AUSTRALIAN ENERGY MARKET COMMISSION

REVIEW

Consultation paper

Review of the Wholesale Demand Response Mechanism

13 March 2025

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Summary

1 The Australian Energy Market Commission (AEMC or Commission) has initiated a review of the wholesale demand response mechanism (WDRM). The review seeks to examine the costs, benefits and effectiveness of the WDRM in terms of its impact on spot prices, accuracy of baselines, and market developments.

2 The WDRM enables consumers to sell demand response in the wholesale market either directly or through specialist aggregators. The demand response delivered is paid the spot price and is measured against a baseline level of consumption.

3 The AEMC is required to review the WDRM under Chapter 3 of the National Electricity Rules (NER), and will consider the role of the WDRM in enabling demand-side participation and its performance to date. Stakeholder feedback and analysis will inform the Commission on whether the WDRM should be changed, remain as is, or be phased out.

4 This consultation paper outlines the proposed approach for this review as well as identifying the issues of interest. The review's terms of reference is available on the project page.

5 Submissions to this consultation paper are requested by COB Thursday 24 April 2025.

The WDRM allows demand response to be offered into the NEM

6 The WDRM was established through a rule made on 11 June 2020 and commenced operation in the national electricity market (NEM) on 24 October 2021. The WDRM allows demand response service providers (DRSP) to offer demand response into the NEM, where it can be dispatched and paid in the same way as generators.

7 The rule change request to establish a wholesale demand response mechanism argued that there were barriers for retailers to engage with consumers to provide demand response. Third parties (that is, non-retailers), by contrast, can specialise in offering demand response services to customers to extract the value of this response. This necessitated the transfer of value of wholesale demand response from the existing retailer to a DRSP, who may be the customer or a third-party service provider engaged by the customer.

8 To date, there has been limited participation in the WDRM compared to expectations in the 2020 final determination; two DRSPs have registered a combined 74 MW of response across 20 wholesale demand response units (WDRUs), which have been dispatched for 1,258 MWh of response.

9 In establishing the WDRM, the Commission considered that if there was to be a move to a two-sided market in the future then this move should replace the WDRM. A two-sided market is characterised by the active participation of the supply and demand side in dispatch and price setting.

10 The Commission's recent rule determinations on *Unlocking CER benefits through flexible trading* (CER benefits) and *Integrating price-responsive resources into the NEM* (IPRR) have progressed two-sided market arrangements:

- From the CER benefits final rule, energy service providers for small and large customers will be able to separate and manage 'flexible' CER from 'passive' loads by establishing secondary settlement points in the energy market. Market participants will also be able to use in-built measurement capability in technology such as electric vehicle (EV) chargers and household batteries.

- IPRR introduced a framework named 'dispatch mode' that allows currently unscheduled price-responsive resources to be scheduled and dispatchable in the NEM, in aggregations or individually. It allows virtual power plants, community batteries, flexible large loads and other price-responsive small resources to compete with large-scale generators and storage in the wholesale market.

11 As a result of the CER benefits and IPRR rule changes, parties with responsive demand can more easily participate in dispatch. This review will consider whether these recent market developments have reduced or removed the need for the WDRM or whether the WDRM still plays an important role in engaging demand side participation in the NEM.

Feedback sought across three areas of interest

12 This consultation paper discusses and sets out questions for stakeholders on three areas of the WDRM:

- benefits and costs:
  - In assessing the benefits of the WDRM the AEMC has proposed a methodology to determine the efficiency gains that have resulted from WDRM dispatch. In addition to the efficiency gains, the review will assess whether the WDRM has impacted retailers offering contracts with demand-responsive options. We will consider the ongoing costs and risks associated with changes to the WDRM in making our recommendations.
  - A formal and detailed cost-benefit assessment is not anticipated to be part of this review. Rather, the Commission will consider the costs and benefits of the WDRM as one input in making its recommendations.
- whether changes should be made to its design:
  - The AEMC will investigate whether changes can and should be made to the design of the WDRM to promote the efficient operation of the mechanism or increase participation. This includes: whether DRSPs should be excluded from frequency control ancillary services (FCAS) cost recovery, the level of the wholesale demand response reimbursement rate (WDRRR), and whether sites with multiple connection points should be able to participate.
- the accuracy and suitability of baselines:
  - Baselines are critical to the operation of the WDRM as they determine the quantity of demand response offered into the market. The AEMC will assess and seek feedback on the accuracy of current baseline methodologies and whether baselines are appropriate for a future with increasing levels of CER.

Submissions are due by 24 April 2025

13 Written submissions responding to this consultation paper must be lodged with AEMC by COB Thursday 24 April 2025 via the AEMC website, www.aemc.gov.au.

Full list of consultation questions

Question 1: Benefits of the WDRM

1. Do you agree with our proposed methodology to estimate the deadweight loss benefits of the WDRM?

2. Is there an alternative approach that the AEMC should consider in measuring the impact of the WDRM on spot prices?
3. Would the results from using a more sophisticated method significantly change the benefit calculation?
4. Are there other benefits of the WDRM and what is their materiality?

Question 2: Costs of the WDRM

1. What are ongoing financial and non-financial costs of facilitating the WDRM?
2. What were the financial and non-financial implementing the WDRM?

Question 3: Potential issues in implementing changes to the WDRM

1. What impact would changes to the WDRM have on existing contracts?
2. What impact would phasing out the WDRM have on existing contracts?
3. Are there alternative mechanisms that would allow existing contracts to continue if the WDRM is phased out?
4. Are there other risks that the AEMC should consider in deciding whether the WDRM should be changed, remain as is or phased out?

Question 4: Are retailers offering demand-responsive contracts?

1. Has the WDRM had a noticeable impact on retailers offering retail offerings with demand responsive aspects?
2. Has the WDRM resulted in customers investing in being able to be more responsive?

Question 5: DRSP exclusion from FCAS cost recovery

1. Should DRSPs continue to be excluded from regulation and contingency FCAS costs?
    - If not, how could they be effectively included in the cost recovery process?

Question 6: Should changes be made to the calculation of the WDRRR?

1. Is the current methodology for calculating the WDRRR appropriately reflecting the wholesale cost component of an average large customer's retail tariff?
    - if not, is there an alternative methodology that would and could it be implemented effectively?

2. Are their other changes that can and should be made to the WDRRR?

Question 7: Should sites with multiple connections participate in the WDRM

1. Should sites with multiple connection points be able to participate in the WDRM?
2. What are the potential benefits and costs of this change?
3. Are there other changes that would have a greater impact on participation in the WDRM?

Question 8: Is the baseline methodology working as intended

1. Are the current baseline methodologies producing accurate baselines for WDRUs?
2. Is the process for requesting new baselines sufficient to ensure that baselines can accommodate a wide variety of loads?
3. Are there any aspects of the baselining process impacting further participation in the WDRM?

Question 9: Are baselines suited for increasing levels of CER?

1. Does the increased volume of investment in CER result in fewer loads able to meet a baseline?
2. Does the combination of CER benefits and IPRR mean that the demand side is appropriately catered for in dispatch?
3. Is there a role for the WDRM in facilitating access to the wholesale market by third-parties?

Question 10: Proposed assessment framework

1. Do you agree with the proposed assessment criteria for this review?
2. Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

How to make a submission

Making a submission

Stakeholders can help shape the recommendations by participating in this review process. Engaging with stakeholders helps us understand the potential impacts of our recommendations and, in so doing, contributes to well-informed, high quality review recommendations.

Each chapter includes questions to guide feedback, and the full list of questions is above. Any other relevant information is welcomed.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with AEMC by COB, Thursday 24 April 2025.

How to make a submission: From the AEMC's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code EPR0099.[1]

Tips for making submissions are available on the AEMC website.[2]

Publication: The AEMC publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[3]

Contact us

To contact us please use the form available on the project page.

1 If you are not able to lodge a submission online, please contact us.

2 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3

3 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission

Contents

1 The context for this review

This chapter sets out the context and approach for this review.

1.1 The review focuses on the costs, benefits and effectiveness of the WDRM

Though this review the AEMC will consider the costs, benefits and effectiveness of the wholesale demand response mechanism (WDRM) having regard to:[4]

1. the impact of the arrangements on the spot price
2. the accuracy of baseline methodologies
3. market and technological development
4. any other matters relating to wholesale demand response that the AEMC considers relevant.

The WDRM was established through a rule made on 11 June 2020 and commenced operation in the national electricity market (NEM) on 24 October 2021. In making the rule, the AEMC committed to reviewing the WDRM. [5]

On 30 May 2024, the AEMC stated it would complete the review by 24 October 2025.[6] This was to allow time to properly investigate the impact of two-sided market options in the closely related reforms of *Integrating price-responsive resources into the NEM* (IPRR) and *Unlocking CER benefits through flexible trading* (CER benefits) rule changes. Final rules for these two reforms were published on 19 December 2024 and 15 August 2024 respectively.

The Commission has also released a terms of reference alongside this consultation paper.

1.2 A two-sided market is the enduring solution

In establishing the WDRM the Commission stated that if there is a move to a two-sided market, this reform should replace the wholesale demand response mechanism:[7]

> The wholesale demand response mechanism will eventually be outgrown by the market because it is reliant on the use of centrally determined baselines. If the move to a two-sided market is made, this reform should replace the wholesale demand response mechanism.

A two-sided market is characterised by the active participation of the supply and demand side in dispatch and price setting. A two-sided market should enable the transition to a reliable and secure future NEM that is characterised by increased variable supply and more flexible, price responsive demand. Furthermore, moving to a two-sided market will assist the NEM in effectively evolving and transitioning to the future power sector, and that will provide enduring consumer benefits.

The AEMC considered that due to the WDRM's reliance on centrally determined baselines, moving to two-sided market arrangements would better facilitate the demand side in the NEM. This is because the counter-factual level of demand that would have occurred without a demand response mechanism can not be known accurately, resulting in an inherent imprecision in the

4 Clause 3.10.7 of the NER.

5 Clause 3.10.7 of the NER.

6 AEMC, Media release, 30 May 2024, available here.

7 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. iv.

baseline process. If the baseline is set too high, consumers will pay more than they need to. If it is too low, then there would not be enough incentive to encourage demand response in the market.

The Commission's recent decisions responding to the CER benefits and IPRR rule change requests have progressed two-sided market arrangements for the NEM.

The CER benefits final rule enabled three key arrangements:[8]

- Large customers will be able to engage multiple energy service providers at their premises — to manage and obtain more value from their CER.
- Energy service providers for small and large customers will be able to separate and manage 'flexible' CER from 'passive' loads by establishing secondary settlement points in the energy market — leading to innovative products and services for consumers.
- Market participants will be able to use in-built measurement capability in technology such as electric vehicle (EV) chargers and streetlights — to enable innovative and essential products and services at a lower cost.

The IPRR rule introduced a framework named 'dispatch mode' that allows currently unscheduled price-responsive resources to be scheduled and dispatchable in the NEM, in aggregations or individually.[9] This allows virtual power plants, community batteries, flexible large loads and other price-responsive small resources to compete with large-scale generators and storage by allowing them to bid into the spot market, set prices, receive dispatch instructions and earn revenue in markets that require scheduling (for example, regulation frequency control ancillary service (FCAS)).

This framework operates similarly to the bidirectional unit framework, which allows bids for both generation and load. By using actual generation or load no baselines are required for the resources participating.

Through the combination of these two reforms, participants can separate flexible and inflexible resources behind a connection point and only participate in the dispatch mode with resources that are able to. As a result, these two reforms provide a flexible and robust method for demand-side participation in the NEM dispatch process.

1.3 Should the WDRM be changed, remain as is or be phased out?

A key question for this review is whether the WDRM has enabled demand-side participation in the NEM. The WDRM's performance to date in achieving this goal will be critical to considering its future. In assessing the future of the WDRM we will have regard to:

- whether recent regulatory and market developments have promoted a two-sided market and whether this has reduced or removed the need for the WDRM[10]
- stakeholder feedback on participating in the WDRM and whether changes could increase participation in and the effectiveness of the WDRM.

In making our recommendations we will consider the cost and complexity associated with any change against the potential benefit of the change.

8 AEMC, Unlocking CER benefits through flexible trading, rule determination, 15 August 2024, p. i.

9 AEMC, Integrating price-responsive resources into the NEM, rule determination, 19 December 2024, iv.

10 In considering the removal of the WDRM the AEMC would consider how this could best be achieved. It would likely require a phasing out of the mechanism to allow existing participants to manage the change.

2 Overview of the WDRM

This chapter provides background relevant to understand the issues set out in the later chapters.

This chapter outlines:

- background information on the WDRM
- the operation of WDRM to date
- the Commission's reasons for excluding small customers
- multiple mechanisms are available for the demand side to participate.

2.1 The WDRM allows demand response to be offered into the NEM

The WDRM allows demand response service providers (DRSP) to offer demand response into the NEM, where it is dispatched and paid like generators. The rule establishing the WDRM made changes to facilitate this, the changes relevant to this review are:

- participant category and registration
- determination of baselines
- dispatch and pre-dispatch
- settlement and cost recovery.

This section provides a summary of these, further information on the suite of changes introduced can be found in the final determination for the WDRM.[11]

Participant category and registration

The rule established the DRSP registration category, which subsumed the previous registration category for market ancillary service providers (MASP) into this new category. Registering as a DRSP is the first step to participate in the WDRM. It is the only participant class that can sell wholesale demand response through the WDRM.

DRSPs may classify one or aggregate multiple qualifying loads as a wholesale demand response unit (WDRU). For a load to be considered a qualifying load it must:

- exist at a single connection point
- not be a small customer or scheduled load
- have appropriate metering equipment installed.

Additionally, the DRSP must have the consent of the relevant customer to provide wholesale demand response.

A DRSP applies to AEMO to classify a qualifying load as a WDRU. AEMO must approve this application if it is satisfied that:

- the load is a qualifying load
- the qualifying load can provide wholesale demand response in accordance with the NER
- the DRSP has adequate communications and telemetry
- when a baseline methodology is applied to the load, it produces a baseline that satisfies the baseline methodology metrics

11 Several other changes were made through the WDRM rule, including changes to the demand side participation (DSP) portal. These changes are not being considered through this review and have not been covered in this section.

- the load satisfies each other requirement in AEMO's wholesale demand response guidelines for classification.

Determination of baselines

Baselines estimate the counterfactual level of consumption that would have occurred were it not for the demand response. Baselines are necessary to allow DRSPs to sell demand response directly into the wholesale market because the quantity of demand response sold (and paid for) is determined as the difference between the baseline and actual levels of consumption.

AEMO's wholesale demand response guidelines set out:

- the process for a DRSP to apply to AEMO for approval to apply a baseline methodology determined by AEMO and associated baseline settings to its wholesale demand response unit
- information about the process for the development of baseline methodologies by AEMO and how proposals for new baseline methodologies may be made
- that AEMO must publish at least one baseline methodology and the related settings in a register
- that AEMO must determine and publish baseline methodology metrics which set out the parameters for assessing the baseline produced by a baseline methodology when applied to a WDRU.

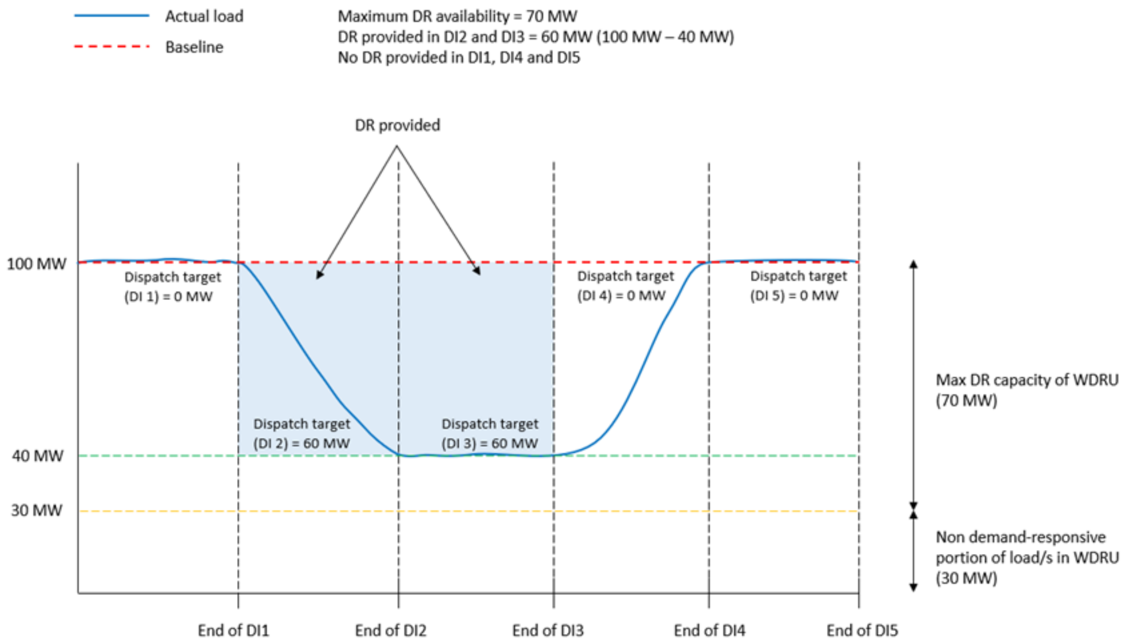
Dispatch and predispatch

DRSPs are treated similarly to other scheduled resources in central dispatch. They have obligations and incentives consistent with those imposed on scheduled generators, including compliance with dispatch instructions.

DRSPs bid in their willingness to reduce demand for each WDRU at certain price points. When dispatched, the DRSP must ensure that their WDRU reduces their load by the amount dispatched. The example in Figure 2.1 illustrates this and shows:

- the maximum demand responsive component of the wholesale demand response unit is70 MW — this is the maximum amount of wholesale demand response the DRSP could provide for that wholesale demand response unit
- the DRSP is dispatched to provide wholesale demand response of 60 MW in dispatch intervals 2 and 3
- it is assumed that the market clearing price exceeds the price at which the DRSP offers to provide this reduction (i.e. the DRSP is cleared and receives a dispatch instruction to provide wholesale demand response).

Figure 2.1: WDRM dispatch example



Source: AEMC
Note: Figure Note

DRSPs are required to submit dispatch bids for all dispatch intervals for the purposes of providing information for pre-dispatch and short term projected assessment of system adequacy (PASA). If a DRSP does not intend to provide demand response for a particular interval, the DRSP may bid available capacity of zero. DRSPs are not required to submit information for MT PASA but do submit information on wholesale demand response over longer time frames through the demand side participation (DSP) Portal.

These obligations and incentives for DRSPs are key to maintaining the integrity of the central dispatch and price setting process.

In addition to the similar obligations for scheduled participants, DRSPs must not submit offers to provide wholesale demand response which:

- encompass loads that are not compliant with the baseline methodology metrics at the time the offer is submitted
- encompass loads that are spot price exposed in the trading interval
- would have been undertaken anyway, even in the absence of a dispatch instruction or is offset by increased consumption at another connection point.

The Australian Energy Regulator (AER) is responsible for enforcing compliance with dispatch instructions and the rules about declaring the available capacity of wholesale demand response units and the provision of genuine demand response. The AER has access to information to identify non-compliance with dispatch instructions, and DRSPs are required to maintain information and records to facilitate the assessment of other provisions in accordance with guidelines made by the AER.[12]

12 For instance the AER's Wholesale demand response participation guidelines.

Settlement

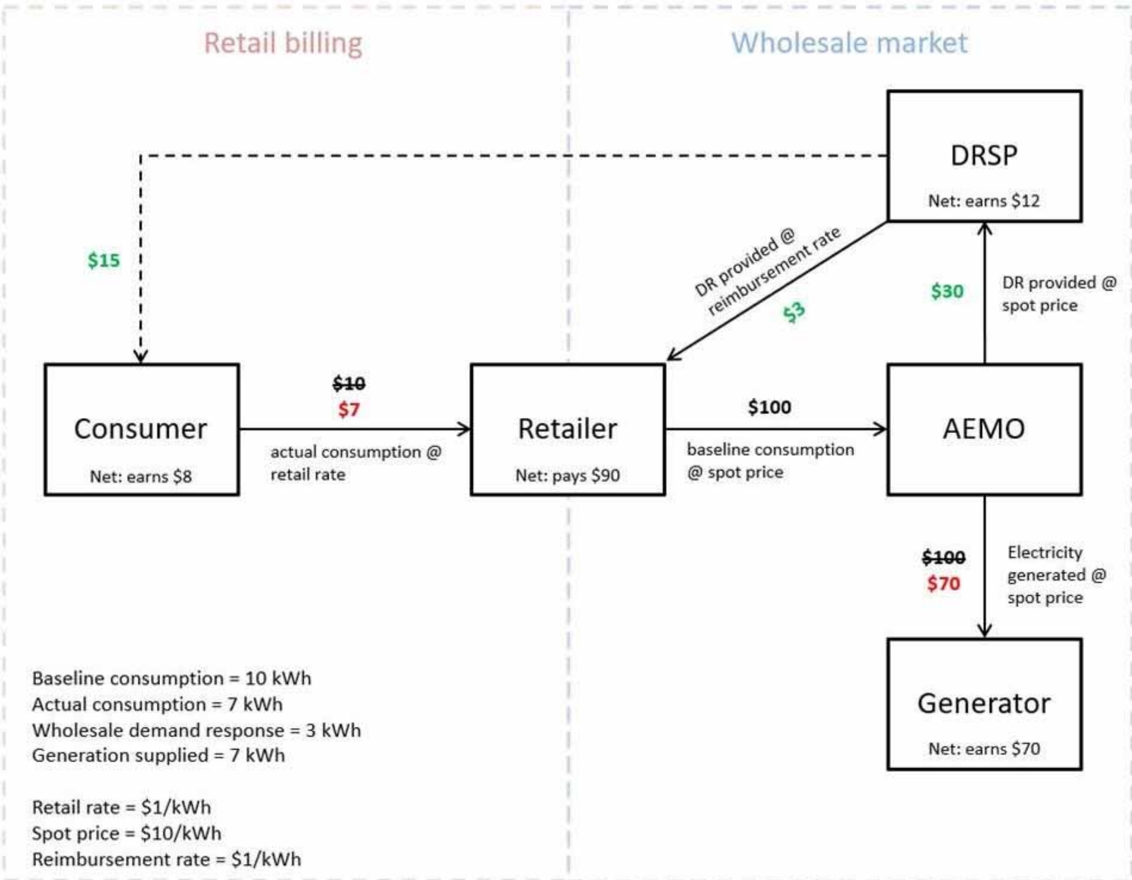
The settlement process for wholesale demand response (WDR) dispatch is managed through AEMO systems, from the customer perspective where WDRM is dispatched:

- the customer's retailer bills them for their actual consumption
- AEMO bills the customer's retailer for their baseline level of consumption
- the DRSP is paid the spot price for the quantity of wholesale demand response provided[13]
- the DRSP pays the retailer the quantity of demand response provided at the wholesale demand response reimbursement rate (WDRRR).

The WDRRR allows the retailer to cover its costs of hedging for the customer's baseline level of consumption in the wholesale market. The WDRRR is calculated by AEMO on a quarterly basis and is based on the peak period load weighted average spot market prices over the previous 12 months. Q1 2025 WDRRR values range from $210/MWh in New South Wales to $118/MWh in Tasmania.[14]

The financial flows described above are illustrated in Figure 2.2 below:

Figure 2.2: WDRM settlement example



Source: AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, p. 42.
Note: The flow 'DR provided at reimbursement rate' goes from DRSP to AEMO and then from AEMO to Retailer.

13 The DRSP will share a proportion of this payment with the customer in accordance with the terms agreed between those parties.

14 AEMO MMS database.

Unlike other scheduled resources, DRSPs are not subject to cost recovery processes for regulation or contingency FCAS costs in respect of their WDRU. The Commission considered that the complexity associated with incorporating DRSPs into FCAS cost recovery would outweigh the associated benefits.

2.2 WDRM participation to date

To date two participants have registered as a DRSP in a NEM, with a combined 74 MW of response across 20 WDRUs. Collectively 1,258 MWhs has been dispatched over 2,225 dispatch intervals since the WDRM began operation in October 2021.

Under the NSW Electricity Infrastructure Roadmap, 95 MW of WDR capacity was awarded in the second round tender for firming infrastructure.[15] This capacity is required to be in place by December 2025.

In the final determination for the WDRM, the Commission analysed the impact of 150 MW of WDRM delivering 1,200 MWh of response each year for five years. Further information on this analysis can be found in appendix A.1, and our methodology for calculating WDRM benefits to date is in section 3.1.1.

When the WDRM awarded under NSW firming infrastructure is registered in the NEM, the capacity of WDRM will be closer to the Commissions' expectation in the final determination. However, the timing of this new New South Wales capacity is later than the Commission anticipated and the volume of response that will be delivered is still unknown.

2.3 Small customers are excluded from participating in the WDRM

In making the WDRM rule, small customers were excluded from the WDRM as they were not considered to be suited to the design mechanism and their inclusion would've involved significant additional costs. The Commission viewed progressing regulatory reforms that facilitate the transition towards a two-sided market, see section 1.2, was the best approach to allow small customers to participate in the market.

The Commission considered that small customers were not suited to the WDRM because:

- the form of demand response typically used with small customers, behavioural demand response, is not suited to being scheduled
- centrally determined baselines have not been demonstrated to work well for small customers
- there is a risk that relying on centrally determined baselines for small customers will lead to distortionary behaviour.

In addition, AEMO outlined that their costs would materially increase as significant systems changes would've been needed to account for the processing of an order of magnitude greater number of customers. Retailers estimated that their costs would be significantly higher to facilitate small customers in the WDRM as well.

See appendix A.2 for further background on the reasoning for excluding small customers.

15 AEMO services, Market Briefing Note, Tender Round 2 — Firming Infrastructure, November 2023, available here.

2.4 There are multiple options for demand-side participation

Demand side participation is an umbrella term for the actions a consumer can take regarding their energy consumption, responding to a wide range of incentives and events occurring in the market. Seven mechanisms enable demand side participation in the NEM. These are:

- The WDRM, as described in section 2.1.
- Contingency FCAS, procured by AEMO through the NEM dispatch engine (NEMDE). FCAS provides frequency responsive reserves that increase or decrease active power to dynamically stabilise supply and demand in the power system and control system frequency. Participation is open to resources that meet the technical requirements defined in AEMO's Market ancillary services specification (MASS).
- The small generator aggregator (SGA) framework, which allows participants to aggregate small units and participate as non-scheduled wholesale market participants. Small units include small generating units (below 30MW) and bi-directional units (below 5MW).
- Voluntarily scheduled resources (VSR), which allows financially responsible maker participants (FRMPs), usually retailers, to nominate resources, either individually or in aggregate, to participate in the wholesale market.
- The scheduled load classification, where loads have their consumption scheduled through the central dispatch process.
- The reliability and emergency reserve trader (RERT) scheme, where out-of-market reserves are procured by AEMO to maintain reliability and system security. For example, an aluminium smelter, which is not participating in the wholesale or FCAS market, may be willing to pause operations to reduce its demand during specific periods of high demand or low supply.
- Network support and control ancillary services (NSCAS), which are non-market ancillary services that may be procured by AEMO or transmission network service providers (TNSPs). These services maintain power system security and reliability and maintain or increase the power transfer capability of a transmission network.

In addition to these market mechanisms, some market customers may choose to be directly spot-exposed or subject to retailer led, or third-party, offerings. These options are explored further in appendix C.

Of all the options outlined above and discussed in appendix C, the WDRM is the only option available for non-FRMPs (parties that are not a retailer), to access the wholesale market spot price. This facilitates specialist demand response providers to contract with large users to deliver demand response to the market.

3 Three key areas for consultation

This chapter discusses, and sets out questions for stakeholders, on three areas of the WDRM:

- the benefits and costs of the WDRM
- whether changes should be made to the design of the WDRM
- the accuracy and suitability of baselines used in the WDRM.

Feedback across these, and any other aspects of interest to stakeholders, will assist the Commission in recommending whether the WDRM should be changed, remain as is or be phased out.

3.1 What are the benefits and costs of the WDRM?

The benefits and ongoing costs of the WDRM are a key input in determining whether the WDRM should be changed, remain as is or be phased out. Important questions to consider when assessing the benefits and costs are:

- the AEMC's proposed methodology for determining the efficiency gains from WDRM dispatch
- the ongoing costs of the WDRM
- what implementation risks the commission should consider
- whether the WDRM has impacted retailer offerings.

A formal and detailed cost-benefit assessment is not anticipated to be part of this review. Rather, the Commission will consider the costs and benefits of the WDRM as one input in making its recommendations.

3.1.1 Estimating the dispatch efficiency gains from the WDRM

A required outcome from this review is an assessment of the impact the WDRM has had on the spot price.[16] This review's analysis will focus on the efficiency gains of the WDRM to date and compare these results to the expectations described in the 2020 final determination.

This section describes:

1. Commissions analysis in the final determination establishing the WDRM
2. this review's proposed methodology to assess the spot price impacts of the WDRM.

The WDRM was introduced to reduce deadweight loss inefficiencies in dispatch

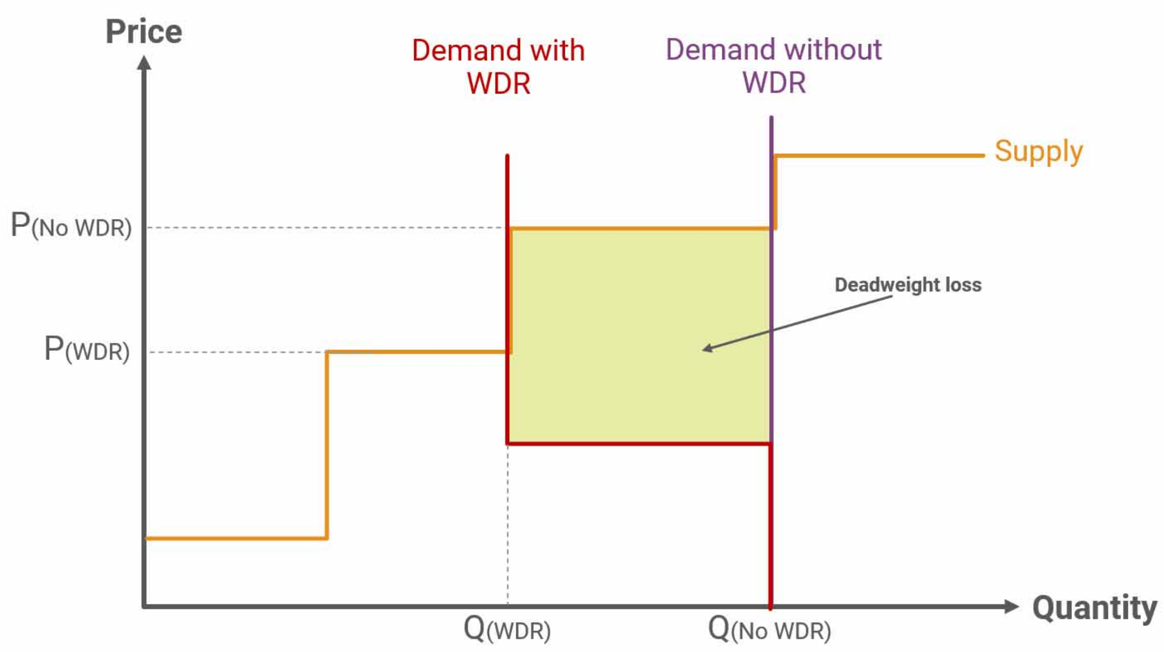
In the final determination for the WDRM, the Commission modelled the deadweight loss efficiency savings that the WDRM would have in the NEM.[17] Deadweight losses represent a loss of economic efficiency where the equilibrium outcome is not achieved. See Appendix A.1 for detailed information on the Commission's modelling in the final determination establishing the WDRM.

Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. This means that at high prices, the implied marginal willingness to pay for electricity for some consumers will be overstated. Figure 3.1 illustrates the inefficiency that is created by the assumed inelastic demand, showing the outcomes in prices and dispatch costs.

16 See clause 3.10.7(b)(1) of the NER.

17 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, pp. 21 - 28.

Figure 3.1: Deadweight loss resulting from assumed, price inelastic demand



Source: AEMC
Note: Figure is not to scale.

As AEMO does not know if and how demand response participants will respond to price, it forecasts demand without WDR to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where demand response participants do respond to the spot price, demand would have been $Q_{(WDR)}$, the efficient price would have been $P_{(WDR)}$.

This difference between the two price-quantity points results in a 'deadweight loss', highlighted above, and represents the welfare loss to society created by the elasticity of the assumed demand curve. This welfare loss means consumers are generally paying more for electricity than they would like to pay.

The WDRM reduces this loss by allowing the preferences of large consumers to be reflected in the demand curve. This results in a demand curve that more closely reflects the underlying preferences of consumers represented by the real demand curve. The resulting price and quantity set by the dispatch engine are consequently lower, and the deadweight loss is smaller representing an efficiency gain relative to the status quo.

Assessing the spot price impact of the WDRM

The proposed analysis for this review aims to calculate the actual reduction in deadweight loss inefficiencies due to the WDRM's operation to date using publicly accessible data from AEMO. This will be done by calculating the cost of additional generation that would have been required in a counterfactual where there was no wholesale demand response. The deadweight loss savings from the WDRM dispatch will be calculated in line with Figure 3.1.

For each interval where one or more WDR units were dispatched, these efficiency gains will be calculated by:

1. using bidding data, construct a bid stack from lowest to highest offers for each dispatchable unit identifier (DUID) and band
2. remove WDR from the bid stack and add the MW of WDR dispatched back into the demand
3. calculate the deadweight loss efficiency gains for that interval as the area between the new supply curve and demand curve with WDR.

The total efficiency gains to date are then calculated as the sum of efficiency gains across all intervals where WDR was dispatched.

In practice, the third step of this methodology is complex as it requires determining which generators would be required to meet the additional demand in the counterfactual scenario. This methodology also requires a number of assumptions which are described in more detail in appendix B.

Alternative methods may be required

The above proposed methodology above relies on a number of assumptions that mean results may not accurately recreate exact dispatch outcomes without the WDRM. Nevertheless, we consider that this methodology is fit for purpose in estimating the economic benefits of the WDRM on the formulation of spot prices. See appendix B.3 for further information.

The Commission will consider using alternative, more sophisticated modelling approaches, where timing and resource constraints permit. These may include using AEMO's NEMDE Queue service or an open-source NEMDE solver, such as Nempy.[18]

Question 1: Benefits of the WDRM

1. Do you agree with our proposed methodology to estimate the deadweight loss benefits of the WDRM?
2. Is there an alternative approach that the AEMC should consider in measuring the impact of the WDRM on spot prices?
3. Would the results from using a more sophisticated method significantly change the benefit calculation?
4. Are there other benefits of the WDRM and what is their materiality?

3.1.2 What are the costs of the WDRM?

The Commission proposes to consider both implementation and the ongoing costs associated with facilitating the WDRM.

The estimate of the implementation costs noted in the final determination was $23-33 million.[19] This included an AEMO cost estimate of $13-17 million and an allowance of $10-16 million in retailer and DRSP costs. The Commission proposes to compare these cost estimates with actuals, and other implementation costs that may have occurred to make improvements in estimating implementation costs for future reforms.

Ongoing costs of the WDRM may include financial costs, such as the system costs for AEMO required to maintain the WDRM, as well as ongoing procedural costs for AEMO and participants

18 Gorman et al., (2022). Nempy: A Python package for modelling the Australian National Electricity Market dispatch procedure. Journal of Open Source Software, 7(70), 3596, https://doi.org/10.21105/joss.03596

19 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. # .

required to support the WDRM. Information on these costs will be a valuable input into the Commission's recommendations in its final report for this review.

Question 2: Costs of the WDRM

1. What are ongoing financial and non-financial costs of facilitating the WDRM?
2. What were the financial and non-financial implementing the WDRM?

3.1.3 Potential issues in implementing changes to the WDRM

The Commission is interested in stakeholder views on what implementation risks it should consider in making its recommendations. For instance, in deciding whether WDRM should be phased out, how this would be implemented and the risks of this decision would be a key consideration.[20]

The Commission is primarily interested in the impact of changes to or phasing out the WDRM would have on existing contracts underpinning WDRM participation. This includes the 95 MW of WDRM capacity that was awarded to EnelX through the NSW long-term energy service agreements (LTESA) contracts, NSW peak demand reduction scheme (PDRS) contracts awarded to WDRM or any out-of-market contracts that may underpin WDR participation.

Question 3: Potential issues in implementing changes to the WDRM

1. What impact would changes to the WDRM have on existing contracts?
2. What impact would phasing out the WDRM have on existing contracts?
3. Are there alternative mechanisms that would allow existing contracts to continue if the WDRM is phased out?
4. Are there other risks that the AEMC should consider in deciding whether the WDRM should be changed, remain as is or phased out?

3.1.4 Are retailers offering demand-responsive contracts

The rule change request to establish a wholesale demand response mechanism argued that there were barriers for retailers to engage with consumers to provide demand response. Primarily, that retailers may opt not to support customer demand response if:

- they lack the experience or the organisational expertise to utilise wholesale demand response
- do not expect to recover the costs of engaging with a consumer to provide wholesale demand response.

Furthermore, the request noted that retailers have other ways of managing wholesale electricity market price risks, such as financial contracts and vertical integration.[21]

Third parties (that is, parties that are not the customers retailer), by contrast, can specialise in offering demand response services to customers. Prior to the introduction of the WDRM, third parties could only provide wholesale demand response by either registering as a retailer

20 In considering the removal of the WDRM the AEMC would consider how this could best be achieved. It would likely require a phasing out of the mechanism to allow existing participants to manage the change.

21 PIAC, TEC and TAI, Wholesale demand response mechanism - rule change request, p. 8.

themselves (which would also require compliance with all retailer obligations) or having a commercial relationship with a retailer.

To allow access by third parties, the value of wholesale demand response needed to be transferred from the existing retailer to a DRSP, who may be the customer or a third-party service provider engaged by the customer. Depending on the load profile of the customer, a retailer may be incentivised to offer contracts with demand response components to reduce their liability. While the WDRRR does aim to reduce this risk for retailers, depending on the risk profile of the retailer, they may be better incentivised to offer a retail plan with a demand response component rather than increasing their hedge protection. This would reduce or remove the ability of a DRSP to contract with that customer to provide WDR.

Question 4: Are retailers offering demand-responsive contracts?

1. Has the WDRM had a noticeable impact on retailers offering retail offerings with demand responsive aspects?
2. Has the WDRM resulted in customers investing in being able to be more responsive?

3.2 Should changes be made to the design of the WDRM?

This review will also investigate whether changes could be made to the design of the WDRM to increase participation in and the effectiveness of the WDRM. In considering whether changes can be made we are seeking feedback on whether:

- DRSPs should continue to be excluded from FCAS cost recovery
- the level of the WDRRR is appropriate
- sites with multiple connections should participate in the WDRM
- other changes could be made to the design of the WDRM.

3.2.1 Should DRSPs continue to be excluded from FCAS cost recovery?

DRSPs are not subject to FCAS cost recovery processes, with the Commission statin in the 2020 final determination that the cost and complexity associated with their incorporation would outweigh the benefits.[22]

Regulation FCAS costs

Regulation FCAS costs are apportioned by scheduled participants' contribution factors, which are determined by how well they follow their dispatch instructions.[23] This relies on four-second data conveyed via SCADA systems.[24] For the participants who don't have this telemetry (typically consumers), contribution factors are recovered on a nominal basis of load consumed, and managed through AEMO's existing settlement systems.

The telemetry and communications standards for WDRUs are set by AEMO through the wholesale demand response guidelines.[25] As a specific data granularity is not required for WDRUs, the current method for determining contribution factors was unlikely to be workable. AEMO also noted

22 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 144.

23 See clause 3.15.6A of the NER.

24 AEMO, *Regulation FCAS Contribution Factor Procedure* is available here.

25 See clause 3.10.1 (a)(2) of the NER.

that including DRSPs in causer pays would require significant changes to the causer pays process.[26]

The final rule did not require contribution factors to be determined for DRSPs as it was unclear how much demand response would be provided through the mechanism, and what the impact of this demand response would be on power system frequency.[27] This removed DRSPs from the recovery of regulation FCAS costs.

Contingency FCAS costs

Contingency FCAS costs are recovered based on a participant's gross consumed energy and/or gross sent out energy in an interval (as applicable), irrespective of what participant category it is registered in.[28] Contingency raise FCAS costs are apportioned among participant who generate, and contingency lower costs are apportioned among those who consume energy.

The Commission considered that WDRU operation was unlikely to result in a low-frequency event, which would trigger the need to use contingency raise FCAS, and as such, these costs should not be recovered from DRSPs.[29] In addition, the Commission noted that the consumers comprising a wholesale demand response unit already indirectly pay for contingency FCAS costs through their retailer who is a market customer. Therefore, having DRSPs pay for contingency FCAS costs could result in an over-allocation of FCAS contingency costs to customers participating in demand response.

Question 5: DRSP exclusion from FCAS cost recovery

1. Should DRSPs continue to be excluded from regulation and contingency FCAS costs?
   - If not, how could they be effectively included in the cost recovery process?

3.2.2 Should changes be made to the calculation of the WDRRR?

The WDRRR is intended to reflect the wholesale cost component of an average large customer's retail tariff. As outlined in section 2.1, this payment allows the retailer for the WDRU to cover its costs of hedging for the customer's baseline level of consumption in the wholesale market.

The WDRRR is calculated as the peak period load weighted average spot price over the 12-month period ending immediately before the start of the quarter.[30] Peak periods are those specified in the "peak load profile" from the contract specification Australian Peak Load Electricity Futures Contract in the ASX 24 Operating Rules of the Australian Securities Exchange.[31]

The Commission considered four alternative methodologies before choosing the one above:[32]

1. rolling average of wholesale prices over the previous 12 months
2. rolling average of peak ASX futures contract prices over the previous 12 months

26 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 145.
27 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 145.
28 AEMC, *Integrating energy storage systems into the NEM*, rule determination, 2 December 2021, p. 48.
29 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, pp. 145-146.
30 See clause 3.15.6B(g) of the NER.
31 If this specification ceases to be in effect AEMO, acting reasonably, may determine an equivalent period. See clause 3.15.6B(g) of the NER.
32 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, pp. 205-206.

3. quarterly peak ASX contract prices traded in the 20 business days immediately prior to the beginning of the quarter in which the demand response is provided, multiplied by a risk weighting of 1.1
4. rolling average of base ASX futures contract prices over the previous 12 months.

On balance, the Commission concluded that the average demand-weighted spot price during peak demand periods was the best option as:[33]

- contract market liquidity issues in South Australia present challenges for methodologies that utilise forward contract prices
- there is no clear or transparent basis on which an appropriate “risk weighting” can be determined for the purposes of method 3 (as listed above)
- retail tariffs of large customers are generally complex and incorporate peak rates to account for variations in load profile, particularly where the customer has high levels of consumption during peak demand periods
- while options for calculating the reimbursement rate may yield incremental improvements in accuracy, they may also add significant complexity to the process of determining the rate
- the average demand-weighted spot price during peak demand periods provides a simple, transparent and objective reference point to approximate the wholesale cost component of the average retail tariff.

Question 6: Should changes be made to the calculation of the WDRRR?

1. Is the current methodology for calculating the WDRRR appropriately reflecting the wholesale cost component of an average large customer’s retail tariff?
   - if not, is there an alternative methodology that would and could it be implemented effectively?
2. Are their other changes that can and should be made to the WDRRR?

3.2.3 Should sites with multiple connections participate in the WDRM

Only customers which comprise a single connection point are eligible to be classified as a WDRU to participate in the WDRM.[34] In April 2022, EnelX submitted a rule change request proposing to allow sites with multiple connection points to participate in the WDRM.

EnelX stated that, while not addressed in the AEMC’s final determination or AEMO’s WDR guidelines, it was their understanding that this restriction was put in place to address a concern about gaming.[35] Their proposed solution was to allow sites with multiple connection points while addressing gaming concerns.

EnelX outlines that many large and commercial and industrial loads are served by multiple electrically interconnected connection points and are prevented from participating in the WDRM. They estimated that 300MW of WDR-capable loads are impacted by this restriction today, with this level expected to increase over time.

33 AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, pp. 209-210.
34 See clause 2.3.6(m)(1)(i) of the NER.
35 EnelX, Expaning eligibility under the WDRM, Rule change request, 14 April 2022.

The AEMC has previously engaged with AEMO and EnelX on this request, and based on AEMC resourcing constraints and concerns about the complexity of the change, the request has not yet been initiated. We will not consider the merits of this rule change during this review, as this will occur during the formal rule change process for this request. The Commission is seeking stakeholder views on whether this change would impact their ability to participate in the WDRM.

This feedback will inform the Commission on how best to prioritise this rule change as part of our forward work program. For instance, if this review finds that changes need to be made to increase participation in the WDRM, this rule change would increase in priority for the AEMC. Conversely, if we recommend that the WDRM should be phased out, then this rule change would reduce in priority for the AEMC.

Question 7: Should sites with multiple connections participate in the WDRM

1. Should sites with multiple connection points be able to participate in the WDRM?
2. What are the potential benefits and costs of this change?
3. Are there other changes that would have a greater impact on participation in the WDRM?

3.3 Do baselines produce an accurate counterfactual demand?

Baselines are critical to the operation of the WDRM as they determine the quantity of demand response offered into the market. If baselines are set too high, consumers will pay more than they need to. If they are too low, there would not be enough incentive to encourage demand response in the market.

There are two aspects of the baseline methodology of particular interest:

- does the baseline methodology process work as intended
- are baselines appropriate for a future with increasing levels of CER active in the NEM.

3.3.1 Is the baseline methodology working as intended

Baselines estimate the counterfactual level of consumption for WDRUs that would have occurred were it not for the demand response. DRSPs can choose from four baseline methodologies, they are largely based on the CAISO “10 of 10” framework and are differentiated by day type:[36]

1. all days baseline methodology
2. business days baseline methodology
3. non-business days baseline methodology
4. business + non-business days composite baseline methodology.

In applying to register a load as a WDRU a DRSP will choose one of these methodologies to apply to the historical demand. The baseline values need to be below accuracy and bias thresholds of 20% and ±4% respectively. No NMIs that have undergone this eligibility assessment have failed to meet these thresholds.[37]

This suggests that the WDRM baseline methodologies and eligibility assent methodology is suitable for a variety of load types. However, AEMO noted that it is difficult to draw firm

36 AEMO, WDRM — baseline methodology register, 4 June 2021.

37 AEMO, *WDRM annual report*, June 2024, p. 15.

conclusions regarding the long-term efficacy of eligibility and compliance methodology or the accuracy and bias thresholds given the limited operation of WDRM to date.

AEMO also undertakes bi-annual compliance testing of WDRUs to ensure that they continue to meet the accuracy and bias statistics. Since AEMO began testing in June 2022, on average 88% of NMIs were compliant with the required accuracy and bias thresholds.[38] AEMO has noted that the non-compliant NMIs were the result of changing load patterns or seasonality of load and may become compliant again.

Process for requesting new baselines

AEMO's WDR guidelines are required to outline a process for how proposals for new baseline methodologies can be made.[39] This requirement reflected that baseline methodologies are not a 'one-size-fits-all' and participants are equipped to develop new approaches that can reflect improvements in baselining or applying baselines to new types of loads.

Following a request for new baselines by EnelX, AEMO recently made a final decision to introduce two new baseline methodology options.[40] These two new options will be implemented for the all days and business days options listed above, and are:

- New CAISO 10 of 10 baseline methodology options with a shorter 20-day lookback period for eligibility and compliance to better accommodate seasonally varying loads.
- New High 5 of 10 baseline methodology options to better accommodate weather-sensitive loads.

In addition to the two new methodologies, AEMO committed to further consultation for a baseline methodology that better accommodates sites with solar PV. As part of this consultation, AEMO will consult on the settings for a trial of a higher baseline methodology accuracy threshold. This includes duration, assessment criteria and transition arrangements.

These developments indicate that the processes put in place through the final rule provide transparency to the market about how new baseline methodologies are being developed and enable innovative approaches to baseline methodologies to be developed over time.

Question 8: Is the baseline methodology working as intended

1. Are the current baseline methodologies producing accurate baselines for WDRUs?
2. Is the process for requesting new baselines sufficient to ensure that baselines can accommodate a wide variety of loads?
3. Are there any aspects of the baselining process impacting further participation in the WDRM?

3.3.2 Are baselines suited for increasing levels of CER?

Across Australia, governments are seeking to achieve net zero emissions by or before 2050, including through policies to accelerate consumer energy resources (CER) uptake. This increased

38 AEMO, Wholesale demand response - Annual report, June 2022, p. 12.
AEMO, Wholesale demand response - Annual report, June 2023, p. 13.
AEMO, Wholesale demand response - Annual report, June 2024, pp. 13-14.

39 See clause 3.10.1(a)(4) of the NER.

40 AEMO, *EnelX baseline methodology proposal*, final report, December 2024, p. 4.

volume of CER may result in less predictable demand profiles for individual load, limiting their ability to pass a baseline assessment.[41]

The baselining approach used in the WDRM requires individual loads to be predictable to produce an accurate baseline measurement. The Commission has previously noted that traditional commercial and industrial resources (for example, commercial chillers), and new types of large loads (for example, data centres) are increasingly active in the NEM.[42] For instance, consumers may:

- invest in specific resources, such as solar panels or batteries
- look to shift their load energy usage on a network or TOU tariffs
- become spot price exposed through a retail offering if they have the flexibility and sophistication to do so.

As loads become more active, a baseline approach to measuring demand responsiveness would be harder to apply, resulting in fewer resources being able to participate in the WDRM. The Commission previously considered that baselines would be a limiting factor and that a move to a two-sided market would be the enduring solution for facilitating the demand side in dispatch.[43]

As noted in section 1.2, the Commission's recent decisions regarding the CER benefits and IPRR rule changes mean that the demand side can more easily participate in dispatch without using baselines. This raises the question of whether these two changes have reduced the need for a WDRM or whether the WDRM still plays an important role in engaging the demand side. In considering this, the Commission will also have regard to whether the third-party access enabled by the WDRM is best placed to provide this access. See section 2.4 for further information about the WDRM facilitates non-FRMP access to the wholesale market.

Question 9: Are baselines suited for increasing levels of CER?

1. Does the increased volume of investment in CER result in fewer loads able to meet a baseline?
2. Does the combination of CER benefits and IPRR mean that the demand side is appropriately catered for in dispatch?
3. Is there a role for the WDRM in facilitating access to the wholesale market by third-parties?

41 To address the broader system impact of increased CER, the IPRR rule introduced monitoring and reporting functions for AEMO and the Australian Energy Regulator to provide evidence on the impact of unscheduled price-responsive resources on AEMO's forecasts.

42 AEMC, *Integrating price responsive resources in the NEM*, rule determination, 19 December 2024, p. ii.

43 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. iv.

4 Making recommendations

When considering the issues within this review, the Commission considers a range of factors and is guided by the national electricity objective (NEO). This chapter outlines:

- the issues the Commission must take into account
- the proposed assessment framework.

4.1 Acting in the long-term interests of consumers

In conducting reviews, the Commission must have regard to the relevant energy objectives.[44] For this review, the relevant energy objective(s) is the NEO:[45]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

4.2 Proposed impact methodology and assessment criteria

4.2.1 Regulatory impact analysis methodology

Considering the NEO and the issues identified in this consultation paper, the Commission proposes to use the set of criteria outlined below to develop and assess its recommendations. These assessment criteria reflect the key potential impacts — costs and benefits — of the NEO framework that will be able to assist the Commission in making its recommendations.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies with the depth of analysis commensurate with the potential impacts of any recommendations. The regulatory impact analysis methodology may be refined as this review progresses, including in response to stakeholder submissions.

4.2.2 Assessment criteria

The proposed assessment criteria and rationale for each is as follows:

- **Principles of market efficiency:** This assessment criterion, and the two key sub-criteria noted below, are central to the aim of the WDRM; to provide appropriate incentives facilitate demand response within central dispatch to maintain productive and allocation efficiency. If this aim is achieved, the framework is likely to promote the long-term interests of consumers in terms of reliability, system security, and cost outcomes. In particular:
  - Efficiency: The Commission will consider whether the WDRM is providing efficient incentives for participants to provide demand response through the central dispatch

44 Section 32 of the NEL.

45 Section 7 of the NEL.

  - process. The extent that the WDRM has lead to efficient wholesale spot prices and dispatch costs will also be considered.
  - Competition: The Commission will consider whether the WDRM resulted in increased consumer choice for demand response and reduced barriers for demand response service providers to offer this response into the market
- **Outcomes for consumers:** Under this criterion, the question is whether the WDRM has resulted in better price signals, incentives and opportunities for consumers to invest in responsive loads and use these assets in the wholesale market.
- **Implementation considerations:** The Commission will assess any potential changes to the WDRM by balancing the cost and complexity of implementation and ongoing regulatory and administrative costs.
- **Principles of good regulatory practice:** In making its recommendations, the Commission will consider whether any proposed changes to the compensation frameworks will lead to an end result that is predictable and durable, while being as simple and transparent as possible.

Question 10: Proposed assessment framework

1. Do you agree with the proposed assessment criteria for this review?
2. Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

A Additional background

This appendix provides further background from the AEMC's 2020 final determination on:

- the benefits modelling in the 2020 final determination
- the reasons for excluding small customers from the WDRM.

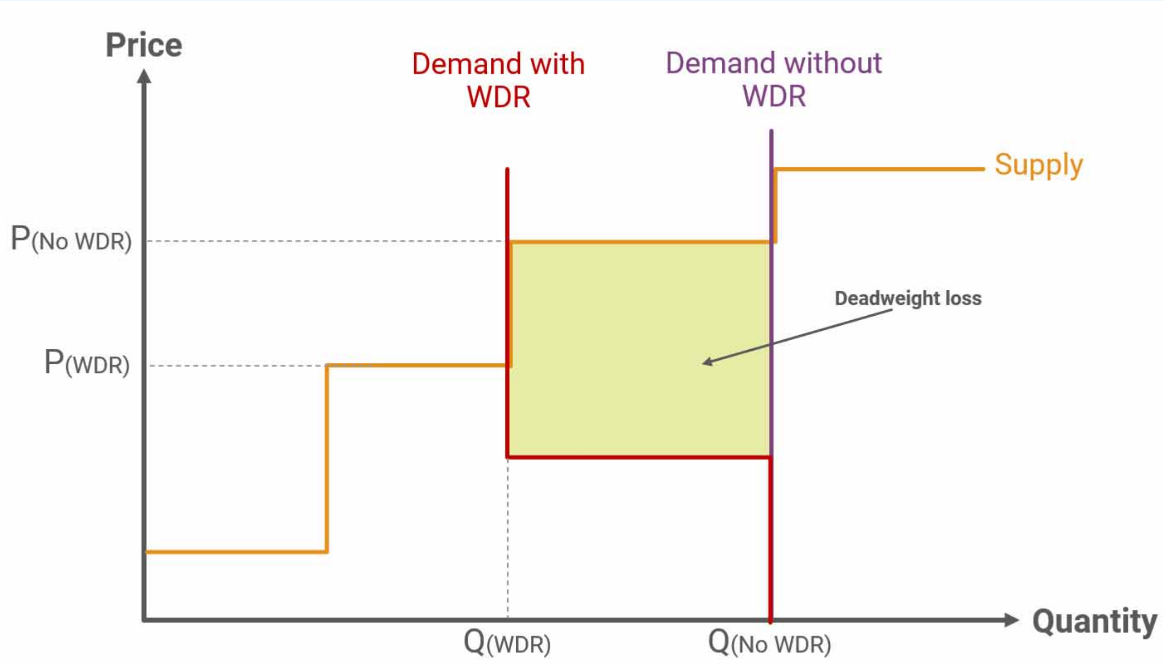
A.1 Final determination analysis

In establishing the WDRM, the Commission completed some basic quantitative modelling to estimate efficiency gains from different levels of WDRM. The modelling showed that the efficiency gains should exceed the implementation costs, promoting consumers' long-term interests. The Commission noted the limitations inherent in assessing the quantitative impacts of the WDRM, and this analysis was used to inform decision-making in addition to the qualitative assessments of the WDRM.[46]

The NEM forecasting process does not assume price-elasticity

Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. This means that at high prices, the implied marginal willingness to pay for electricity for some consumers will be overstated. Figure A.1 illustrates the inefficiency that is created by the assumed inelastic demand, showing the outcomes in prices and dispatch costs.

Figure A.1: Deadweight loss from price inelastic demand forecasts



Source: AEMC
Note: Figure not to scale

As AEMO does not know how load will respond to price, it forecasts demand to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of

46 See section 2.4.2 of the final determination for further detail.

$P_{(spot)}$. However, where demand does respond to the spot price, actual demand would have been $Q_{(efficient)}$, and the efficient price would have been $P_{(efficient)}$.

This results in a ‘deadweight loss’, highlighted above, which represents the welfare loss to society created by the elasticity of the assumed demand curve. This welfare loss means consumers are generally paying more for electricity than they would like to pay and FCAS is required to balance supply and demand.

The WDRM reduces this loss by allowing the preferences of large consumers to be reflected in the demand curve. This results in a demand curve that more closely reflects the underlying preferences of consumers represented by the real demand curve. The resulting price and quantity set by the dispatch engine are lower, and the deadweight loss is smaller representing an efficiency gain relative to the status quo.

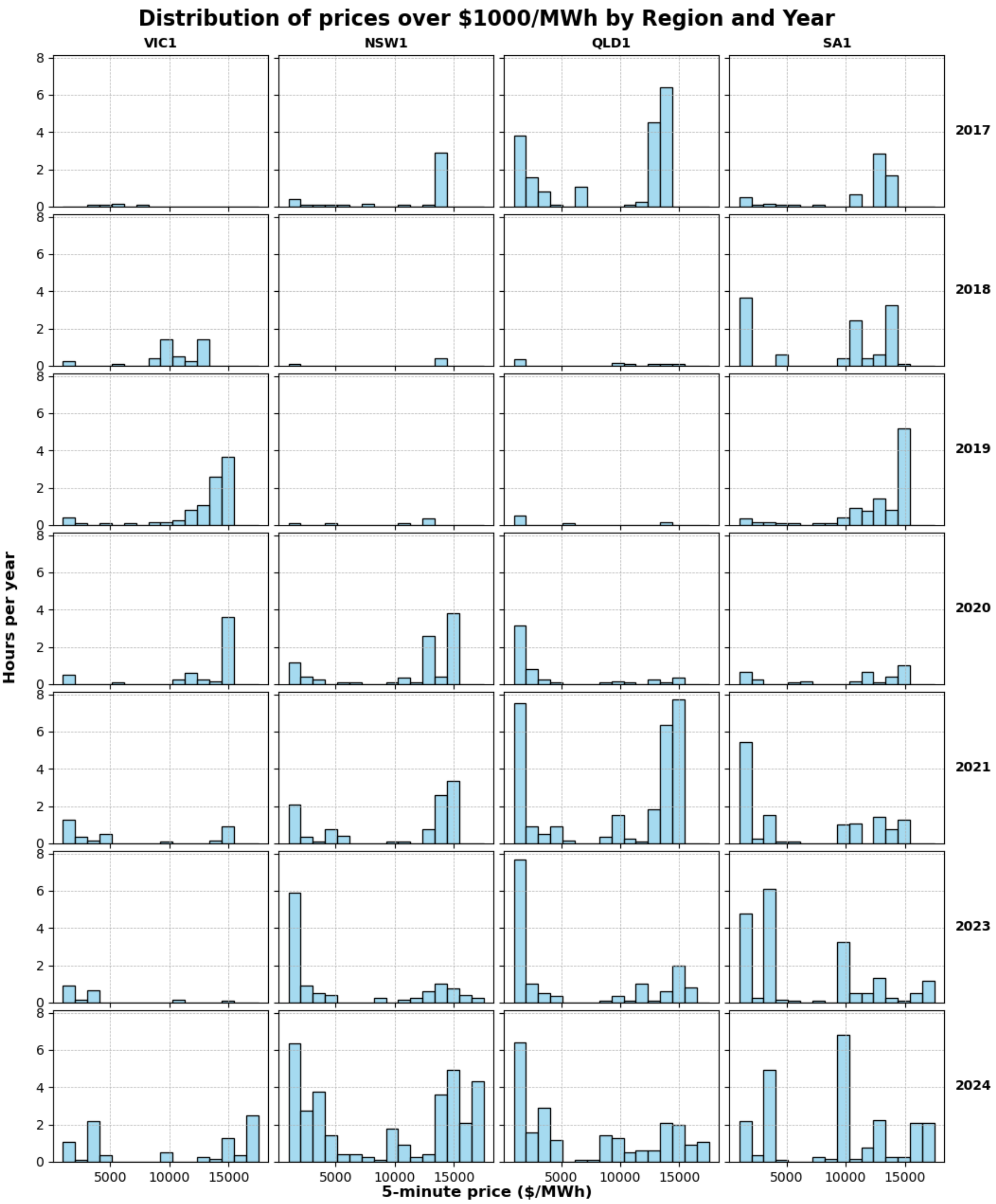
Final determination modelling assumptions

The modelling for the final determination estimated the efficiency gain for different levels of additional wholesale demand response enabled by the WDRM. It used a set of simplified assumptions and was a heuristic for considering the relationship between the amount of demand response, its impact on spot prices and the resulting increase in efficiency. The modelling assessed the impact of the WDRM over five years and assumed:

- a hypothetical region that represents the entire NEM
- that there are eight hours of high prices per year where demand reductions are dispatched through the mechanism.

Five years was used as an estimate of the period that the mechanism may be in place before a possible transition to a two-sided market design. The assumption of eight hours is considered to be a conservative (low) estimate of the duration of high priced events across the NEM per year. Figure A.2 shows that since 2017 there has been more than eight hours of high priced intervals (over $1,000/MWh) per year across the NEM.

Figure A.2: Distribution of high-priced dispatch interval



Source: AEMC analysis of AEMO MMS data
Note: 2022 was removed due to the significant market events that occurred during that year.

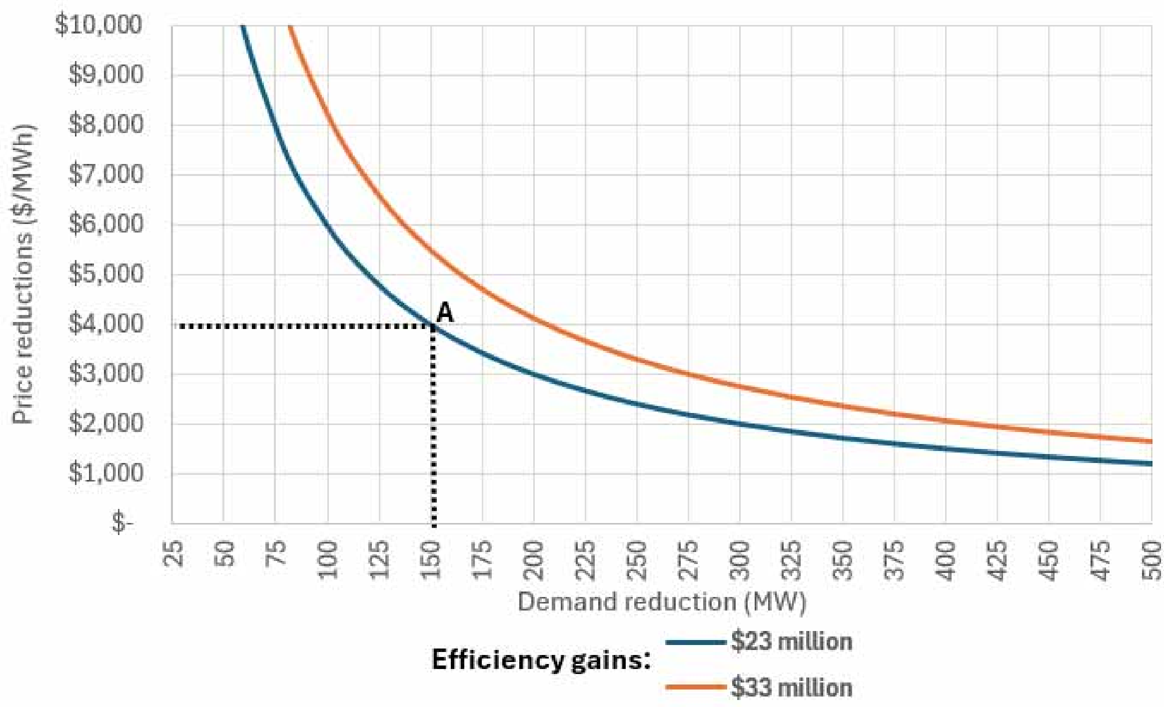
This figure has been updated since the Commission's final determination to include up to CY24. Figure A.2 shows that high-priced events have remained in the NEM, presenting opportunities for WDRM to be dispatched and impact price setting dynamics.

Modelling results from the final determination

Based on the assumptions above, the modelling considered two efficiency gain curves from demand response, where the response resulted in price reductions of $4,000/MWh and $5,000/MWh in each interval it operated respectively. Total implementation costs of the WDRM were assumed to be $23-33 million. This includes the AEMO cost estimate of $13-17 million and an allowance of $10-16 million in retailer and DRSP costs.

Any point on the blue line in Figure A.3 represents an efficiency gain (reduction in deadweight loss) of $24 million. For instance, point A indicates if the WDRM enables 150MW of additional demand response that results in a price reduction of $4,000/MWh for eight hours per year over five years, an efficiency gain of $23 million can be achieved.

Figure A.3: Modelled deadweight loss efficiency saving



Source: AEMC
Note: Figure Note

The model also considered the upper end of the assumed cost range, $33 million. As illustrated by the figure above, if 200 MW of WDRM can deliver $4,125/MWh price reductions in the wholesale price per dispatch interval, the efficiency gains enabled by the mechanism would exceed the upper end of the cost range.

Given the historical analysis of high-priced intervals and feedback on the potential amount of demand response that could be provided, the Commission considered the assumptions above reasonable. Based on this analysis, the Commission considered it reasonable to assume that there will be enough demand response to high prices to at least offset the implementation costs (if they are within the assumed range).[47]

Benefits not included in the modelling

47 AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, p. 27.

There are a number of benefits and costs that may arise from the introduction of a wholesale demand response mechanism that were not included in the final determination model, including:

- Increased transparency of demand side participation in the wholesale market. The benefits assessed in this model were derived only from a more efficient demand side utilisation of electricity. Making this demand response transparent to the rest of the market informs market participants and the market operator and can drive more efficient unit commitment decisions.
- Increased competition for the provision of wholesale demand response from retailers. The introduction of the WDRM was expected to place greater competitive pressure on retailers to offer demand response products to consumers in competition with DRSPs. This was expected to lead to more price responsive demand being facilitated outside the mechanism.
- If a two-sided market was implemented, the extent to which costs accounted for in the model are costs that would be incurred in the transition to the two-sided market (that is, costs that could be attributed to that transition rather than to the demand response mechanism).
- The model excluded the ongoing costs to AEMO of operating the mechanism, and the ongoing costs to retailers and DRSPs for facilitating this mechanism. While the Commission did not have access to detailed information on these costs, it expected that they would be relatively small and would therefore not fundamentally change the outcome of the analysis.

Conclusion

As discussed in its final determination, the Commission considered that this analysis demonstrated, under a reasonable set of assumptions, the efficiency gains enabled by this mechanism should exceed the implementation costs, promoting the long term interests of consumers.[48]

A.2 Small customers are unable to participate in the WDRM

As set out in its final determination, the Commission excluded small customers from the WDRM.[49] The Commission considered that small customers were not suited to the WDRM because:

- the form of demand response typically used with small customers, behavioural demand response, is not suited to being scheduled
- centrally determined baselines have not been demonstrated to work well for small customers
- there is a risk that relying on centrally determined baselines for small customers will lead to distortionary behaviour.

In addition, the Commission considered that there would likely be significant additional costs and complexity associated with including small customers in the WDRM.

A.2.1 Behavioural demand response is not suited to scheduling

Behavioural demand response is uncertain and does not suit the accuracy and predictability required to participate in the WDRM.

Behavioural demand response involves eliciting some amount of demand response from consumers on request, without having direct controls on consumers' loads. This was the most common type of demand response that small customers engage in at the time of the final determination.[50] While these programs provide customers with the opportunity to provide demand

48 AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, p. 28.

49 AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, pp. 78-84.

50 AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, p. 79.

response, they often mean the party calling for the demand response is unsure how much will be provided.

Being scheduled requires participants to provide information to the market ahead of real time, submit dispatch offers every five minutes and a commitment to meet dispatch targets. Given this, the Commission concluded that behavioural demand response programs were not suited to being scheduled.[51]

A.2.2 Centrally determined baselines do not work well for distributed controllable devices

Small customer loads consume energy at variable times and are not suited to the baseline process at individual NMIs required for the WDRM.

A number of devices that small customers would be expected to use to provide wholesale demand response are also highly variable in the timing of their electricity consumption, for example:

- pool pumps
- household batteries
- electric vehicles.

Because these loads can be easily adjusted to consume at different times of day, they are difficult to accurately baseline. For example, the charging regime of an electric vehicle will be highly dependent on a number of variables relating to the use of that vehicle. This makes developing accurate baselines for electric vehicles very difficult.

Small customer loads can be aggregated together and the inherent variability among those loads can be balanced out, making aggregated small customer loads easier to predict than individual small customer loads. However, the settlement model set out in the final determination relies on baselines being determined at individual NMIs. As such, the benefits of developing baselines to apply to a portfolio of small customers would not be realised under this mechanism.

In order for small customer baselines to be accommodated in the WDRM, AEMO would need to set very broad baseline methodology metrics. In essence, this would mean allowing participation of loads that have inaccurate or biased baselines. This would in turn have the effect of reducing the efficacy of the mechanism and imposing risks on the market more broadly. Consequently, the Commission did not consider it appropriate to have the baseline methodology metrics broadened to allow for highly variable loads and devices to participate.[52]

A.2.3 Certain baseline methodologies may lead to distorted small customer behaviour

Introducing centrally determined baselines for small customer demand response may also introduce the risk of driving inefficient behaviour, depending on the baseline methodology.

Much of the small customer demand response would be delivered through smart devices that can vary consumption times without affecting customers. Because of this it is possible that paying for a reduction from a baseline would encourage consumers to shift consumption to peak periods, the opposite of the intention of the mechanism. This is explained further in Box 1 below:

51 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 79.

52 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 82.

Box 1: DISTORTIONARY CONSUMER BEHAVIOUR

If small customers were paid to reduce consumption relative to a baseline weighted towards recent consumption patterns, it is possible this would encourage consumption during peak periods.

Imagine a DRSP that signed up a number of customers with pool pumps that normally clean pools in the middle of the day. Also imagine that these customers all had flat retail tariffs. Because the customers do not mind what time the pool pumps are operated (both in terms of impact on the pool and because the retail rate is flat), the DRSP is given full control in exchange for the best possible profitability from the wholesale market.

The DRSP would be encouraged to move the consumption of the pool pumps out of the middle of the day and into peak periods. The DRSP would do so because it is more likely that there could be high wholesale prices in the peak, from which the DRSP (and customer) can profit if the pool pump is operating in the peak and can be turned off to provide demand response, provided the baseline indicates the customer usually consumes at this time.

What has actually occurred is that:

- the pool pumps are no longer being operated during the day when solar output is its greatest
- the pool pumps consume electricity in the evening which increases system demand in the wholesale market and pushes up wholesale prices at this time
- when the wholesale price gets high enough, the pool pumps will be turned off and will consume overnight or in the middle of the day.

In the end, all consumers are being paid to turn off pool pumps that would have never been on in that peak period in the first place.

Source: AEMC, Wholesale demand response mechanism, rule determination, 11 June 2020, pp. 82-83.

This behaviour arises because these loads are highly controllable and can be changed without a material impact on the customer (unlike larger commercial loads), and because the baseline methodology does not include an adjustment to account for this behaviour.

A key point to note is that all of these devices are well suited to providing wholesale demand response — they can be controllable and changes to consumption times do not have significant impacts on the customer. In fact, there are retailers using pool pumps, batteries and electric vehicles to provide wholesale demand response. However, a mechanism that pays for demand response relative to a centrally determined baseline that is based on recent consumption patterns may encourage inefficient usage of these devices.

A.2.4 Costs and complexity

The Commission considered that if small customers were able to participate in the mechanism, this would significantly increase costs for the market operator and retailers.[53] This is because if AEMO and retailer systems are required to account for a greater number of customers, the complexity and costs would significantly increase.

There was also difficulty in adequately addressing the application of energy-specific consumer protections to arrangements between small customers and DRSPs.[54] Energy consumers are protected by energy specific provisions under the National Energy Retail Law and associated

53 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 84.

54 The Commission noted a holistic review of consumer protections was required to consider consumer protections in non-traditional energy services and products, which included wholesale demand response. AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, p. 31.

National Energy Retail Rules (NERR), which relate to the supply of energy by distributors and the sale of energy by retailers to customers. These protections would not apply to the relationship between customers and DRSPs given that the service provided by DRSPs to customers is not a sale or supply of energy.

Given the close linkages between the NERL and the NERR, the Commission considered it was not possible to consider one in isolation of the other.[55] It noted that it is likely that any change to the application of the relevant consumer protections would require changes to the NERL as well as to the NERR. Which require the approval of the COAG Energy Council and could not be made through changes to the NER alone.

55 AEMC, *Wholesale demand response mechanism*, rule determination, 11 June 2020, pp. 31-32.

B Example of dispatch efficiency gains analysis

This appendix provides an example and further information on the AEMC's proposed approach and methodology for estimating the deadweight loss benefits of the WDRM for this review.

B.1 Example of calculating deadweight loss savings for a single interval

Interval: November 12th 2021, 12:25pm, NSW

Price: $43.65/MWh

WDR dispatched: 10MW, single unit (DRXNDA01), bid in at $0

Price setters: ER02, ER03

In this interval:

- Eraring units 2 and 3 are price setting, with offers in their band 3, where they have offered 70MW each at $42.99/MWh and $43.03/MWh respectively. Both offers are adjusted to $43.65/MWh when accounting for the marginal loss factors 0.9849 and 0.9858 respectively.
- The targeted dispatch in this interval is 277.84MW for each DUID, which comprises 210MW in their band 1 offers and 67.84MW in their band 3 offers.
- In the counterfactual where the NSW demand response unit does not bid into the market, there will be an additional 10MW that needs to be covered by other generators.
  - ER02 and ER03 have an additional 2.16MW each in their price setting band 3 offers, they will be dispatched in these bands to cover 4.32MW.
  - In the bid stack, the next lowest offer after ER02 and ER03's band 3 offers is UPPTUMUT's band 4 MLF adjusted offer of 335MW at $50.10/MWh. UPPTUMUTs targeted dispatch in this interval is 2.93MW (from its band 4 offer), so they will be dispatched to cover the remaining 5.68 MW in the counterfactual.

The deadweight loss benefits from this counterfactual is calculated as:

$(ER02_{Offer} - WDR_{Offer}) \times (ER02_{Dispatch})/12 + (ER03_{Offer} - WDR_{Offer}) \times (ER03_{Dispatch})/12 + (UPPTUMUT_{Offer} - WDR_{Offer}) \times (UPPTUMUT_{Dispatch})/12$

As the WDR bid in at $0/MWh this simplifies to:

($43.65 x 2.16 + $43.65 x 2.16 + $50.10 x 5.67)/12

This results in avoided deadweight loss of $39.39 from WDR dispatch in this interval.

B.2 Modelling assumptions

The interval described above is a simple case, where there are only two DUIDs from the same region setting the price, and these are from offers in the energy market only. There are many intervals that are more complicated, and in these intervals, a number of assumptions must be made:

- generator offers are reflective of their short-run marginal costs, and reflect their cost of additional generation
- WDRUs would have consumed at their baseline level had not been dispatched
- generator bids would have been the same had WDR not been dispatched
- all generators across the NEM are included in the counterfactual bid stack (i.e. the entire NEM is interconnected during these intervals)

- no constraints impact the DUIDs which generate more in the counterfactual
- no generators reduce their generation in the counterfactual (i.e. additional demand is met by additional generation only, rather than additional generation being met by large increases in some generators balanced by small decreases by other generators)
- the price setting DUIDs are identified using AEMOs NEMPRICESETTER files, which in turn involve a number of additional assumptions described below.

B.2.1 Price setting in the NEM is often very complex

Dispatch prices are set through AEMO's NEM Dispatch Engine (NEMDE), which determines dispatch and spot prices across the NEM every five minutes. It is formulated as a linear programming optimisation to find the least-cost mix of resources to meet demand, and the spot price is formulated as the marginal cost of supplying an additional 1 MW of demand. There are several implications that arise from setting spot price via marginal costs, including:

- a single marginal unit does not always set the price, and as a corollary to this, the aggregate offer curve often doesn't provide information on the units setting the spot price, i.e. the simple picture of spot price being the intersection of demand and the aggregate offer curve is not always correct.
- the final spot price can have multiple contributors since small adjustments to the dispatch of multiple different units can result in an overall least cost dispatch to provide the next 1 MW of demand.
- due to NEMDE co-optimising dispatch across all markets, the final energy spot price can be set by contributions from the different FCAS markets.
- this could include some generators reducing their generation in response to an increase in demand (for example if a unit is required to generate more in the energy market, it may have to reduce its generation in one or many FCAS markets)
- often there are "tie-breaking" situations where there are multiple units with the same offers.

Due to these intricacies and the complexity of the optimisation challenge, the proposed methodology for this review relies on a number of assumptions to determine the price setting DUID:

- the marginal price setting DUID or DUIDs are determined based on energy market offers only (market = ENOF); we consider impacts from FCAS markets to be minimal
- in the case of multiple price setters with the same offer, we consider all of these DUIDs to be price setters in the bid stack
- in the case of multiple price setters with different offers, the one which the highest "increase" field is chosen (i.e. the one that must increase its generation by the most given a 1MW increase in demand)
- any tie-breaking variables are ignored
- if the price setter files indicate that some generators must reduce their generation as a result of an additional 1 MW in demand, we ignore these reductions in our calculation of benefits.

B.3 Our proposed methodology is suitable for the majority of WDR dispatch intervals

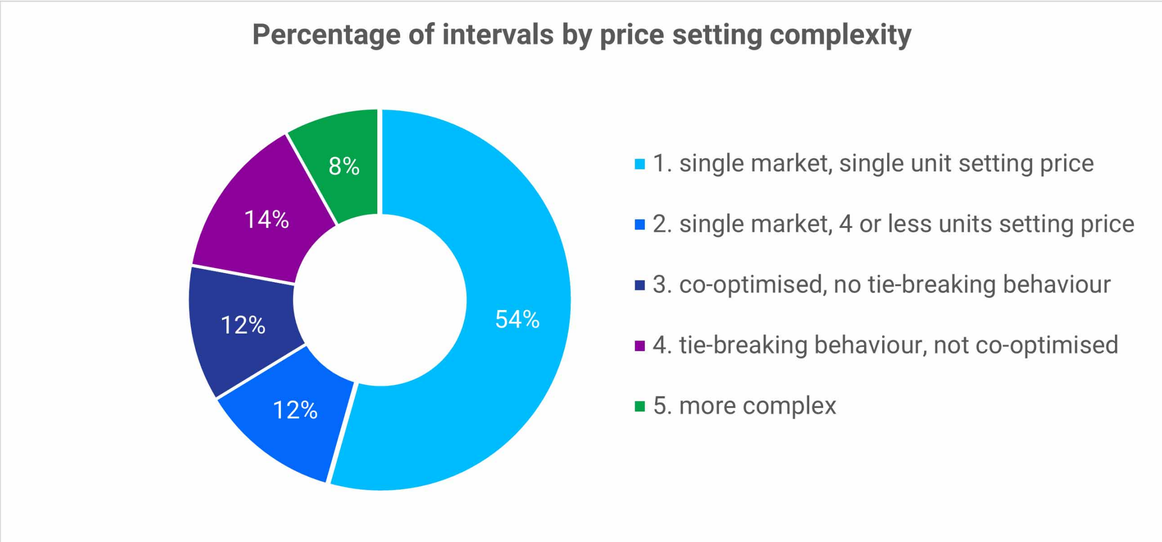
We consider that the proposed methodology to assess the potential efficiency gains of the WDRM for this review is suitable across the majority of intervals in which WDR was dispatched.

We have analysed the price setter files for intervals where WDR was dispatched to determine how frequently these complex price setting dynamics occur. We have split these intervals into the following groups:

1. Single market, single unit setting price; these are the simplest intervals in which the price in the energy market is set but a single unit that has bid into the energy market.
2. Single market, four or less units setting price; this is the second simplest case in which the price in the energy market is set by four or fewer units in the energy market (usually this is four units of the same plant).
3. Co-optimised, no tie-breaking behaviour; in these cases the price in the energy market is set by a combination of offers from both the energy market and FCAS markets. There is no tie-breaking variables introduced.
4. Tie-breaking behaviour, not co-optimised; in these cases the price is being set by offers from the energy market only, however there are some tie-breaker variables introduced by NEMDE to solve the optimisation.
5. More complex; this bucket contains all intervals that are more complex than those above.

The results of this analysis is shown in Figure B.1 below.

Figure B.1: Complexity of price setting intervals when WDR was dispatched



Source: AEMC
Note: Figure Note

Using the methodology with the assumptions outlined above, we can calculate counter-factual generation costs for the intervals in categories 1-4 of complexity, which together comprise roughly 92% of intervals where WDR was dispatched.

- In the first category, our proposed methodology for calculating benefits works well as it requires the fewest assumptions.
- In the second category, where there is more than one unit setting price, we will take the unit with the highest “increase” field as the price setter, and if there are instances where this value is the same across units we will consider all units as the price setter.
- In the third category, we will ignore FCAS markets as we assume their contributions to energy spot prices are minimal.

- In the fourth category we will ignore the tie-breaking variables and make the same assumptions as in case two, wherein we assume the unit with the largest “increase” is the price setter, and if there are units with the same “increase” we treat them all as price setters.

C Demand side participation options

This appendix provides an overview and background to the services and market categories that currently enable demand side participation in the NEM. These are:

- voluntarily scheduled resources
- small resource aggregators
- spot-exposed market customers
- scheduled load
- retailer and third-party offerings
- reliability and emergency reserve trader (RERT)
- contingency FCAS.

C.1 Voluntarily scheduled resources

The final rule for the *Integrating price-responsive resources into the NEM* rule change allows participants to nominate multiple or a singular qualifying resource as a voluntarily scheduled resource (VSR) and participate in central dispatch. A participant who has nominated a VSR will be referred to as a voluntarily scheduled resource provider (VSRP) with respect to this VSR. They will also retain their existing registration category, for example, IRP or Market Customer, and any existing obligations under the rules for the connection points in their VSR.

VSRs are required to comply with the requirements of central dispatch, including providing offers and comply with dispatch instructions.[56]

The rule change was made to allow resources such as virtual power plants (VPPs), community batteries, flexible large loads and other price-responsive small resources to directly interact with the spot market. Through participation in the spot market and exposure to spot prices, this creates financial incentives for VSRs to provide demand response when the cost of electricity is high.

VSRs are required to comply with central dispatch, meaning that their level of demand response is transparent to AEMO and the market, leading to more accurate demand forecasts and the associated efficiency benefits.[57] Furthermore, the demand response of VSRs is not estimated using a baseline (like the WDRM or various out-of-market demand response options), as VSRs are paid based on their actual energy usage that is dictated by dispatch instructions.

C.2 Small resource aggregators

The small resource aggregators (SRA, formerly small generation aggregators) framework allows participants to aggregate small units and participate as a non-scheduled wholesale market participant.[58] Small units include small generating units (below 30MW) and bi-directional units (below 5MW).[59] The SRA framework allows aggregators to buy and sell energy in the spot market, in addition to participating in contingency ancillary services (if they meet the associated technical requirements).

56 Resources aggregated together as one VSR are required to comply with dispatch on the aggregated, rather than the individual, level.

57 The cost-benefit analysis in the final determination for *Integrating price-responsive resources into the NEM* identified benefits through cost reductions to FCAS, generation, RERT, and emissions reductions.
AEMC, Integrating price-responsive resources into the NEM, rule determination, 19 December 2024, p. iv.

58 An AEMO factsheet on the SRA framework can be found here.

59 See the definitions in chapter 10 of the NER.

The spot market exposure creates a form of wholesale demand response, as aggregators can contribute to reducing operational demand by reducing (increasing) their non-scheduled demand (generation) to maximise profits. SRAs can also provide demand response through contingency FCAS (see appendix C.7) if they meet the relevant technical requirements.

To participate in the SRA framework, each unit included in a aggregation must have its own connection point and a NEM-compliant metering installation. In addition, a unit's auxiliary load must be behind its connection point, and the connection point cannot be used to supply retail customer loads.

This means that households and businesses with solar and/or storage behind a single connection point cannot participate in the SRA framework, as their consumption cannot be considered as an auxiliary load in the definition of a small resource connection point.[60]

However, general household or business load can be separated from the responsive resource using the embedded networks framework. Multiple child connection points can be created under the embedded networks arrangement, such that retail load can be on a separate connection point to small generating or bi-directional units, which would be on their own child connection point with a separate, on-market meter.

C.3 Spot-exposed market customers

Market customers encompass market participants with one or more market connection points that are registered with AEMO as a customer. Market customers buy and sell energy passing through their connection points from the spot market, and hence are spot-exposed. The requirements for market customers include being registered as a market participant by AEMO and complying with the associated obligations.[61] Market customers are not scheduled through central dispatch, but they can choose to through becoming a scheduled load (discussed in appendix C.4).

Small loads (such as households and businesses) may encounter challenges meeting and complying with the relevant requirements to be a market customer. Retailers are market customers and represent their customers (including small load customers) by being their financially responsible market participant (FRMP). Retailers can manage spot-exposure through financial hedging contracts or by incentivising their customers to reduce demand during periods of high prices.

Large loads may be more capable in meeting the requirements to be a market customer. The direct exposure to, and settling through, the spot market as a market customer provides financial incentives to reduce demand and avoid excessive energy costs when spot prices are high. However, incentives to be price-responsive and provide wholesale demand response decrease if the large load is fully or partially hedged (such as through cap contracts, swap contracts, or PPAs).

C.4 Scheduled load

Market customers or integrated resource providers can have assets at a`market connection point' (excluding generating plant) classified as a scheduled load.[62] Scheduled loads must comply with requirements and obligations under the NER to participate in central dispatch. This includes

60 The definition is available in the *Integrating energy storage systems into the NEM* final rule schedule 6, see the AEMC project page [here](#).

61 For example, market customers must comply with prudential and settlement requirements, pay relevant participant fees, and any other obligations in the NER.

62 See clause 2.3.4A of the NER.

complying with bidding regulations (if the scheduled load bids into dispatch) and information provision to AEMO (such as information of ST PASA and MT PASA).

Through participation in central dispatch, scheduled loads pay for their electricity consumption at the spot price and must comply with dispatch instructions. Spot-exposure provides an incentive to scheduled loads to be price-responsive and reduce demand when spot prices are high.

The rules for scheduled loads do not restrict small loads participating in the NEM as scheduled loads. However, small loads may not be able to meet requirements of being scheduled, namely be able to submit valid bids to AEMO for central dispatch and have adequate communications and/or telemetry to comply with dispatch instructions.[63]

C.5 Retailer and third-party offerings

Offerings from retailers and third-party services providers to customers can deliver demand response. There are a range of options currently available to both small and large loads, however all options need the participating loads to have 5-minute metering to be able to assess demand responses.

Virtual power plants (VPPs) are an aggregation of CER that operate in a coordinated manner. The VPP operator may seek to minimise costs for VPP participants by managing their CER for them (such as choosing when to charge or discharge batteries). This can include reducing demand, or increasing generation, across the VPP during high price or demand periods. Small loads can participate in VPPs if they meet the requirements set by the retailer, such as having a smart meter, solar and a battery. If a VPP complies with the relevant technical requirements, it can also participate in the contingency FCAS markets. The IPRR rule change will allow VPPs to bid into, and be dispatched in, central dispatch. The incentives for consumers to participate in VPPs depend on the available conditions and fee structures of VPP offerings, which can vary between VPP operators.

Behavioural demand response programs are initiatives that can be offered by retailers or third-party services providers to incentivise lower customer demand during high price or demand periods. Typically, customers are informed of an upcoming period and are offered incentives (such as financial rewards) if they reduce demand during the relevant period.[64] The structure and magnitude of incentives can vary between providers. These programs can enable a range of customers with appropriate metering to provide demand response, from households and small businesses to large businesses and industrial loads. The amount of demand response available through such programs is dependent on the accessibility and incentives of retailer offerings (in addition the capability of customers to reduce demand).

Retailers can provide other demand response incentives to customers such as through time-of-use tariffs. These tariff structures offer fixed rates for energy consumption according to the time of day. By providing a higher rate for customers during peak periods and conversely lower rates during shoulder and off-peak periods, customers are incentivised to shift their load away from peak periods and avoid higher rates. High price and demand periods are highly correlated to peak periods in the NEM. In this way time-of-use tariffs could contribute to positive system outcomes by incentivising consistent demand management (i.e. demand response) by customers.

63 NER clause 2.3.4A outlines the requirements for classification as a scheduled load.

64 Smart meters are required to participate in such programs as they allow the amount of a customer's demand response to be calculated against a baseline.

Retailers can also offer spot pass-through contracts to customers, which directly exposes those customers to spot prices. Having exposure to the volatile spot price creates clear and direct financial incentives for customers to be price-responsive and reduce demand during high price periods. Retailers can offer spot pass-through contracts to both small and large loads.

C.6 Reliability and emergency reserve trader

The reliability and emergency reserve trader (RERT) mechanism allows AEMO to contract out-of-market reserves to maintain reliability and system security.[65] AEMO can procure RERT providers to respond on short notice (between three hours and seven days), medium notice (between seven days and 10 weeks), or long notice (more than 10 weeks and if unserved energy is forecast in an Electricity statement of opportunities).

RERT providers are typically unscheduled load (such as industrial loads or aggregated small loads) that can be curtailed when needed, or unscheduled generation that can provide active power when needed. Obtaining commitments from RERT providers provides a pool for AEMO to draw on as an emergency form of demand response that can be relied upon during high demand periods to prevent load shedding.

Parties can be incentivised to provide RERT through the financial compensation they would receive if activated. The amount of compensation is dependent on the terms of their RERT contract with AEMO.

C.7 Contingency FCAS

FCAS is procured by AEMO as market ancillary services to stabilise power system frequency and maintain the supply-demand balance, by increasing (raise FCAS) or decreasing (lower FCAS) active power. Regulation FCAS serves to manage small frequency deviations that arise from natural fluctuations in frequency due to changing generation and load conditions. Contingency FCAS is used to provide balancing reserves to respond to large frequency deviations, typically from contingency events such as the trip of a large generator or load.[66]

There are ten FCAS markets that are co-optimised through central dispatch with the energy market for each 5-minute dispatch interval. The co-optimisation of the energy and FCAS markets works to find the least-cost dispatch of resources that meets both energy and FCAS constraints.

To provide FCAS, providers must meet the technical requirements outlined in AEMO's market ancillary service specification (MASS).[67] FCAS providers can include both utility-scale generation, storage and load units, as well as aggregated loads (such as VPPs).[68] Loads participating in contingency FCAS act as a form of demand response by increasing or decreasing their load in response to a contingency event.

FCAS providers bid their capacity for their relevant FCAS services to AEMO and are paid the market clearing price in terms of dollars per megawatt enabled per hour.[69] When FCAS providers deliver FCAS, they are also paid based on any associated energy usage. The market formulation of FCAS (combined with minimum FCAS enablement constraints to signal FCAS demand) provide

65 The AEMO webpage for RERT can be found here.

66 There are four contingency FCAS categories or markets each for raise and lower FCAS to separate different response times: very fast, fast, slow, and delayed.

67 AEMO's MASS can be found on its webpage here.

68 NER clause 3.8.3 permits aggregation of loads to be treated as one ancillary service load for central dispatch. The loads must be connected within a single region and be operated by a single person.

69 In other words, FCAS providers are paid if they are enabled for FCAS, regardless of whether they deliver FCAS.

incentives for participants to participate in FCAS, in addition to the potential to be paid for FCAS without necessarily needing to provide a response.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CER	Consumer energy resources
CER benefits	Unlocking CER benefits through flexible trading
Commission	See AEMC
DRSP	Demand response service provider
DSP	Demand side participation
FCAS	Frequency control ancillary service
FRMP	Financially responsible market participant
IPRR	Integrating price-responsive resources into the NEM
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NSCAS	Network support and control ancillary services
NSW	New South Wales
PASA	Projected assessment of system adequacy
PDRS	Peak demand reduction scheme
RERT	Reliability and emergency reserve trader
SRA	Small resource aggregator
TNSP	Transmission network service provider
VSR	Voluntarily scheduled resource
VSRP	Voluntarily scheduled resource provider
WDR	Wholesale demand response
WDRRR	Wholesale demand response reimbursement rate
WDRM	Wholesale demand response mechanism