POSITION PAPER

Default Market Offer Price 2020-21

September 2019

AUSTRALIAN ENERGY REGULATOR

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Contents

Invitation for submissions

Interested parties are invited to make submissions on this Position Paper by 18th October

We will consider and respond to all submissions received by the date in our final decision.

Submissions should be sent to: DMO@aer.gov.au

Alternatively, submissions can be sent to:

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Australian Energy Regulator
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Submissions should be in PDF, Microsoft Word or another text readable document format.

We prefer that all views and comments be publicly available to facilitate an informed and transparent consultative process. Views and comments will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

1. clearly identify the information that is the subject of the confidentiality claim
2. provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential information will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014), which is available on our website.[1]

1 AER, https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information, viewed 17 September 2019.

Shortened forms

Shortened form	Extended form
ACCC	Australian Competition and Consumer Commission
ACS	Alternative Control Services
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ASX	Australian Securities Exchange
CARC	Customer acquisition and retention costs
CDR	Consumer Data Right
CER	Clean Energy Regulator
CL	Controlled load
COAG EC	Council of Australian Governments Energy Council
CPI	Consumer Price Index
DMO	Default market offer
DNSP	Distribution network service provider
DoEE	Department of Environment and Energy
DUOS	Distribution use of system
ECA	Energy Consumers Australia
EME	Energy Made Easy
ESB	Energy Security Board
ESCV	Essential Services Commission Victoria
EWOSA	Energy and Water Ombudsman South Australia
FiT	Feed-in tariff
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal

kW	Kilowatts
kWh	Kilowatt hours
kVa	Kilovolt amperes
LAR	Local area retailer
LRET	Large-scale Renewable Energy Target
MMO	Median 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
NMI	National Metering Identifier
NUOS	Network use of system
OTC	Over the counter
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic
QCA	Queensland Competition Authority
REPI	Retail Electricity Pricing Inquiry
RET	Renewable Energy Target
RIS	Regulatory Impact Statement
RPP	Renewable Power Percentage
RRO	Retailer Reliability Obligation
SAPN	SA Power Network
SME	Small and medium-sized business customers (enterprises)

SRES	Small-scale Renewable Energy Scheme
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

The Default Market Offer (DMO) came into effect on 1 July 2019. The DMO is a new rule which limits the price that retailers can charge electricity customers on default contracts known as standing offer contracts. A customer might be on a standing offer if they have never switched to a retailer's market offer, or if they were placed on one when their market offer expired.[2]

The AER's role is to determine the maximum price that a retailer can charge a standing offer customer each year. We refer to this as the DMO price.

Our DMO price determination applies to small business and residential customers on flat rate tariffs in areas where there is no other retail price regulation – South Australia, New South Wales and south-east Queensland.

The DMO price for each area also acts as a 'reference price' for residential and small business offers in that area. When advertising or promoting offers, retailers must show the price of their offer in comparison to the DMO/reference price. This aims to help customers more simply compare the price of different offers.

The Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Regulations) sets out the legislative framework for the DMO.

In April 2019, we published our first DMO price determination, which set the DMO price for 1 July 2019 to 30 June 2020. We refer to this throughout this paper as our DMO 1 determination.

This Position Paper is the first step in our process to determine DMO prices for the 2020-21 year. We refer to this as our DMO 2 determination.

Alongside this paper, we have also published a report by ACIL Allen Consulting (our Consultants) on the approach to forecasting the wholesale and environmental costs for 2020-21.

1.1 Context for this paper

The policy objectives for the DMO 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

2 Other causes for customers being on standing offers include poor or no credit history or for not engaging with the market for whatever reason.

- not reduce incentives for competition, innovation and market participation by customers and retailers.

In our DMO 1 determination we achieved these objectives by setting the DMO price at the 50th percentile (mid-way) point in the range between the median standing offer (the upper bound) and median market offer (lower bound) in each distribution zone.

We chose these upper and lower points because:

- The median standing offer was an indication of what the majority of standing offer customers were likely to be paying. Given the policy objective of reducing prices for standing offer customers, the DMO price would naturally have to be below this point.
- The median market offer provided a reasonable indication of the efficient costs of supplying a customer in each zone. To meet the policy objectives of allowing retailers to make a reasonable retail margin and not dis-incentivise competition, innovation and participation, the DMO price would need to be above this point.

1.2 DMO 2 determination

The primary consideration for our DMO 2 methodology is to maintain the balance of objectives we achieved in our DMO 1 determination.

Replicating our DMO 1 methodology is unlikely to achieve this outcome.

The Regulations require that from 1 July 2019 retailers' standing offer prices must not be higher than the DMO price in each zone. For most retailers (73 to 96 per cent), this has meant reducing their standing offer prices to comply with the cap. As a consequence, the median standing was 7-11 per cent lower in July 2019 than in October 2018, before the DMO was introduced.

Replicating our DMO 1 approach of selecting the mid-point in the median standing offer/market offer range, where the median standing offer is now around the DMO level, would therefore result in us automatically determining a price lower than DMO 1.

While this would reduce prices for customers, this does not align with our policy objectives. The DMO is designed to act as a fall-back for those who are not engaged in the market, and not be a low-priced alternative to a market offer.

Additionally, with the introduction of the DMO price cap reducing standing offer prices from an excessive level, the assumptions that led us to use the median standing offer as upper bound of our range are no longer relevant.

This Position Paper is the first step in our process to determine the DMO 2 price. It puts forward three possible alternative methodologies for determining the DMO price, for stakeholder consultation. In summary, these are:

1. **Option 1**, **adjusting our DMO 1 price to reflect forecast changes in retailers' input costs.** In summary, under this approach we would:

(a) adjust the environmental, wholesale and network components of the retail bill ‘cost stack’ to take into account the forecast changes for the 2020-21 period

(b) update the residual costs (including retail costs) in line with changes to the cost of inflation.

2. **Determining a new DMO price** by either:

(a) option 2, using a cost based ‘bottom up’ approach of determining the forecast efficient cost of each component of the retail cost stack, with an added allowance for retail costs and competition

(b) option 3, similar to our DMO 1 determination, establishing criteria to determine a new DMO price in relation to observed market offers (for instance, at a fixed percentage above the median market offer).

This paper also seeks stakeholder feedback on other key aspects of our DMO determination:

- The annual usage assumptions from which DMO prices are calculated, including the timing and pattern of the usage.
- Determining DMO prices for customers on time of use (TOU) and solar tariffs (which are not covered under the current Regulations). The Commonwealth Government has flagged its intention to amend the Regulations to apply to these tariffs for the 2020-21 determination. It has requested we consider these issues in the development of our determination.[3] The Government's request is included as Attachment B to this paper.

1.3 Preliminary AER views

At this preliminary stage, our preferred approach to determining the price for DMO 2 is option 1, to adjust the DMO 1 price based on forecast changes in input costs.

We determined our DMO 1 price using a pragmatic methodology based on retailers' observed market offer prices, rather than the more traditional approach of estimating a retailers' efficient costs using a 'bottom up' cost assessment approach.

Our 'top down' market prices approach was well-suited to meeting the policy goal of establishing a safety net price above the level retailers' efficient costs.

While it did not require a detailed breakdown of individual cost stack components, it did require careful judgement and analysis of how the DMO price intersected with market and standing offers.

Based on our analysis and the available evidence, we were satisfied in our Final Determination, that our DMO 1 price balanced the policy objectives.

[3] The Hon Josh Frydenberg, Treasurer, and the Hon Angus Taylor, Minister for Energy, Letter to the AER, 6 September 2019

- *Preventing unjustifiably high standing offer prices* – Our DMO 1 price achieved this outcome by being lower than nearly all retailers' standing offers, including those of the relevant local area retailer (LAR) in each distribution zone (that is, the retailer with the vast majority of standing offer customers).
- *Allowing retailers to recover their efficient costs* – The DMO 1 price was well above the in each distribution zone, which we considered was a reasonable indication of retailer's efficient costs.
- *Not reducing incentives for innovation, investment, competition and market participation by customers and retailers* – The DMO 1 price was significantly higher than most market offers in each distribution zone, meaning customers on a DMO would have a strong incentive to shop around and switch.

It is very early days, but based on preliminary stakeholder feedback and our analysis in our Final Determination, the available evidence we have so far, suggests that our DMO 1 price has appropriately balanced the policy objectives. Therefore, using DMO 1 as a starting point for DMO 2 seems a reasonable approach. The market is still responding to the introduction of the DMO and our proposed approach (option 1) would provide retailers and consumers with a degree of stability, in comparison to re-determining a new DMO price.

We intend to keep the DMO 1 price under review, and monitor how retailers and consumers respond to the DMO. As part of quality assurance process, we would cross-check the results of this approach with further analysis of retailers' costs and offers in the market to provide assurance the cap level is meeting the policy objectives. We will also rely on information provided by the ACCC through the course of their inquiry into the National Electricity Market (NEM).[4]

Sections 3 and 4 of this Position Paper provide more analysis of our preferred option and potential alternative approaches.

In regard to annual usage, our preliminary view is that the benchmark consumption figures we used for DMO 1 continue to be appropriate for use in our DMO 2 determination. We consider the figures remain representative, provide certainty to retailers and allow stakeholders to more easily compare what is occurring in the electricity market over time. Section 5 of this position paper discusses annual usage.

In regards to the application of the DMO price cap to TOU and solar customers, our initial view is that the DMO prices developed for flat rate/non-solar tariffs would be suitable to use for TOU and solar customers. Section 6 discusses these issues.

4 ACCC, *Inquiry into the National Electricity Market*, August 2019.

1.4 Next steps

Table 1 outlines our timetable for the development of DMO 2 prices.

Table 1: DMO 2 proposed timetable

Stage	Indicative Timing
Publish Position Paper	19 September 2019
Submissions open for 4 weeks	19 September - 18 October 2019
Bilaterals stakeholder discussions	September - October 2019
Public forum	November 2019
Publish draft determination	December 2019 - January 2020
Submissions open for 4 weeks	February 2020
Issue final determination	April 2020
Retailer implementation	May - June 2020
DMO 2020-21 in force	1 July 2020

2 Background

2.1 Who are we

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 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 driving effective competition where this is feasible, providing effective regulation where competition is not feasible, and equipping consumers to participate effectively in the market.

2.2 Policy context for the Default Market Offer

Under the NERL and the National Energy Retail Rules (NERR), all retailers are required to provide services to residential and small business customers under a standard retail contract if the small customer does not otherwise accept a market offer.[5] [6]

Standing offers were initially envisaged as a safety net following market deregulation, containing customer safeguards that are not required in market retail contracts, such as access to paper bills, minimum periods before bill payment is due, a set period for reminder notices, and no more than one price change every six months.[7]

The number of customers on standing offers has continued to reduce over time as more customers take up market offer contracts. However, around 681,000 residential customers across South Australia, south-east Queensland and New South Wales (between 9 and 14 per cent of all customers) are on standing offers. 88 per cent of these are customers of one of the 'Tier 1' retailers - AGL, EnergyAustralia and Origin Energy.[8]

Around 115,000 small business customers (15 to 25 per cent) are on standing offers in these areas. 86 per cent of these are with a Tier 1 retailer.

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5 NERL, s. 22(1); NERR, r. 16.

6 Retailers must publish, on their websites, a standard retail contract for all distribution zones in NEM regions that they operate in. Retailers' standard retail contracts must adopt the model terms and conditions set out in the NERR.

7 ACCC, *Retail Electricity Pricing Inquiry - Final Report*, June 2018, p. 240.

8 Ibid, pp. 141, 241–242; AER, *Annual report on compliance and performance of the retail energy market 2017-18*, pp. 29-30.

In 2018 the ACCC found standing offer contracts[9]:

- were no longer working as a safety net, as originally intended
- were unjustifiably expensive, with retailers having incentives to increase standing offer prices as a basis to advertise artificially high discounts
- penalised customers who had not taken up a market offer, acting as a ‘loyalty tax’.

To address these concerns the ACCC recommended the introduction of a default market offer that would cap what retailers could charge residential and small business standing offer customers.[10]

The Commonwealth Government accepted the recommendation and made the Regulations to give effect to the DMO, which came into effect on 1 July 2019.

The ACCC also recommended the introduction of a 'reference bill', against which retailers would have to compare the price of their offers.[11] This aimed to address confusing discounting practices by providing a consistent basis against which customers could compare the price of different offers.

Under the Regulations, the DMO price for each area also acts as a reference bill (or ‘reference price’) for offers in that area. When advertising or promoting offer pricing, retailers must show the price of their offer in comparison to the DMO/reference price.

Policy objectives

The ACCC was clear that the purpose of the DMO was to act as a fall-back for those who are not engaged in the market, and should not be a low-priced alternative to a market offer.[12]

It provided clear guidance about how the default offer price should be set. Specifically, it made clear that while the DMO price must reduce unjustifiably high standing offer prices:

- it should allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and customer acquisition and retention costs (CARC)
- it should not dis-incentivise competition, innovation and market participation by customers and retailers.

We balanced these objectives in our DMO 1 determination by setting 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 zone

9 ACCC, *Retail Electricity Pricing Inquiry Final Report*, June 2018, Chapter 12.
10 Ibid, recommendations 30 and 49.
11 Ibid, recommendations 32 and 50.
12 Ibid, Chapter 12.

this was the mid-point (50th percentile) in the range between the median standing and median market offer.[13]

Balancing these policy objectives remains a primary consideration as we commence the process of determining DMO 2 prices.

2.3 Our role

The AER's role in setting DMO prices is set out in Part 3 of the Regulations. These require that each year we determine:

- how much electricity a broadly-representative small customer of a particular type in a particular distribution region would consume in a year[14], as well as the timing and pattern of that consumption[15] (the model annual usage).
- a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of that type in that region (the DMO price).[16]

We must make these determinations for network distribution zones that are not otherwise subject to electricity price regulation.[17] These are in:

- New South Wales – Ausgrid, Endeavour Energy and Essential Energy network distribution zones
- South-east Queensland – Energex distribution zone
- South Australia – SA Power Networks (SAPN) distribution zone

The Regulations currently require we determine prices for the following supply arrangements and tariff types

- residential customers on a flat rate tariff
- residential customers on a flat rate usage tariff with controlled load (CL)
- small business customers (less than 100 MWh) on a flat rate usage tariff.

The Commonwealth Government has flagged its intention to expand the Regulations' 'maximum price' and 'reference bill' requirements to include customers with TOU tariffs (referred to as 'flexible' tariffs in the Regulations) and solar-specific offers.[18]

13 AER, *Final Determination – Default Market Offer Prices 2019-20*, April 2019.

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

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

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

17 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.

18 DoEE, *Regulation Impact Statement - the introduction of a Default Market Offer (DMO) price cap and reference bill on retail electricity prices*, April 2019.

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.

2.4 Default Market Offer – preliminary market observations

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

As the agency responsible for determining DMO prices each year, we consider it is necessary to understand any DMO-related impacts so that they can inform our future DMO price determinations.

As part of our recent Retail Market Affordability Report, we looked at prices of retailers' generally available standing offers and market offers following the introduction of the DMO prices on 1 July 2019, comparing this to offers available in October 2018 (before the DMO methodology was published) and June 2019, immediately before the introduction of the DMO.[19] The purpose of this analysis is to provide a snapshot of how the market has moved immediately following the DMO's introduction.

We emphasise that this analysis is preliminary, and that is too early to draw any strong conclusions about the impact of the DMO. This is because:

- The July 2019 dataset represents a static snapshot of a point in time around three weeks after the introduction of DMO prices. In a dynamic market, we expect electricity retailers will respond to competitors by adapting their offerings and pricing, meaning significant changes would become apparent over a longer period of time.
- Market offer prices will be influenced by changes in network prices which form a major component of retail pricing. From July 2019 network prices increased in some areas but reduced or remained flat in others. Changes in retail prices may be explained in part by changes in these costs.

19 AER, *Affordability in retail energy markets - 2018-19*, September 2019.

2.4.1 Offer price analysis – key observations

Our analysis looked at changes to highest, lowest and median market offer prices, before and after the introduction of the DMO on 1 July 2019, as well as changes to discounting practices. The main observations were:

- As expected, the price of the majority of standing offers and high priced market offers from October 2018 have reduced to the DMO level.
- The median market offer price has not changed significantly throughout October 2018 to July 2019 but we have observed a reduction in the number of market offers.
- We have seen a slight reduction in the price of the lowest market offers for the residential flat rate (up to 3 per cent) compared to October 2018 but a more significant fall for small to medium businesses (between 6-17 per cent).
    - This appears to be largely driven by Tier 2 retailers. Tier 1 retailers have removed some of their lowest priced market offers in some regions.
    - In contrast, from June 2019 the price of the lowest market offers have increased (up to 6 per cent) in the Essential and SAPN zones, and remained flat or marginally increased in the other zones.
    - However, the prices for small businesses have mostly reduced post-DMO.
- Retailers have significantly reduced the number of offers with conditional discounts (to between 13-25 per cent of all their market offers (down from 47-56 per cent).
- We have seen a reduction in the size and prevalence of discounts but this does not necessarily mean consumers are worse off. The reference price Rules prevent retailers from advertising artificially high discounts, and our analysis shows annual prices have reduced to the DMO level.
- Slightly different trends emerge in the comparisons between October 2018 and July 2019, and June 2019 (immediately before the DMO introduction) to July 2019.
    - This may reflect different pricing strategies by retailers reacting early in June 2019 in anticipation of DMO changes.
- Overall, the trends suggest retailers used the introduction of the DMO to rationalise their range of market offers and, in many cases, simplify their offerings by moving away from conditional discounts. We will continue to monitor these changes over the longer term.

3 Approaches to setting the DMO annual price

Under part 3 of the Regulations, we are required to set the DMO price each year for standing offer customers on residential flat rate and small business customers. This chapter outlines the approach we are proposing to use for DMO 2 and the alternatives we have considered.

Applying our DMO 1 approach (of selecting the mid-point in the median standing offer/market offer range) for DMO 2 would further reduce the DMO price. This is because standing offers, which DMO 1 used as the upper bound, have reduced to the DMO 1 level. Since the DMO was introduced in July, the median standing offer prices are 7-11 per cent lower than in October 2018. The DMO has reset the upper bound of standing offer prices, and therefore reusing the DMO 1 methodology for DMO 2 would automatically result in a lower price. As a result, we need to develop an alternative approach for DMO 2 that continues to meet our policy objectives.

Our research has identified three broad pricing methodologies for setting the DMO annual price for 2020-21 and onwards.

Our preferred option is a **price based approach using DMO 1 (option 1).** We would take the DMO annual price we set for 2019-20 and update it for our forecast changes in efficient costs of supply for 2020-21.

Alternatively we could **re-calculate all components of the DMO price** by either reassessing retail market prices or undertaking a bottom up cost assessment. In summary:

- **Price based approach using observed market offers in 2019-20 (option 2).** We would use market offer prices, such as the median of a selection of market offer tariffs, or a set percentile of the highest market offers, to select a price point in 2019-20. We would then update this price point for our forecast of changes in input costs for 2020-21 to set the DMO annual price.
- **Bottom up cost assessment (option 3)**. This is the most well-known approach and has been used by jurisdictional regulators for retail price regulation. This involves the regulator estimating each main cost component that a retailer would incur for supplying services to consumers and summing this up to set the price level. For our purposes, this approach would also require us to determine what amount above the estimate of efficient costs we should allow to meet our policy objectives.

  We explore these approaches in more detail in the following section of this paper.

3.1 Option 1 (preferred): Price based approach using DMO 1

Based on our analysis and the available evidence, we were satisfied in our Final Determination, that the DMO 1 price balanced the policy objectives. In our Final Determination, we explain that the DMO 1 price achieved the policy objectives by:

- Preventing unjustifiably high standing offer prices. The DMO 1 price was lower than nearly all retailers' standing offers, including that of the relevant LAR in each distribution zone.[20]
- Allowing retailers to recover the efficient costs of providing services including a reasonable retail margin and CARC. The DMO price was well above the median market offer (i.e. our proxy for a retailer's assumed efficient costs) in each distribution zone.
- Not dis-incentivising innovation, competition and market participation by customers and retailers. The DMO price was significantly higher than most market offers in each distribution zone, meaning customers on a DMO price would have a strong incentive to shop around and switch.

Based on the information currently available at this stage, we consider these objectives can continue to be met if we carry forward the DMO 1 price into the next determination period (2020-21) by adjusting the price for forecast changes in the underlying cost of supply. This includes:

- **The wholesale energy, environmental and network costs.** These costs will need to be assessed annually as they are subject to both regular and significant change and these changes are beyond the reasonable control of retailers.
- **The remaining retail bill costs** we are proposing to index by Consumer Price Index (CPI).

We are mindful that this approach, in exceptional circumstances, may not capture material and unavoidable changes in costs caused by major changes to the industry, such as regulatory reform. **We are therefore proposing as part of the determination process, where appropriate, to make specific adjustments to the DMO price each year to account for these cost changes. The criteria and process we use for this has been set out in step change assessment framework** that will pass through any additional material cost changes to an efficient and prudent retailer's cost of supply expected to be incurred during the determination time period. The framework would only allow consideration of these costs in the development of our annual DMO price determination, and would remain in place for the determination period.

Our proposed forecasting methodology for assessing the retail bill costs, including the proposed step change framework, is set out in Section 4.

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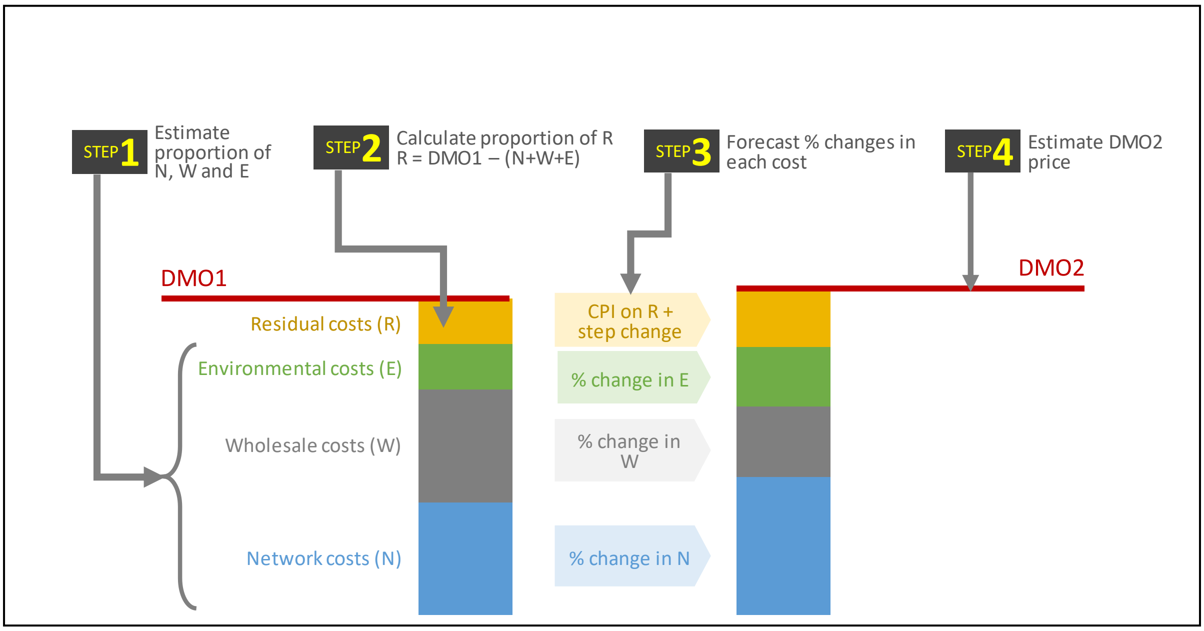
20 The Local Area Retailer is the retailer (always a Tier 1) that acquired the region's customer base at the time of retail privatisation. Most standing offer customers are with their LAR.

Figure 1 below outlines our proposed approach.

Figure 1: Illustrative example of DMO 2 price assessment methodology



It is very early days of the implementation of the DMO. The information available to us at this stage, and for the Final Determination, suggests the DMO 1 is an appropriate starting point for DMO 2. Whether the DMO 1 price continues to meet our policy objectives is in part contingent on retail market performance. Importantly, we are mindful that the retail market is still in the early stages of adjusting to the recent regulatory changes and reflecting the underlying costs of supply for the 2019-20 period. We are therefore monitoring how the market performs and the impact the DMO price has on market outcomes.[21]

Before reaching a decision on the DMO 2 price, we therefore plan to cross-check our DMO price against market offer prices and an indicative cost stack. This indicative cost stack will include an estimate of retailer costs. We will rely on publicly available retail costs benchmarks, taken by other regulators, such as Independent Competition and Regulatory Commission (ICRC), Queensland Competition Authority (QCA) and Essential Services Commission Victoria (ESCV). We will also rely on information provided by the ACCC through the course of their inquiry into the NEM. For example, the most recent ACCC report provided detailed estimates of the actual costs faced by retailers historically, such as a detailed breakdown of the retail cost component.[22]

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21 AER, *Affordability in retail energy markets*, September 2019; This report includes our initial assessment of how retail prices have changed since the DMO was introduced.

22 ACCC, *Inquiry into the National Electricity Market*, August 2019.

We consider this approach strikes the right balance between the importance of ensuring the DMO price remains in line with changes in costs and providing industry with stability. This approach aims to maintain the same level of consumer protection we provide in DMO 1 for DMO 2. It is very early days but based on preliminary stakeholder feedback and our analysis for our Final Determination, the available evidence we have so far, suggests that our DMO 1 price has appropriately balanced the policy objectives.

The DMO is a significant regulatory reform to the retail market. At this early stage, retailers and consumers are still responding to the new rules. Adapting our DMO 1 approach will provide a degree of regulatory stability while the new rules are bedding in.

Also, in our view, the alternative approaches we have identified would not suit our policy objectives. We discuss these below.

3.2 Re-calculate all components of the DMO price by either reassessing the market or a bottom up cost assessment

Alternatively we could reassess the DMO price for 2020-21. We consider there are two approaches available, these are the top down market price and the traditional bottom up methodology.

This approach would be necessary if we consider:

- we cannot carry forward the DMO 1 price as it no longer meets our policy objectives, and/or
- there is a more appropriate pricing methodology for our purpose.

In our view, there are material challenges in applying these alternative methodologies to calculate the DMO price.

3.2.1 Option 2: Top down market assessment

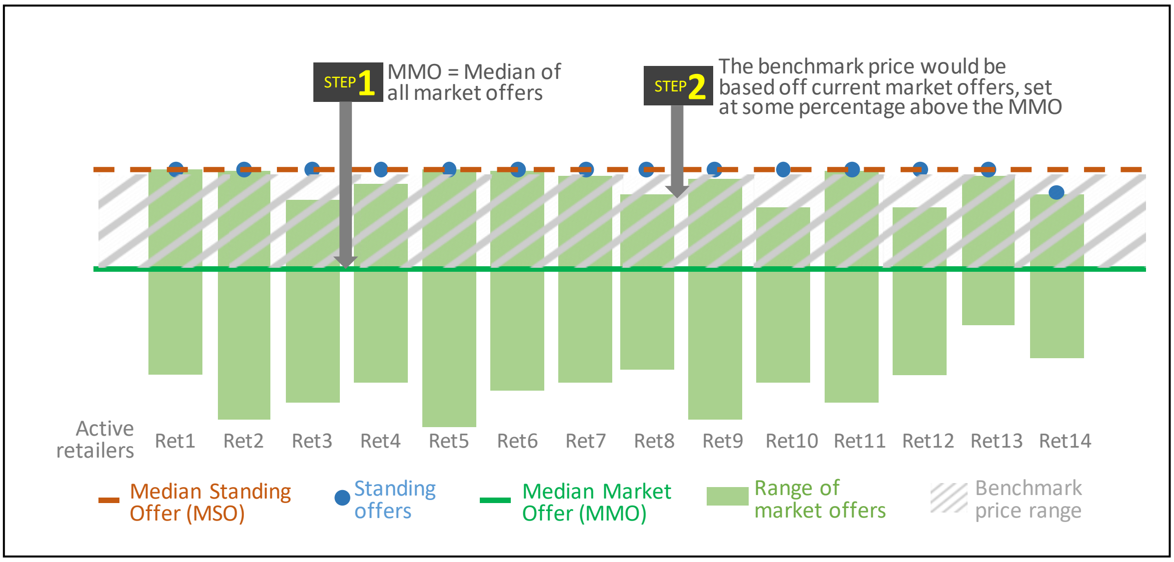
This approach has two aspects; firstly, for each customer type in each region, we would select a DMO price point based on observed market prices, and then adjust the price point to take into account the underlying changes in costs of each retail price component.

This approach is similar to the DMO 1 price methodology. Instead of using the spread of standing offers and market offers to derive the DMO price, we would use observed market offer prices to derive a benchmark(s).

For example, if we assume that the median market offer is a suitable proxy for the efficient costs of supply, to meet our policy objectives for the DMO, we could set the DMO price at a set percentage above the median market offer.

Under this approach a price is derived from current market offers rather than the market offers for the period in which the price would apply. As such, to ensure this price point reflects the underlying costs of supply for the subsequent year, we would then assess forecast changes of costs to determine if the price point requires further adjustment.

Figure 2: Illustration of top down market offer based assessment



This approach has similar benefits to the now completed DMO 1 top down approach in that it derives an appropriate price from the market offers rather than just relying on cost forecasting. Changes in retail prices in the competitive segment could be a good indicator of retailer costs.

However, we note that there is a significant risk of retailers causing market distortions and gaming the offer spread in response to this methodology. For instance, by attempting to influence the DMO price through pricing decisions on market offers. Further, many other factors drive pricing decisions of retailers other than costs. For instance, we would need to consider how market offers might have changed in response to other drivers such as the introduction of the DMO 1.

At these early stages of the introduction the DMO price, retailers and consumers are still responding to the DMO. Therefore, we expect market offer prices to continue to change as the reforms bed in.

These challenges mean that it may be difficult to calculate a reliable annual DMO price using market offers alone.

3.2.2 Option 3: Detailed bottom up cost assessment

For each customer type, the bottom up cost assessment forecasts the annual retail bill by assessing each individual cost component to construct the total cost of supply. In effect, this approach seeks to create a cost stack of efficient costs that retailers incur in supplying electricity.

For the purposes of the DMO price, this can be represented in the following equation form:

$$Wholesale\ energy\ costs + Environmental\ costs + Network\ Costs \\ + Residual\ costs\ (\ including\ Retail\ costs) = DMO\ price$$

A bottom up assessment will therefore require the residual costs identified in option 1 to be re-assessed and determined.

As the AER currently has no information gathering powers for the DMO price determination, we would need to rely on publicly available information to assess this cost component. Subject to the voluntary provision of this information or an external independent resource (such as the ACCC publishing this information as a part of their monitoring role), we would likely need to rely on current regulatory cost assessments, such as the Essential Services Commission's Victorian Default Offer (VDO) or the QCA pricing decision, to determine efficient retailer costs. In the event that the AER receives information-gathering powers for the DMO, we will nonetheless require a substantial lead in time to refine our retailer information requirements before the information can be applied to a bottom up cost assessment.

A bottom up cost assessment is traditionally used to identify efficient costs. The DMO is not aiming to be set at the lowest price in the market, or even close to the lowest offer. Therefore, to use this method for our purposes, we would need to undertake analysis to determine how far above efficient costs we should set the DMO price. This analysis would most likely involve similar top down price analysis that we undertook to set the DMO 1 price.

Given the DMO is not aiming to identify efficient costs; this option does not appear proportionate for our policy objectives.

Stakeholder questions:

1. For our DMO 2 price determination, do you agree with our proposed approach of carrying forward the DMO 1 price whilst taking into account the changes in forecast changes in input costs?
2. Do you consider there is an alternative methodology to determine DMO 2 that better meets our policy objectives?

4 Forecasting changes in the cost of supply

In our preferred approach, we propose to carry forward the DMO 1 price by assessing the changes in wholesale, environmental and network costs for each DMO price for each customer type in each distribution region.

There are a broad variety of retailers present in each jurisdiction that will have different approaches to managing the underlying retail bill costs. Our assessment of retail bill costs requires us to assess a representative retailer that broadly reflects efficient operations of a retailer in the jurisdictions in which the DMO applies. As a result of this, we are therefore mindful that our cost forecasts may not be the exact costs faced by a particular retailer.

We consider an appropriate retailer benchmark is an efficient, prudent and risk adverse retailer with an established customer load. Our pricing assessment has therefore made a number of assumptions as to how this representative retailer manages their costs of supply. As discussed in more detail below, these assumptions will be an important driver of the DMO 2 price, and pose a number of challenges as to how we reasonably reflect how market fundamentals may change in the DMO 2 pricing period.

This initial forecast assessment will have three features:

1. ACIL Allen Consulting will forecast the changes in wholesale and environmental costs from 2019-20 to 2020-21. Using the same forecasting methodology, this assessment will require an assessment of the 2019-20 costs and 2020-21 costs to determine the rate of change.
2. We will assess network costs to pass through changes in network tariffs. We will determine, for each customer type in each distribution network, the change in annual network costs from 2019-20 to 2020-21.
3. Following these assessments, we are proposing to index the remaining DMO bill costs by CPI.

As shown in Figure 1, we are calculating the change in costs from DMO 1 to DMO 2, rather than the absolute level of costs. However, in order to calculate the change, the cost assessments set out above will provide a cost stack of the above four cost components for DMO 1. We will then use the same methodology to forecast the changes in costs for DMO 2.

Finally, as a part of our determination process we are proposing a step change assessment framework to pass through any additional material cost changes to a retailer's cost of supply that have not been captured by our initial cost forecast assessment.

Set out below is our proposed forecasting methodology for each of these costs components.

Consultant report on wholesale and environmental cost forecasts

For the wholesale and environmental cost forecasts, our Consultant report provides a detailed overview of these cost components, the forecasting options available and a recommended forecasting approach.

As outlined in section 5 of the Consultant report, the proposed approach has proven to be a reliable indicator of costs over the eight years it has been applied in the annual QCA Pricing decisions.

In assessing the forecasting options available to the AER, we requested our Consultant to explore the merit of a more simplified cost forecasting approach along with the traditionally detailed approach. Whilst our Consultant has recommended a detailed forecasting approach for DMO 2, the consultancy report also recommends we continue to explore the merit of applying a more simplified forecasting approach in later DMO price determination periods.

Our approach for the wholesale and environmental cost components is set out below and is informed by this report.

Stakeholder questions:

3. Does our representative retailer broadly reflect retailers in each of the markets the DMO will apply?
4. Do you consider there is merit in considering a more simplified forecasting methodology, such as the contract portfolio index, in future DMO pricing decisions? (As outlined in the ACIL Allen Consulting report)

4.1 Wholesale electricity costs

Retailers are responsible for purchasing electricity from the wholesale energy market to supply electricity to customers. Wholesale electricity in eastern and southern Australia is traded through the NEM, where supply and demand conditions determine prices every thirty minutes – the spot market.

The spot market price is driven by various factors affecting the supply-demand balance at any point in time. Whilst some supply-demand factors will result in long term impacts on the spot price, such as the availability of generation capacity or the change in customer load, short term changes in supply and demand conditions, such an unplanned plant availability or a weather event, also arise and in turn cause market volatility.

Whilst all retailers must purchase energy through the spot market, retailers largely charge customers a set price for the supply of electricity. At a point in time this set price may not reflect the actual prices the retailer pays in the spot market. When this occurs, the retailer takes on a risk to absorb the difference in these costs. The retailer mitigates this risk by entering into electricity futures contracts traded on the Australian Securities Exchange (ASX) or negotiated directly between the parties (over-the-counter), to lock in future electricity prices. Alternatively, participants can balance out the risks across each market by having both generation and retailing businesses.

As the futures contract market is a reflection of expectations of spot market outcomes, at any point in time the traded contract price will also depend on the expected supply and demand conditions and will therefore vary across time as the market's expectations change.

In addition to the hedging costs and the residual spot market exposure, the retailer will also need to pass on costs associated with the additional services provided in the NEM. These costs include market fees such as the Australian Energy Market Operator (AEMO) charges and ancillary service charges for services that manage the power system's safety, security and reliability.

4.1.1 Our approach to forecasting change in wholesale energy costs

This section provides an overview of the factors we will need to consider when forecasting the changes in wholesale energy costs. The Consultant will provide the forecast of the wholesale energy costs. The discussion below should be read in conjunction with the Consultant report that provides a detailed overview of the proposed forecasting methodology for DMO 2.[23]

This section is comprised of two parts; our proposed methodology to forecast energy purchase costs (contract futures costs and the residual exposure to the spot), and then an overview of the additional costs of electricity supply.

4.1.2 Forecasting energy purchase costs

As set out in the Consultant report, a retailer's energy purchase costs are estimated based on a market based approach which comprises of a combination of hedging and spot market costs. As outlined in the Consultant report, market based approaches make use of financial derivative data due to the availability and transparency of this cost information. This does not imply that retailers only use financial derivatives to manage their risk.

This approach has three key parts:

1. The simulation of a representative retailer's energy supply requirements (the customer load profile) for each customer type.
2. The resulting efficient hedging requirement and approach, or the contracting strategy
3. The cost of meeting the retailer's hedging requirement and the residual exposure to forecast spot market price outcomes.

Each of these parts are discussed below.

23 ACIL Allen Consulting, *Default Market Offer, Wholesale and Environmental costs*, September 2019.

1. The retailer's customer load profile

A retailer’s energy supply requirement is reflected through its customer load profile. 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.

A specific retailer’s customer load profile may vary between retailers depending on the type of customers they have. For example a retailer with small to medium sized industrial business customers may have a significantly different load profile to a retailer with predominantly residential solar customers.

Whilst we are mindful of this, we must determine a profile that is broadly representative of each of the three customer types under assessment. We consider the total consumption in the distribution zone (Network System Load Profile or NSLP)[24] and the Controlled Load Profile (CLP) provides the best estimate for these customer types. These profiles provide a good indicator of a broadly reflective retailer load. Further detail on the NSLP and CLP is outlined in the Consultant report. As discussed in the Consultant report a key challenge is how these historical load profiles should be adjusted to reflect the forecast load in the DMO 2 pricing period.

In our view, there is limited value in separating the NSLP into residential and small business customer profiles. This is due to the broad variety of customers that represent a residential or small business customer load. For example, in the case of small business customers if we were to construct a representative load profile we would need to make assumptions around when the typical business uses electricity and the likely level.

2. The retailer’s hedging requirement and approach

A retailers energy purchase costs is in part determined by its acquisition of electricity futures contracts, or for a vertically integrated entity, the internal allocation and valuation of generation capacity through a natural hedge (internal transfer pricing).

A retailer’s hedging strategy will depend on a variety of factors such as:

- their internal management of generation and other energy assets, risk management strategies
- the nature and scale of their retail customer load
- when customers are contracted (timing of contract purchases will be influenced by the retailer’s certainty regarding the customer load profile).

An appropriate hedged position is based on the retailer’s expectation of wholesale spot price outcomes for the relevant period. The retailer will apply a hedging strategy to achieve the correct hedging product mix and in turn the overall anticipated exposure to the spot.

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24 AEMO, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Metering/Load-Profiles, viewed 17 September 2019.

We are required to determine a hedging strategy that broadly reflects an efficient retailer's hedging operations. We consider the appropriate benchmark for a broadly reflective retailer's hedging strategy is a risk adverse retailer with an established customer load. The retailer will undertake a simplified hedging approach and will hedge their forecast load prior to the commencement of the pricing period.

The Consultant report discusses the hedging approach in further detail. In summary:

- The approach assumes that a prudent and efficient retailer will completely hedge its forecast customer load prior to the commencement of the pricing period.
- It is assumed the hedge book consists of a portfolio of base, peak and cap quarterly contracts. Multiple hedging strategies would be tested by varying the mix of base/peak/cap contracts for each quarter.

The retailer will gradually build up the hedge book requirement. The book build in this approach is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price. As outlined in the Consultant report, no time limit is proposed to be placed on the book build – it would start when the first observable trade is made in the ASX Energy data.

Alternative retailer hedge strategies

As noted in the Consultant report, the representative retailer is presumed to implement a simple hedging requirement and approach. In our view this represents a base line in hedging costs. We note that where a retailer has an established customer load, more sophisticated retailers may elect to undertake a different hedging strategy such as a more risky approach. The decision to take on this additional price risk is based on the retailer’s view that the retailer’s wholesale energy costs could be lowered or optimised by applying a different hedging strategy.

We consider the above characterisation of more sophisticated hedging strategy is appropriate as a key objective of a retailer is to retain and acquire new customers. In carrying out this objective in a competitive market, a retailer will aim to minimise underlying costs to provide sustainably competitive offers and contracts in the market.

For example, so long as the retailer’s customer load is certain, a retailer would likely only defer purchase of futures contracts if they considered there was value in doing so, i.e the retailer expects the future spot prices to be below the contract price. This approach would only be undertaken if it was likely to improve the financial position of the retailer rather than increasing the underlying cost of supply.

3. The cost of meeting the retailer's hedging requirement and the residual exposure to forecast spot market price outcomes

Calculating the cost of futures contracts

To determine the cost of contracting the required volumes of base, peak and cap futures contracts we will need to use publicly available pricing information. We consider the best available pricing information are the ASX futures contract markets.

As outlined in the Consultant report, the volume of trades in South Australia is very small and there are gaps in the data for some products, where trade is absent for a longer period of time. Therefore, the assessment may be informed by the broker data for over-the-counter (OTC) contracts to fill in those gaps wherever required.

For each region, based on the ASX volume and pricing information available for the relevant contract types, the representative contract price will be the trade weighted average of the ASX energy daily settlement prices since the relevant contract was listed.

This approach reflects our view that a prudent retailer will acquire the required contract volumes gradually in the lead up to the pricing period, rather than all at once. As outlined in the Consultant report, when a contract commences trading on the ASX, trading volumes traditionally increase up to the point when the hedge book build is complete.

The forecast spot price outcome

Along with the cost of contracting a fully hedged position, a retailer may also have residual exposure to the spot market due to unexpected changes in demand or moderate increases in spot prices that are not completely hedged such as cap contracts.

As outlined in the Consultant report, the spot price forecast includes forecasting half hourly wholesale spot prices – generally by simulating the NEM using a proprietary wholesale energy market model. The system load for each region of the NEM satisfied by scheduled and semi-scheduled generation would be used to model the regional wholesale electricity spot prices. The NSLPs and CLPs would be used to model the half-hourly cost of procuring energy for the distribution zones.

Further detail of this modelling approach can be found in the Consultant report.

4.1.3 Additional electricity costs of supply

In addition to energy purchase costs we will also need to take into account the additional costs incurred by retailers. These costs are outlined in

Table 2 below and discussed in the Consultant report.

Table 2: Additional costs of supply

Cost	Description	Source proposed for DMO 2
Industry fees	NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability, the National Transmission Planner and Energy Consumers Australia.	AEMO latest budget report[25]
Ancillary services fees	AEMO charges for the costs of these services	AEMO's most recently reported 52 week ancillary service costs[26]
Prudential costs	This includes the prudential costs of both AEMO settlement and ASX futures initial margin requirements.	ASX, AEMO and Consultant forecasts[27]
Network losses	Energy costs will need to account for distribution and transmission losses	AEMO loss factors reports[28]
Reliability and Emergency Reserve Trader (RERT) costs	AEMO charges to maintain power system reliability and system security using reserve contracts.	AEMO historical RERT costs[29]

Stakeholder questions:

5. Do you consider the use of the NSLP and CLP is an appropriate proxy to model a representative retailer's load profile?
6. Do you consider the proposed hedging strategy is appropriate?
7. Do you consider there are improvements to the ACIL Allen Consulting's proposed wholesale cost forecast methodology?

29 AEMO, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT/RERT-Reporting, viewed 17 September 2019.

4.2 Environmental costs

Environmental schemes at both a Commonwealth and State level require retailers to allocate electricity supply from renewable sources and improve customer energy efficiency. The costs of these schemes incurred by the retailer form the environmental 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 is the cost of complying with the RET. Retailers have an obligation to purchase renewable energy certificates from generators and surrender them to the government in proportion to the overall amount of energy consumed by their customers. The costs to purchase these certificates are passed on to all customers. The RET scheme is comprised of two components:

1. **Large-scale Renewable Energy Target (LRET)**

   The overall cost of meeting the LRET obligation is the cost of acquiring the necessary amount of large-scale generation certificates (LGCs). The number of LGCs under the LRET required to be surrendered by a retailer each year is determined by the amount of electricity their customers have consumed in that year, and a Renewable Power Percentage (RPP) set annually for a calendar year by the Minister for Energy.[30]

2. **Small-scale Renewable Energy Scheme (SRES)**

   The small-scale technology certificates (STCs) under the SRES reflect the installation of and generation by eligible solar hot water or small generation, which is generation from rooftop solar photovoltaic (PV) units. Retailers have the option of either purchasing an STC on the market or from the clearing house. The liability of STC surrender is estimated annually for a calendar year as the Small-scale Technology Percentage (STP).[31]

In addition to the RET costs, a retailer typically also passes through jurisdictional scheme costs, which include energy efficiency incentives to assist consumers in reducing their energy consumption and to drive take up of solar PV generation. For some schemes, discussed below, the distribution network businesses pass these costs on to retailers through their annual tariffs.

- In the New South Wales distribution zones, the distribution network service providers (DNSPs) recover the cost of contribution towards the Climate Change Fund scheme.
- In Energex the applicable Queensland Solar Bonus Scheme is currently funded by the Queensland government, and the DNSP does not recover costs from its customers. [32] As on the publication of this Position Paper, we do not have any information on whether the government's subsidy would continue beyond 2020. If the mechanism changes to

30 CER, http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage, viewed 17 September 2019.

31 CER, http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage, viewed 17 September 2019.

32 Energex, AER Approved - Energex Pricing Proposal 2019-20, May 2019.

recovering the costs under the scheme partly or fully through the DNSPs, we would make the necessary changes in our assessment.

- In SAPN, the DNSP is obliged to make PV feed-in tariff (FiT) payments to qualifying customers that have solar PV generators under jurisdictional scheme obligations (JSO), and recover the cost from all its customers.[33]

We propose to assess these costs as part of network cost pass throughs. We have discussed the methodology to estimate these costs in Section 4.3.

For other energy saving schemes, the costs are incurred by the retailer directly. Retailers then pass through these costs on to the whole customer base.

- New South Wales and South Australia have jurisdiction specific schemes where the costs are directly recovered from the retailer. In New South Wales distribution zones, retailers are required to purchase certificates to fund New South Wales Energy Savings Scheme (ESS).[34] In the SAPN zone, the retailers are required to provide incentives to households and businesses by offering energy audits and undertaking energy efficiency activities under the Retailer Energy Efficiency Scheme (REES).[35] As outlined in the Consultant report, we propose to assess these costs as part of the environmental cost forecast.
- We note that in the SAPN zone, in addition to the FiT recovered through the network tariffs there is a retailer PV FiT scheme, where retailers determine the amount of FiT payments and mechanisms for recovery of costs. Therefore, we consider these costs would be included in retail costs.[36] We propose to assess these costs as part of the residual cost component, which has been discussed in Section 4.4.

4.2.1 Our approach to forecasting change in environmental costs

This section provides an overview of the factors we will need to consider when forecasting the changes in RET energy costs. Our Consultant, will provide the forecast of the cost of meeting RET and the environmental costs not recoverable through network tariffs. The discussion below should be read in conjunction with the detailed approach for environmental costs outlined in the Consultant report.

The approach to estimate RET costs is comprised of three steps:

1. Estimating RPP and STP

As outlined above, RPP and STP are set for the calendar years. As set out in the Consultant report, the actual values of the renewable percentages for the current

33 SAPN, *AER Approved - SA Power Networks Pricing Proposal 2019-20*, May 2019.
34 IPART, https://www.ess.nsw.gov.au/Home/About-ESS/Overview-of-the-ESS, viewed 17 September 2019.
35 Essential Services Commission of South Australia (ESCOSA), https://www.escosa.sa.gov.au/industry/rees/overview, viewed 17 September 2019.
36 SA Government, https://www.sa.gov.au/topics/energy-and-environment/energy-bills/solar-feed-in-payments, viewed 17 September 2019.

calendar year set by the Minister of Energy and the estimated values for the next calendar year would be used in the cost assessment. The next calendar year's percentages would be estimated using data published by the Clean Energy Regulator (CER).

2. **Estimating LGC and STC prices**

   As set out in the Consultant report, a retailer's RET costs would be estimated based on a market based approach which would comprise of average LGC prices and clearing house STC prices. The average LGC prices would be estimated using LGC forward prices provided by an energy brokerage company.

3. **Estimating RET costs**

   RET costs for the relevant calendar years would be estimated by multiplying the expected relevant average certificate prices and percentage values. To determine RET costs for a financial year, the costs for the two calendar years would be averaged. Since the cost is expressed as a cost per MWh, it is applicable across all retail electricity tariffs.

Stakeholder questions:

8. Do you consider there are improvements to the ACIL Allen Consulting's proposed environmental cost forecast methodology?

4.3 Network costs

The network costs in a retail electricity bill represents the cost of transporting electricity through the transmission and distribution network grid.

Under the National Electricity Rules (NER), the AER regulates network charges, which cover the efficient costs of building and operating electricity networks, and provide a commercial return to the stakeholders that fund the business. It approves network tariffs that the DNSPs annually set for customer use of the network. It is then up to the retailer to determine how these network tariffs are translated into a customer's tariff structure.

These network tariffs are typically constituted of two components. Firstly, Network Use of System (NUOS) charges that largely recover the costs of providing transmission and distribution of electricity through the network infrastructure. In addition these include the costs of jurisdiction specific schemes which are recovered across the entire customer base, which are outlined in Section 4.2.

Secondly, metering charges to recover the cost of providing the Alternative Control Services (ACS), relating to the DNSP's installation and maintenance of type 5 manually read interval meters and type 6 accumulation meters.[37] This is a legacy cost from when the DNSP was solely responsible for the installation and maintenance of meters. With the introduction of the 'Power of Choice', it is now the responsibility of the retailer to install smart meters. However, until a consumer's meter is replaced with a digital meter, the DNSPs are required to provide for accumulation meters. These ACS metering charges will therefore be included in our assessment of network costs.

4.3.1 Our approach to forecasting change in network costs

In assessing the network costs, we consider the representative retailer will pass through the applicable network tariff to the customer. In determining the changes in network costs, we therefore propose to pass through changes in the applicable network tariff, as outlined in Table 3.

Table 3 below sets out the current network tariffs that we propose to apply for each customer type in each distribution region. As discussed in Section 6, we consider the representative residential customer for general usage is a standard flat rate customer with an accumulation meter. We will therefore only have reference to relevant non-TOU network tariffs.

Table 3: Network tariffs to assess the change in network costs

Distribution zone	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 closed
Endeavour	Residential Energy (anytime) N70	Controlled Load 1 N50 Controlled Load 2 N54	General Supply TOU N84
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

37 AEMC, *Expanding competition in metering and related services rule change*, 2015, p. 3.

SAPN	Residential Single Rate (RSR) (flat rate fixed and variable tariffs)	Residential Single Rate (RSR) (CL variable tariff)	Business single rate (BSR)

Network tariffs are adjusted through an annual pricing review, where the network service provider proposes tariffs for the next financial year based on the annual change in revenue set in the relevant determination, as well as other factors[38].

For all jurisdictions, aside from Victoria, the AER usually assesses and approves the next financial year's tariffs by mid-May of each year. However, this process is further delayed where the AER is also determining a network business' five year forward revenue (revenue reset).[39]

Given the timing of annual network tariff approvals, particularly for the distribution zones undergoing a revenue reset, our cost assessment may not be able to incorporate the actual changes in annual tariffs. This is because the Regulations require the AER to make our DMO determination by 1 May of each year.

In the case of DMO 2, whilst the New South Wales distribution network tariffs may be approved by 31 April 2020, SAPN and Energex tariffs will not be available as the regulatory determination process for these distribution zones will only be completed by the end of April 2020.

Network regulatory determinations

In the absence of the relevant financial year's approved network tariff we will need a different approach to forecast how network costs will change.

We consider the best available forecast is the annual change in revenue provided in the AER's network revenue determinations. Each revenue decision sets caps on a network businesses' revenue for a forward looking five year period. The determination sets out the annual change in revenue, which in turn provides an indication of how network tariffs may change.

We therefore propose to use the change in annual revenue to estimate changes in Distribution use of system (DUOS), Transmission use of system (TUOS) and ACS costs.[40] These forecast network cost changes will then be applied to the relevant network tariffs from the last approved annual pricing proposal.

38 These factors include under/over recovery of revenue due to lower/higher network demand than initially forecast, Network cost pass throughs and changes to jurisdictional requirements.

39 NER s. 6.18.2; For network businesses outside Victoria, this determination is generally approved by the AER by the end of April, and the DNSP is required submit the tariff proposal to the AER as soon as practicable, and in any case within 15 business days, after publication of the distribution determination.

40 Referred to as X-factors in AER network revenue determinations.

For changes in costs of the jurisdictional schemes outlined in Section 4.2, we propose to use the information from the most recent approved annual prices.

At the commencement of a regulatory reset period, the first year's annual revenue requirement will have taken into account the previous period's revenue recovery. The first year of the revenue determination is therefore likely to be an accurate overall reflection of how network tariffs will change.

Within the regulatory reset period, we may also need to rely on the network revenue determinations when the relevant network tariffs are yet to be approved by the AER. We are mindful that the annual revenue requirements, set out in the revenue determination, do not account for other factors that affect annual network tariffs, such as the annual under- or over-recovery of network revenue within the reset period. For example, an under recovery of annual network revenue due to a lower than forecast network demand. Should this circumstance arise, we will need to consider additional network pricing information and consult with the network business to determine whether a better network cost forecast is available.

Stakeholder questions:

9. Are the proposed tariffs appropriate for assessing network cost changes?

4.4 Retail costs

Following the assessment of the wholesale, environmental and network costs we will identify the residual, which will include the retail costs. We will determine an appropriate rate of change to the residual costs of the DMO price as part of our forecasting approach.

Retail costs are incurred by retailers to acquire, service and retain customers, including meeting regulatory obligations. Other regulators' definitions of retail costs might differ by including/excluding some types of costs in different components of the cost stack.[41] For example, we propose to consider prudential and RERT costs in wholesale costs rather than retail costs.

Under our proposed pricing methodology, retail costs include:

- costs to serve or operating expenses to manage billing systems, handle customer enquiries, and comply with regulatory obligations;
- CARC to gain or retain customers

41 Other regulators include other Australian state based electricity regulators such as Independent Pricing and Regulatory Tribunal (IPART), ICRC, QCA and ESCV.

- a retail margin or the return to investors for exposure to systematic risks associated with providing retail services
- other costs such as depreciation, amortisation, interests and taxes.
- jurisdictional energy saving schemes costs directly incurred by the retailer (see Section 4.5).

Costs to serve can be further elaborated on to include (also known as retail operating costs):[42]

- labour costs (including salaries and training) – considered to be significant
- debt and debt collection costs considered to be significant
- Information Technology (IT) and billing costs
- leasing costs
- customer service (if not included in labour costs)
- ombudsman schemes and hardship programs
- A 'normal' level of regulatory costs would be included here as standard. Additional regulatory costs that are more significant might need to be explicitly accounted for. This is discussed later in the paper.

CARC can be broken down to include: costs of competition and costs of acquisition channels (eg. Third party comparison websites, door to door sales, telemarketing, other marketing spend, retention teams and related costs).[43]

As part of our DMO 1 Final Determination we concluded that the retail costs are adequately reflected in the 2019-20 DMO price. The DMO is also not aiming to drive efficiencies in the retail operating costs. It is designed to provide fall-back protection for those that do not, or cannot, switch retailer or tariff. As a result, in our view, detailed annual assessments of the underlying retail costs such as the costs to serve and CARC are not required at this stage.

4.4.1 Our approach to forecasting change in retailer costs

It is generally accepted that representative retail costs do not vary significantly over time, unless there is a significant change required in a retailer's business operations or in customer service requirements.

As part of our DMO 1 Final Determination we conclude that the retail costs are adequately reflected in the 2019-20 DMO price. The DMO is also not aiming to drive efficiencies in the retail operating costs. It is designed to provide fall-back protection for those that do not, or cannot, switch retailer or tariff. As a result, in our view, detailed annual assessments of the underlying retail costs such as the CTS and CARC are not required at this stage.

42 ACCC, *Retail Electricity Pricing Inquiry - Final Report*, June 2018, Chapter 10.
43 Ibid.

We therefore propose to calculate the residual costs in DMO 1 and index these costs by CPI. As outlined in the following section our methodology must nonetheless be sufficiently flexible to pass through any material changes in retail costs that, in exceptional circumstances, are not appropriately captured under our forecasting methodology.

Stakeholder questions:

10. Do stakeholders have additional information we should consider in relation to the proposed adjustments to the residual costs?

4.5 Step change framework for material changes in retail costs

We propose to use a step change framework as part of assessing the DMO each year and any changes made as a result of this framework of this would remain in place for the determination period. This will allow us to identify changes in retail costs that, in exceptional circumstances, are not accurately reflected by applying a general rate of change adjustment. The step change framework allows for either an increase or decrease in costs.

Below are our proposed criteria and process for assessing step changes in retailer costs. It is similar to other Australian electricity regulators' step change criteria as well as the AER's own criteria used for transmission and distribution found in our network expenditure forecast assessment guidelines.[44] Given there is already an allowance for regulatory costs in the costs to serve component of retail costs, our starting position would be that only exceptional circumstances are likely to require explicit compensation as step changes.

Proposed criteria

1. There is an exogenous change in a retailer operating environment which is mandatory and would be incurred by an efficient and prudent retailer within the DMO determination period.
2. The change will lead to a material overall change in the retail costs of an efficient and prudent retailer.
3. The change in retail costs are not compensated in our forecast of other cost elements.

Planned approach for making step change decisions

We propose to assess any potential step change in retail costs through the following process;

1. We will assess publicly available information to identify any likely step change requirements. This will include; information pertaining to regulatory changes, industry

44 Step change policies have been applied by IPART, ICRC and ESCOSA.

reports and commentary, and public financial records, such as listed company results. When required we will contact retailers to seek additional information.

2. We will then assess these cost changes against our criteria and provide our stated position in the draft determination.
3. Stakeholders will then have an opportunity to respond to our draft assessment in response to our draft determination. Should stakeholders disagree with our assessment or consider the AER should take into account further information relevant to our decision, then stakeholders may provide us with relevant information.
4. When assessing additional information, whilst we will consider all information that is provided to us in this process, we will place a stronger weight on information that provides a transparent and factual representation of the actual costs incurred by a retailer, and the proportionality of these costs, as a result of an exogenous change in the retailer's operating environment.

4.5.1 Step change assessment for 2020-2021 – regulatory initiatives

We have undertaken a preliminary assessment to identify any potential step changes in retail costs. In particular, we have considered whether any regulatory initiatives will lead to significant changes in costs for retailers that should be reflected in DMO 2.

In the DMO 1 Final Determination, the changes to the hardship framework, the Power of choice reforms, and the five minute settlement rules were all determined to not have a material change on retailer costs. For DMO 2, we have used our proposed step change framework outlined above to assess the following regulatory initiatives:

- Five Minute Settlement
- Retailer Reliability Obligation (RRO)
- Consumer data right (CDR).

We discuss these in turn below. We also discuss our views on broader changes, referred to as changes to the state of the world (i.e. changes to external operating environment).

Overall, we believe that all the regulatory initiatives that will lead to retailers to incur costs over the DMO 2 time period can be absorbed by the existing costs to serve and are not material enough to need specific adjustments through a step change.

If any retailer disagrees with our assessments and believes there should be an explicit adjustment, it should submit data on the costs associated with implementing the regulatory obligation.

Five Minute Settlement

The soft-start of Five Minute Settlement begins on 1 July 2021. The five minute settlement rule change will change settlement periods from 30 minutes to 5 minutes. This will impose compliance costs on retailers as they update their systems (including settlement; risk management; trading; billing; reporting; data collection and storage) and processes to reflect the five minute settlement intervals, and renegotiate any longer term hedging contracts.

In terms of quantifying the costs of this rule change on retailers, the Final Rule Determination published by Australian Energy Market Commission (AEMC) notes that the one-off costs of these system changes would not be insignificant. Because of this, the final rules were published in 2017, allowing a transition period of three years and seven months. This was intended to reduce the implementation costs for market participants, for example, by reducing the number of longer term contracts that extended past the commencement date that retailers would need to renegotiate. We expect that an efficient and prudent retailer[45] would already have begun making most of the necessary changes to their operations before the DMO 2 time period, especially considering the Commission, in its final rule determination, recommended that market participants begin transitioning to five minute settlement without delay in consultation with AEMO. Because of this we don't believe there will be an increase to implementation costs above those forecast for DMO 1, and so do not propose any additional cost allocation for DMO 2.[46]

Retailer Reliability Obligation

The RRO came into effect on 1 July 2019. The Regulatory Impact Statement (RIS) published by Council of Australian Governments Energy Council (COAG EC) estimates the costs of RRO at $77 million for the whole sector (including entities other than retailers) over 10 years, and this includes preparatory costs incurred ahead of the 1 July 2019 commencement date. Additionally, the RIS notes that RRO is also estimated to generate forecasted savings in credit costs for retailers of $234 million.[47]

Other costs may be incurred by retailers if a T-3 or T-1 event is declared.[48] This would impose additional costs for retailers that need to increase or adjust their hedging strategies. At this date, an event has not been declared in any of the DMO regions so we do not plan on making any further adjustments to retail costs of the DMO 2 price as a result of the RRO. If this changes before the final DMO price is due to be finalised, we will revisit the issue.

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45 The proposed step change policy looks at costs incurred by an efficient retailer that is expected to begin responding to the changes as soon as there is enough certainty over the new rules.

46 AEMC, *National Electricity Amendment (Five Minute Settlement) Rule*, 2017.

47 Savings in retailer credit costs are also flagged to benefit retailers: 'The Retailer Reliability Obligation's projected reduction in wholesale market costs (see above) will reduce retailer credit costs. Estimated credit cost savings for 2020-21 to 2029-30 are $234 million based on a 5% rate of interest.'; Energy Security Board (ESB), Retailer Reliability Obligation Decision Regulation Impact Statement, December 2018.

48 A T-3 event refers to AEMO forecasting a material reliability gap occurring in three years'. A T-1 event refers to AEMO forecasting a material reliability gap in one years' time.

This is in line with the ESCV's 2019 and 2020 decision. ESCV noted that without an event declared, the RRO is unlikely to impact retailer hedging for the period of the first VDO or the following 2020 periods.[49]

Consumer data right

The rollout of the CDR to the energy sector is intended to improve third party access to consumer data and product data that is currently held by different participants in the sector. While the Treasury is yet to determine the exact scope, the data sets that could be included within the CDR that are held by retailers include: National Metering Identifier (NMI) standing data, metering data, billing data and customer-provided data. The timing of the implementation of the CDR in the energy sector is to be determined. It is therefore uncertain as to whether the eventual costs to be incurred by retailers, if designated by the Treasury as data holders, should be accounted for in DMO 2 at this time. We will monitor the rollout of this initiative and will take a judgment on whether to make further adjustments to DMO 2 to reflect any CDR costs as part of preparing the draft determination.

Step change assessment for 2020-2021 – changes to the state of the world

Changes in the external operating environment can also lead to changes to retailers costs. For example, as noted in submissions to DMO 1 – a decline in the economy or an increase in living costs such as wholesale electricity prices will lead to an increase in debt and debt obligations and the application of hardship schemes. This issue was considered in DMO 1 and we determined that there would not be significant changes in costs due to these factors for the time period of DMO 1. For DMO 2, there has been no new evidence that this risk has increased, so we do not propose making any changes for DMO 2.

Stakeholder questions:

11. Do you consider our step change framework is appropriate?
12. Is there any other information the AER should have regard to when deciding to make a specific adjustment for retail costs?
13. Do you agree with our initial assessment of potential step changes?

49 In the 2020 issues paper, it notes that 'As the first chance that a reliability gap will be identified under the Retailer Reliability Obligation will not occur until late 2022 it will not impact the cost of wholesale electricity purchases for sale in 2020. For this reason we are not proposing to consider the Retailer Reliability Obligation costs for the regulatory period beginning 1 January 2020.'

5 Model annual usage determination

Under Part 3 of the Regulations, for each annual DMO price determination we are required to determine:

- a 'broadly representative' annual usage amounts for residential and small business customers in each distribution zone, from which a DMO price and reference bill can be calculated, including the timing and pattern of that use[50]
- a per-customer annual price.

This chapter outlines our proposed approach to determining annual usage for our DMO 2 determination.

5.1 DMO 1 approach

In DMO 1, we calculated the residential flat rate model annual usage per customer from the distribution business' annual pricing model for 2018-19.[51] In doing so we took the total forecast usage and divided it by the forecast customer numbers.[52] We considered that this approach met the criteria of being broadly representative as it:

- identified information specific to residential customers within a distribution zone.
- was recent, had been subject to quality assurance by the network businesses and had been assessed by the AER in the context of the annual pricing approval processes.

To determine the model annual usage for CL customers, and the relative proportion of CL and non-CL usage, we undertook the following steps:

- Analysed data provided in each distribution business' annual pricing proposals for 2018-19 to determine the average CL consumption of customers with a CL.
- Analysed residential consumption data collected by ACIL Allen Consulting during the 2017 Energy Consumption Benchmark project to determine the proportion of total consumption of CL and non-CL. [53] This analysis indicated that across the areas for which we are determining DMO prices, the proportion of CL usage was consistently close to 30 per cent of total usage. Given this outcome, we used the 30 per cent figure across all calculations.
- Derived the total consumption by applying the 30 per cent figure to the CL consumption, e.g.: If CL (30%) is 1900 kWh pa, non-CL consumption (70%) will be approximately 4,400 kWh pa.

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

51 AER, Pricing proposals and tariffs, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs?f%5B0%5D=type%3Aaccc_aer_pricing_proposal, viewed 17 September 2019; Some of the annual pricing models are not published, as they are commercial-in-confidence.

52 The exception to this is Ausgrid distribution zone which outlined a different methodology, which we also found reasonable.

53 ACIL Allen Consulting, *Energy consumption benchmarks report*, October 2017.

- Divided the remainder of total residential usage not allocated to customers with CL by the number of flat rate customers.
- In some cases, we calculated the flat and CL usages directly from the model or alternatively we contacted the distribution business directly to clarify this data.

For offers with multiple CL components, we analysed distributor data to determine the average proportion of CL1 and CL2 usage in each distribution zone.[54]

Our position was to adopt a model annual usage of 20,000 kWh for small business customers, consistent with our previous determination and information published by Energy Consumers Australia (ECA).[55] Stakeholders supported this approach in our previous determination.[56]

5.2 Summary of proposed approach for DMO 2

Our proposed position is to continue to use the annual usage from our DMO 1 Final Determination. We are also proposing to maintain our previous CL usage amounts.

We consider maintaining the previous usage determination provides certainty to retailers and allows stakeholders to more easily compare what is occurring in the electricity market over time. In considering whether the proposed usage assumptions remain broadly representative, our view is there should be a high threshold for justifying any changes. We consider this high threshold important as changes to our usage assumptions will:

- impact the methodology of DMO determinations
- increase the regulatory burden placed on stakeholders, requiring retailer system changes
- impact the comparability of the DMO reference price across years.

We will continue to monitor usage assumptions as part of future determinations to ensure they remain fit for purpose.

Our view is that our previous DMO 1 usage determination is still broadly representative. In reaching this view we cross-checked with other information available to us, that is we:

1. Reviewed the distribution businesses' updated annual 2019-20 pricing proposal usage forecasts. We note that some of the usage figures differ from the previous determination forecasts. The variation observed is less than 10 per cent for most distribution zones with the exception of SA CL which is approximately 20 per cent. This is not unexpected given we would anticipate a difference in figures year on year. This is because variations in

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54 Some distribution zones have multiple controlled load options which have different times of operation. For example overnight only for a hot water heater and a set period during the day for pool pumps. Retailers may bundle these together in a retail offer of flat rate and controlled load, or have a retail offer with flat rate and two controlled loads.

55 Energy Consumers Australia, *SME Retail Tariff Tacker report*, June 2018; The 20,000 kWh figure is based on a rounded average consumption for small businesses in various NEM by Jacobs Australia for AEMO.

56 Business SA, *Submission to AER on Default Market Offer Position Paper*, 6 December 2018 pp 1-4; AGL, *Submission to AER on Default Market Offer Position Paper*, 10 December 2018, p. 7.

weather each year can make a significant difference to household energy use. These observed changes are therefore not necessarily an indication of a broader shift in energy consumption trends.

2. We reviewed whether there was any other publically available information sources. In our view, our previous approach uses the most representative and verifiable data available to us. We do not have any new information that suggests the need to move away from our previous approach.

5.3 Our model annual usage assumptions

Our proposed position on annual usage amounts and the timing and pattern of supply is consistent with the previous determination.

Table 4 sets out the model annual usage amounts for residential and small business tariffs in each distribution zone.

Table 4: Model annual usages

Distribution Zone	Residential - flat rate#	Residential - flat rate with controlled load total++		Small business^
		General (non-CL) consumption	CL Consumption	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	20,000 kWh
Endeavour	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	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' annual pricing proposals

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

^ Source: Energy Consumers Australia, Small and Medium Enterprises (SME) Retail tariff tracker

5.4 Timing and pattern of supply

Consistent with DMO 1, we propose flat consumption – daily consumption is assumed to be the same across the year with no adjustments for seasonality, or variation between weekday/weekend consumption.

We have also considered whether there is a need to make a separate determination for solar and TOU customers, given the Government's intention to proceed with amendments to the Regulations.[57] Our view is that the usage assumptions for flat rate customers can be applied to solar and TOU customers. Our reasoning for this view is discussed further in Section 6 below.

Our assumption of apportioning 30 per cent of total consumption as CL across all distribution zones is unchanged.

Our position on how total CL usage should be allocated across tariffs with multiple CLs has not changed from our previous Determination. As with the annual usage, we do not have more recent information that would enable us to update these assumptions.

Stakeholder questions:

14. What additional information should we consider in relation to the proposed usage assumptions?
15. Are there any other factors that we should consider in applying the usage assumptions outlined in this section?

57 DDoE, *Regulation impact statement – the introduction of a Default Market Offer (DMO) price cap and reference bill on retail electricity prices*, April 2019, p. 36. See also Appendix B - Ministers' letter to the AER, 6 September 2019

6 Time of use and solar tariffs

The Regulations currently set the DMO price as a maximum price for standing offer customers on residential flat rate tariff types, with and without CL, and small business flat rate tariffs.

These tariffs are the most common types of standing offer tariffs in the market, meaning the vast majority of customers on standing offers in the relevant price deregulated regions receive the benefits of the DMO. Neither solar or TOU tariff types are covered by the maximum price provisions.

The Regulations also require retailers to compare all their offers to the DMO price when marketing or promoting them. This DMO price reference bill applies to residential flat rate, CL and TOU tariff types. The Regulations' reference bill provisions to not apply to customers with solar tariffs, and consequently we did not consider these customers in our DMO 1 determination.

The Commonwealth Government has indicated that it wants to ensure that the maximum number of customers benefit from the introduction of the DMO and reference price. The intention, subject to consultation on amendments, is to revise the Regulations[58], with effect from 1 July 2020 to:

1. extend the DMO maximum price provisions to customers with installed solar PV and TOU (flexible) tariff structures; and
2. extend the reference price to solar customers.

We understand the Government intends to shortly commence consultation on the above revisions to the Regulations.

The Government has requested we consider these issues as part of our DMO 2 determination. Should the Regulations be amended, our role would be to make annual usage and price determinations that encompass solar and flexible tariff customers.

This chapter outlines our proposed position on solar and TOU standing offers, should the Government implement changes to the Regulations. Our initial view is that:

- the DMO prices and annual consumption developed for flat rate/non-solar tariffs are suitable to use for TOU and solar customers
- for the timing and pattern of TOU consumption, we are proposing to use the *TOU period usage allocations* we used for DMO 1.

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58 DDoE, *Explanatory Statement - Competition and Consumer (Industry Code - Electricity Retail) Regulations 2019*.

6.1 Time of use

TOU pricing applies different charges to electricity usage at different times of the day or week. Days are commonly split into peak, off-peak and shoulder periods.

Peak periods are intended to correspond to the times the network faces high demand, but in practice are wide periods that cover much of the day. These tariffs also include a fixed daily supply charge.

As noted, at the time of our DMO 1 determination, only the Regulations' reference bill provisions applied to residential TOU tariffs.

To facilitate consistent calculation of retailer annual bills we determined:

- that retailers TOU annual prices should be compared to the flat rate DMO price (with and without CL).
- the timing and pattern of supply of this usage. We used a simplified set of TOU period usage allocations that assigned a set proportion of annual usage to peak, shoulder and off-peak periods (the *TOU period usage allocations*).[59]

The DoEE's Explanatory Statement for the Regulations indicates it did not expect us to determine a separate DMO price or usage for TOU tariffs. It states: [60]

> *No specific amount will be determined for residential customers with a flexible [TOU] tariff. Rather, the amounts applying to residential customers with a controlled load will cover both flat and flexible controlled load tariffs (and similarly for the amounts applying to residential customers without a controlled load).*

We have considered whether this approach would be consistent with our obligations under the Regulations, and whether it would meet the policy objectives.

Our position, consistent with the DoEE's expectation, is to use the flat rate DMO annual usage and price for residential TOU tariffs. For the timing and pattern of this usage, we are proposing to use the *TOU period usage allocations* we used for DMO 1.

For DMO 1 we were not required to set a DMO price or usage for small business customers on flexible tariffs. We understand that the Government does not intend to extend the price cap provisions of the Regulations to small business customers on TOU tariffs. Consequently, this Position Paper does not discuss these.

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59 AER, *Final Determination – Default Market Offer Prices 2019-20*, April 2019, Appendix H.

60 DoEE, *Explanatory Statement - Competition and Consumer (Industry Code - Electricity Retail) Regulations 2019*, p.11.

6.1.1 Summary of proposed approach for DMO 2

Per-person annual price

Considering the Government's intention to amend the Regulations so that the DMO price cap applies to residential customers on TOU tariffs, our position is that the price determination for residential customers on flat rate tariffs (with and without CL) is a reasonable per-person price to apply to TOU customers.

The information that is available to us at this time indicates that the annual price paid for the consumption of electricity for TOU customers is very similar to the annual price paid by flat rate consumers.

We acknowledge that that there may be differences between retailer costs for serving a flat rate customer and a serving a TOU customer, due to different network costs, for example.

However at this time, we consider that, due to the comparatively small number of customers on TOU standing offers, the revenue impacts on retailers are unlikely to be significant. We note this may change over time and we will revisit this issue in future determinations.

We also note that the level of the DMO price is sufficiently above efficient costs to allow retailers to absorb any mis-match in costs between TOU and flat rate customers without affecting their ability to recover efficient costs.

Annual usage

The Regulations' reference price requirements apply to retailers when advertising and promoting TOU market offers. Our DMO 1 determination was that the per-customer usage for customers a flat rate tariff was broadly representative of customers on TOU tariffs (with and without CL).

Considering the intention to amend the Regulations so that the DMO price cap provisions apply to standing offer TOU customers, our position is that the relevant flat rate per customer usage remains broadly representative of TOU tariff customers.

At this time, we do not have evidence available to us which suggests the annual consumption of TOU customers is substantively different from that of customers on flat rate tariffs.

While we acknowledge that there may be some factors that lead to differences in usage profiles between customers on the different tariff types (such customers shifting their usage in response to price signals) we have no evidence to indicate the net annual usage of a particular customer would be different.

Additionally, due to the relatively recent introduction of TOU tariff types in the DMO areas, we consider there are likely to be relatively few customers on TOU standing offers at this time (as most would be on market offers). However, this number will increase over time[61].

We will continue to monitor this issue in future years. In the event we received formal information gathering powers to assist in our DMO price setting role, we could seek usage data from stakeholders that would help us understand differences in usage and develop more reflective determinations if necessary.

Timing and pattern of supply

Should the maximum price protections be extended to residential TOU customers, we would need to determine, under our 'timing and pattern' considerations, how much usage a broadly representative TOU customer would use annually across peak, off peak and shoulder periods. The amount of electricity a customer uses across these periods can impact the annual price.

For DMO 1, for the purpose of the reference price provisions, we determined TOU period allocations for each area. We based these on information used in our *Energy Made Easy* (EME) website, developed as part of the 2017 Energy Consumption Benchmark project.

We consider the same TOU period usage allocations remain reasonably representative for the TOU DMO maximum price. That is, when setting prices for TOU standing offers so that they do not exceed the DMO price, retailers would have to use the relevant period usage allocation as the basis for their annual bill. Table 5 provides an illustrative example of how these could apply.

61 For example DNSP assignment policies for flexible tariffs; AER, *Final Decision – Tariff Structure Statements – Ausgrid, Endeavour and Essential Energy*, February 2017.

Table 5: Illustrative example of a standing offer price calculation - 3-period TOU

Illustrative example of a standing offer price calculation - 3-period TOU			
DMO price	**$1467** Based on 3900kWh/yr		
		Annual period allocation - 3 period TOU (kWh/yr)	cost/yr
Daily supply charge	$1/day		$365
Peak	$0.35/kWh	1244.1	$435.44
Shoulder	$0.30/kWh	1540.5	$465.79
Off-peak	$0.17/kWh	1115.4	$189.62
Compliant SO price			**$1455.85**

The TOU period allocations meet the criteria of being 'broadly representative'. The allocations are based on ACIL Allen Consulting's 2017 Energy Bill Benchmark analysis, which are used on our *EME* website.[62]

The period allocations have only recently been introduced and have been generally supported by stakeholders in DMO 1. This approach also provides certainty for retailers, given they are already applying these profiles for the reference bill.

Another reason for using the period allocations is that no clear alternative is apparent.

We currently have no information-gathering powers that would enable us to collect usage data to develop detailed usage profiles, although this may change in the future. We note that the AER must update the Energy Consumption Benchmarks by December 2020. While we plan to review these assumptions when the research is complete, this will not be available in time for our DMO 2 determination process.

62 ACIL Allen Consulting, *Energy consumption benchmarks report*, October 2017.

Even if we were to gain access to such data, we note the inherent challenge in attempting to develop a 'representative' usage profile to calculate a single TOU-specific DMO price, given the variance in households' usage patterns.

6.1.2 TOU Reference bill considerations

In some instances, the times that underpin our TOU periods may not align with those on some network tariffs. While usage/timing determinations are only required to be representative of the customer, (i.e. not network pricing patterns) we have considered the impact on retailers below.

We note that if retailers chose to mirror such a network tariff in their retail tariff, when advertising these tariffs under the reference price rules, the mismatch may over-, or under-state the difference between the TOU DMO reference price and TOU tariff price.

We do not consider this makes the simplified allocations unsuitable. This is because:

- TOU customers will be comparing on a like-for like basis as the usage allocation assumptions apply to all retailers operating within the applicable distribution zone. Therefore the proposed usage allocations are not likely to disproportionally affect one retailer over another.
- In response to DMO 1, some retailers raised concerns regarding minimising volume risk, noting retailers typically set prices that match the structure of the network tariff to which the customer is assigned. As we set out in DMO 1, in our view retailers are in the best position to manage any associated risks with potential mismatch between how retailers structure offers to customers and the cost structures the retailer faces in terms of network costs. We note retailers are not obliged to reflect network tariffs to retail customers and the mismatch only impacts how the TOU tariff is displayed as a reference price. The DMO does place requirements on how retailers structure tariffs.
- Retailers who are concerned about revenue risk from a mismatch between the usage/period assumptions in a network tariff could address this through their period pricing. The DMO design allows this by allowing flexibility to assign fixed/variable/period charges so long as the cap is not exceeded.

6.2 Solar

The Government has flagged its intention to amend the Regulations for the 2020-21 determination period to extend its operation to solar customers.[63]

If the scope of the Regulations was expanded in this way, the AER would have to determine a broadly representative model annual usage and price for customers that also have solar tariffs.

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63 DoEE, *Regulation impact statement – the introduction of a Default Market Offer (DMO) price cap and reference bill on retail electricity prices*, April 2019, p. 36. See also Appendix B - Ministers' letter to the AER, 6 September 2019

The DoEE's Explanatory Statement for the Regulations notes the usage and price determinations for a non-solar customers would be suitable to use as the DMO price for solar customers. In flagging its intention to include solar tariffs in the Regulations, it states: [64]

> *…no specific amount will be determined for residential customers who receive a feed-in tariff for a rooftop PV system. Instead, the amounts applying to residential customers with a controlled load will cover both solar and non-solar tariffs (and similarly for the amounts applying to residential customers without a controlled load).*

On the evidence available to us, it is reasonable that the annual usage and price determined for non-solar customers encompass solar customers. Our reasons for this view are discussed below.

6.2.1 Solar usage considerations

In considering what constitutes a broadly representative usage for each of the residential customer types that also have solar systems; we have reviewed a range of publicly available research and analysis.

Available analysis however does indicate that the consumption from the grid of solar customers is broadly similar to that of non-solar customers.

The ACCC's REPI final report found that solar and non-solar customers used a similar amount of electricity, but noted there were variances for a range of reasons.[65] REPI found:

> *Data provided by retailers indicate that, on average, solar customers and non-solar customers use a similar amount of electricity from the grid. However, households with solar are typically larger than non-solar households which also include a larger proportion of consumers who live in apartments. This indicates that solar customers on average use more electricity than non-solar households, but this increased usage is offset by their solar PV generation.*

Similarly usage profile research on Victorian customers conducted by ACIL Allen Consulting indicates that, while seemingly counter-intuitive, there was little difference in total consumption of households with solar panels and those without.[66]

> *The expectation would be that, by generating electricity, solar panels reduce the amount of electricity import to the household from the grid. This result does not contradict this, but it shows that this effect is offset by households with solar panels also using more electricity in other ways.*

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64 *Explanatory Statement - Competition and Consumer (Industry Code - Electricity Retail) Regulations 2019*, p.11.
65 ACCC, *Retail Electricity Pricing Inquiry - Final Report*, June 2018, p. 26.
66 ACIL Allen Consulting, *Victorian Energy Usage Profiles*, March 2019, p. 33.

In the absence of more detailed consumption data, we are satisfied on the basis of these finding that the usage of non-solar customers is broadly the same as that of solar customers, and therefore is suitable.

We note that this situation may change for future years should the AER be given formal information gathering powers. This may enable us to get detailed consumption data from retailers should we consider it necessary to update the solar usage figures in future determinations.

Stakeholder questions:

16. Have we appropriately balanced the policy objectives in our proposed approach to assessing a DMO price for time-of-use tariffs?
17. Are there other data sources or factors we should take into consideration if we are required to determine a DMO price for time-of-use tariffs?

6.2.2 Solar DMO price

Our preliminary view is that it not feasible to include consideration of solar exports in a solar DMO price, and that pricing considerations should exclude consideration of credits earned by exporting energy to the grid. We understand that proposed amendments to the Regulations will clarify this approach.

Specifically, a solar DMO price that attempted to model a 'typical' solar customer would in reality be likely to only be representative of a small proportion of customers due to factors such as geographical differences in solar radiation, the wide variety of system sizes, and differences in the range of retailer feed-in credits.

In general, solar tariffs published on EME are identical to non-solar tariffs, but with the addition of retailer FiTs as a component available to customers with PV systems. As we propose to exclude consideration of power exported to the grid, the price of a solar and non-solar tariff will be the same based on the same annual consumption. In this context, and assuming solar and non-solar customers' usage is the same, we see no practical reason to make fundamental changes to the representative customer determinations now that they are inclusive of solar customers.

Other considerations

We anticipate the majority of solar PV customers would be on market offers. Currently we do not have oversight over the number of customers with solar PV systems that are on standing offers, however, we consider it a reasonable assumption most solar customers would be on market offers.

We consider that using the existing DMO price and applying it to solar customers is the most reasonable approach. In reaching this view we have considered and balanced the various policy objectives.

We consider this to be the most beneficial approach for relevant stakeholders for a number of reasons:

- a separate price may impact the offers available to solar customers; as many market offers have solar aspects to them
- a single price point assists customer understanding. Complex offerings are a barrier to consumer engagement
- regulatory consistency in the market enables stakeholders to have greater confidence in the market and in their ability to promote innovation and investment
- given the policy objective, our DMO 2 price should be set above efficient costs, therefore, some variations in the standing offer prices for solar, in comparison to flat rate standing offers, could be accommodated without impacting market participation for solar standing offers.

These aspects are important for customers being able to benefit from competitive market place, through pricing or innovative products.

Stakeholder questions:

18. Do stakeholders consider the proposed approach would appropriately balance the policy objectives if we are required to determine a DMO price for solar tariffs?
19. Is there additional information we should consider if we are required to determine a solar reference price?

Appendix A - Stakeholder questions

In responding to this consultation please respond to the questions outlined in the table below.

Stakeholder Questions

Section 3 - Approaches to setting the DMO annual price

1. For our DMO 2 price determination, do you agree with our proposed approach of carrying forward the DMO 1 price whilst taking into account the changes in forecast changes in input costs?
2. Do you consider there is an alternative methodology to determine DMO 2 that better meets our policy objectives?

Section 4 - Forecasting changes in the retailer's cost of supply

3. Does our representative retailer broadly reflect retailers in each of the markets the DMO will apply?
4. Do you consider there is merit in considering a more simplified forecasting methodology, such as the contract portfolio index, in future DMO pricing decisions? (As outlined in the ACIL Allen Consulting report)

Section 4.1 - Wholesale electricity costs

5. Do you consider the use of the NSLP and CLP is an appropriate proxy to model a representative retailer's load profile?
6. Do you consider the proposed hedging strategy is appropriate?
7. Do you consider there are improvements to the ACIL Allen Consulting's proposed wholesale cost forecast methodology?

Section 4.2 - Environmental costs

8. Do you consider there are improvements to the ACIL Allen Consulting's proposed environmental cost forecast methodology?

Section 4.3 - Network Costs

9. Are the proposed tariffs appropriate for assessing network cost changes?

Section 4.4 - Residual costs

10. Do stakeholders have additional information we should consider in relation to the proposed adjustments to the residual costs?

Section 4.5 - Step Change Framework for material changes in retailer costs

11. Do you consider our step change framework is appropriate?
12. Is there any other information the AER should have regard to when deciding to make a

specific adjustment for retail costs?

13. Do you agree with our initial assessment of potential step changes?

Section 5 - Model annual usage

14. What additional information should we consider in relation to the proposed usage assumptions?
15. Are there any other factors that we should consider in applying the usage assumptions outlined in this section?

Section 6.1 – Time of Use

16. Have we appropriately balanced the policy objectives in our proposed approach to assessing a DMO price for time-of-use tariffs?
17. Are there other data sources or factors we should take into consideration if we are required to determine a DMO price for time-of-use tariffs?

Section 6.2- Solar

18. Do stakeholders consider the proposed approach would appropriately balance the policy objectives if we are required to determine a DMO price for solar tariffs?
19. Is there additional information we should consider if we are required to determine a solar reference price?

Appendix B - Ministers' letter requesting the AER consider TOU and solar

TREASURER
MINISTER FOR ENERGY AND EMISSIONS REDUCTION

MS19-000439

Ms Paula Conboy
Chair
Australian Energy Regulator
GPO Box 520
MELBOURNE VIC 3000

6 SEP 2019

Dear Ms ~~Conboy~~ Paula

As you are aware, on 1 July 2019, the Australian Government's *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Code) commenced, conferring fucntions on the AER to make annual price and usage determinations, and requiring retailers to:

- cap their 'flat rate' electricity standing offers at the AER-determined price;
- compare their offers to the price cap; and
- ensure conditional discounts are not the most conspicuous pricing feature in advertising.

The Government is focused on reducing electricity prices and ensuring the market is easy for customers to navigate. We therefore consider it essential for these protections in the Code to be available to the largest number of customers possible.

As the Government previously indicated in its consultation and the Regulation Impact Statement, we propose to expand the Code to cover residential flexible ('time-of-use') customers and residential and small business customers with solar PV from 1 July 2020. Accordingly, we ask that the AER consider these types of customers in the development of its price and usage determinations for the 2020-21 period.

We ask that you work closely with officials from the Treasury and the Department of the Environment and Energy throughout this process, and undertake consultation as appropriate.

Yours sincerely

Joshua Frydenberg

JOSH FRYDENBERG
Treasurer

Angus Taylor

ANGUS TAYLOR
Minister for Energy and Emissions Reduction

Cc: Mr Rod Sims, Chair, Australian Competition and Consumer Commission

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