
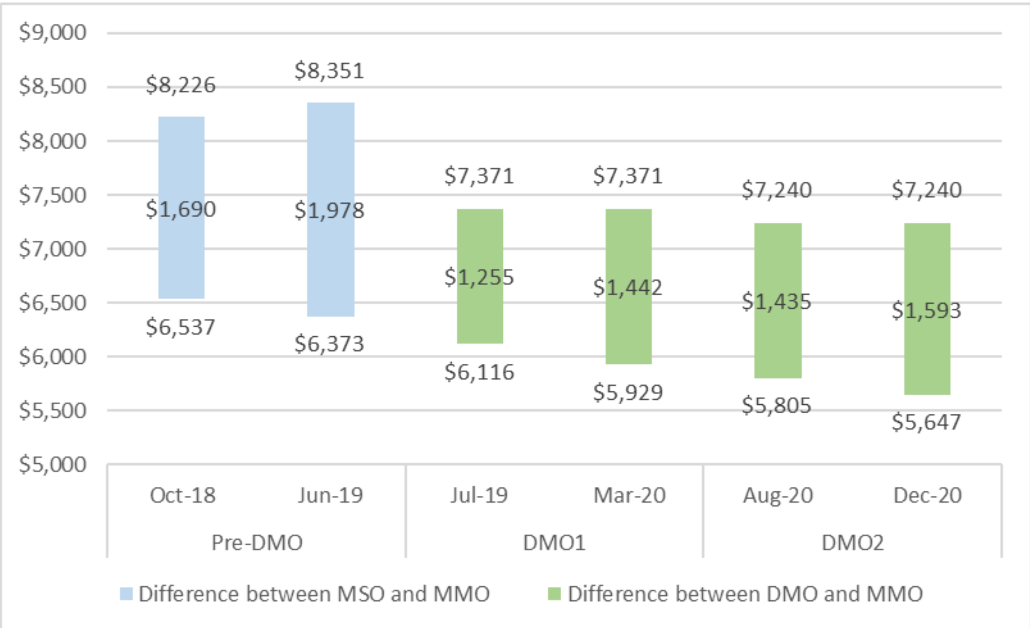


Figure C2: Small business flat rate tariff



Comparing the DMO to median market offer prices in Endeavour's region

Figure C3: Residential flat rate tariff

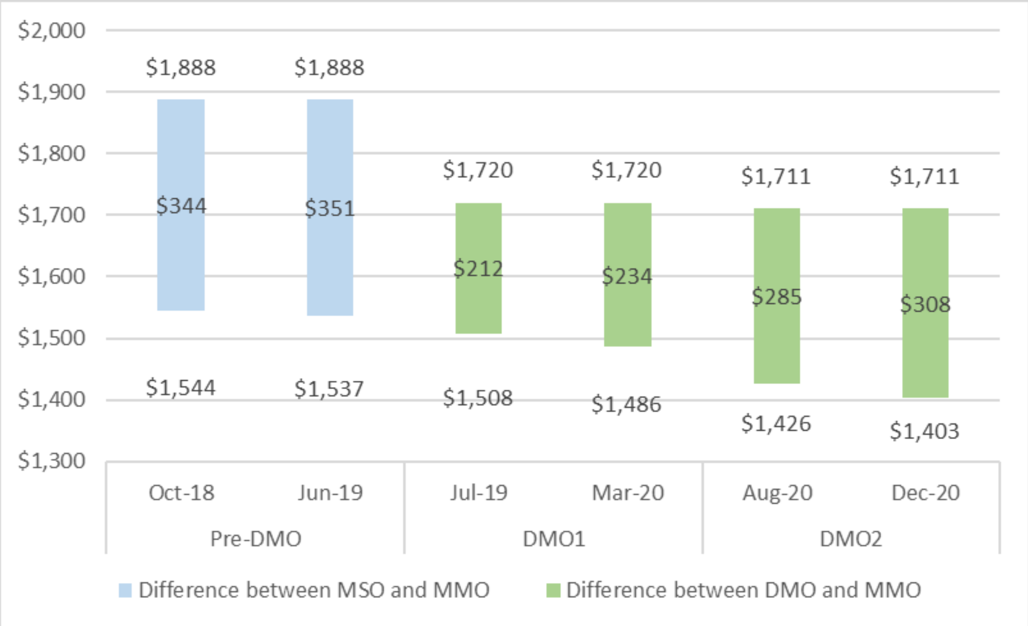
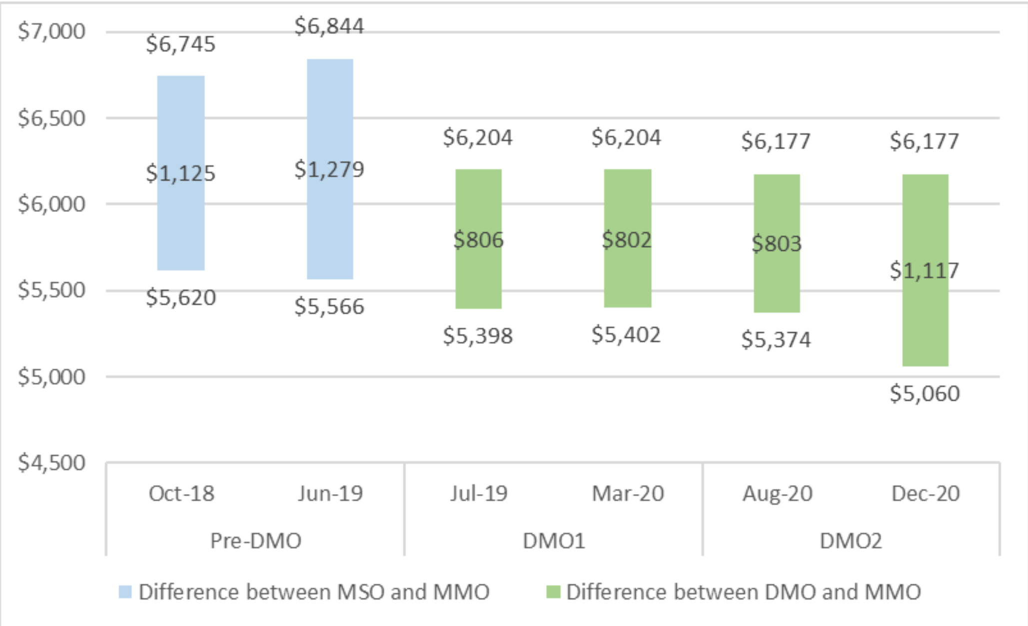


Figure C4: Small business flat rate tariff



Comparing the DMO to median market offer prices in Essential Energy's region

Figure C5: Residential flat rate tariff

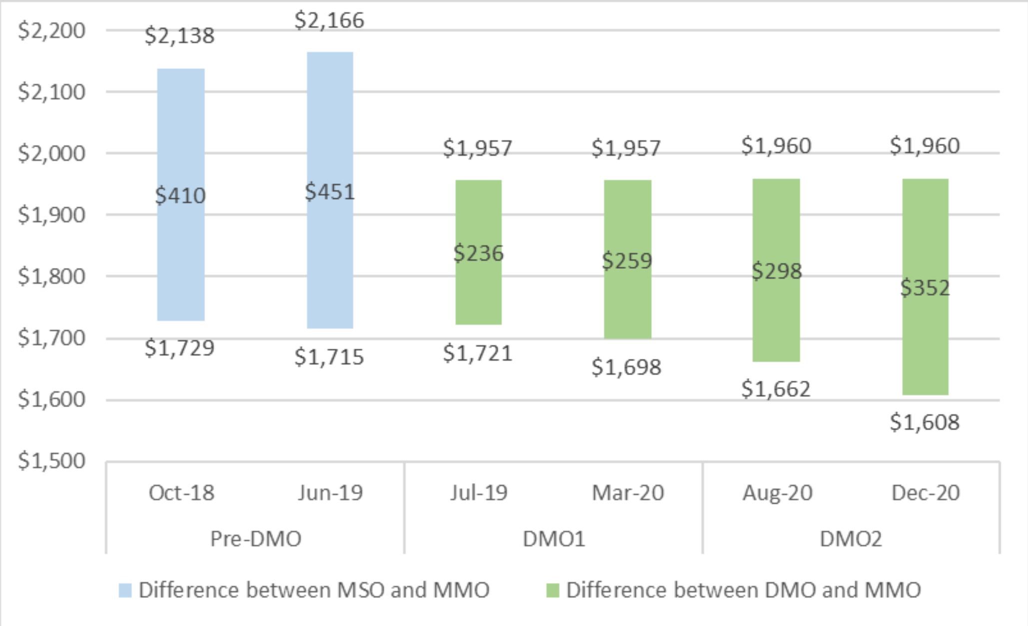
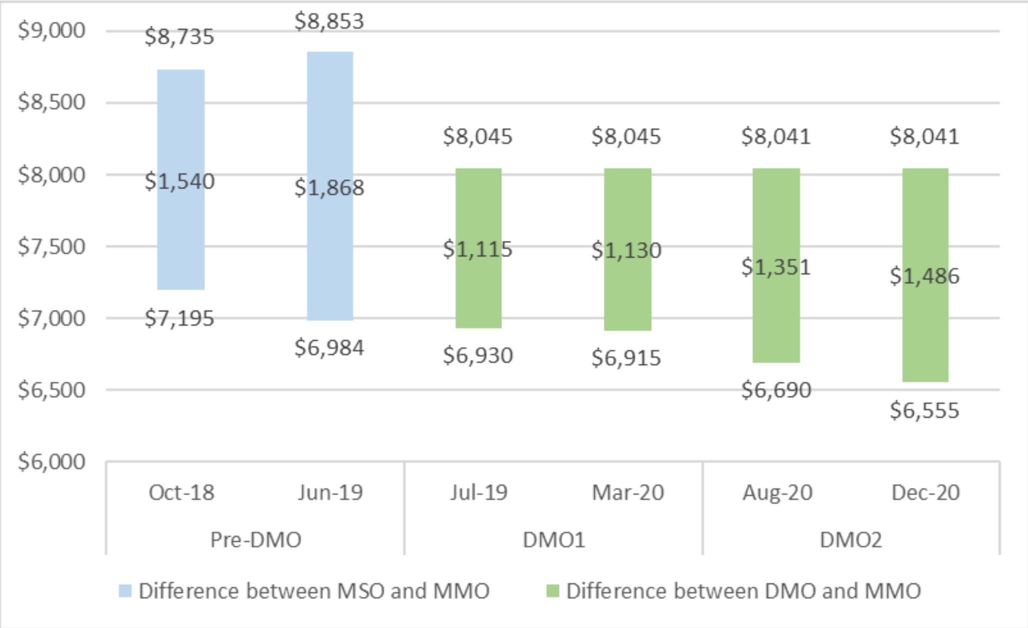


Figure C6: Small business flat rate tariff



Comparing the DMO to median market offer prices in Energex's region

Figure C7: Residential flat rate tariff

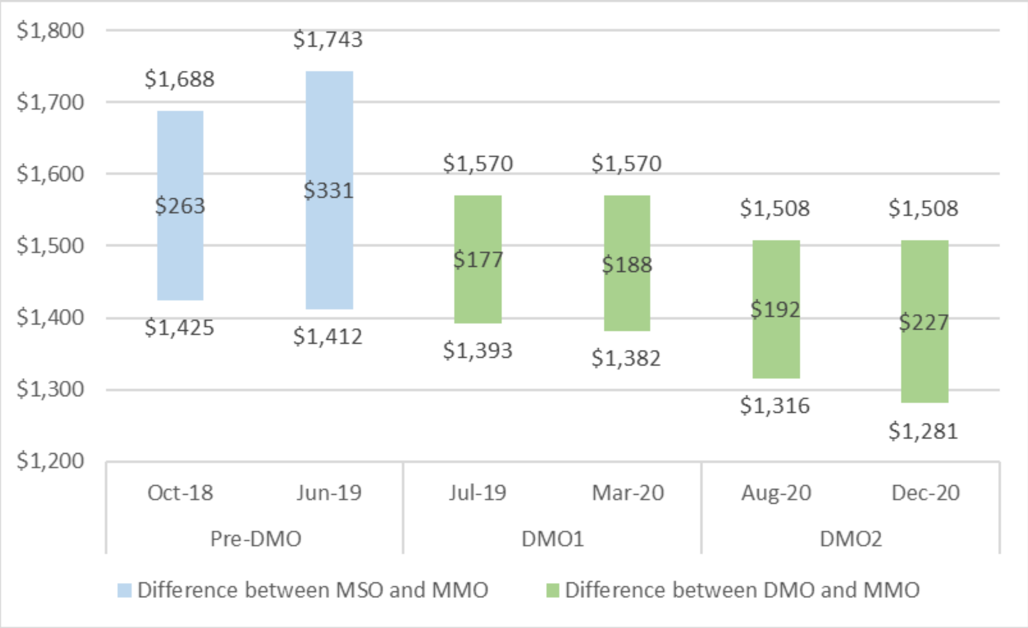
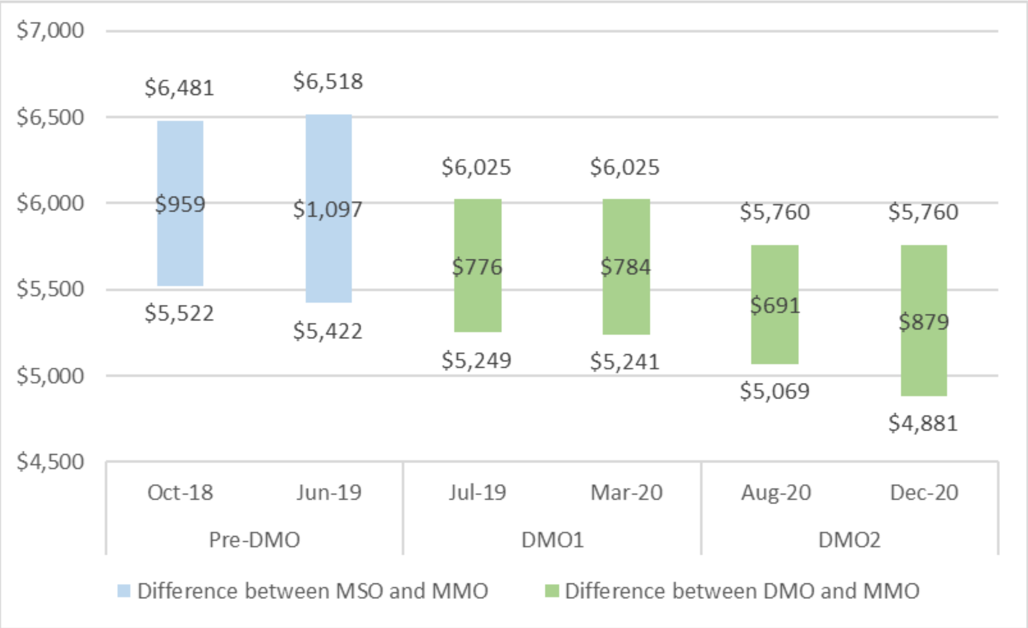


Figure C8: Small business flat rate tariff



Comparing the DMO to median market offer prices in SAPN's region

Figure C9: Residential flat rate tariff

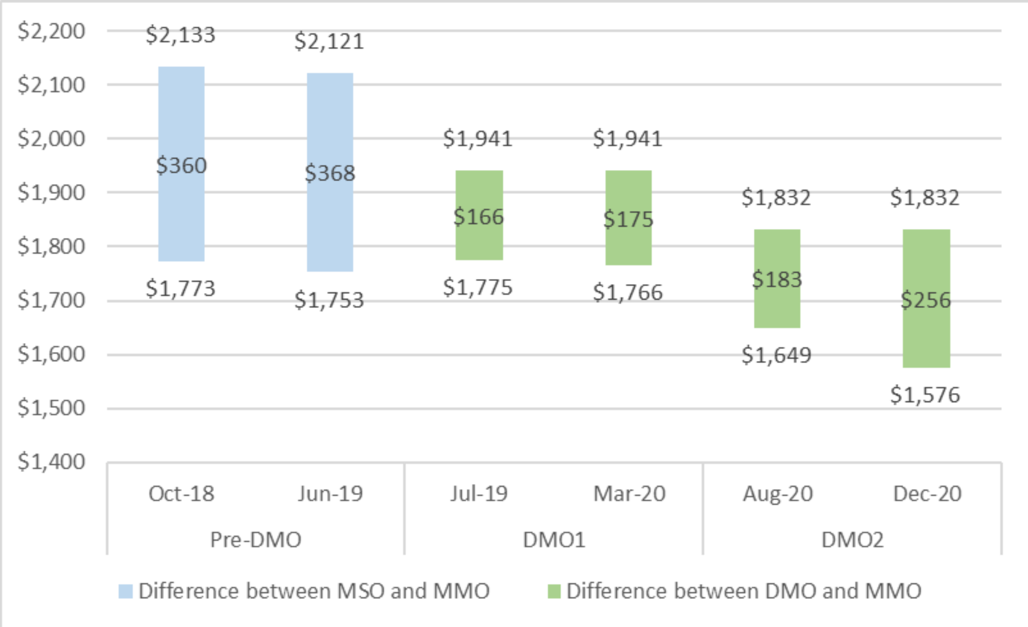
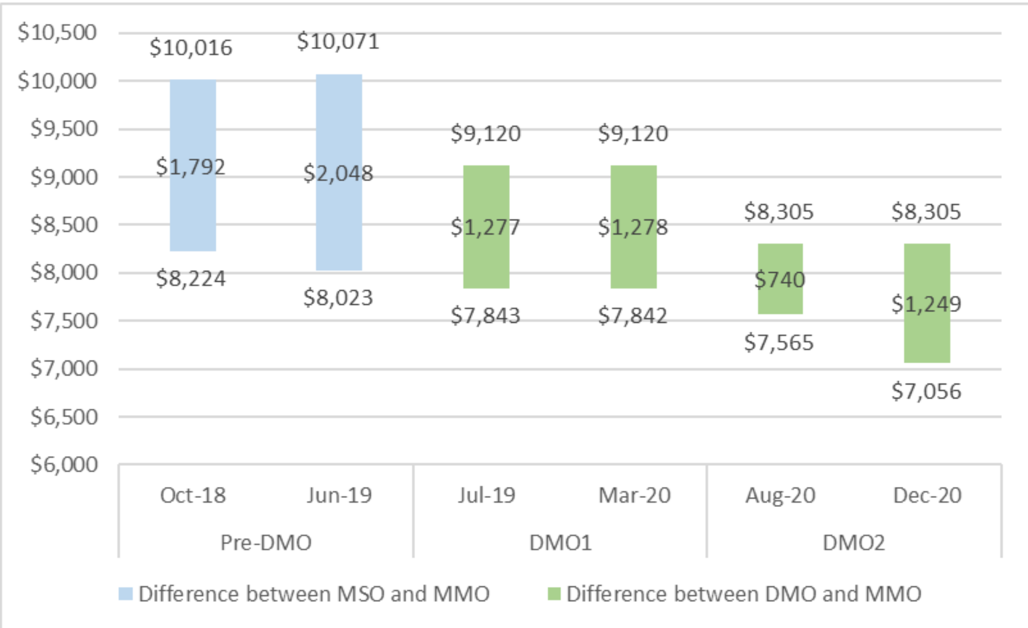


Figure C10: Small business flat rate tariff



D Matters we have had regard to in determining DMO prices

Regulations section 16(4)	AER considerations
(a) the prices electricity retailers charge for supplying electricity in the region to that type of small customer	Our DMO 1 determination was made using a price-based approach, using generally available market and standing offer prices. We also considered the DMO price in relation to market offer prices in each area, as well as the LAR's standing offer price. For DMO 2, we applied an index to the DMO 1 price, and we are continuing this approach for DMO 3. As such, price considerations are embedded in the DMO prices.
(b) the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region	In our DMO 1 determination we noted observed standing and market offers (on a portfolio basis) reflect a typical market participant's expectations about the efficient costs of providing retail services in particular distribution regions, including a reasonable profit margin. We set DMO prices above the observed median market offer in each distribution region to exclude any potential below cost prices/loss-leading offers that may not reflect a reasonable profit margin. Our DMO 2 approach preserved retail costs at around the same level by: • indexing the residual retail component by CPI, while allowing material retail cost changes to be passed through to the DMO price • adjusting the overall DMO price in line with forecast changes to underlying network, environmental and wholesale costs. This approach enabled retailers to continue to make a reasonable profit. This approach will be repeated for DMO 3.

(c) the following costs: (i) the wholesale cost of electricity in the region; (ii) the cost of distributing and transmitting electricity in the region; (iii) the cost of complying with the laws of the Commonwealth and the relevant State or Territory in relation to supplying electricity in the region; (iv) if relevant to the region—the cost of acquiring and retaining small customers; (v) the cost of serving small customers;	As for our DMO 2 determination, for our DMO 3 Draft Determination, we have had regard to the forecast direction and magnitude of changes for the main types of costs, in particular wholesale energy costs, transmission and distribution costs, and environment costs. Specifically, we have had regard to: • forecast changes in the wholesale energy costs for 2021-22. • the AER's pricing determinations for regulated transmission and distribution costs • forecast costs of complying with regulatory requirements such as the LRET, SRES, jurisdictional schemes and feed-in tariff (FiT) schemes. • retail cost component of charges.[213] We have also considered specific costs for residential TOU customers. These matters are discussed in chapters 3 and 4.
(d) any other matter the AER considers relevant.	We have had regard to the policy intent of introducing a DMO price, as outlined in the ACCC's REPI final report. This was to: • reduce excessive standing offer prices • provide a consistent base from which market offer discounts should be calculated. In recommending a DMO, the ACCC was explicit in its intention DMO price should be set at levels that: • enable retailers to recover the efficient costs of servicing customers in each distribution region, including costs for acquiring and retaining customers. • did not dis-incentivise competition, customer engagement, innovation and investment. In its submission to our

[213] This includes consideration of residual costs and step changes. See discussion in section 3.3.

	DMO 1 Position Paper, the ACCC re-stated its position that the DMO should not be the lowest or near lowest price in the market.[214]

[214] ACCC, *Submission to the AER DMO Position Paper*, 20 March 2019: https://www.aer.gov.au/system/files/ACCC%20-%20AER%20Default%20Market%20Offer%20-%20Submission%20to%20Draft%20Determination%20-%2020%20March%202019.PDF

E Draft legislative instrument

Draft Legislative Instrument

Draft Default Market Offer Prices

2021-22

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2021*.

2. Commencement

This instrument commences on 1 July 2021.

3. Authority

This instrument is made under section 16(1) of the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).

4. Definitions

In this Determination:

a) ***Regulations*** means the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019*; and

b) ***Residential Annual Usage without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

c) ***Residential Annual Price without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

d) ***Residential Annual Usage with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

e) ***Residential Annual Price with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

f) ***Small Business Annual Usage*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

g) ***Small Business Annual Price*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

h) ***General Usage*** means the non-controlled load usage of a small customer under s 6(2)(a) of the Regulations; and

i) ***Controlled Load Usage*** means the controlled load usage of a small customer under s 6(2)(a) of the Regulations.

j) Terms defined in the Regulations have the same meaning in this instrument.

5. Per-customer usage determination

In accordance with s 16(1)(a)(i) of the Regulations, the AER determines the per-customer amount of electricity supplied in specified distribution regions to small customers of the following types:

Per-customer annual usage determination				
Distribution region	**Residential Annual Usage without Controlled Load**	**Residential Annual Usage with Controlled Load**		**Small Business Annual Usage**
		General Usage	***Controlled Load Usage***	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	20,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	20,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	20,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	20,000 kWh
SA Power Networks	4,000 kWh	4,200 kWh	1,800 kWh	20,000 kWh

6. Timing or pattern of supply determination

In accordance with s 16(1)(a)(ii) of the Regulations, the AER determines the timing or pattern of the supply of electricity in specified distribution regions to small customers:

a) Seasonality assumptions, all tariff and customer types

For all tariff and customer types, consumption has no seasonal weighting. That is, kilowatt hours consumed are assumed to be the same on each day of the year.

b) Daily usage profile for Flexible Tariffs (Time of Use tariffs, including the South Australian TOU CL tariff) – Residential Usage without Controlled Load and General Usage / Residential Usage with Controlled Load

i. Ausgrid distribution region

Flexible Tariff (Time of Use tariff) daily usage profile – Daily Residential Usage without Controlled Load (3,900 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.21**	**0.19**	**0.18**	**0.16**	**0.15**	**0.14**	**0.14**	**0.14**	**0.15**	**0.16**	**0.17**	**0.18**	**0.20**	**0.21**	**0.22**	**0.23**	**0.22**	**0.22**	**0.21**	**0.21**	**0.21**	**0.21**	**0.20**	**0.20**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.22**	**0.23**	**0.24**	**0.25**	**0.27**	**0.29**	**0.31**	**0.32**	**0.32**	**0.32**	**0.30**	**0.30**	**0.29**	**0.27**	**0.26**	**0.25**	**0.24**	**0.23**	**0.22**

Flexible Tariff (Time of Use tariff) daily usage profile – Daily General usage – Daily Residential Usage with Controlled Load (4,800 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.26**	**0.23**	**0.22**	**0.20**	**0.19**	**0.18**	**0.17**	**0.17**	**0.18**	**0.20**	**0.21**	**0.23**	**0.24**	**0.26**	**0.27**	**0.28**	**0.27**	**0.27**	**0.26**	**0.26**	**0.26**	**0.25**	**0.25**	**0.25**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.25**	**0.25**	**0.25**	**0.26**	**0.26**	**0.27**	**0.28**	**0.30**	**0.31**	**0.33**	**0.35**	**0.38**	**0.40**	**0.40**	**0.39**	**0.37**	**0.36**	**0.35**	**0.34**	**0.32**	**0.31**	**0.30**	**0.29**	**0.27**

ii. Endeavour Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,900 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	0.25	0.23	0.22	0.21	0.19	0.19	0.19	0.19	0.20	0.21	0.23	0.24	0.26	0.27	0.27	0.26	0.24	0.22	0.20	0.19	0.18	0.17	0.17	0.17
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	0.18	0.19	0.20	0.23	0.25	0.28	0.31	0.35	0.38	0.41	0.43	0.46	0.47	0.46	0.45	0.43	0.42	0.40	0.38	0.36	0.34	0.31	0.29	0.28

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (5,200 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	0.27	0.25	0.23	0.22	0.21	0.20	0.20	0.20	0.21	0.23	0.24	0.26	0.27	0.28	0.29	0.28	0.26	0.23	0.21	0.20	0.19	0.18	0.18	0.18
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	0.19	0.20	0.22	0.24	0.27	0.30	0.33	0.37	0.41	0.43	0.46	0.49	0.50	0.49	0.48	0.46	0.44	0.42	0.41	0.38	0.36	0.33	0.31	0.29

iii. Energex distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.20**	**0.18**	**0.17**	**0.16**	**0.15**	**0.15**	**0.15**	**0.14**	**0.15**	**0.15**	**0.17**	**0.19**	**0.21**	**0.24**	**0.27**	**0.27**	**0.26**	**0.26**	**0.25**	**0.25**	**0.25**	**0.25**	**0.24**	**0.25**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.25**	**0.25**	**0.25**	**0.26**	**0.26**	**0.27**	**0.27**	**0.29**	**0.31**	**0.33**	**0.36**	**0.38**	**0.40**	**0.41**	**0.40**	**0.40**	**0.39**	**0.37**	**0.34**	**0.32**	**0.31**	**0.30**	**0.27**	**0.23**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,400kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.19**	**0.18**	**0.16**	**0.15**	**0.15**	**0.14**	**0.14**	**0.14**	**0.14**	**0.15**	**0.16**	**0.18**	**0.20**	**0.23**	**0.25**	**0.26**	**0.25**	**0.25**	**0.24**	**0.24**	**0.24**	**0.24**	**0.23**	**0.24**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.24**	**0.24**	**0.24**	**0.25**	**0.25**	**0.25**	**0.26**	**0.28**	**0.29**	**0.32**	**0.34**	**0.37**	**0.38**	**0.40**	**0.39**	**0.38**	**0.37**	**0.35**	**0.33**	**0.31**	**0.30**	**0.29**	**0.26**	**0.22**

iv. Essential Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.23**	**0.22**	**0.21**	**0.20**	**0.18**	**0.17**	**0.17**	**0.17**	**0.18**	**0.19**	**0.20**	**0.22**	**0.23**	**0.25**	**0.27**	**0.27**	**0.27**	**0.26**	**0.26**	**0.26**	**0.25**	**0.25**	**0.25**	**0.25**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.25**	**0.25**	**0.25**	**0.25**	**0.26**	**0.27**	**0.28**	**0.30**	**0.32**	**0.33**	**0.35**	**0.38**	**0.39**	**0.37**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.29**	**0.27**	**0.26**	**0.25**	**0.24**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,600 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.23**	**0.22**	**0.21**	**0.20**	**0.18**	**0.17**	**0.17**	**0.17**	**0.18**	**0.19**	**0.20**	**0.22**	**0.23**	**0.25**	**0.27**	**0.27**	**0.27**	**0.26**	**0.26**	**0.26**	**0.25**	**0.25**	**0.25**	**0.25**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.25**	**0.25**	**0.25**	**0.25**	**0.26**	**0.27**	**0.28**	**0.30**	**0.32**	**0.33**	**0.35**	**0.38**	**0.39**	**0.37**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.29**	**0.27**	**0.26**	**0.25**	**0.24**

v. South Australian Power Networks distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,000 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.28**	**0.27**	**0.23**	**0.21**	**0.19**	**0.18**	**0.16**	**0.15**	**0.15**	**0.15**	**0.16**	**0.17**	**0.18**	**0.18**	**0.19**	**0.20**	**0.20**	**0.20**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.19**	**0.19**	**0.19**	**0.20**	**0.21**	**0.22**	**0.23**	**0.25**	**0.27**	**0.28**	**0.30**	**0.32**	**0.33**	**0.34**	**0.34**	**0.33**	**0.32**	**0.30**	**0.28**	**0.26**	**0.24**	**0.23**	**0.28**	**0.28**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,200 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.30**	**0.28**	**0.24**	**0.22**	**0.20**	**0.19**	**0.17**	**0.16**	**0.16**	**0.16**	**0.17**	**0.18**	**0.18**	**0.19**	**0.20**	**0.21**	**0.21**	**0.21**	**0.20**	**0.20**	**0.20**	**0.20**	**0.19**	**0.19**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.20**	**0.20**	**0.20**	**0.21**	**0.22**	**0.23**	**0.24**	**0.26**	**0.28**	**0.30**	**0.31**	**0.33**	**0.35**	**0.36**	**0.36**	**0.35**	**0.34**	**0.32**	**0.30**	**0.28**	**0.26**	**0.24**	**0.29**	**0.29**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Controlled Load usage – (1,800 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.25**	**0.25**	**0.25**	**0.25**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.18**

c) Controlled Load annual usage allocations

i. Ausgrid distribution region (kWh/year)

CL1 only	CL2 only	CL 1 and 2 (% of total)	
		CL1 (67%)	CL2 (33%)
2,000	2,000	1,340	660

ii. Endeavour Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (67%)	CL 2 (33%)
2,200	2,200	1,474	726

iii. Energex distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (29%)	CL 2 (71%)
1,900	1,900	551	1,349

iv. Essential Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (77%)	CL 2 (23%)
2,000	2,000	1,540	460

v. South Australian Power Networks distribution region (kWh/year)[215]

CL 1 only	CL 2 only	CL 1 and 2
1,800	NA	NA

215 Refer to section 6.b)v. for the daily usage profile for the TOU CL tariff.

7. Per-customer annual price determination

In accordance with s 16(1)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price for supplying electricity in specified distribution regions to small customers of the types set out below.

Per-customer annual price determination (all prices GST-inclusive)

Distribution region	Annual Residential Price without Controlled Load	Annual Residential Price with Controlled Load	Small Business Annual Price
Ausgrid	$1,372	$1,886	$6,663
Endeavour Energy	$1,575	$1,969	$5,652
Energex	$1,439	$1,717	$5,443
Essential Energy	$1,849	$2,212	$7,542
SA Power Networks	$1,715	$2,086	$7,963

DATED THIS [XX] DAY OF [MONTH] 2021

Australian Energy Regulator

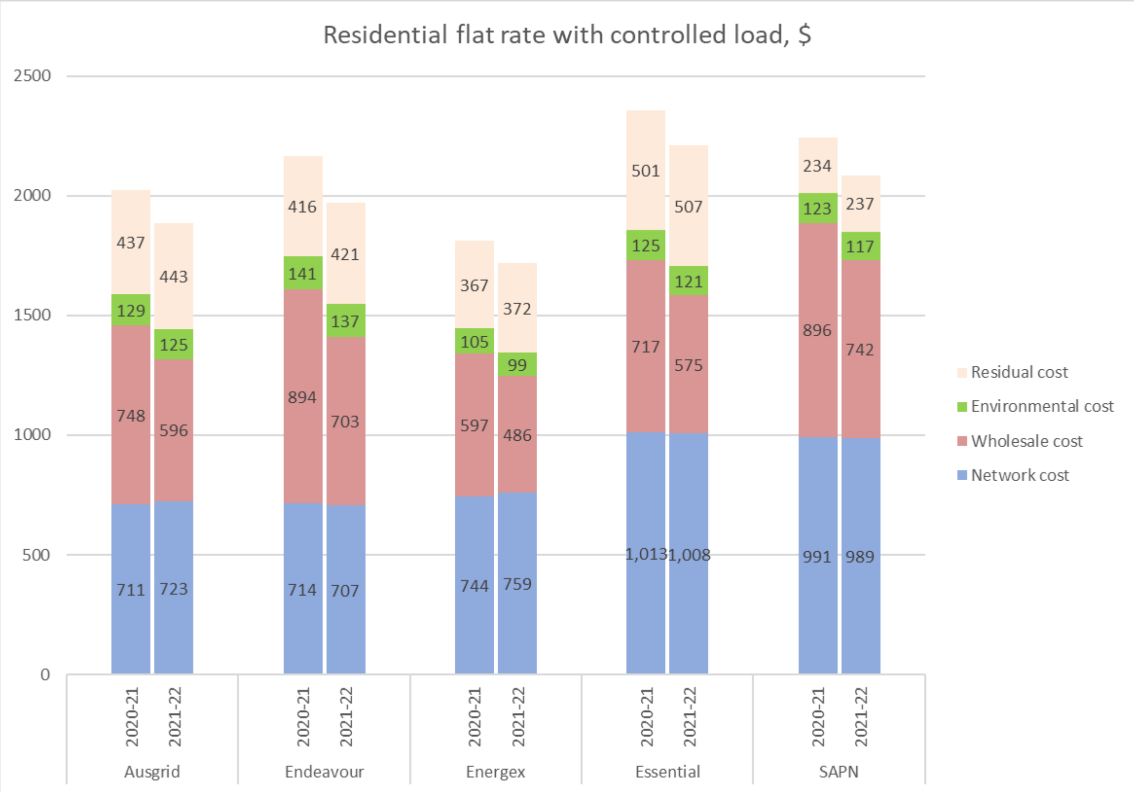
F DMO 2 to DMO 3 price movements

DMO price movements for residential flat rate tariff

Figure F1: Residential flat rate tariff

DMO price movements for residential flat rate with controlled load tariff

Figure F2: Residential flat rate with controlled load tariff



DMO price movements for small business flat rate tariff

Figure F3: Small business flat rate tariff