Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (WHOLESALE DEMAND RESPONSE MECHANISM) RULE 2020

NATIONAL ENERGY RETAIL AMENDMENT (WHOLESALE DEMAND RESPONSE MECHANISM) RULE 2020

PROPONENTS
Public Interest Advocacy Centre, Total Environment Centre and the Australia Institute
Australian Energy Council
South Australian Government

12 MARCH 2020

DETERMINATION

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 This draft determination sets out a series of changes proposed by the Commission to the National Electricity Rules (NER) to facilitate wholesale demand response in the national electricity market (NEM), principally through implementing a wholesale demand response mechanism. This represents a significant reform for the NEM. Under this draft rule, consumers would be able to sell demand response in the wholesale market through specialist aggregators for the first time.

2 This draft rule represents an important reform for the NEM. It would introduce a low-cost mechanism for transparently engaging the demand side in central dispatch. Since the NEM commenced, the demand side has rarely participated in central dispatch. However, under this mechanism, consumers would be able to actively participate in central dispatch and be rewarded for the value they provide to the system. In addition, this mechanism would capture the benefits of greater demand side participation and share these benefits with all consumers.

3 This mechanism also provides for more flexible capacity in the wholesale market. Wholesale demand response will be able to compete with peaking generation in times of tight supply and demand balance.

4 The opportunity to introduce a wholesale demand response mechanism arises because there is growing interest across industry in participating in wholesale demand response, as highlighted by the three rule change requests received by the Commission. This draft rule would provide those consumers with greater opportunities to participate in the wholesale market in a manner that values their response while also improving reliability. Wholesale demand response will contribute to improving reliability and security in the NEM.

5 This is the second draft determination and second draft rule published for this rule change. The first draft determination was published on 18 July 2019, which set out a wholesale demand response mechanism. On 5 December 2019 the Commission extended the time for making a final determination until 11 June 2020. This extension followed the provision of supplementary information by the market operator, the Australian Energy Market Operator (AEMO), on implementing the proposed mechanism. It also followed a request from the COAG Energy Council to the Energy Security Board (ESB) (which includes the Commission) for advice on the design of a two-sided market for the NEM,[1] which the COAG Energy Council considers to be a priority project.

6 The second draft rule implements a wholesale demand response mechanism that is similar in form to the mechanism set out in the previous draft determination. The second draft rule is a more preferable rule because it has introduced a new settlement mechanism and made a number of additional changes to the proposals set out in the rule change requests that improve the functionality of the mechanism. Following the extension, the Commission has made several improvements to the mechanism design. These improvements are designed to

1 A two-sided market for electricity would be one that is informed by quantity and price inputs from both consumers and producers of electricity. This would represent an evolution from the largely supply-side market that has characterised the NEM to date.

achieve:

- lower implementation costs for AEMO due to reduced investment in systems that is expected to become redundant if a two-sided market is introduced. For example, the changes to the process for determining baseline[2] methodologies has reduced overall implementation costs and, as centrally determined baselines are not expected to feature in a two-sided market, reduced the scale of systems investment that could be made redundant.
- an earlier start date. The implementation date in the first draft determination was guided by the time needed for AEMO to update its systems to implement the mechanism. By reducing the costs and complexity of implementing the mechanism, the implementation date has been brought forward from 1 July 2022 to 24 October 2021. This means wholesale demand response can be provided through the mechanism prior to the summer of 2021/22.
- greater opportunities to learn about demand side participation in the event that a two-sided market is introduced. The COAG Energy Council has highlighted the transition to a two-sided market as a priority. This transition would mean a greater role for the demand side of the market in processes such as scheduling and dispatch. The second draft rule presents an important opportunity to learn from the approach taken with scheduling demand response and to use this to inform the design of scheduling and dispatch suitable for a two-sided market.

What is wholesale demand response?

7 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. It also implies an active role for the demand side of the market, as opposed to a passive role.

8 In electricity markets, active demand side participation promotes efficient consumption of electricity. The more consumers participate in the market and respond to market price signals, the more accurately they can pick the right level of electricity consumption for them. In the long-run, a greater level of demand side participation will improve the efficiency of the dispatch process by delivering the lowest combination of resources to achieve the supply-demand balance.

9 Demand response is a subset of demand side participation. There are different types of demand response: wholesale (e.g. responding to changes in the wholesale price), emergency (for example, participating in the RERT), network (for example, using demand response to offset the need for network build) and ancillary services (for example, load changing to manage frequency). While the equipment that provides these different types of demand response is often the same, the services provided are distinct.

Rationale for wholesale demand response mechanism

10 The rule change requests that are the subject of this draft determination seek to facilitate

2 Baselines refer to the counterfactual level of consumption that is used to measure demand response i.e. how much did the level of demand change?

wholesale demand response in the NEM.

11 Providing wholesale demand response in the NEM has been difficult to date because consumers need to be technically equipped to respond (e.g. with advanced metering and control over consumption), as well as needing a 'signal' to respond to. Most consumers elect to not respond to wholesale prices themselves, and instead a retailer typically manages the risk on their behalf.

12 Recently, there have been a number of trials and state government funded schemes which are all encouraging wholesale demand response. In addition, a number of retailers and third party service providers either utilise demand response or enable consumers to do so themselves with offerings which sit outside trials.

13 The role of consumers, and importantly the technology to enable consumer participation, is changing. Technology has evolved and become cheaper, such that more consumers want to participate directly in the wholesale market and are equipped to do so. There is capability and significant interest now to accommodate consumers who want to engage and participate.

14 As the sector continues to transform, there is increasing variability, not only on the supply side (with more weather-dependent, renewable generation), but also on the demand side. Increases in intermittent generation and the uptake of batteries and electric vehicles will make forecasting the demand side increasingly challenging, without more information being provided by the demand side.

15 The Commission considers that there need to be changes in the wholesale market to provide greater scope for consumers to participate in wholesale demand response. A mechanism to facilitate wholesale demand response will unlock underutilised demand response and provide more opportunities for consumers to participate in the wholesale market by offering their demand reductions in as a supply resource.

16 A wholesale demand response mechanism allows consumers to bid their willingness to consume electricity at different prices into the wholesale market. This is effectively what a two-sided market would facilitate: a wholesale electricity market informed by both quantity and price information from the supply and demand sides of the market. While a two-sided market may have broader scope, particularly in relation to the level of market participation, the implementation and use of the mechanism will inform market design choices in the development of a two-sided market.

Mechanism focuses on large customers

17 The wholesale demand response mechanism set out in this second draft determination is designed to allow meaningful volumes of demand-side participation in dispatch and associated system operation benefits at minimal cost and in the near term. This means the design, which requires loads to be controllable for the purposes of scheduling and predictable for the purposes of baselines, is most suited to large customers and unlikely to suit participation by small customers. The Commission is conscious that small customers also want to participate in demand response, and technological changes are increasingly creating options for them to do so. As noted in this determination, there are a number of

opportunities emerging under the current arrangements for these consumers to participate in demand response. However, extending this mechanism to cater for small customers would increase the costs and extend the implementation time given the increased system and process complexity required to include them.

18 Including small customers in the mechanism would:

- significantly increase complexity of the systems changes needed to introduce the mechanism which would in turn, significantly increase the implementation costs and time needed to implement the mechanism
- provide limited additional benefits as small customer demand response is not suited to participating in central dispatch in the short to medium term
- require the development of baselines for individual small customers which is difficult to do accurately.

19 Small customers have options to provide wholesale demand response through direct control devices such as pool pumps, electric vehicles or electric hot water, or through behavioural demand response (such as responding to prompts from a retailer). Neither direct control nor behavioural demand response from small customers is likely to fit within the parameters of the wholesale demand response mechanism in this draft rule.

20 It is difficult to determine baselines for discretionary consumer loads that are subject to direct control given the challenges in estimating the counterfactual level and timing of consumption. The quality of a baseline is directly related to how predictable a load is. If a load is very predictable, the baseline can be treated as being more certain. As loads become more unpredictable, it becomes harder to reasonably predict what the consumer would have done had they not provided wholesale demand response. Large commercial and industrial loads are often more predictable. This is because they operate large processes, often on fixed timetables and fixed hours. However, the loads small customers are likely to use to provide demand response are highly variable, such as batteries and pool pumps. In addition, these loads can consume at almost any time of day with minimal impacts on the customer, which makes it very easy to load shift on a daily basis, unlike more steady commercial loads. This variability makes it very difficult to determine baselines accurately on an individual customer level when these customers are using controllable devices. Opening the mechanism to these consumers may also encourage inefficient consumption if aggregators are able concentrate their consumption in peak periods in order to 'game' a higher baseline.

21 Consumers who are not providing demand response through a controllable device may instead provide behavioural demand response. While these programs provide customers with the opportunity to provide wholesale demand response, they often mean the party (e.g. aggregator) calling for the demand response is unsure how much will be provided. As such, behavioural demand response programs are not suited to being scheduled through the mechanism.

22 As explained above, small customers are unlikely to be able to provide material amounts of wholesale demand response through the mechanism. Designing the systems to accommodate that possibility, regardless of the uptake, would involve significant costs. After

undertaking extensive consultation, the Commission understands that including small customers in the mechanism would result in materially higher implementation costs for AEMO and market participants.

23 If the mechanism was designed to include small customers, it would impose higher costs on the market and deliver unclear benefit. These costs would inevitably be required to be recovered from consumers. There is also a risk that these costs would become redundant as the industry moves towards a two-sided market. For these reasons, the mechanism in the second draft rule focusses on delivering wholesale demand response from large customers.

24 Therefore, the Commission's second draft rule determination is to not make a draft retail rule, as retail rule changes would only be required if the mechanism extended to small customers.

25 The Commission notes that small customers will increasingly provide valuable demand response. There is a growing number of opportunities for small customers in this regard, either participating through retailer-led demand response programs or providing emergency reserves through the reliability and emergency reserve trader. The value to individual consumers and to consumers collectively of more small customer demand response will grow as digitalisation becomes more prominent. A two-sided market would result in consumers benefiting from this demand response capacity.

26 The Commission also has a work program assessing how consumer protections should be applied as more small customers participate in demand response. It will be important to make sure there are the appropriate energy specific consumer protections in place as more small customers engage in demand response.

Two-sided market is the enduring solution

27 The Commission notes there is significant stakeholder interest in promoting demand response opportunities for residential customers, and facilitating small customer demand side participation would benefit consumers and the NEM. In seeking to engage small customer demand side participation and share the benefits with all consumers, care needs to be taken in selecting the right framework. The Commission considers that the best approach is to develop a two-sided market, which is more suited to small customer involvement.

28 The Commission considers that 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. A two-sided market is characterised by the active participation of the supply and demand side in dispatch and price setting. Moving to a two-sided market should enable the transition to a future NEM characterised by increased variable supply and more flexible, price responsive demand.

29 With these expanded opportunities, a move to a two-sided market will be essential. The growing number of consumers equipped to actively participate in the market will eventually lead to the market outgrowing the mechanism.

30 The wholesale demand response mechanism will eventually be outgrown by the market because it is reliant on the use of centrally determined baselines. The wholesale demand response mechanism under the draft rule relies on setting a baseline quantity against which

the value of demand response would be calculated and paid. However, it is impossible to exactly know this counterfactual level. If the baseline is set too high, consumers will pay more than they need to. If it is too low, then there won't be enough incentive to encourage demand response in the market.

31 On 14 November 2019, the Commission published a paper on the impacts of digitalisation on the NEM.[3] This paper sets out some thinking on digitalisation and the potential to move to a two-sided market. The Commission called for stakeholders to provide further discussion and debate on concepts presented in the paper. The Commission did not seek submissions on the paper but invited stakeholders to draw on it when they engage in the ESB's 2025 market design work.[4] The ESB (which includes the AEMC) has been tasked with providing COAG Energy Council with advice on a two-sided market for the Energy Council meeting on 20 March 2020.

Overview of the second draft rule

32 The Commission has determined to make a more preferable draft electricity rule. The wholesale demand response mechanism introduced under the second draft rule would:

- promote greater demand side transparency and assist with power system reliability
- promote the ability for consumers who participate in the mechanism to change their level of consumption in response to the wholesale electricity price
- increase the level of consumer choice in relation to wholesale demand response
- minimise the impacts of any distortions introduced under the mechanism, particularly to the wholesale market as well as retailers' hedging and positions in the contract market
- reduce the extent of upfront costs imposed on AEMO and the market, specifically retailers, compared to the mechanisms proposed in the rule change requests and in the first draft rule.

33 The second draft rule puts in place a number of changes to introduce a wholesale demand response mechanism. The second draft rule:

- introduces a new market participant category, a demand response service provider (DRSP)
- places obligations on DRSPs that, as much as practicable, replicate those applied to scheduled generators, for example, similar information provision and scheduling obligations
- sets out a process for having baseline methodologies determined and applied to wholesale demand response units
- provides for DRSPs to be settled in the wholesale market for the wholesale demand response they have provided at the prevailing spot price

3 AEMC, *How digitalisation is changing the NEM - The potential to move to two-sided market,* 14 November 2019, available at: https://www.aemc.gov.au/sites/default/files/2019-11/How%20digitalisation%20is%20changing%20the%20NEM.pdf

4 For more information, see http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-issues-paper-%E2%80%93-september-2019.

- sets out consequential changes to other aspects of the NER, including changes to RERT provisions
- makes additional changes to related aspects of the NER, such as the demand side participation information provisions, to improve the integration of the demand side
- sets out implementation timeframes for the mechanism.

Changes between first and second draft rules

34 A number of changes have been made between the first and second draft rules. These changes have been made to reduce the associated implementation costs and improve consistency with a two-sided market. The key changes between this draft rule and the previous draft rule are that the second draft rule:

- changes the dispatch model to be more consistent with how consumers would be expected to participate through a two-sided market. The second draft rule therefore presents an important opportunity to learn from the approach taken with scheduling demand response and using this to inform design of scheduling and dispatch in a two-sided market. This approach is also lower cost to implement for AEMO.
- no longer provides for market participants to develop and submit baseline methodologies to AEMO for approval. The Commission understands that requiring AEMO to build in this flexibility would impose significant costs. Instead, the second draft rule allows market participants to raise new methodologies for AEMO to consider implementing. This will still allow for innovative approaches to be developed but in a way that minimises costs and minimises investment that may not be necessary in a two-sided market.
- removes the requirement for FCAS costs to be recovered from DRSPs. AEMO has advised that implementing this would be costly and would provide limited benefits. Under the second draft rule, AEMO would need to report on whether DRSP participation is impacting on the cost and quantity of FCAS being procured. If it is shown that DRSPs have a material impact on FCAS needs, the framework should be adjusted to recover some of these costs from DRSPs.
- removes the 5MW minimum aggregation requirement. DRSPs no longer need to aggregate at least 5MW of wholesale demand response capacity. Under the first draft rule, DRSPs would have been able to bid in less than 5MW of demand response in any case. As such, the Commission considers that the 5MW threshold would in practice have been an unnecessary procedural hurdle for AEMO and DRSPs, and determined that it would be appropriate to remove the 5MW threshold while still maintaining the scheduling obligations.
- requires AEMO to provide retailers with information about when their retail customers are participating in wholesale demand response. This assists retailers in managing their exposure in the wholesale market in periods where wholesale demand response is being provided.
- brings forward the implementation date from July 2022 to 24 October 2021. By reducing the costs and complexity of the mechanism for AEMO to implement, the implementation date can be brought forward, allowing wholesale demand response to be provided through the mechanism earlier.

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TABLES

FIGURES

1 THE RULE CHANGE REQUESTS

1.1 The rule change requests

The Australian Energy Market Commission (AEMC or Commission) received three requests to make a rule regarding demand response in the wholesale electricity market.

- On 31 August 2018, the Total Environment Centre (TEC), the Australia Institute (TAI) and the Public Interest Advocacy Centre (PIAC) submitted a rule change request to the Commission to make an electricity rule, along with consequential retail rules, to introduce a wholesale demand response mechanism. This mechanism would allow third parties (i.e. those who are not the financially responsible market participant (FRMP), usually a retailer, for a consumer) to offer demand response into the wholesale electricity market in a transparent, scheduled manner.[5]
- On 18 October 2018, the Australian Energy Council (AEC) submitted a second, related rule change request to the Commission, to make an electricity rule to introduce an obligation for retailers to negotiate in good faith with third parties looking to provide wholesale demand response through a wholesale demand response register. These third parties would also be scheduled in the wholesale market.[6]
- On 30 October 2018, the South Australian Government submitted a third, related rule change request to the Commission. As with the first rule change request, this proposal seeks to make electricity and retail rules that would allow third parties to offer wholesale demand response into the wholesale market. The rule change request also proposed the introduction of a transitional market for wholesale demand response, a separate wholesale demand response market.[7]

1.2 Rationale for the rule change requests

The three rule change requests identified the requirement that third party demand response providers either be registered as a retailer or have a commercial relationship with a retailer to provide wholesale demand response as creating challenges for the integration of demand response in the NEM.[8]

PIAC, TEC and TAI considered that there are commercial barriers to developing the required partnerships between retailers and demand response providers, with this contributing to a sub-optimal level of wholesale demand response in the NEM in comparison to other energy markets.[9]

5 This rule change request is available on the AEMC website under project code ERC0247/RRC0023. See: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

6 This rule change request is available on the AEMC website under project code ERC0248/RRC0025. See: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-register-mechanism.

7 This rule change request is available on the AEMC website under project code ERC0250/RRC0027. See: https://www.aemc.gov.au/rule-changes/mechanisms-wholesale-demand-response.

8 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, p. 7; AEC, *Wholesale demand response register mechanism - rule change request*, p. 1; South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 3.

9 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, p. 7.

The AEC suggested that a key concern of demand response providers is that their investments (for example, in equipment to facilitate demand response) are at risk of becoming stranded should their customers change retailers, as a subsequent retailer may decide not to continue with the previous retailer's existing demand response arrangement.[10]

The South Australian Government raised the related issue that if a retailer does not offer demand response products, or provide a direct signal of the wholesale price to customers, its customers have no incentive to change their energy consumption.[11] Further, the South Australian Government noted that the lack of a mechanism for portfolio demand response, and the fact that consumers may not have the capacity to manage their demand at all times, limits consumers' ability to take advantage of demand response offerings.[12]

1.3 Solution proposed in the rule change requests

1.3.1 Wholesale demand response mechanism

To address the issues identified their rule change requests, PIAC, TEC and TAI and the South Australian Government proposed changes to introduce a wholesale demand response mechanism in the NEM and create a new category of market participant in the NEM: the demand response service provider (DRSP).[13]

This proposal involves transferring the value of wholesale demand response from the existing FRMP (i.e. the retailer) to a DRSP, who may be the customer or a third party service provider engaged by the customer. The model proposed by the rule proponents has the following features:[14]

- DRSPs could submit demand response bids into the wholesale market.
- Demand response offers would be scheduled in a manner similar to bids submitted by generators.
- The DRSP would be exposed to the spot price for the difference between a baseline level of consumption estimated to have occurred were it not for the demand response, and the actual level of consumption. The FRMP would be settled in the wholesale market at the spot price for the baseline level of consumption. This would allow the value of the wholesale demand response to accrue to the DRSP without the involvement of the retailer.
- The DRSP would earn the spot price from the wholesale market for the reduction in energy demand by its participating customers and would pay customers for the value of their demand reduction based on agreed commercial arrangements.
- All retail energy customers would be free to participate in this mechanism.

10 AEC, *Wholesale demand response register mechanism - rule change request*, p. 1.

11 South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 2.

12 Ibid, p. 3.

13 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, p. 3; South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 4.

14 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, p. 9; South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 4.

The rule change requests from PIAC, TEC and TAI and the South Australian Government did not include drafting for a proposed rule.

1.3.2 Wholesale demand response register

To address the issues identified in its rule change request, the AEC proposed NER changes to create a framework within which parties can negotiate agreements to facilitate wholesale demand response in the NEM. The key features of the proposal include:[15]

- the creation of a new category of market participant, the Demand Response Aggregator (DRA), which would apply to parties that control demand response and behind-the-meter generation at a connection point (the DRA could also be the FRMP at the connection point)
- requiring AEMO to maintain a register of the demand-side capabilities of registered DRAs
- where a customer who is already participating in demand response changes FRMP, the new FRMP would be required to accept the previous FRMP's DRA arrangements or negotiate changes to DRAs and associated agreements in good faith
- where a customer who is already participating in demand response intends to change demand response arrangements and has provided written notice of this intention to their FRMP, the FRMP would be required to negotiate changes to DRAs and associated agreements in good faith
- where a customer who is not participating in demand response intends to enter into a demand response arrangement and has provided written notice of this intention to their FRMP, the FRMP would be required to negotiate in good faith with prospective DRAs
- loads registered with a DRA may either be continuously classified as scheduled loads, or alternatively could remain "dormant" until such time as the DRAs intended the loads to be active in the market or a Lack of Reserve Notice is issued by AEMO.

The rule change request from the AEC did not include drafting for a proposed rule.

1.3.3 Separate wholesale demand response market

The South Australian Government also proposed the creation of an additional market, designed specifically for demand response and which operates separately from the wholesale electricity market. It is proposed to be introduced as a transitional measure prior to the implementation of a wholesale demand response mechanism (if applicable) to enable the benefits of the mechanism to be realised sooner.[16] However, the Commission noted in the consultation paper that it was proposing to treat this as an alternative mechanism to the proposed wholesale demand response mechanism discussed above.

This market would be operated by AEMO and would be co-optimised with the existing spot market to ensure demand can be met in the most cost-efficient way. Retailers would be responsible for costs associated with the market, which they would be able to spread across their customers.

15 AEC, *Wholesale demand response register mechanism - rule change request*, p. 2.
16 South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 7.

This new market would require the use of baselines to measure demand response activities of customers. That is, in order to determine the quantity of wholesale demand response being offered into the separate market, a baseline for participating consumers would be needed.

As it would be a separate market to the spot market, it would not require changes to existing settlement processes in the spot market.

The rule change request from the South Australian Government did not include drafting for a proposed rule to implement this additional market.

1.4 Relevant background

In July 2018, the Commission published the final report for its *Reliability frameworks review.*[17] In the final report, the Commission made a series of complementary recommendations aimed at supporting increased demand side integration into the wholesale market.[18] These recommendations did not aim to lock in a particular type of demand side participation, but instead left it open for different types of demand side participation to be provided in the wholesale market in the future. This recognises that new technologies and new business models evolve over time. The recommendations included that demand response providers should be able to be recognised on equal footing with generators in the wholesale market and so be able to more readily offer wholesale demand response in a transparent manner to the Australian Energy Market Operator (AEMO).[19] This is the subject of this second draft rule determination, following the submission of the three rule change requests discussed above.

1.5 The rule making process

Commencement

The Commission commenced six rule change projects, two in respect of each rule change request.

- In respect of the rule change request from the Public Interest Advocacy Centre, the Total Environment Centre and the Australia Institute, the Commission commenced a rule change project titled *Wholesale demand response mechanism* (ERC0247). The Commission also opened a consequential rule change project under the retail rules, *Wholesale demand response mechanism - retail* (RRC0023).
- In respect of the rule change request from the Australian Energy Council, the Commission commenced a rule change project titled *Wholesale demand response register mechanism* (ERC0248). The Commission also opened a consequential rule change project under the retail rules, *Wholesale demand response register mechanism - retail* (RRC0025).
- In respect of the rule change requests from the South Australian Government, the Commission commenced a rule change project titled *Mechanisms for wholesale demand*

17 AEMC, *Reliability frameworks review - final report*, July 2018.

18 These recommendations are discussed in more detail in chapter 4.

19 AEMC, *Reliability frameworks review - final report*, July 2018, p. 45.

response (ERC0250). The Commission also commenced a related rule change project under the retail rules, *Mechanisms for wholesale demand response - retail* (RRC0027).

Consultation paper

On 15 November 2018, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change requests. [20] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 21 December 2018.

The Commission received 37 submissions as part of the first round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions were discussed and responded to in the draft determination published in July 2019.

First extension of time

On 7 February 2019, the Commission extended the period of time for making the draft determination for each of the three rule change requests to 18 July 2019 under section 107 of the National Electricity Law (NEL) and section 266 of the National Electricity Retail Law (NERL). The Commission considered this extension to be necessary due to the complexity of the issues raised in the three rule change requests and in stakeholders' submissions to the consultation paper. Several stakeholders also requested that additional time be allowed for consideration of these issues and further consultation. The extension was therefore intended to allow the Commission to undertake additional stakeholder consultation and incorporate outcomes from proposed trials related to wholesale demand response.[21]

Workshop and technical working groups

The Commission held a stakeholder workshop on 5 March 2019 in Melbourne to discuss the rule change requests. The workshop agenda and slides from the workshop are available on the project page.

The Commission also formed a technical working group of experts from industry, demand response providers and consumer groups. To date, the Commission has convened four technical working group meetings:

- on 22 March 2019
- on 15 April 2019
- on 27 May 2019
- on 11 October 2019.

Discussion notes from these technical working group meetings are also available on the project page.

First draft determination

20 This notice was published under s.95 of the National Electricity Law (NEL) and s.251 of the National Energy Retail Law (NERL).

21 Due to the revised publication date for the draft determination, the Commission also extended the time for making the final determination for each of the three rule change requests to 14 November 2019 under section 107 of the NEL and section 266 of the NERL.

On 18 July 2019, the Commission published two consolidation notices:[22]

- The first notice related to the consolidation of ERC0247, ERC0248 and ERC0250. The three electricity rule change requests are consolidated under ERC0247 and named *Wholesale demand response mechanism*.
- The second notice related to the consolidation of RRC0023, RRC0025 and RRC0027. These three retail rule change requests are consolidated under RRC0023 and named *Wholesale demand response mechanism - retail*.

On 18 July 2019, the Commission published a draft determination and more preferable draft electricity rule under s. 91A of the NEL. It also determined not to make a draft national energy retail rule.

The Commission received 40 submissions as part of the second round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this second draft rule determination. Issues that are not addressed in the body of this document are set out and addressed in appendix I of this determination.

Public hearing

Following the publication of the first draft determination:

- The AEMC received two requests, from ENGIE and SIMEC Energy, to hold a pre-final rule determination hearing in relation to the first draft determination. The hearing was held on 6 August 2019. [23]
- The Commission also held two stakeholder consultation workshops on the first draft determination on 16 August and 22 August 2019. [24]

Further extensions of time

On 10 October 2019, the Commission extended the period of time for making the final determination for the rule change requests to 5 December 2019 under s. 107 of the NEL and s. 266 of the NERL. The Commission considered this extension was necessary due to complexity and the volume of issues raised by stakeholders in submissions in relation to how the rule is put in place in the regulatory framework.

On 5 December 2019, the Commission extended the time for making a final determination until 11 June 2020 under section 107 of the NEL and section 266 of the NERL. This extension followed the provision of supplementary information by AEMO on the systems changes and costs associated with implementing the proposed mechanism. The Commission considered this extension was necessary to allow for further consideration of how the mechanism may be designed to reduce implementation costs and timeframes and, to the extent possible, avoid costly system changes that may become redundant in the transition to a two-sided market. Chapter 5 sets out how the second draft rule seeks to achieve these objectives. The

22 These notices were published under section 93(1)(a) of the NEL and section 248 of the NERL.

23 A transcript of the hearing, and associated materials, are available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

24 The discussion notes and agendas for both workshops can be found at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

extended timeframe for making a final determination was also intended to allow time for the Commission to consult with stakeholders on the proposed changes from the first draft determination set out in this second draft determination.

1.6 Structure of second draft determination

The remainder of this second draft determination is structured as follows:

- Chapter 2: the second draft rule determination, including the Commission's assessment framework and summary of reasons
- Chapter 3: context for this second draft rule determination
- Chapter 4: the Commission's approach to small customers and the development of a two-sided market
- Chapter 5: rationale for changes between the first and second draft rules
- Chapter 6: overview of the mechanism set out in the second draft rule
- Appendix A: legal requirements for making the second draft rule and determination
- Appendix B: table summarising changes between the second draft rule and the first draft rule published in July 2019
- Appendix C: the registration process introduced under the second draft rule for a new participant category, a demand response service provider
- Appendix D: how demand response service providers will be integrated with central dispatch
- Appendix E: the information provision requirements placed on demand response service providers
- Appendix F: the process for determining baselines under the second draft rule
- Appendix G: the settlement model introduced in the second draft rule
- Appendix H: the consequential and complementary changes which are proposed alongside the introduction of the mechanism
- Appendix I: summary of other issues raised in stakeholder submissions on the first draft determination.

1.7 Consultation on second draft rule determination

The Commission invites submissions on this second draft rule determination, including the more preferable second draft rule, by 23 April 2020.

Any person or body may request that the Commission hold a hearing in relation to the second draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 19 March 2020.

Submissions and requests for a hearing should quote project number ERC0247 and may be lodged online at www.aemc.gov.au.

All enquiries on this project should be addressed to Declan Kelly on (02) 8296 7861 or Declan.Kelly@aemc.gov.au. A final determination and final rule are scheduled for publication on 11 June 2020.

2 SECOND DRAFT RULE DETERMINATION

2.1 The Commission's second draft rule determination

The Commission's second draft rule determination is to make a more preferable draft electricity rule. The more preferable draft rule would:

- introduce a new participant category, a DRSP, who will be allowed to classify loads for the purpose of providing wholesale demand response through the wholesale demand response mechanism
- require DRSPs to participate in central dispatch, including following dispatch instructions in the wholesale market
- place obligations on DRSPs that, as far as practicable, replicate those applied to other scheduled participants
- set out a process for having baseline methodologies determined and applied to wholesale demand response units
- provide for DRSPs to be settled in the wholesale market for the wholesale demand response they have provided
- set out consequential changes to other aspects of the NER, including changes to RERT provisions
- make additional changes to related aspects of the NER, such as the DSP portal, to improve the integration of the demand side
- set out implementation provisions for this rule, including requiring AEMO and the AER to prepare new guidelines and update existing guidelines to take into account the amending rule.

A summary of the second draft rule is provided in chapter 6. More detail on the various aspects of the second draft rule is also provided in the appendices.

The Commission's reasons for making this second draft rule determination are set out in section 2.4 and section 2.5.

The Commission has determined to not make a draft retail rule in respect of the rule change requests.[25] This is because:

- the mechanism set out in this draft determination would be costly to extend to small customers
- small customers would be unlikely to capture any value from being able to participate in the mechanism
- the Commission was not able to satisfy itself that a rule including small customers would be likely to contribute to the achievement of the national energy retail objective (NERO), due to the difficulty in adequately addressing the application of energy-specific consumer protections to arrangements between small customers and DRSPs under these rule

25 The relevant project code is RRC0023, in relation to the consolidated rule change requests from PIAC, TEC and TAI, the AEC, and the South Australian Government.

change requests, given that a holistic review is required which may conclude that changes to the NERL are necessary[26]

- the Commission considers that progressing regulatory reforms that facilitate the transition towards a two-sided market is the best approach to allow small customers to more actively participate in the market.

Because the mechanism will not be extended to include small customers, the retail rules do not need to be changed to accommodate this participation. The reasons for not including small customers in the mechanism are outlined in section 2.5 and covered in more detail in chapter 4.

This chapter outlines:

- the rule making test for changes to the NER and NERR
- the assessment framework for considering the rule change requests
- how the more preferable second draft electricity rule is likely to contribute to the achievement of the national electricity objective
- why a retail rule is not likely to contribute to the achievement of the national energy retail objective
- the Commission's consideration in deciding to make a uniform rule in accordance with the Northern Territory legislation adopting the NEL.[27]

Further information on the legal requirements for making this second draft rule determination is set out in appendix A.

2.2 Rule making tests

2.2.1 Contributing to the achievement of the NEO

The rule change requests covered by this second draft rule determination relate to both the NER and the NERR. As such, in making a second draft rule determination, the Commission must follow the decision making framework under the NEL and NERL respectively.

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[28] This is the decision making framework that the Commission must apply.

The NEO is:[29]

> 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:

26 The Commission has commenced the Consumer protections in an evolving market review, which is considering (among other issues) the consumer protections which should apply to the provision of new energy products and services, including demand response. The Commission published two issues papers for this review in December 2019. These papers are available at https://www.aemc.gov.au/market-reviews-advice/consumer-protections-evolving-market.

27 *National Electricity (Northern Territory) (National Uniform Legislation) Act* 2015, referred to here as the NT Act.

28 Section 88 of the NEL.

29 Section 7 of the NEL.

> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Under the Northern Territory legislation adopting the NEL, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[30]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[31]

(c) all of the electricity systems referred to above.

For the rule change requests considered in this second draft determination, the Commission has determined that the reference to the national electricity system in the NEO is (c), the national electricity system and the local electricity systems (noting that the rule will not have effect in relation to the local electricity systems).

2.2.2 Contributing to the achievement of the NERO

Under the NERL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national energy retail objective (NERO).[32] This is the decision making framework that the Commission must apply.

The NERO is:[33]

> to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.

Under the NERL, the Commission must also, where relevant, satisfy itself that the rule is "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers" (the "consumer protections test").[34]

30 Section 14A of the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

31 These are specified Northern Territory systems, defined in schedule 2 of the NT Act.

32 Section 236(1) of the NERL.

33 Section 13 of the NERL.

34 Section 236(2)(b) of the NERL.

Where the consumer protections test is relevant in the making of a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been met.[35] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made.

There may be some overlap in the application of the two tests. For example, a rule that provides a new protection for small customers may also, but will not necessarily, promote the NERO.

2.2.3 Making a more preferable second draft rule

Under s. 91A of the NEL and s. 244 of NERL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO and the NERO.

In this instance, the Commission has made a more preferable draft electricity rule. The reasons are set out below.

2.2.4 Rule making in relation to the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL.[36] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.[37]

As the Commission has determined to make a more preferable second draft electricity rule which relates to parts of the NER that apply in the Northern Territory,[38] the Commission is required to consider whether to make a uniform or differential draft rule under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[39] A differential rule is a rule that:

- varies in its terms as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

35 That is, the legal tests set out in sections 236(1) and (2)(b) of the NERL.

36 The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

37 The version of the NER that applies in the Northern Territory is available on the AEMC website.

38 While the key provisions of the draft rule amend chapters 2-4 of the NER, which do not apply in the Northern Territory, other parts of the NER amended by the draft rule do apply in the Northern Territory. However, these changes will not affect Northern Territory local electricity systems.

39 Section 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and the local electricity systems, and has effect with respect to all of those systems.[40]

The Commission has determined to make a uniform second draft rule as it does not consider that a differential draft rule will, or is likely to, better contribute to the achievement of the NEO than a uniform draft rule.

2.3 Assessment framework

The Commission has assessed the rule change requests against an assessment framework focussed on a consideration of consumers and the promotion of their interests in the long term. This assessment framework incorporates feedback provided to the Commission from submissions to the consultation paper and first draft determination, as well as through its technical working group meetings.

Wholesale demand response relies on consumers changing their consumption (or generation) of energy in response to a signal to do so. Consumers can respond to these signals and choose to consume or generate less or more compared to what they otherwise would have done. For example, consumers can consume less or shift consumption at a particular time in order to reduce their exposure to high spot prices, or to help market participants manage their positions in the contract market. The mechanisms set out in the rule change requests provide potential ways to promote wholesale demand response, but other options exist.

An active demand-side of the market, characterised by the presence of demand side participation, can promote efficient consumption of electricity. Where load is able to effectively respond to prices as signalled by the spot market, it would be an efficient outcome for it to choose its level of consumption based on its willingness to pay for consuming electricity compared to the cost of supplying that electricity.

Demand side participation can be more efficient than dispatching generation. Economic inefficiency results when electricity is consumed despite the cost of supplying it exceeding the value gained by its consumption. By having the demand side respond to high spot prices by reducing consumption, wholesale demand response can provide a more cost-effective option for meeting peak demand than using peaking generation. Enabling greater demand side participation in the wholesale electricity market is also a recognition of the fact that in some situations the opportunity cost of demand reductions may be lower than the opportunity cost of generation.

In other words, by changing their load patterns in response to a signal relating to wholesale prices, consumers are able to make the trade-off between the costs of consuming electricity and the costs of reducing their electricity consumption (and so, for example, not being able to produce widgets or heat their home). This benefits the consumer by promoting

40 Section 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

consumption of electricity at an efficient price. It also benefits the market (and hence consumers) by reducing the costs of providing for power system reliability.

In assessing the rule change requests against the NEO and the NERO, the Commission has considered the following principles:

- promoting competition and consumer choice
- resilience of the framework
- not distorting efficient market outcomes
- reliability and transparency
- appropriate risk allocation
- administrative and implementation costs
- appropriate consumer protections
- robustness to climate change mitigation and adaptation risks.

2.3.1 Competition and consumer choice

Where feasible, providing for consumer choice in the provision of services generally leads to more efficient operational and investment decisions. Competitive markets which enable consumers to choose also tend to be more flexible to changing conditions because they provide incentives for participants to innovate and minimise costs over time.

Competition is a process by which inefficient costs are discouraged. It lowers the combination of supply-side and demand-side resources at any given moment in time, as well as through time. Alternatively described, competition provides incentives for market participants to provide services at levels that consumers value (including with regard to the level of reliability), given the price.

Competitive markets also provide a mechanism for collating information from participants and providing signals to inform future actions. Competitive markets therefore encourage efficient decision-making on the basis of this information.

Competition, where feasible, should therefore promote the efficient levels of electricity consumption and generation.

2.3.2 Resilient framework

Regulatory arrangements must be flexible to changing market conditions. They should not be implemented to address issues specific to a particular time period or jurisdiction, or the prevailing technology or business model of the day. Regulatory frameworks should support the right mix of resources over time, encompassing technological developments and changes in consumer behaviour. Markets with resilient designs are characterised by:

- innovation, because business models are able to emerge without being unnecessarily restricted by regulatory frameworks and because participants face incentives to provide services in a least cost manner
- low barriers to entry and exit, because regulatory frameworks provide consistent signals for undertaking investment decisions.

Regulatory stability for market participants can be maintained where changes to the regulatory frameworks are made in a transparent manner.

2.3.3 Non-distortionary

Efficient electricity markets are characterised by:

- efficient allocation of electricity services to market participants who value them the most, typically through price signals that reflect underlying costs
- provision of, and investment in, electricity services at lowest possible cost through employing the least-cost combination of inputs
- the ability of the market to readily adapt to changing supply and demand conditions over the long-term.

When making changes to the regulatory framework to facilitate demand response in the wholesale market, the Commission bears in mind that these changes should not distort efficient market outcomes. That is, any regulatory changes should not detract from the ability of the NEM to provide for the least cost combination of supply-side and demand-side options at any point in time. A distortionary change to regulatory frameworks would detract from the efficiency of the current market frameworks.

2.3.4 Reliability and transparency

Market participants make investment and operational decisions based on market signals in the spot and contract markets. Prices in these markets provide signals for generators and consumers to invest in assets, and produce and consume electricity, as well as providing information about the balance of supply and demand across different places and times. Providing greater amounts of information to market participants will improve their ability to make efficient decisions in both operational and investment time frames on both the supply and demand side of the market.

To provide more information to the rest of the market, wholesale demand response should be provided in a way that is transparent to the rest of the market. In addition to improving efficient decision-making in the wholesale market, for demand response to contribute to reliability outcomes it is important that wholesale demand response is transparent to the system operator.

2.3.5 Risk allocation

Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Placing inappropriate risks on consumers, who may not be best placed to manage these risks, is likely to result in higher prices if these risks cannot be managed and reduced over time.

Conversely, placing risks with market participants (who may be better placed to manage them) will only result in higher prices being passed on to consumers where competition permits. Solutions that allocate risks to market participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.

2.3.6 Administrative and implementation costs

Changes to regulatory frameworks come with associated costs. These costs include both those imposed to implement the change and the ongoing costs associated with the change. These costs result from necessary changes to information technology systems, billing arrangements and other market process. Generally costs should be attributed to the party who is best able to reduce the extent of the costs over time. However, where costs are imposed in implementation and cannot be mitigated through market mechanisms, these costs should be minimised relative to the benefits of the regulatory changes.

The Commission has considered the implementation efficiency of the proposals set out in the rule change requests, the approach set out in the first draft determination and the approach set out in this second draft determination. This is necessary so that the implementation and ongoing costs, ultimately borne by consumers, do not exceed the benefits of introducing a mechanism.

2.3.7 Appropriate consumer protections

A competitive retail market should be backed by a strong consumer protection framework for those that need it most. This framework should facilitate consumers accessing the benefits of competitive markets on fair and reasonable terms, while maintaining the right to access energy as an essential service.

The energy-specific consumer protections were developed in the context of regulating traditional services and the Australian energy retail market being opened up to competition. At the heart of this framework is the principle that consumers have a right to access energy (as an essential service) on fair and reasonable terms.

In addition, in light of the new technologies, innovation in products and services, and changes in consumer preferences, consideration should be given to the appropriate application of consumer protections to new energy services. Changes to the rules that impact on the level of consumer protections should not expose consumers to additional risks.

Customers participating in wholesale demand response through an energy service provider or aggregator may be exposed to potential risks as a result of not being covered by consumer protections in the NERL and NERR in respect of these services.

2.3.8 Commission decision-making and climate change risks

Climate change manifests through two broad types of risk:

- how the physical world is changing or likely to change as a result of climate change (adaptation risk)
- how policy makers, consumers and investors are responding, or are likely to respond, to the risks presented by climate change (mitigation risk).

The Commission makes its decisions on changes to the NER and NERR with reference to the NEO and the NERO, as discussed above. These objectives do not specifically require the Commission to have regard to the long-term interests of consumers with respect to climate change or the environment. Instead, the NEO and NERO direct the Commission to consider the achievement of economic efficiency in the long-term interests of consumers with respect to specified matters, being the price, quality, safety, reliability and security of the supply of electricity and energy services.

However, in making its decisions under the NEL and NERL in respect of the wholesale demand response rule change requests, the Commission also has regard to relevant factors that can affect the specific matters identified in the NEO and the NERO. This includes considering whether its decisions are robust to any impacts of climate change mitigation or adaptation risks on the price, quality, safety, reliability and security of supply of electricity and energy services.

2.4 Summary of reasons - more preferable draft electricity rule

The more preferable second draft electricity rule made by the Commission is attached to and published with this second draft rule determination. The key features of the more preferable second draft rule are outlined at the start of this chapter.

Further detail on the more preferable second draft rule can be found in chapter 6 of this determination.

The Commission's determination to make a second draft rule introducing a wholesale demand response mechanism at this time reflects the facts that:

- Technologies have evolved such that more consumers want to and can participate directly in the wholesale market. The rule change requests received by the Commission, and the subject of this second draft determination, highlight a growing interest across industry for the wholesale market to accommodate consumers who are able to engage in the wholesale market. There are currently barriers that have limited the opportunities for consumers to participate in wholesale demand response.
- Wholesale demand response may contribute to promoting reliability and security in a more affordable way than peaking generation.
- Certain elements of the wholesale demand response mechanism would provide opportunities to gain valuable experience with processes that will be useful in the transition to a two-sided market, including increased demand side participation in the scheduling arrangements used in the wholesale market.

2.4.1 Assessment of the draft rule against the assessment criteria

Having regard to the issues raised in the rule change requests and during consultation, the Commission is satisfied that the more preferable second draft electricity rule will, or is likely to, contribute to the achievement of the NEO for the following reasons:

- **Promoting reliability and transparency:**
  - The mechanism introduced under the second draft rule will promote greater demand side transparency and assist with reliability. Under the second draft rule, wholesale demand response units will need to be scheduled to participate in the wholesale market. This will increase the capacity of resources that can be relied upon to be dispatched in order to promote reliable outcomes for consumers. This may allow

DRSPs to be dispatched ahead of more expensive peaking generation and therefore lower the wholesale electricity price. This should lead to reduced need for peaking capacity. By participating transparently, DRSPs will also contribute to the ability of other market participants to make informed operational decisions, since participants will be able to incorporate information about wholesale demand response participating through the mechanism into their operational and investment decisions.

- The second draft rule requires these parties to be scheduled i.e. make offers to provide wholesale demand response and receive dispatch targets. Without the obligations associated with scheduling, the wholesale demand response would be less certain and would not be able to be relied upon by AEMO for reliability purposes.
- Under the second draft rule, DRSPs will also be required to provide relevant information through pre-dispatch, the short-term projected assessment of system adequacy (ST-PASA) and the demand side participation (DSP) portal. This will provide a greater level of information to AEMO and the market over various timeframes, which will further promote more efficient operational and investment decisions by AEMO and market participants.
- The second draft rule also increases the transparency and reporting relating to the DSP portal

- **Promoting efficient utilisation of electricity services**:
  - The second draft rule promotes the ability for consumers who participate in the mechanism to change their level of consumption (or export of generation) in response to the wholesale electricity price. This will occur through their reduced consumption or increased generation competing directly with the supply-side, and so the supply-side should be more competitive, with this reflected in the wholesale price.
  - Demand response sold through the mechanism can avoid more expensive generation being dispatched when the supply-demand balance is tight, leading to an efficient clearing of the spot market.
  - Wholesale demand response has the effect of reducing demand in high priced periods. Over the short term, this would have the benefit of suppressing high wholesale spot prices and reducing the total costs of supplying consumers' demand for electricity.
  - In the long term, this should lead to the least-cost combination of resources to meet demand. This will reduce the costs that are recovered from all consumers.
- **Promoting consumer choice and competition**:
  - The mechanism introduced under the second draft rule will increase the level of consumer choice in relation to providing wholesale demand response and accessing service providers to assist with providing wholesale demand response. By increasing the ability for consumers to provide wholesale demand response through the mechanism, it would have the effect of increasing the level of competition among providers of wholesale demand response services to customers. As a result, consumers should receive greater value for providing a given level of wholesale

demand response under the second draft rule when compared to the current arrangements.

- Under the second draft rule, wholesale demand response provided through the mechanism directly competes with scheduled generation, increasing competition in the wholesale market.

- **Minimising the extent of any distortionary impacts**:
  - The second draft rule seeks to minimise the impacts of any distortions introduced under the mechanism, particularly to the wholesale market and retailers' hedging and positions in the contract market. The Commission acknowledges the potential for distortionary impacts and costs being imposed on the market through the introduction of centrally determined baselines. The second draft rule seeks to address these impacts in the following ways:
    - The second draft rule requires AEMO to determine the appropriate baseline methodology metrics through stakeholder consultation. These metrics will constitute the appropriate thresholds for baselines applied to wholesale demand response units. A wholesale demand response unit will need to demonstrate compliance with these metrics when classifying load as a wholesale demand response unit initially and over time, in order to continue participating in central dispatch. As a result, any wholesale demand response unit unable to comply with the metrics (and by inference, unable to be accurately baselined) will not be able to participate in dispatch and settlement under the mechanism. This will reduce the exposure of other market participants to inaccurate baselines.
    - The second draft rule allows for these metrics to be made more rigorous as baseline methodologies improve over time. The second draft rule provides for a process by which new baseline methodologies can be developed through consultation between stakeholders and AEMO.
    - The Commission notes that centrally determined baseline-related risks cannot be entirely avoided under the wholesale demand response mechanism. Baselines will be impossible to accurately determine, and particularly difficult for variable loads. This is one of the reasons the mechanism is not suited to small customers participating - these customers typically provide demand response through highly variable and controllable devices. As noted in chapter 4 and in a separate paper on digitalisation,[41] the Commission considers a longer term solution for capturing the benefits of wholesale demand response will be to move toward a two-sided market which would not rely on centrally determined baselines. The COAG Energy Council has highlighted the design of a two-sided market as a priority and has requested the Energy Security Board (which includes the Commission) provide advice on this priority for the COAG Energy Council meeting on 20 March 2020.
  - The second draft rule also seeks to reduce the risks for retailers by providing for a retailer to be informed when a customer for which it is the FRMP has an arrangement

41 AEMC, *How digitalisation is changing the NEM - The potential to move to a two-sided market,* 14 November 2019, available at: https://www.aemc.gov.au/sites/default/files/2019-11/How%20digitalisation%20is%20changing%20the%20NEM.pdf

with a DRSP, and the baseline methodology being used for that customer. This will assist the retailer in managing its exposure to the wholesale market. In addition, it will provide the retailer with information to be able to adjust its arrangement with that customer (if necessary) to account for any change in risk profile introduced by virtue of that customer providing wholesale demand response.

- The second draft rule also requires a DRSP to pay a retailer, using a pre-determined reimbursement rate, for the amount of demand response provided by their shared customer (covering the amount of energy the customer would have otherwise purchased from the retailer if it had not provided demand response, and for which the retailer remains liable in the wholesale market). This should result in the retailer's hedging position being largely unaffected and the retailer not being exposed to costs that it is unable to manage. By providing for this adjustment in settlements, the second draft rule will minimise the extent of any changes in relation to contract market positions and the associated costs of maintaining these hedging positions.

- **Minimising the extent of any upfront costs**:
  - The dispatch and settlement model introduced under the second draft rule seeks to reduce the extent of upfront costs imposed on AEMO and the market, specifically retailers.
  - By allowing retailers to continue to bill their consumers for actual consumption (as opposed to the baseline level of consumption), the second draft rule minimises the extent of the changes required to retailer billing systems. This will result in materially reduced upfront costs for retailers when compared to the proposals set out in the rule change requests from PIAC, TEC and TAI, and from the South Australian Government.
  - The second draft rule will require a number of changes to AEMO systems. In developing the rule, the Commission has sought to reduce the extent of these upfront system change costs by minimising the extent to which AEMO will be required to adjust existing systems. In addition, the proposed implementation time frames are intended to strike the appropriate balance between introducing the mechanism in a timely manner, and providing AEMO with sufficient time to manage upfront costs.
  - After consultation with AEMO, the Commission has also made changes between the first draft rule and the second draft rule that are intended to reduce the extent of AEMO's upfront costs, including:
    - — removing the ability for market participants to submit their own baseline methodologies
    - — not including DRSPs in the systems and processes for FCAS cost recovery and affected participant compensation
    - — removing the requirement for DRSPs to submit information to AEMO for the purposes of MT PASA, instead utilising the existing DSP portal
    - — changes to the requirements applying to participation by DRSPs in central dispatch, including to allow for utilisation of the existing systems and processes applying to scheduled loads

  - — revising the rules relating to the process of classifying wholesale demand response units, including removing the requirement to aggregate to 5 MW.
- The aim of minimising upfront costs has also informed the Commission's decision to focus on facilitating wholesale demand response from large customers as discussed in chapter 4.

- **Robust to climate mitigation and adaptation risk**
  - The Commission considers that the second draft rule is robust to the impacts of climate change mitigation and adaptation risks on the price, reliability and security of supply of electricity.
  - **Adaptation and reliability and security of supply:** One of the key modelled impacts of anthropogenic climate change is an increase in the frequency and severity of extreme weather events.[42] Extreme weather is likely to impact the power system by increasing the extent to which generation and network assets may be damaged or unable to provide generation or network services, and by driving uncertainty around generation availability from an increasingly weather dependent generation fleet. Together, these impacts may affect the reliability and security of supply of electricity. As discussed above, the Commission considers the wholesale demand response mechanism will assist in the reliability of the NEM by incentivising additional sources of transparent, scheduled peaking capacity that may be able to operate when other forms of capacity are limited or unavailable, and therefore considers the mechanism is robust to adaptation risks to system reliability.
  - **Mitigation and reliability and security of supply:** Among the various economy wide measures that may be used to mitigate the impacts of climate change, the rollout of variable renewable generation is the primary measure adopted in the NEM power system. The Commission considers that the wholesale demand response mechanism is robust to risks to reliability and security of supply arising from this shift in the generation fleet, for the reasons discussed above.
  - **Adaptation and the price of electricity in the short term:** Climate change impacts, in the form of extreme weather events, may affect the wholesale price of electricity at the time of the event by affecting both supply and demand. The Commission considers that the wholesale demand response mechanism is robust to these impacts as it incentivises demand reduction as an alternative to dispatchable generation during high-price periods, that may operate to limit or suppress price spikes.
  - **Mitigation and the price of electricity in the longer term:** As noted above, a key form of climate change mitigation measure adopted in the NEM is the increased use of variable renewable generation. This is increasing the need for dispatchable sources of supply, which are currently relatively costly. By incentivising demand

42 See: Seneviratne, S.I., N. Nicholls, D. Easterling, C.M. Goodess, S. Kanae, J. Kossin, Y. Luo, J. Marengo, K. McInnes, M. Rahimi,M. Reichstein, A. Sorteberg, C. Vera, and X. Zhang, 2012: Changes in climate extremes and their impacts on the natural physical environment. In: *Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* [Field, C.B., V. Barros, T.F. Stocker, D. Qin, D.J. Dokken, K.L. Ebi, M.D. Mastrandrea, K.J. Mach, G.-K. Plattner, S.K. Allen,M. Tignor, and P.M. Midgley (eds.)]. *A Special Report of Working Groups I and II of the Intergovernmental Panel on Climate Change (IPCC)*. Cambridge University Press, Cambridge, UK, and New York, NY, USA, pp. 109-230.

reductions that may compete with existing forms of dispatchable supply, such as gas peaking plants and energy storage, the Commission considers that the wholesale demand response mechanism may operate to moderate the price of electricity over the longer term, and is therefore robust to this impact of mitigation risks on the NEM.

2.4.2 More preferable draft rule

The Commission considers the second draft rule is likely to better contribute to the achievement of the NEO than the proposals set out in the proponents' rule change requests.

Rule change request from PIAC, TEC and TAI - wholesale demand response mechanism

A number of the basic elements of the mechanism under the second draft rule are based on the model proposed by PIAC, TEC and TAI. However, a key practical implication of the model proposed by PIAC, TEC and TAI would be that retailers would be required to charge their individual customers at their baseline level of consumption, rather than their actual level of consumption. This would require all retailers to make costly, complex and time-consuming changes their existing retail billing systems. The Commission considers that the second draft rule better contributes to the NEO for the following reasons:

- Under the second draft rule, retailers would be able to continue to bill customers based on actual consumption, thereby significantly reducing the changes required to retailer billing systems and the associated implementation costs relating to the proposed settlement model.
- The second draft rule incorporates a number of changes from the first draft rule (and PIAC, TEC and TAI's rule change request) which would significantly reduce the overall implementation costs associated with the mechanism and allow it to be implemented prior to the summer of 2021-22.

Rule change request from AEC - demand response register

The AEC's rule change request proposed an extension of the current arrangements for wholesale demand response. However, the Commission considers the second draft rule better contributes to the NEO for the following reasons:

- In the register proposal, substantial scope is provided to the retailer to determine whether a demand response arrangement is consistent with its business model. This would provide little certainty to the demand response aggregator or consumer that its demand response arrangement would be maintained following a change of retailer.
- Good faith negotiation is unlikely to be accessible for most consumers looking to participate in wholesale demand response. The Commission considers that there would be significant information asymmetry between the retailer and the consumer such that there would be little avenue for a consumer to challenge a retailer.
- In contrast, under the second draft rule, a change of retailer would not affect a consumer's demand response arrangements with a DRSP, promoting competition and consumer choice.

Rule change request from South Australian Government - separate market for demand response

The Commission also considers the second draft rule is likely to better contribute to the achievement of the NEO than the proposal for a separate market for wholesale demand response set out in the South Australian Government's rule change request. The Commission considers the second draft rule better contributes to the NEO for the following reasons:

- The proposal set out by the South Australian Government would have involved the costs of wholesale demand response being recovered in a smeared manner. Retailers have limited ability to manage such costs, as they are very difficult to incorporate into their hedging strategies. This would have resulted in increased costs being imposed on consumers. The second draft rule sets up a settlement model that allows participants to manage their costs, minimising the extent of any distortionary costs, while also minimising administrative costs.
- The proposal set out by the South Australian Government was considered by the proponent to be advantageous compared to the other proposals as it did not impact on retailer billing systems and consequently, would not require as much time to implement. The second draft rule also avoids making any changes to retailer billing systems. In addition, both the South Australian Government proposal and the second draft rule would require changes to AEMO's systems. The second draft rule would be able to be implemented as quickly as the South Australian Government proposal.

Proposal set out in stakeholder submission

The Commission has also considered alternative options raised by stakeholders. An alternative option was submitted by Intelligent Energy Systems in response to the consultation paper. A summary of the proposal and the Commission's response is provided below.

BOX 1: ALTERNATIVE PROPOSAL SUBMITTED BY INTELLIGENT ENERGY SYSTEMS (IES)

IES submitted an alternative proposal to the Commission to facilitate wholesale demand response.[1]

Under this proposal, in addition to paying the retail tariff, a consumer would receive or pay the difference between the average of five-minute spot prices (over a pre-determined period of time such as a day, calculated ex post) and the five-minute spot price for that particular dispatch interval, for each unit of consumption.

For each dispatch interval:

Consumer payment ($) = Q x Pr + Q x (Ps – Pa)

Where:

- Q is the quantity of electricity consumed (kWh)
- Pr is the retail tariff price ($/kWh)
- Pa is the average of five-minute spot prices over a pre-determined period ($/kWh)
- Ps is the five-minute spot price ($/kWh).

A positive number in this equation would represent a payment from the consumer to the retailer.

This is illustrated by the graph below, which shows payments/receipts made by/to a consumer in addition to payments made consistent with the retail tariff:

Figure 2.1: IES proposed arrangements

Source: IES, submission to consultation paper, p. 3.

The intent of this proposal is that it:

- exposes the consumer to the spot price on its consumption – and so provides it with incentives to reduce its consumption when the spot price is high
- limits the consumer's exposure to the spot price by also exposing it to the average price over the period – meaning that it is not exposed to sustained high periods of high spot prices
- avoids the needs for baselines.

The Commission agrees that these arrangements would encourage demand reductions when the spot price is high relative to the average spot price. However, it also encourages an increase in demand when the price is low relative to the average spot price. This can be demonstrated by rearranging the equation above, as follows:

Consumer payment ($) = Q x ((Pr + Ps) – PA)

As can be seen, whenever the average price exceeds the sum of the spot price and retail tariff, the consumer payment will be negative, i.e. the consumer will be paid to consume.

For example, if the retail price is $200/MWh ($0.2/kWh), the spot price is $1,000/MWh and the average spot price is $2,500/MWh then the consumer will earn $1,300/MWh for every unit of energy it consumes – despite the fact that the spot price is still relatively high (compared to a longer-term average) suggesting that the market is tight.

Of course, an average spot price of $2,500/MWh over a sustained period (e.g. the course of a day) is unlikely – and longer time periods over which the average is calculated would further reduce this likelihood. But even in lower priced market conditions, these outcomes could arise. For example, if the average spot price was $300/MWh for the day, but $90/MWh in a particular interval, the consumer would profit $10/MWh by consuming electricity (if its retail tariff was $200/MWh).

It is the consumer's retailer, and the system as a whole, which loses from these arrangements:

- The retailer will have to incur greater costs in the spot or contract market to cover the increased consumption of the consumer.
- This in turn passes through to higher spot and contract prices for all market participants, higher fuel costs for the additional consumption encouraged by the mechanism, and conceivably even investment in additional generation.

For these reasons, the Commission does not consider this proposal to be an appropriate option to facilitate wholesale demand response in the NEM, and considers that the second draft rule is likely to better contribute to the achievement of the NEO.

Note: 1. Intelligent Energy Systems, submission to consultation paper, p. 4.

2.5 Summary of reasons - no draft retail rule

Having regard to the issues raised in the rule change requests and during consultation, the Commission has decided not to make a draft retail rule. The Commission is not satisfied that a draft retail rule relating to wholesale demand response will, or is likely to, contribute to the achievement of the NERO for the following reasons:

- **It is unlikely that large numbers of small customers would participate in the mechanism**
  - Baselines have not been demonstrated to work well for small customers. In order to allow a third party to sell wholesale demand response, a counterfactual is used to determine the quantum of response provided. The quality of a baseline is directly related to how predictable a load is. If a load is very predictable, the baseline can be treated as being more certain. As loads become more unpredictable, it becomes harder to reasonably predict what the consumer would have done had they not provided wholesale demand response. Large commercial and industrial loads are often more predictable. This is because they operate large processes, often on fixed timetables and fixed hours. However, the loads small customers are likely to use to provide demand response are highly variable. This makes it very difficult to determine baselines accurately. As such ,it is unlikely that small customer loads would be able to meet AEMO's baseline methodology metrics, meaning they would be unable to participate in the mechanism.
  - Behavioural demand response, a form of demand response often used for small customers, is not suited to being scheduled. Behavioural demand response involves eliciting some amount of demand response from consumers on request, rather than using automated control systems. Often it involves the consumer being provided with the option of participating in demand response on the day. Consumers that are not providing demand response through a controllable device may instead provide behavioural demand response. While these programs provide customers with the opportunity to provide wholesale demand response, they often mean the party calling for the demand response is unsure how much will be provided. As such, behavioural demand response programs are not suited to being scheduled. Indeed, any requirements to meet scheduling obligations would likely make them untenable. Given the demand response provided through the mechanism is required to be scheduled (for the reasons discussed above), and the unsuitability of behavioural demand response for scheduling, behavioural demand response would not be able to participate in the mechanism.
- **Baselines may encourage inefficient behaviour by small customers**

    - Centrally determined baselines may, depending on the methodology used, encourage inefficient outcomes from discretionary resources such as those typically used by small customers providing demand response. By paying customers to reduce consumption relative to a centrally determined counterfactual that is based on usage in immediately preceding intervals, customers are encouraged to consume more in peak periods in anticipation of high spot prices. This is likely to have a greater impact with small customers as most small customer devices that would be available to provide demand response (i.e. pool pumps, batteries etc.) would be able to shift consumption times without inconveniencing the consumer. On the other hand, large customer loads are likely to be less discretionary and less able to be consistently moved to particular times of day for the purposes of inflating the baseline.
- **The costs of including small customers would likely outweigh the benefits**
    - After undertaking extensive consultation, the Commission understands that including small customers in the mechanism would result in significantly higher implementation costs for AEMO and market participants.
    - By focussing on large customers, a significant amount of wholesale demand response can be facilitated while minimising the systems changes required by AEMO and market participants.
    - In addition, small customers are not expected to be able to provide material amounts of wholesale demand response through the mechanism. For the reasons listed above, the forms of demand response typically used by small customers are unlikely to meet the requirements to be able to participate in the mechanism. As such, extending the mechanism to include small customers would impose higher costs on the market and deliver unclear benefit. These costs would inevitably be required to be recovered from consumers.
- **The energy-specific consumer protections framework does not currently extend to demand response provided through third parties**
    - Energy consumers are protected by energy specific provisions under the National Energy Retail Law and associated rules, which relate to the supply of energy by distributors and the sale of energy by retailers to customers.
    - Under the current arrangements, these specific protections would apply to customers of retailers that are providing wholesale demand response through that retailer. For example, through the programs described in chapter 3.
    - However, 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. The NERL would not require a DRSP to be an authorised retailer (and nor would a DRSP be a distributor).
- **The retail rule change request would not allow for consumer protections for small customers to be addressed holistically:**
    - It is important that there is proper consideration of the appropriate consumer protections that should be extended to consumers participating in wholesale demand response, as well as other non-traditional energy services and products.

- Given the close linkages between the NERL and the NERR, it is not possible to consider one in isolation of the other. It is likely that any change to the application of the relevant consumer protections will require changes to the NERL as well as to the NERR. Changes to the NERL require the approval of the COAG Energy Council and could not be made through these rule change requests.

- **The Commission has started a holistic review of consumer protections:**
  - There has been significant market evolution in recent years in relation to non-traditional energy services and products. The nature and application of the energy-specific consumer protections have not been adapted to these changes. This applies to wholesale demand response as well – as noted above customers providing wholesale demand response through an entity who is not a retailer would not be covered by the retail law or rules in respect of the services provided by that entity.
  - Our 2019 *Retail competition review*[43] recognised that there is a need to analyse and update the retail law and rules to remove barriers to innovation and extend consumer protections to new models of essential service supply.
  - On 12 December 2019, the Commission published an issues papers on the review of consumer protections. This paper discussed how the market's evolution raises some regulatory issues related to new energy products and services, including demand response, and whether there is a need for potential changes to the application of energy specific consumer protections.
  - A final report on the Commission's analysis of the consumer protections framework for energy markets will be published along with the annual retail competition review report in June 2020. This will include recommendations on changes to the NERL and NERR to make sure that consumer protections for new energy products and services and the traditional sale of energy remain appropriate in an evolving market. The COAG Energy Council will need to consider and approve these recommendations before any changes to the law can be made.

Changes to the retail rules are not required if small customers are not participating in the mechanism. Accordingly, the Commission has determined not make a draft retail rule.

43 See: https://www.aemc.gov.au/market-reviews-advice/2019-retail-energy-competition-review

3 CONTEXT

Energy markets are changing. A range of new products and services are emerging that are redefining the way in which electricity is supplied to consumers, how consumers engage with the market and how and when electricity is used. Consumers can benefit from the evolving market arrangements and through their choices provide important signals to businesses throughout the energy system.

An active demand-side, characterised by the active participation of consumers, promotes efficient outcomes in the wholesale market. The supply side of the market provides a product or service at a price, and the demand side (i.e. consumers) responds to the price/value of the product or service being offered. Where load can effectively respond to prices, it can choose its level of consumption based on its willingness to pay for consuming electricity compared to the cost of that electricity. This has benefits to the individual consumer and to the system as a whole.

Wholesale demand response will play an increasingly important role in the future of the national electricity market (NEM), notably as an alternative to peaking generation. There is a need for flexible and dispatchable resources on both the supply and demand side to accommodate the increasing penetration of variable generation and changing consumer preferences and to promote efficient outcomes in the wholesale market. It is anticipated that a more active demand-side means that consumers will play an increasingly important role in helping to match supply and demand in the NEM. Demand response can be more cost-effective for both the consumer and the power system than building new generation and network capacity.

This development is being driven by technological advancements allowing the demand side to become more dynamic. Historically, high upfront costs and technical limitations associated with the equipment needed to facilitate demand response (e.g. advanced metering, monitoring and communications equipment) posed a barrier to many consumers, particularly small customers, undertaking demand response. However, declines in the costs of these technologies in recent times, as well as the emergence of new technologies and platforms, are making it cheaper and easier for consumers to provide demand response in a manner that is cost-effective and convenient to them.

These technology changes, along with the increasing recognition of the utility of demand response, are driving the emergence of new programs and product offerings which increase consumers' access to demand response and help to assess the capabilities and potential contribution of demand response in the NEM in different contexts. The variability of spot prices in the NEM and the potential for high prices during peak demand periods, which is a market-design characteristic intended to provide appropriate investment and operational signals for generators, also provides an incentive for consumers that are exposed to the spot price to reduce their consumption (or increase their generation) during these periods. However, most consumers do not currently receive these price signals under their retail electricity contracts. Instead, their retailer manages these risks for them and sells energy to the consumer, often at a fixed wholesale price. These rule change requests focus on ways to increase signals and incentives for consumers to engage in demand response.

This chapter explores some of the existing programs and trials relating to demand response which are currently in development or under way in the NEM, as well as relevant products already being offered by retailers. These products and programs illustrate that there is a range of different ways consumers can provide demand response, including through participation in the Reliability and Emergency Reserve Trader (RERT), residential virtual power plants (VPPs), aggregation of loads to provide market ancillary services, direct spot price pass-through contracts and other retail and network tariff structures that incentivise demand reductions at certain times.

The wholesale demand response mechanism will provide an additional avenue for large customers to undertake demand response. However, this is only one type of demand response that will occur in the wholesale market. Other types of demand response are currently being trialled, including through products and programs that will allow small customers to become more active demand-side participants. As technologies continue to emerge and become cheaper, and consumer awareness of demand response grows, customers will continue to experiment with different ways of providing demand response, including those that sit outside of the wholesale demand response mechanism. The Commission considers that the wholesale demand response mechanism will be complementary to existing demand response programs, as well as to the development of new programs, as it will provide an important source of learnings and will facilitate the development of new technologies and skills among market participants.

3.1 What is demand response?

3.1.1 Categories of demand response

Demand response refers to consumers of electricity changing their level of consumption in response to short-term signals.

There are different types of demand response: wholesale, emergency, network and ancillary services, as shown in the table below. While the equipment that provides these different types of demand response is often the same, the services provided are distinct. There are also clear interactions between these different types of demand response. For example, there are interactions between wholesale and emergency demand response.

The Australian Competition and Consumer Commission (ACCC) highlighted these interactions in its *Retail Electricity Pricing Inquiry*, noting that there are coordination issues to consider when it comes to demand response participating in different markets (e.g. high spot prices, which may incentivise wholesale demand response, may not occur at the same time as localised network issues).[44] It should also be noted that emergency demand response typically sits outside of the wholesale market.

44 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, available at: https://www.accc.gov.au/publications/restoring-electricity-affordability-australias-competitive-advantage.

Table 3.1: **Categories of demand response**

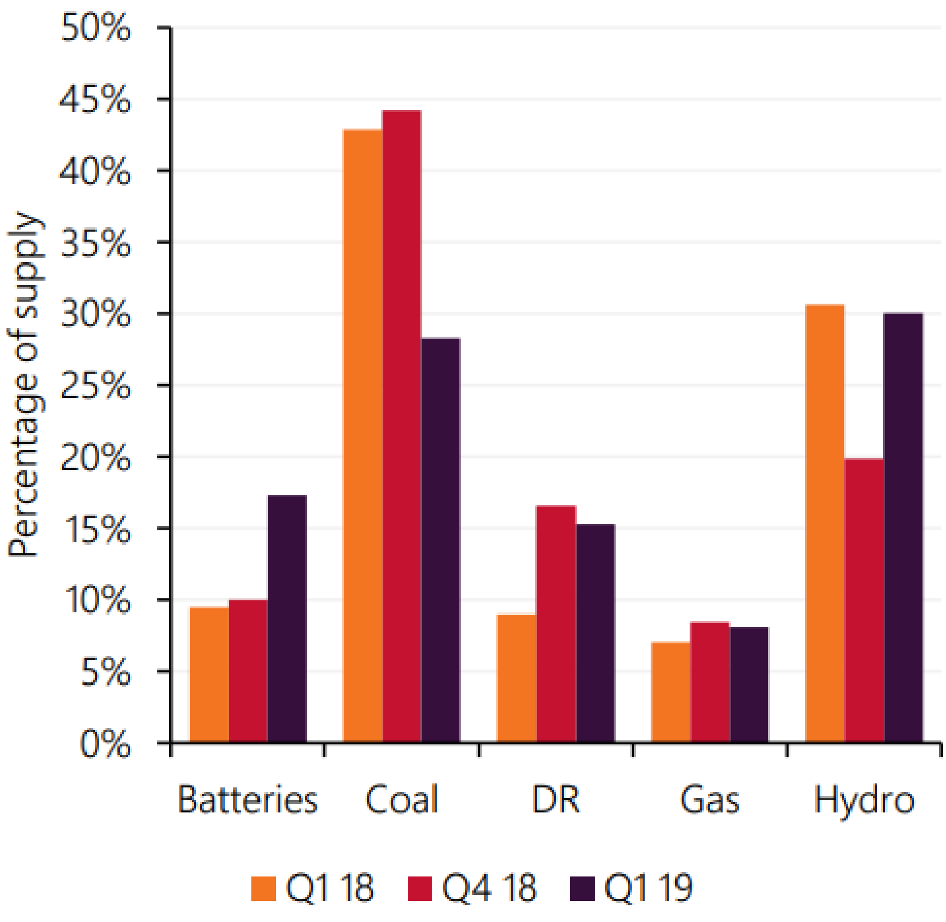
TYPE	DESCRIPTION	CURRENT STATUS
Wholesale demand response	Demand response used to change the quantity of electricity bought in the wholesale market, which could be used to manage spot price exposure, or to help market participants manage their positions in the contract market.	Due to the lack of transparency around how much wholesale demand response is currently being utilised, it is difficult to draw firm conclusions about how much demand response is occurring in the NEM, or whether this level is efficient. Wholesale demand response is the subject of the rule change requests addressed in this determination.
Ancillary service demand response	Demand response employed for providing ancillary services. For example, responding quickly to brief, unexpected imbalances in supply and demand by participating in the frequency control ancillary service (FCAS) markets.	Large energy users have used demand response to provide FCAS. Market ancillary service providers (MASPs) can offer customers' loads into FCAS markets. Currently, there are three MASPs using demand response to provide FCAS.
Emergency demand response	Demand response employed by the system operator during supply emergencies, with the service being centrally dispatched or controlled to avoid involuntary load shedding. This is generally provided by out-of-market reserves.	Demand response can – and currently is – participating in the Reliability and Emergency Reserve Trader (RERT).
Network demand response	Demand response employed to help a network business to provide network services to consumers	The existing regulatory framework provides a number of incentives and obligations for non-network options (including demand response) to be adopted by a network service provider where it is efficient to do so.

The ability of MASPs to offer demand response into FCAS markets was established by the National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule 2016 No.10. These changes commenced on 1 July 2017. A MASP is not required to be a customer's retailer to offer such demand response services, but must satisfy certain registration requirements and deliver FCAS services in accordance with AEMO's specifications just as any other market participant is required to do. Box 2 details the impacts this rule change has had on FCAS markets in the NEM.

BOX 2: IMPACT OF DEMAND RESPONSE ON FCAS MARKETS

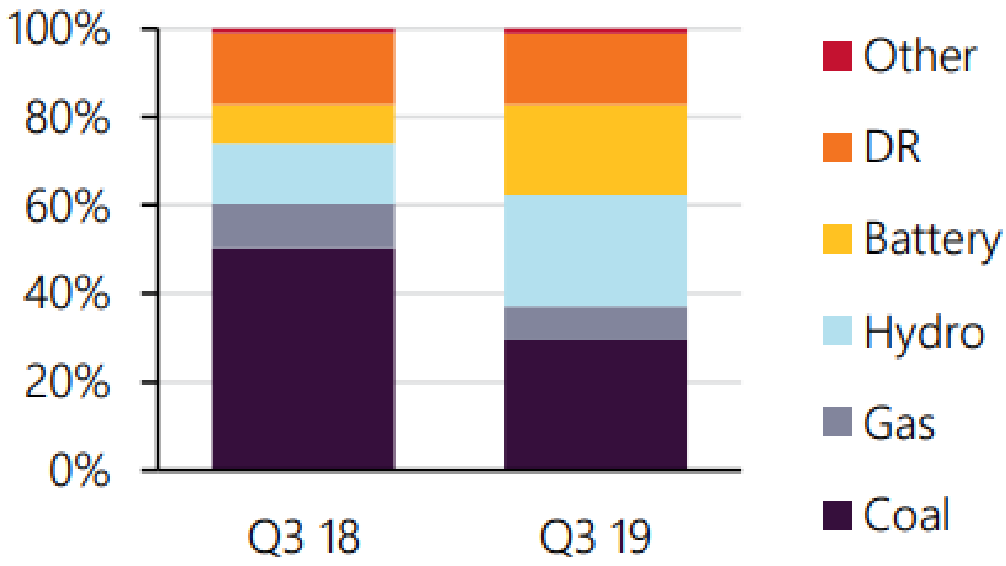
The establishment of the MASP participant category and the introduction of demand response into FCAS markets has resulted in increased competition for the provision of such services. This is highlighted by data published by AEMO. Figure X shows that the share of demand response in the supply of FCAS increased from around 9% in Q1 2018 to 15% in Q1 2019. Data published in AEMO's *Quarterly Energy Dynamics* for Q3 2019 shows that this share has since increased to just under 20%, as illustrated in Figure X.

Figure 3.1: FCAS supply mix, Q1 2018 to Q1 2019



Source: AEMO, *Source: Quarterly Energy Dynamics - Q1 2019*Source: , p. 20. Available at: Source: https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q1-2019.pdfSource: .

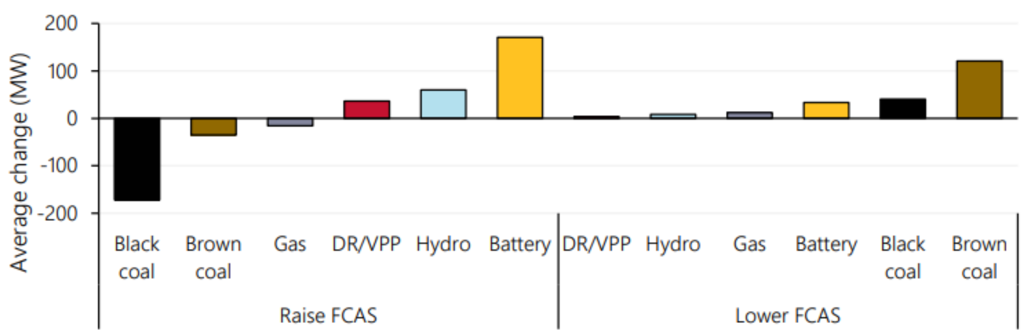
Figure 3.2: FCAS supply mix, Q3 2018 to Q 3 2019



Source: AEMO, *Source: Quarterly Energy Dynamics - Q3 2019*Source: , p. 20. Available at: Source: https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q3-2019.pdfSource: .

The most recent data for Q4 2019 shows that the amount of FCAS provided by demand response and VPPs increased by 36.6 MW between Q4 2018 and Q4 2019, as illustrated in Figure X.

Figure 3.3: Change in FCAS supply - Q4 2019 versus Q4 2018



Source: AEMO, *Source: Quarterly Energy Dynamics - Q4 2019*Source: , p. 22. Available at: Source: https://aemo.com.au/-/media/files/major-publications/qed/2019/qed-q4-2019.pdf?la=en&hash=A46E0A510AE9F127B0A991B312C54460Source: .

This data suggests that as the share of FCAS provided by demand response, batteries and hydro generators increases, the share provided by coal-fired generators decreases.

Demand response has also shown the potential to reduce FCAS costs. AEMO noted that in Q2 2019, reduced contingency raise costs were a function of a 107% increase in the supply of FCAS from a range of MASPs offering demand response at comparatively low prices.[1]

Note: 1. AEMO, *Note: Quarterly Energy Dynamics - Q2 2019, p. 18.*

An active demand-side, characterised by the presence of demand response, promotes efficient consumption of electricity. Consumers would be able to trade off consumption against price signals from across the power system. In practice, benefits from an active demand side would include consumers:

- electing to avoid consumption during local network peaks and defer investment in capital intensive networks
- adjusting consumption during scarcity to maintain the supply-demand balance, often at a lower cost than doing so with expensive peaking generation
- providing the least cost resource for maintaining the power system within its secure limits, e.g. by responding to and correcting frequency deviations
- providing a low cost, controllable resource to correct the supply demand balance in place of involuntary load shedding.

Where consumers are able to effectively respond to prices, it would be an efficient outcome for consumers to choose their level of consumption based on the range of different services they can access or provide.

The AEMC commissioned The Brattle Group to update a previous report on demand response in other international jurisdictions, which was published in 2015 relation to the *Demand response mechanism and ancillary services unbundling* rule change,[45] to help inform the AEMC's assessment of the three rule change requests addressed in this determination. The Brattle Group's findings are summarised in Box 3 and the full updated report is available on the AEMC website.

BOX 3: THE BRATTLE GROUP REPORT ON DEMAND RESPONSE IN OTHER JURISDICTIONS

The AEMC asked The Brattle Group to assess the same six jurisdictions that were covered in the previous report and provide an update on relevant developments. These were: PJM interconnection, ISO – New England, Ontario, Alberta, Singapore and Electricity Reliability Council of Texas (ERCOT).

These markets can be considered to be a cross-section of different types of market design. Some have capacity payments for generation and demand response in addition to the wholesale energy market; whereas others only reward participants through the wholesale energy market. There are also differences in terms of the volatility of wholesale market outcomes, and size and type of generation mix. The report provides more detail on the characteristics and design of the energy markets in each of these jurisdictions.

The Brattle Group was asked to look specifically for changes and developments in relation to wholesale demand response since the time The Brattle Group last reviewed these

45 The Brattle Group, *International Review of Demand Response Mechanisms*, October 2015. Available at: https://www.aemc.gov.au/rule-changes/demand-response-mechanism.

jurisdictions. In particular, The Brattle Group was asked to look at how wholesale demand response is facilitated in a transparent and schedulable manner.

The key findings from The Brattle Group report were:

- As the electricity industry transforms toward intermittent generation sources, wholesale demand response will become increasingly important for balancing the system.
- Since its previous report in 2015, there do not appear to have been significant increases in the amount of demand response quantities that are registered in those jurisdictions that either provide wholesale demand response, or ancillary services. Further, some jurisdictions had shown decreases in the quantities of registered demand response.
- In some jurisdictions, the rules that govern participation of demand response in the wholesale market have been changed in order to make demand response able to be dispatched and so relied on by the system operator, in order for this to assist with reliability. Necessarily, this has generally reduced the amount of demand response that can be offered and provided in these wholesale market since not all demand response can meet these characteristics. For example, to better support reliability PJM now requires demand response providers to be available all year round, rather than just at particular times of the year, which has reduced the number of available providers.
- In jurisdictions where demand response providers receive upfront availability payments, there tend to be higher levels of demand response being made offered for use in the wholesale market. However these resources were infrequently dispatched in the wholesale energy market, because prices were not as volatile and so often did not reach levels where the demand response would be economic to dispatch.
- In jurisdictions where demand response providers don't receive an upfront availability payment, most wholesale demand response occurs through loads simply responding to the wholesale price. However, since this is not clearly integrated in the wholesale market, the demand response that occurs is not transparent to the rest of the market and so it is difficult to quantitatively assess how much there is.

The Brattle Group also looked at proposals being considered by the European Union. The report found that the proposed European legislative framework calls for demand response aggregators to be able to contract with customers directly without needing to go through or have an arrangement with the retailer. This legislative framework is yet to be developed. The proposal would require aggregators to compensate retailers if they imposed costs on the retailers.

Source: The Brattle Group, *International Review of Demand Response Mechanisms in Wholesale Markets*, June 2019. Available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

3.1.2 Types of wholesale demand response

The rule change requests the subject of this second draft determination seek to facilitate wholesale demand response in the NEM. There is a range of ways wholesale demand response can be incentivised and facilitated. A number of examples are set out in Table 3.2.

Table 3.2: Types of wholesale demand response

DESCRIPTION	CONSUMER IMPACTS	IMPACTS ON MARKET PARTICIPANTS	PARTIES INVOLVED
Interruptible supply contracts based on consumers shedding interruptible loads (e.g. facility shifting production to periods outside high spot prices, or at night). Arrangements can be through either: • availability payments, which electricity consumers receive for nominating a demand response resource that they can commit • dispatch payments, which electricity consumers receive if they actually shed load in response to a request.	Potential cost savings for businesses. Some costs to businesses for implementation of technology and infrastructure.	Retailers - provides an alternative to hedge against high wholesale spot prices Network service providers (NSPs) - may provide a mechanism to defer network augmentations, reduce load at risk, or improve supply quality and reliability	Large commercial and industrial energy users Retailers NSPs Specialist third party demand response aggregators
Direct load control of appliances such as hot water, air conditioners and pool pumps – typically through contracts with consumers to enable cycling/shut down on short notice	Potential cost savings for businesses and residential consumers	Costs for NSPs to establish programs NSPs may also have some network augmentations savings	Commercial and residential consumers NSPs
Price based approaches utilising different tariff arrangements: • time of use - cost-reflective pricing in which the day is divided into time bands and different prices are charged during each	Timely energy consumption information Price signals for customers which would allow them to more effectively manage their peak electricity usage and reduce costs	NSPs - potential for deferring network capital expenditure for peak demand period capacity Retailers - benefits for	Currently technology enabled in large commercial and industrial businesses Some small to medium business and residential

DESCRIPTION	CONSUMER IMPACTS	IMPACTS ON MARKET PARTICIPANTS	PARTIES INVOLVED
time band (i.e. peak, off-peak and shoulder). • seasonal time of use - aim to better reflect the differing seasonal costs of electricity supply, and therefore to apply a different TOU price schedule at different times of year. • dynamic peak price - seek to more closely mirror supply and demand conditions where for a few hours each year the cost of electricity supply is highly skewed from the average. • peak-time rebates - alternative form of dynamic peak pricing where customers are paid a rebate for reducing energy use during specific dispatch events.		competition and innovative product and service options Some cost impacts -IT systems and customer management	consumers Retailers NSPs
Allowing third parties to bid demand reductions into the wholesale market under a wholesale demand response mechanism of the kind set out in this draft determination.	Potential for participating consumers to earn money by selling their demand response Reduced peak wholesale prices due to increased competition between demand response and generation	Specialist third party demand response aggregators - direct access to the wholesale market Retailers - hedging strategies and potential systems changes NSPs - may have some	Large commercial and industrial energy users Specialist third party demand response aggregators

DESCRIPTION	CONSUMER IMPACTS	IMPACTS ON MARKET PARTICIPANTS	PARTIES INVOLVED
		network augmentations savings Cost impacts for AEMO, including IT systems changes, which will impact market participant fees	

3.2 Existing demand response trial initiatives in the NEM

This section sets out a number of trials aiming to facilitate the integration of demand response in the NEM which are currently under way.

3.2.1 ARENA/AEMO demand response RERT trials

In May 2017, the Australian Renewable Energy Agency (ARENA) and AEMO partnered to trial demand response services using the RERT (i.e. emergency demand response) arrangements in the NER.[46] The trial will run for three years from summer 2017/18 to summer 2019/20. The objectives of this initiative include:[47]

- demonstrating that demand response is an effective source of reserve capacity for maintaining reliability of the electricity grid during contingency events and that demand response resources can be rapidly developed for deployment from summer 2017/18
- providing an evidence base to inform the merits and design of a new market or other mechanism for demand response to assist with grid reliability and security, allowing for greater uptake of renewable energy
- improving the commercial and technical readiness of demand response providers and technologies, in particular to help demonstrate and commercialise the use of demand response for grid security and reliability.

Ten pilot projects, representing a broad range of technical and commercial solutions, were awarded funding under the initiative to manage electricity supply during extreme demand peaks. The trial has contracted for 143 MW of demand response in 2017-18, 190 MW in 2018-19 and 203 MW in 2019-20, across New South Wales,[48] Victoria and South Australia.[49]

Further details on the programs funded under this program and the lessons learnt from the first year are set out in Table 3.3.

46 The RERT is a function conferred on AEMO under the NER. Under the RERT, AEMO can enter into reserve contracts so it can call upon resources not available to the market if needed to ensure reliability of supply meets the reliability standard, and to maintain power system security.

47 ARENA, *Demand Response RERT Trial: Year 1 Report*, March 2019. Available at: https://arena.gov.au/assets/2019/03/demand-response-rert-trial-year-1-report.pdf.

48 Funding for the procurement of reserves in New South Wales was provided by the New South Wales Government through the AEMO/ARENA tender process.

49 AEMO, Summer 2017-18 operation review, p. 31.

Table 3.3: Overview of projects funded as part of the ARENA demand response RERT trial

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
Retailers			
AGL	**Peak Energy Rewards Program:** Residential demand response AGL offered customers a sign-up incentive of $50, as well as $2 per kWh reduction as compared to their baseline consumption. Over the four events that AGL ran during year 1 of the program, the average incentive earned by customers was $12. The average for the top 10 per cent of participating customers was $43, while for the bottom 10 per cent it was $2. In December 2019, AGL extended the program into Victoria with over 11,000 customers signing up. More than 8,000 NSW customers are involved in the program in 2020. AGL also plans to expand the program into other states prior to summer 2020-21. **Peak Energy Rewards Managed For You:** Residential demand response Following the launch of Peak Energy Rewards, AGL launched a subsequent program – Peak Energy Rewards Managed For You – giving customers the option of having their own device, such as an air conditioner, remotely triggered during a demand response event. In exchange for allowing AGL to control these devices, customers are paid a financial incentive. Incentives under this program were significantly higher, with a $300 sign up incentive and a flat $30 payment per event.	18	20

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	The Managed For You program was initially launched in February 2018 with air conditioner control, involving retro-fitting air conditioners with a Demand Response Enabling Device (DRED). The program was expanded to electric vehicles in March 2018 using smart charging stations. While AGL initially had 123 enrolments in the air conditioner program, only 58 were subsequently confirmed and 45 successfully proceeded to final installation (primarily due to incompatibility with Australian Standard AS 4755 rendering customers' assets incompatible with DREDs). **Commercial and industrial demand response** AGL contracted commercial and industrial customers to provide 10 MW of demand response from 1 December 2017, increasing to 17 MW in January 2018. These customers were offered both an availability fee and a dispatch fee as incentives to participate. Customers across 34 sites included data centres (1 site), telecommunications (3 sites), shopping centres (11 sites), manufacturing and recycling plants (4 sites), water utility pumping stations and treatment plants (15 sites) and a university campus (1 site).		
EnergyAustralia	EnergyAustralia's demand response portfolio draws on initiatives across all customer segments. The portfolio employs the following approaches: **Mass Market (MM) Behavioural Demand Response:** Residential demand response Residential customers receive incentives under the PowerResponse	38	49

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	program if they reduce their consumption in response to an SMS notification. **MM Circuit Level Control Device campaign:** Residential demand response Residential customers install innovative, high quality circuit-level monitoring and remote-control capable devices at their premises and can receive incentives if they allow EnergyAustralia to switch off appliances such as air-conditioners, pool pumps or other loads at the circuit level after a series of notifications. **Battery storage group control** This activity involved developing group control capability to aggregate a large proportion of battery storage devices. For a financial incentive, customers allow EnergyAustralia to remotely charge and/or discharge their battery into the grid after a series of notification steps. **On site generation** A group of EnergyAustralia customers have linked their assets to a virtual power plant (VPP) platform to allow for remote control and orchestration of their distributed energy resources (DER). The VPP includes a range of generators which can be called upon when needed and business activities can be curtailed or shifted when advance notice is given. **Commercial and industrial customers**		

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	EnergyAustralia has collaborated with a number of major customers and a VPP provider to trial a range of capabilities at certain sites which are managed simultaneously to provide load reduction during events. This includes pre-cooling/heating at large sites, and curtailing low temperature freezers under managed conditions. **Large scale industrial load curtailment** Several of EnergyAustralia's largest customers have participated in and provided demand response through curtailment of a core business activity. Each has gone through a process of change management to ensure their availability fits within requirements of notification and activation times while still being able to manage core business activities.		
Flow Power	**Energy Under Control**: Commercial and industrial demand response Flow Power is working with commercial and industrial customers to provide strategic demand response. Participating customers will install technology which allows a "controller" to remotely reduce their load when an event is triggered by AEMO. Customers must pay for the installation of the controller and receive payments for both availability and activation under the program.	5	20
Powershop	**Curb Your Power**: Residential demand response This is an opt-in program where customers are notified to curtail their electricity usage during times of peak demand. The program is entirely voluntary and certain customers are excluded from participation (e.g. vulnerable customers). The program currently has 10,364 customers.	5	5

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	Residential customers receive a $10 power credit if they hit their 'curb target'. The power credit can be used by customers to purchase electricity with Powershop. The curb target for a residential customer is a 10% reduction from their baseline or a reduction of 1 kWh every hour of the Event. This is also the minimum curb target for small business customers, however these customers can earn more credits if they meet higher load reduction thresholds.		
Demand response aggregators			
Enel X	**Advancing Renewables Program:** Commercial and industrial demand response Enel X has developed a 20 MW reserve in NSW and a 30 MW reserve in Victoria, as part of its contracts for the trial. The portfolio comprises commercial and industrial energy users who are capable of implementing load curtailment within 10 minutes of receiving dispatch instructions from Enel X indicating that a demand response event is commencing. Enel X has installed its own metering technology at customer sites for purposes of monitoring customer facility demand and facilitating demand response. Additionally, a portion of the sites have been equipped with control equipment that allows Enel X to remotely initiate a load reduction. Participating customers were paid both availability payments and energy payments. Payment terms were negotiated on a case-by-case basis, depending on their individual operational requirements, size of	50	50

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	loads, cost of reducing load, magnitude and complexity of required on-site technology and controls work, opportunity cost of other energy management strategies, and other commercial considerations.		
Zen Ecosystems	Zen Ecosystems (ZE) ran multiple DR events in summer 2018. ZE's goal was to target small to medium-sized loads (typically HVAC, refrigeration and lighting) at scale, using the ZenHQ cloud platform to deliver DR signals manually or automatically. ZenHQ is a centralised energy control system for multi-site businesses which combines smart, connected thermostats and lighting controls with cloud software to view and manage those devices. The incentive used by Zen in its initial *Save the Grid* program was based on intention. When Zen notified participating customers of an event, they asked whether the customer intended to participate and reduce their energy consumption. If the customer answered in the affirmative, they were given 2 movie tickets. The *Save the Grid* program was the forerunner to the much larger *Help the Grid* program that was marketed by the RACV and attracted about 1,400 participants. The only incentive in that program was an entry into a draw for a chance to win a weekend at an RACV resort on the Surf Coast.	5	15
Industrial customer			
Intercast & Forge	Intercast & Forge is a foundry in South Australia which provided load curtailment on its own upon notification from AEMO, without an aggregator as intermediary. The business has installed sophisticated	10	10

PROPONENT	PROGRAM DESCRIPTION	MW CONTRACTED	
		YEAR 1	YEAR 3
	energy systems that allows it to provide dispatchable demand response by powering down furnaces during peak events.		
Distribution network service provider			
United Energy	**Demand Response Service** United Energy delivers demand response services through the use of remote-controlled voltage reduction at its 47 zone substations. This service uses an existing fleet of smart meters deployed across the distribution network to provide time-lagged customer voltage data from all connected smart meters to enable reductions in voltage while maintaining voltage compliance during the demand response event. United Energy's first test of its demand response reserve capability achieved approximately 15-20 MW of demand response.	12	30

Source: The information set out in this table is drawn from reports published by ARENA and the participants in the demand response RERT trials, including ARENA's *Demand Response RERT Trial Year 1 Report* published in March 2019 and the knowledge sharing reports published by the proponents.

In March 2019, ARENA published a report on the outcomes of the first year of the trial program.[50] The report notes that, while the performance by individual participants was varied, overall the combined portfolio delivered more demand response than was contracted for across the year. Early results also indicate that the success of the trial continued to build in the second year, with an increase in the combined contracted capacity from 143 MW to 187 MW and a number of lessons learnt from year one already being applied by the proponents with positive outcomes.

Some of the key learnings arising out of the trial to date include:[51]

- Challenges with the baseline methodology used in the trial were noted early in Period 1 of the program.[52] ARENA has commissioned a separate study on the applicability of this methodology to specific types of loads that had been recruited for this program, but had not previously been used in RERT applications.
- A number of the proponents noted that the very tight timeframes for year 1 of the trial, while unavoidable, posed a significant challenge, specifically for recruitment. However, this is not anticipated to be a recurring issue for the program moving forward.
- Proponents that were not the retailer of the customers within their portfolios reported several issues regarding access to metering data.
- EnergyAustralia noted that revisions to metering data from the market can be made several months after an event, and this has the potential to materially change the level of performance achieved by an aggregator and that of individual customers within the aggregator’s portfolio.

The program has also provided valuable insights into engaging with and managing participating customers, the drivers of customer participation in demand response events, challenges created by technology issues and approaches to manage the risk of under-delivery of demand response. So, while the trial has focussed on facilitating emergency demand response, it has provided useful insights and learnings for wholesale demand response. Further, given the participants received funding to make customers demand response ready, it is expected that some of these would participate in wholesale demand response in the future.

3.2.2 Virtual power plant demonstrations

AEMO is collaborating with ARENA, the AEMC, the AER and members of the Distributed Energy Integration Program (DEIP) to establish VPP demonstrations. A VPP broadly refers to an aggregation of resources coordinated using software and communications technology to deliver services that have traditionally been performed by a conventional power plant. VPPs can deliver multiple services to increase the potential ‘value stack’ delivered to consumers,

50 ARENA, *Demand Response RERT Trial Year 1 Report*, March 2019.

51 Ibid, p. 16.

52 The program uses the "10 of 10" baseline methodology used by the California Independent System Operator (CAISO). This methodology uses an average of the previous 10 ‘like days’ (i.e. not weekends, public holidays or event days) to create a baseline profile of consumption for a customer.

including by participating in markets for both energy and frequency control ancillary services (FCAS), as well as entering into network support agreements with NSPs. Currently, VPP value stacking in the NEM is in the very early stages of development.

AEMO has established a framework to allow VPPs to demonstrate their capability to deliver services in energy and FCAS markets. By trialling VPP operations while their aggregated fleets remain of a small scale (less than 5-10 MW per VPP operator), the VPP demonstrations aim to inform the effective integration of VPPs into the NEM as they reach a larger scale.

AEMO published a consultation paper seeking stakeholder feedback on the demonstrations program in November 2018.[53] AEMO secured funding from ARENA for the program in April 2019. In July 2019 AEMO published the technical specifications for participants in the demonstrations and opened registrations for participation. AEMO's final design for the demonstrations accommodates three different models for participation:[54]

1. **Retailer engages with VPP coordinator**: A retailer and a separate VPP coordinator (who is not required to be a registered participant in the NEM) may jointly participate in the trial in respect of connection points where the retailer is the financially responsible market participant (FRMP). This arrangement will require the retailer and the separate VPP operator to enter into a commercial agreement, and the retailer will participate as the Market Customer in contingency FCAS markets and be exposed to energy market prices.
2. **Retailer is also the VPP coordinator**: A retailer, who is also the VPP coordinator, can participate as a Market Customer with respect to multiple connection points at which it is the FRMP.
3. **VPP coordinator as MASP**: A VPP coordinator who is registered as a MASP may participate in the trial in contingency FCAS markets only.

The VPP Demonstrations aim to:

- provide an understanding of whether VPPs can reliably control and coordinate a portfolio of resources to stack value streams relating to FCAS, energy, and possible network support services
- develop systems that provide AEMO with operational visibility of VPPs to understand their impact on power system security, local power quality, and how they interact with the market
- provide insights on how to improve consumers' experience of VPPs in future
- provide insights as to what cyber security measures VPPs currently implement, and whether VPP cyber security capabilities should be augmented in future

53 AEMO, *NEM Virtual Power Plant (VPP) Demonstrations Program – Consultation paper,* November 2018. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2018/NEM-VPP-Demonstrations-program.pdf.

54 AEMO, *NEM Virtual Power Plant (VPP)Demonstrations Program: Final Design,* July 2019. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/VPP-Demonstrations/NEM-VPP-Demonstrations_Final-Design.pdf.

- allow the Commission and AEMO to make informed changes to the regulatory frameworks, systems and processes required to facilitate the smooth integration of VPPs in the NEM.

The Commission notes that Solar Quotes provides information on existing VPP programs to small customers to help them compare the details and potential benefits of these programs when deciding whether to participate in a VPP.[55]

3.2.3 State government programs

Most jurisdictions in the NEM have established, or are developing, programs to incentivise the uptake of technology that will enable residential and business customers to participate in demand response programs.

South Australia

In February 2018, the South Australian Government announced plans to establish a 250 MW VPP in partnership with Tesla by creating a network of 50,000 homes fitted with smart meters, rooftop solar panels and battery storage systems.[56] The first stages of the trial involve installing these technologies in 1,100 SA Housing Trust properties. The first 100 of these systems had been installed as at July 2018. Once these installations are complete, Tesla will test the ability of the systems to operate together to reduce demand during peak periods, thereby reducing electricity bills for participating households. If the initial phase of the trial is successful and other key criteria for the initiative are met, the full program may be rolled out to a further 24,000 public housing properties and 25,000 private properties.

The South Australian Government has also announced an $11 million trial scheme which will seek to incentivise energy consumers to utilise new technologies to change their consumption behaviour, particularly during periods of peak demand.[57] Under the scheme, South Australian businesses will be provided grants of up to $2.5 million to implement innovative demand response ideas. Applications for grants under this program closed on 21 December 2018.

The following projects have been announced as receiving funding under this program:

- Embertec has been awarded $584,049 to implement a project involving efficient targeting and automated control of residential air conditioning loads.
- Amber Electric has been awarded $800,000 to implement a project involving automating the demand response of residential loads in response to wholesale prices in partnership with Symbiot Technology.
- Enel X has been awarded $2,000,000 to implement a project involving the use of commercial customers' existing backup generators to provide demand response.

55 See https://www.solarquotes.com.au/battery-storage/vpp-comparison/.

56 For more information, see: https://virtualpowerplant.sa.gov.au/.

57 For more information, see: http://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/south_australian_demand_management_trials_program.

- SA Power Networks has been awarded $975,000 to implement a project involving advanced voltage control in partnership with the CSIRO and Future Grid.
- The University of Adelaide has been awarded $675,000 to implement a project involving the use of digitised tri-generation and nanogrids for demand management.

New South Wales

The NSW Government is currently developing its *Empowering Homes* program.[58] Under this program, the NSW Government will support the installation of up to 300,000 solar-battery systems across the state, over 10 years. The program will be providing interest-free loans to NSW residents to install solar and battery systems. A pilot of the program will be undertaken in the Hunter region in the first quarter of 2020 and will run for up to 12 months.

In November 2019, the NSW Government released the NSW Electricity Strategy.[59] Part of this strategy involves the setting of an Energy Security Target for NSW, which would identify the level of supply needed to meet customer demand, plus an appropriate reserve margin. Under the strategy, the NSW Government may consider actions that deliver investments needed to avoid a breach of the EST in the event of an anticipated capacity shortfall, including demand response measures.

Australian Capital Territory

Under the $25 million *Next Generation Energy Storage* program, the ACT Government is supporting the roll out of up to 36 megawatts of smart battery storage systems in up to 5,000 eligible ACT homes and businesses. The program is delivered through a range of battery storage providers, which were selected by the ACT Government after a competitive selection process. Around 1,100 systems have been supported under the program to date, with the rate of installation expected to increase through 2019.[60]

Queensland

The Queensland Government has a concessions program in place under which households and small businesses could apply for interest-free loans or grants to purchase a battery system or a combined solar and battery system up until 30 June 2019. Assistance packages were available offering grants of $3,000 and interest-free loans of up to $6,000, repayable within 10 years. 3,650 assistance packages were available across both the loans and grants for battery systems and the loans and grants for combined solar and battery systems.[61]

Victoria

Under its *Solar Homes Program*, the Victorian government offers a range of rebates on residential solar PV and battery systems. In 2019-20 the government will offer 1,000 rebates of up to $4,838 for solar battery systems. These rebates will be available to people in

58 For more information, see: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/empowering-homes

59 NSW Government, *NSW Electricity Strategy*, November 2019. Available at: https://energy.nsw.gov.au/government-and-regulation/electricity-strategy.

60 For more information, see https://www.environment.act.gov.au/energy/cleaner-energy/next-generation-renewables.

61 For more information, see https://www.qld.gov.au/community/cost-of-living-support/concessions/energy-concessions/solar-battery-rebate/about-the-program.

designated suburbs who have already installed solar panels, but have not already accessed a solar rebate.[62]

3.3 Availability of demand response products in the NEM

In addition to the above programs, some consumers are already able to access retail electricity products which allow them to provide wholesale demand response. A number of retailers and third party service providers either utilise demand response or enable consumers to do so themselves with offerings which sit outside the trials noted above. These are examples of the different types of wholesale demand response referred to in section 3.1.2.

Some retailers that are currently facilitating wholesale demand response are highlighted in Box 4. A number of these product offerings have emerged quite recently in the NEM. The Commission notes that several third parties, such as Tesla, Reposit Power, Powerpal and Ohmie HOME, currently offer services to residential customers to help them manage their energy usage and utilise their household load and appliances to engage in demand response through retailers.

BOX 4: EXISTING WHOLESALE DEMAND RESPONSE PRODUCTS OFFERED BY RETAILERS

ERM Power

ERM Power is an electricity retailer and generator that operates across the NEM. ERM Power is an energy retailer for commercial and industrial customers. As a part of its energy retailing, ERM Power develops bespoke demand response contracts with its customers. These commercially-negotiated contracts include arrangements that:

- pass through spot prices and help the customer anticipate and minimise exposure to price spikes, or
- involve ERM Power calling upon these customers to reduce consumption to help manage ERM Power's exposure to the wholesale electricity price.

Flow Power

Flow Power is an electricity retailer that operates in all regions of the NEM. Flow Power emerged from a company that offered energy management services (specialising in demand management) to medium and large energy users. It has since opted to register as a retailer and connect customers to the wholesale market. Flow Power's retail contracts pass on wholesale price signals to its customers, and it helps those customers manage consumption in a way that reduces costs. Flow Power's customers are typically medium to large energy users who are able to change consumption in response to wholesale spot prices. These customers can either do this manually or install a device that allows Flow Power to remotely adjust

62 For more information, see https://www.solar.vic.gov.au/Solar-rebates/Solar-batteries.

demand.

Amber Electric

Amber Electric is a new entrant electricity retailer. It participates in the NEM through the retail license platform offered by Energy Locals. Amber initially launched in Sydney in mid-2018 and has subsequently expanded to South Australia. Amber offers spot price pass through contracts to customers and charges a flat fee of $10 per month. The company offers a portal through which customers can monitor real-time wholesale prices and forecast prices and adjust their usage accordingly. Amber intends to start offering retail contracts in Victoria, Queensland, ACT and the rest of NSW in the near future. Amber has also recently commenced a VPP pilot project in partnership with SwitchDin to offer smart energy management systems to ten Amber customers who have pre-existing household batteries to allow them to automatically respond to wholesale prices.

Stanwell

Stanwell's retail business, Stanwell Energy, offers demand response products to all its customers and has a number of existing customers with demand response products incorporated in their contracts. These represent customers with load requirements of around 10 to 100 MW that are willing and able to make available a fraction of their total load for demand response. Stanwell Energy's demand response products typically involve an availability payment as well as remuneration if the load is activated to provide demand response. Stanwell Energy calculates the customer's baseline, which is used to calculate the applicable payments. Stanwell Energy activates these contracts when there is a market benefit in doing so, and so the market naturally sets the value and timing of these resources. Customers are typically not obliged under their contracts to participate if called to activate at a time that would adversely affect their operations.

Powerclub

Powerclub is a new entrant retailer which offers retail contracts in New South Wales, Queensland, South Australia, ACT and Victoria. Powerclub offers spot price pass through contracts to customers and charges an annual membership fee of $39 for residential consumers. The company's product includes a feature called Powerbank, which customers can deposit funds into to act as a 'buffer' to smooth out fluctuations in the wholesale price. Powerclub also has a different corporate structure to most retailers - customers that join become a part owner of the company and gain access to voting rights and distribution of profits.

Pooled Energy

Pooled Energy is a specialist electricity retailer which offers pool automation systems that optimise the operation of a customer's pool pump in response to wholesale electricity prices. Pooled Energy directly controls these devices to reduce customers' energy costs. The company has installed its systems in 1,400 swimming pools across Australia. Pooled Energy has plans to expand its product offering to include monitoring and control of air conditioners.

AGL Energy

AGL Energy is currently accepting registrations from customers with battery storage systems to participate in a VPP as an add-on to their existing electricity plan. AGL will "actively manage" participating customers' battery up to 30 times a year to either supply the customer's load, charge the battery or hold its state of charge steady. Customers can receive a $45 quarterly credit and a one-off $100 sign-up credit towards their electricity bill over the first 12 months.

Recent consumer surveys undertaken by Energy Consumers Australia (ECA) and The Australia Institute (TAI) provide some insights into consumers' interest in participating in demand response. ECA's *Energy Consumer Sentiment Survey* published in June 2019 found that, when asking residential and small business consumers whether they would be prepared to reduce their energy use during periods of very high demand, a high proportion of respondents (between 43 per cent and 60 per cent depending on the jurisdiction) said that they would be willing to do so without requiring a financial incentive.[63] Approximately one in four consumers said that they would only reduce their consumption with a financial incentive.[64]

The Australia Institute also conducted a survey of consumers in 2017 which indicated that 81 per cent of respondents were either somewhat interested or very interested in receiving payments for conserving energy for short periods during peak demand.[65]

The AER also considered the levels of wholesale demand response in the NEM in its 2018 *Wholesale electricity market performance report*.[66] While the AER noted that its enquiries with participants indicated that the uptake of demand response products had decreased recently, this was partly due to demand for those in-market products being crowded out by the "out-of-market" Reliability and Emergency Reserve Trader (RERT).[67] Market participants indicated to the AER that the higher priced RERT mechanism is redirecting customers from existing demand response agreements, rather than creating an incentive for new capacity and security services, or new demand response contracts.[68] The AER also noted that it intends to monitor the effect of proposed changes to integrate more demand response into the market and participants' reactions to any such developments, as well as the impact of AEMO's RERT management on market driven demand side participation.[69]

63 ECA, *Energy Consumer Sentiment Survey June 2019*, p. 23. Available at: https://energyconsumersaustralia.com.au/wp-content/uploads/Energy-Consumer-Sentiment-Survey-Report-June-2019.pdf.

64 Ibid.

65 TAI, *Polling - Demand Response*, September 2017. Available at: http://www.tai.org.au/sites/default/files/Polling%20Brief%20-%20Sept%202017%20-%20Demand%20Response%20FINAL.pdf.

66 AER, *Wholesale electricity market performance report - December 2018*, Available at: https://www.aer.gov.au/wholesale-markets/market-performance/aer-wholesale-electricity-market-performance-report-2018.

67 Ibid, p. 35.

68 Ibid, p. 61.

69 Ibid, p. 65.

In 2018, PIAC conducted a research project involving consumers contacting 23 retailers in NSW through a range of mediums to ask if they offered demand response programs for individual customers. Of the retailers contacted, only one retailer that currently serves less than 0.01% of NSW residential electricity customers offered a demand response product.[70]

3.4 Previous rule changes relating to demand response

3.4.1 Demand side participation portal

In 2015, the Commission made a rule requiring registered participants to provide information about demand side participation to AEMO through AEMO's Demand Side Participation (DSP) Portal.[71] The DSP rule sought to improve AEMO's visibility of demand side participation in the NEM and allow this information to be incorporated into its demand forecasts. However, this information is not currently transparent to the market. As such, it is of limited use in assessing the levels of wholesale demand response which currently exist in the NEM. The second draft demand response rule proposes changes to increase the transparency and utility of the information submitted to the DSP Portal. These changes are discussed in detail in appendix H.

Since the publication of the first draft determination in July 2019, AEMO has published the *Demand side participation forecast and methodology* report (DSP report),[72] which sets out AEMO's approach to forecasting demand side participation and the extent to which, in general terms, demand side participation information submitted to the DSP Portal has informed AEMO's development or use of load forecasts in exercising its functions under the NER. The DSP report identifies the "program groups" which were used in 2019 to estimate the quantities of demand side participation in the NEM, which included RERT providers, individual industrial loads, customers on network event programs, customers involved in programs relating to connections with network-controlled load and customers included in other programs that could incentivise demand side participation, such as market-exposed connections and demand reduction contracts. The DSP report also includes information on AEMO's approach to estimating the prices at which demand response would be triggered, the calculation of baselines and the probability of customers responding to price events.

The below table from the DSP report sets out statistics relating to each category of demand response program determined by AEMO based on information submitted to the DSP Portal, including the type of demand side participation, the number of distinct connections, the reported sum of potential demand response in MW and the number of programs in that category. This data suggests that nearly 3,572 MW of potential demand response exists in the NEM. However, AEMO notes that this includes demand response potential which has been excluded from AEMO's calculations and further analysis is required to assess the robustness of this estimate.

70 PIAC, submission to consultation paper, p. 6.

71 AEMC, National Electricity Amendment (Improving demand side participation information provided to AEMO by registered participants) Rule 2015 No. 4, available at: https://www.aemc.gov.au/rule-changes/improving-demand-side-participation-information-pr.

72 AEMO, *Demand side participation forecast and methodology*, August 2019. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.

Figure 3.4: Summary of information submitted to the DSP Portal in 2019

Category	DSP type	Distinct number of connections	Reported sum of potential response (MW)	Number of programs
Connections on network event tariffs	Load reduction	2,593	Not reported	1
Connections on retail time-of-use tariffs	< not specified >	1,173,980	Not reported	30
Connections on retail time-of-use tariffs	Embedded generation	15	1.8	1
Connections with energy storage	< not specified >	10,054	Not reported	9
Connections with energy storage	Energy storage	112,155	0.2	2 out of 4
Connections with network-controlled load	< not specified >	0	Not reported	3
Connections with network-controlled load	Embedded generation	6	11.0	1
Connections with network-controlled load	Load reduction	2,545,004	2,624.0	57 out of 58*
Market exposed connections	< not specified >	964	Not reported	19
Market exposed connections	Embedded generation	20	36.9	4 out of 4
Market exposed connections	Load reduction; embedded generation	258	109	1
Other	< not specified >	35	49.2	3 out of 4
Other	Embedded generation	39	95.8	16
Other	Energy storage	758	4.5	2
Other	Energy storage; embedded generation	0	4.0	1
Other	Load reduction	71,705	605.5	17 out of 21
Other	Load reduction; embedded generation	2	30.0	1

Source: AEMO, *Demand side participation forecast and methodology*, August 2019, p. 19.

3.4.2 Demand management incentives for networks

The AEMC also made a rule in 2015 to help balance the incentives on distribution businesses to make efficient decisions in relation to network expenditure, including investment in demand management.[73] The rule amended the existing arrangements in the NER to provide

73 AEMC, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015 No. 8. Available at: https://www.aemc.gov.au/rule-changes/demand-management-embedded-generation-connection-i.

greater clarity to the AER and stakeholders in respect of how a demand management incentive scheme should be designed and applied. Two mechanisms were established under the new framework:

- Demand management incentive scheme (DMIS) - the objective of the incentive scheme is to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme rewards distribution businesses for implementing relevant non-network options that deliver net cost savings to retail customers.
- Demand management innovation allowance (DMIA) - the objective of the innovation allowance is to provide distribution businesses with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance funds innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

The Commission received a rule change request from Energy Networks Australia in March 2019 seeking to require the AER to develop a DMIS and DMIA for transmission networks. The Commission published a final rule in relation to this rule change request in December 2019, which applies the DMIA to transmission networks. However, the final rule does not apply the DMIS to transmission networks as the Commission is not satisfied that the benefits of doing so would outweigh the upfront costs to consumers.[74]

74 AEMC, National Electricity Amendment (Demand management incentive scheme and innovation allowance for TNSPs) Rule 2019 No. 10. Available at: https://www.aemc.gov.au/rule-changes/demand-management-incentive-scheme-and-innovation-allowance-tnsps.

4 SMALL CUSTOMERS AND THE TWO-SIDED MARKET

This second draft determination sets out a mechanism that provides more opportunities for consumers to capture the value of responding to wholesale prices, compared to the current arrangements. In order for the mechanism to result in wholesale demand response that can be relied on by the system operator, and so provide reliability related benefits, as well as to minimise risks imposed on the market, the mechanism features a number of elements including scheduling obligations and centrally determined baselines. This mechanism is also a solution that can exist within the market at the moment, given current levels of technology.

The wholesale demand response mechanism set out in this determination would involve a number of new processes. As with any new regulatory change introduced into the NEM, there are associated implementation and operational costs. In developing this draft mechanism, the Commission has made a number of decisions to balance the extent of these costs against the expected benefits. One of these decisions is to focus on the participation of large customers in the mechanism.

The mechanism in the second draft rule better meets the assessment framework and is likely to better contribute to the achievement of the NEO, compared to the mechanisms proposed in the rule change requests and the mechanism set out in the first draft determination. It is the mechanism that best enables existing large customers that currently do not see direct wholesale prices to provide wholesale demand response through having a relationship with a third party that can be introduced in the short-term.

However, as technology and consumer preferences evolve, how consumers interact and participate in the wholesale market will continue to change. The solutions that enable demand response from large customers do not necessarily work for small customers, particularly in light of digitalisation and technological development. As flagged in the first draft determination, the wholesale demand response mechanism should not be thought of as a silver bullet, nor an enduring mechanism. Instead, alternative options that provide small customers and the market with greatest value over the longer term should be explored.

The Commission has carefully considered the application of the mechanism to small customers. The checks and balances in the mechanism that provide benefits to the market and reduce any associated risks to participants are likely to also make the mechanism very challenging for small customer participation. Instead of reducing these checks and balances and potentially compromising the integrity of the mechanism, the Commission recommends considering alternative avenues for small customers to participate in the market.

The Commission understands that representatives of consumers from across the NEM have noted that small customers wish to participate and offer wholesale demand response. While the Commission agrees that consumer preferences include being more active in the electricity market, there have been rapid developments in the opportunities available for small customers to participate in wholesale demand response currently, as discussed in chapter 3. In addition, the mechanism introduced in the second draft rule is not well suited to small customers, and to allow small customers in the mechanism would create significant costs. These costs would be likely to outweigh the benefits of small customers being included.

Noting the significant stakeholder interest in promoting demand response opportunities for residential customers, and facilitating small customer demand side participation in NEM, care needs to be taken in selecting the right framework. The Commission considers that the best approach is to develop a two-sided market, which is more suited to small customer involvement.

The rest of this chapter sets out:

- a summary of stakeholder comments on small customer participation
- the reasons why this mechanism is not well suited to small customers
- the opportunity presented by focussing on large customers
- why a different approach is needed for small customers.

4.1 Stakeholder comments

A number of stakeholders commented on the participation of small customers in the wholesale demand response mechanism in response to the position set out in the first draft determination.

General position

A number of stakeholders considered small customers should be able to participate in the mechanism:[75]

- **Bluescope** noted the importance of considering consumer protections but urged inclusion of small customers given their contribution to peak demand.
- **Powerpal** also noted that small customers are likely to be contributing to peak demand and that the risk averse approach was to include small customers at the commencement of the mechanism.
- In the **PIAC** joint submission[76] it was noted that households are the main contributor to peak demand, and research by Energy Consumers Australia found more than half of household consumers were willing to voluntarily lower their energy use at peak times and even more were prepared to act with a financial incentive. The submission stated that delaying participation by these households is a missed opportunity.[77]
- **Tesla** noted that limiting participation to large customers would inadvertently exclude new technology types.
- The **Victorian Greenhouse Alliance** urged the Commission to have a clear plan for the inclusion of households and small businesses.

75 Submissions to the first draft determination: EUAA, p. 2; Bluescope, p. 2; EEC, p. 1; ECA, p. 2; Rheem, p. 1; Powerpal, p. 5; Victorian Greenhouse Alliance, p. 2, Tesla, p. 2; PIAC joint submission, p. 1; PIAC, p. 1.

76 The submission was submitted by PIAC on behalf of various energy consumer groups and businesses. It is referred to in this determination as "the PIAC joint submission". The signatories were: Australian Council of Social Service; The Australia Institute; Australian Industry Group; Combined Pensioners & Superannuants Association; Consumer Action Law Centre; Buildings Alive; Enel X; Energy Efficiency Council; Ethnic Communities Council; Major Energy Users; NSW Council of Social Service; The Physical Disability Council of NSW; Public Interest Advocacy Centre; Queensland Council of Social Service; Rheem; Renew; Reposit; South Australian Council of Social Service; Tasmanian Council of Social Service; Tenants Union; Total Environment Centre; Victorian Council of Social Service.

77 The PIAC joint submission to first draft determination, p. 2.

Other stakeholders suggested that focussing on the participation of large customers in the first draft rule was appropriate:[78]

- **Energy Queensland** supported limiting participation to large customers until the effectiveness of the mechanism can be assessed and a review of energy-specific consumer protections can be completed.
- **ERM Power** considered excluding small customers to be prudent given the nature of electricity as an essential service.
- **Snowy Hydro** suggested that the consumer protections issues needed to be considered alongside the systems costs and complexities associated with aggregations of small customers participating.
- **EnergyAustralia** noted that by not extending the mechanism to include small customers, it would allow AEMO systems to develop and mature, allow thorough consideration of consumer protections and allow for further work to be completed on costs and benefits.
- **AGL** suggested that there is not necessarily an urgency to include small customers. There are large volumes of large customer load available to address the rule change's objectives. AGL suggested working towards including small customers in a steady and thoughtful manner. It also noted that AGL does not necessarily believe the mechanism is the best approach for encouraging demand side participation from small customers.

Review of consumer protections

The first draft determination noted that the Commission was undertaking a review of the appropriate energy specific consumer protections that should apply to new energy service providers. Stakeholder submissions provided feedback on this:

- **AEMO** supported a holistic review of energy-specific consumer protections.[79]
- **Tesla** agreed consumer protections are a critical element. It noted that there are mechanisms to provide additional protections to consumers, including New Energy Technology (NET) Consumer Code.[80]
- The **South Australian Government** strongly urged undertaking the necessary review of consumer protections as soon as possible. It also suggested that the New Energy Tech Consumer Code is an alternative way to address consumer protections for small customers.[81]
- **Energy Consumers Australia** submitted that if additional or amended consumer protections are contemplated, the Commission should consider faster, more flexible approaches that put the onus on the sector to deliver positive outcomes for consumers. The ECA highlighted the New Energy Tech Consumer Code, as demonstrating the potential of industry-led approaches at a time when technology and service models are

78 Submissions to first draft determination: Energy Queensland, p. 6; ERM Power, p. 5; Snowy Hydro, p. 2; Stanwell, p. 9; EnergyAustralia, p. 2; AGL, p. 3.

79 AEMO, submission to first draft determination, p. 6.

80 Tesla, submission to first draft determination, p. 2.

81 South Australian Government, submission to first draft determination, p. 4.

changing. ECA also requested the Commission consider ways to create early opportunities for smaller energy consumers to benefit from the flexibility associated with low risk loads like hot water services and pool pumps.[82]

- In the **PIAC** joint submission, it was noted that:[83]
  - There are household demand response options which have no material risk of affecting people's health and wellbeing - such as pool pumps and household batteries- and these should be part of the demand response market from day one.
  - Some demand response options - such as hot water systems and smart appliances - may cause inconvenience, but have no material risk of harm to health or wellbeing. These should be part of the demand response market from day one, subject to DRSPs being signatories to the New Energy Tech Consumer Code (NETCC).
- The **AER** encouraged the Commission to prioritise its consideration of consumer protections.[84]
- The **Clean Energy Council** recommended that the consumer protections review is completed to enable small customer participation by the implementation date.[85]
- **Victorian Greenhouse Alliance** submitted that existing Australian consumer law provides key protections for people within energy contracts, and these could be adequately reviewed in the timeframe for the rule change request. In addition, there are many household demand response options, which pose no risk to quality of life – pool pumps and household batteries offer considerable flexibility and value to the market.[86]
- **AGL** suggested that considering small customers at a later date will allow adequate time to consider consumer protections. It would also provide the opportunity to test scheduling and baselines on large customers prior to applying to aggregated small customers.[87]
- **Powerpal** highlighted the consequences of not including small customers which it considered to be increased likelihood of involuntary load shedding.[88]
- In its submission, **EnergyAustralia** provided a list of consumer protections that should be considered in the consumer protections review, including:[89]
  - Premises requiring life support equipment and/or customers who are not registered as requiring life support but may be at risk if they reduce demand on hot or very cold days, for example elderly customers
  - Customers in hardship and vulnerability
  - Data privacy and security and energy specific family violence protections

82 Energy Consumers Australia, submission to first draft determination, p. 2.
83 PIAC joint submission to first draft determination, p. 2.
84 AER, submission to first draft determination, p. 4.
85 Clean Energy Council, submission to first draft determination, p. 3.
86 Victorian Greenhouse Alliance, submission to first draft determination, p. 2.
87 AGL, submission to first draft determination, p. 2.
88 Powerpal, submission to first draft determination, p. 5.
89 EnergyAustralia, submission to first draft determination, pp. 4-5.

- Maximum timeframes to provide payments to participating customers, these should not be protracted as customers are anticipating income
- Protections for customers whose DRSP has entered into administration
- Dispute resolution processes when there is disagreement over whether a customer provided a response, including Ombudsman schemes
- Advanced notification to customers of potential activation so they can make alternate arrangements if required
- Information about the credit-worthiness of a supplier is accessible to customer
- Minimum requirements for contracts
- Contract termination and final bill settlement processes
- Notice to customers of changes to reimbursement rates or conditions
- Whether exit fees or late payment fees are permissible
- Pre-contractual duty of DRSPs including Explicit Informed Consent which ensures customers have been provided simple, clear, fair and complete information about the product including:
  - what the demand response product entails
  - the service that is being contracted and the customer's obligations and commitments
  - the DRSP's obligations and commitments
  - the financial compensation the customer can expect to receive
  - the respective roles and responsibilities of the DRSP and the retailer
  - clear information on any penalties that may apply to the customer if they are unable to provide the contracted service
- Clear information on bills regarding:
  - Volume of demand response provided and associated reimbursements
  - Roles and responsibilities of the retailer and DRSP
  - Emergency contact details and the process for customers to withdraw from obligations at short notice if required (for example air-conditioning is required on a hot day due to visitors with life support requirements or health)
  - Dispute process if customer believes they have reduced load which has not been recognised
  - Financial incentive rates and qualifying conditions
- Other energy service protections such as cooling off periods and interpreter services.

Practical application of the mechanism to small customers

A number of stakeholders discussed the practical application of the mechanism as set out in the first draft determination to small customers:

- **Delta Electricity** considered restricting the scheme to large customers is sensible due to complexities associated with setting and monitoring baselines. Delta Electricity suggested that baselines are more error prone when applied to customers with more unpredictable consumption.[90]

- **Dr. Martin Gill** noted that demand response from small customers cannot be accurately measured. Validating small customer demand response may involve major changes to the current metering arrangements and costs. Developing viable and robust methods to replace actual measurements is complex. Until viable methods are developed, the Commission's decision to exclude consumer demand response from the energy market is considered prudent.[91]
- **AGL** suggested that if the mechanism were to be applied to small customers, it could be assessed and settled on a portfolio basis for each retailer.[92]
- **AEMO** made a similar point, noting that if baselining was to be extended to small customers in the future, AEMO recommends that baselines should be determined on a portfolio or aggregation basis only. AEMO also noted that a different approach would be needed for settlement.[93]
- **Aurora Energy** noted that the nature of market settlement for the small customer group varies depending on whether a customer has a basic or advanced (interval) meter. As basic metered customers are settled on a net system load profile, payment for demand response would create a cross subsidy across customers and retailers, as a retailer's settlement would still be based on the net system load profile (i.e. it would be impossible to apply a baseline). For this reason, Aurora Energy submitted that any demand response mechanism for the small customer segment is conditional on customers having advanced meters.[94]

Impacts on market participants

Some stakeholders highlighted the impact of extending the mechanism to include small customers:

- **ERM Power** suggested that extending the mechanism to small customers may act as a barrier to new entrant retailers. These retailers often use load following hedges to manage spot price risk and volume risk. Being exposed to the baseline level of consumption would make it harder and more costly to set up these contracts.[95]
- **Snowy Hydro** suggested that including small customers would result in additional costs being imposed on retailers, including:[96]
    - recovering and storing data from DRSP for reconciliation
    - reconciliation between amounts provided to retailer and the amounts billed in the wholesale market
    - costs in managing and hedging the baseline level of small customers.

90 Delta Energy, submission to first draft determination, pp. 1-2.
91 Dr. Martin Gill, submission to first draft determination, p. 2.
92 AGL, submission to first draft determination, p. 3.
93 AEMO, submission to first draft determination, p. 6.
94 Aurora Energy, submission to first draft determination, p. 2.
95 ERM Power, submission to first draft determination, p. 6.
96 Snowy Hydro, submission to first draft determination, p. 5.

- **AEMO** noted that if small customers were to participate in the mechanism, there would be the need to determine a more robust approach to the churn of customers between different DRSPs. If a retail market-like approach were to be taken this would have significant implications for AEMO procedures and systems – specifically MSATS and CATS.[97]

Alternative approaches for small customers

In its submission to the draft determination, **Intelligent Energy Systems** suggested that its submitted approach may be more applicable for small customers. Intelligent Energy Systems made the following points:[98]

- the first draft determination focussed on large customers and acknowledged that the mechanism is only likely to be viable for occasional use, at times of very tight supply. Further, the requirement for scheduling will likely discourage many potential providers and the need to work with an aggregator/service provider will dilute the customer benefit.
- small customers would better respond to a different approach. That approach would avoid a requirement to be scheduled, but would provide ample ex post information about the nature of a customer's price sensitivity.
- all customers in IES's alternative arrangement would need to considered in regard to the impact of their load fluctuations on power system frequency. With such an alternative approach, as outlined in IES's original submission, more short term load flexibility within a secure envelope can be made available to meet the increasing demands of semi-scheduled generation.

4.2 Challenges for small customer participation in the mechanism

There are three primary reasons why the mechanism in the second draft rule would present challenges in relation to the participation of small customers:

- 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.

Importantly, if it were costless to include small customer participation in the mechanism, these challenges would not be a reason to exclude them - this would mean a mechanism could be designed such that if a particular small customer met the criteria, it could participate in the mechanism. However, there are likely to be significant costs associated with extending the mechanism to these customers. Retailers have estimated that their costs would be significantly higher if small customers were to be included. In addition, it would materially

97 AEMO, submission to first draft determination, p. 6.

98 IES, submission to first draft determination, p. 2.

increase costs for AEMO as significant systems changes would be needed to account for the processing of an order of magnitude greater number of customers. Therefore, including small customers in the mechanism would likely not provide new opportunities to a significant number of small customers, but would impose systems costs on the market as a whole, which would flow through to energy consumers collectively.

4.2.1 Behavioural demand response is not suited to scheduling

Being scheduled in the wholesale market comes with a number of obligations. These include being required to provide information to the market ahead of real time, submit dispatch offers every five minutes and making a commitment to meet dispatch targets. Scheduled participation is integral to the functioning of the wholesale market, in particular AEMO's ability to manage reliability and security. Scheduled participants allow for price discovery to occur and by providing information ahead of real time, allow other market participants to make more informed unit commitment decisions.

Scheduling can be onerous and is not suited to all types of wholesale market participants. Traditionally, most energy consumers have been non-scheduled. Under the current arrangements, there is little incentive for a load to become scheduled. Typically, being scheduled has an associated cost and, from the perspective of an individual load, negligible benefit. On top of this, most consumers cannot practically comply with being scheduled. The associated obligations are difficult to comply with, particularly as energy is often just an input into a consumer process.

Wholesale demand response provided through the mechanism is required to be scheduled, as this provides the most value to the market as a whole. However, this means that some types of demand response are not suited to participation in the mechanism. One example is behavioural demand response, which is the most common type of demand response that small customers engage in.

Behavioural demand response involves eliciting some amount of demand response from consumers on request, without having direct controls on consumers' loads. Often it involves the consumer being provided with the option of participating in demand response on the day. An example is the Powershop demand response program where customers can decide to participate and receive a credit if they provide a reduction. Behavioural demand response programs represent the majority of the offers available to small customers at the moment, including three of the mass market demand response solutions being provided through the AEMO-ARENA RERT trial.[99]

While these programs provide customers with the opportunity to provide wholesale demand response, they often mean the party calling for the demand response is unsure how much will be provided. As such, behavioural demand response programs are not suited to being scheduled. Indeed, any requirements to meet scheduling obligations would likely make them untenable.

99 More information on this trial is included in chapter 3.

Given the importance of scheduling the demand response provided through the mechanism, and the unsuitability of behavioural demand response for scheduling, behavioural demand response would not be suited to participation in the mechanism.

The alternative to behavioural demand response is having demand response provided through devices that can be remotely controlled by the DRSP, such as pool pumps and batteries. However, as noted below, the more controllable these discretionary devices are, the more difficult it is to determine an accurate baseline for them.

4.2.2 Centrally determined baselines do not work well for distributed controllable devices

Baselines for measuring demand response have been used in a number of jurisdictions and a number of applications. In the consultation paper for this rule change, the Commission set out that, in order to have a view on how much response was provided, the counterfactual level has to be estimated. The Commission also set out that baselines are inevitably wrong to some extent and this should be minimised where possible.

It is a feature of the wholesale demand response mechanism to have these counterfactual baselines determined by AEMO. In order to allow a third party to sell wholesale demand response, this counterfactual is used to determine the quantum of response provided.

The quality of a baseline is directly related to how predictable a load is. If a load is very predictable, the baseline can be treated as being more certain. As loads become more unpredictable, it becomes harder to reasonably predict what the consumer would have done had they not provided wholesale demand response.

Large commercial and industrial customer loads are often relatively predictable. This is because they operate large processes, often on fixed timetables and fixed hours. These parameters can change, but it does mean these types of consumers are better suited to baselines.

There are large loads that are not suited to having a baseline determined. For example, large pumps are highly controllable and can run at any time of day. Because these loads can and regularly do change the times they use electricity, it becomes very difficult to meaningfully predict the timing of their energy consumption. This point was noted in ARENA's findings in relation to baselines used in the ARENA-AEMO demand response RERT trial.[100]

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 is

100 Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response RERT Trial*, September 2019, p. 1.

going to 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.

In its submission to the first draft determination, AEMO, who would be responsible for determining consumer baselines, noted:[101]

> the baselining approach in the draft mechanism is not well suited to measurement of smaller energy volumes and small consumer loads. Due to the behavioural nature of small consumers'responses, and the technical characteristics of the load profile of households, it is difficult to establish predictable baselines and verifiable demand responses of individual small consumer loads. This difficulty has been evident during the first year of the joint AEMO-ARENA demand response trial.

Devices that can consume energy at variable times, particularly those that are expected to enable small customers to participate in demand response, are not suited to having their electricity consumption centrally predicted.

The report by Oakley Greenwood on the baselines used in the AEMO-ARENA RERT trial found that none of the baseline methodologies tested on *aggregated* residential NMIs resulted in baselines with 'good' accuracy in more than 40 per cent of the simulated events. By contrast, all of the methodologies produced an 'acceptable' level of accuracy in at least 70 per cent of the simulated events. The results are provided below.

Table 4.1: Portfolios of residential customer baselines

BASELINE METHODOLOGY	'GOOD ACCURACY'	'ACCEPTABLE ACCURACY'
10 of 10	27%	70%
Maximum temperature	37%	76%
Average temperature	33%	83%
Day of week & maximum temperature	40%	77%
Day of week & average temperature	23%	80%

Source: Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response RERT Trial,* prepared for ARENA, September 2019, pp. 14-16.

Note: This table presents the percentage of simulated event days with 'good' and 'acceptable' accuracy for weather-sensitive residential loads in VIC using different baseline methods. More information on the baseline methodologies can be found in the Oakley Greenwood report.

Note: Good accuracy was defined as having a Relative Root Mean Square of the Errors (RRMSE) of < 10%. Acceptable accuracy was defined as having RRMSE < 20%.

In addition, Oakley Greenwood found that none of the baseline approaches that were tested were found to produce good or acceptably accurate baselines for the residential PV segment in any of the simulated events. Oakley Greenwood concluded that the results of this analysis suggest the '10 of 10' baseline methodology currently used in the RERT may be adequate for

101 AEMO, submission to first draft determination, p. 6.

certain types of loads, particularly those of larger commercial and industrial customers whose energy consumption is relatively similar from day to day and not particularly weather sensitive.[102]

In order for small customer baselines to be accommodated under the second draft rule, 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 does not consider it appropriate to have the baseline methodology metrics broadened to allow for highly variable loads and devices to participate.

Small customer loads can be aggregated together and the inherent variability among those loads can be balanced out. This makes aggregated small customer loads easier to predict than individual small customer loads. However, the settlement model set out in this 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.

4.2.3 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. Because much of the small customer demand response would be delivered through smart devices that can vary consumption times without affecting customers, 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 discussed in Box 5.

BOX 5: DISTORTIONARY CONSUMER BEHAVIOUR

If small customers were being paid to reduce consumption relative to a baseline weighted towards recent consumption patterns, it is possible it 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 return in 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 are going to be high wholesale prices in the peak, from which the DRSP (and customer) can profit if the pool

102 Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response RERT Trial,* prepared for ARENA, September 2019, pp. 14-16.

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.

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 highly controllable and changes to consumption times do not have significant impacts on the customer. Indeed, 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.

4.3 The opportunity presented by large customers

Presently, the commercial and industrial sector is the biggest provider of wholesale demand response. These customers represent both latent demand side flexibility and existing demand side flexibility that can be better utilised. Across a relatively small number of customers, a significant portion of the NEM's electricity demand is consumed.

This means that the systems designed to enable demand response from these customers can be designed at lower cost than systems covering customers of all types. By focussing on large customers, the Commission considers the mechanism can deliver the greatest amount of additional wholesale demand response at a reasonable cost.

If these systems are required to account for a greater number of customers, the complexity and costs significantly increase. We understand that if small customers were able to participate in the mechanism, this would significantly increase costs for the market operator and retailers.

The additional implementation costs imposed would be incurred regardless of whether small customers were actually able to participate in the mechanism. These costs would be imposed on AEMO and retailers and eventually recovered from all consumers. Consequently, the Commission would need to anticipate there would be enough wholesale demand response enabled through the mechanism to offset these costs. However, given the challenges outlined above the Commission considers it is unlikely that small customers would be able to provide material amounts of wholesale demand response through the mechanism sufficient to offset the additional costs associated with extending the mechanism to small customers.

4.4 A different approach is needed for small distributed energy resources

Digitalisation in the energy sector involves a power system and market that efficiently utilises digital technologies to make it easier to choose and control how, when and where power is generated, delivered and used, including to empower customers to optimise their energy use within their homes and businesses. Digitalisation is increasing in the NEM. There are two key policy questions related to digitalisation, namely:

- How can the regulatory framework make sure consumers are able to capture the full value of digitalisation and distributed energy resources?
- How can the regulatory framework adapt so that all consumers can share in these benefits?

Further consideration should be given to the regulatory framework that would best achieve the above.

In its submission to the first draft determination, AEMO noted that small customers engaging with the market may be better suited to approaches other than a wholesale demand response mechanism , such as more straightforward incentive and arbitrage arrangements, including via the Small Generation Aggregator connection point or accessing network tariffs designed to incentivise similar behaviour to that which is targeted by the mechanism.[103]

Some other options that could collectively provide more value for small customer demand response, which are explored below, include:

- progressing towards a two-sided market
- allowing multiple trading relationships at a single connection point.

4.4.1 Two-sided market

On 14 November 2019, the Commission published a paper on the impacts of digitalisation on the NEM.[104] This paper sets out some thinking on digitalisation and the potential to move to a two-sided market. This paper also noted:

- Consumers are already starting to benefit from increased digitalisation in the energy sector.
- Increasing digitalisation will facilitate more advanced engagement in energy markets through increased remote communication, control and automation of consumer devices.

103 AEMO, submission to first draft determination, p. 7.

104 AEMC, *How digitalisation is changing the NEM - The potential to move to two-sided market,* 14 November 2019, available at: https://www.aemc.gov.au/sites/default/files/2019-11/How%20digitalisation%20is%20changing%20the%20NEM.pdf

- There is an opportunity to establish a fit-for-purpose framework ahead of the fundamental, consumer-led changes that will follow increased digitalisation. The sector should be considering changes to the market framework now in anticipation of these changes.

The effect of digitalisation is likely most pronounced among small customers. These are the customers who have previously had limited ability to engage and dynamically adjust their consumption. The customers benefiting from digitalisation may also be well suited to providing demand response. However, for the reasons noted earlier in this chapter, these customers would not be well accommodated through the wholesale demand response mechanism set out in the determination and the Commission considers a two-sided market would provide a better avenue for small customers to provide demand response.

The Commission is contributing to further work being undertaken by the ESB to assess how regulatory reforms can best facilitate the transition to a two-sided market, with specific reference to the benefits to small customers.

4.4.2 Multiple trading relationships

Under current arrangements, a consumer is only able to engage with a single financially responsible market participant at a connection point in respect of any interactions with the wholesale market.

There are a number of situations in which a consumer may wish to engage with separate service providers at the same connection point:

- domestic consumers could separate electricity charging for uncontrollable loads and controllable loads (such as air conditioning, hot water, pool pumps and electric vehicles) between retailers, allowing the consumer to choose the best available tariff structure for each type of load
- a consumer may be a party to a virtual power plant arrangement and wish to have their residential storage and solar PV separately metered to enable participation with the virtual power plant.

These arrangements would not rely on centrally determined baselines. This is because, even though the loads are able to be managed by different retailers, there is no need to credit a reduction from a baseline level.

In the future, the regulatory framework could accommodate both multiple trading relationships and a two-sided market as these are not mutually exclusive.

Further exploration of multiple trading relationships and whether it can better enable small customers responding to wholesale prices is warranted. The Commission will be considering the application of multiple trading relationships to electric vehicles through its *2020 Retail competition review*. The Commission published an issues paper for this review on 20 February 2020.[105] A final report is scheduled for publication by 30 June 2020.

105 AEMC, *2020 Retail Energy Competition Review: Electric Vehicles,* February 2020. Available at: https://www.aemc.gov.au/market-reviews-advice/2020-retail-energy-competition-review.

5 CHANGES TO DESIGN OF THE MECHANISM FROM FIRST DRAFT RULE

On 5 December 2019, the Commission extended the time for making a final determination on the rule change requests until 11 June 2020, following the provision of supplementary information by AEMO on the systems changes and costs associated with implementing the proposed mechanism. The primary purpose of this extension was to allow for further consideration of how to reduce implementation costs and timeframes and, to the extent possible, avoid system changes that may become redundant in the transition to a two-sided market.

This chapter sets out the key changes between the first draft rule published in July 2019 and the second draft rule published with this determination, and the rationale for these changes.

5.1 Background

The supplementary information provided to the Commission by AEMO in November 2019 advised that, based on initial, indicative analysis undertaken by AEMO:[106]

- AEMO would need to potentially build four new systems and amend 20 existing systems in order to implement the wholesale demand response mechanism outlined in the first draft determination.
- AEMO has identified a range of costs indicating that there are several options available to meet the design requirements across many of the systems that need amendment, as well as building for the inclusion of small customers under the wholesale demand mechanism proposal.
- AEMO's initial cost estimate to implement the mechanism proposed in the first draft determination ranged from $40 million to $95 million, depending on the functionality requirements, the nature of customers offering demand response and the need to uplift various systems to deliver additional features.
- Some of the proposed features and systems when implemented would run the risk of being redundant or requiring significant modification in the foreseeable future, given longer term market design needs, and could result in stranded costs in the context of the transition to a two-sided market. This further reinforced the benefits of taking a tactical and cost-effective approach to facilitating wholesale demand response prior to the introduction of a two-sided market.

AEMO also noted that the Energy Security Board (ESB) has been tasked by the COAG Energy Council with delivering advice on the high-level design of future ahead and two-sided markets in March 2020, which will be followed by a more detailed design and implementation process.

106 AEMO, *Supplementary information - Wholesale Demand Response (WHR) Rule,* November 2019. Available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

Based on the above analysis, AEMO proposed that a staged approach to the rule change requests be undertaken which would allow more time for the AEMC and AEMO to work together to identify design changes to the mechanism which would allow for an earlier implementation date, reduce the implementation costs and complexity and increase the utility of the mechanism in the transition to a two-sided market. The Commission agreed with this approach and extended the timeframe for publication of the final determination to facilitate this.

5.2 Overview of key changes from first draft rule

The Commission has assessed a number of potential changes to the wholesale demand response mechanism in collaboration with AEMO to identify options for reducing the implementation costs and timeframes while maintaining the integrity and utility of the mechanism in the context of the transition to a two-sided market.

The changes from the first draft rule to the second draft rule primarily focus on reducing the scope of the changes required to AEMO's systems to accommodate DRSPs participating in the wholesale demand response mechanism, thereby allowing AEMO to use existing or simplified systems and processes. These key changes are set out in the table below. This table is intended to identify the changes from the first draft rule that were made primarily with the objective of reducing implementation costs and timeframes for the mechanism and does not capture all of the changes from the first draft rule. For a comprehensive list of changes, see appendix b.

Table 5.1: **Key changes from first draft rule to reduce implementation costs and timeframes**

ISSUE	POSITION UNDER FIRST DRAFT RULE	POSITION UNDER SECOND DRAFT RULE
Scheduling of wholesale demand response (covered in appendix D)	• DRSPs would submit bids to reduce demand for a wholesale demand response unit by a specified amount in a dispatch interval. • The demand reduction bid by the DRSP would be treated as a substitute for generation in NEMDE. • The quantity of demand reduction bid by the DRSP would be measured by reference to the actual load at the start of the first dispatch interval in	• The portion of the load/s within a WDRU that constitutes the demand responsive part of the load/s would be determined during the registration process and registered as the maximum responsive component of the WDRU • DRSPs would submit bids that would be treated in a similar manner to bids by normally-on scheduled loads. • In each dispatch interval, a DRSP would need to submit a bid which would consist of the portion of the maximum responsive component that can respond at different

ISSUE	POSITION UNDER FIRST DRAFT RULE	POSITION UNDER SECOND DRAFT RULE
	which the DRSP was dispatched. • Dispatch and assessment of conformance with dispatch targets would be based on actual metered consumption and would not involve baselines.	wholesale electricity prices. • If the wholesale price exceeds the price at which the DRSP would consume electricity, it will reduce consumption (or increase generation) and provide wholesale demand response. • When the DRSP does not wish to provide demand response it will bid at the market price cap to ensure that the WDRU is not dispatched to provide demand response (ie the responsive component will continue consuming at the maximum level). • In effect, DRSPs will be making dispatch bids to reduce consumption. When the DRSP is dispatched based on its bid to reduce consumption, it will be paid for providing wholesale demand response. • AEMO will undertake post-event assessments of conformance with dispatch targets to determine whether the anticipated amount of demand response occurred. • There will be a limit, per region, to the amount of wholesale demand response that can be provided with lower standard telemetry. That is, non SCADA grade telemetry. This may still have been the case under the first draft rule; however, it has been made explicity and transparent under the second draft rule.
FCAS cost recovery (covered in appendix D)	• DRSPs would have been required to pay: • a share of regulation FCAS costs in the	• DRSPs would not be subject to FCAS cost recovery.

ISSUE	POSITION UNDER FIRST DRAFT RULE	POSITION UNDER SECOND DRAFT RULE
	same way as market customers • a share of contingency raise costs in the same way as other sources of supply in the market.	
Provision of information for MT PASA (covered in appendix E).	• DRSPs would have been subject to the same information provision requirements as generators (i.e. to provide information on wholesale demand response unit availability over a two-year timeframe).	• DRSPs would not be required to provide information to AEMO for the purposes of MT PASA. • DRSPs would be required to provide information into the DSP portal.
Baseline methodologies (covered in appendix F).	• Market participants would have had the ability to submit new baseline methodologies to AEMO for approval, subject to them meeting the baseline methodology metrics.	• Market participants would not have the ability to develop and submit baseline methodologies to AEMO for approval. • Instead, market participants could propose that AEMO develop new baseline methodologies, which would be able to be considered by AEMO and potentially implemented as a methodology that could be used under the mechanism.
Implementation timeframes (covered below).	• The mechanism would be introduced on 1 July 2022.	• The mechanism would be introduced on 24 October 2021.

These changes are based on discussions between AEMO and the Commission, and also form the basis of a high-level design of the mechanism developed by AEMO and delivered to the Commission in February 2020. The key changes are discussed in more detail in the relevant appendix.

5.3 Benefits of changes from first draft rule

The Commission considers that the changes to the design of the mechanism described in section 5.2 will have a number of important benefits for AEMO, market participants and consumers. These are discussed below.

5.3.1 Reduced implementation costs

In its supplementary submission, AEMO noted that the implementation costs associated with the mechanism in the first draft rule ranged from $40-95 million. AEMO has advised that it now expects the implementation costs of the mechanism in the second draft rule to range from $13-17 million. The reduction in expected implementation costs resulted from:

- Scheduling and dispatch of wholesale demand response that leveraged the existing processes for the dispatch of scheduled loads.
- Removal of DRSPs from MT-PASA and FCAS cost recovery, meaning these AEMO systems will not need to be changed.
- AEMO determining baseline methodologies, with consultation, instead of allowing market participants to develop and submit their own baseline methodologies.

The Commission considers the mechanism outlined in the second draft determination is likely to reduce the amount of systems investment that may be made redundant if there is a transition to a two-sided market. For example, the proposed approach to scheduling and dispatch has lower costs and is informative for the development of a two-sided market.

Changes have also been made to reduce implementation costs associated with systems that may be made redundant if there is a move to a two-sided market. For example, the second draft determination sets out a simpler approach for determining baseline methodologies that reduces upfront costs. This is considered appropriate because systems dedicated to centrally determined baselines are not likely to be needed in a two-sided market.

5.3.2 Consistency with two-sided market

As discussed in chapter 4, the Commission considers the market should transition towards a genuine two-sided market which allows consumers to capture the full benefits of digitalisation and technological innovation.

The potential transition to a two-sided market is a priority for the COAG Energy Council and, as such, the mechanism set out in this second draft rule accounts for the possible introduction of a two-sided market.

The Commission considers that the mechanism set out in this determination would provide market participants with the opportunity to gain valuable experience with processes and practices which will be useful in the longer-term transition to a two-sided market. In particular, the requirement that DRSPs participate in the market in a similar manner to scheduled loads will provide learnings to those participants which will be directly relevant to a future two-sided market in which loads would participate in scheduling in some form. This mechanism will also present an opportunity to understand how a number of regulatory frameworks and obligations currently applied to scheduled participants should be applied to a both sides of a two-sided market. For example, how scheduling obligations should reasonably be extended to demand-side participants in a two-sided market.

In its information paper on how digitalisation is changing the NEM[107], the Commission noted that a key design element of a two-sided market is the extent to which both supply and demand are required to provide information on generation and consumption (in the same way as a scheduled participant). Increased digitalisation and responsiveness of loads is likely to reduce the cost of loads bidding in the same way as scheduled generation in the future. This would have a number of benefits for the market, including:

- increasing the information available to set the price of electricity
- providing stronger incentives for participants to respond to these market signals
- incentivising the most flexible technology to enter the market, whether it is generation or consumption
- reducing information asymmetries, leading to more efficient market signals
- increasing competition in the market.

The Commission acknowledged that there is a spectrum of ranging from compulsory to voluntary participation in the context of scheduling both supply and demand in a two-sided market. A starting premise for a two-sided market is that there will be more of the market participating in the scheduling process. That is, more market participants will be providing information to the market about their intentions. It is envisioned that the transition to a two-sided market would involve iterative reforms to facilitate scheduling of the demand side in some form.

Scheduling and the associated obligations established in the NER were designed for large, controllable generating units and loads. The reasons for introducing a semi-scheduled category was to acknowledge that it would have been difficult for intermittent generators to comply with these obligations. It is now important to revisit what scheduling is fundamentally needed for and then consider how this should apply to a much more diverse set of market participants. This rule change process provides an opportunity to answer some of these questions about what scheduling should look like in a two-sided market.

In this context, the mechanism will provide valuable learning opportunities for market participants. As discussed in appendix d, the second draft rule requires DRSPs to participate in the market in a similar manner to scheduled loads. DRSPs would be required to make dispatch bids for how much electricity the responsive components of wholesale demand response units will consume at various price bands. This will involve developing an understanding of how these loads operate day to day, and how they are able to participate in the wholesale market.

The Commission considers that participants in the mechanism will benefit from the experience of having to comply with similar information provision obligations to scheduled generators, bid in each dispatch interval and comply with dispatch instructions from AEMO. In developing the set of scheduling obligations under which DRSPs will participate in the mechanism, the Commission sought to balance existing obligations against the need to explore new approaches as digitalisation becomes more prominent.

107 AEMC, *How digitalisation is changing the NEM: The potential move to a two-sided market*, November 2019.

The opportunity to gain experience in these processes may also provide an incentive for retailers to participate in the mechanism as they may see the value of this experience in a future two-sided market. The Commission considers that these learning opportunities contribute to the overall benefits of implementing the mechanism.

5.3.3 Earlier implementation of the mechanism

Under the first draft rule, the mechanism would have commenced on 1 July 2022. This implementation date was based on advice from AEMO and feedback from stakeholders about the scope of the systems changes that would have been required to accommodate the mechanism as proposed in the first draft rule, having regard to other regulatory reforms such as five minute settlement and global settlement.

The commencement date for the mechanism under the second draft rule would be 24 October 2021. AEMO have advised that the changes to the design of the mechanism discussed in section 5.2 would reduce the time and resources needed to update AEMO's systems to accommodate the mechanism. As such, the date from which customers can participate in the mechanism has been brought forward. The earlier implementation date under the second draft rule would also allow the mechanism to be implemented prior to the 2021-22 summer. As such, wholesale demand response provided through the mechanism would be able to assist with the management of reliability events which may occur over that peak summer period.

Some aspects of the second draft rule which relate to specific processes or matters unrelated to the implementation of the mechanism would commence prior to the commencement of the mechanism. The second draft rule also contains transitional clauses, which would commence shortly after the final rule is made and facilitate the introduction of a mechanism in such a way that participants can prepare effectively for this.

A commencement date for the mechanism of 24 October 2021 allows the mechanism to be in place prior to the summer of 2021-22 and thereby help manage peak demand events over the summer.

This approach balances bringing forward the benefits of the mechanism with the ability of AEMO and market participants to manage the transitional requirements and interactions with other regulatory reforms.

The proposed commencement dates for the various components of the second draft rule are summarised in Table 5.2.

Table 5.2: **Commencement timeframes under the second draft rule**

SCHEDULE OF AMENDING RULE	PARTS OF THE NER COVERED BY SCHEDULE	COMMENCEMENT DATE OF SCHEDULE
1	Chapter 2 - Registered participants and registration	24 October 2021

SCHEDULE OF AMENDING RULE	PARTS OF THE NER COVERED BY SCHEDULE	COMMENCEMENT DATE OF SCHEDULE
2	Rule 3.7D - Demand side participation information	31 March 2021
3	Chapter 3 (except rule 3.7D) - Market rules	24 October 2021
4	Chapter 4 - Power system security Chapter 4A - Retailer Reliability Obligation Chapter 7 - Metering	24 October 2021
5	Chapter 10 - Glossary	24 October 2021
6	Chapter 11 - Savings and transitional rules	18 June 2020

6 OVERVIEW OF THE SECOND DRAFT RULE

This chapter provides an overview of the second draft rule, including the wholesale demand response mechanism and other changes introduced under the second draft rule or recommended in this second draft determination.

The Commission has determined to not make a draft retail rule in respect of the rule change requests. The Commission has determined that the wholesale demand response mechanism introduced under this second draft rule is not suited to small customer participation. Chapter 4 sets out why the Commission does not think small customers are suited to the mechanism and alternative options for small customers accessing wholesale demand response. Because only large customers are able to participate in the mechanism, there isn't a need to change the retail rules. The Commission's reasons for not making a draft retail rule are set out further in chapter 2.

6.1 Wholesale demand response mechanism

6.1.1 Participant category and registration

The second draft rule introduces a new market participant category: a demand response service provider (DRSP). Registering as a DRSP would be the first step for those seeking to participate in the wholesale demand response mechanism. This will be the only participant class that is able to sell wholesale demand response through the wholesale demand response mechanism. If a retailer wanted to provide wholesale demand response through the mechanism, it will need to register as a DRSP.

A DRSP will need to register as such with AEMO and obtain AEMO's consent to classify loads as wholesale demand response units.

Registration and classification are important steps in the process of facilitating more wholesale demand response through the mechanism. These steps provide for:

- the obligations that a DRSP is required to comply with in order to be approved as a provider of wholesale demand response
- an opportunity to assess the suitability of loads to participate in the mechanism, including technical characteristics such as the ability for its baseline to be determined accurately and the maximum quantity of wholesale demand response that can be provided by the load (the maximum responsive component).

Under the second draft rule:

- The DRSP registration category will be combined with the existing registration category for market ancillary service providers (MASP).[108]
- To be eligible for registration as a DRSP, a person must obtain the approval of AEMO to classify a load as an ancillary service load or a wholesale demand response unit.[109]

108 Clause 2.3AA of the second draft rule. Entities currently registered as a MASP will have their registration category automatically renamed as a DRSP registration.

109 Clause 2.3AA.1(b) of the second draft rule.

- A load can only be classified as both an ancillary service load and a wholesale demand response unit by the same demand response service provider or market customer (as the case may be).[110]
- The application for classification must identify the qualifying load and specify the proposed baseline methodology for the load.
- A load can be a qualifying load if:[111]
  - the load comprises a single connection point (including an on-market child connection point, or a parent connection point in respect of all its off-market child connection points)
  - the load is neither a small customer load nor a scheduled load
  - the DRSP has the consent of the relevant customer and has arrangements to provide wholesale demand response with that load
  - the appropriate metering is installed.
- AEMO must approve the classification of a qualifying load as a wholesale demand response unit if AEMO is reasonably satisfied that:[112]
  - the load is a qualifying load
  - the qualifying load can provide wholesale demand response under the NER at least equal to the maximum responsive component proposed by the DRSP.
  - the DRSP has adequate communications and telemetry
  - a baseline methodology can be applied to the load that produces a baseline satisfying the baseline methodology metrics
  - the load satisfies each other requirement in AEMO's wholesale demand response guidelines for classification.
- DRSPs can apply to aggregate two or more wholesale demand response units such that they are treated as one for the purposes of central dispatch.[113]
- AEMO may determine appropriate requirements for telemetry and communications equipment.[114] AEMO has advised that a qualifying load that has a demand responsive capacity of 5 MW or more would be required to use SCADA. If an aggregated wholesale demand response unit includes such a qualifying load, all other loads within the wholesale demand response unit would also be required to use SCADA (regardless of their size).
- AEMO would be allowed to determine an upper limit on the amount of non-visible demand response (i.e. demand responsive loads not using SCADA) that can participate in the mechanism in each region.[115] Once this threshold has been reached, AEMO could impose more onerous telemetry requirements on any loads seeking to be classified as

110 Clause 2.3.5(e1) of the second draft rule.
111 Clause 2.3.6(m)(1) and clause 2.3.6(f) of the second draft rule.
112 Clause 2.3.6(e) of the second draft rule.
113 Clause 3.8.3(a2) of the second draft rule.
114 Clause 3.10.1(b)(1) of the second draft rule.
115 Clause 3.10.1(c) of the second draft rule.

wholesale demand response units in that region, including a requirement that they use SCADA.[116]

- AEMO must approve aggregation if:[117]
  - the aggregated wholesale demand response units are connected within a single region
  - power system security is not materially affected
  - appropriate control systems exist
  - any other requirements set out in AEMO's wholesale demand response guidelines have been satisfied.
- AEMO must develop a guideline that outlines the above requirements for classification of a load, as well as any others AEMO considers necessary for classifying a load as a wholesale demand response unit, or for aggregation for participation in central dispatch.[118]

This aspect of the second draft rule is discussed further in appendix C of this determination.

6.1.2 Dispatch and pre-dispatch

Under the second draft rule, DRSPs would participate in central dispatch in a transparent, scheduled manner. DRSPs are treated in a similar manner to other scheduled participants, i.e. a DRSP would submit dispatch bids and when cleared by NEMDE, receive dispatch instructions to provide wholesale demand response to a specified level. DRSPs would also be able to set the wholesale market price. Consequently, DRSPs would have a number of obligations and incentives consistent with the obligations imposed on scheduled generators, including compliance with dispatch instructions. These obligations and incentives are key to maintaining the integrity of the central dispatch and price setting process.

The general principle that DRSPs should be treated in a similar manner to scheduled participants guides the Commission's approach to how DRSPs should participate in these processes. However, in some instances these obligations have been modified to better suit the nature of DRSPs and wholesale demand response and to allow existing systems and processes to be utilised by AEMO. Without scheduling, the availability of demand response is less certain and this would substantially reduce the reliability benefits associated with the mechanism.

Under the second draft rule:

- DRSPs would be required to submit the available capacity of its wholesale demand response unit to provide wholesale demand response for all dispatch intervals.[119] For a wholesale demand response unit, available capacity would be determined taking into account the following principles:

116 Ibid.

117 Clause 3.8.3(b2) of the second draft rule.

118 Clause 3.10.1(a) of the second draft rule.

119 Clause 3.7.3(e) and clause 3.8.4(f) of the second draft rule.

- Available capacity would be capped at the maximum demand response component of the wholesale demand response unit.[120]
- Available capacity would be required to be specified as zero when the wholesale demand response unit is not baseline compliant or is spot price exposed.[121]
- Wholesale demand response would only be available when it is the result of wholesale demand response activity and there would be no change in flow at another connection point that offsets the quantity provided.[122] A DRSP is responsible for making sure these requirements are met in relation to the quantities of demand response it bids into the market.[123]

- DRSPs would be required to submit dispatch bids for all dispatch intervals for the purposes of providing information for pre-dispatch. If a DRSP does not intend to provide demand response for a particular interval, the DRSP will need to manage this by adjusting the bidding approach it would take for that interval (such as bidding at the market price floor).
- A DRSP would submit dispatch bids in a similar manner to scheduled loads, but only for the available capacity of the wholesale demand response unit (i.e. dispatch bids to consume varying levels of electricity at different price thresholds).
- A DRSP would be required to submit dispatch bid in price and quantity pairs in whole MW increments.[124]
- A DRSP's dispatch bid must specify:[125]
  - price bands and the corresponding prices at which the DRSP would provide wholesale demand response
  - ramp up and ramp down rates.
- A DRSP's bid will be included in dispatch in every dispatch interval, as the DRSP will be either:
  - dispatched to consume at the full capacity of the available demand responsive load if the market clearing price is below the threshold identified in the DRSP's bid or
  - dispatched to consume an amount less than the full capacity of the demand responsive load (i.e. to provide a demand reduction) if the market clearing price is above the threshold identified in the DRSP's bid.
- The DRSP's dispatch instruction would be to consume the amount of demand responsive load which it is cleared for in NEMDE.
- When the DRSP is receiving an instruction to remain at its available capacity, this will not be treated as a dispatch instruction for the purposes of the rules. If the DRSP is cleared to provide wholesale demand response, a dispatch instruction will be given.[126] AEMO has

120 Definition of *available capacity* in Chapter 10 of the second draft rule.
121 Clauses 3.8.2A(c) and (d) of the second draft rule.
122 Definition of *wholesale demand response* in Chapter 10 of the second draft rule.
123 Clause 3.8.22A(a2) of the second draft rule.
124 Clause 3.8.7B of the second draft rule.
125 Ibid.
126 Clause 4.9.2B of the second draft rule.

indicated that in practice, the dispatch instruction will specify the quantity of wholesale demand response to be provided by specifying a quantity less than available capacity and this would be explained in AEMO's procedures.[127]

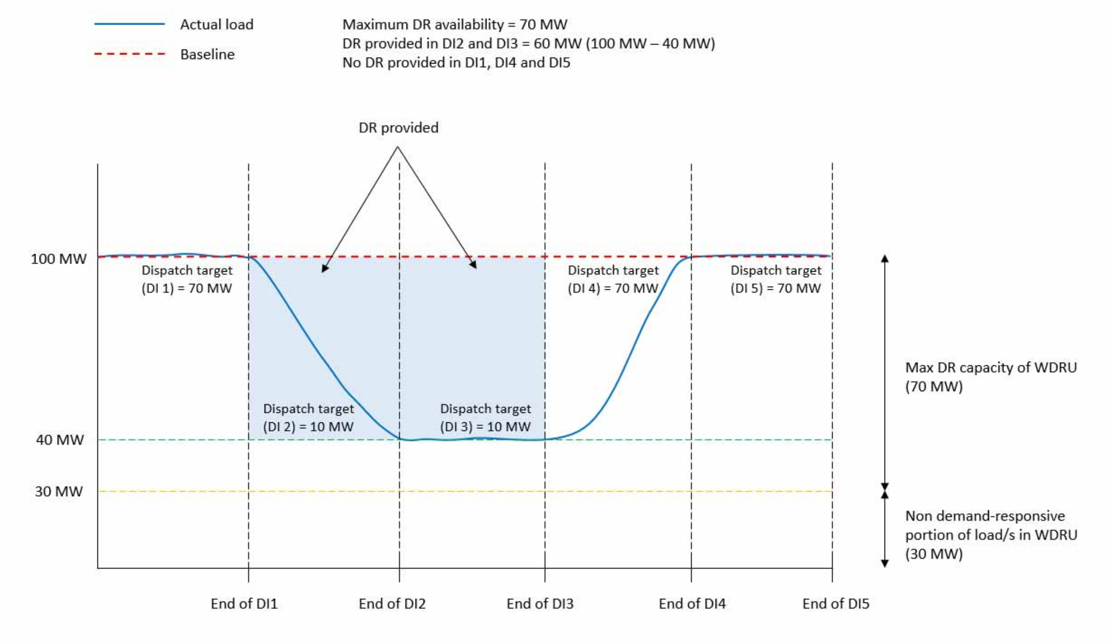
- DRSPs must not submit dispatch offers to provide wholesale demand response which:
  - encompass loads that are not compliant with the baseline methodology metrics at the time the offer is submitted[128]
  - would have been undertaken anyway, even in the absence of a dispatch instruction.[129]
- The DRSP is required to comply with its dispatch instructions. AEMO will need to assess whether a DRSP has achieved this by comparing actual consumption (and export) and the baseline on an ex-post basis. DRSPs would be required to maintain certain information and records to facilitate this assessment.[130]

Figure 6.1 provides an illustration of how DRSPs would be scheduled under the second draft rule. In this example:

- the maximum demand responsive component of the wholesale demand response unit is 70 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. For this to occur, the market price would have exceeded the price at which the DRSP nominated that it would consume its full capacity.
- 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).

127 Clause 4.9.2B(e) of the second draft rule.
128 Clause 3.8.2A(a) of the second draft rule.
129 Clause 3.8.2A(b) of the second draft rule.
130 Clause 3.8.2A(i) of the second draft rule.

Figure 6.1: Scheduling of DRSPs under the second draft rule



Source: AEMC

This aspect of the second draft rule is discussed further in appendix D.

6.1.3 Information provision

Increasing the transparency of wholesale demand response in the NEM was identified as one of the key benefits of this rule change by the rule proponents. Increased transparency contributes to the efficient operation and management of the wholesale electricity market by providing more information to the system operator and participants, so that investment and operational decisions can be better informed. This will also allow AEMO to better forecast demand and supply, as well as power flows across the system.

To facilitate this, the Commission considers that DRSPs should generally be subject to the same information provision requirements as existing scheduled generators, unless a particular requirement is not appropriate or necessary to apply to DRSPs.

Each DRSP will be required to provide the following information to AEMO:

- short term PASA inputs applying to the DRSP's wholesale demand response units, including available capacity for each trading interval under expected market conditions, PASA availability for each trading interval and projected daily wholesale demand response capability for wholesale demand response constrained wholesale demand response units[131]

131 Clause 3.7.3(e) of the second draft rule.

- any information required for publication by AEMO in the *Electricity Statement of Opportunities* (ESOO)[132]
- information required to be submitted through AEMO's DSP portal.

AEMO is required to publish information obtained through the short-term PASA,[133] the ESOO[134] and the demand side participation portal[135].

DRSPs would not be subject to the information provisions requirements applying to generators in respect of medium-term PASA or the Energy Adequacy Assessment Projection (EAAP).

This aspect of the second draft rule is set out in appendix E.

6.1.4 Determination of baselines

The second draft rule sets up a process for determining a baseline for wholesale demand response that participates in the wholesale demand response mechanism.

Baselines are an estimate of the counterfactual level of consumption that would have occurred were it not for the demand response. They are necessary to allow demand response providers 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.

The framework under the second draft rule captures the benefits of having a central body determining the initial series of baseline methodologies while also allowing for improvements to be made over time.

The second draft rule differs from the first draft rule by removing the framework that would allow market participants to submit baseline methodologies to AEMO for consideration. While this framework would have provided greater flexibility, it would also introduce substantial administrative and systems costs for AEMO. The Commission considers the preferable approach is to require AEMO to produce methodologies for initiation of the mechanism and allow new methodologies to be developed with AEMO through consultation.

Some flexibility will be retained as the baseline methodologies developed by AEMO will allow for parameters to be set to apply the baseline methodology to a particular load (the baseline settings).

Under the second draft rule, AEMO is required to:

- develop a guideline, in consultation with stakeholders, which sets out:[136]
  - information about the process for development of baseline methodologies by AEMO and how proposals for new baseline methodologies may be made

132 Clause 3.13.3A of the second draft rule.
133 Clause 3.7.3(a) of the NER.
134 Clause 3.13.3A(a) of the NER.
135 Clause 3.7D(c) of the second draft rule.
136 Clause 3.10.1(a) of the second draft rule.

    - 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
- develop one or more baseline methodologies in accordance with the guideline and publish the methodologies and related settings in a register[137]
- determine:[138]
    - the baseline methodology metrics which set the thresholds for an acceptable baseline methodology
    - arrangements for regular and systematic testing of baselines' compliance with the baseline methodology metrics
- monitor and report on the baseline methodologies used under the demand response mechanism.[139]

DRSPs must:

- demonstrate that the baseline methodology and baseline settings it proposes to apply to a load will produce a baseline capable of complying with the baseline methodology metrics in order to classify that load as a wholesale demand response unit[140]
- establish and implement measures in accordance with good electricity industry practice to identify when its wholesale demand response unit is not baseline compliant or is spot price exposed.[141]

This aspect of the second draft rule is discussed further in appendix F.

6.1.5 Settlement and cost recovery

There are several ways in which DRSPs could be compensated for reducing demand under a wholesale demand response mechanism involving centralised settlement. The approach taken to settlement and cost recovery can have a significant impact on the extent of the costs associated with changes to retailers' and AEMO's systems to accommodate the mechanism, which are ultimately borne by consumers.

Accordingly, the Commission has sought to develop a settlement model which is cost-effective for consumers and market participants. In particular, the settlement model applying under the second draft determination would:

- allow retailers to continue to bill customers based on actual consumption, thereby significantly reducing the changes required to retailer billing systems and the associated implementation costs
- reduce the scope of the changes required to AEMO's settlement systems

137 Clause 3.10.3 of the second draft rule.
138 Clause 3.10.2 of the second draft rule.
139 Clause 3.10.6 of the second draft rule.
140 Clause 2.3.6(e)(3) of the second draft rule.
141 Clause 3.8.2A(g) of the second draft rule.

- avoid imposing unmanageable or unhedgeable risks on retailers, leading to increased costs for consumers.

Where a customer undertakes wholesale demand response, the financial flows under the settlement model applying under the second draft rule (and under the DRSP's contract with the customer) would be as follows:

- The customer will be charged by the retailer for its actual consumption of electricity at the customer's retail rate
- The retailer will be charged by AEMO for the customer's baseline level of consumption in the wholesale market, at the wholesale price.
- The DRSP will receive a payment from AEMO for the quantity of demand response provided by the customer (i.e. the customer's baseline level of consumption minus its actual consumption) at the wholesale price[142]
- The DRSP will share a proportion of this payment with the customer in accordance with the terms agreed between those parties
- In order for the retailer to recover a portion of the cost it incurs by hedging for the customer's baseline level of consumption in the wholesale market but only being paid by the customer for metered energy, the DRSP will pay to the retailer (via AEMO) an amount equal to the quantity of demand response provided by the customer (i.e. the customer's baseline level of consumption minus its actual consumption) multiplied by a predetermined reimbursement rate[143]
- The reimbursement rate will be calculated by AEMO on a quarterly basis and will be based on the load weighted average spot market prices over the previous 12 months.[144]

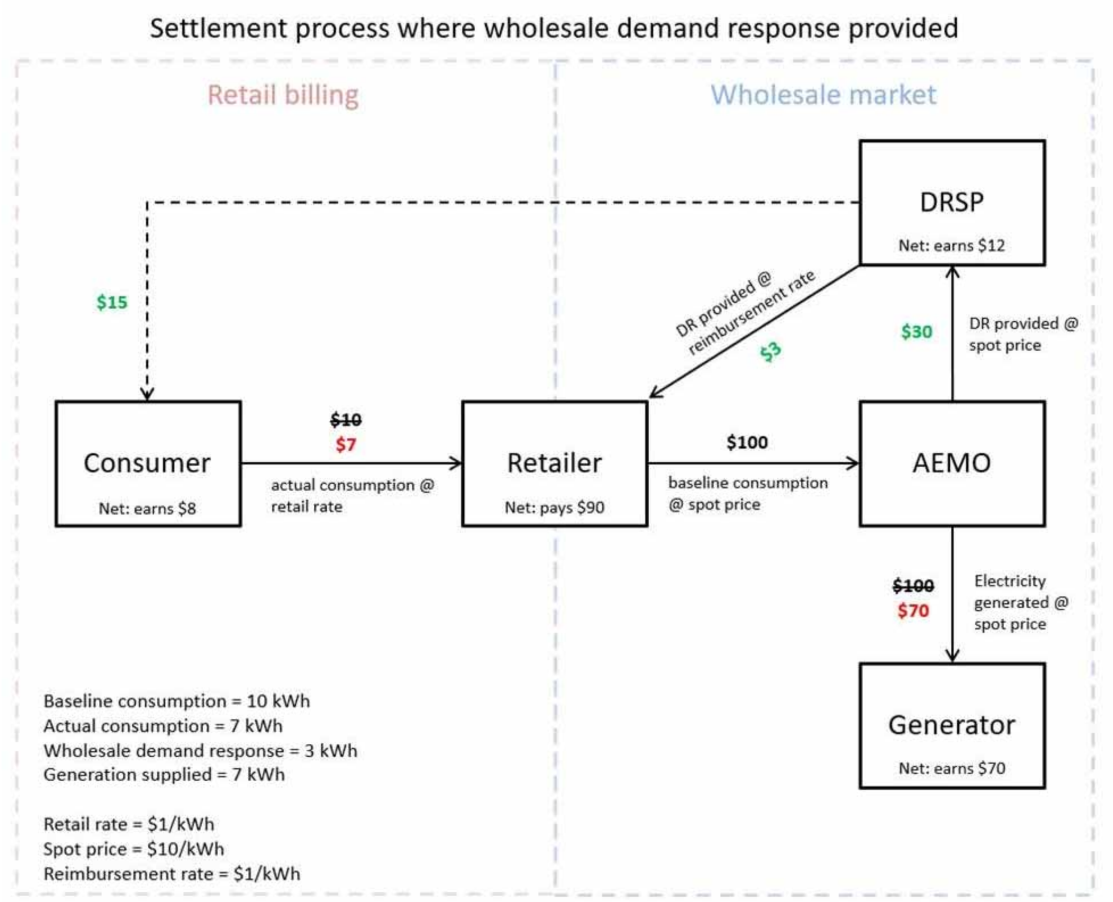
The financial flows described above are illustrated in Figure 6.2.

142 Clause 3.15.6B(a) of the second draft rule.

143 Clause 3.15.6B(b) of the second draft rule.

144 Clauses 3.15.6B(e) and (f) of the second draft rule.

Figure 6.2: Settlement model under the second draft rule - worked example



This aspect of the second draft rule is discussed further in appendix G.

6.2 Other changes - demand side participation portal

Under the second draft rule:

- AEMO is obliged to:
  - publish annual reports (without disclosing any confidential information) setting out a range of information about retailer-led, DRSP-led and network-led wholesale demand response, based on the data submitted to the Demand Side Participation (DSP) Portal[145]

145 Clause 3.7D(c) of the second draft rule.

- review the Demand Side Participation Information Guidelines as necessary to reflect the amending rule[146]
- Registered Participants are required to submit a report in the DSP Portal even where they have no demand response arrangements with customers.[147]

6.3 Implementation

The substantive parts of the rule implementing the wholesale demand response mechanism would commence on 24 October 2021. This approach attempts to balance the benefits of the mechanism with the ability of AEMO and market participants to manage the transitional requirements and interactions with other regulatory reforms. The second draft rule includes several changes to the design of the mechanism under the first draft rule to accommodate this earlier implementation date.

The following specific aspects of the second draft rule will commence before 24 October 2021:

- Schedule 2 of the second draft rule, which includes the changes to the obligations on AEMO and market participants other than DRSPs with respect to the Demand Side Participation (DSP) Portal discussed in appendix H, will commence on 31 March 2021. This is intended to ensure that these changes take effect when the DSP Portal opens for submissions on 31 March 2021.
- Schedule 6 of the second draft rule, which sets out the transitional rules relating to the establishment of the wholesale demand response mechanism, will commence on 18 June 2020. The transitional rules relate primarily to the development or amendment of guidelines and procedures by AEMO and the AER, allowing those entities to commence that process soon after the rule is made. Key guidelines and procedures are required to be in place by 24 June 2021 (four months before the mechanism starts), in order to allow entities to apply to AEMO for registration as DRSPs, and to seek classification of loads as wholesale demand response units, from that date.[148] This will allow DRSPs to prepare to commence trading wholesale demand response from 24 October 2021.

The commencement dates for the various components of the second draft rule are set out in Table 6.1.

Table 6.1: **Commencement timeframes under the second draft rule**

SCHEDULE OF AMENDING RULE	PARTS OF THE NER COVERED BY SCHEDULE	COMMENCEMENT DATE OF SCHEDULE
1	Chapter 2 - Registered participants and	24 October 2021

146 Clause 11.120.7(a) of the second draft rule.

147 This would be a "no activity" report. Clause 3.7D(b)(2) of the second draft rule. The Commission proposes to recommend that the reporting requirements clause be made a civil penalty provision.

148 Clauses 11.120.2-7 of the second draft rule.

SCHEDULE OF AMENDING RULE	PARTS OF THE NER COVERED BY SCHEDULE	COMMENCEMENT DATE OF SCHEDULE
	registration	
2	Rule 3.7D - Demand side participation information	31 March 2021
3	Chapter 3 - Market rules	24 October 2021
4	Chapter 4 - Power system security Chapter 4A - Retailer Reliability Obligation Chapter 7 - Metering	24 October 2021
5	Chapter 10 - Glossary	24 October 2021
6	Chapter 11 - Savings and transitional rules	18 June 2020

ABBREVIATIONS

ACL	Australian Consumer Law
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered price cap
ARENA	Australian Renewable Energy Agency
Commission	see AEMC
CPT	cumulative price threshold
DER	distributed energy resources
DRSP	Demand Response Service Provider
ECA	Energy Consumers Australia
EMMS	Electricity Market Management Systems
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
MASP	Market Ancillary Service Provider
MCE	Ministerial Council on Energy
MDP	Metering Data Provider
MSATS	Market Settlement and Transfer System
MW	megawatt
NEL	National Electricity Law
NEM	national electricity market
NEMDE	national electricity market dispatch engine
NEO	national electricity objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	national energy retail objective
NERR	National Energy Retail Rules
NMI	national metering identifier
NSP	network service provider
PASA	projected assessment of system adequacy
PIAC	Public Interest Advocacy Centre
RERT	Reliability and Emergency Reserve Trader
RSSR	reliability standard and settings review
TAI	The Australia Institute
TEC	Total Environment Centre
VPP	virtual power plant

A LEGAL REQUIREMENTS UNDER THE NEL AND NERL

This appendix sets out the relevant legal requirements under the NEL and NERL for the Commission to make this second draft rule determination.

A.1 Second draft rule determination

In accordance with s. 99 of the NEL and s. 256 of the NERL the Commission has made this second draft rule determination in relation to the rules proposed by the Public Interest Advocacy Centre, Total Environment Centre and the Australia Institute, by the Australian Energy Council, and by the South Australian Government.

The Commission's reasons for making this second draft rule determination are set out in chapter 2.

A copy of the more preferable second draft rule is attached to and published with this second draft rule determination. Its key features are described in chapter 6.

A.2 Power to make the second draft rule

The Commission is satisfied that the more preferable second draft rule falls within the subject matter about which the Commission may make rules. The more preferable second draft rule falls within s. 34 of the NEL as it relates to regulating the operation of the national electricity market and to regulating the activities of persons (including registered participants) participating in the national electricity market (NEL ss. 34(1)(a)(i) and (iii)).

A.3 Commission's considerations

In assessing the rule change requests the Commission considered:

- its powers under the NEL and NERL to make the second draft rule
- the rule change requests
- feedback provided at public forums on 5 March 2019, 16 August 2019 and 22 August 2019
- feedback provided at the public hearing on 6 August 2019[149]
- feedback provided at the technical working group meetings[150]
- submissions received during the first and second rounds of consultation[151]
- advice provided by AEMO on the technical systems changes required to implement the wholesale demand response mechanism and the estimated costs of those changes

149 A transcript of this hearing is available on the project page: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

150 Summaries of these meetings are available on the project page https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

151 These submissions can be accessed on the project page: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

- the Commission's analysis as to the ways in which the proposed rules will or are likely to contribute to the NEO and NERO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for the rule change requests.[152]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[153] The more preferable second draft rule is compatible with AEMO's declared network functions because it does not affect those functions.

A.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may, jointly with the AER, recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

A.4.1 Amendments to existing provisions

The Commission's more preferable second draft rule amends rule 3.7D(b) of the NER, regarding reporting by registered participants of demand side participation information. This rule is not currently classified as a civil penalty provision. However, the Commission considers that this rule should be classified as a civil penalty provision to promote compliance with this obligation, given the importance to the market of obtaining demand side participation information and the relative difficulty to date in obtaining this information. AER staff provided an initial indication that the AER supports this recommendation.

The Commission's more preferable second draft rule amends the clauses of the NER listed below. These rules are currently classified as civil penalty provisions under Schedule 1 of the National Electricity (South Australia) Regulations. The Commission considers that these rules should continue to be classified as civil penalty provisions and therefore does not propose to recommend any change to their classification to the COAG Energy Council. AER staff provided an initial indication that the AER supports this approach.

Table A.1: **Amendments to existing civil penalty provisions**

CLAUSE	SUBJECT OF CLAUSE AND CHANGE
Clause 2.3.5(g)(1)	Requirement that Market Ancillary Service Provider and Market Customer comply with any terms and conditions imposed by AEMO as part of approval of classification of a load as an ancillary service load pursuant to clause 2.3.5(f). The clause is amended to replace Market Ancillary Service Provider with DRSP.

152 Under s. 33 of the NEL and s. 225 of the NERL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

153 Section 91(8) of the NEL.

CLAUSE	SUBJECT OF CLAUSE AND CHANGE
Clause 2.3.5(g)(2)	Requirement that Market Ancillary Service Provider and Market Customer ensure that market ancillary services provided using the relevant ancillary services load are provided in accordance with the co-ordinated central dispatch process operated by AEMO under the provisions of Chapter 3 and in accordance with the market ancillary service specification. The clause is amended to replace Market Ancillary Service Provider with DRSP.
Clause 2.3.5(g)(4)	Requirement that Market Ancillary Service Provider or Market Customer that submits a market ancillary service offer in respect of the relevant ancillary service load comply with the dispatch instructions from AEMO in accordance with the Rules. The clause is amended to replace Market Ancillary Service Provider with DRSP.
Clause 2.3.5(h)	Requirement that Market Ancillary Service Provider or Market Customer with an ancillary service load only sell the market ancillary services produced using that ancillary service load through the spot market in accordance with the provisions of Chapter 3. The clause is amended to replace Market Ancillary Service Provider with DRSP.
Clause 3.7.3(e)	Requirement that certain short term PASA inputs be submitted by each relevant Scheduled Generator or Market Participant in accordance with the timetable and represent current intentions and best estimates. The clause is amended so that the certain short term PASA inputs include available capacity of each wholesale demand response unit, PASA availability of each wholesale demand response unit and projected daily wholesale demand response availability for units that are wholesale demand response constrained.
Clause 3.8.4(a)	Requirement that Scheduled Generator and Market Participant notify AEMO of available capacity of certain scheduled units. The clause is amended so that the certain scheduled units include wholesale demand response units.
Clause 3.8.4(b)	Requirement that subsequent changes may only be made to the information provided under clause 3.8.4(c), (d) and (e) in accordance with clause 3.8.22. The clause is amended to include clause 3.8.4(f), which is a new clause (discussed in new rules to be classified as CPPs, below).
Clause 3.8.19(a)	Requirement that Scheduled Generator or Market Participant notify AEMO: • if it reasonably expects one or more of its particular scheduled units or loads is unable to operate in accordance with dispatch instructions in any trading interval; • that such particular scheduled units or load is inflexible in that trading interval; and • a fixed loading level at which it is to be operated in that trading interval. The clause is amended to include wholesale demand response units.

CLAUSE	SUBJECT OF CLAUSE AND CHANGE
Clause 3.8.19(b)(1)	Requirement that where a Scheduled Generator, Semi-Scheduled Generator or Market Participant advises AEMO that a unit, service or load is inflexible that a brief, verifiable and specific reason is provided. The clause is amended to include wholesale demand response units.
Clause 3.8.20(g)	Requirement that Scheduled Generator, Scheduled Network Service Provider and Market Customer ensure it is able to dispatch the relevant plant as required under the pre-dispatch schedule. The clause is amended to include DRSPs.
Clause 3.13.3(b)	Requirement that Scheduled Generators, Semi-Scheduled Generators and Market Participants provide AEMO with the bid and offer validation data relevant to their scheduled loads, scheduled network services, and generating units in accordance with schedule 3.1. The clause is amended to include wholesale demand response units.
Clause 3.13.3(b1)	Requirement that Scheduled Generators, Semi-Scheduled Generators and Market Participants which have aggregated certain loads, services or units in accordance with clause 3.8.3 must provide AEMO with certain information. The clause is amended to include wholesale demand response units and to require that AEMO is provided with the number of individual wholesale demand response units that have been aggregated in accordance with clause 3.8.3.

A.4.2 New provisions the Commission proposes to recommend be classified as civil penalty provisions

The Commission's more preferable second draft rule includes the addition of the rules set out in the following table into the NER.

The Commission considers that these new provisions should be classified as civil penalty provisions for consistency with similar provisions (currently classified as civil penalty provisions) that apply to other types of registered participants, and to promote compliance with these new obligations so that the new mechanism operates effectively. AER staff have provided an initial indication that the AER supports this recommendation.

Table A.2: **New provisions proposed to be recommended as civil penalty provisions**

CLAUSE	SUBJECT OF NEW CLAUSE
Clause 2.3.6(h)	Requirement that DRSP comply with any terms and conditions imposed by AEMO as part of approval of classification of a load as a wholesale demand response unit pursuant to clause 2.3.6(g).
Clause 2.3.6(i)	Requirement that if DRSP submits a dispatch bid in respect of a wholesale demand response unit, the DRSP must comply with dispatch instructions from AEMO in accordance with the Rules.

CLAUSE	SUBJECT OF NEW CLAUSE
Clause 2.3.6(k)	Requirement that DRSP notify AEMO if a load the DRSP has classified as a wholesale demand response unit ceases to be a qualifying load as soon as reasonably practicable and in any event no later than 10 business days after becoming aware that the load ceases to be a qualifying load.
Clause 3.8.2A(c)	Requirement that DRSP submit available capacity of zero for a wholesale demand response unit in respect of a trading interval if the DRSP becomes aware (whether by reason of the DRSP's own knowledge or a notification by AEMO) that the wholesale demand response unit is not baseline compliant during the period in which the trading interval falls; or where two or more wholesale demand response units have been aggregated in accordance with clause 3.8.3, any one of the wholesale demand response units are not baseline compliant during the period in which the trading interval falls.
Clause 3.8.2A(d)	Requirement that DRSP submit available capacity of zero for a wholesale demand response unit in respect of a trading interval if the wholesale demand response unit is spot price exposed in respect of the trading interval; or where two or more wholesale demand response units have been aggregated in accordance with clause 3.8.3, any one of the wholesale demand response units is spot price exposed in respect of the trading interval.
Clause 3.8.2A(f)	Requirement that DRSP establish and implement measures in accordance with good electricity industry practice to identify any wholesale demand response unit of the DRSP that is not baseline compliant or is spot price exposed in respect of a trading interval.
Clause 3.8.2A(i)	Requirement that DRSP retain the information specified in the wholesale demand response participation guidelines in the manner, and for the period, specified in the guidelines.
Clause 3.8.4(f)	Requirement that DRSP inform AEMO, two days ahead of each trading day, of a MW capacity profile and an up ramp rate and a down ramp rate for wholesale demand response units.
Clause 4.9.2B(c)	Requirement that DRSP, with respect to wholesale demand response units in relation to which a dispatch bid has been submitted for a particular trading interval, ensure that appropriate personnel or electronic facilities are available at all times to receive and immediately act upon dispatch instructions issued by AEMO to the DRSP.
Clause 4.9.8(f)	Requirement that DRSP ensure that each of its wholesale demand response units is at all times able to comply with its latest dispatch bid.
Clause 4.9.9E	Requirement that DRSP must, without delay, notify AEMO of any event which has changed or is likely to change the availability of any of the DRSP's wholesale demand response units, as soon as the DRSP becomes aware of the event.

CLAUSE	SUBJECT OF NEW CLAUSE
Clause 4.11.1(c1)	Requirement that DRSP must in respect of its wholesale demand response units arrange the installation and maintenance of all remote control equipment and remote monitoring equipment in accordance with the standards and protocols determined and advised by AEMO for use in the relevant control centre.

In addition, the Commission has inserted a new clause 3.8.22A(a2), which provides that for the purposes of the requirement in clause 3.8.22A(a) that a dispatch bid not be false, misleading or likely to mislead, the making of a dispatch bid by a DRSP is deemed to represent to other Market Participants through the pre-dispatch schedules published by AEMO that the available capacity the subject of the dispatch bid will, if dispatched, result in a deviation from the baseline for the unit that is the result of wholesale demand response activity (that is, additional) and is not the result of load shifting.

The whole of clause 3.8.22A is currently classified as a rebidding civil penalty provision. The Commission proposes to recommend that the new clause 3.8.22A(a2) also be classified as a rebidding civil penalty provision, for consistency with the other paragraphs of this clause. AER staff have provided an initial indication that the AER supports this recommendation.

A.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may, jointly with the AER, recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The Commission's more preferable second draft rule includes the addition of clause 3.8.2A(d), which requires a DRSP to submit available capacity of zero for a wholesale demand response unit in respect of a trading interval if the wholesale demand response unit is spot price exposed (under its retail contract) in respect of the trading interval, or where two or more wholesale demand response units have been aggregated in accordance with clause 3.8.3, if any one of the wholesale demand response units is spot price exposed in respect of the trading interval.

Under spot pass price through retail arrangements, a retailer passes the wholesale costs and associated risks through to the customer. If a DRSP breaches clause 3.8.2A(d), the relevant retailer may suffer losses given the likely disparity between the reimbursement rate and the spot price. The retailer would be liable for the baseline quantity in the wholesale market and would remain exposed to these wholesale costs and associated risks, which would be inconsistent with the risk management approach retailers take in spot price pass through arrangements.

The Commission considers that this new clause 3.8.2A(d) should be classified as a conduct provision to allow a retailer that suffers loss or damage as a result of a DRSP breaching this clause to recover the amount of loss or damage by action in court, pursuant to section 61B of the NEL. AER staff noted that they propose to defer to the Commission's judgement as to whether persons other than the AER ought to have the ability to commence proceedings for breaches of this new provision.

A.6 Review of operation of second draft rule

The more preferable second draft rule would require the Commission to conduct a formal review of the operation of the rule. The review would be conducted under clause 3.10.7 of the more preferable second draft rule, which would require the Commission, following the third anniversary of the commencement of clause 3.10.7, to:

- conduct a review of the arrangements for the provision of wholesale demand response under the rules in accordance with clause 3.10.7(b) and the rules consultation procedures; and
- publish a report of its findings and recommendations.

The review would be required to consider the costs, benefits and effectiveness of the arrangements having regard to:

- the impact of the arrangements on the spot price;
- the accuracy of baseline methodologies;
- market and technological developments; and
- any other matters relating to wholesale demand response which the Commission considers relevant.

B TABLE OF CHANGES BETWEEN FIRST DRAFT RULE AND SECOND DRAFT RULE

This table provides a summary of the amendments between the first draft rule and second draft rule.

Table B.1: Summary of amendments from first draft rule to second draft rule

REFERENCE	SUMMARY OF AMENDMENT
Chapter 2	
2.3.4(d)	Changes clarify that a load that has been classified as a wholesale demand response unit cannot be classified as a scheduled load. This mirrors the requirement that a scheduled load cannot be classified as a wholesale demand response unit.
2.3.5	In the first draft rule, these provisions were moved from clauses 2.3AA.1(b)(1) and (2) in much the same form as they appeared in those clauses. Following consultation feedback, the drafting has been clarified and some duplication removed.
2.3.5(e1)	A new clause 2.3.5(e1) implements the principle that a load already classified as a wholesale demand response unit can only be classified as an ancillary services load by the same person. This principle reflects AEMO's system requirements.
2.3.6 and 2.3.7	Clauses 2.3.6 and 2.3.7 in the first draft rule have been merged and amended. Rule 2.3.7 was no longer required as the concept of a scheduled wholesale demand response unit (comprising aggregated wholesale demand response units) has been removed from the Rules. The concept is no longer required due to the 5MW threshold for participation in dispatch also being removed. Consent to aggregation for dispatch purposes will still be required from AEMO, by means of an application under Chapter 3, and the minimum quantity that can be dispatched will remain 1 MW. In practice this means that applications for consent to classification for loads offering less than 1 MW of wholesale demand response will only be possible where AEMO also consents to aggregation of separate loads to allow the minimum 1 MW dispatch size to be met, as AEMO needs to be reasonably satisfied that a load, if classified, is able to be used to provide wholesale demand response in accordance with the Rules. Most of the eligibility criteria have now been moved to a new defined term 'qualifying load'. A DRSP can only apply for consent to classify a load as a wholesale demand response unit if it is a qualifying load. If the load ceases to be a qualifying load, the DRSP must tell AEMO and the load will cease to be classified.

<table>
<tr><th>REFER-
ENCE</th><th>SUMMARY OF AMENDMENT</th></tr>
<tr><td></td><td>The criteria for a load to be a qualifying load include most from the first draft rule. Some of the criteria have been simplified and the following changes have also been made through the definition of 'qualifying load' in paragraph (m):
• The definition requires each connection point to be treated as a separate load. This is required because the baseline will be calculated for the single connection point and in settlement, the financially responsible Market Participant is paid the reimbursement rate which cannot be apportioned among different financially responsible Market Participants. Aggregation under Chapter 3 can used where a site has more than one connection point and wishes to be treated as a single wholesale demand response unit for dispatch purposes. Baselines and settlement calculations are not able to be aggregated across multiple connection points.
• A parent connection point can be classified as a wholesale demand response unit but only in respect of all off-market child connection points in the embedded network.
• An on-market child connection point can be classified as a wholesale demand response unit, but not an off-market child connection point.
• The definition now states expressly that the DRSP must have customer consent for the load to participate in the mechanism.
• The exclusion of small customer loads has been clarified so as to allow small customers who are business customers but have elected to aggregate sites for the purpose of the National Energy Retail Rules (and so have given up some customer protections under those Rules) to participate in the mechanism in respect of individual loads.
• The DRSP is responsible for notifying AEMO within 10 business days if its load ceases to be a qualifying load.
The clause has been amended to remove reference to approval of a proposed new baseline methodology. The revised process for development of baseline methodologies is discussed further below in relation to clause 3.10.1.

In deciding whether to consent to classification of a wholesale demand response unit, AEMO will assess whether the load is a qualifying load, whether it is able to be used to provide wholesale demand response in accordance with the Rules, whether it can provide wholesale demand response to at least the level of the proposed maximum responsive component, communications and telemetry, the proposed baseline methodology and baseline settings and other matters provided for in the wholesale demand response guidelines for classification of a load as a wholesale demand response unit.

To mirror the principle in clause 2.3.5(e1), paragraph (f) ensures that if a load has already been classified as an ancillary services load, it can only be classified</td></tr>
</table>

REFER-ENCE	SUMMARY OF AMENDMENT
	as a wholesale demand response unit by the same person.
2.3.6(j) (now deleted)	Old clause 2.3.5(j) required the wholesale demand response capability of a wholesale demand response unit to be sold through the spot market. This has been removed. The principle that wholesale demand response is only paid for under the Rules if dispatched remains (clause 2.3.6(i)). The second draft rule also refers to payment where the wholesale demand response unit is subject to a clause 4.8.9 instruction.
2.3AA.1(b)	In the first draft rule, registration as a DRSP could occur before the applicant had received approval to classify a load as either an ancillary service load in accordance with clause 2.3.5 or as a wholesale demand response unit in accordance with clause 2.3.6. The second draft rule requires approval for classification to occur at the same time, consistent with the current approach under the Rules.
Chapter 3	
Whole Chapter	The term 'scheduled wholesale demand response unit' has been replaced with 'wholesale demand response unit'. The concept of a scheduled wholesale demand response unit (comprising aggregated wholesale demand response units) has been removed from the Rules as a result of the 5MW threshold for participation in dispatch also being removed. The definition of 'wholesale demand response unit' in Chapter 10 explains where a reference to a wholesale demand response unit means the aggregated units. Under the second draft rule, DRSPs will submit dispatch bids (not dispatch offers) and as a consequence, where used in relation to a wholesale demand response unit, the term 'dispatch offer' has been replaced with 'dispatch bid'.
3.2.2	The reference to 'wholesale demand response' in this rule has been removed as it is not necessary to refer to it in this context.
3.7.1	References to DRSPs and wholesale demand response units have been removed from this clause as it is proposed that AEMO will not be collecting this information for its 24-month forecasts.
3.7.2(f)(5C)	References to DRSPs and wholesale demand response units have been removed from this clause as it is proposed that wholesale demand response units will not participate in the medium term PASA process.
3.7.3(d)(1)(ii)	The phrase 'assuming they are not providing wholesale demand response' in the first draft rule has been deleted. This wording was not needed. It was intended to indicate that the load of a wholesale demand response unit is to be included without adjusting for changes due to the provision of WDR. The Commission considers that it is clear in the context of the clause that any adjustment for wholesale demand response is made after the calculation under paragraph (d)(1)(ii).

REFER-ENCE	SUMMARY OF AMENDMENT
3.7.3(d)	A drafting change has been made to remove an unecessary 'for'.
3.7.3(e)(5)	The word order has been changed to avoid the phrase "wholesale demand response constrained wholesale demand response units".
3.7.3(h)	The drafting in subparagrah (1) has been corrected to remove the requirement to assume that wholesale demand response units will not be dispatched. Draft subparagraphs (3A), (4AC), (4AD) and changes to subparagraphs (4) and (4A) have been removed or reversed. In the second draft rule, it is proposed that AEMO will not provide short term PASA information about wholesale demand response unit availability to the level of detail provided for in this provision in the first draft rule.
3.7D	In the first draft rule, information about contracts to provide wholesale demand response by wholesale demand response units was excluded from the demand side participation information collected and published under this rule. In the second draft rule, this has been reversed and this change is reflected in the amendments through this rule.
3.8.1(e)	The clause provides for use of the dispatch algorithm for central dispatch. A reference to wholesale demand response units has been included in the clause to correct an omission.
3.8.2(d)	This clause provides for AEMO to reject bids and offers for plant that does not have the correct equipment in place to support the issuing of dispatch instructions and the audit of responses. The draft change to this clause is no longer required and has been reversed, since the term 'dispatch bid' includes dispatch bids made in respect of wholesale demand response units.
3.8.2A	This new clause has been reworked following consultation feedback and to reflect the new model. The key principles from the first draft rule remain the same but are now dealt with through the definitions and requirements relating to available capacity, as explained below. In addition, AEMO no longer has an obligation to exclude a wholesale demand response unit that is not baseline compliant from dispatch. Instead, the DRSP must take steps in accordance with good electricity industry practice to inform itself when its wholesale demand response unit is not baseline compliant or is spot price exposed and so ineligible for dispatch. This is explained further below in relation to clause 3.8.2A(e).
3.8.2A(b)	This new paragraph requires a DRSP to comply with paragraphs (c) to (d) of the clause and AEMO's guidelines when determining the available capacity of its wholesale demand response unit. Under the second draft rule, in determining the available capacity of its wholesale demand response unit, a DRSP will need to consider:

REFER-ENCE	SUMMARY OF AMENDMENT
	• the requirement in the definition of available capacity in Chapter 10, which caps available capacity at the maximum responsive component • the definition of wholesale demand response in Chapter 10, since the effect of this definition is to treat a deviation from baseline as wholesale demand response only if it results from wholesale demand response activity and is not at the same time offset by a change in load at another connection point • the revised definition of wholesale demand response activity in Chapter 10 which requires the activity to have been undertaken in response to a dispatch instruction and to be one that would not otherwise have occurred • the definition of baseline deviation offset, which is used in the definition of wholesale demand response to implement the principle that the deviation from baseline cannot be offset by a change in load at another connection point • AEMO's wholesale demand response guidelines, which it is proposed may include requirements relating to when a wholesale demand response unit is permitted to declare itself unavailable (rather than declaring availability and bidding at the market price cap).
3.8.2A(c)	Under this paragraph, a DRSP must specify available capacity of zero if it becomes aware that its wholesale demand response unit is not baseline compliant. The first draft Rule assumed that frequent baseline compliance testing by AEMO could be used to identify non-baseline compliant units and automatically excluded the units from dispatch. In the second draft Rule, the obligation has been shifted to the DRSP to take steps to identify when a wholesale demand response unit is not baseline compliant, notify AEMO (under clause 3.10.2) and declare itself unavailable. AEMO will still conduct baseline compliance testing and notify the DRSP if the unit is not baseline compliant. The obligation to declare the wholesale demand response unit unavailable only arises once the DSRP is aware of baseline non-compliance. This means there is a risk that some non-compliant units may participate for a time. This risk is mitigated through the obligation for the DRSP to take steps to identify non-compliance under clause 3.8.2A(f), discussed further below.
3.8.2A(d)	Under this paragraph, a DRSP must specify available capacity of zero for a wholesale demand response unit that is spot price exposed, as defined in Chapter 10. Unlike paragraph (c), this rule applies at all times and is not limited to circumstance in which the DRSP becomes aware of the spot price exposure. DRSPs will need to establish systems to identify a spot price exposed wholesale demand response unit before declaring the unit to have available capacity. Spot-price exposed wholesale demand response units are excluded from

REFER-ENCE	SUMMARY OF AMENDMENT
	providing wholesale demand response in a trading interval as retail charges at spot price (or spot price plus a margin) are assumed to represent unhedged load. If a spot-price exposed (unhedged) load participates in the wholesale demand response mechanism, under clause 3.15.6B the retailer will pay for the wholesale demand response at spot price and receive the reimbursement rate, but will not have a hedge to offset the difference between the spot price and the reimbursement rate. Similar issues arise in relation to a retailer's purchase of a customer's on-site generation at spot prices. Examples of retail contracts that result in a wholesale demand response unit being spot price exposed for a particular interval include contracts under which: • charges for electricity consumed in that interval are set at the spot price, or at spot price plus a retail margin or retail service fee • charges for excess consumption in that interval above a cap are set at spot price, or at spot price plus a retail margin or retail service fee, and the customer has reached the cap • payments for export by an on-site generator are at spot price, or at spot price less a margin. In practice retailers are likely to seek to mitigate the risk that a spot price-exposed retail customer offers wholesale demand response through contractual arrangements with the retail customer. However, the Commission considers that DRSPs also have an important role to play in mitigating this risk to the market as reflected in the second draft rule. The Commission has recommended that the requirement for the DRSP not to include a WDRU in its dispatch offer in intervals in which it is spot price exposed be a conduct provision.
3.8.2A(e)	This paragraph gives effect to the arrangements in clause 3.8.23(c)(6) under which AEMO may require the available capacity of a wholesale demand response unit to be set at a level specified by AEMO. This may occur where the wholesale demand response unit has been declared non-conforming for failure to follow dispatch instructions.
3.8.2A(f)	This new paragraph requires DRSPs to establish and implement measures in accordance with good electricity industry practice to identify if its wholesale demand response unit is not baseline compliant or is spot price exposed. As the wholesale demand response markets and the role of the DRSP are new, the Commission has considered whether a reference to 'good electricity industry practice' in this context is workable. Having regard to the definition in the Rules, (as amended by the second draft rule), the Commission considers that this sets an appropriate reference point for determining what is expected of market

REFERENCE	SUMMARY OF AMENDMENT
	participants. The standard may also be informed by guidelines made by the AER and by the baseline testing procedures made by AEMO. Retailers may also be expected to have in interest in ensuring appropriate monitoring standards are developed over time and adhered to.
3.8.2A(f) and (g) (now deleted))	These paragraphs in the first draft rule explained what a dispatch offer for wholesale demand response represents and the process to be used by AEMO to determine the loading level. The matters covered in paragraph (f) of the first draft rule have been moved to clause 3.8.7B(g) or Chapter 4. Paragraph (g) has been deleted as it is not required.
3.8.2A(h), (i) and (j) (were (h) and (i))	The provisions under which the AER will make guidelines for clause 3.8.2A have been amended to provide for the AER to provide guidance about the records a DRSP must maintain relating to compliance with clause 3.8.2A and its wholesale demand response activities. The AER may provide other guidance in its discretion.
3.8.3(a2)	Consequential amendments to the clause reflect removal of the term 'scheduled wholesale demand response unit'. A note has been included to clarify that aggregation does not apply to settlement, as the arrangements for aggregated wholesale demand response units are different to those that apply to aggregated loads and generating units.
3.8.3(b2)-(b4)	New subparagraph (4) in paragraph (b2) allows AEMO to specify other requirements for aggregation in the wholesale demand response guidelines. New paragraph (b3) allows AEMO to specify conditions of consent including conditions under which AEMO may require aggregated wholesale demand response units to be disaggregated. New paragraph (b4) requires a DRSP to comply with the conditions. These provisions are intended to work together to allow AEMO to specify in the guidelines circumstances in which AEMO will require an aggregated unit to disaggregate. For example, disaggregation may be required for system security reasons.
3.8.3A(a)(2)	The cross reference to clause 3.8.7B has been removed and consequential changes made. Clause 3.8.3A is not intended to apply in relation to wholesale demand response units.
3.8.4(f)	This paragraph sets out the information a DRSP must provide about the available capacity of its wholesale demand response unit. The second draft rule clarifies that this is subject to the principles for determining available capacity of a wholesale demand response unit in clause 3.8.2A.
3.8.5(b)(4) (now	Draft subparagraph (b)(4) is no longer required as dispatch bids are covered by clause 3.8.5(b)(1).

REFERENCE	SUMMARY OF AMENDMENT
deleted)	
3.8.7B	The obligation to notify AEMO whether the wholesale demand response unit intends to participate in central dispatch has been removed, as DRSPs will notify AEMO of the available capacity of a wholesale demand response unit under other provisions. The clause has been expanded to cover the range of matters relating to wholesale demand response dispatch offers, including: • the content of the dispatch offer; • maximum and minimum prices; • that the MW quantity is to apply at the connection point • how the offer is to be interpreted in central dispatch; • the option to include the daily quantity constraint.
3.8.7B	The obligations to notify usage prediction for the 30 minutes after a wholesale demand response unit is dispatched has been removed as AEMO have indicated this is no longer required under the proposed new model.
3.8.21(n)	New paragraph (n) requires AEMO to notify the financially responsible Market Participant when a wholesale demand response unit is dispatched. Only the fact of dispatch must be notified. AEMO is not required to provide other details such as the loading level. This requirement has been included in response to stakeholder comments on the first draft rule.
3.8.22	A reference to wholesale demand response units has been added to paragraph (b) to correct an omission from the first draft Rule.
3.8.22A(a2)	As in the first draft rule, DRSPs will make a specific representation to the effect that any wholesale demand response offered is genuine wholesale demand response – that is, it would not have otherwise occurred and is not offset elsewhere at the same time. For the second draft rule, the drafting of the representation in new paragraph (a2) has been amended to reflect the new approach to defining wholesale demand response and wholesale demand response activity and to use the new defined terms 'baseline deviation' and 'baseline deviation offset'.
3.8.22A(e)	A reference to wholesale demand response units has been added to subparagraph (e)(2) to correct an omission from the first draft rule.
3.8.23	Proposed amendments to the clause are intended to give AEMO a more relevant set of remedies where a wholesale demand response unit is not following dispatch instructions. These include requiring a change to the value of the maximum responsive component of the wholesale demand response unit or requiring available capacity to be capped or reduced to zero until the non-conformance is remedied. Minor drafting corrections have also been made.
3.9.1(3A)	References to wholesale demand response units in this clause have been

REFER-ENCE	SUMMARY OF AMENDMENT
	removed as they will not be subject to a direction.
3.9.3C(a)	In the first draft rule, a reference to wholesale demand response was included in the reliability standard in this clause. Following further consideration, it is proposed that this be removed.
3.9.7	In the first draft rule, amendments extended the clause to wholesale demand response units as well as generating units. Following discussion with AEMO, the Commission understands that wholesale demand response units will not be constrained on and so it is proposed the change should be reversed.
3.10.1	Amendments to the content of the wholesale demand response guidelines have been made to reflect changes in Chapter 2 and to remove reference to material that will be included by AEMO in registration guidance and application forms. Other matters to be included in the guideline are: • information about telemetry and communications equipment for wholesale demand response units • the methodology to be used to determine the threshold above which AEMO may require all wholesale demand response units in a region to have SCADA, discussed further below • information about the process for approval to apply a baseline methodology and baseline settings to a wholesale demand response unit or to change the maximum responsive component of a wholesale demand response unit • requirements for determining and notifying available capacity of a wholesale demand response unit. The second draft Rule removes the requirement for the guidelines to include the determinations to be made by AEMO under clause 3.10.2 relating to baseline methodology metric and baseline compliance testing. This has the effect of removing the requirement for AEMO to consult under the Rules consultation procedure on changes to the determinations. AEMO will still be required by Chapter 11 to consult on the initial determinations. The first draft Rule provided for AEMO to develop baseline methodologies for classes of load that AEMO expected could participate in the mechanism. DRSPs could also submit their own proprietary methodologies for approval. Following discussions with AEMO, the Commission understands that allowing DRSPs to submit baseline methodologies for approval would be costly and also likely to be impractical as AEMO's systems would need to be designed to handle multiple forms of baseline methodology. The second draft Rule provides for only AEMO to determine baseline methodologies, in the form of an initial set of methodologies (expected to cover the types of load that would seek to participate in the mechanism from the outset) and additional methodologies developed by AEMO in response to requests from DRSPs from time to time. Clause 3.10.1 requires

<table>
<tr><th>REFER-
ENCE</th><th>SUMMARY OF AMENDMENT</th></tr>
<tr><td></td><td>the guidelines to set out information about the development process, including how AEMO will determine which load categories to develop baselines for, and how a Registered Participant can propose that AEMO develop a new methodology.

AEMO will consult on the process for developing baseline methodologies when it consults on the guidelines. This leaves it open to AEMO to determine the most appropriate process, which may include consultation, technical working group, third party developers or a propose – consult process.

It is proposed that AEMO would have a discretion to determine additional conditions for approval of classification of a load as a wholesale demand response unit or for aggregation, so as to allow AEMO to consider matters such as the configuration of a site and whether there is potential for load shifting. The extent of this discretion was not clearly articulated in the first draft Rule and so clause 3.10.1 has been amended in the second draft Rule to allow AEMO to specify requirements it reasonably considers necessary having regard to:

• the need not to distort the operation of the market;
• the need to maximise the effectiveness of wholesale demand response at the least cost to end use consumers of electricity; and
• any other matters determined by AEMO acting reasonably (which might for example include the NEO or system security).

AEMO will determine appropriate requirements for telemetry and communications equipment. Paragraph (c) allows AEMO to determine an upper limit on the amount of wholesale demand response not using SCADA that can participate in the mechanism in each region. Once this threshold has been reached, AEMO could impose more onerous telemetry requirements on any loads seeking to be classified as wholesale demand response units in that region, including a requirement that they use SCADA. AEMO must publish the thresholds and information about progress towards reaching them.</td></tr>
<tr><td>3.10.2</td><td>Paragraph (b) has been amended to refer to export as well as consumption and to clarify that consumption and export are to be measured using metered data.

The provisions dealing with baseline compliance have been moved to clause 3.10.4.</td></tr>
<tr><td>3.10.3 (was 3.10.5)</td><td>Clause 3.10.5 from the first draft rule has been moved to clause 3.10.3 due to the change in the process for baseline methodology development.

A new paragraph (b) requires the baseline methodology to specify the parameters that are set on a case by case basis. These become the ‘baseline settings’ when approved.</td></tr>
</table>

REFER-ENCE	SUMMARY OF AMENDMENT
3.10.4	This clause deals with baseline compliance and non-compliance and reflects the following principles: • While the baseline methodology is intended to produce a forecast or counterfactual (the baseline), its accuracy is tested using historic metering data. That is, baseline compliance is a rolling test, not a per-trading-interval test. • The testing will occur at a particular point in time using metering data up to that point in time (so that time periods cannot be cherry-picked to produce a favourable result. The particular set of historic metering data used to test accuracy will depend on the baseline methodology metrics determined by AEMO. • A wholesale demand response unit is baseline compliant in a period if it produces a compliant baseline using the approved methodology and approved baseline settings. • If a wholesale demand response unit is shown not to be baseline compliant at any time, it remains non-compliant until it is shown to be compliant. To achieve compliance, the DRSP may seek AEMO's consent to change the baseline methodology and baseline settings applied to the wholesale demand response unit.
Former 3.10.3(b)	The paragraph stating that a wholesale demand response unit is only eligible for dispatch if it is baseline compliant has been removed, as the point is covered in clause 3.8.2A.
3.10.4(c) and (d) (was 3.10.3(d))	Consequential changes reflect the removal of the 'scheduled wholesale demand response unit' concept from the Rules.
3.10.5(b) to (e) (was 3.10.4(b)-(d))	The clauses have been amended so that AEMO has a discretion to determine procedures setting out a mechanism for adjusting baselines for abnormal conditions. The clauses have been reworded for clarity, to require AEMO to limit the frequency and timing of the adjustments and to give AEMO more discretion to limit the use of the mechanism. Clause 3.10.6(c) has been amended to require a report under this clause to include information about: • proposals for new baseline methodologies received by AEMO and new baseline methodologies being developed • the frequency and extent of wholesale demand response units declared to be non-conforming under clause 3.8.23(a).

REFERENCE	SUMMARY OF AMENDMENT
3.10.6(c)	Clause 3.10.6(c) has been amended so as to require a report under this clause to include information about: • proposals for new baseline methodologies received by AEMO and new baseline methodologies being developed; and • the frequency and extent of wholesale demand response units declared to be non-conforming under clause 3.8.23(a).
3.12.1(a)	A reference to clause 3.15.6B has been included in the list of clauses for which information is to be included in statements in accordance with the timetable in that clause.
3.12.2	References to wholesale demand response units have been removed from the clause as it is no longer proposed that they will participate in this mechanism.
3.12.2A	References to wholesale demand response units have been removed from the clause as it is no longer proposed that they will participate in this mechanism.
3.13.4	In the first draft rule, wholesale demand response unit availability was included with the pre-dispatch information about generating plant availability published under subparagraph (f)(4). In the second draft Rule it is proposed that the information will instead be taken into account in the forecast of peak load under subparagraph (f)(1). Consequential changes have been made in subparagraph (f)(5A) and (5B) and paragraphs (h). Similarly, the requirement to provide specific information relating to wholesale demand response units has been removed from paragraphs (p), (r) and (t).
3.14.5A(a)	A new paragraph (3) has been added to extend to objectives of compensation to include maintaining the incentive for Demand Response Service Providers to supply wholesale demand response.
3.14.5A(d)	Amendments have been made to allow for the calculation of the compensation payable to a Market Suspension Compensation Claimant in relation to wholesale demand response.
3.14.5A(f1)	New paragraph (f1) provides for AEMO to determine the benchmark value for wholesale demand response in the market suspension compensation methodology.
3.14.5A(h)	Amended to include a reference to DRSPs.
3.14.5A(j)	Amended to include a reference to DRSPs and to refer to benchmark values for wholesale demand response.
3.14.5B(a)	Amended to include a reference to the supply of wholesale demand response.
3.14.5B(d) and new (d1)	New paragraph (d1) defines the direct costs incurred by the Market Suspension Compensation Claimant in respect of a wholesale demand response unit supplying wholesale demand response. A consequential change has been made to paragraph (d).

REFER-ENCE	SUMMARY OF AMENDMENT
3.15.6A	References to wholesale demand response units and DRSPs, and related amendments have been removed from the clause as it is no longer proposed that they will be included in the scope of the arrangements in this clause.
3.15.6A(i)(1)	Drafting changes clarify that the phrase "which has metering to allow their individual contribution to the aggregate deviation in frequency of the power system to be assessed" applies to DRSPs as well as Market Customers.
3.15.6B(a) and (d)	Typographical errors have been corrected (for example, reference to 'load' replaced with 'unit").
3.15.6B	Loss factors have been included in the settlement equations. The transmission loss factors have been applied in determining the trading amount (TA) under clauses 3.15.6B(a) and (b). The distribution loss factors have been applied in the calculation of the wholesale demand response settlement quantity in clause 3.15.6B(c). This follows a similar approach to the calculation of spot market trading amounts under clause 3.15.5. However, the definition of TLF omits a reference to virtual transmission nodes (since these cannot be used to provide wholesale demand response).
3.15.6B(c)	The equation for calculation of WDRSQ has been corrected to take into account BSQ and ME being negative when electricity is being consumed by a load. New subparagraphs (c)(1) and (2) clarify that a settlement quantity is only calculated when the wholesale demand response unit has been dispatched to provide wholesale demand response (and so is a 'dispatched wholesale demand response unit' in the trading interval, as required by the opening words of clauses 3.15.6B(a) and (b)).
3.15.6B(e) and (f)	AEMO, rather than the AER, will be required to calculate the reimbursement rate. A requirement for AEMO to publish the rate has been added.
3.15.7(c)	To correct a drafting oversight from a previous version of the Rules, a reference to Demand Response Service Provider has been added in the definition of "AMP" in paragraph (c). The Rules are intended to allow a Market Ancillary Service Provider to receive a payment under clause 3.15.7 in respect of market ancillary services provided pursuant to a direction. This is reflected in the current definition of 'Directed Participant'. Under this rule change, the term 'Market Ancillary Service Provider' will be replaced with 'Demand Response Service Provider'.
Schedule 3.1	Schedule 3.1 sets out the bid and offer validation data to be provided by Scheduled Generators, Semi-Scheduled Generators and Market Participant. A new table for wholesale demand response units has been added.
Chapter 4	

REFERENCE	SUMMARY OF AMENDMENT
4.3.1(l)	In the first draft rule, a reference to wholesale demand response capacity was added in this paragraph. In the second draft rule, it is proposed not to make this change on the basis wholesale demand response will be adequately taken into account in the general reference to demand. This is consistent with the proposed approach to the reliability standard in clause 3.9.3C(a).
4.8.4	In the first draft rule, a reference to wholesale demand response capacity was added in this paragraph. As for clause 4.3.1(l) in the second draft rule, it is proposed not to make this change.
4.9.1(b)	The drafting of the proposed amendment to this clause has been corrected.
4.9.2B(a) and (b)	The revised clauses provide for dispatch instructions to be used for central dispatch of wholesale demand response units up to the available capacity of the wholesale demand response unit (or aggregate available capacity of aggregated wholesale demand response units).
4.9.2B(c)	The phrase 'at all relevant times' has been amended to read 'at all times'. Under the first draft Rule, a DRSP could choose when to participate in central dispatch and this paragraph only required the DRSP to have personnel and facilities available to respond to dispatch instructions at relevant times. In the second draft Rule, a DRSP must always participate in central dispatch for its wholesale demand response unit and so must have the personnel and equipment available at all times.
4.9.2B(d)	This new paragraph provides for AEMO to make a power system operating procedure covering arrangements for notifying a Demand Response Service Provider whether its wholesale demand response unit is being dispatched to provide wholesale demand response in a trading interval. It is intended that the procedures will implement the following principles: • when not dispatched, a DRSP will receive an instruction for its wholesale demand response unit to remain at available capacity • when the DRSP is cleared to provide wholesale demand response, a dispatch instruction will be given which will specify a MW level below the available capacity • the difference between the available capacity and the dispatched quantity is the quantity of wholesale demand response required to be provided. A DRSP will be required to comply with the power system operating procedures under existing provisions of the Rules.
4.9.5(a2)	References to 'scheduled wholesale demand response unit' have been changed to 'wholesale demand response unit' and drafting has been corrected.
4.9.9E	This clause has been amended to clarify that the DRSP is only required to provide information about a change in availability of wholesale demand response made available by the Demand Response Service Provider to AEMO.

REFER-ENCE	SUMMARY OF AMENDMENT
4.9.9E	The AEMC proposes to recommend that this clause be classified as a civil penalty provision for consistency with other similar provisions. This clause was not included in the list of proposed civil penalty provisions in the first draft rule. Some drafting changes have also been made.
4.11.1(c1)	Amendments to the clause clarify that it is the responsibility of the DRSP for a wholesale demand response unit to arrange the installation and maintenance of the remote control equipment and remote monitoring equipment under this clause.
Chapter 4A	
4A.E.1(c)	A consequential change has been made to paragraph (c) to reflect the change in Chapter 3 under which contracts for wholesale demand response are to be included in AEMO's Demand Side Participation Information Portal.
4A.F.3(b)	Amendments to clause 4A.F.3(b)(3) provide for wholesale demand response provided by a liable entity's customer to be taken into account in the calculation of a liable entity's liable load for a compliance TI.
4A.F.3(f)	Amendments to clause 4A.F.3(f) provide for the total amount of wholesale demand response to be taken into account in the calculation of adjusted peak demand for a compliance TI.
Chapter 7	
Part F	The heading has been amended to reflect the extended scope of this Part.
7.15.5	The heading has been amended to read 'Access to energy data' as a new clause 7.15.6 deals with access to baseline data.
7.15.6	New clause 7.15.6 will: • require baseline data to be treated as confidential information under the Rules • deem baseline data to be information provided by the customer (for clause 8.6.2(c)), consistent with the equivalent provision for energy data • require a DRSP to give its customer baseline data on request • require AEMO to give DRSPs and retailers access to baseline data relating to their customers • allow a DRSP to access baseline data held by AEMO relating to its wholesale demand response units • allow a retailer to access baseline data held by AEMO relating to its customers' connection points.
Chapter 10	
abnormal baseline	A new definition has been added to refer to a notice given to AEMO in accordance with a procedure that may be made by AEMO to adjust a baseline

REFER-ENCE	SUMMARY OF AMENDMENT
notice	during abnormal conditions (for example, during periods of planned maintenance).
abnormal baseline notice	A new definition has been added to refer to the procedures to be made by AEMO governing the circumstances and frequency for the giving of an abnormal baseline notice.
available capacity	A new paragraph has been added to provide for the available capacity of a wholesale demand response unit to be capped at the maximum responsive component and to be limited or reduced to zero where required under clauses 3.8.2A(b) to (d) or clause 3.8.23(c)(6).
Affected Participant	It is proposed that no changes would be made to this definition as wholesale demand response units will not be within the scope of the arrangements in clause 3.12.2.
baseline compliance testing	The reference to the wholesale demand response guidelines has been removed, as clause 3.10.1 no longer provides for AEMO's determination of the testing arrangements to be included in the guidelines.
baseline compliant	The definition has been simplified to refer to the definition in clause 3.10.4(a), which explains when a wholesale demand response unit is baseline compliant.
baseline data	A new definition specifying the data that a DRSP must provide to a customer or a customer representative on request. The categories of information are: • the baseline methodology and baseline settings approved for application to a wholesale demand response unit • periods when the wholesale demand response unit has been dispatched to provide wholesale demand response and the quantity of wholesale demand response provided.
baseline deviation	This new definition describes the deviation from baseline that is required to occur when wholesale demand response is provided. The term is principally used in defining wholesale demand response and the representation in clause 3.8.22A(a2).
baseline deviation offset	This new definition describes an adjustment in energy flow over a period that offsets a baseline deviation over the same period. The term is principally used in defining wholesale demand response and the representation in clause 3.8.22A(a2).
baseline methodology	Consequential changes reflect the changes to the way baseline methodologies will be made. The definition has also been simplified.
baseline settings	This new term cross-references the definition in Chapter 3.
constraine	The drafting changes have been reversed as a consequence of changes to

REFER-ENCE	SUMMARY OF AMENDMENT
d off, constrained on	Chapter 3.
dispatch bid	As DRSPs will be making dispatch bids not dispatch offers, this definition has been amended.
dispatch bid price	As DRSPs will be making dispatch bids not dispatch offers, this definition has been added and is used in Chapter 3.
dispatch offer	As DRSPs will be making dispatch bids not dispatch offers, the changes to this definition have been reversed.
dispatch offer price	As DRSPs will be making dispatch bids not dispatch offers, the changes to this definition have been reversed.
dispatched wholesale demand response unit	To clarify the drafting, this definition has been amended.
good electricity industry practice	A reference to the provision of wholesale demand response has been included. The term is used in relation to the obligation of a DRSP to take steps to ensure it can comply with the obligations not to make dispatch offers for wholesale demand response units that are spot price exposed or baseline non-compliant.
loading level	The drafting has been corrected to provide that for a wholesale demand response unit, the loading level is the level of wholesale demand response to be provided
Market Settlement and Transfer Solution Procedures	In new paragraph (b), the reference to MSATS being used for "the transfer of that responsibility between Market Participants" has been deleted in response to AEMO comments. MSATS will still be used to record the Demand Response Service Provider responsible for the wholesale demand response unit. Other amendments extend this to the maximum responsive component of the wholesale demand response unit and the baseline settings.
Market Suspension Compensation Claimant	The definition has been amended to include a "Demand Response Service Provider who supplied … wholesale demand response during a market suspension pricing schedule period".
maximum responsive component	This new term is used for the maximum wholesale demand response a wholesale demand response unit can provide. This figure is principally used to cap available capacity.

REFERENCE	SUMMARY OF AMENDMENT
qualifying load	This new term cross references the definition in Chapter 2.
scheduled plant	In the defined term 'scheduled plant", the reference to wholesale demand response units has been removed and replaced with a reference to ancillary service loads. The term 'scheduled plant' is only used in clause 4.8.9(a1). The effect of the change to the definition is: • a direction under clause 4.8.9(a) to an ancillary service load is taken to be a direction • a direction under clause 4.8.9(a) to a wholesale demand response unit is taken to be a clause 4.8.9 instruction.
small customer load	This new term cross references the definition in Chapter 2.
spot price exposed	A new definition specifies when a wholesale demand response unit is spot price exposed for the purposes of rule 3.8.2A. The definition applies on a per trading interval basis and by reference to the actual spot price. A wholesale demand response unit is not intended to be spot price exposed within the meaning of this definition merely because forecasts of spot price are taken into account in setting a retail supply rate or because the retailer pays the market at spot price
wholesale demand regional reimburse ment rate	This new term cross references the definition in Chapter 3.
wholesale demand response	In response to comments by stakeholders on the first draft rule, this definition has been replaced. The key points are: • the relevant response is a deviation from baseline • this can be achieved through a decrease in load, an increase in export or a combinate of the two • the response must be the result of wholesale demand response activity • there must not also be a baseline deviation offset.
wholesale demand response	Changes to the definition reflect the change to the definition of wholesale demand response. The key elements have been retained: • it must be an

REFER-ENCE	SUMMARY OF AMENDMENT
activity	• activity undertaken in response to a dispatch instruction to achieve a baseline deviation • the activity must be one that would not have been undertaken except to provide the wholesale demand response.
wholesale demand response dispatch bid	As DRSPs will be making dispatch bids not dispatch offers, this definition has been amended.
wholesale demand response participation guidelines	This new term cross references the provision in Chapter 3 under which these will be made.
wholesale demand regional reimbursement rate	This new term cross references the definition in Chapter 3.
wholesale demand response settlement quantity	Cross references the definition in Chapter 3.
wholesale demand response unit	New paragraph (b) explains when the term refers to two or more units that have been aggregated for dispatch purposes. This reflects the removal of the concept of a scheduled wholesale demand response unit.
Chapter 11	
Whole rule	The numbering has changes to rule 11.120
11.120.1	Definitions have been updated to use the clause numbering in the second draft rule.
11.120.2(a) and (b)	As the determinations of the baseline methodology metrics and frequency of baseline compliance testing are not part of the wholesale demand response guidelines, this clause now refers to them separately.
11.120.2(c)	Consequential changes reflect the removal of scheduled wholesale demand response units from the final Rule and the changes to the process for development of baseline methodologies.

REFER-ENCE	SUMMARY OF AMENDMENT
11.120.3	The time for making a baseline methodology has been moved to 4 months before the effective date (from 6 months), reflecting the proposed earlier implementation schedule.
11.120.4	Consequential changes have been made to the provision under which the AER will make the initial wholesale demand response participation guidelines under new clause 3.8.2A(h).
11.120.5	A new clause gives AEMO an additional 15 business days to consider applications for registration of a DRSP and consent to classification of a load as a wholesale demand response unit.
11.120.11 6	Additional procedures or guidelines that will need to be reviewed by AEMO before market start have been added to paragraph (a). A new paragraph (c) requires the AEMC to review and if necessary, amend, the compensation guidelines made under clause 3.14.6(e).

C PARTICIPANT CATEGORY AND REGISTRATION

The second draft rule establishes a new participant category - a DRSP. This participant would be able to engage in offering wholesale demand response into the wholesale market through the wholesale demand response mechanism. It would be able to do so without also being the FRMP for the load providing that demand response.

The DRSP would be consolidated with the existing market ancillary service provider (MASP) category. This means that the DRSP could also choose to offer frequency ancillary services as well, if it wishes to and the load has been classified appropriately.

Registering as a DRSP will be the first step for those seeking to participate in the wholesale demand response mechanism.

This appendix provides detail on the DRSP participant category and registration process established under the second draft rule. It sets out:

- a background to registration categories, including related categories
- a summary of relevant stakeholder comments
- the Commission's analysis and conclusions.

C.1 Overview

The second draft rule would introduce a new distinct service to be provided in the wholesale market: wholesale demand response. To enable the provision of this service, a new market participant category and registration and classification processes would be established.

A DRSP would be the only participant class that is able to sell demand response through the wholesale demand response mechanism. If retailers wish to provide wholesale demand response through the mechanism, they would need to separately register as DRSPs.

A DRSP would need to register as such with AEMO and classify loads as wholesale demand response units.

Registration and classification provide for:

- attaching the obligations that a DRSP is required to comply with in order to be approved as a provider of wholesale demand response
- an opportunity to assess the suitability of loads to participate in the mechanism, including technical characteristics and the applicability of baselines.

The second draft rule includes a process for assessing the eligibility of loads to participate in the wholesale demand response mechanism. This is necessary because these participants are scheduled and the wholesale demand response units may comprise portfolios of physically separate loads, which have not been accommodated in central dispatch to date.

Under the current rules, all scheduled wholesale market participants are scheduled generators, loads or storage facilities (which are also scheduled loads).[154] These parties must demonstrate compliance with a range of technical performance standards prior to the finalisation of their connection agreement. This provides AEMO with greater certainty regarding the technical characteristics of these participants. AEMO does not have the same certainty of technical performance with regard to aggregated portfolios comprised of resources connecting under less prescriptive connection arrangements. Without a demand response unit classification regime such as the one in the second draft rule, AEMO would have limited opportunities to assess whether these aggregated loads would impact on the security or reliability of the power system, particularly when responding simultaneously.

To address this, the second draft rule introduces a process to classify wholesale demand response units. This would allow AEMO to assess the technical suitability of each load seeking to provide wholesale demand response. It would also allow AEMO to assess whether the load is likely to be able to meet the requirements of the baseline methodology metrics, using the baseline methodology nominated by the DRSP.

There is an existing MASP category that allows the parties registered in this category to classify load to participate in ancillary services markets. Under the second draft rule, the MASP registration category would be subsumed into the DRSP category. This means there would be a single registration category that allows persons to classify loads as wholesale demand response units and/or ancillary services loads, provided they meet the requirements set out in the NER and by AEMO. This is similar to how a generator is treated, where it registers as a generator, and then chooses to participate in the wholesale energy market, frequency control ancillary services market, or both.

C.2 Proponents' views

All of the rule change proponents proposed the introduction of a new participant category. These views are set out below.

C.2.1 PIAC, TEC and TAI

In their rule change request, PIAC, TEC and TAI proposed the introduction of a new category of market participant, a DRSP. PIAC, TEC and TAI proposed that the NER be amended to:[155]

- Allow DRSPs to register as market participants to provide demand response services and ancillary services to the wholesale market
- Allow for load to be classified as 'demand response load' by a DRSP
- Provide for obligations with which this class of market participant must comply
- Provide for payment and calculation of market fees for DRSPs.

154 MASPs share some of the characteristics of scheduled participants e.g. submitting bids to AEMO for enablement. However, MASPs are not scheduled for energy in the wholesale market.

155 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, p. 9.

PIAC, TEC and TAI noted that there may be implications of the above that the Commission should consider applying to the existing MASP market participant category.[156]

C.2.2 AEC

In its rule change request, the AEC proposed that a new registration category would be introduced, a demand response aggregator (DRA). The AEC proposed that the NER would be amended to:[157]

- allow DRAs to register
- establish a technical relationship between the DRA and AEMO in regards to obligations relating to information provision and scheduling.

The AEC noted that as its proposal would not introduce a settlement relationship between the DRA and AEMO, there would be no need to place prudential requirements on the DRA.

C.2.3 South Australian Government

The South Australian Government's proposal included the introduction of a DRSP market participant category. Under the South Australian Government's proposal:[158]

- the DRSP would need to demonstrate its intention to classify load as demand response load within a reasonable period of time
- the DRSP would also need to demonstrate its ability to comply with the relevant provisions in the NER.

The South Australian Government also noted that, where a new meter is required, the DRSP could be required to coordinate with the metering coordinator to arrange for the new meter.[159]

C.3 Stakeholder comments

In submissions to the first draft determination, stakeholders provided feedback on the proposed registration and classification process.

- Enel X and the Energy Efficiency Council supported the introduction of a new participant category.[160]
- Flow Power suggested that the rule should allow for a retailer to contest the choice of baseline methodology applied to load.[161]
- Stanwell suggested that AEMO should approve the specific aggregation of wholesale demand response units. It also recommended reducing the threshold of demand response units from 1 MW to 5 MW.[162]

156 Ibid.
157 AEC, *Wholesale demand response register mechanism - rule change request*, p. 1
158 South Australian Government, *Mechanisms for wholesale demand response - rule change request*, pp. 4-5.
159 Ibid, p. 5.
160 Submissions to first draft determination: Enel X, p. 1; Energy Efficiency Council, p. 1.
161 Flow Power, submission to first draft determination, p. 4.
162 Stanwell, submission to first draft determination, p. 4.

- In its submission Tesla noted that the first draft rule was not entirely consistent with the AEMO's position on battery storage assets. The current 5MW threshold for storage to register as scheduled generation assets and scheduled loads applies to individual assets only, however in this case, the draft rule has suggested that this should apply equally to aggregated loads cumulatively totalling more than 5MW.[163]
- Enel X supported the consolidation of the DRSP and MASP participant categories. In doing so, Enel X supported the separate classification of loads for the purposes of providing FCAS and wholesale demand response.[164]
- Enel X sought confirmation on whether DRSPs would be able to add and remove NMIs from portfolios for dispatch. It suggested that it is important that this can occur and in a simple manner.[165]
- In relation to technical requirements for wholesale demand response units, Enel X made the following points:[166]
  - It is not necessary or appropriate to rely on SCADA links
  - it would be beneficial for the Commission to provide policy guidance to AEMO on these technical requirements
  - the requirements should be proportionate to the service provided, accommodate the characteristics of the assets providing the service, and be adaptable.
- In its submission, Tesla sought clarification on a number of points:[167]
  - how the consolidation of the DRSP and MASP category would impact on assets looking to register as small generation aggregators and MASPs
  - whether there is a maximum size of individual asset that can be included in an aggregated portfolio.
- AEMO's submission highlighted a number of concerns regarding the classification and registration process under the first draft rule, and made recommendations that in relation to these points:[168]
  - AEMO considered the first draft rule deviated from the approach otherwise adopted in Chapter 2 of the NER by requiring AEMO to approve the classification of wholesale demand response units which would not directly be able to participate in central dispatch. It also raised concern with the draft rule process for establishing scheduled wholesale demand response units.
  - AEMO submitted that it supports a policy that facilitates automation in allowing a DRSP to add or remove a wholesale demand response units into/from aggregations. It suggested that this policy intent can be better implemented through the classification function (as part of AEMO's registration function) rather than through the customer churn processes.

163 Tesla, submission to first draft determination, p. 4.
164 Enel X, submission to first draft determination, p. 2.
165 Ibid.
166 Ibid
167 Tesla, submission to first draft determination, pp. 3-4.
168 AEMO, submission to first draft determination, pp. 8-9.

- AEMO recommended that the final rule provide AEMO with the ability to disaggregate an aggregated wholesale demand response unit under certain circumstances.
- AEMO noted that if the final rule were to exclude small customers, its preference would be that the DRSP is responsible for confirming the relevant customer size.
- The Australian Energy Council supported the proposed threshold of 5MW for wholesale demand response units. The Energy Council suggested the rule should require that aggregations are ultimately connected to the same transmission network identifier ("TNI") (since AEMO's NEM Dispatch Engine performs its calculations at the TNI level).[169]

C.4 Analysis and conclusions

BOX 6: SECOND DRAFT RULE - REGISTRATION AS A DRSP AND CLASSIFICATION OF LOADS AS WHOLESALE DEMAND RESPONSE UNITS

Registration is the process by which an entity is admitted by AEMO into the NEM to allow it to participate in the market. DRSPs will be required to be registered in order to provide wholesale demand response in the wholesale market, in accordance with the second draft rule.

The second draft rule:

- introduces a registration process for DRSPs
- introduces a classification process for determining the eligibility of loads to participate in wholesale demand response through the mechanism
- combines the new participant category, DRSP, with an existing participant category, MASP.

Benefits of the second draft rule

The registration process under the second draft rule would allow entities (which may include, but importantly are not limited to, retailers) to register as DRSPs for the purposes of providing wholesale demand response. By combining the DRSP and MASP categories, it also reduces the overlap between related registration categories.

The second draft rule introduces a wholesale demand response unit classification step following registration. This would allow AEMO to assess the technical suitability of each load seeking to provide wholesale demand response.

Changes from first draft rule

The changes from the first draft rule to second draft rule are:

- removal of the 5MW minimum aggregation requirement: DRSPs no longer need to aggregate at least 5MW of wholesale demand response capacity. Under the first draft rule, DRSPs would have been able to bid in less than 5MW of demand response in any case. As such, the Commission considers that the 5MW threshold would in practice have

169 Australian Energy Council, submission to first draft determination, p. 2.

been an unnecessary procedural hurdle for AEMO and DRSPs, and determined that it would be appropriate to remove the 5MW threshold while still maintaining the scheduling obligations

- moving the decision to aggregate wholesale demand response units for participation in central dispatch to Chapter 3 of the NER: the Commission understands that this approach is more consistent with existing mechanisms for aggregation and would therefore reduce system changes and so implementation costs for AEMO
- removal of the concept of a *scheduled wholesale demand response unit*: in the final rule, the concept of scheduled wholesale demand response (as distinct from a wholesale demand response unit) is no longer needed in light of the two changes noted above. As such, the term has been removed to simplify the final rule
- introducing the concept of the *maximum responsive component* of the wholesale demand response unit, being that portion of the load which is controllable and can therefore be price responsive. The maximum responsive component may include generation as well, if the site has the capacity to export electricity. The DRSP will specify this component, in MW, on classification, and AEMO must be reasonably satisfied that the wholesale demand response unit is capable of providing a quantity of wholesale demand response at least equal to the maximum responsive component, in order to approve the classification
- allowing AEMO to determine, in consultation with market participants, a methodology for determining a threshold for the total quantity of wholesale demand response in each region above which AEMO will impose more onerous telemetry and communications equipment requirements (i.e. a requirement to use SCADA or an approved equivalent) on loads seeking to be classified as wholesale demand response units.

C.4.1 Interaction with other registration categories

Under the second draft rule, the DRSP participant category is combined with the MASP participant category into a single category.[170] Following registration, a DRSP would be able to classify loads as:[171]

- wholesale demand response units for the purposes of providing wholesale demand response, and/or
- ancillary service loads for the purposes of providing market ancillary services.

The second draft rule combines the two into a single participant category in recognition of the extent of overlap between the entities likely to wish to provide both types of services. By combining the registration categories, it removes unnecessary duplication of process. However, as there are different requirements placed on loads participating in the wholesale demand response mechanism and those providing market ancillary services, there would be

170 The transitional arrangements under the final rule transfer the registration of existing MASPs to this new participant category. These existing MASPs would not need to re-register. See clause 11.118.9 of the final rule.

171 Clause 2.3AA of the final rule.

different classification processes for the loads used to provide each service. That is, a DRSP will need to separately satisfy AEMO that a load is capable of meeting the requirements for participating in the wholesale market through the demand response mechanism *and* providing market ancillary services (where the same load is intended to be used to provide both services; alternatively, a load could be classified for one of these services only).

The second draft rule does not directly accommodate the co-optimisation in the dispatch engine for a DRSP providing FCAS and wholesale demand response. While a DRSP may be offering both services with the same loads, it is possible that different loads will be participating in FCAS and wholesale demand response at the same time. As such, it would not be appropriate to co-optimise the services provided from two resources. Instead, a DRSP would need to manage offering FCAS and wholesale demand response with the same load in the same dispatch interval and bid accordingly. For this reason, if a load is being used to offer both wholesale demand response and FCAS, the MASP and the DRSP must be one and the same as this entity must be able to control and co-optimise the bids for both services.

The distinction between these services is reflected in the ongoing obligations set out in the second draft rule, e.g. some obligations apply to DRSPs where they are providing market ancillary services; and other obligations apply to DRSPs where they are participating in the wholesale market. The Commission has not made substantive changes to the obligations applying to MASPs. Instead, the same obligations are preserved, but apply to DRSPs acting in their capacity of providing market ancillary services.

While stakeholders have suggested there is an intersection between the DRSP category and the small generation aggregator participant category, the Commission considers that these frameworks are sufficiently distinct that there would be little benefit arising from their consolidation.[172] The primary distinction is that being a small generation aggregator at a connection point means being the FRMP at that connection point, whereas a DRSP does not need to be the FRMP. The Commission expects that there will be participants that register as both a DRSP and a small generation aggregator.

While the DRSP will interact with customers at different NMIs, it will not be the FRMP. Each NMI that has a DRSP associated with it will still need to have a FRMP, typically a retailer. The DRSP and the FRMP will not have a direct relationship; however, the FRMP would be notified when a NMI for which it is responsible has a DRSP allocated to it. This would allow the FRMP to make any necessary changes to systems or hedging arrangements to accommodate a customer with a DRSP.

C.4.2 Registration process

Registration is the process by which an organisation is admitted by AEMO into the NEM to allow it to participate in the market. DRSPs are required to be registered in order to provide wholesale demand response in the wholesale market,under the second draft rule.

This would allow the DRSP to undertake its two primary functions:

172 This is consistent with the recommendations made in the Commission's *Frequency control frameworks review* final report, where it was noted that these frameworks suit typically different aggregations.

- indicate loads that are able to provide demand response or ancillary services to the market
- provide wholesale demand response and ancillary services from those loads and to be paid accordingly.

To be eligible for registration as a DRSP, the draft rule requires that the person seeking registration obtains the approval of AEMO to classify a load as an ancillary service load or as a wholesale demand response unit.[173]

The classification process is discussed below. Upon classification, end-users' NMIs would be tagged as being involved in the provision of the relevant service(s).

While it is not expected that a DRSP would be regularly indebted to the market, under the second draft rule AEMO would be able to set prudential requirements for DRSPs where it considers this necessary. For example, the possibility of the DRSP's load consuming above the baseline may necessitate the DRSP meeting prudential requirements. This is consistent with AEMO's current role in determining the credit requirements and prudential settings for market participants.[174]

C.4.3 Classification of qualifying loads as wholesale demand response units

The second draft rule allows DRSPs to apply to AEMO to classify qualifying loads as wholesale demand response units. The classification process is intended to make sure that the loads participating in the mechanism are appropriate in terms of customer type and technical capability. This process has been refined in the second draft rule based on detailed consultation with AEMO, with the aim being to have a classification process that is straightforward for AEMO to implement and for DRSPs to engage in.

To be considered a qualifying load:[175]

- **It must exist at a single connection point**: each wholesale demand response unit must have its own connection point. This is important for determining baselines and settling the wholesale demand response provided. However, in relation to embedded networks, a parent connection point can be a wholesale demand response load in respect of all of its associated child connection points that are not on-market. A child connection point can be a qualifying load only if it is on-market.
- **It cannot be a small customer or a scheduled load**: under the second draft rule, only large customers are able to participate in the mechanism. Loads that are already scheduled are already participating in the central dispatch process and can respond to wholesale prices. The reasoning for not including small customers is set out in chapters **2 and 4** of this determination.
- **The DRSP needs to have the consent of the relevant customer and arrangements in place to provide wholesale demand response.**

173 Clause 2.3AA.1(b) of the second draft rule.

174 See clause 2.4.2(a) of the NER, to which DRSPs would be subject as Market Participants.

175 Clause 2.3.6(m) of the second draft rule.

- **The appropriate metering is installed:** each load must have a type 1, 2, 3 or 4 meter for the purpose of the recording time varying load data. This data is needed for the purposes of settlement and baseline determination.

When a DRSP makes an application to AEMO to classify a qualifying load as a wholesale demand response unit, it must:[176]

- identify the qualifying load
- specify the proposed maximum responsive component of that load
- specify the baseline methodology and baseline settings that it proposes will apply.

The second draft rule places an obligation on AEMO to develop a guideline that provides details on the above technical requirements, as well as any others AEMO considered relevant for classifying load as wholesale demand response units, having regard to the need not to distort the operation of the market and the need to maximise the effectiveness of wholesale demand response at the least cost to end use consumers of electricity.[177] The Commission considers that this will allow AEMO to apply requirements that would prevent load shifting within a site, for example.

Under the second draft rule, AEMO must approve the classification of a load as a wholesale demand response unit if it is reasonably satisfied that:[178]

- the load is a qualifying load
- the load can provide wholesale demand response in accordance with the NER
- the load is capable of providing a quantity of wholesale demand response at least equal to the maximum responsive component
- the DRSP has adequate communications and telemetry in place to support the issuing of dispatch instructions
- when a baseline methodology is applied to the load (using the relevant baseline settings and historical metering data), it:
  - produces a baseline that satisfies the baseline methodology metrics, and
  - can apply to that load having regard to any other criteria outlined in the wholesale demand response guidelines produced by AEMO
- the load satisfies each other requirement in the wholesale demand response guidelines for classification as a wholesale demand response unit.

A DRSP must also immediately notify AEMO if a load classified as a wholesale demand response unit ceases to be a qualifying load.[179]

Single DRSP per NMI

In order to preserve the integrity of the baseline methodology, there would only be one DRSP allocated to a NMI at any one time. This means that, without a customer's consent to cease

176 Clause 2.3.6(b) of the second draft rule.
177 Clause 3.10.1 of the second draft rule.
178 Clause 2.3.6(e) of the second draft rule.
179 Clause 2.3.6(k) of the second draft rule.

its arrangement with one DRSP and commence a new arrangement with another DRSP, a DRSP would not be able to classify a load as a demand response load where that load already has an allocated DRSP.[180] The customer consent and transfer process would occur through contracts between DRSPs and customers.

C.4.4 Telemetry requirements

AEMO has advised that a lack of visibility of loads participating in the mechanism could create potentially significant risk and uncertainty for AEMO's operation of the power system, particularly if there are large amounts of load responding to wholesale prices through the mechanism. To address this, AEMO has proposed that any load with a maximum responsive component of 5 MW or above would be required to provide SCADA (or an approved equivalent) for the maximum responsive component. This will make sure that changes in these larger loads are visible to AEMO in real time, thereby allowing fluctuations in these loads in response to wholesale prices to be managed more effectively. The second draft rule does not directly address this proposed requirement, as this would be dealt with through the telemetry requirements to be developed by AEMO. The Commission understands that loads with maximum responsive components of less than 5 MW would not be automatically required to provide SCADA (subject to the threshold discussed below).

Given the potential risks associated with having large amounts of non-visible load participating in the mechanism, AEMO has also advised that it requires the ability to set a limit on the amount of demand responsive load without SCADA that can participate in each region if necessary to address system security risks. The Commission considers that it is appropriate for these risks to be addressed in the second draft rule, to the extent practicable to do so. The second draft rule therefore allows AEMO to set an upper limit on the amount of non-visible demand response (i.e. demand responsive loads not using SCADA) that can participate in the mechanism in each region.[181] Once this threshold has been reached, AEMO could impose more onerous telemetry requirements on any loads seeking to be classified as wholesale demand response units in that region, including a requirement that they use SCADA (or an approved equivalent). AEMO would be required to consult with market participants when determining the methodology used to determine this threshold.[182] The Commission expects that this methodology would clearly and robustly specify the process AEMO would use to determine the threshold. In addition, the second draft rule sets out a number of principles AEMO must have regard to when setting the threshold.[183] AEMO must also publish and update information each month on the progress towards reaching the threshold in each region so that this information is transparent to participants.[184] There would be no limit on the amount of demand responsive load using SCADA which could participate in each region.

180 This is provided for through clause 2.3.6(m)(1)(v) of the second draft rule.
181 Clause 3.10.1(c) of the second draft rule.
182 Clause 3.10.1(e) of the second draft rule.
183 Clause 3.10.1(b) of the second draft rule.
184 Clause 3.10.1(d) of the second draft rule.

C.4.5 Aggregation of wholesale demand response units

A DRSP is able to apply to AEMO to aggregate units for the purpose of participating in central dispatch in a similar manner to aggregation applications for generating units or ancillary services loads (noting that, even if aggregated for dispatch, settlement will occur on an individual unit basis).[185]

The Commission considers the benefits of DRSPs being allowed to offer wholesale demand response in the wholesale market are related to the level of transparency and certainty provided by the wholesale demand response units acting in a scheduled manner.

In the first draft rule, the Commission required aggregation for the purposes of central dispatch, applying at a portfolio level of 5 MW. This was consistent with AEMO's position that batteries of 5 MW have the potential to impact power system security, and therefore a battery must be registered in the NEM and treated as a scheduled participant.

The second draft rule removes this aggregation requirement. The Commission understands that by removing this restriction (but continuing to allow aggregation where the DRSP considers it would be useful):

- the process of approving the classification of a wholesale demand response unit will be easier for AEMO and DRSPs and therefore less costly
- the framework established under the second draft rule would be more consistent with the current mechanisms for aggregation.

By removing this 5MW threshold, the Commission considers the second draft rule is more likely to have lower implementation costs. The second draft rule retains the benefits of wholesale demand response units being scheduled through central dispatch.

Aggregation of wholesale demand response units would allow for multiple units to be bid into central dispatch together. These units would be treated individually for the purposes of settlement.

The Commission understands that AEMO's telemetry requirements would allow multiple loads to be aggregated in a wholesale demand unit with a total responsive component of more than 5 MW without requiring SCADA. However, AEMO has advised that due to technical system limitations, a single wholesale demand response unit could not accommodate some loads using SCADA and some not using SCADA. This would mean that if a DRSP seeks to aggregate a load that is greater than 5 MW (and would therefore require SCADA) with other loads, those other loads would also be required to use SCADA regardless of their demand responsive capacity. Alternatively, the DRSP could choose not to aggregate a load that has SCADA with loads that do not have SCADA (and would otherwise not need it).

185 Clause 3.8.3 of the second draft rule.

D INTEGRATION WITH CENTRAL DISPATCH

D.1 Overview

This appendix sets out how wholesale demand response facilitated through the mechanism will participate in central dispatch and pre-dispatch. Participation in these processes means that these parties can be scheduled, providing AEMO with greater certainty that the wholesale demand response will be available.

Under the second draft rule, DRSPs will participate in central dispatch in a transparent, scheduled manner. DRSPs are treated in a similar manner to other scheduled participants, i.e. DRSP will submit dispatch instructions and when cleared by NEMDE, receive dispatch targets to provide wholesale demand response. DRSPs will also be able to set the wholesale market price.

The principle that DRSPs should be treated in a similar manner to scheduled participants has guided the Commission's approach to how DRSPs should participate in central dispatch. However, it is worth noting that in some instances, the obligations have been modified to better suit the nature of DRSPs and wholesale demand response.

There is also an opportunity through this rule change process to explore a greater role for the demand side in central dispatch. As the market moves toward a two-sided market, the demand side will have an increasing prominent role in central dispatch. However, in doing so, consideration should be given to the differences between large, centralised generators that make up typical scheduled participants, and less controllable and more decentralised demand side participants. Through the scheduling approach for DRSPs in this draft rule, there will be opportunities to explore the implications of involving more of the market in central dispatch.

Under the second draft rule, DRSPs will be dispatched based on the physical capability of the wholesale demand response units to provide wholesale demand response. Settlement for wholesale demand response will be based on a subsequent assessment of how much wholesale demand response was provided, with reference to the baseline.

This appendix sets out:

- background information on the wholesale market, the dispatch process and the pre-dispatch process
- the proponents' views
- the relevant stakeholder comments
- the Commission's analysis and conclusions.

D.2 Background

D.2.1 The wholesale market

The NEM's spot market is a gross pool design with mandatory participation. Generators sell, and market customers buy, all of their electricity through the spot market, which matches supply and demand (near) instantaneously, including an allowance for a sufficient quantity of reserves.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Once these offers and bids are received, AEMO then forecasts the expected consumer demand for electricity in each region for each 5-minute dispatch interval. The dispatch engine seeks to optimise outcomes by attempting to maximise the value of trade given the physical limitations of the power system. These physical limits are known as "constraints" which, for example, restrict how much electricity can flow over a particular piece of equipment i.e. keeping it within its technical limits.

Scheduled participants currently provide information that feeds into a number of processes ahead of real time. This information assists AEMO to operate the power system in a safe, secure and reliable manner and helps market participants form expectations about future price outcomes to guide operational decisions.

In addition, scheduling participants provide the market operator with greater certainty that this capacity will be available. Scheduled participants need to have the capacity to receive and respond to dispatch instructions. This provides the market operator with certainty that this capacity will be delivered to the market. This certainty is in turn crucial for accounting for this capacity in the reliability framework.

D.2.2 Dispatch and pre-dispatch

Dispatch

The dispatch process is fundamental to the operation of the NEM. It is the process by which supply and demand are matched and the market is cleared. The dispatch process operates through NEMDE. The NEMDE runs a security constrained optimisation to find the least-cost way to match the supply and demand sides of the NEM within its technical limits.

The dispatch process is key for scheduled participants to recover revenue and run equipment under economic conditions. Scheduled participants (both loads and generators) submit price-quantity pairs into AEMO. This allows participants to nominate the wholesale price at which they would like to generate or consume.

Scheduled participants in dispatch actively participate in the price setting process. The offer price associated with the marginal unit of supply will become the price on which the market is cleared.

Pre-dispatch

Pre-dispatch is a key information provision process for market participants. It informs market participants of expected market conditions. It also helps the market operator in assessing expected market conditions and managing security and reliability.

Pre-dispatch takes participant bids and offers, and AEMO's demand forecasts. AEMO will then provide the market with a forecast of load and expected prices which will in term assist participants in making operational decisions. This cycle iterates in the approach to real time and participants continue to adjust their position on the basis of this more up-to-date information.

D.2.3 Scheduled loads under the current arrangements

The current arrangements allow for the demand side to participate as scheduled load in the wholesale market. AEMO's dispatch processes are already set up to accommodate this functionality.

A market customer can request that AEMO classify any of its market loads as a scheduled load.[186]

The choice of being scheduled or non-scheduled lies with the market customer. It is only if a customer decides, in respect of its load, to become a scheduled load that the customer will participate in AEMO's central dispatch process.

To date, with the exception of a few pumped storage facilities and large-scale batteries,[187] no market customers have elected to classify load as scheduled load.

Under the current arrangements, there is little incentive for a load to become scheduled. Typically, being scheduled has an associated cost and, from the perspective of an individual load, negligible benefit. From the perspective of the broader market, having more loads scheduled provide benefits. However, under the current arrangements, due to the lack of scheduling incentives or obligations to be scheduled, the demand side participates passively in the wholesale market.

D.3 Proponent's views

This section sets out the proponents' views regarding dispatch as set out in the respective rule change requests.

D.3.1 PIAC, TEC and TAI

In their rule change request, PIAC, TEC and TAI proposed that demand response offers would be scheduled, in order to create consistency with how generators are treated in the wholesale market. The proponents noted that wholesale demand response under the mechanism would only be allowed on a scheduled basis.[188]

The proponents noted:[189]

- that there will need to be some consideration of the exact form of scheduling that is most appropriate for offers of flexibility from aggregated demand-side resources, as their characteristics are quite different from those of conventional generators.
- scheduling obligations for small volumes of wholesale demand response may be limited to advanced notification of the start of a DR event rather than price-based central dispatch.

186 Clause 2.3.4(d) of the NER.

187 Large-scale storage facilities must register both as scheduled generators and scheduled loads under AEMO's interim guidance for storage facilities.

188 PIAC, TEC and TAI, *Wholesale demand response mechanism - rule change request*, pp. 9, 14.

189 Ibid, p. 15.

D.3.2 AEC

In the AEC's proposal, it set out two suggested treatments for curtailed loads' interaction with the spot market, each with purported advantages and disadvantages:[190]

1. loads registered with a DRA must be classified as scheduled loads, which obliges them to continuously provide short and long-term availability information to AEMO, and to bid and rebid their behaviours to the same level of transparency as scheduled generators.
2. loads registered with a DRA could be dormant until such time as the DRAs intended the loads to be active in the market, or a Lack of Reserve Notice is issued by AEMO. Should either of these conditions occur, then DRAs would be required to participate in the spot market as a scheduled load for the relevant period, thereby only suffering the compliance burden for the critical period.

The AEC suggested that the compliance burden of Option 2 would not be markedly less than Option 1, since a DRA would be obliged to have the systems and processes in place to participate in the market regardless. The Energy Council also expected the requirements for scheduled loads to be naturally improved and expanded as a result of the proposed rule, and this would be an additional benefit of the rule.

D.3.3 South Australian Government

In its proposal, the South Australian Government noted:[191]

- it considered that DRSPs would be dispatched in the same manner as a scheduled generator. If its offer to reduce demand is cleared through the wholesale market, it would be dispatched to reduce consumption by the amount it is cleared for.
- The consequences of not meeting dispatch would be consistent with the dispatch targets for scheduled generators. Compliance with dispatch would be assessed by the AER and the DRSP may be required to pay costs such as FCAS causer pays.
- Depending on the nature of the load, it would have ramp rate constraints.

D.4 Stakeholder comments

A number of stakeholders commented on the role for demand response in central dispatch in submissions to the first draft determination.

General comments

- **Delta Electricity** did not support the proposal to allow DRSPs to provide bids only for periods of their choosing. For pre-dispatch and PASA purposes, Delta felt it would be beneficial to the market and AEMO to understand the availability of demand response at all times. In addition, Delta Electricity supported the view that the final rule should require DRSPs to comply with all the provisions of the good-faith rebidding requirements.[192]

190 AEC, *Wholesale demand response register mechanism - rule change request*, p. 3.

191 South Australian Government, *Mechanisms for wholesale demand response - rule change request*, p. 3.

192 Delta Electricity, submission to first draft determination, p. 2.

- **Delta Electricity** commissioned a Marsden Jacob report that considered the draft rule does not recognise that the close equivalence of capacity for reliability is based on its certainty of being there, not whether it is centralised. This leads to the issue of the assumed economic advantages of central scheduling over non-centralised operation. The position of the draft rule in relation to the value of centralised scheduling could be interpreted as a mistrust of the ability of the market to respond, which does not recognise that the trend is towards decentralised markets.[193]
- **Electricity Exchange** submitted that the provision of active, centrally dispatched demand response should be more beneficial to the participating consumer than the provision of passive, price-responsive demand response as it supports the deterministic operation of the power system.[194]
- **ENGIE** suggested that the scheduling obligations may lead to high compliance requirements, which could be a barrier to entry, may be costly, and will again reduce benefits to the customer.[195]
- **Infigen** supported including DRSPs in central dispatch and treating DRSPs similarly to generators. It also noted that allowing DRSPs to also bid in a controlled increase in net load could deliver significant value and improve system operation.[196]
- **PIAC** noted:[197]
    - DRSPs should be only dispatched in the intervals they are providing DR, and will need to meet dispatch targets
    - Over delivery of DR relative to dispatch target should be allowed and settled, but causer-pays charges should reflect any resultant impact on system.
    - Flexibility is needed to avoid unnecessarily penalising DRSPs or customers, and a dispatch target should be able to be zero in last interval
- **Reposit** considered that extending the structure to incentivise an increase in demand during low or negative price periods will increase the overall effectiveness of demand response in the system.[198]
- **Stanwell** is unsure why these new dispatch categories are necessary. For consistency with other scheduled participants, it may be easier for DRSPs to be "available" and "not available".[199]
- **Enel X** supported the requirement for DRSPs to be scheduled.[200]

Scheduling obligations

- **Enel X** noted that it will be challenging for most loads to accurately follow a linear dispatch trajectory or provide their full dispatch capability immediately following the

193 Marsden Jacob, report submitted by Delta Electricity to first draft determination, p. 20.
194 Electricity Exchange, submission to first draft determination, p. 4.
195 ENGIE, submission to first draft determination, p. 3.
196 Infigen, submission to first draft determination, pp. 2, 4.
197 PIAC, submission to first draft determination, p. 14.
198 Reposit, submission to first draft determination, p. 1.
199 Stanwell, submission to first draft determination, p. 5.
200 Enel X, submission to first draft determination, p. 4.

receipt of a dispatch instruction. For this reason, it may not be appropriate for a DRSP's compliance with dispatch instructions to be assessed based on an expectation that the portfolio will ramp down in a linear fashion. A framework that recognises and accommodates the various capabilities and characteristics of all sources of supply will support participation and competition in the mechanism, and thus maximise the potential benefits to consumers.[201]

- The **Major Energy Users** counselled the Commission not to apply too many requirements and conditions on DRSPs. It commented that its members report that the conditions and requirements applied by AEMO for the provision of RERT services are considered so onerous that some end users have elected not to provide RERT services even though they are quite capable of doing so at relatively low cost.[202]
- **Mondo** suggested that the final rule should not be solely guided by the treatment of demand response units as generators. It suggested that the draft rule could be enhanced by relaxing scheduling requirements or alternatively by paying demand response units more to reflect the added system benefits.[203]
- **Stanwell** submitted that it had observed price spikes as a result of unscheduled demand response loads returning to normal consumption levels. For this reason, Stanwell suggested that rather than just providing an expected consumption profile with no obligation to follow the profile, the scheduled demand response units should participate in dispatch until they receive a target from AEMO to return to its prior level of consumption. The same as other scheduled participants, if the DRSP wishes to no longer be cleared for dispatch they have the option to rebid to achieve this outcome. Alternatively, the scheduled demand response unit should be obligated to follow its provided 30 minute consumption profile with a causer pays penalty applicable for not following the profile.[204]

Directions

In the draft rule, DRSPs would not have been subject to directions in respect of wholesale demand response units. Stakeholders provided the following feedback:

- **AGL** suggested the Commission consider whether DRSPs could be subject to directions during dispatch intervals where they had previously indicated that it would participate in the market (i.e. it was available during pre-dispatch).[205]
- **AEMO** considered it may be appropriate to direct a DRSP in some circumstances. This could be to direct a scheduled WDRU to come on or off. Because, conceptually, scheduled WDR can substitute for generation, AEMO considers that provisions for direction should apply equally to DRSPs. AEMO suggested that where the direction requires the provision

201 Enel X, submission to first draft determination, pp. 5-6.

202 Major Energy Users, submission to first draft determination, p. 2.

203 Mondo, submission to first draft determination, p. 3.

204 Stanwell, submission to first draft determination, p. 6.

205 AGL, submission to first draft determination, p. 5.

of energy or a service, directed participant compensation arrangements should also apply.[206]

- **Enel X** supported the decision to not subject DRSPs to directions under clause 4.8.9 of the NER.[207]

FCAS causer pays and cost recovery

- The **Clean Energy Council** supported DRSPs facing causer pays and compliance with dispatch targets. It suggested the Commission consider how loads that do not have consistent ramp rates or cannot respond to dispatch signals, such as aggregated distributed energy resources, comply with AEMO's dispatch ramp rates to avoid these loads attracting unavoidable causer pays penalties.[208]
- **AEMO** noted that while it agreed with the principle of aligning the arrangements for generation and wholesale demand response to the greatest practicable extent, AEMO considered it implausible that a DRSP could trigger a need for contingency raise services. Consequently, AEMO did not think the allocation of these costs to DRSPs was not aligned with the principle of causer pays. AEMO recommended that DRSPs are excluded from the recovery of contingency raise FCAS costs.[209]
- **AEMO** noted that adding causer pays to the settlement arrangements will add cost and complexity to AEMO's settlements system implementation. It recommended that the Commission review the inclusion of DRSPs in these arrangements, because the likely benefit of inclusion will outweigh the cost and complexity of inclusion.[210]

Telemetry

- **Enel X** does not consider it necessary or appropriate to require DRSPs to provide four second data in real time, via SCADA or any other means. Thus, if DRSPs are to be liable for regulating FCAS costs, an alternative means to calculate contribution factors may be required.[211]
- **AEMO** highlighted a number of options for how telemetry would work with DRSPs. It noted that Real-time data is required for processes including operational forecasting, contingency analysis, constraints, and conformance monitoring. AEMO recommended the final rule should not be prescriptive with regard to telemetry so that AEMO has flexibility in managing these unknowns via procedural or other means.[212]

Information provision to other participants

A number of stakeholder raised points regarding the information provided to participants in real time apart from the DRSP and AEMO:

206 AEMO, submission to first draft determination, p. 16.
207 Enel X, submission to first draft determination, p. 4.
208 Clean Energy Council, submission to first draft determination, p. 2.
209 AEMO, submission to first draft determination, p. 19.
210 Ibid.
211 Enel X, submission to first draft determination, p. 6.
212 AEMO, submission to first draft determination, p. 17.

- **Ausgrid** asked for DNSPs to be provided with a greater level of transparency regarding the operation of DRSP demand response. It noted that providing distributors with this information would not require disclosure of any confidential information regarding the commercial arrangements between DRSPs, customers or retailers. It suggested that the following data to be made available to the relevant distributor:[213]
  - Demand response load scheduled to be dispatched within the relevant network by NMI
  - Period of scheduled demand response by NMI.
- Ausgrid also noted that without access to locational demand response information, there is a risk that the loads prepared for shedding will change suddenly as a result of demand response within the prepared loads, resulting in less load being ready for shedding when called for by AEMO.[214]
- **ENA** noted that a majority of issues can be resolved simply by notifying the relevant DNSP of each NMI scheduled to be dispatched through the mechanism along with event durations. p. 2.[215]
- **Energy Queensland** recommended that further consideration is given to whether DNSPs and other impacted participants should be provided with advance notice when a large-user is intending to enter into an agreement with a DSRP and when they will be participating in the wholesale demand response mechanism.[216]
- **Momentum Energy** believed that retailers will require the following additional information, should the mechanism be introduced, in order to suitably manage their wholesale and retail portfolio load risk and to provide adequate market transparency:[217]
  - notification of existing and new customers that have appointed a DRSP and historical load information covering the DR load and actual load
  - advice on the methodology used to determine each customer’s baseline consumption
  - real time advice on when each customer's demand response is dispatched
  - advice on whether the customer’s demand response result in any increase in load at other times.
- **Snowy Hydro** submitted that retailers will not know when their commercial and industrial customers will be dispatched in real time in the mechanism. Retailers must have this critical information in order for them to make any adjustments to their hedging strategies to cater for any demand response that is dispatched in their retail portfolio.[218]
- **Stanwell** suggested that, in future, to accurately price and assess a new customer, retailers will also require access to the demand response history of the customer. It is not

213 Ausgrid, submission to first draft determination, p. 4.
214 Ibid.
215 ENA, submission to first draft determination, p. 2.
216 Energy Queensland, submission to first draft determination, p. 8.
217 Momentum Energy, submission to first draft determination, p. 4.
218 Snowy Hydro, submission to first draft determination, p. 4.

clear how demand response from an aggregated resource will be able to be allocated to individual loads for future pricing processes.[219]

- **Stanwell** also suggested the retailer would require information relating to:[220]
  - Demand response bids for customer (so as to allow the retailer to determine whether or not the customer is likely to provide demand response)
  - The relevant baseline of the customer (so that the retailer can determine whether or not the customer is likely to provide demand response)
  - Live consumption (the retailer will use this in conjunction with the information above to determine whether or not the customer is likely to provide demand response)
  - The dispatch targets of the customer
  - STPASA and MTPASA submission for the customer.
- **Enel X** noted comment made at the public workshops on the draft determination that indicated that some retailers want access to information about a customer's availability, when it is dispatched, and how much it is settled for. Enel X did not agree that such information should be made publicly available on an individual NMI / wholesale demand response unit basis. Retailers presumably have access to the meter data of their customers who are offering demand response via a DRSP. Allowing retailers (and the public) to have visibility of such information for customers that aren't theirs raises privacy and competition concerns, and would limit participation in the mechanism.[221]
- **PIAC** noted that energy retailers have indicated a preference for having access to various data and information. PIAC supported actions to ensure transparency that promote better market operation and outcomes, but considered that information should be provided on the basis that providing this information results in market benefits that are greater than the cost to the market, and/or ameliorates or addresses a negative impact on a given retailer in question that:[222]
  - has arisen, or would arise, as a direct result of their customer's demand response activity
  - could not be more efficaciously addressed through other means.
- **CS Energy** submitted that it would prefer to have access to the baseline ex-ante and noted that determining this would be costly. It also raised a concern that the baseline calculated by the retailer may not match the settled baseline, a price retailers were likely to pass through to consumers.[223]
- **ERM Power** suggested the final rule could impose an obligation for a customer who enters into a demand response arrangement with a DRSP to notify the retailer that a demand response arrangement has been entered into, the dates of the agreement and details of the equipment to be subject to demand response. The retailer should then have

219 Stanwell, submission to first draft determination, p. 7.
220 Ibid.
221 Enel X, submission to first draft determination, p. 8.
222 PIAC, submission to first draft determination, p. 14.
223 CS Energy, submission to first draft determination, p. 6.

the option to operate a child meter on the power supply facilities to the equipment subject to demand response. This would be at the retailer's expense. This would allow the retailer to monitor their customer's load and manage their own expectations of when demand response may be dispatched.[224]

AEMO submission

AEMO's submission provided substantive feedback on the draft rule in relation to the integration of DRSPs into central dispatch (where not covered under the above sub-headings). AEMO made the following points:[225]

- It is important that load restoration following a demand response event should occur in an orderly manner and should be required in accordance with dispatch instructions in a similar way as if it was being dispatched. This is necessary to ensure the appropriate controls are in place to manage the timing and ramp rate of the restoration.
- further considerations of load inflexibility profiles (such as minimum notification times, and capability to execute smaller MW step changes) may be required. Loads cannot necessarily be treated the same as generation, AEMO will need to consider how to use inflexibility profiles or other methods to ensure linear ramp rates are adhered to. AEMO proposes that this is address in procedures and further consultation outside of the final rule.
- the final rule should allow, at a minimum, for the following through procedures or other means outside of the NER to accommodate present unknowns:
  - AEMO to have discretion to define and approve communication protocols based on industry standards and hardware offerings that will accommodate most participants in the long run.
  - AEMO to have reasonable discretion to determine the granularity of required real-time data (for example, dispersed grid node loads vs aggregated nodes) on a case-by-case basis.
- it recommended that the final rule should allow flexibility for the co-optimisation of energy and FCAS from a DRSP to evolve in the future, potentially by allowing for the treatment of energy and FCAS dispatch of DRSPs to be described in procedures.

Clarifications

A number of stakeholder sought clarification on the operation of the draft rule in relation to participation in central dispatch.

- **AGL** sought clarification on whether there is any other incentive for the DRSP to follow the dispatch instructions (or penalty for not following a 0 MW instruction), or whether the DRSP is free to participate in other forms of demand response during those dispatch intervals.[226]

224 ERM Power, submission to first draft determination, p. 5.

225 AEMO, submission to first draft determination, pp. 15 - 20.

226 AGL, submission to first draft determination, p. 4.

- **EnergyAustralia** submitted that it is unclear in the draft rule whether a DRSP will be penalised if it has bid into the market and received a dispatch target of 0 MW, but it continues to provide a reduction in load. EnergyAustralia noted that this could affect AEMO's assessment of the supply demand balance if it assumes that a DRSP with a target of 0MW will resume consumption at the previous level. DRSP's should be bound by the same requirements to follow their dispatch targets as any other scheduled or semi scheduled unit and DRSPs should also be included in AEMO's nonconformance process.[227]
- **Infigen** asked for further clarification on how DRSPs will bid the response from multiple customers in a region: would each customer be in a separate bid with AEMO, or would they be aggregated. If aggregated, appropriate systems will be required to communicate to AEMO which specific resource will be/was activated. We expect that baselining should be applied only to that specific resource(s).[228]
- **Stanwell** submitted that the Commission has not indicated how Fast Start Inflexibility Profiles could work with demand response loads. Loads may have a fixed pattern of demand response or demand restoration that would be efficient for AEMO to incorporate into dispatch.[229]
- **Tesla** sought clarification on:[230]
  - Optimising assets for frequency market participation will distort a customer's rolling load profile and baseline. Where assets are also being used to provide FCAS, it will be important that customers are not inadvertently penalised. Alternatively, if a DRSP elects to only register their aggregated assets as ancillary services load, do baselines apply?
  - Are aggregated portfolios less than 5MW treated as unscheduled? The AEMC also notes that causer-pays factors should be applied to DRSP who deviate from their dispatch target. Again, Tesla supports this in principle, and thinks it is a critical step in treating demand response as equivalent to generation. However, this approach will also need to take into account the comments on dispatch targets noted above.
- **Enel X** sought clarification on:[231]
  - whether the obligation on DRSPs to provide AEMO with an assessment of their technical capacity to provide wholesale demand response (i.e. regardless of expected wholesale prices), or whether DRSPs would have the ability to specify through this process that they do not intend to make capacity available.
  - what is meant by "participating in dispatch" and how and when this is determined
  - the rules that apply if a DRSP submits an offer to provide wholesale demand response, but is not cleared by NEMDE.

227 EnergyAustralia, submission to first draft determination, p. 12.
228 Infigen, submission to first draft determination, p.
229 Stanwell, submission to first draft determination, p. 6.
230 Tesla, submission to first draft determination, pp. 3-4.
231 Enel X, submission on first draft determination, pp. 4 - 6.

D.5 Commission's analysis and conclusions

BOX 7: INTEGRATION WITH CENTRAL DISPATCH UNDER THE SECOND DRAFT RULE

The second draft rule sets out:

- a process for wholesale demand response units to participate in central dispatch.
- a process for wholesale demand response units to be aggregated for the purpose of central dispatch
- the obligations that apply to DRSPs as scheduled participants, including obligations to comply with dispatch instructions
- a process through which the DRSP would be scheduled only in periods where it is available for dispatch
- how DRSPs would participate in the pre-dispatch process
- other changes to the NER necessary to accommodate the integration of DRSPs into pre-dispatch and dispatch.

Under the second draft rule, DRSPs will be dispatched based on the physical capability of the wholesale demand response units to provide wholesale demand response. Settlement for wholesale demand response (as set out in appendix G) will be based on a subsequent assessment of how much wholesale demand response was provided, with reference to the baseline.

Benefits of the second draft rule

The second draft rule will facilitate the transparent participation of DRSPs in the wholesale market. In the short term, this will allow DRSPs to be dispatched instead of more expensive peaking generation and lower the wholesale electricity price. By participating transparently, DRSPs will also contribute to the ability of other market participants to make informed operational decisions. It will also assist AEMO in its operation of the market and, importantly, enable demand response to be relied upon by the system operator so it can contribute to power system reliability.

It will also be an opportunity to explore how participation in central dispatch can be extended to a larger number of participants. This may be useful in a longer-term transition to a two-sided market which can be informed by lessons learned in the scheduling and dispatch of demand response through this mechanism.

Changes from first draft rule

There are changes between the first draft rule and second draft rule that reduce the costs associated with the implementation of the mechanism, reduce the complexity associated with integration and provide AEMO with greater flexibility with regards to how DRSPs are treated by AEMO in dispatch. These changes include:

- A DRSP would submit dispatch bids in a similar manner to scheduled loads, but only for the available capacity of the wholesale demand response unit (i.e. dispatch bids to consume varying levels of electricity at different price thresholds).
- A DRSP's dispatch bid will be included in dispatch in every dispatch interval. When the DRSP is receiving an instruction to remain at its available capacity, this will not be treated as a dispatch instruction. If the DRSP is cleared to provide wholesale demand response, a dispatch instruction will be given.
- Removal of the minimum 5MW aggregate size for wholesale demand response units to participate in dispatch (while retaining the minimum dispatch bid size of 1MW)
- Removal of the requirement for regulation FCAS costs to be recovered from DRSPs on the basis of contribution factors. AEMO has advised that implementing this would be costly and would provide limited benefits. In addition, DRSPs are not allocated contingency FCAS costs as these are already paid for by market customers on behalf of the participating consumer.
- Requiring AEMO to provide retailers with information about when their retail customers are participating in wholesale demand response. This would assist retailer in managing their exposure in the wholesale market in periods where wholesale demand response is being provided.

This section is structured as follows:

- Benefits of greater transparency in the wholesale market
- An overview of DRSPs participating in central dispatch
- Telemetry requirements for wholesale demand response units
- DRSP obligations when participating in central dispatch
- AEMO's operation of central dispatch
- DRSP participation in pre-dispatch
- AEMO's operation of pre-dispatch
- Separation of dispatch and settlement
- Clause 4.8.9 directions for DRSPs
- Information provided to other market participants about dispatch of wholesale demand response.

D.5.1 Benefits of transparency in the wholesale market

The NEM wholesale market relies on participants submitting information regarding their intentions in advance of real time. The types of participant that are obligated to provide this information to the market are typically scheduled generators and scheduled loads.

Scheduling participants has two main benefits:

- By being cleared through the dispatch engine, scheduled participants' bids and offers are accounted for in determining the price and quantity of electricity cleared.
- Through submitting their bids and offer in advance of real time, scheduled participants provide greater amounts of information to other market participants. Providing greater amounts of information to these market participants will improve their ability to make efficient decisions in operational and investment timeframes on both the supply and demand side of the market.

In addition, scheduling participants provides the market operator with greater certainty that this capacity will be available. Scheduled participants need to have the capacity to receive and respond to dispatch instructions and must comply with them. This provides the market operator with certainty that the dispatched capacity will be delivered to the market. This certainty is in turn crucial for accounting for this capacity in the reliability framework.

As the demand side of the market becomes increasingly capable of making dynamic consumption decisions, it will be important to increase the information flows from these demand side participants to the rest of the market. Scheduling is one way of eliciting this information from the demand side. The participation of the demand side in central dispatch is also being explored in the Energy Security Board's consideration of the two-sided markets.

The Commission considers it key to the development of the wholesale market to encourage demand side participants to engage in the wholesale market transparently. This includes providing information into both dispatch and pre-dispatch. This is particularly the case for price responsive demand side participants.

As such, the second draft rule sets out a process by which DRSPs can participate in the wholesale market as scheduled participants.

D.5.2 Overview of DRSPs participating in central dispatch

Under the second draft rule, the Commission has sought consistency of treatment between scheduled wholesale demand response units and other scheduled participants in central dispatch to the extent it is practicable to do so, taking into consideration the systems changes and associated costs required to facilitate this. The Commission considers the value of wholesale demand response facilitated through the mechanism is greater if it occurs transparently and with certainty. Transparency will improve the functioning of the wholesale market and contribute to power system reliability.

In principle, the second draft rule treats DRSPs similarly to scheduled generators through settlement and similar to scheduled loads in dispatch. A number of obligations that apply to scheduled loads in relation to dispatch would also apply to DRSPs. In some instances these obligations have been modified to better account for the technical characteristics of DRSPs and wholesale demand response. As such, the second draft rule seeks to accommodate the practical challenges with requiring DRSPs to meet these obligations while still achieving the reliability benefits associated with the mechanism.

Under the second draft rule, DRSPs would be responsible for declaring the available capacity of the demand responsive components of load comprising a wholesale demand response unit. The DRSP would need to make dispatch offers for this available capacity these in every dispatch interval, reflecting the available demand response at the market price at which it would respond.

The table below provides an overview of how DRSPs will participate in dispatch under the second draft rule, highlighting which obligations apply depending on difference circumstances.

Table D.1: Scheduling related obligations under different circumstances

CONDITION	DRSP HAS NO AVAILABLE CAPACITY	DRSP IS NOT CLEARED TO PROVIDE WHOLESALE DEMAND RESPONSE	DRSP IS CLEARED TO PROVIDE WHOLESALE DEMAND RESPONSE
Must participate in pre-dispatch	Yes	Yes	Yes
Will receive a dispatch instruction from AEMO	No	No	Yes
Must provide wholesale demand response in accordance with the dispatch instruction	No	No	Yes
Wholesale demand response is settled at the spot price	No	No	Yes

D.5.3 Aggregation of wholesale demand response units

The second draft rule also allows for DRSPs to aggregate wholesale demand response units for the purpose of participation in central dispatch.[232] Aggregation of wholesale demand response units will enable loads with individual capacity below the 1 MW dispatch threshold to offer wholesale demand response into central dispatch and may also simplify the dispatch process for DRSPs and AEMO by allowing DRSPs to make a single dispatch offer for multiple wholesale demand response units.

Under the second draft rule, AEMO must approve applications for aggregation if:

- aggregated wholesale demand response units are connected within a single region
- power system security will not be materially affected by the proposed aggregation

232 Clause 3.8.3(b2) of the second draft rule.

- each other requirement for aggregation in the wholesale demand response guidelines must have been satisfied in respect of the proposed aggregation.

If AEMO approves an application for aggregation made under paragraph, AEMO may include specification of circumstances in which aggregated wholesale demand response units would need to be disaggregated. This would allow AEMO to address concerns regarding potential adverse impacts arising from large aggregations of wholesale demand response units. It would also allow AEMO to require a DRSP to disaggregate groups of wholesale demand response units, for example if they are not being effectively accounted for in network constraints.

D.5.4 Telemetry requirements for DRSPs

Large scheduled generators have SCADA links to AEMO. This provides AEMO with real time information relating to the output of those units. These links have been in place for a long period of time. In addition, while a link is expensive, it is relatively cheap compared to the cost of an individual generating unit.

This is not the case for most loads. With the exception of a some large loads, most consumers do not have SCADA links. Not only is installing these links expensive, it would be exceptionally expensive if required for most small wholesale demand response units.

The information provided by AEMO to participants through SCADA is integral to the functioning of dispatch and to demand forecasting. As such, the DRSP will need to provide the same information to AEMO. If DRSPs provide AEMO with information through processes other than SCADA, this may pose associated challenges for AEMO in managing the security and reliability of the power system.

The second draft rule does not specify that information must be conveyed to AEMO through a SCADA link. Instead, AEMO will have the flexibility to specify a process through which it would be able to receive information from DRSPs.[233]

This approach seeks to enable the greatest amount of demand response to be provided through the mechanism without posing operational challenges to AEMO. As such, for each region in the NEM, AEMO will be able to accommodate:

- an established capacity of non-SCADA connected wholesale demand response units
- all SCADA connected loads looking to participate in wholesale demand response through the mechanism.

Through the second draft rule, AEMO would be required to publicly set out:[234]

- how much non-SCADA demand response could be registered in each region
- how much non-SCADA demand response had already been registered in each region.

In addition, AEMO would be required to set the limit for non-SCADA connection demand response as the maximum level that would not pose a material risk to power system security

233 The Commission notes that this issue is being considered in AEMO's VPP demonstrations. More information is available here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations

234 Clause 3.10.1 of the second draft rule.

and enable the efficient operation of wholesale demand response in the market. AEMO would be required to consult on the methodology used to arrive at these regional limits.

This approach enables consumers who do not have SCADA connections to participate through the mechanism. Equally, it enables AEMO to manage any possible risks to power system security that may result from reduced visibility of these wholesale demand response units that do not have SCADA connections.

D.5.5 DRSP participation in dispatch

This section sets out in detail how DRSPs will participate in central dispatch under the second draft rule.

DRSP wholesale demand response bids

Under the second draft rule, DRSPs would be required to declare the available capacity of their wholesale demand response units and make dispatch bids for that available capacity. The available capacity will reflect the portion of the wholesale demand response unit the DRSP is able to control and adjust through central dispatch. If the DRSP has available capacity it must declare it. If the DRSP has available capacity but does not wish to provide wholesale demand response, it may adopt a bidding strategy that makes dispatch unlikely but if extreme prices are reached and the wholesale demand response unit is dispatched, it must respond.

In determining available capacity, the DRSP must take into account only its capacity to provide wholesale demand response as the result of wholesale demand response activity and where that is not offset by a change to the load at another connection point. The DRSP must declare available capacity of zero if the wholesale demand response unit is not baseline compliant at the time or is spot price exposed for the trading interval, or AEMO has declared it to be ineligible for dispatch due to failure to comply with dispatch instructions.[235]

For central dispatch, DRSPs will make dispatch bids for wholesale demand response units. DRSPs will submit dispatch offers in price and quantity pairs. These price - quantity pairs will need to be in whole MW increments, consistent with dispatch offers from other wholesale market participants.

In up to ten bands, these dispatch offers will specify:[236]

- price bands and the corresponding prices at which the DRSP would provide wholesale demand response
- up and down ramp rates.

This bid could represent the wholesale demand response unit either reducing consumption, exporting electricity or shifting from consumption to exporting.

The sections below work through the dispatch process for DRSPs.

235 Clause 3.8.2A of the second draft rule.

236 See clause 3.8.7B of the second draft rule.

DRSP is dispatched to consume at the maximum capacity available for that dispatch interval

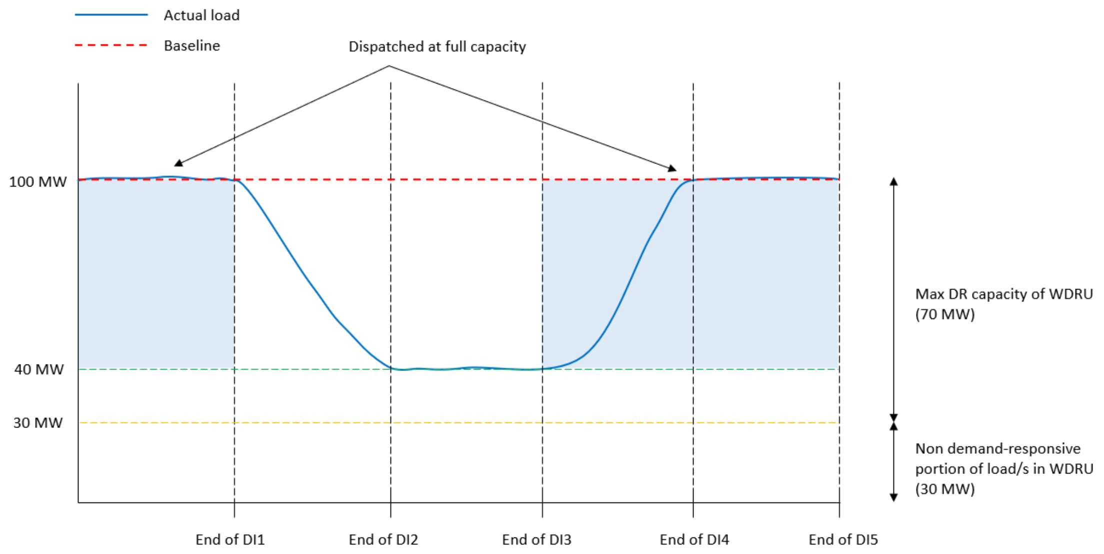
When a DRSP makes a dispatch bid, it will submit this bid to AEMO. The DRSP's bid would reflect its willingness to adjust its consumption or export electricity at different prices. For example, if a DRSP controlled 10MW, it could make a dispatch bid for 10MW at a price of $10,000/MWh. This would mean that if the market price cleared below $10,000/MWh, the DRSP would receive a dispatch target to consume 10MW.

Alternatively, if the market price cleared at $14,000/MWh, the DRSP would receive a dispatch target of 0 MW i.e. provide wholesale demand response.

When the DRSP is given an instruction for the wholesale demand response unit to consume its maximum availabile capacity for that dispatch interval, it will still receive a dispatch instruction from AEMO.[237] However, for the purposes of the NER, this dispatch instruction won't be assessed for non-conformance.

The figure below shows outside the three dispatch intervals, the DRSP has no available wholesale demand response.

Figure D.1: No demand response provided



Source: AEMC

DRSP is dispatched to consume at a level below its maximum availability for that dispatch interval

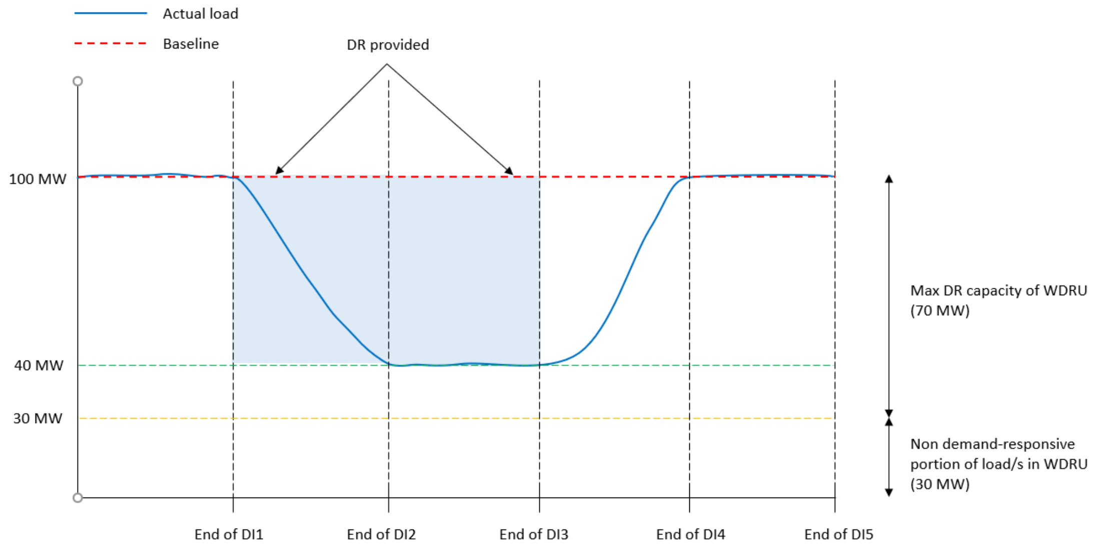
When a DRSP makes a dispatch bid that is cleared by AEMO, it will receive a dispatch instruction to provide wholesale demand response. The dispatch instruction will account for

237 Its actual load may also be taken into account in determining whether it is baseline compliant.

any ramp rate limitations on the scheduled wholesale demand response unit.[238] The DRSP will be obligated to comply with this dispatch instruction.

In subsequent dispatch intervals where the DRSP continues to provide wholesale demand response, it would continue to make dispatch bids to AEMO and receive new dispatch targets. This is demonstrated in the figures below.

Figure D.2: Providing wholesale demand response



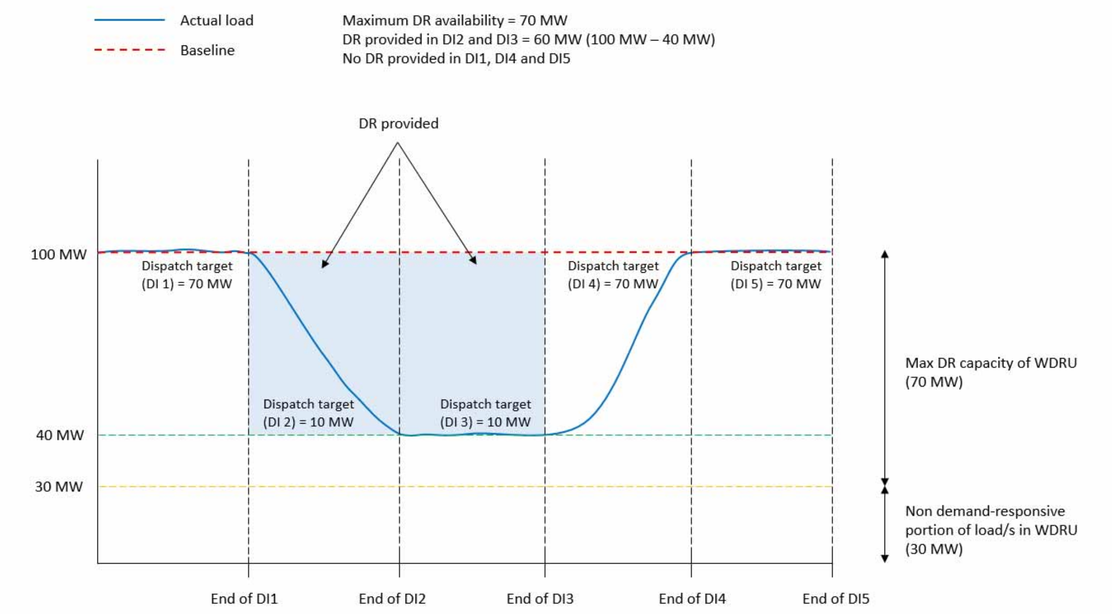
Source: AEMC

The graph below shows the above example but adds in numbers to provide additional clarity. In this example:

- In dispatch intervals 1, 4 and 5, the DRSP is not dispatched to provide wholesale demand response.
- In dispatch intervals 2 and 3, the DRSP received a dispatch instruction to reduce consumption below its available capacity (i.e. reduce consumption to 10 MW) and provide wholesale demand response.

238 Sub-clause 3.8.2A(d) of the second draft rule.

Figure D.3: Providing wholesale demand response with numbers added



Source: AEMC

D.5.6 AEMO's operation of dispatch

AEMO operates the dispatch process to provide for the least-cost combination of supply and demand. The dispatch process does so by issuing dispatch instructions taking into account the technical limitations of the power system.

Under the second draft rule, AEMO will be required to account for the participation of DRSPs when operating dispatch. DRSPs will compete with other scheduled participants the wholesale market. Scheduled wholesale demand response units will be treated equivalently to other scheduled participants by NEMDE.

The process set up under the second draft rule seeks to minimise impacts on the existing central dispatch process by maintaining consistency between wholesale demand response units and those that apply to other scheduled participants. The most notable difference is the greater flexibility afforded to DRSPs regarding participation in dispatch. DRSPs are only required to declare availabile capacity up to the demand responsive component of the load it has registered. This would allow the DRSP to have greater certainty when submitting its dispatch bids regarding the availability of response. AEMO will continue to develop demand forecasts for loads that are not scheduled (either through DRSPs or as scheduled loads), including the non-responsive component of the wholesale demand response units.

D.5.7 DRSP participation in pre-dispatch

Regardless of whether availability may be zero, DRSPs will need to submit information for the purposes of pre-dispatch and information about availability and ramp rate two days ahead.[239] This information will inform AEMO's pre-dispatch forecasts.

AEMO's operation of pre-dispatch should be adjusted to account for the additional capacity provided by scheduled wholesale demand response units over the pre-dispatch timeframes.

The operational load forecasts shown in pre-dispatch should not be adjusted to account for any wholesale demand response provided by DRSPs. This would result in wholesale demand response being accounted for twice - once as additional capacity, and once as a reduction in demand.

The Commission notes that, as a scheduled participant, DRSP bids should be reflected in pre-dispatch. Transparency relating the expected level of demand response in pre-dispatch timeframes will be important for other market participants and AEMO making operational decisions.

However, undertaking significant systems changes to reflect this explicitly is expected to have high associated costs. As such, the Commission considers it appropriate for wholesale demand response provided through the mechanism to be represented as scheduled load in the pre-dispatch schedules. This would provide sufficient clarity to market participants while minimising expected impacts on AEMO systems.

D.5.8 Settlement

Under the second draft rule, settlement for wholesale demand response will not be linked directly to the dispatch instruction. In settlement, the quantity of wholesale demand response provided will be assessed against the baseline ,which reflects a counterfactual level of demand of the wholesale demand response unit as a whole. The dispatch instruction relates to the available capacity of the demand responsive component of the wholesale demand response unit.

In practice the two figures (the quantity dispatched and the quantity settled) should be very similar provided that the DRSP is following its dispatch instructions and the baseline is accurate.

The DRSP will be dispatched and settled on different quantities. This imposes additional complexity on the DRSP in formulating its dispatch offers as the DRSP will need to account for the settlement implications separately to dispatch.

However, the Commission considers the additional complexity imposed on the DRSP is unavoidable. The alternative would require scheduling DRSPs to provide wholesale demand response relative to their baselines. The Commission considers this infeasible because it will result in the total amount of supply being scheduled by the market varying depending on the baseline methodologies in use at the time.

239 Clause 3.8.3(f) of the second draft rule.

Alternatively, DRSPs could be settled on the wholesale demand response they provide through dispatch. However, in practice, this would mean the DRSP would have the ability to influence the baseline in the period directly prior to dispatch. Consumers incentives to turn loads on and then immediately turn them off. By using baselines for settlement, the second draft rule seeks to mitigate these short-term incentives to influence the amount of wholesale demand response provided.

To assist the DRSP in managing this complexity, it will have access to the baseline methodology for each of its wholesale demand response units. This will provide the DRSP with the information necessary to adjust dispatch offers regarding expected settlement outcomes.

D.5.9 FCAS cost recovery

FCAS cost recovery operates differently depending on the service.

- For regulation FCAS, scheduled participants have contribution factors determined by looking at how they follow their dispatch instructions. This requires telemetry that provides AEMO with high granularity information. For the participants who don't have this telemetry (typically consumers), it is recovered on a nominal basis of load consumed.
- For contingency FCAS, the raise costs are apportioned amongst generators and the lower costs are apportioned amongst loads.

Under the second draft rule, DRSPs would not be subject to FCAS cost recovery processes. Based on advice from AEMO and discussions with stakeholders about the complexity associated with incorporating DRSPs into FCAS cost recovery, the Commission considers that the costs of doing so would outweigh the associated benefits. In addition, AEMO has other tools under the second draft rule to incentivise DRSPs to comply with dispatch targets and manage non-compliance. The reasons for excluding DRSPs from FCAS cost recovery are discussed further below.

Regulation FCAS costs

Under the first draft rule, contribution factors would have been determined for DRSPs in the dispatch intervals in which they were instructed to provide wholesale demand response and these would have been used to determine the contribution DRSPs would make to regulation FCAS costs.

However, the determination of contribution factors for scheduled participants relies on four second data conveyed via SCADA systems.[240] The second draft rule does not specify the granularity with which DRSPs must provide data to AEMO. The reasons for this are discussed in appendix d.5.4. Consequently, the current method for determining contribution factors is unlikely to be workable for DRSPs.

AEMO have also noted that including DRSPs in causer pays would require significant changes to the causer pays process. In its submission to the first draft determination, AEMO noted

240 AEMO's causer pays procedure is available here: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

that adding causer pays to the settlement arrangements will add cost and complexity to AEMO's settlements system implementation. This is because AEMO would expect to receive data from DRSPs in a different granularity to the information it receives from other market participants.

Given it is 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, the second draft rule does not require contribution factors to be determined for DRSPs.

The Commission notes that if there are significant quantities of wholesale demand response being provided by DRSPs in the future, it may be necessary to revisit the application of causer pays.

Contingency raise costs

Broadly, contingency raise costs are recovered from supply and contingency lower costs are recovered from customers.

Under the second draft rule, DRSPs will be not required to pay contingency raise costs.

In its submission to the first draft determination, and in subsequent discussions with the AEMC, AEMO has suggested that there is a low likelihood of a wholesale demand response unit resulting in a low frequency event (and hence triggering the need to use contingency raise FCAS). As such, these costs should not be recovered from these loads.

The Commission agrees that wholesale demand response units are unlikely to cause low frequency events, particularly as AEMO is able to establish procedures that are intended to mitigate adverse power system impacts of DRSPs increasing load in a disorderly manner after dispatch. AEMO has also advised that excluding DRSPs from the recovery of contingency raise costs will reduce the implementation costs of the mechanism, as this will allow the settlement process for DRSPs to be undertaken separately from settlement for other market participants, thereby reducing the scope of the changes required to AEMO's systems. Given that the benefits of including DRSPs in the recovery of contingency raise costs are considered to be relatively minor, the Commission has determined to exclude DRSPs from this process under the second draft rule. In addition, the Commission notes that the consumers comprising a wholesale demand response unit already indirectly pay for contingency FCAS costs through their retailer who would is a Market Customers. Therefore, having DRSPs pay for contingency FCAS costs could result in an over-allocation of FCAS contingency costs to customers participating in demand response.

D.5.10 Clause 4.8.9 directions for DRSPs

Under the second draft rule, DRSPs would not be able to be directed under clause 4.8.9 of the NER. The Commission considers that the provisions relating to directions would not provide a DRSP with reasonable grounds to not respond to a direction. For example, if the DRSP had not capacity to provide a response, the NER would not necessarily accommodate this as a reason for not responding to a direction.

The Commission notes that under the second draft rule, AEMO is able to issue a direction under clause 4.8.9 of the NER to a DRSP in respect of ancillary services load. This is consistent with the existing arrangements for MASPs.

AEMO is also able to issue a clause 4.8.9 instruction to a DRSP is respect of its wholesale demand response unit.

D.5.11 Information provision to participants in real time

More information would be provided to retailers

Under the second draft rule, retailers would have access to information about which NMIs had a relationship with a DRSP and which baseline methodology was being used for that NMI. However, there would be no real time information on whether a DRSP was being dispatched, or what the baseline at that point in time would be.

In submissions to the first draft determination, a number of retailers sought greater levels of information to assist them in managing their exposure in the wholesale market at the baseline level. That is, to be able to know their real time liability in the wholesale market, as well as being able to manage this by adjusting their contracting position, when demand response is being provided by their customers.

It was also noted that the settlement model under the draft rule would not directly address this issue. The settlement model intends to keep the retailer whole but this relies on the retailer still undertaking its wholesale risk management function through hedging. This issue could increase the risks imposed on retailers that would not be addressed through the reimbursement rate.

The Commission agrees that retailers are exposed to uncertainty regarding their wholesale market exposure when their customers are participating in wholesale demand response through the mechanism. This uncertainty will be difficult to manage without more information.

However, it is also noted that in the times where demand response is likely to be provided through the mechanism, there is likely to be a strong incentive on the retailer to minimise its net buying position in the wholesale market. That is, retailers should be incentivised to increase output of any generation assets or undertake its own demand response.

As such, knowing the baseline in real time, while it would provide the retailer with more information, may not result in a retailer undertaking different actions. In addition, the baselines determined by AEMO won't be being determined in real time as these baselines are used for settlement ex-post. Having AEMO determine baselines in real time would result in significantly higher implementation costs.

To address the above, the second draft rule provides retailers with a greater level of information without providing them with the actual baselines used in real time. Retailers will know which NMIs (for which they are the FRMP) are being dispatched to provide wholesale demand response. AEMO is required to provide this information to the FRMP. By being provided with this information, retailers should be better able to manage their exposure in the wholesale market.

Second draft rule does not provide more information to network service providers

Some stakeholders also submitted that DNSPs should be provided with more information regarding the provision of demand response in their networks. It was noted that the provision of wholesale demand response could impact on the ability for DNSPs to meet their network service obligations.

The Commission agrees that it is important for DNSPs to have sufficient information to allow them to provide network services. DNSPs are likely to need more information about the timing, location and capacity of demand side participation. This information will be necessary to manage the planning and operation of these networks.

However, until it becomes apparent how much wholesale demand response is provided through the mechanism, it is not clear whether information regarding its dispatch would meaningfully improve DNSPs ability to operate their networks. Also, given the significant development of wholesale demand response offers outside the mechanism, the Commission considers information provision to DNSPs regarding demand side participation should be considered more broadly.

Over time, the Commission considers the wholesale market should move towards a two-sided market. This two-sided market would likely mean greater amounts of information are provided to the market. The development of a two-sided market should consider the appropriate avenues for providing DNSPs with the appropriate information to manage their networks.

As such, the second draft rule does not introduce provisions to provide more information on wholesale demand response to DNSPs.

The Commission notes that there are other changes that have been made to the regulatory framework that are intended to provide NSPs with greater levels of information regarding demand side participation within their networks. For example, the recently introduced distributed energy resource register provides DNSPs with greater visibility of devices connected to the distribution network.

E INFORMATION PROVISION

E.1 Overview

This appendix discusses the requirements regarding the information DRSPs must provide to AEMO for the purposes of AEMO's information processes and forecasting. Information provision requirements relating to other types of demand response (i.e. non-mechanism wholesale demand response) for which information must be provided to the Demand Side Participation (DSP) portal are discussed in appendix H.

Increasing the transparency of wholesale demand response in the NEM was identified as one of the key benefits of this rule change by the rule proponents. Increased transparency contributes to the efficient operation and management of the wholesale electricity market by providing more information to the system operator and participants, so that investment and operational decisions can be better informed. This would also allow AEMO to better forecast demand and supply, as well as power flows across the system.

To facilitate this, the Commission considers that DRSPs should generally be subject to the same information provision requirements as existing market participants, unless a particular requirement is not appropriate or necessary to apply to DRSPs.

The remainder of this appendix outlines:

- current information provision requirements under the NER
- stakeholders' views on the information provision requirements for DRSPs set out in the first draft rule
- the Commission's analysis and conclusions relating to information provision under the second draft rule.

E.2 Background

Provision of information by market participants and AEMO is critical to reliability outcomes in the NEM, as it allows market participants, the system operator, regulators and policy-makers to make better-informed decisions. The role of forecasts is particularly important. Forecasts provide market participants and AEMO with the best information available at any given moment in time to inform decisions they need to make in the present.

Some forecasting is done by AEMO, while some is done by participants themselves. AEMO provides a range of forecasts to the market of metrics such as demand, supply and price, which cover a range of time frames. These are based on its own analysis, as well as information provided by participants as inputs to its processes.

Participants, including generators, retailers and network businesses, also do their own forecasting, based on their own view of the future and their market position. The outcomes from participant forecasting activities feed into their investment and operational decisions, as well as the information that they provide continually to AEMO for its forecasting purposes.

Some of AEMO's key publications and information processes, which are informed by information provided to it by market participants, include:

- Pre-dispatch schedules – forecasts 30-minute pre-dispatch data by region to the end of the next market day, which is updated half hourly and also includes a 5-minute pre-dispatch which forecasts one hour ahead.
- Projected Assessment of System Adequacy (PASA) – projects whether there will be a balance of supply and demand for different forward intervals:
  - The short-term PASA forecasts the supply-demand balance for six days following the next trading day. This report is published every two hours and provides information for each half-hour within the reporting period.
  - The medium-term PASA forecasts the supply-demand balance for the next two years.[241] This report is published weekly and provides information for each day within the reporting period.
- Energy Adequacy Assessment Projection (EAAP) – provides information on the impact of potential energy constraints, particularly those relating to inputs to production (for example, water shortages or constraints on fuel supply) or energy availability. This report is published annually.
- Electricity Statement of Opportunities (ESOO) – projects whether there will be adequate supply of electricity over a ten year-period based on existing and committed generation capacity. This report is published annually.

The purpose of these forms of supplementary information is to inform the market of prevailing and expected conditions, and when reserves may be running low, entice a market response, if possible. For example, if the ESOO identifies a potential shortage of generation in a location in, say, five years' time, the expectation is that revealing this information to the market will prompt new investment to alleviate that problem. In a similar vein, AEMO's first step when publishing a low reserve condition or lack of reserve notice is to seek a market response, for example, ideally, generators will come online in anticipation of the high spot prices that are likely to prevail during the identified period.

Market participants are also required to provide demand side participation information to AEMO in accordance with the demand side participation information guidelines. This information is recorded by AEMO in its DSP Portal. Changes proposed in the second draft rule to strengthen the role of the DSP Portal in increasing the transparency of demand response in the NEM are discussed further in appendix H.

E.3 Stakeholder comments

A number of stakeholders commented in submissions to the first draft determination on the provision of information to AEMO by DRSPs participating in a wholesale demand response mechanism.

Relevant stakeholder comments included the following:

241 The AEMC has recently published a final rule in response to a rule change request from ERM Power in relation to the MT PASA forecast period. The final rule extends the period for which information on generator availability is provided under MT PASA from two years to three years. The final determination and final rule are available at https://www.aemc.gov.au/rule-changes/improving-transparency-and-extending-duration-mt-pasa.

- **Snowy Hydro** suggested that if "non-firm" wholesale demand response is being factored into MT PASA, this may result in inaccurate information being provided to the market which could ultimately delay investment in supply side generation when it is required.[242]
- **EnergyAustralia** sought clarity on whether all market data of wholesale demand response units provided into MT PASA and pre-dispatch, including price bands and volumes, PASA availability, ramp rates and dispatch targets, will be published in accordance with the timetables applying to all current generators and scheduled loads.[243] EnergyAustralia also considered that:
  - DRSPs should be subject to the EAAP, as their customers could be subject to fuel (or similar) constraints.[244]
  - There is a risk that AEMO's forecasting methods could lead to an under procurement of generation if, for example, there is an extended period of load reduction provided by DRSPs, in which AEMO's short term forecasting could calibrate to assume there is a lower volume of demand.[245]
- **Enel X** suggested that it was not clear from the draft rule what obligations are associated with participation in pre-dispatch by DRSPs.[246] Enel X also noted that:
  - it supports the recognition under the draft determination that the information provision requirements that currently apply to generators should be modified and only applied where necessary, due to the differences in the characteristics and operation of DRSPs compared to other market participants[247]
  - it supports the decision not to require DRSPs to provide information to AEMO as an input to the EAAP[248]
  - it would be helpful if the final determination provided further information about the impact that the five-minute settlement rule change will have on the various information provision obligations[249]
  - it is likely to be very difficult for a DRSP to provide accurate information for the ESOO and MT PASA timeframes and it may therefore be more appropriate to only subject DRSPs to ST PASA obligations, or to find ways for DRSPs to feed into the ESOO and MT PASA forecasts less formally[250]
  - it sought assurance that DRSPs would not be penalised if there were legitimate reasons for any information provided turning out to be incorrect and clarity on whether a DRSP's inputs to the these processes would relate to existing, contracted capacity only, or is expected to also include the DRSP's projections of the amount of

242 Snowy Hydro, submission to first draft determination, p. 5.
243 EnergyAustralia, submission to first draft determination, p. 7.
244 Ibid, p. 11.
245 Ibid, p. 12.
246 Enel X, submission to first draft determination, p. 5.
247 Ibid, p. 6.
248 Ibid, p. 7.
249 Ibid.
250 Ibid.

additional demand response capacity it expects to contract with over the forecast period.[251]

- **AEMO** commented in its submission to the draft determination on the inclusion of DRSPs in ST PASA, MT PASA and pre-dispatch:
  - ST PASA and pre-dispatch procedures and systems would not currently be fit for purpose to accommodate the provision of information by DRSPs as set out in the draft rule. However, changes to these systems are anticipated such that they would be capable of appropriately accommodating DRSP information by 1 July 2022.[252]
  - AEMO expressed scepticism about the value of including this information in MT PASA, and instead recommended one of the following alternative approaches:[253]
    - DRSPs only be required to input information into MT PASA if requested by AEMO
    - DRSPs be required to provide information into MT PASA, but AEMO retain the discretion to publish MT PASA values based on its own forecasts rather than the inputs provided by a DRSP, or
    - DRSPs be required to provide data to the DSP Portal rather than MT PASA.

E.4 Commission's analysis and conclusions

BOX 8: INFORMATION PROVISION UNDER THE SECOND DRAFT RULE

The second draft rule:

- requires DRSPs to provide information relating to the availability of wholesale demand response over various timeframes to AEMO for the purposes of pre-dispatch, the DSP portal, ESOO and ST PASA, in accordance with the existing requirements imposed on market participants
- does not require DRSPs to provide information to AEMO as an input to the EAAP, as the information currently provided by generators for this purpose is not considered to be relevant to wholesale demand response
- does not require DRSPs to provide information to AEMO as an input to MT PASA, as the information DRSPs would be able to provide for this purpose would be of limited utility and would involve additional implementation costs for AEMO and market participants.

Benefits of the second draft rule

Requiring DRSPs to provide the relevant information to AEMO would increase the transparency of the level and availability of wholesale demand response in the NEM. AEMO can utilise this information to develop more accurate forecasts of the demand-supply balance, which would result in more efficient operational and investment decisions by AEMO and

251 Ibid.

252 AEMO, submission to first draft determination, p. 14.

253 Ibid.

market participants.

Differences between first draft and second draft rule

The first draft rule required DRSPs to provide information relating to the availability of wholesale demand response to AEMO for the purposes of MT PASA. This requirement has not been included in the second draft rule based on feedback provided by AEMO and market participants which indicates that the benefits of requiring DRSPs to provide this information would be unlikely to outweigh the associated costs. Instead, DRSPs are required to provide information through the DSP portal.

The first draft rule also imposed additional obligations on AEMO to publish specific information regarding wholesale demand response for the purposes of ST PASA. The second draft rule does not specifically include new obligations on AEMO in this regard, as the Commission considers that the existing requirement that AEMO publish information relating to forecast load in each region (adjusted to make allowance for scheduled loads and demand response) would adequately capture information about wholesale demand response.

Minor administrative changes have also been made to some provisions in the second draft rule to clarify the specific requirements of the information to be provided by DRSPs.

The Commission considers that, as a general principle, the existing information provision requirements currently imposed on generators should also apply to DRSPs to the extent possible. The Commission acknowledges that some stakeholders have queried the utility of requiring DRSPs to provide certain information to AEMO. Extending these obligations to DRSPs is consistent with the market design principles in the NER which aim to increase the level of market transparency in the interests of achieving a very high degree of market efficiency and to avoid the special treatment of any particular technology.[254] Nevertheless, it is appropriate that these requirements be modified as necessary to account for the differences in the characteristics and operations of DRSPs as compared to other market participants.

AEMO's information processes and the inputs currently associated with them are summarised in Table E.1. This table is not an exhaustive list of all the information published by AEMO but highlights the main variables and outputs for each process and document.

254 NER clause 3.1.4(a).

Table E.1: AEMO's information processes under existing framework

VARIABLES	ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
Forecast timeframe	Ten years NER clause 3.13.3(q)	Two years NER clause 3.7C(b)(1)	Two years, extended to three years for generator availability NER clause 3.7.2(a)	Six days NER clause 3.7.3(b)	One day Clauses 3.13.4(e), 3.8.20(a) Note: AEMO also publishes a five-minute pre-dispatch schedule
Frequency of publication	Annually (by 31 August) NER clause 3.13.3(q)	At least annually NER clauses 3.7C(b)(2)and 3.7C(d) Note: clause3.9.3D(b1) requires the Reliability Standard Implementation Guidelines (RSIG) to set out the factors AEMO will consider in determining whether it has an obligation to publish an EAAP under 3.7C(d)(2)	Weekly NER clauses 3.7.2(a) and 3.13.4(a)	Two-hourly Note: clause 3.7.3(a) requires publication at least daily, but AEMO publishes it every two hours	30 minutes Note: clause 3.8.20(a) requires a pre-dispatch schedule covering each trading interval
Resolution of forecast	Annually	30-minute traces	Daily NER clause 3.7.2(a)	30 minutes Note: NER clause	30 minutes Note: NER clause

VARIABLES	ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
				3.13.4(c) requires publication of outputs of ST PASA for each trading interval	3.8.20(b) requires the pre-dispatch process to have a resolution of one trading interval
Purpose	Provides technical and market data that informs the decision-making processes of existing and potential market participants, as they assess opportunities in the NEM over a 10-year outlook period. NER clause 3.13.3(q)(5)	Provides analysis to market participants and other interested persons that quantifies the impact of energy constraints on energy availability over the 24-month period, such as water storages during drought conditions or constraints on fuel supply for thermal generation, or supply adequacy in the NEM. NER clause 3.7C(a)	Provides analysis of power system security and reliability of supply prospects to inform participants and enable them to make decisions about supply, demand and transmission network outages in respect of periods up to three years in advance. NER clause 3.7.1(b)	Provides analysis of power system security and reliability of supply prospects to inform participants and enable them to make decisions about supply, demand and transmission network outages in respect of a six day half-hourly reserve outlook. NER clause 3.7.1(b)	Provides projections of the prices and generation dispatch based on market participants' bids and offers, and AEMO forecasts of demand and other system conditions. NER clause 3.13.4(f)
Information provided by participants under current framework (*italicised* text indicates that this is a NER requirement)	Participant surveys. Capacity based on evidence of project status (existing, committed etc) *Participants must provide required*	*Generator must provide updated Generator Energy Limitation Framework (GELF) if there has been a material change that impacts the energy*	*Generators must provide information regarding unit availability for each day and weekly energy constraints to AEMO in accordance with the*	*Participants must update AEMO of any changes in generator availability in relation to the ST PASA as soon as they occur.* NER clause 3.7.3(e)	A generator must not make a dispatch offer that is false, misleading or likely to mislead. This includes if it: 1) does not have a

VARIABLES	ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
	information to AEMO as soon as practicable after participant becomes aware of any information required for publication by AEMO. NER clause 3.13.3(t)	*constraints associated with that GELF.* NER clause 3.7C(i)	*timetable published by AEMO.* *Generators must update AEMO of any changes in generator availability in relation to the MT PASA as soon as they occur. This will be based on planned / actual outage profile.* NER clause 3.7.2(d)	Participants will monitor and update near term availability & capability based on latest plant and weather conditions.	genuine intention to honour the offer, or 2) does not have a reasonable basis to make it. NER clauses 3.8.22A(a) and (b) Re-bidding is required when the participant becomes aware of changes to the basis of the offer. NER clause 3.8.22A(d) Participants must ensure that they are able to dispatch relevant plant required under the schedule. NER clause 3.8.20(g)

Table E.2 sets out how the existing information provision requirements imposed on market participants will apply to DRSPs under the second draft rule. AEMO will also be required to publish the relevant information in accordance with existing processes and timeframes in the NER. This is reflected in the second draft rule.

Table E.2: **Application of existing information processes to DRSPs under second draft rule**

ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
Requirements applying to DRSPs under second draft rule				
DRSPs would be subject to the same information provision requirement as generators. This is a high-level obligation and it is reasonable to expect that DRSPs will be able to comply with this requirement.	The existing requirement on scheduled generators to submit GELF declarations to AEMO does not apply to DRSPs under the draft rule. The purpose of these declarations is to support the calculation of energy restricted business scenarios relating primarily to water shortages and other restrictions on fuel supply for large generators.[1] This is not considered to be relevant to demand response, as loads do not face the same fuel input constraints as traditional generators.	The existing requirement on scheduled generators to submit information to AEMO for the purposes of MT PASA does not apply to DRSPs under the second draft rule. The Commission understands that it would be difficult to forecast the availability of a load or groups of load to provide demand response over a multi-year timeframe with a high degree of accuracy.[2] In addition, AEMO has submitted that this information would be of limited utility for the purposes of its demand forecasts. AEMO has also advised that	DRSPs are subject to the same information provision requirement as generators. It is expected that DRSPs will be able to forecast their demand response availability over the relevant timeframe with a reasonable degree of accuracy. The Commission understands that AEMO is currently considering broader changes to ST PASA procedures and systems in response to a range of changes in the market. As discussed in appendix e.3, AEMO has indicated that any such changes to ST PASA will include modifications to accommodate information	Refer to appendix D for details on scheduling requirements.

ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
		requiring DRSPs to participate in MT PASA would involve substantial systems changes and associated implementation costs. The Commission considers that it would still be useful for this information to be captured in some form in a cost-effective manner. Accordingly, the second draft rule requires DRSPs to submit information on wholesale demand response over longer timeframes through the DSP Portal. This is discussed further in appendix h.	provided by DRSPs. Given that wholesale demand response will be treated similarly to scheduled loads for the purposes of dispatch under the second draft rule, the Commission considers that AEMO's existing obligations to publish information relating to load forecasts (adjusted to make allowance for scheduled loads and wholesale demand response) for the purposes of ST PASA would sufficiently capture information on wholesale demand response. As such, the second draft rule does not include specific ST PASA reporting requirements relating to wholesale demand response. However, the Commission expects that information	

ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
			published by AEMO for the purposes of ST PASA would sufficiently distinguish between wholesale demand response and scheduled loads in order to provide clarity to participants on the levels of wholesale demand response participating in the market over the period covered by ST PASA.	
Do the information provision requirements applying to DRSPs differ from those for generators?				
No – the requirements applying to DRSPs will be the same in principle as those currently imposed on generators.[3]	Yes – the requirements currently imposed on generators do not apply to DRSPs under the second draft rule for the reasons discussed above.	Yes – the requirements currently imposed on generators do not apply to DRSPs under the second draft rule for the reasons discussed above.	No – the requirements applying to DRSPs will be the same in principle as those currently imposed on generators.[4] Although DRSPs have to provide similar information as generators in ST PASA, AEMO is not required to report that information in the same way as it reports generator information for the reasons discussed above.	Refer to appendix D for details on scheduling requirements.

ESOO	EAAP	MT PASA	ST PASA	PRE-DISPATCH
			AEMO's ST PASA Process Description will also require amendment to clarify the specific processes which will apply to DRSPs. Equivalents to relevant terms such as "energy constrained scheduled generating unit" have been developed for demand response.[5]	

1. AEMO, *Guide to Generator Energy Limitation Framework (GELF) Declarations: Energy Adequacy Assessment Projection (EAAP)*, May 2014. Available at: http://www.aemo.com.au/-/media/Files/PDF/Guide_to_GELF_Declarations_2014_July.pdf.

2. The Commission's final determination on the rule change request submitted by ERM Power in relation to MT PASA, published on 20 February 2020, imposes a requirement that MT PASA inputs meet the standards of ST PASA (i.e. that information provided to AEMO must represent the market participant's 'current intentions and best estimates'). Available at: https://www.aemc.gov.au/rule-changes/improving-transparency-and-extending-duration-mt-pasa.

3. Clause 3.13.3A of the second draft rule.

4. Clause 3.7.3 of the second draft rule.

5. Chapter 10 of the second draft rule - see new definitions of "wholesale demand response unit" and "wholesale demand response constraint".

F DETERMINATION OF BASELINES

F.1 Overview

The second draft rule sets up a process for determining a baseline for wholesale demand response that participates in the wholesale demand response mechanism.

Baselines are an estimate of the counterfactual level of consumption that would have occurred were it not for the demand response. They are necessary to allow demand response providers 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.

In summary the second draft rule:

- requires AEMO to, in consultation with stakeholders, develop wholesale demand response guidelines. These guidelines will set out, among other things:
  - information about the process for development of baseline methodologies, including how proposals for new baseline methodologies may be made
  - the process for a DRSP to apply to AEMO for approval to apply a baseline methodology to a wholesale demand response unit (a step in the classification of a load as a wholesale demand response unit)
- requires AEMO to develop arrangements for the regular testing of baselines and assessing baseline compliance
- requires AEMO to monitor and report on the baseline methodologies used under the demand response mechanism.

DRSPs would be required to demonstrate compliance with the requirements set out in AEMO's guidelines in relation to baseline methodologies in order to classify load as demand response load. DRSPs would also need to be able to demonstrate compliance on an ongoing basis.

The framework captures the benefits of having a central body determining the baseline while also allowing for innovative approaches to be developed over time but in such a way that minimises costs.

This appendix provides more detail on the role for baselines in the demand response mechanism. It sets out:

- an overview of baselines in the second draft rule
- background on the role for baselines in a wholesale demand response mechanism
- a summary of relevant views from the proponents
- a summary of relevant stakeholder comments
- the Commission's analysis and conclusions.

F.2 Background

This section provides more information on why the second draft rule sets up a framework for centrally determining baselines.

F.2.1 What are baselines?

A baseline is an estimate of expected behaviour that would otherwise have occurred were it not for some event. It is similar to a forecast in many ways. The key difference between a baseline and a forecast is that a baseline attempts to isolate and discount the effect of a particular variable. A forecast of consumption would try to account for the variation in load over the forecast period. When setting a baseline for demand response, it is trying to show 'what would demand have been in the absence of any demand response to a particular signal.'

For most consumers, determining a baseline for demand response would mean trying to assess what their consumption would be under their existing retail contracts in the absence of a signal to change their consumption.

Baselines are typically calculated by looking at historical consumption and using that to predict future consumption. Different weightings are given to different historic time periods. For example, some methodologies place more weighting on the level of consumption closer to the time when wholesale demand response has been dispatched, and so when the baseline will be calculated.

For wholesale demand response, at a high-level there can be considered to be four different approaches to setting and settling the baseline. The approaches are differentiated by two factors:

1. whether they are set by a central body or by agreement between the buyer and seller of the demand response
2. whether they are settled through the centralised market settlements or settled outside the market.

These are set out in the table below.

Table F.1: Four approaches to setting and applying baselines

	CENTRALISED SETTLE-MENT	DECENTRALISED SETTLEMENT
Centrally set baseline methodologies	Centralised wholesale demand response mechanisms. Baselines of this nature are introduced under the second draft rule.	The baseline methodology would be centrally determined. The price paid for the demand response would be settled out of the market.
Decentrally set baselines	Centrally administered settlement, with the	There would be no central approach to determining or settling

	CENTRALISED SETTLEMENT	DECENTRALISED SETTLEMENT
	methodology for the baseline agreed between two participants.	baselines. This is how wholesale demand response currently occurs.

F.2.2 What makes a good baseline?

A 'good' baseline has a number of qualities or attributes:

- Accurate under a range of conditions
- Does not display a consistent error or bias
- Not susceptible to manipulation
- Adaptable to changes in consumer characteristics.

When developing a baseline methodology, the aim is to deliver baselines characterised by the above qualities.

Below, each of the characteristics of baselines are discussed in more detail.

Accuracy

The accuracy of a baseline refers to how well it is able to predict the counterfactual level of consumption. This relates to any single instance of demand response, and the average over time. An accurate baseline would have little or no difference from the actual consumption when demand response is not being provided.

This section discusses challenges associated with:

- Setting an accurate baseline
- Measuring the accuracy of a baseline

It also discusses issues that arise if the baseline is inaccurate.

Challenges with setting an accurate baseline

The challenges with setting an accurate baseline are similar to the challenges with forecasting. A baseline needs to account for a wide range of variables that might influence consumption decisions, including but not limited to:

- the day of the week
- the air temperature
- any seasonal variations
- changes in operational patterns, such as the installation of new machines
- increased night time operation due to increased production schedules
- availability of other resources including staff or raw materials for making widgets.

Since there are many factors that may influence consumption, inevitably the consumer is likely to be best placed to know the baseline. However, any party (including the consumer) trying to estimate the baseline will not know precisely what the level of consumption would be in the absence of demand response. Estimating the baseline would be easier when a party shares incentives with the consumers, such as an aggregator representing the consumer, as aligned incentives can help with overcoming information asymmetry.

Models of a customer's behaviour, based on that consumer's previous behaviour and/or the behaviour of similar consumers, can attempt to explain the variation in consumption of electricity and predict future consumption. However, in much the same manner that forecasts will never be perfect, these models will never be able to fully account for fluctuations in consumption.

Challenges with measuring the accuracy of a baseline

Because a baseline is not observed but rather is a counterfactual, it cannot be directly quantitatively measured for accuracy when the demand response occurs. This is unlike a forecast, which can be directly compared to actual consumption over the forecast period.

Instead, baseline methodologies can be tested to see whether they produce accurate results at those times when demand response does *not* happen, by comparing the baseline against the consumer's actual historic consumption or the actual historic consumption of a similar consumer or group of consumers with no demand response arrangements.

This makes it difficult for any party to retrospectively assess whether demand response was appropriately quantified or not.

Consequences of inaccurate baselines

When a baseline is "wrong" (i.e. it does not reflect what the consumer's electricity use would have been in the absence of demand response), it means that the quantity of demand response that was accounted for will be wrong. If the baseline is too high, the amount of demand response will be overestimated. If the baseline is too low, the amount of demand response will be underestimated. As a result, either too much or too little value relating to demand response will be transferred from the buyer to the seller of demand response. This will result in the DRSP either being paid for more demand response than was provided, or being underpaid for the quantity provided.

In a single instance, if the baseline is wrong, the demand response will either be over or undervalued. However, if the baseline is correct *on average* when wholesale demand response is being dispatched,[255] over time, then the fair value for the demand response should be exchanged between the retailer and the demand response provider. If it is correct on average, the over- and under-valuation of the demand response should cancel out over time.

So, while in the short-term, the value attributed to demand response through settlements may be incorrect, the distortionary impacts should be at least partially mitigated in the medium-term if the average error in the baseline is zero. This effect is demonstrated when using baselines for aggregated portfolios.

255 That is, the average amount that the baseline methodology over or under-estimates the demand response quantity

Bias

Bias refers to whether the baseline is consistently too high, or too low. This could be the case, for example, if the baseline methodology did not account for temperature and the baseline was typically utilised on days with elevated temperatures.

When the baseline is biased, it results in either the buyer or seller of demand response being overcharged or underpaid. It is important that there is confidence that a baseline methodology is consistent and unbiased - to the extent that it has a systemic bias, there are likely to be winners and losers. Under a centrally settled baseline, this would result in distortionary costs being imposed on the market.

The distortionary costs arising under a biased, centrally settled baseline would be imposed on the party suffering the bias which will subsequently result in broader inefficiencies. Either the demand response provider will be consistently undervalued and consequently, will not provide demand response under all circumstances where it would be efficient. Alternatively, the retailer will be consistently over charged for demand response that did not in reality occur. These costs will need to be recovered from the retailer's consumers and represent a cost to the retailer (and ultimately consumers).

Participant influence over baseline

A tendency for a baseline to be either too high or too low may also be the result of the buyer or seller of the demand response having the ability to influence the setting of the baseline in a manner which is not economically efficient for consumers as a whole.

When participating in a wholesale demand response mechanism, participants would be economically incentivised to maximise the amount earned through the arrangement or mechanism. Under the mechanism, the customer and the DRSP both have influence over the baseline since this is determined based on the actions of the consumer. Increasing the baseline provides an opportunity for a demand response provider to increase the quantity of demand response it is credited for without necessarily physically undertaking that demand response. Similarly, decreasing the baseline provides an opportunity for a buyer of demand response (i.e. a retailer) to pay for less demand response than was provided. This could occur if:

- The seller or buyer of the demand response has the ability to artificially inflate/deflate the baseline. Depending on the methodology for determining the baseline, it is possible that the seller of demand response would have the opportunity to 'inflate' the baseline such that, when the demand response was dispatched, the baseline was artificially high. For example, this opportunity could arise if the baseline is determined based on recent past (at the time of the demand response event) consumption. Parties may inflate their consumption in the lead up to a demand response event, if it was not too expensive for them to do so. This would result in the demand response provider being credited for a greater amount of demand response than actually occurred – and distort consumption behaviour. The opposite could occur if a buyer has influence over the baseline; however, in practice it is likely to be more challenging for the buyer to manipulate the baseline.

- The seller of demand response could observe the inaccuracy in the baseline and use this to inform commitment decisions. For example, the seller could elect to provide demand response when the baseline was inaccurate and overestimating expected consumption. If this was possible, the seller would be more likely to provide demand response when the baseline was *inaccurately high*. Conversely, it would be less likely to undertake wholesale demand response when the baseline was *inaccurately low*. As such, while a backward looking assessment of the baseline methodology itself may have found it to be unbiased, the seller of demand response may take advantage of the errors in the baseline by favouring demand response at those specific times that the baseline was favourable (incorrectly high). This would result in additional, inefficient costs being imposed on the retailer.

Some baselines may be more robust to opportunities for participants to influence them. For example, if a baseline was reliant on an extensive catalogue of consumption history, it would be difficult for a consumer to undertake short term measures to inflate the baseline. However, the downside of such an approach would be that the baseline would likely become increasingly inaccurate if it did not reflect the natural variations in a consumer's load profile occurring closer to real time. There is therefore a trade-off between basing the baseline on recent data (which is more easily manipulated) and long term data (which is more likely to be inaccurate when applied to any specific short time interval).

Robustness and/or flexibility

A baseline should also be able to account for changes in the nature of the load being baselined. That is, a baseline methodology should remain accurate and unbiased following changes to the consumption i.e. errors should remain as close to zero as possible.

A baseline could be made more robust by:

- regularly revising or updating the methodology
- requiring participating consumers to advise of changes to typical operation or consumption.

In addition, different methodologies could be applied for different loads. For example, if a consumer installed rooftop PV, it could be transferred from one methodology to another that better accounts for the addition of rooftop PV.

Summary

Determining good methodologies and baselines is challenging, although it may become easier over time as technology evolves and new approaches are developed. If it is done poorly, it will result in costs being imposed on consumers for a service that wasn't provided. The draft rule seeks to address these risks through the measures set out in appendix f.5.1.

F.3 Proponents' views

F.3.1 PIAC, TEC and TAI

In its proposal, PIAC, TEC and TAI proposed changes to the NER relating to baselines and baseline methodologies should focus primarily on high level principles. Under their proposal, there would be principles in the NER for AEMO, and potentially the AER, to decide on the details of the implementation via procedures and guidelines. These procedures and guidelines could be readily adapted as the mechanism matures in the market.

The baselines under the PIAC, TEC and TAI proposal would be centrally determined, and centrally settled. That is, they would be determined by AEMO and settled in central market settlements.

The rule change request also noted that the baseline methodologies should also be refined through AEMO and ARENA's 2017-2020 in-market demand response trials (which are discussed in chapter 2).[256]

F.3.2 AEC

In its proposal, the AEC noted that the register would not rely on theoretically determined baselines. The AEC considered that centralised determination of baseline methodologies would be unlikely to be applicable for many commercial and industrial loads, and especially for residential loads. Under the AEC proposal, baselines would be determined in a decentralised manner and would be settled outside of market settlements, between retailers and demand response aggregators.[257]

F.3.3 South Australian Government

In its proposal, the South Australian Government noted that setting a baseline would be a key consideration in introducing a wholesale demand response mechanism. The South Australian Government proposed that a set of high level principles pertaining to the baseline methodology should be established by the Commission, including that the methodology be:[258]

- flexible and capable of being changed over time
- consistent across participants
- limit opportunities for gaming
- be verifiable
- place risk on the parties best placed to manage the risk.

The baselines under the South Australian Government proposal would be centrally determined, and centrally settled.

The South Australian Government suggested that the establishing the methodology in a guideline rather than the NER may better enable flexibility.

F.4 Stakeholder comments

In submissions to the first draft determination, a number of stakeholders provided comment on the framework for establishing baseline methodologies and using them in crediting wholesale demand response.

256 PIAC, TEC, and TAI, *Wholesale demand response mechanism - rule change request,* p. 15.

257 AEC, *Wholesale demand response register mechanism - rule change request,* pp. 3-4.

258 South Australian Government, *Mechanisms for wholesale demand response - rule change request,* pp. 6-7.

General

- **AEMO** noted that baselines are a difficult and inexact toolset, and while the model may be suitable for connection points with large, predictable loads, the design is not suitable for smaller and less predictable loads. It agreed with the Commission that centrally determined baselines should not be an enduring feature of a two-sided market.[259]
- The **South Australian Government** considered the materiality of the risk of perverse incentives in the determination of baselines to often be overstated. Considering that large consumers core business is not in the electricity market, they are unlikely to be driven to capture electricity market revenue at the detriment of their core business. The determination of feasible baselines has been demonstrated in other markets which proves the issues can be overcome.[260]
- **Meridian Energy** noted that one of its key learnings in its demand response program is that it is almost impossible to develop a baseline methodology that rewards genuine participants only. Despite testing numerous baseline methodologies we have been unable to identify a baseline which rewards all genuine participants, all of the time, and not overly rewards non-responsive participants. The substantial variation of customer usage, behaviour patterns and behind-the-meter generation and storage indicates that it is unlikely that a standardised and centralised approach to baseline methodology will ever be successful.[261]
- **Delta Electricity** submitted that no analysis or evidence was provided regarding the type and variation in error that would be expected in relation to baselines. Given the central role of baselines in the mechanism, the risks associated with baselines is unknown.[262]
- **Electricity Exchange** suggested that the Commission adopts a validation methodology which would allow DSRPs to choose the most appropriate forecasting as they see fit, provided the forecast reflects previously observed behaviour within a specified historical period such as the previous 12 weeks. Choosing a validation methodology rather than a baseline methodology allows participation to be more inclusive of a broader range of participants and, in particular, industries that can offer the highest volumes.[263]
- The **Energy Efficiency Council** noted that AEMO can draw on numerous successful international examples to support this process. A robust baseline methodology should prevent gaming by ensuring that an energy user would have to substantially inflate their energy use for long periods of time in order to game the mechanism.[264]
- **Energy Queensland** highlighted that there are enduring issues associated with the use of artificial baselines for settlement and billing purposes which result in the need for a rigorous process for the development of baseline methodologies and an onerous

259 AEMO, submission to first draft determination, p. 7.
260 South Australian Government, submission to first draft determination, p. 3.
261 Meridian Energy, submission to first draft determination, p. 2.
262 Delta Electricity, submission to first draft determination, p. 19.
263 Electricity Exchange, submission to first draft determination, pp. 6-8.
264 Energy Efficiency Council, submission to first draft determination, p. 1.

monitoring, compliance and enforcement regime to mitigate the risk of inaccuracy and "additionality".[265]

- **ENGIE** submitted that baseline methodologies are only likely to ever be inaccurate and uncertain – as is the case with forecasting which by its nature is impossible to accurately predict.[266]
- **EUAA** questioned if there might be a perception that AEMO is both judge and jury in deciding whether an innovative baseline methodology is acceptable. It suggested that perhaps there is a role for the AER as an arbitrator.[267]
- **Flow Power** noted that there will be incentives to manipulate and game baselines because the outcome of such behaviour lies with a third party (retailer) who will foot the bill.[268]
- **PIAC** suggested a number of practical measures and metering configurations can support more accurate baselining. These should be used to the full extent that they are practicable and do not limit participation.[269]

Metrics

- **AEC** considered that it will be very important for AEMO's procedures to be robust. To ensure this is the case, and to allow stakeholders to assess the rule change against the NEO properly, the AEC would have expected the principles for the determination of baselines to be set out in the draft rule.[270]
- **Delta Electricity** submitted that it would be appropriate that the Commission to provide more detailed guidance on the principles and frameworks to be used by AEMO in developing the demand response baseline methodology guidelines.[271]
- **Snowy Hydro** considered that irrespective of the checks and balances provided to strengthen baselines, they will always expose retailers to potential risks. Snowy Hydro's view was that DRSPs must ensure its consumption must not vary within some very tight parameters outside of its normal consumption range.[272]
- **AEMO** noted that the definitions of accuracy and bias appear to limit the determination of these measures to the connection point. It is unclear how much discretion AEMO would have to consider more innovative approaches to measurement and assessment of baseline compliance, including the use of sub-metering, without the need for a Rule change. AEMO recommended that the definitions of accuracy and bias be reviewed to promote flexibility in assessing baseline compliance.[273]

Other

265 Energy Queensland, submission to first draft determination, p. 6.
266 ENGIE, submission to first draft determination, p. 3.
267 Energy Users Association of Australia, submission to first draft determination, p. 3.
268 Flow Power, submission to first draft determination, p. 4.
269 PIAC, submission to first draft determination, p. 16.
270 AEC, submission to first draft determination, p. 2.
271 Delta Electricity, submission to first draft determination, p. 2.
272 Snowy Hydro, submission to first draft determination, p. 6.
273 AEMO, submission to first draft determination, p. 11.

- **BlueScope** considered it important that the rule prohibits load shifting between NMIs but this should not extend to mandatory aggregation of NMIs. BlueScope suggests that the rules allow for each site to customise their approach to the treatment of multiple NMIs when developing and measuring baselines.[274]
- **EUAA** supported the ability of one company to aggregate NMI's across the one site. This could be the result of the commercial negotiation between the C&I customer and the DRSP. This provides benefits in reduced forecasting error. DRSPs should also have the flexibility to nominate DR from aggregated NMIs.[275]
- **EnergyAustralia** noted that AEMO's guidelines will also need to consider how it will verify baselines that are submitted by a prospective DRSP whose customer is already providing DR with another DRSP as the customer no longer has a 'raw' actual consumption trace upon which to determine a baseline as it has already been providing demand response.[276]
- **Mondo** highlighted that there may be value in aligning and standardising the baseline process under the final rule and the RRO to achieve administrative efficiencies.[277]
- **AEMO** recommended that the rule allow AEMO to limit the number of abnormal conditions notices in respect of a specific scheduled wholesale demand response unit.[278]

Additionality

A number of stakeholders provided comments in relation to additionality:

- **AGL** considered that the DRSP should be able to "value stack" services from their demand response capability, so long at they are not providing multiple demand response services in the same dispatch interval (which would not meet the requirements of being "additional")[279]
- **EnergyAustralia** noted that clarification should be provided on whether customers are precluded from registering for multiple services and providing them in different trading intervals. It was unclear how the rules will adequately ensure that demand response provided is genuine and that the load has not shifted to another NMI associated with the site.[280]
- **Major Energy Users** suggested that the same end user could provide multiple services from different parts of its operations and the rules need to be flexible enough to recognise this reality. To preclude recognition for the different services when it is more likely that the different services will be provided at different times would have the potential for end users not to provide one or the other demand response service, to the overall detriment of the electricity market.[281]

274 BlueScope, submission to first draft determination, p. 2.
275 Energy Users Association of Australia, submission to first draft determination, p. 3.
276 EnergyAustralia, submission to first draft determination, p. 12.
277 Mondo, submission to first draft determination, p. 3.
278 AEMO, submission to first draft determination, p. 12.
279 AGL, submission to first draft determination, p. 4.
280 EnergyAustralia, submission to first draft determination, p. 11.
281 Major Energy Users, submission to first draft determination, p. 3.

- **Mondo** noted that while DRSPs would face barriers to value stacking, under the current arrangements retailers will be free to continue value stacking resulting in higher returns for retailer-led demand response. This is likely to distort customer decision making in favour of retailer demand response.[282]
- **PIAC** noted, however, that this additionality test may require more nuance to mitigate the unintended consequences of preventing legitimate, efficient value stacking, which provides a wider benefit to all consumers. This includes reducing load to respond to transmission or distribution peaks that coincide with high wholesale prices, especially when the business case for demand response is dependent on the revenue from both value streams.[283]

Retailer impacts

- **AEC** submitted that the major shortcoming in the use of baselines is their effect on retailers' forecasts. As it stands, retailers forecast their aggregated load, and either self-generate or purchase financial contracts to back their load, on the basis of forecasts which take into account the diversity between customers and the diversity between customer segments. Attributing individual baselines to customers, with their inherent inaccuracies and margins for error, may result in retailers losing the ability to take advantage of diversity, and cause retailers to purchase more than they need to mitigate their risk.[284]
- **EnergyAustralia** noted that it will be important to have information regarding when part of its load is going to be activated so it can manage its spot risk exposure appropriately. Without this information, retailers are likely to face increased risk management costs to minimise their pool exposure, reducing benefits of the demand response rule change.[285]
- **Snowy Hydro** noted that baseline methodologies create significant retail risk as they will be based on assumptions and will be open to gaming. Retailers will need to incorporate this risk into their retail contracts, which would result in another cost on consumers.[286]

Accuracy and bias

In relation to the baseline methodology metrics under the first draft rule, stakeholders made the following comments.

- **Momentum Energy** noted that it is disappointing that the Commission has not provided any detail on the principles under which AEMO will be expected to assess the proposed baseline methodologies and the accuracy/bias parameters.[287]
- **AGL** considered that DRSPs would not necessarily be manipulating the baseline or using a biased baseline, but simply bidding in to maximise profits (as would be expected). Therefore, it is likely that any baseline inaccuracies will tend to overpay the DRSP.[288]

282 Mondo, submission to first draft determination, p. 2.
283 PIAC, submission to first draft determination, p. 15.
284 AEC, submission to first draft determination, p. 2.
285 EnergyAustralia, submission to first draft determination, p. 7.
286 Snowy Hydro, submission to first draft determination, p. 1.
287 Momentum Energy, submission to first draft determination, p. 4.
288 AGL, submission to first draft determination, p. 6.

- **AGL** suggested that the regulated accuracy of measured energy in the NEM is generally between +/- 0.5% and +/- 2.0% at rated load, depending on the size of the customer. AGL suspects that current assessments of an "accurate" baseline in literature on demand response would be in the order of +/- 20% to +/- 30%. This may be acceptable to parties in bilateral agreements to provide demand response but is a significant risk and cost to the NEM if used in centralised settlement. AGL considers the baseline accuracy for the DRM should be an order of magnitude lower than this.[289]
- **CS Energy** noted that the key to ensuring the baseline demonstrates the attributes of a "good" baseline is that the baseline methodology is regularly reviewed, tested and updated as necessary.[290]
- **Delta Electricity** suggested that given the complexity of downstream operations associated with parties providing demand response, it would potentially be very difficult to distinguish gaming from normal variations in operations. This could make parties wary of undertaking normal operational changes for fear of this being misunderstood.[291]
- **EnergyAustralia** noted that the risk that baselines are inaccurate is borne by retailers and DRSPs who face financial settlements on its basis. It therefore believes it is preferable for the AER to instead prescribe the performance criteria for baselines, not AEMO.[292]
- **Flow Power** suggested that for baseline methodologies at the individual NMI level to produce a 'good baseline', AEMO is likely to either: [293]
  - have to develop, maintain and operate a large number of methodologies to accommodate the diverse load profiles of large customers, the cost of which will be borne by consumers, or
  - set thresholds that limit participation to a few large customers, possibly with predictable or flat loads, raising the question of how effective the mechanism is, especially when considering that currently there is nothing stopping these customers from participating in other forms of demand response.
- **Infigen** considered that baseline methodologies represent a potential source of gaming. For example, DRSPs could choose to offer a (small) response only when their resource was already below the baseline, thereby increasing settlement for no benefit. That is, a load that happens to be 10 MW below its baseline (due to the inaccuracy of the baseline) could be activated by a further 1 MW and be settled for 11 MW. Conversely, whenever the load was above the baseline, it might not be activated at all. The AER should be seeking to detect and discourage such behaviour. It would be prudent to create explicit obligations in the NER for these types of checks and balances, and appropriate responses.[294]

289 AGL, submission to first draft determination, pp. 6-7.
290 CS Energy, submission to first draft determination, p. 4.
291 Delta Electricity, submission to first draft determination, p. 19.
292 EnergyAustralia, submission to first draft determination, p. 12.
293 Flow Power, submission to first draft determination, p. 4.
294 Infigen, submission to first draft determination, p. 3.

- **Meridian Energy** noted that there may be a perverse incentive for a DRSP to contract with customers that appear to be responsive under deemed standardised baselines, with no incentive for underlying actual change in consumption or benefit to the market.[295]

Baseline compliance

- AEMO considers that there is currently uncertainty regarding the consequences for a DRSP of a baseline not being baseline compliant under the first draft rule. It should be the responsibility of the DRSP to ensure that a WDRU is not used to provide demand response if it has been found to not be baseline compliant.[296]

Dispute process

- **AGL** suggested that there should be a dispute mechanism for retailers should a retailer disagree with the baseline being applied to its customer, for example if it considered that it did not meet the accuracy or other requirements for that customer.[297]
- **Momentum** was of the view that the FRMP should also have the ability to approve or disapprove of a baseline methodology for each site as it will incur some of the risks associated with an inaccurate baseline.[298]
- **Stanwell** suggested that there should be a mechanism for the retailer to challenge whether a baseline is appropriate.[299]

Spot price pass through

- **PIAC** considered spot exposed retail customers should not be paid by a DRSP to reduce load that is also reducing their retail costs.[300]
- The **AEC** highlighted that the use of baselines is particularly problematic if employed by wholesale pool price pass-through customers. It noted that it is clear that the mechanism is not intended for these customers, but it is not clear how they can be excluded from gaming its use.[301]
- **EnergyAustralia** noted that it is important to clarify that customers on wholesale price pass through are prohibited from participating.[302]

Reporting requirements

- **CS Energy** submitted that the baseline reporting requirements are not sufficiently robust to ensure the baseline is updated following review. It proposed that:[303]
  - the process should include a positive obligation on AEMO to revise the baseline methodologies and baseline methodology metrics if improvements are identified; and

295 Meridian Energy, submission to first draft determination, p. 2.
296 AEMO, submission to first draft determination, p. 12.
297 AGL, submission to first draft determination, p. 7.
298 Momentum, submission to first draft determination, p. 4.
299 Stanwell, submission to first draft determination, p. 8.
300 PIAC, submission to first draft determination, p. 15.
301 AEC, submission to first draft determination, p. 3.
302 EnergyAustralia, submission to first draft determination, p. 10.
303 CS Energy, submission to first draft determination, p. 5.

- the process to revise the methodology and/or metrics should be commenced at the same time AEMO's report is published, as until revised, the market will continue to settle on a baseline which AEMO has identified as requiring improvement.

ARENA submission

ARENA's submission was accompanied by a report by Oakley Greenwood assessing the use of baselines in the AEMO-ARENA RERT program. It made the following points relating to its analysis on baselines:[304]

- The analysis undertaken on the '10 of 10' methodology suggested that this baseline methodology, currently used in the RERT, may be adequate for certain types of loads, particularly those of larger commercial and industrial customers whose energy consumption is relatively similar from day to day and not particularly weather sensitive.
- Where the load shape is not relatively consistent from day to day, the '10 of 10' methodology[305] can result in the baseline not being an accurate estimate.
- The '10 of 10' methodology might not be appropriate for the following types of loads:
  - Highly weather-sensitive loads. This was primarily an issue for residential facilities, but also for some smaller commercial facilities where weather (and particularly ambient temperature) has a material impact on total energy demand.
  - Loads influenced by rooftop PV generation. This was only cited as an issue for residential facilities, though it applies in principle to commercial and industrial facilities where the PV generation capacity is material compared to the load providing demand response.
  - Loads that vary from day to day, but in a consistent pattern. For example, where the facility has a different level or schedule of operation on specific days of the week (this was primarily cited as an issue for commercial and industrial facilities).
  - Highly intermittent loads. For example, where the facility or specific load providing demand response is driven by internal activity factors that are not related to external variables such as weather or day.
- Other approaches that may offer better alternatives for these types of loads include anchoring or the use of control groups:
  - Anchoring assesses the shape of consumption of the facility on days of like temperature in the past and the pre- and post-period consumption of the facility on the event day to construct the baseline.
  - A control group is a group of customers whose consumption on event days can be assumed (or has been shown) to be similar to that of the customers providing demand response. The difference between consumption on the day of a demand response event of the control group and the demand response customers is taken to represent the amount of demand response delivered.

304 Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response RERT Trial,* prepared for ARENA, September 2019.

305 The '10 of 10' methodology uses the consumption of the 10 most recent qualifying days to construct a baseline.

F.5 Commission's analysis and conclusions

BOX 9: BASELINES UNDER THE SECOND DRAFT RULE

The second draft rule introduces a framework for determining baseline methodologies for demand response load. Under the mechanism:

- AEMO will determine one or more initial baseline methodologies in consultation with stakeholders prior to the commencement of the mechanism, and additional methodologies, or additional baseline settings that may be applied to a methodology, may be developed over time
- AEMO will also set baseline methodology metrics in consultation with industry, setting the parameters for accuracy and bias of baselines
- therefore, the baselines for specific loads and intervals will be centrally determined, using the relevant baseline methodology, baseline settings and load data
- and so wholesale demand response will be settled through the wholesale market ex post, with reference to the baseline.

The second draft rule:

- requires AEMO to prepare baseline methodology metrics to assess whether a particular baseline methodology can sufficiently accurately predict a particular load's consumption. These metrics will be prepared in line with principles set out in the NER, and through the Rules consultation procedure.
- requires AEMO to establish arrangements for regular and systematic testing of demand response loads against the approved baseline methodologies, to determine whether the loads remain compliant with the metrics
- requires AEMO to prepare wholesale demand response guidelines, which will cover:
  - the process for a DRSP to apply to AEMO to have a baseline methodology applied to a wholesale demand response unit
  - any other information or requirements relating to the supply of wholesale demand response that AEMO considers appropriate.
- requires AEMO to determine one or more initial baseline methodologies
- places an obligation on AEMO to annually report on outcomes relating to baselines used under the mechanism, and how AEMO proposes to improve the accuracy and reduce the bias of these over time.

Benefits of the second draft rule

The framework for determining baselines under the second draft rule will:

- allow DRSPs to sell demand response into the wholesale market

- allow AEMO to develop an approach to centrally determining and settling baselines in consultation with stakeholders, which will allow more innovative approaches to be included over time, while minimising the costs to AEMO of allowing this to happen.

Changes from first draft rule

There are a number of changes that have been made between the first draft rule and second draft rule. These changes primarily seek to manage the costs associated with determining and applying baselines while preserving the integrity of the mechanism, as well as allowing baseline methodologies to be refined and improved over time as technology and data on baselines evolve. The key changes include the following:

- Where a wholesale demand response unit is spot price exposed in a trading interval, a DRSP will be obligated not to bid this load in to provide wholesale demand response. This will reduce the risks imposed on market participants while also preventing double dipping.
- The second draft rule places the obligation on the DRSP to not make dispatch offers in respect of wholesale demand response units that are not baseline compliant, rather than requiring AEMO to exclude such offers from dispatch. This is more consistent with similar types of obligations in the NER.
- The second draft rule no longer provides for market participants to develop and submit baseline methodologies to AEMO for approval. The Commission understands that requiring AEMO to build in this flexibility would impose significant costs. Instead, the second draft rule allows market participants to raise new methodologies for AEMO to consider implementing. This will still allow for innovative approaches to be developed but in a way that minimises costs.
- The second draft rule allows AEMO to develop a range of baseline settings, which may be applied to a baseline methodology to adjust it in specified ways for particular types of loads. The applicable baseline settings will be determined upon classification of the wholesale demand response unit and will also be visible to the relevant retailer.

This section is structured as follows:

- How the second draft rule addresses challenges with baselines
- AEMO to set baseline methodology metrics
- DRSP compliance with baseline methodology metrics
- Adjusting baselines under abnormal conditions
- Monitoring and reporting on outcomes relating to baselines
- Spot price exposed loads
- The treatment of additionality
- AER assessment of compliance.

F.5.1 How the second draft rule addresses challenges with baselines

As discussed in appendix f.2, there are a number of challenges that arise with having centrally determined and administered baselines.

The second draft rule seeks to address or mitigate these challenges by:

- Requiring AEMO to develop a series of baseline methodology metrics relating to accuracy and bias in consultation with stakeholders and informed by principles in the NER.[306] This will allow broad stakeholder input into determining the appropriate baseline metrics that will minimise the impact of any baseline errors on the market and market participants.
- Placing obligations on AEMO to regularly test how well a baseline methodology applies to individual loads.[307] If the baseline methodology does not produce a baseline that meets the baseline methodology metrics when applied to a wholesale demand response unit, that unit will not be able to provide wholesale demand response.[308]
- Placing obligations on AEMO to regularly report on outcomes relating to the use of baselines.[309]
- Placing obligations on AEMO to report on whether stakeholders have proposed alternate baseline methodologies and whether it is developing new methodologies.[310]
- Placing obligations on DRSPs to not to provide wholesale demand response wholesale demand response in respect of loads that are either not baseline compliant or are spot price exposed.[311]
- Placing obligations on the AER to enforce and provide guidelines in relation to the wholesale demand response mechanism. Under the second draft rule, DRSPs must not provide wholesale demand response that is not additional. That is, wholesale demand response should not be settled when it would have occurred anyway. The AER is required to develop guidelines in accordance with the Rules consultations procedures providing guidance on the information a DRSP must keep regarding compliance with its obligations relating to additionality, and these guidelines may also include guidance on DRSP requirements relating to baseline compliance and spot price exposure.[312]

The rest of this section provides more detail on the treatment of baselines under the second draft rule.

F.5.2 AEMO to set baseline methodologies

Rationale

Under the second draft rule, AEMO would be required to develop baseline methodology metrics and a register of baseline methodologies. This register would set out the baseline

306 Clauses 3.10.2 and 11.120.2(b) of the second draft rule.
307 Clause 3.10.2 of the second draft rule.
308 Clause 3.8.2A(c) of the second draft rule.
309 Clause 3.10.6(b) of the second draft rule.
310 Clause 3.10.6(b) of the second draft rule.
311 Clauses 3.8.2A(c) and (d) of the second draft rule.
312 Clause 3.8.2A(g) of the second draft rule.

methodologies that will be used to determine the quantity of wholesale demand response provided by a DRSP.

The Commission considers that a decentralised approach to determining a baseline is preferable in terms of risk allocation. That is, when baselines are determined between two market participants outside of the NER, these parties can allocate the risks of baseline inaccuracy between them. However, allowing DRSPs to directly participate in the wholesale market requires a framework in the NER that allows for baselines to be centrally administered for wholesale settlement. As such, the second draft rule places an obligation on AEMO to determine baseline methodologies. Over time, the Commission considers the market framework should move towards a decentralised approach such as a two-sided market where baselines are not required to be centrally determined.

Developing baseline methodologies can be challenging and resource-consuming. In addition to allowing third parties to participate, there are economies of scale benefits realised by having AEMO determine baseline methodologies centrally. Having baseline methodologies centrally determined will reduce the costs of establishing baselines for wholesale settlement at the commencement of the mechanism relative to requiring individual DRSP to determine these methodologies. In addition, the Commission understands that the administrative costs imposed on AEMO to administer baselines are materially reduced when it develops the baselines itself as opposed to allowing DRSPs to do so.

The methodologies determined and published by AEMO will be able to be used by market participants providing demand response through means other than the mechanism. The mechanism and AEMO's guidelines will not impact on, or prevent commercial entities agreeing to, alternative baseline arrangements outside of the NER for non-scheduled wholesale demand response (for example, in contracts between a retailer and end-user for behavioural demand response).

Wholesale demand response guidelines

Under the second draft rule, AEMO would be required to develop wholesale demand response guidelines. These guidelines will provide detail on a range of matters relating to wholesale demand response. In relation to baselines, these guidelines will set out:[313]

- information about the process for development of baseline methodologies, including how proposals for new baseline methodologies may be made
- the process for a DRSP to apply to AEMO for approval to apply a baseline methodology to a wholesale demand response unit when it is being classified (or at a later date, if the DRSP wishes to change to a different baseline)
- any other information relating to the supply of wholesale demand response under the NER.

In developing these guidelines, AEMO is required to follow the Rules consultation procedure.[314] This will allow stakeholders to provide input into the guidelines.

313 Clause 3.10.1 of the second draft rule.

314 This is set out in Rule 8.9 of the NER.

Baseline methodology metrics

AEMO will also need to determine the baseline methodology metrics. These metrics will be used to test the efficacy of baseline methodologies in predicting a load's consumption patterns (when it is not providing demand response), both at the time of classification of wholesale demand response units and during regular testing of these loads after classification.

AEMO will need to develop the baseline methodology metrics in line with a set of principles in the NER. The metrics must assess accuracy and bias:[315]

- Accuracy: meaning the deviation between the baseline for a wholesale demand response unit and its actual consumption or export (in periods when it is not providing demand response).
- Bias: meaning the deviation between actual consumption or export of a wholesale demand response unit and its baseline for each of the measures of baseline accuracy consistently exhibiting error:
  - in a single direction, or
  - under the same circumstances.

The baseline methodology metrics must be assessed in particular trading intervals and across multiple intervals for accuracy and bias.

In determining the metrics, AEMO must also have regard to:[316]

- the need to not distort the operation of the market
- the need to maximise the effectiveness of the wholesale demand response at the least cost to consumers
- the level of accuracy achieved by AEMO's short-term demand forecasts and forecasts of intermittent generation.

The Commission considers the metrics produced by AEMO should require baselines to exceed the levels of accuracy considered 'good' in the AEMO-ARENA demand response RERT trials.[317] The standard for baselines used for wholesale demand response, which is required to be reliable and predictable, should be higher than that experienced with emergency demand response such as the RERT. This should reflect improvements in baseline methodologies arising from that trial and the likelihood of more frequent utilisation for the purposes of wholesale demand response. The baselines used for the RERT should also be improved where possible.

F.5.3 DRSP compliance with baseline methodology

Under the second draft rule, DRSPs will need to show that a baseline can be determined for the load that complies with the baseline methodology metrics both during classification and in an ongoing sense.

315 Clause 3.10.2 of the second draft rule.

316 Clause 3.10.2(f) of the second draft rule.

317 Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response RERT Trial*, prepared for ARENA, September 2019, p. 7.

A wholesale demand response unit is considered baseline compliant if the baseline methodology and baseline settings applied to the wholesale demand response unit produce a baseline that satisfies the baseline methodology metrics. Conversely, a wholesale demand response unit becomes non-compliant when the baseline for a wholesale demand response unit does not meet the baseline methodology metrics.[318]

Under the second draft rule, AEMO must determine and publish arrangements for regular and systematic testing to show whether wholesale demand response units are baseline compliant.[319] AEMO must also determine the frequency with which the baseline compliance testing will occur, which may be different for different wholesale demand response units or classes of wholesale demand response unit.[320]

Under the second draft rule, DRSPs are required to demonstrate that their loads will be able to meet the baseline methodology metrics and other requirements under the wholesale demand response guideline. This means the DRSP will need to show that the load can meet the requirements relating to accuracy and bias of the chosen baseline methodology prior to being classified as a wholesale demand response unit.[321]

AEMO will be required to set out the process for DRSPs to demonstrate compliance with these metrics.[322] For example, this could include calculating the baseline for a range of intervals in the previous year and comparing these to actual loads during those intervals.

Either during the classification process or in the course of periodic checks by AEMO, where a load is found to be outside the specific metrics set out by AEMO in relation to the chosen baseline, that load will not be able to provide wholesale demand response.[323] This load will be prohibited from providing wholesale demand response until it is able to demonstrate compliance with the requirements in respect of its chosen baseline methodology. It could potentially do so by requesting approval to change to a different baseline methodology or different baseline settings, as outlined in appendix f.5.5.

Under the second draft rule, the obligation is placed on the DRSP to not offer wholesale demand response from loads that are not baseline compliant.[324]

The DRSP is required to establish and comply with measures to identify whether its wholesale demand response units are not baseline compliant.[325] If a DRSP becomes aware that its unit is not compliant, it is required to inform AEMO.[326] Likewise, if AEMO becomes aware that a wholesale demand response unit is not baseline compliant, it must inform the

318 Clause 3.10.4 of the second draft rule.
319 Clause 3.10.2(d) of the second draft rule.
320 Clause 3.10.2(e) of the second draft rule.
321 Clause 2.3.6(e)(5) of the second draft rule.
322 Clauses 3.10.1 and 3.10.2 of the second draft rule.
323 Clause 3.8.2A(c) of the second draft rule.
324 Clause 3.8.2A(c) of the second draft rule.
325 Clause 3.8.2A(f) of the second draft rule.
326 Clause 3.10.2(i) of the second draft rule.

DRSP.[327] The onus would remain on the DRSP to provide an availability of zero for this wholesale demand response unit.

F.5.4 Adjusting baselines under abnormal conditions

The second draft rule allows AEMO to establish a process by which DRSPs can nominate to AEMO that an event or circumstance will materially change the consumption pattern of the wholesale demand response unit, such that it proposes to temporarily vary its baseline.[328]

If AEMO establishes this process, the DRSP may wish to use it in order to maintain compliance with the baseline methodology metrics. For example, in the circumstances where a load is operating at half capacity during maintenance, the DRSP will be able to notify AEMO of this fact, and have the baseline adjusted appropriately, in order to remain baseline compliant.

Under the second draft rule, AEMO may prepare abnormal baseline notice procedures.[329] In determining the abnormal baseline notice procedures, AEMO must set out conditions that:[330]

- only permit an abnormal baseline notice to be given where the cause of the abnormality is not something that could have been reasonably accounted for in the baseline methodology
- limit the frequency of abnormal baseline notices and the number of trading intervals to which a factor specified in the notice may be applied.

In addition, AEMO may specify in the abnormal baseline notice procedures:[331]

- requirements for the submission of abnormal baseline notices including timing and content;
- information to be provided to AEMO or records to be made by the DRSP in connection with an abnormal baseline notice;
- events or circumstances that are taken to have been accounted for in the baseline methodology and in respect of which no abnormal baseline notice may be given;
- conditions limiting or precluding the submission of an abnormal baseline notice where reasonably considered necessary by AEMO to maintain the accuracy and reliability of baseline calculations; and
- any other terms and conditions reasonably determined by AEMO.

The second draft rule does not allow for the DRSP to adjust the baseline upward and to use this baseline in settlement. This is to prevent DRSPs from manipulating baselines to receive payment for additional wholesale demand response that would have not actually occurred.

327 Clause 3.10.2(h) of the second draft rule.
328 Clause 3.10.5(b) of the second draft rule.
329 Clause 3.10.5(b) of the second draft rule.
330 Clause 3.10.5(d) of the second draft rule.
331 Clause 3.10.5(e) of the second draft rule.

F.5.5 Developing new baseline methodologies

Under the second draft rule, market participants are able to submit proposals for the development of new baseline methodologies to AEMO for consideration.[332]

Under the first draft rule, market participants were able to submit baseline methodologies to AEMO that AEMO would then need to consider against the baseline methodology metrics for that load.[333] However, AEMO advised that this framework would have imposed significant upfront costs on AEMO to be able to assess, implement and administer bespoke approaches to baselines.

As such, the second draft rule removes the framework for baseline methodologies to be directly submitted by market participants. However, it is important that the framework under the rule still allows for the development of new baseline methodologies. As has been demonstrated in the AEMO-ARENA RERT trial, baseline methodologies are not 'one-size-fits-all'. This trial also showed that market participants are equipped to develop new approaches that can reflect improvements in baselining or applying baselines to new types of loads.[334]

For this reason, the second draft rule provides for stakeholders to propose that AEMO develop new baseline methodologies. These methodologies would be able to be considered by AEMO and potentially implemented as a methodology that could be used under the mechanism. To provide transparency to the market about how new baseline methodologies are being developed, AEMO would be also required, under the second draft rule, to report on both new baseline methodologies proposed to it, and new baseline methodologies being developed.[335]

The second draft rule would therefore enable innovative approaches to baseline methodologies to be developed over time, particularly as experience is gained using baselines for wholesale demand response. In facilitating the development of new baseline methodologies, the second draft rule balances this against the extent of the upfront cost in implementing and administering these new baselines.

F.5.6 Monitoring and reporting of baselines

The second draft rule requires AEMO to report on outcomes relating to baseline accuracy. AEMO will be required to annually publish a report covering:[336]

- information about baseline methodologies available for use and the extent to which they are being used
- for each baseline methodology and type of wholesale demand response unit, an assessment of accuracy and bias as measured during the classification process and during ongoing testing

332 Clause 3.10.1(a)(4) of the second draft rule.

333 Clause 3.10.2(e) of the first draft rule.

334 See section 5 of the Oakley Greenwood report for a discussion of alternative approaches to baselines submitted by proponents in the RERT program. Oakley Greenwood, *Baselining the ARENA-AEMO Demand Response Trial,* prepared for ARENA, September 2019, p. 19.

335 Clause 3.10.6(b) of the second draft rule.

336 Clause 3.10.6(b) of the second draft rule.

- any periods of time where wholesale demand response units have been ineligible for dispatch due to not being baseline compliant
- potential improvements which may include:
  - changes to baseline methodology metrics as a result of the development of new baseline methodologies
  - the development of new baseline methodologies
  - any other any measures that may be taken to improve the accuracy or reduce the bias of baseline methodologies
  - changes to the wholesale demand response guidelines or the NER
- the timing and process for making any improvements.

By having AEMO undertake monitoring and reporting on baselines, it will improve transparency to the rest of the market regarding the utilisation of centrally determined baselines.

F.5.7 Spot price exposed loads

The second draft rule places an obligation on the DRSP to submit zero availability to provide wholesale demand response from wholesale demand response units that are spot price exposed.[337]

The mechanism introduced in the second draft rule provides an additional avenue for consumers to respond to wholesale prices and capture the benefits. The appropriate customers for this mechanism are those who are not currently participating in wholesale demand response.

A number of stakeholders considered that, under the first draft rule, retailers could be exposed to significant risk if spot price exposed customers participated in the wholesale demand response mechanism. This was because:

- retailers will be charged in the wholesale market for the baseline level of consumption
- the mechanism keeps retailers whole through the reimbursement rate, which is intended to reflect the wholesale price component of an average retail rate, and would not relate to retailer liability under a spot price pass through contract.

The Commission agrees that spot price exposed loads are not suited to participating in the wholesale demand response mechanism because:

- These customers already face a strong incentive to provide wholesale demand response by being exposed to the wholesale price. If spot price exposed customers were to participate, it would have the effect of exposing the retailer to the spot price and allowing the customer to ' double dip' i.e. avoid the spot price that would have been passed through by the retailer *and* receive a payment from the DRSP.
- The demand response provided by spot price exposed customers would likely not be additional. The Commission notes that this was the intent of the additionality provisions

337 Clause 3.8.2A(d) of the second draft rule.

under the first draft rule. Spot price exposure provides customers with a strong incentive to respond to wholesale prices. Under the clauses relating to additionality, this would mean that, if a customer was already going to respond to wholesale prices, it should not also provide wholesale demand response through the mechanism. However, by making the provision more explicit in the second draft rule, the Commission considers this will reduce the risks imposed on retailers and the risks of double dipping.

Therefore, the second draft rule precludes spot-price exposed customers participating in the wholesale demand response mechanism in the interval in which the customer is exposed to the spot price.

Under the second draft rule, a wholesale demand response unit considered to be exposed to the spot price in a trading interval if the purchase price for electricity in the contract between that customer and the relevant FRMP is equal to, or varies by reference to, the spot price in that trading interval. This means that if, in a specific interval, the price in the retail arrangement between the customer for the wholesale demand response unit and the FRMP has some form of spot price exposure, that customer cannot also provide wholesale demand response through the mechanism. This includes if:

- the spot price exposure only applied to some of the load
- only a portion of the spot price was passed through.

The Commission notes that spot price exposure can vary from direct pass through to more complex arrangements, for example where only a share of the load is spot price exposed or that spot price pass through exposure only occurs if a certain threshold is met. Noting that the concerns around double dipping and retailer risks arise specifically in the intervals where the wholesale demand response unit is spot price exposed, which may be only a portion of the day or year (depending on the retail contract), the second draft rule only places the prohibition on those specific trading intervals. A DRSP would still be able to contract with a customer who has a spot price pass through arrangement with their retailer and offer wholesale demand response in the intervals where the customer is not spot price exposed.

The Commission also notes that this issue may alternatively be addressed by retailers making spot price pass through offers to customers conditional on not participating in the mechanism.

F.5.8 Treatment of additionality

A number of stakeholders commented on whether the first draft rule would permit the DRSP to 'value stack'. This refers to capturing value in multiple parts of the supply chain simultaneously. For example, by providing demand response, a customer may be simultaneously providing value in the wholesale market and to the relevant network service provider.

The second draft rule is, in general terms, consistent with the first draft rule in this regard, although the approach to the drafting has changed. In the second draft rule, the Commission proposes that a DRSP may become liable for significant penalties if it makes a dispatch bid for wholesale demand response which will, if dispatched, not be the result of responding to instructions in central dispatch.[338] This means that DRSPs should only offer wholesale demand response when it is additional to the activities that that load was already going to undertake. In effect, this is intended to prevent consumers paying for a demand reduction that was *already going to occur.*

The Commission considers it important that, if a customer was already going to reduce its consumption, and paying that customer more would not provide additional demand response, this payment should not occur. This would have the effect of increasing costs in the wholesale market without the procurement of any additional wholesale demand response. For example, the additionality provisions should prevent:

- a payment being made to a factory that had already decided to shut down for maintenance
- a payment being made to a customer if that customer had already decided to respond to a peak network event and a payment from the wholesale market would not elicit any more wholesale demand response.

This does not mean the second draft rule prevents value stacking in all circumstances. If value stacking enables a customer to provide additional demand response, a DRSP would be able to offer this in the wholesale demand response mechanism. In effect, this means that, through the introduction of the wholesale demand response mechanism, more value stacking for demand response should be able to occur than is currently the case. For example, if a payment from a network service provider alone was insufficient to encourage demand response from a customer, but the combination of that payment and a payment in the wholesale market enables a response, this would satisfy the additionality requirement and the customer would be eligible to offer that response in the wholesale market.

The second draft rule also prevents wholesale demand response being offered by a DRSP where the response would be directly offset by an increase in consumption elsewhere at the same time.[339] This is intended to prevent a demand reduction appearing to be provided at one NMI, but in reality load has simply been shifted to another NMI during the same interval. This behaviour could allow a DRSP to be credited with providing wholesale demand response that did not actually occur. As such, the second draft rule prevents DRSPs from offering this activity as wholesale demand response.

F.5.9 AER assessing compliance

Under the second draft rule, the AER will also have a role in assessing whether participants are manipulating baselines to inefficiently increase the amount of demand response credited.

The AER will need to enforce compliance in respect of DRSP bidding. This relates to the DRSP bidding in good faith, which incorporates the obligation on DRSPs to not offer wholesale demand response that would not have otherwise occurred.

338 Clause 3.8.22A(a2) of the second draft rule, proposed to be part of the rebidding civil penalty provision, and the definition of "wholesale demand response activity" in chapter 10 of the second draft rule. These provisions are discussed further below.

339 See paragraph (e) of the definition of "wholesale demand response" and the definition of "baseline deviation offset" in Chapter 10 of the second draft rule.

When a DRSP is making a dispatch bid, the bid represents to other Market Participants in pre-dispatch that the wholesale demand response offered would be result of specific activity on behalf of the DRSP (that the DRSP would not otherwise undertake).[340] A dispatch bid from a DRSP would be considered false or misleading if the DRSP does not have a genuine intention to honour that representation or a reasonable basis to make it.[341]

The AER must develop wholesale demand response participation guidelines in accordance with the Rules consultation procedures which: [342]

- must include guidance about information DRSPs must retain regarding compliance with their obligations in relation to additionality, baseline compliance and spot price exposure, to assist the AER in monitoring these obligations, and
- may include guidance relating to the requirements on DRSPs in relation to baseline compliance and spot price exposure.

The AER must publish these guidelines and may amend them from time to time.

340 Clause 3.8.22A(a2) of the second draft rule.

341 Clause 3.8.22A(b) of the second draft rule.

342 Clause 3.8.2A(g) of the second draft rule.

G SETTLEMENT AND COST RECOVERY

G.1 Overview

This appendix sets out the approach to settlement and cost recovery under the demand response mechanism. Wholesale demand response which is provided through the wholesale demand response mechanism needs to be appropriately rewarded. The settlement and cost recovery framework sets out how DRSPs will be paid and the associated financial flows between market participants.

Cost recovery arrangements for wholesale demand response (other than through the new mechanism) involve either:

- the customer enjoying lower electricity bills via the benefit of having avoided the wholesale price, or
- an alternative arrangement, whereby the customer receives a payment that has been bilaterally negotiated between the retailer (or a network service provider) and the customer in return for reducing consumption.

However, under the new wholesale demand response mechanism, cost recovery occurs through AEMO's central settlement, similar to how generation is currently paid. This appendix sets out the settlement and cost recovery model applying under the second draft rule.

The remainder of this appendix outlines:

- approaches to rewarding consumers for providing wholesale demand response otherwise than through the new mechanism
- stakeholders' views on the settlement model proposed under the first draft rule
- the Commission's analysis and conclusions in relation to settlement and cost recovery under the new mechanism.

G.2 Background

G.2.1 How is wholesale demand response currently rewarded in the NEM?

In the NEM, the wholesale spot price is able to rise considerably - up to the market price cap[343] - in response to the short-term supply-demand balance, and so the demand side can respond to wholesale market price signals. To the extent that all consumers could fully participate in this, the NEM would become a true two-sided market, consistent with the vision that the Commission set out in its digitalisation discussion paper.[344]

In contrast, in other markets where participants are paid availability payments the spot price for energy generally has a much lower market price cap (reflecting the fact that generators receive much of their revenue from these capacity availability payments). As such, demand response providers are not exposed to high price signals incentivising them to reduce consumption and so an alternative source of payment (the availability payment) is required.

343 The market price cap is currently set at $14,700 in accordance with the process set out in the NER.

344 AEMC, *How digitalisation is changing the NEM: The potential move to a two-sided market*, November 2019. Available at: https://www.aemc.gov.au/sites/default/files/2019-11/How%20digitalisation%20is%20changing%20the%20NEM.pdf.

If there is a high spot price in the NEM, parties directly exposed to the spot price should be incentivised to shift their consumption (or their customers' consumption) to avoid the high price at this point in time. The wholesale electricity market rewards reduced consumption with the *avoided costs* of purchasing from the wholesale market at that time.

There are a number of specific mechanisms in the NEM and in some types of energy contracts whereby consumers can be rewarded (either through a reduction in costs or a payment) for wholesale demand response, for example (some of these are also summarised in chapter 3):

- A consumer may be the FRMP (i.e. it may itself be a wholesale market customer) in which case it directly changes its exposure to the spot price by changing its consumption
- A consumer may be supplied electricity by a retailer, but be on a spot price pass through arrangement, which again means that it avoids the spot price by reducing its consumption
- A consumer may be supplied by a retailer and have a tariff that does not reflect the spot price in the short term. In this case, its retailer (which is exposed to the spot price) might incentivise the consumer to reduce its consumption. The retailer benefits if the reduction of its spot price exposure exceeds any payment made to its customer. The nature of this payment is a matter for commercial negotiation between the retailer and its customer. The existence and quantity of the reward depends on private negotiations between the retailer and the customer (rather than on an automatic market-based reward mechanism).

In each case, the retailer or consumer may have a commercial arrangement with a third party service provider to facilitate the consumer reducing its consumption at certain times.

In cases where the customer is not on a spot price pass through contract, the payment from the retailer for the demand response provided by the customer may be based on, or relative to, a baseline level of consumption. Both the baseline and the payment made by the retailer are determined by commercial negotiation between those two parties. No other parties are required to be involved in this process. Under these arrangements, to the extent that there is a *payment* to a consumer for reducing their demand at a particular point in time, this is funded by the parties participating in that arrangement. For example, if a retailer offers a demand response program, then it will give customers an amount to reward them for reducing their demand. This reward could either occur through a monetary payment, or a non-financial reward (e.g. a free movie ticket). The cost of this reward is recovered as part of the retailer's operating costs, which it recovers from all of its customers. Examples of existing demand response programs are set out in chapter 3.

Under such arrangements, at some times the cost to the retailer of providing the customer with a financial reward may exceed the benefit to the retailer of avoided wholesale costs. This risk is borne by the retailer. However, the retailer is also in a position to manage or mitigate this risk. In addition, retailers may realise value through these programs in other ways, such as increasing customer loyalty by offering such programs.

G.2.2 What is the difference between actual and baseline consumption?

The rule change requests refer to actual and baseline levels of consumption. Baselines are discussed in detail in appendix F. Loads that are participating in a wholesale demand response mechanism must, by definition, have both actual and baseline levels of consumption.

- The actual level of consumption is a consumer's metered, physical consumption of electricity. Under the arrangements prior to the introduction of the new mechanism, consumers are billed for their actual consumption and retailers are responsible for purchasing this load from the wholesale market.
- The baseline level of consumption is the predicted, counterfactual level of consumption that would otherwise have happened were it not for the demand response.

Ideally, if the customer is not providing demand response, then its baseline level of consumption should be the same as its actual level of consumption - because the baseline level of consumption is meant to be an approximation of consumption that would otherwise have happened in the absence of demand response.

G.3 Settlement model under the first draft rule

This section provides a high-level summary of the options for facilitating cost recovery which were considered in the first draft determination, as well as the settlement model that was proposed under the first draft rule.

The settlement models which were proposed by the rule change proponents and considered in the first draft determination included:

- **Integrated settlement:** This model was proposed by PIAC, TEC and TAI and the SA Government and would broadly operate as follows where a consumer has provided wholesale demand response:[345]
  - In order to have sufficient money from settlements in order to pay the demand response providers, retailers of the consumer which is undertaking demand response would be charged by AEMO for energy consumption at a NMI (at the NEM spot price) based on the baseline energy consumption rather than actual energy consumption.
  - The retailer would bill the customer for their baseline amount of energy consumption.
  - The DRSP would be paid the difference between the customer's baseline consumption and their actual consumption (i.e. the amount of demand response provided) multiplied by the spot price.
  - The DRSP (if it is not itself the customer that provided the demand response, noting that market customers could register as DRSPs and manage their own load accordingly) would share the value of that payment with the customer in accordance with the commercial agreement between those parties.
- **Separate settlement:** The SA Government also proposed a transitory demand response model which would allow third parties to sell wholesale demand response into a market

345 PIAC, TEC and TAI, *Wholesale demand response energy market mechanism: Rule change request*, August 2018, p. 4.

which is separate from the wholesale market, recovering costs via a charge levied on all retailers (and passed on to their customers).[346] Under this settlement model, the costs for wholesale demand response would be recovered from consumers in a smeared manner, similar to the way in which the current RERT costs are recovered.

- **Private settlement:** The Australian Energy Council's proposal to establish a wholesale demand response register did not involve any changes to existing settlement arrangements in the NEM.[347] Payments for wholesale demand response under this proposal would remain a matter for commercial negotiation between the parties involved and so would not be centrally settled.

The Commission proposed an alternative settlement model under the first draft rule which addresses a number of issues relating to practicality, implementation costs and market design principles associated with the models described above.

Under the settlement model proposed in the first draft determination, settlement would operate as follows where a customer provides wholesale demand response through the mechanism:

- AEMO would bill retailers for the customer's baseline level of consumption at the wholesale price
- retailers would continue to bill customers for their actual consumption (as they do currently)
- DRSPs would be paid the spot price for the difference between the actual and baseline level of consumption
- retailers would recover the discrepancy between what they recover from the customer and what they are charged in the wholesale market from the DRSP, via AEMO's settlement process. This amount would be calculated based on a wholesale demand response reimbursement rate (reimbursement rate)
- the customer would receive a share of the payment to the DRSP for the wholesale demand response provided in accordance with the commercially agreed terms between those two parties.

The reimbursement rate under the first draft rule would be calculated by the AER on a quarterly basis and would be based on average wholesale prices over the previous 12 months. This rate is intended to be a proxy for the wholesale cost component of the customer's retail tariff.

G.4 Stakeholder comments on settlement model

The vast majority of stakeholders commented on the settlement model in submissions to the first draft determination. These comments primarily focused on the reimbursement rate. In general, stakeholders:

346 South Australian Government, rule change request, October 2018, p. 6.

347 AEC, rule change request, October 2018, p. 2.

- requested greater clarity on the purpose of the reimbursement rate and how the position in the draft determination was determined[348]
- suggested alternative methodologies for calculating the reimbursement rate which they considered may better meet the purpose of keeping retailers whole (the alternative methodologies proposed by stakeholders are discussed further below)
- noted that the reimbursement rate is problematic for retailers with customers directly exposed to the spot price.[349]

Some stakeholders also suggested that the reimbursement rate could simply be removed from the design of the mechanism, on the basis that the reimbursement rate payments from DRSPs to retailers are anticipated to be a relatively small proportion of the total financial flows under the mechanism.[350]

Other specific comments on the reimbursement rate included:

- the adoption of both a peak and off-peak reimbursement rate is encouraged as customers may have peak and/or off-peak rates in their retail sales agreements[351]
- while there is a need for simplicity and transparency in determining the reimbursement rate, this should not occur at the expense of this rate not being reflective of a retailer's foregone revenue[352]
- retailers don't purchase energy to supply their customers on a long-term "set & forget" basis - they are constantly reassessing their portfolios and buying (and selling) different products according to their individual risk appetites, to match their expected demand, based upon current forecasts of weather, price and other relevant parameters[353]
- It would be more equitable for retailers to recover the full retail tariff relevant to the customer for the relevant time when demand response was activated to ensure that the risks for retailers are minimised and retail prices are not unduly impacted[354]
- as the reimbursement rate is based on the net system load shape, it will excessively penalise retailers with a portfolio of peakier customers and most retailers will respond rationally to this economic incentive to actively avoiding demand response customers due to higher costs of supplying and increased uncertainties.[355]
- it would be more appropriate to calculate the reimbursement rate based on an independently determined forward curve of the wholesale market but this also needs to reflect the short term hedges that retailers also purchase and a retail risk margin[356]
- any reimbursement rate methodology should consider the following matters:[357]

348 For example: Snowy Hydro, p. 1; Australian Energy Regulator, p. 3; ERM Power, p. 2.
349 For example: Clean Energy Council, p. 2; Flow Power, p. 5.
350 Brickworks, submission to first draft determination, p. 1; Major Energy Users, submission to first draft determination, p. 5.
351 Aurora Energy, submission to first draft determination, p. 1.
352 Ibid.
353 Australian Energy Council, submission to first draft determination, p. 3.
354 Delta Electricity, submission to first draft determination ,p. 2.
355 Meridian Energy/Powershop, submission to first draft determination, p. 2.
356 Momentum Energy, submission to first draft determination, p. 3.
357 Snowy Hydro, submission to first draft determination, p. 6.

- a retailer's hedging is dynamic and a customer's contract price will reflect the time, load, and temperature at the time of the commercial transaction
- demand response is likely to be dispatched at times of peak demand when prices are high prices and this should be reflected in hedging costs
- high prices are not equal across the day but only for a few hours and it is costly to hedge for these periods
- hedge prices generally trade at a premium to spot prices with a built in margin so any rate which is based on the spot rate would not fully compensate retailer.

- while retailers have highlighted the potential for them to under-recover their costs under the reimbursement rate approach, it is important to note that there is also the potential for retailers to receive a windfall gain if the reimbursement rate is too high[358]
- it should be clarified that DRSPs will also have visibility of the reimbursement rate, or that it will be made publicly available.[359]

Of those stakeholders that commented on the settlement model in submissions to the first draft determination, all noted that the model set out in the first draft rule is preferable to an alternative model where customers are billed on their baseline level of consumption, due to the significantly reduced impact on retailer billing systems and associated implementation costs.

Alternative methodologies for calculating the reimbursement rate proposed by stakeholders in submissions to the draft determination included:

- using average peak ASX futures contract prices over the previous 12 months[360]
- using 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 to reflect the fact that the rate may not reasonably reflect the costs incurred by the retailer[361]
- using average base ASX futures contract prices over the previous 12 months[362]
- using average peak wholesale prices over the previous 12 months.[363]

These stakeholders generally suggested that the alternative methodology proposed better reflects the costs incurred by the retailer in the intervals in which wholesale demand response is likely to be provided by customers.

Stakeholders also commented on the party who should be responsible for determining the reimbursement rate. Both the AER and AEMO submitted that this function should be conferred on AEMO, rather than the AER, to reduce administrative complexity.[364]

358 Enel X, submission to first draft determination, p. 11.
359 Ibid, p. 11.
360 Submissions to first draft determination: AEC, p. 3; CS Energy, p. 4; Energy Queensland, p. 9; AGL Energy, p. 7; Infigen Energy, p. 2.
361 ERM Power, submission to first draft determination, p. 3.
362 Energy Users Association of Australia, submission to first draft determination, p. 4.
363 EnergyAustralia, submission to first draft determination, p. 8.
364 AEMO, submission to first draft determination, p. 18; AER, submission to first draft determination, p. 3.

Other comments on the settlement model more generally included:

- The basis of the payment from the DRSP to the customer for the demand response provided is that the customer is not "seeing" the spot price, and this is needed to provide that signal. As the DRSP would have a business model to capture a proportion of this value, the incentives for the customer to undertake DR would be proportionally reduced.[365]
- The socialisation of the cost of the delivered demand response among retailers would considerably enhance the level of participation in the mechanism.[366]
- It was not clear from the draft rule whether net exports at a site (for example as a result of having an onsite generator or battery) could also be credited as wholesale demand response.[367]

G.5 Commission's analysis and conclusions

BOX 10: SETTLEMENT MODEL UNDER THE SECOND DRAFT RULE

The second draft rule maintains the settlement model set out in the first draft rule, including the methodology for determining the reimbursement rate. This settlement model has the following key features:

- AEMO will bill retailers for the customer's baseline level of consumption in the wholesale market
- retailers will bill customers for their actual consumption
- retailers will recover the discrepancy between what they recover from the customer and what they are charged in the wholesale market (that is, the difference between baseline and actual consumption) from the DRSP, via AEMO's settlement process. This amount will be calculated based on a reimbursement rate.
- the reimbursement rate will be a rolling average of demand-weighted spot prices over the previous 12 months and will be calculated by AEMO on a quarterly basis.

Benefits of second draft rule

The Commission considers that the settlement and cost recovery model applying under the second draft rule addresses a number of significant issues associated with other models proposed by the rule change proponents. In particular, the settlement model will:

- allow retailers to continue to bill customers based on actual consumption, thereby significantly reducing the changes required to retailer billing systems and the associated implementation costs
- reduce the scope of the changes required to AEMO's settlement systems

365 Delta Electricity, submission to first draft determination, p. 13.

366 Electricity Exchange, submission to first draft determination, p. 5.

367 Enel X, submission to first draft determination, p. 14.

- avoid imposing unmanageable or unhedgeable risks on retailers, which would have led to increased costs for consumers.

Further, the reimbursement rate methodology adopted under the second draft rule provides a simple, transparent and objective process for approximating the wholesale cost component of an average retail tariff, particularly for large commercial and industrial customers, in order to allow retailers to recover their costs.

Differences between first draft rule and second draft rule

The most material difference between the first draft rule and the second draft rule in relation to the settlement process is that AEMO, rather than the AER, has been given the function of determining the reimbursement rate. This change was based on stakeholder feedback and will make this process more administratively efficient.

The settlement equations under the second draft rule have also been amended to:

- account for distribution and transmission losses in transactions for wholesale demand response, in order to treat wholesale demand response on an equal footing with generation
- provide that the calculation of the wholesale demand response settlement quantity is based on metered energy rather than adjusted gross energy, such that the amount of wholesale demand response provided will not be adjusted for unaccounted for energy (UFE).

There are a number of ways in which demand response providers could be compensated for reducing demand under a wholesale demand response mechanism involving centralised settlement. The approach taken to settlement and cost recovery can have a significant impact on the extent of the costs associated with changes to retailers' and AEMO's systems to accommodate the mechanism, which are ultimately borne by consumers.

Accordingly, the Commission has sought to develop a settlement model which is cost-effective for consumers and market participants. The settlement model adopted in the second draft rule addresses a number of issues associated with alternative models proposed by the rule change proponents and can be considered to be a pragmatic compromise between capturing the benefits of the separate settlement model proposed by the South Australian Government and still allowing the costs to be allocated to those retailers whose customers are participating in the mechanism.

The key features of this settlement model are discussed in detail below.

G.5.1 Wholesale market billing

The second draft rule introduces separate settlement equations for wholesale demand response. Under the second draft rule, the retailer will purchase electricity in the wholesale market for its customers' baseline level of consumption (consistent with the proposals in the models put forward by PIAC, TEC and TAI, and the South Australian Government). Given that the retailer is not the party facilitating the wholesale demand response by the customer, the retailer's exposure in the wholesale market should be the same regardless of whether the customer is providing demand response at any point in time. If the retailer were only billed by AEMO for the customer's actual reduced consumption where the customer is providing demand response through the mechanism, the retailer would receive the benefit of the reduced exposure to the spot price despite not having taken any action to facilitate this. In addition, this would result in a shortfall of funds required to pay the DRSP (and in turn the customer) for the demand response provided.

The DRSP will be paid in the wholesale market for the amount of wholesale demand response provided at the spot price. A settlement transaction would only occur for a DRSP in a trading interval in which its WDRU is dispatched to provide wholesale demand response. If a DRSP has an aggregated WDRU that is dispatched to provide wholesale demand response, a settlement transaction will occur for each of the loads within the aggregated unit. However, if the aggregated WDRU is dispatched at its maximum responsive component (i.e. the WDRU is not providing wholesale demand response in that trading interval), no settlement transaction for wholesale demand response would occur for any loads within the unit. The approach to dispatch under the second draft rule is discussed further in appendix D.

The settlement equations under the second draft rule have also been amended to account for distribution and transmission losses in transactions relating to wholesale demand response. This is based on feedback from AEMO that it is desirable to account for these losses to ensure that quantities of, and prices paid for, wholesale demand response more closely align with energy settlement.[368] This is consistent with the principle that wholesale demand response should be treated equivalently to generation where possible.

The Commission has considered the interaction between the settlement of wholesale demand response and the changes to the allocation of "unaccounted for energy" (UFE) introduced by the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 No. 14 (global settlement rule).[369] The Commission does not consider that any changes are required to the provisions in that rule relating to the calculation and allocation of UFE as a result of the introduction of the wholesale demand response mechanism. However, the settlement equations for wholesale demand response under the second draft rule have been amended to provide that the calculation of wholesale demand response settlement quantity is based on metered energy rather than adjusted gross energy, such that the amount of wholesale demand response provided will not be adjusted for unaccounted for energy (UFE) when the global settlement rule takes effect.

The settlement equations under the second draft rule also provide for retailers to be charged by AEMO for the difference between their customer's actual and baseline consumption in the wholesale market (i.e. to provide that retailers are liable up to the baseline level of consumption).[370] The calculation of this amount is separate to the existing calculation of a

368 AEMO, submission to first draft determination, p. 17.

369 Available at: https://www.aemc.gov.au/rule-changes/global-settlement-and-market-reconciliation.

370 Clause 3.15.6B(b) of the second draft rule.

retailer's liability in the wholesale market for its customer's actual consumption, which is based on "adjusted gross energy" (AGE) for the customer's connection point.[371] The latter calculation already incorporates the retailer's allocation of UFE for the relevant distribution area and retailers will continue to be charged for this amount under the second draft rule.

In other words, AEMO will still be able to fully recover payment for UFE from retailers based on the methodology introduced by the global settlement rule. Wholesale demand response will not result in the creation of any additional UFE, as it does not create additional demand that must be supplied by generators (which may subsequently lead to increased UFE in the system). As such, the new settlement equations introduced under the second draft rule do not include any adjustments for UFE in respect of wholesale demand response.

The wholesale demand response settlement equations also address cost recovery from the DRSP, via AEMO, in the form of the reimbursement rate paid to retailers, which is discussed in detail below.

AEMO will need to review its existing guidelines and procedures relating to settlement, and may need to develop new guidelines and procedures, to account for retailers being charged for the customer's baseline level of consumption where wholesale demand response is provided through the mechanism. The second draft rule includes transitional provisions to address this.[372]

G.5.2 Retail billing

Retailers will continue to bill customers based on their actual electricity consumption under the approach set out in the second draft rule. The Commission considers that there is a significant benefit to this approach, as it avoids substantial changes to retailer billing systems. The Commission understands that the changes to retailers' systems which would be required to facilitate billing customers for their baseline level of consumption (as proposed in the models put forward by PIAC, TEC and TAI, and the South Australian Government) would likely be the most significant component of the costs associated with implementing a demand response mechanism. As such, allowing retailers to continue to bill customers for actual consumption should substantially reduce the costs and complexity of implementation for retailers. This will also avoid any potential confusion that may arise from customers being billed by retailers for electricity they did not consume (i.e. if retailers were instead required to bill customers for their baseline level of consumption).

Given that network costs and the costs of environmental schemes are based on actual consumption, retailers will continue to recover these costs in full from customers.

G.5.3 Retailer hedging

Given that retailers will be required to purchase the baseline level of consumption in the wholesale market, the Commission expects that retailers will contract to hedge to this level. The Commission considers that this should not have a significant impact on retailers'

371 NER, clause 3.15.6(a).

372 Clauses 11.120.2 and 11.120.6 of the second draft rule.

approaches to risk management, as a customer's baseline should reflect the amount of electricity the customer would have consumed in the absence of providing wholesale demand response. This means that a retailer's exposure in the wholesale market should be approximately unchanged following the implementation of a wholesale demand response mechanism, regardless of whether or not its customer is participating in the mechanism. However, the Commission acknowledges that retailers may require additional information about customers that have an arrangement with a DRSP in order to adjust their hedging strategy for those customers if required in real-time (for example, in relation to higher-than-usual load after a period of providing demand response). The Commission has sought to address this concern by making such additional information available to retailers under the second draft rule. This is discussed further in appendix D.

G.5.4 Retailer cost recovery from DRSP

When the retailer is billed in the wholesale market at the baseline level of consumption and subsequently charges its consumers for their actual consumption, the retailer will under-recover. That is, there will be some amount of 'missing money'. This amount represents the difference between the actual and baseline consumption multiplied by the customer's retail rate, as this is the amount the customer would have paid the retailer (to cover the wholesale energy purchases the retailer would have made for that customer) if the customer had not provided demand response.

Under the settlement model set out in the second draft rule, this cost will be recovered from the customer via the DRSP through AEMO's settlement process. This is intended to address the missing money issue and not impose any unmanageable costs on that retailer or its customers.

The amount the retailer is not recovering from the customer (due to the customer providing demand response) is equal to the difference between the customer's actual and baseline consumption (i.e. the demand response provided)[373] multiplied by the customer's retail tariff. The amount payable by the DRSP to the retailer in respect of this under-recovery - the reimbursement rate - will then be accounted for by AEMO in the net amount payable by AEMO to the DRSP (for the demand response provided)[374] and the net amount charged by AEMO to the retailer (for electricity purchased in the wholesale market).[375] Subtracting this amount from the net amount paid to the DRSP by AEMO simplifies the cost recovery process, as this removes the need for AEMO to issue a separate bill to the DRSP charging it for this amount.

G.5.5 Examples illustrating settlement for wholesale demand response

The flows of money between the customer, the retailer, AEMO and the DRSP under this settlement model are worked through in Box 11. These are simplified models and do not account for the impacts of retailers' hedging positions.

373 This amount is the "wholesale demand response settlement quantity" calculated under clause 3.15.6B(c) of the second draft rule.

374 This amount will be calculated under clause 3.15.6B(a) of the second draft rule.

375 This amount will be calculated under clause 3.15.6B(b) of the second rule.

BOX 11: SETTLEMENT MODEL UNDER THE SECOND DRAFT RULE

Financial flows in a typical trading interval in the absence of wholesale demand response

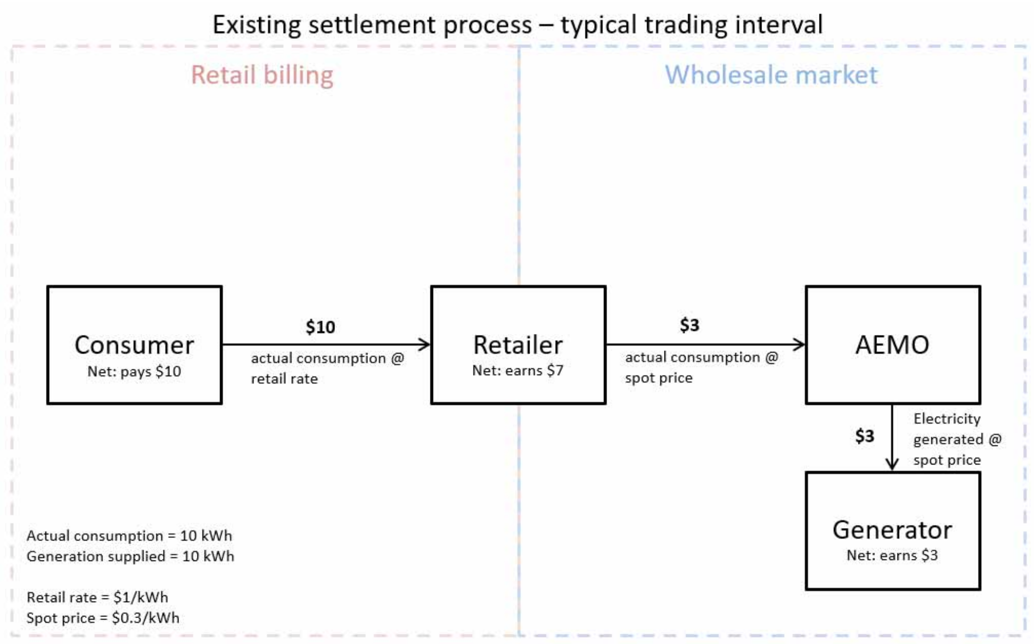
Under existing settlement processes (i.e. in the absence of wholesale demand response provided under the mechanism), in a typical trading interval where the spot price is relatively low (in comparison to the customer's retail tariff), the retailer would earn money as the amount it recovers from its customer is higher than the amount the retailer pays in the wholesale market.

In this scenario:

- the retailer is paid by the customer for the customer's actual consumption at the retail rate
- the retailer pays for the customer's actual consumption in the wholesale market at the spot price
- the generator is paid for the amount of electricity supplied at the spot price.

This scenario is depicted in Figure X. In this example, the customer is consuming 10 kWh of electricity at a retail rate of $1/kWh and a spot price of $0.3/kWh (these figures are for illustrative purposes only).

Figure G.1: Existing settlement process - no wholesale demand response (typical trading interval)

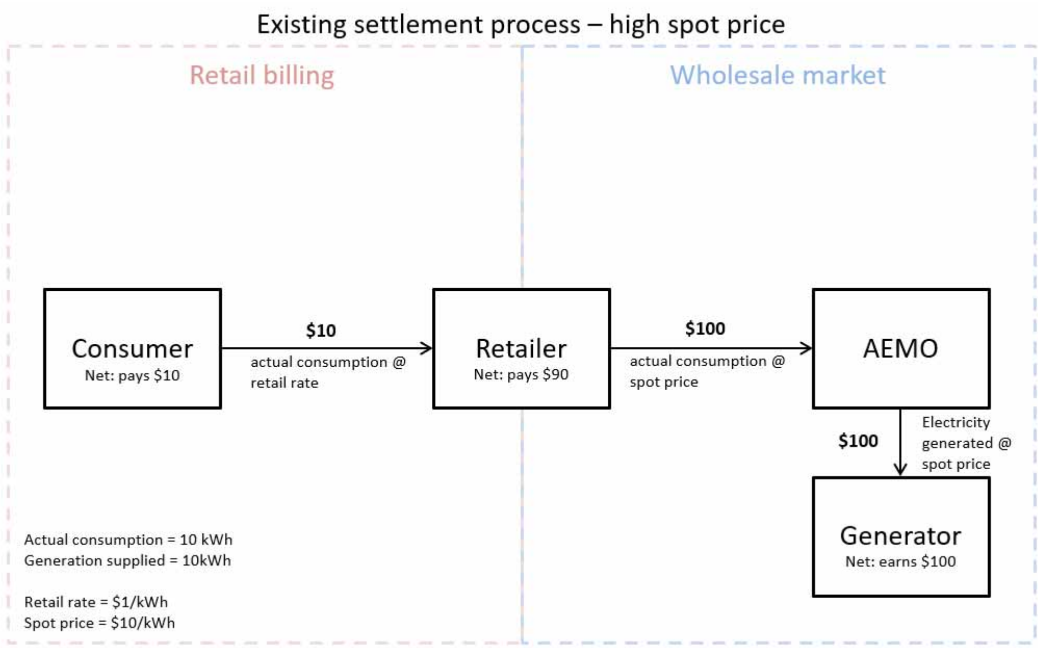


Financial flows during periods of high spot prices in the absence of wholesale demand response

While the example in Figure X represents financial flows during a typical trading interval, wholesale demand response could be expected to be provided by customers primarily during trading intervals where the spot price is high relative to the customer's retail tariff, as this is when customers will receive the most value for demand response. In these trading intervals, the retailer is likely to make a net payment to the wholesale market.

This scenario is depicted in Figure X. In this example, the customer is consuming 10 kWh of electricity at a retail rate of $1/kWh and a spot price of $10/kWh (these figures are for illustrative purposes only).

Figure G.2: Existing settlement process - no wholesale demand response (high spot price)



The retailer recovers the following through the payment it receives from the customer:

- total network costs
- total environment scheme costs
- total wholesale costs
- total retail costs
- retail margin.

These are assumed away for the above examples.

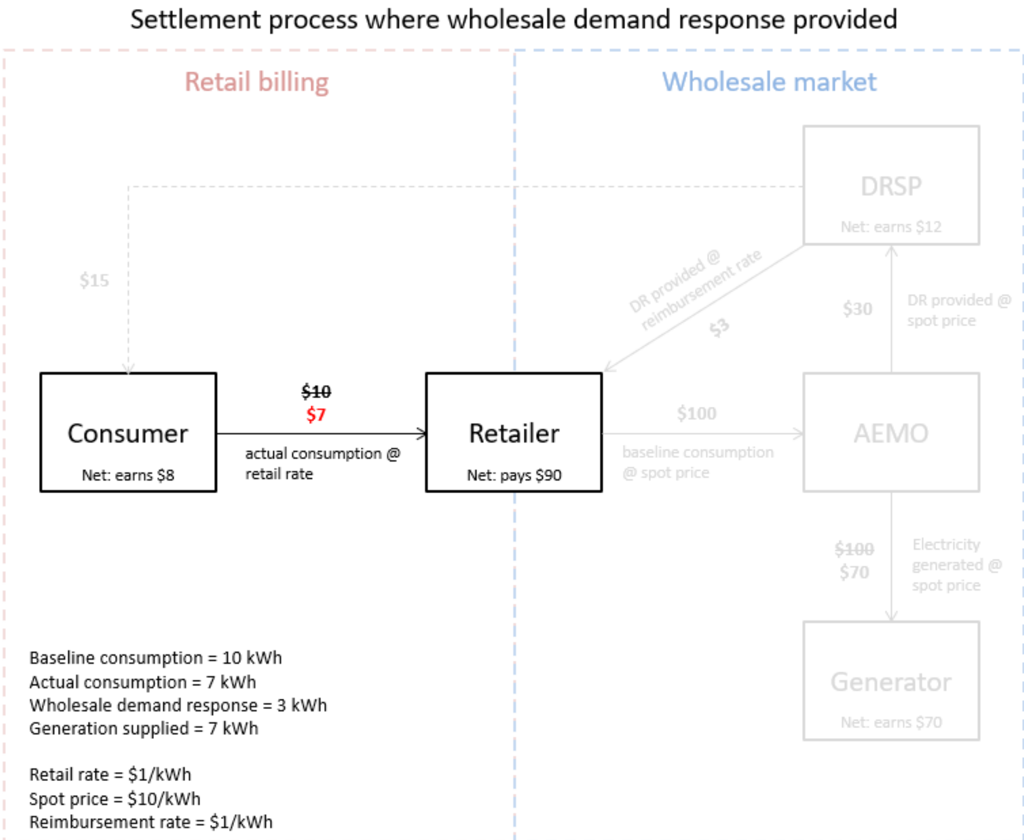
Financial flows where wholesale demand response provided through the mechanism

In the following example, a DRSP sees forecasts of high prices and calls on a consumer (with whom it has a pre-existing commercial relationship) to reduce consumption. The consumer's baseline level of consumption is centrally determined to be 10 kWh. The consumer also has a retail rate of $1/kWh. The wholesale price reaches $10/kWh and the consumer reduces its actual consumption from 10 kWh to 7 kWh.

<u>Financial flows between customer and retailer</u>

The retailer would charge the customer for its actual energy consumption at the customer's retail rate. This payment is depicted in Figure X.

Figure G.3: Settlement under the wholesale demand response mechanism - worked example (1 of 4)



This financial flow is calculated as follows:

- Payment from customer to retailer = actual consumption (7 kWh) x retail rate ($1/kWh)

Importantly, as discussed above, facilitating the retailer continuing to bill the customer for actual consumption, rather than baseline consumption, would allow retailers to avoid making significant changes to their retail billing systems and is therefore expected to substantially reduce the implementation costs associated with the mechanism.

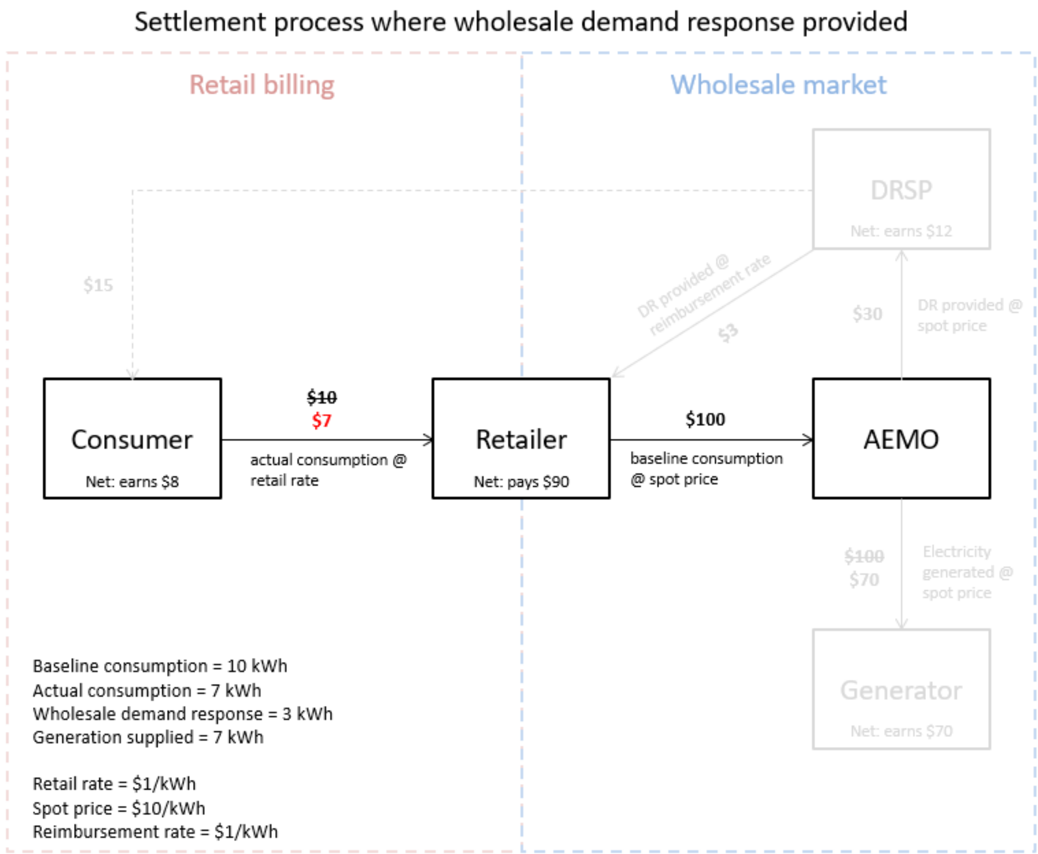
However, if the retailer is only charging the customer for actual consumption it is recovering payment from its customer for a lower amount of energy (in MWh) than the amount of energy for which it is liable to AEMO, as it is paying for the customer's baseline level of consumption in the wholesale market.

The settlement model applying under the second draft rule addresses this issue by providing for the retailer to recover a payment for this amount of energy from the DRSP, via AEMO's settlement process (as discussed further below).

Financial flows between retailer and AEMO

The retailer would pay AEMO for the customer's baseline level of energy consumption at the spot price in the wholesale market. This payment is depicted in Figure X.

Figure G.4: Settlement under the wholesale demand response mechanism - worked example (2 of 4)



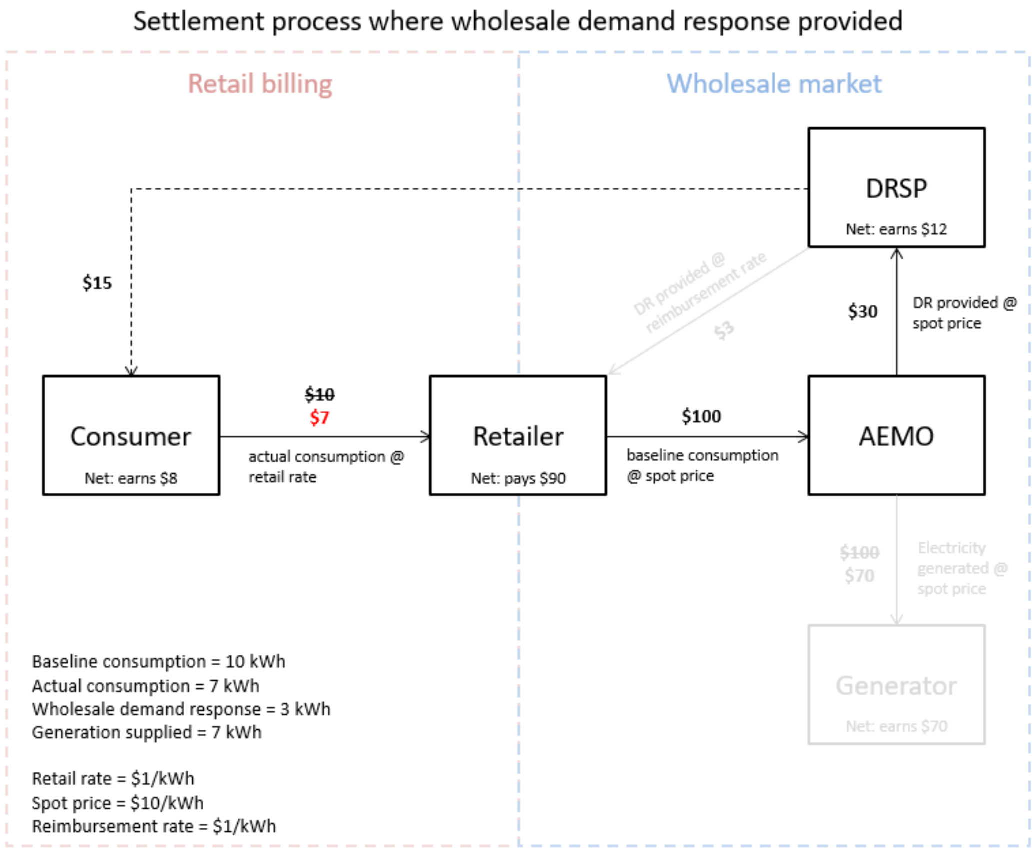
This financial flow is calculated as follows:

- Payment from retailer to AEMO = baseline consumption (10 kWh) x wholesale rate ($10/kWh)

<u>Financial flows between AEMO, DRSP and customer</u>

The DRSP would be credited for the quantity of wholesale demand response in the spot market and would share some of this value with the customer, in accordance with its contract with the customer. These payments are depicted in Figure X.

Figure G.5: Settlement under the wholesale demand response mechanism - worked example (3 of 4)



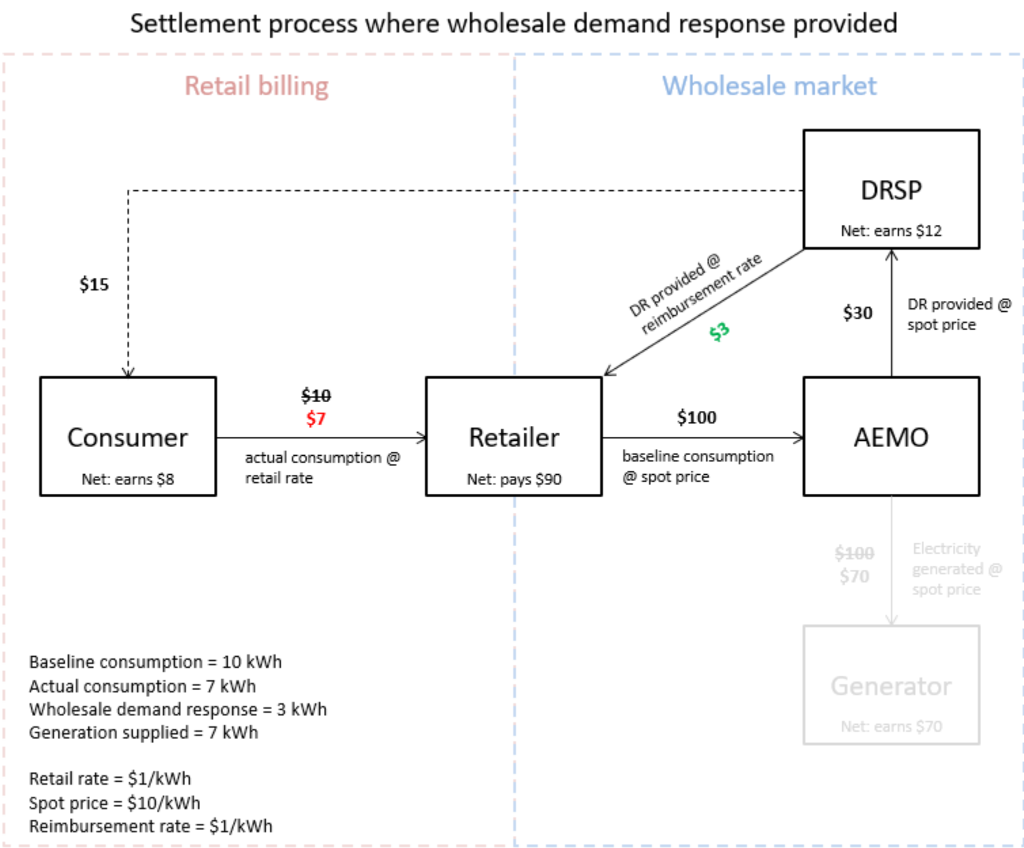
These financial flows are calculated as follows:

- Payment from AEMO to DRSP = difference between baseline and actual consumption (3 kWh) x wholesale rate ($10/kWh)
- Payment from DRSP to customer is calculated in accordance with the commercial agreement between the parties.

Financial flow from DRSP to retailer

The amount the retailer does not recover from its customer as a result of the customer providing demand response is equal to the difference between baseline consumption and actual consumption multiplied by the customer's retail rate. Under this settlement model, the DRSP will be charged by AEMO for an amount which is intended to reflect this reduction in retailer revenue, and this payment would flow through to the retailer in settlement. This payment is depicted in Figure X.

Figure G.6: Settlement under the wholesale demand response mechanism - worked example (4 of 4)



This financial flow is calculated as follows for the purposes of this example:

- Payment from DRSP to retailer (via AEMO) = Difference between baseline and actual consumption (3 kWh) x retailer rate ($1/kWh)

This payment allows the retailer to recover the same amount as it would if it billed the customer at the baseline (or if the customer had not provided demand response), without incurring the costs associated with changing its billing systems. (This is based on the assumption that the reimbursement rate is the same as the wholesale component of the customer's retail tariff in this example.)

In this example, the retailer recovers the following through the payment it receives from the customer:

- total network costs
- total environment scheme costs (noting that these are based on actual consumption)
- wholesale costs for actual consumption
- retail costs
- retail margin for actual consumption.

The retailer recovers an amount in respect of the demand response provided by the customer through the payment received from the DRSP.

<u>Summary</u>

Over the course of the trading interval:

- The consumer has reduced consumption and only consumes 7 kWh. The consumer pays the retailer $7 for the actual amount of energy, 7 kWh. The retailer subsequently purchases the baseline amount of energy, 10 kWh, from the wholesale market for $100 (noting that this is the sum of the two separate amounts charged to the retailer).
- The DRSP is credited $30 for the quantity of demand response.[1] The DRSP shares $15 with the consumer for undertaking the demand response, in accordance with the previously agreed contract between the DRSP and the consumer.
- The retailer's liability to AEMO and recovery from the consumer are the same as if the consumer did not provide demand response, as the retailer recovers the difference between the baseline and actual consumption, 3 kWh, at the retail rate, $1/kWh, from the DRSP (via AEMO).[2]

Consumption above the baseline

In the event that the customer's actual consumption inadvertently goes above their baseline in a wholesale demand response dispatch interval (rather than reducing), the financial flows depicted in Figure X would effectively be reversed. Rather than receiving a payment for demand response, the DRSP would be required to pay an amount equal to the difference between the customer's baseline and actual consumption at the spot price. This means that the DRSP is exposed to both the positive, as well as negative, monetary flows, which the Commission considers is appropriate. This payment would flow through to the customer’s retailer, through AEMO.

Behind-the-meter generation

In addition to reductions in demand, wholesale demand response may involve customers with behind-the-meter generation exporting electricity to the grid (where this export is in excess of the baseline, i.e. the amount of electricity the customer would otherwise be expected to export to the grid at that time).[3] The customer's actual consumption would be below zero during those periods. The settlement model set out in the second draft rule will still apply in this scenario, meaning the customer's DRSP will be credited for providing wholesale demand response provided that the customer's actual consumption was below their baseline (noting that the customer's baseline could also go below zero if they are normally exporting during these periods).

For example, if a customer's baseline level of consumption in a particular trading interval is 10 kWh and the customer is actually exporting 2 kWh to the grid during that interval, the DRSP will be credited for 12 kWh of wholesale demand response at the spot price. The Commission considers that this framework provides appropriate incentives for consumers with behind-the-meter generation to participate in the wholesale demand response mechanism (noting that, for the reasons discussed in appendix D, customers exposed to the spot price in a particular trading interval will be unable to participate in the mechanism in that interval either by providing demand reductions or increased generation).

Note: 1. This amount is the outcome of the calculation under clause 3.15.6B(a) of the second draft rule.
Note: 2. The retailer's net payment of $90 is the outcome of the calculation under clause 3.15.6B(b) of the second draft rule.
Note: 3. See clause 3.8.7B(g) of the second draft rule.

This settlement model places each party involved in largely the same net position they would be in under the settlement model proposed by PIAC, TEC and TAI and the South Australian Government. The key difference is that under the settlement model in the second draft rule, the 'missing money' is recovered from consumers indirectly through the consumer receiving a lower payment from the DRSP. However, the net outcome for the consumer should be the same given that the consumer is also paying less to the retailer (for actual rather than baseline consumption). This approach facilitates the same settlement outcomes without requiring retailers to make costly changes to their billing systems.

G.5.6 How is the payment from the DRSP to the retailer calculated?

Under this approach, in order to calculate the amount to be recovered by the retailer from the DRSP, the DRSP and AEMO would need to know either:

- the actual retail tariff for the customer providing the demand response (which in the example above is assumed to be known), or
- if the actual tariff is not known (discussed further below), a wholesale demand response reimbursement rate (reimbursement rate) which would seek to reflect the wholesale component of an average retail rate (this rate is not intended to capture the retail margin, network costs and the costs of environmental schemes).

The Commission considers that there are a number of issues associated with requiring retailers to provide the actual retail tariffs of demand response customers to DRSPs and AEMO, which include:

- **Complex retail tariff arrangements:** Many existing customers that are capable of providing wholesale demand response are large commercial and industrial customers.

The retail contracts for these customers are generally highly bespoke negotiated arrangements. These arrangements often involve complex tariff structures under which the customer is charged different rates based on a number of variable criteria, including the time of consumption and whether certain consumption thresholds are exceeded within a particular period. The Commission understands that it would be difficult for such complex retail tariffs to be recorded in AEMO's systems and used to calculate the amount to be recovered from the DRSP, as this would require all the criteria involved in calculating the customer's bill to be applied to the avoided consumption which constitutes the demand response provided by the customer. Given that many commercial and industrial customers participating in the demand response mechanism may be subject to such arrangements, this could significantly complicate the cost recovery process.

- **Implications for confidentiality and competition:** Details of the retail tariffs a retailer is offering to its customers, particularly in the context of bespoke arrangements for large customers, are information which is likely to be considered commercially sensitive and confidential. Further, there is no restriction under the second draft rule on retailers registering as DRSPs and participating in the demand response mechanism. Accordingly, imposing a requirement on retailers to provide details of the retail tariffs of their demand response customers to DRSPs may result in them being compelled to provide this information directly to other competing retailers. This outcome may be detrimental to retail competition, as the retailer receiving this information could use it to gain an unfair competitive advantage in the market (e.g. by using this knowledge to approach a retailer's demand response customers and offer them a marginally cheaper retail tariff). While this risk could be reduced by only requiring this information to be provided to AEMO (which could use it to calculate the payments required in settlement), this would have commercial implications for DRSPs, as they would no longer have full visibility of the net amount they could expect to earn for providing demand response. The Commission understands from discussions with stakeholders that these confidentiality and competition concerns would be material in respect of commercial and industrial customers.

Given the issues described above, the Commission considers that the preferable approach is to provide for the cost to be recovered from the DRSP based on a predetermined reimbursement rate. Network costs and the costs of environmental schemes, which are based on actual consumption, will be recovered from the customer, as is currently the case.

Purpose of reimbursement rate

As discussed above, the reimbursement rate is intended to reflect the wholesale cost component of an average large customer's retail tariff. This is because the retailer is liable to AEMO for an amount of energy in the wholesale market in respect of which it will not receive payment from the customer where the customer provides demand response through the mechanism. This is the cost of the electricity the retailer is liable to purchase in the wholesale market which is not consumed by, and therefore not charged to, the customer. In the absence of demand response being provided by the customer, the retailer would have recovered an amount in respect of that cost from the customer through the customer's retail tariff. In general, a retailer would determine the total wholesale costs it expects to incur in relation to a particular customer by considering a number of variables, including the shape of the customer's load profile across different time periods. These costs would then be incorporated into the customer's retail rate and recovered by the retailer on a smeared basis across a particular time period (the duration of the customer's retail contract). A retailer would generally not directly recover the actual wholesale costs it incurs in a particular trading interval from the customer, unless that customer is on some form of spot price pass through arrangement with the retailer.

The purpose of the reimbursement rate is therefore to reflect, to the extent practicable, the wholesale cost component of an average large customer's retail tariff. In developing a methodology that achieves this outcome, trade-offs exist between the need for the methodology to be simple and transparent and the potential to incorporate additional complexity into the methodology for incremental improvements in accuracy. The Commission has considered these trade-offs in developing the methodology adopted in the second draft rule (as discussed further below).

The reimbursement rate is not intended to account for the retail margin of the retail rate charged to customers. The Commission considers that the significant complexity associated with attempting to incorporate an average retail margin into the calculation of the reimbursement rate would outweigh the benefits of doing so, given that the retail margin on the amount of wholesale demand response provided by a large customer would ultimately be a very small and likely immaterial amount.

Given that the amount the retailer recovers from the DRSP will be calculated based on the reimbursement rate, this amount may not be precisely reflective of the amount the retailer does not recover from the customer in every transaction where the customer provides wholesale demand response. However, it can be expected that any discrepancy between the customer's actual retail tariff and the reimbursement rate for that customer will be relatively small. This approach also provides retailers with a higher degree of certainty about the costs they are able to recover from the DRSP than if this cost were required to be smeared across their customer base. In addition, retailers can address the potential risks associated with any deviation between the reimbursement rate and a particular customer's actual retail tariff through commercial negotiations with that customer. This approach may be particularly applicable to large customers with highly bespoke and commercially negotiated retail tariffs.

As discussed in appendix g.4, some stakeholders suggested that the reimbursement rate introduces unnecessary complexity into the settlement framework given the relatively small proportion of financial flows this rate will be used to determine. However, the Commission considers it is important that the settlement model under the second draft rule allows retailers to recover amounts in respect of their wholesale costs from the DRSP of the participating customer in order to maintain the integrity of the mechanism. In addition, it is appropriate for retailers to remain in the same financial position regardless of whether their customer is participating, given that the retailer will not be involved in the provision of the demand response through the mechanism.

The Commission considers that the model adopted in the first draft determination and second draft determination is preferable to one in which retailers are required to make significant and costly changes to their billing systems or are required to recover the costs from all consumers. Therefore, while there may be minor discrepancies arising from differences between the reimbursement rate and a particular retail rate, the Commission considers that the benefits gained far outweigh these costs.

Approach adopted under the first draft rule

Under the first draft rule, the Commission proposed that the reimbursement rate be calculated based on the average spot prices for the previous 12 months and be determined on a quarterly basis.[376] The first draft rule conferred the function of calculating the reimbursement rate on the AER, given that it has existing functions relating to the monitoring of wholesale electricity markets under the National Electricity Law. It was proposed that the AER would provide the reimbursement rate to AEMO for application in settlement to calculate the payment from the DRSP to the retailer.

Consideration of alternative methodologies for calculating reimbursement rate

In determining the methodology that should apply to the calculation of the reimbursement rate under the second draft rule, the Commission has sought to understand the different outcomes for the reimbursement rate resulting from the different methodologies proposed by stakeholders, compared to the methodology set out in the first draft rule. This is important when determining the trade-offs between a simple or more complex methodology. To assess the materiality of the difference between the different methodologies, the Commission undertook quantitative modelling to determine the historical rates produced by different methodologies in each mainland NEM region. Analysis of the results of this modelling is set out in Box 12.

BOX 12: MODELLING OF REIMBURSEMENT RATE METHODOLOGIES

As discussed in section X, a number of alternative methodologies for calculating the reimbursement rate were proposed by stakeholders in response to the draft determination. The Commission has calculated the reimbursement rates that would be produced by a number of these methodologies over a three year period. The methodologies modelled and the rationale for doing so are described in Table X.

Table G.1: Reimbursement rate methodologies modelled

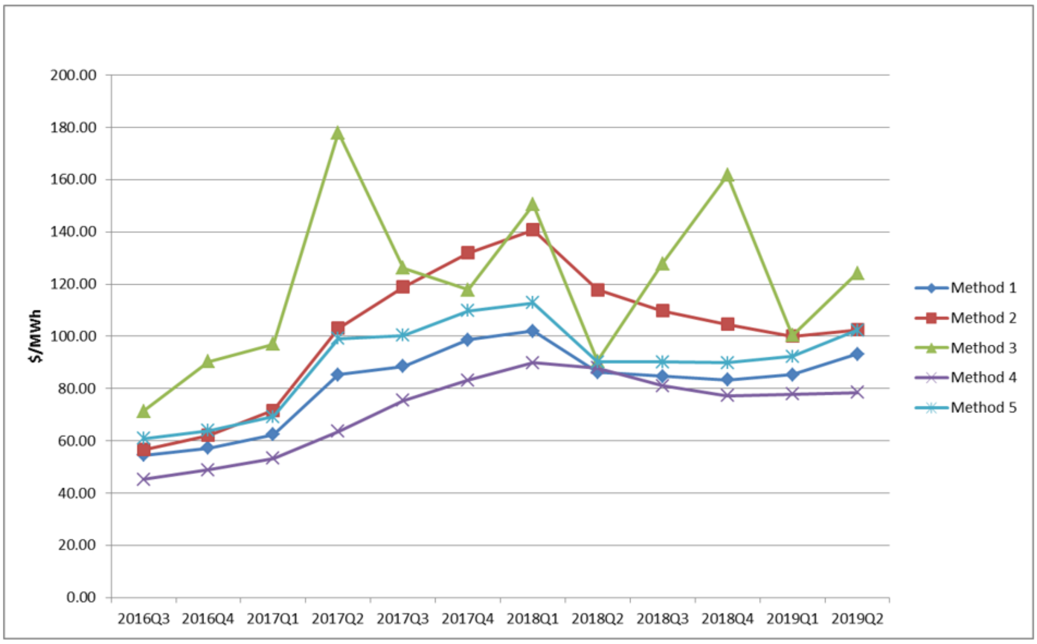
NO.	DESCRIPTION	RATIONALE
1	Rolling average of wholesale prices over the previous 12 months	This was the methodology set out in the first draft rule.

376 Ibid.

NO.	DESCRIPTION	RATIONALE
2	Rolling average of peak ASX futures contract prices over the previous 12 months	Some stakeholders suggested that forward contract prices form the basis of retailers' hedging strategies and peak forward contract prices would better reflect the periods in which demand response would be expected to be provided
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	It was suggested that this risk weighting is appropriate to reflect the fact that the rate may not reasonably reflect the costs incurred by the retailer (an analogy was drawn to the framework for participant compensation following market suspension)
4	Rolling average of base ASX futures contract prices over the previous 12 months	It was suggested that this would allow a single reimbursement rate to be applied to any interval within the relevant calendar year, noting that high prices and demand response may occur in either peak or off-peak periods depending on the supply and demand conditions at the time
5	Rolling average of peak wholesale prices over the previous 12 months	It was suggested that this would reflect the additional risk premium retailers incur to manage the risk of high price events

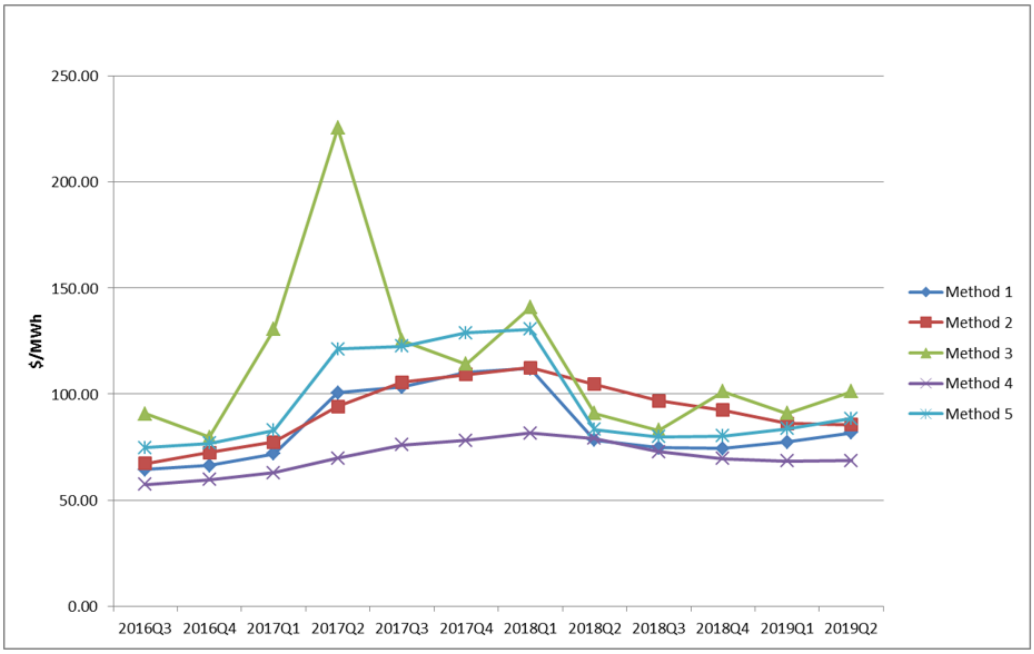
The results of this modelling for each jurisdiction are set out in the below figures.

Figure G.7: Reimbursement rate modelling - NSW



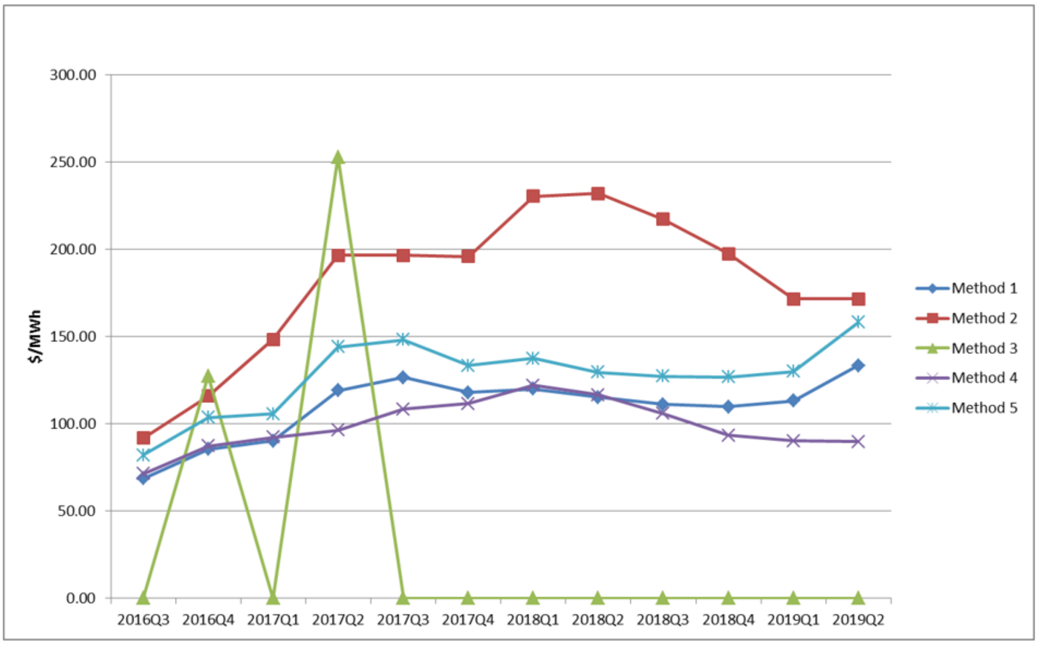
Source: AEMC internal modelling based on publicly available data.

Figure G.8: Reimbursement rate modelling - QLD



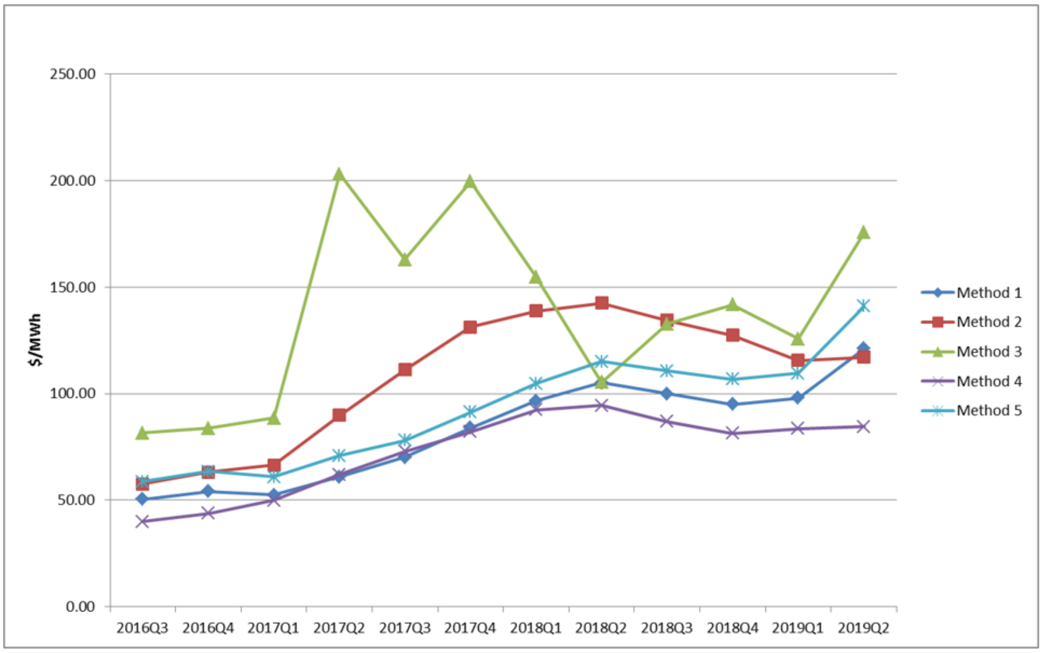
Source: AEMC internal modelling based on publicly available data.

Figure G.9: Reimbursement rate modelling - SA



Source: AEMC internal modelling based on publicly available data.

Figure G.10: Reimbursement rate modelling - VIC



Source: AEMC internal modelling based on publicly available data.

The following insights can be drawn from this modelling:

- In all regions, there is a relatively consistent variance between Method 1 (average spot prices), Method 4 (average forward base contract prices) and Method 5 (average peak spot prices), with the rate for Method 1 sitting in between the rate for the other two methods. The magnitude of the difference between the rates is relatively small.
- Method 3 produces a very volatile rate, and is not practicable in South Australia due to the lack of liquidity in the contract market.
- Method 2 (forward peak contract prices) generally produces a higher reimbursement rate than Method 1 (average spot prices). However, the magnitude of the difference between these methods differs across jurisdictions and time periods. There are multiple periods in New South Wales, Queensland and Victoria in which the rates produced by these two methodologies are very similar. In South Australia, Method 2 would have historically produced a significantly higher reimbursement rate than Method 1. However, the two rates appear to be converging in all jurisdictions in recent quarters.

Approach adopted under second draft rule and rationale

Under the second draft rule, the reimbursement will be calculated on a quarterly basis and will be based on a rolling average of demand-weighted wholesale prices over the previous 12 months. This is consistent with the methodology proposed under the first draft determination. This approach has been informed by stakeholder feedback on the first draft determination, technical working group meetings and the internal modelling presented in Box 12.

The Commission considers that there are a number of factors which support maintaining the reimbursement rate methodology proposed under the first draft determination in place of alternative methodologies. These include:

- Contract market liquidity issues in South Australia present challenges for methodologies that seek to utilise forward contract prices, as evidenced by the modelling in Box 12. While this may be addressed by adopting different methodologies for different jurisdictions, the Commission understands that this would involve additional costs due to the increased complexity this would impose on AEMO's settlement processes and systems.
- There is no clear or transparent basis on which an appropriate "risk weighting" can be determined for the purposes of Method 3. In any case, this method produces very volatile results in most regions, and does not currently produce any rate in South Australia.
- The Commission does not consider that methodologies which are based on average peak spot prices (i.e. Method 5) better reflect what the retailer would otherwise have recovered from the customer through the customer’s retail tariff than methodologies based on average spot prices (i.e. Method 1). As discussed above, the purpose of the reimbursement rate is to reflect the wholesale cost component of an average customer's retail tariff. In general, these costs would be recovered from the customer by the retailer on a smeared basis across the duration of the retail contract, rather than being recovered

directly for the time period in which they are incurred. Accordingly, the argument that peak prices better reflect the wholesale costs the retailer is not recovering from the customer in periods when demand response is provided suggests a misunderstanding of the purpose of the reimbursement rate.

- Stakeholders have acknowledged in technical working group meetings that there are options for calculating the reimbursement rate which may yield incremental improvements in accuracy, but would also add significant complexity to the process of determining the rate. In addition, no methodology is capable of producing a rate that accurately reflects the wholesale costs incurred for every retailer, as each retailer utilises different pricing strategies for their customers and different hedging strategies. The Commission considers that the modelling presented in Box 12 illustrates that the variance between the method adopted in the first draft determination and the alternative methodologies proposed by stakeholders is relatively small, and the payment based on this rate will only represent a small proportion of the amounts settled under the mechanism and a small proportion of the amounts the retailer otherwise receives from the customer.
- The average demand-weighted spot price provides a simple, transparent and objective reference point to approximate the wholesale cost component of the average retail tariff. This is especially true for large commercial and industrial customers, particularly those that have relatively flat and stable loads. The Commission understands that average spot prices should be more reflective of the wholesale cost component of these customers' tariffs than for small customers with peakier load profiles.

As discussed in appendix g.4, both AEMO and the AER suggested in submissions to the first draft determination that the responsibility for determining the reimbursement rate should be conferred on AEMO, rather than the AER, in order to reduce complexity. Given that the methodology adopted under the second draft rule maintains a simple and clear formula in the NER for determining the reimbursement rate based on transparent, publicly available information, the Commission agrees that it is appropriate and administratively expedient for AEMO to calculate the reimbursement rate. Accordingly, the second draft rule confers this function on AEMO. The Commission considers that this function is within the scope of AEMO's powers under the NEL.

H CONSEQUENTIAL AND COMPLEMENTARY CHANGES

H.1 Overview

This appendix sets out a number of complementary and consequential measures to the introduction of the wholesale demand response mechanism. This appendix sets out:

- consequential changes arising from introduction of the mechanism, including systems changes not covered elsewhere in the determination
- changes that are complementary to the introduction of a mechanism.

Table H.1: **Overview of appendix**

CONSEQUENTIAL CHANGES	COMPLEMENTARY CHANGES
Changes relating to: • the requirements applying to DRSP participation in the reliability and emergency reserve trader (RERT) • the interaction between wholesale demand response provided through the mechanism and the retailer reliability obligation (RRO) • the entitlement of a DRSP to claim compensation following a market suspension • AEMO's systems necessary to support the introduction of the wholesale demand response mechanism and the new DRSP participant category.	Changes and recommendations relating to: • AEMO's DSP portal • Energy Made Easy • the relationship between CPT, APC and wholesale demand response • retailers facilitating more wholesale demand response.

Some of the measures identified involve changes to the NER under the second draft rule, while others do not require changes to the rules and can be progressed separately.

The remainder of this appendix outlines the background for each of the relevant measures, as well as the Commission’s analysis and conclusions.

H.2 Commission's analysis and conclusions

BOX 13: SECOND DRAFT RULE AND RECOMMENDATIONS

Systems changes

The second draft rule:

- would require AEMO to update a number of systems and procedures to accommodate the introduction of DRSPs. These systems include information provision and market settlement systems, and the related procedure documents.
  - AEMO will need to store new standing data for NMIs relating to the allocation of a DRSP and the baseline methodology. There would also need to be procedures updated to allow DRSPs to request changes to NMI standing data.
  - AEMO would need to be able to settle retailers and DRSPs for the amount of demand response provided.
- would require metering data providers (MDPs) to provide metering information to DRSPs in addition to the participants they currently provide with meter data.
- would require B2B Procedures to facilitate B2B Communications between the DRSP and other existing market participants.

Benefits of the second draft rule

The second draft rule would require a more limited number of systems changes to accommodate the introduction of DRSPs, compared to the first draft rule. These systems changes would facilitate the settlement of DRSPs for wholesale demand response at a cost AEMO estimates to be considerably lower than would have been the case under the first draft rule.

Changes from first draft rule

The second draft rule is less prescriptive about the systems changes AEMO would need to undertake to implement the second draft rule, and has reduced the number of systems AEMO would need to change. These changes are intended to provide AEMO with sufficient flexibility to make the necessary changes in the least cost manner and without constraining any future system developments AEMO may consider.

The second draft rule also provides retailers with additional information to assist with managing additional exposure in the wholesale market. This additional information would be provided centrally by AEMO.

Consequential changes

The second draft rule:

- clarifies how the existing out-of-market provisions relating to the RERT apply to DRSPs
- provides for a minor amendment to the RERT Guidelines, which is to be published by the Reliability Panel prior to the commencement of the wholesale demand response mechanism
- provides for the RERT Procedures to be amended by AEMO prior to the commencement of the wholesale demand response mechanism to take into account the amending rule
- amends the rules which give effect to the RRO to clarify that all wholesale demand response provided by a liable entity’s customers will be included in the calculation of that liable entity’s liable load for compliance purposes

- clarifies that a demand side participation contract that is a qualifying contract for the purposes of the RRO may include wholesale demand response
- amends the definition of "directed participant" to clarify that the term only applies to DRSPs in their capacity as a provider of market ancillary services and not as a provider of wholesale demand response (i.e. to maintain the existing position under the rules)
- amends the definition of "Market Suspension Compensation Claimant" to clarify that compensation is also available to DRSPs that provide wholesale demand response during a market suspension event.

Benefits of the second draft rule

The second draft rule:

- ensures that AEMO will provide guidance and transparency about how the RERT out-of-market provisions will apply to scheduled demand response
- preserves existing signals to the market that the RERT is an out-of-market service that is only to be used after market responses have been exhausted, including in relation to wholesale demand response
- clarifies the application of existing directions and compensation frameworks to DRSPs in order to reduce AEMO's implementation costs.

Changes from the first draft rule

The second draft rule includes additional minor changes to the provisions giving effect to the RRO to clarify that all wholesale demand response provided by a liable entity’s customers is to be taken into account in the calculation of the liable entity's liable load for a compliance trading interval.

The second draft rule also addresses the application of the framework for compensation following market suspension to DRSPs, which was not covered in the first draft rule, and removes DRSPs from the Affected Participant framework.

Complementary changes

The second draft rule:

- requires AEMO to review the Demand Side Participation Information (DSPI) Guidelines to reflect the changes to the demand side reporting requirements under the second draft rule
- requires all registered participants to report in accordance with the DSPI Guidelines, even if the report states that the participant has no demand side information to report
- requires DRSPs to submit information regarding wholesale demand response over longer timeframes to AEMO using the DSP Portal
- requires AEMO to publish additional information regarding the demand side participation information submitted using the DSP Portal.

The second draft determination also notes that the Commission:

- recommends that AEMO review the DSP portal to ensure participants are able to report all wholesale demand response provided by their customers
- recommends that the AER consider the feasibility of making changes to the Energy Made Easy comparison tool to ensure that:
  - spot price pass through contracts and other demand response services offered by retailers are represented, and that their cost and competitiveness is accurately portrayed to users of the tool
  - retailers provide easy-to-understand information about the risks and requirements involved with retailer-led demand response arrangements, particularly where customers are materially exposed to the wholesale market price.
- may request that the Reliability Panel review the APC in light of recent events highlighting the interaction between the APC and wholesale demand response
- will review the existing APC Compensation Guidelines to ensure the guidelines adequately deal with compensation for wholesale demand response providers, and may undertake a more holistic review of this guideline to clarify the circumstances in which different parties can claim compensation following the application of the APC
- recommends that retailers commit in the Energy Charter to facilitating greater access to demand response products and services for customers.

Benefits of second draft rule and recommendations

The second draft rule and the areas for further work highlighted in the second draft determination would, if implemented:

- allow consumers and retailers to make better informed decisions in relation to the provision of wholesale demand response
- encourage retailers and DRSPs to provide competitive and fairly valued demand response products to consumers
- ensure that consumers have the appropriate incentives to provide wholesale demand response during periods of peak demand.

Changes from first draft rule

The first draft rule did not require DRSPs to submit information about wholesale demand response through the mechanism to AEMO using the DSP Portal, as this information would be transparent to AEMO through the scheduling of wholesale demand response units participating in the mechanism and, over a two-year forward period, through MT PASA. Given that DRSPs would not be subject to the information provision requirements relating to MT PASA (the reasons for which are discussed in section X), the second draft rule requires DRSPs to submit information relating to wholesale demand response over longer timeframes to AEMO through the DSP Portal. This will ensure that the value of this information can be captured in a cost-effective manner.

The first draft rule also amended the definition of the reliability standard to expressly include a reference to wholesale demand response. The second draft rule reverses this change (i.e. reverts to the existing definition of the reliability standard under the NER), as the Commission considers that the concept of wholesale demand response is already captured by the reference to "energy demanded" in relation to the reliability standard.

Under the first draft rule, DRSPs that have their dispatch quantity affected by a RERT-related intervention event would have been included in the definition of "affected participant". This change has not been included in the second draft rule based on advice from AEMO that this would materially increase the implementation costs of the mechanism.

The following two sections provide more information on:

- the consequential changes arising under the second draft rule
- the complementary changes made in the second draft rule and other recommendations to facilitate wholesale demand response.

H.3 Consequential changes

The wholesale demand response mechanism under the second draft rule impacts on various aspects of the current market design. As such, the Commission has considered whether additional changes to the NER are required to account for the interaction between the mechanism and other existing parts of the regulatory framework. This section sets out the Commission's consideration of the key aspects of the NER that interact with the mechanism and whether incidental changes are required to account for these interactions.

The consequential changes arising from the second draft rule discussed in this chapter relate to the interaction between the mechanism and:

- the Reliability and Emergency Reserve Trader (RERT)
- the Retailer Reliability Obligation (RRO)
- the definition of the reliability standard
- the directed participants framework
- the compensation framework for affected participants
- the framework for compensation following market suspension
- changes to AEMO's systems.

H.3.1 Reliability and emergency reserve trader

On 2 May 2019, the Commission made a final rule on the *Enhancement to the Reliability and Emergency Reserve Trader (RERT)* rule change.[377] The RERT is an existing mechanism that allows AEMO to contract for emergency reserves, such as generation or demand response, that are out of market. It is an important part of the regulatory framework that AEMO uses

377 AEMC, *Enhancement to the Reliability and Emergency Reserve* rule change - final determination, May 2019. Available at: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader.

as a last resort at times when the market has not provided enough reserves to meet demand e.g. during extreme heat events. The Commission's final rule provides AEMO with the flexibility and appropriate discretion when using the RERT (or emergency reserves) to manage the transition in the power system, while minimising costs to consumers, and in a transparent manner.

A key element of the Commission's final determination was the clarification of the out-of-market provisions in the NER. The out-of-market provisions provide that:

- scheduled reserves which have been in the wholesale market during the 12 months prior to signing a RERT contract cannot provide emergency reserves and cannot be in the wholesale market for the duration of their RERT contract
- unscheduled reserves cannot be in the wholesale market for the trading intervals to which their RERT contract relates.

The purpose of these clarifications was to make it clear that the wholesale market is the primary means by which reliability is delivered and that incentives to invest in market reserves need to be preserved, so that costs of reliability are minimised for consumers.

A key principle underlying the wholesale demand response mechanism set out in the second draft rule is that wholesale demand response participating in the mechanism should be treated equivalently to generation in a range of respects. The Commission considers that it is appropriate for this treatment to extend to participation in the RERT. This will ensure that the existing signals to the market that the RERT is an out-of-market service that is only to be used after market responses have been exhausted will also apply to wholesale demand response.

As such, the second draft rule clarifies that the existing out-of-market provisions also apply to DRSPs. This means that AEMO must ensure that DRSPs:

- are not participating in the wholesale market for the term of their reserve contract[378]
- who have been in the wholesale market at any time during the 12 months prior to signing a RERT contract do not participate in the RERT.[379]

Under the out-of-market provisions, unscheduled emergency reserves, which may include demand response that is undertaken outside of the wholesale demand response mechanism, cannot be both in RERT and in the wholesale market for the trading intervals to which the RERT contract relates. The rules also require AEMO to be transparent in its RERT procedures regarding how it intends to apply the provisions for unscheduled reserves. The second draft rule extends this obligation on AEMO to also apply to scheduled wholesale demand response.[380] This means that AEMO will be required to provide details in its RERT procedures about how the relevant provisions will be applied to DRSPs that are subject to a scheduled reserve contract. The Commission considers that this is appropriate given that wholesale demand response has not been scheduled in NEM in this manner in the past and it would be

378 Clause 3.20.3(g)(1) of the second draft rule.

379 Clause 3.20.3(g)(2) of the second draft rule.

380 Clause 3.20.7(e)(1)(ii) of the second draft rule.

helpful to market participants for AEMO to provide guidance and transparency about how the out-of-market provisions will apply to scheduled demand response.

Retailers' liability for RERT payments is currently calculated based on the actual consumption of the retailers' customers.[381] This would continue to be the case under the second draft rule. The Commission considers that if RERT payments were to instead be calculated based on baseline levels of consumption, this would reduce the incentive to provide demand response during periods in which the RERT is used as the reduction in energy use would have no impact on the retailers' RERT liability. In addition, customers providing demand response during these periods have presumably not contributed to the reliability issue in the market (and in fact may have assisted in the rebalancing of supply and demand) and should not therefore be charged for RERT at their baseline level of consumption. Continuing to calculate these amounts based on actual consumption should also minimise the extent of any changes required to AEMO's systems.

The second draft rule also provides for:

- a minor amendment to the RERT Guidelines, which is to be published by the Reliability Panel prior to the commencement of the wholesale demand response mechanism[382]
- the RERT Procedures to be amended by AEMO prior to the commencement of the wholesale demand response mechanism to take into account the amending rule.[383]

The AER also noted in its *Wholesale electricity market performance report 2018* that it intends to monitor the impact of AEMO’s management of the RERT on market driven demand side participation.[384]

H.3.2 Retailer reliability obligation

The package of law and rule changes implementing the RRO commenced on 1 July 2019.

The RRO builds on existing spot and financial market arrangements in the electricity market to facilitate investment in dispatchable capacity and demand response. It is designed to incentivise retailers, on behalf of their customers, to support the reliability of the power system through their contracting and investment decisions. In other words, the RRO forms part of the NEM’s reliability framework, creating additional signals for investment by providing incentives to retailers to obtain contracts that will support reliability further.

The RRO does this by requiring electricity retailers (and other liable entities) to demonstrate they have entered into sufficient contracts for dispatchable capacity (including demand response) to cover their share of system peak demand at the time of the gap between demand and supply. The obligation to secure sufficient qualifying contracts would be triggered if there is a material gap (i.e. a breach of the reliability standard) between forecast

381 NER, clause 3.15.9.

382 Clause 11.118.8 of the second draft rule.

383 Clause 11.118.6(a)(6) of the second draft rule.

384 AER, *Wholesale electricity market performance report 2018*, December 2018. Available at: https://www.aer.gov.au/wholesale-markets/market-performance/aer-wholesale-electricity-market-performance-report-2018.

demand and supply three years out from the period in which the gap is forecast and the AER has subsequently made a 'T-3 reliability instrument'.[385]

If the gap persists one year out from the forecast gap, then AEMO is able to apply to the AER to make a 'T-1 reliability instrument'. If, one year out (T-1), a material reliability gap remains, the AER will require liable entities to report their net contract positions. AEMO may then commence procurement of emergency reserves at T-1 (i.e. 12 months ahead of the gap) through the RERT framework to address the remaining gap, with costs to be recovered through the Procurer of Last Resort cost recovery mechanism.

The intent of the RRO rules is to require retailers to enter into hedging contracts to cover their expected consumption 12 months in advance. A key question considered by the Commission is whether the obligations applying to retailers under the RRO should apply with respect to the actual level of consumption, or the baseline level of consumption, of the retailer's customers where those customers provide wholesale demand response.

A number of stakeholders commented on the interaction between the RRO and the wholesale demand response mechanism in submissions to the first draft determination:

- ERM Power sought clarification and assurance that retailers are to be assessed against actual demand values rather than baseline values (where a retailer is not using demand response contracts as part of their contract position), as retailers will not necessarily have visibility of whether their customers will be engaging in demand response activities through a DRSP one year in advance.[386]
- Flow Power expressed concern that baselines may be calculated differently under the demand response mechanism and the RERT, meaning a retailer may be compliant under one approach but not the other for the purposes of the RRO.[387]
- Stanwell submitted that retailers should not be in a position where wholesale demand response has been added back to their liable load but they do not have access to the demand response contract to offset against this load.[388]

Under the demand response mechanism, retailers will have no foresight of whether their customers may be dispatched for wholesale demand response over this period. While a retailer will know whether its customer has an arrangement with a DRSP, the retailer will not know the terms of that arrangement. In addition, if the customer is dispatched for wholesale demand response, the retailer will be liable in the wholesale market for the customer's baseline level of consumption. As such, the Commission expects that retailers will face the same incentives in relation to their hedging for this period regardless of whether the retailer has customers participating in the mechanism. As a result, the Commission considers that the obligations applying to the retailer under the RRO should be assessed with regard to the baseline level of consumption for any customers that were dispatched for wholesale demand

385 When AEMO identifies a material gap three years out, it has to apply to the AER to make a "T-3 reliability instrument". This instrument is then the trigger for the RRO mechanism and obligations, such as requiring retailers to have enough contracts in place.

386 ERM Power, submission to first draft determination, p. 5.

387 Flow Power, submission to first draft determination, p. 6.

388 Stanwell, submission to first draft determination, p. 8.

response. The second draft rule therefore amends the rules which give effect to the RRO to clarify that all wholesale demand response provided by a liable entity's customers will be included in the calculation of that liable entity's liable load for compliance purposes.[389]

Contracts between customers and DRSPs will generally not be qualifying contracts for the purposes of the RRO. This is because the customer's retailer is not the counter-party to the contract (i.e. the contract allows the demand response to be sold into the wholesale market as a supply-side resource, not directly to the retailer). However, the contract between the DRSP and the customer may count as a qualifying contract where the DRSP and the retailer are the same entity. In addition, as noted by a number of stakeholders, DRSPs will be able to sell financial contracts to retailers for wholesale demand response.[390] These contracts would be qualifying contracts for the purposes of the RRO. In those circumstances, the DRSP would have to ensure it can back the contract by managing how its customers are dispatched, consistent with how peaking generators defend cap positions. This scenario is already provided for under the rules.

The second draft rule makes minor changes to the RRO rules to clarify that a demand side participation contract that is a qualifying contract may include wholesale demand response.[391]

The Commission recommends that the AER's contracts and firmness guidelines address the circumstances where a retailer has a qualifying contract for the provision of demand response with its own customer and that customer subsequently enters into a wholesale demand response arrangement with a DRSP.

H.3.3 Reliability standard

The reliability standard is the maximum expected unserved energy in a region of 0.002 per cent for a given financial year as a share of total energy demanded in that region. In general terms, 'unserved energy'means the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation or interconnector capacity. The reliability standard represents a trade-off between the prices paid for electricity and the cost of not having energy when it is needed: increasing levels of reliability involves increased costs. The reliability standard is set at a level that provides a balance between delivering reliable electricity supplies and maintaining reasonable costs for customers (i.e. an economic trade off between affordability and reliability, based on what consumers value).

The reliability standard is currently specified in the NER by reference to "generation and inter-regional transmission elements" in the NEM and is set as a maximum expected unserved energy in a region of 0.002% of the "total energy demanded in that region" in a financial year.[392] The definition of the reliability standard does not expressly reference wholesale demand response. However, wholesale demand response is implicitly captured by the reliability standard, as the definition of unserved energy refers to the amount of energy "demanded, but not supplied, in a region".[393] This definition does not apply to intentional

389 Clause 4A.F.3(b)(3) of the second draft rule.

390 Submissions to consultation paper: Enel X, p. 19; Powershop/Meridian Energy, p. 4.

391 Clause 4A.E.1 of the second draft rule.

392 NER, clause 3.9.3C(a).

reductions in energy usage by a consumer in response to wholesale prices (i.e. wholesale demand response), as this is not energy which is demanded by the consumer. As such, wholesale demand response can be considered as a reduction in the "energy demanded" in a particular region for the purposes of the reliability standard, which in turn reduces the amount of generation and inter-regional transmission elements needed to meet that demand.

Given that the Commission considers the reference to "energy demanded" in relation to the reliability standard implicitly captures wholesale demand response, the second draft rule does not propose any changes to the current definition of the reliability standard in the NER. The Commission notes that this is a change from the first draft rule.

H.3.4 Directed participants

The NER currently provide for registered participants to be the subject of a direction by AEMO in respect of scheduled plant or market generating units.[394] Such directions may require those participants to take action necessary to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.[395] In those circumstances, the directed participant is entitled to recover compensation for the service provided in order to comply with the direction.[396] AEMO's power to issue a direction under the rules will not extend to DRSPs in respect of wholesale demand response, as the direction must relate to a "scheduled plant" or "market generating unit", which will not capture wholesale demand response units under the second draft rule.[397] The Commission considers that allowing AEMO to direct DRSPs could have very significant implications for customers within the relevant wholesale demand response unit, as those customers could have valid financial and commercial reasons for not being able to reduce consumption during the relevant period (e.g. a manufacturing business that is working to fill a significant purchase order). As DRSPs will not be subject to directions to provide wholesale demand response, the provisions relating to compensation for directed participants also do not apply to DRSPs in their capacity as providers of wholesale demand response under the second draft rule. DRSPs may however be subject to a clause 4.8.9 instruction issued by AEMO, as is the case with any other registered participant.[398] No compensation is payable in relation to the issuing of a clause 4.8.9 instruction.

The Commission notes that the existing definition of "directed participant" expressly includes market ancillary service providers (MASPs). Given that this registration category is combined with DRSPs under the second draft rule, the second draft rule amends the definition of "directed participant" to clarify that the term only applies to DRSPs in their capacity as a provider of market ancillary services and not as a provider of wholesale demand response (i.e. to maintain the existing position under the rules). For consistency, the second draft rule also amends the definition of "scheduled plant" in respect of which AEMO can issue directions

393 NER, Chapter 10.

394 NER clause 4.8.9(a1)(1).

395 NER clause 4.8.9(a)(1).

396 NER clause 3.15.7(a).

397 NER clause 4.8.9(a1)(1).

398 NER clause 4.8.9(a1)(2).

to include ancillary services loads, and includes a reference to demand response service providers (in respect of market ancillary services) in the formula providing for compensation to directed participants.[399]

H.3.5 Affected participants

The interventions framework in the NER provides AEMO with the tools to intervene in the market for reliability purposes (e.g. in the event of a breach of the reliability standard) or for power system security purposes (e.g. to maintain voltage).The interventions framework includes not only directions but the RERT and the issuing of instructions by AEMO.

When AEMO intervenes in the market, it is required to compensate both market participants who were directed, and those affected by the direction. Affected participants are those parties whose dispatch targets have been affected as a result of an AEMO intervention event, and therefore include entities which are not themselves subject to directions. Affected participants are entitled to receive from, or pay to, AEMO an amount that puts them in the position they would have been in but for the direction or RERT activation. For example, if a generator's output is reduced as a result of an intervention, it will be paid compensation by AEMO to put it in the position that it would have been in had the intervention event not occurred.

Under the first draft rule, the definition of "affected participant" was amended to include a DRSP that has its dispatch quantity affected by a RERT-related intervention event. This would have meant that a DRSP would receive or pay compensation if it is affected by the exercise of the RERT, and this compensation would be calculated in the same way as for other affected participants.

The second draft rule does not expand the definition of "affected participants" to include DRSPs in relation to either directions or the RERT, and therefore DRSPs would not be eligible for compensation if they are affected by those interventions. This is based on advice from AEMO that including DRSPs in the affected participant compensation framework would require changes to a number of systems and processes that would materially increase the implementation costs of the mechanism. In addition, the Commission made a final rule on the *Application of compensation in relation to AEMO interventions* rule change in December 2019 which provided that affected participant compensation is no longer payable if the intervention is to obtain a security service that is not traded in the market (e.g. system strength).[400] The vast majority of AEMO intervention events currently occurring in the market relate to directions for system strength. While affected participants would still be entitled to compensation for intervention events that trigger intervention pricing, these are typically infrequent and short-lived. As such, the Commission considers that DRSPs would rarely be in a position to claim compensation in relation to an AEMO intervention event if they were to be included in the definition of affected participant. Given the associated implementation costs,

399 Clause 3.15.7(c) of the second draft rule.

400 AEMC, *Application of compensation in relation to AEMO interventions,* December 2019. Available at: https://www.aemc.gov.au/sites/default/files/documents/erc0282_-_national_electricity_amendment_application_of_compensation_in_relation_to_aemo_interventions_rule_2019.pdf.

the Commission considers it appropriate not to include DRSPs in this framework under the second draft rule.

H.3.6 Compensation following market suspension

On 15 November 2018, the Commission made a final rule establishing a new compensation framework in the NER so that certain market participants who incur a loss during a market suspension event can be compensated.[401] This was in response to a rule change request from AEMO in the wake of the 2016 market suspension in South Australia.

The compensation framework under the NER is designed to strike a fair and efficient balance between the interests of market participants and consumers. The framework will apply if, during a market suspension, prices are set by the Market Suspension Pricing Schedule (MSPS) rather than by the normal central dispatch and pricing process. The aim of the existing framework is to ensure that, when prices in the MSPS are too low to cover generators' short run costs, compensation is available so that generators do not incur a loss. This is designed to remove the current incentive for generators to withdraw from the market and await direction by AEMO when MSPS prices are low.

The second draft rule amends the definition of Market Suspension Compensation Claimant to clarify that compensation is also available to DRSPs that provide wholesale demand response during a market suspension event. Provisions relating to the calculation of compensation in these circumstances have also been amended to account for DRSPs; AEMO is required to determine the relevant amounts.[402] The Commission considers this to be appropriate, as it is consistent with the principle of treating DRSPs as equivalent to generators and ensuring that they are subject to the same incentives and regulatory processes during and following a market suspension event, to maintain their incentive to supply wholesale demand response during the event.

H.3.7 System changes

The second draft rule has a number of implications for systems within AEMO, retailers and metering data providers. These systems changes are necessary under the second draft rule to accommodate the introduction of DRSPs into market settlement.

In its submission to the first draft determination, AEMO noted the previous design of the mechanism would necessitate a long lead time and high implementation costs, due to complexity introduced by process and system design – the mechanism touches multiple key AEMO processes and operational systems including metering, settlement, dispatch, and forecasting, all of which would have required some degree of modification.[403]

AEMO also recommended that the second draft rule and determination not be prescriptive on the solution design, to allow flexibility for AEMO to implement the most efficient design.[404]

401 AEMC, Participant compensation following market suspension - final determination, November 2018. Available at: https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi.

402 Clauses 3.14.5A and B of the second draft rule.

403 AEMO, submission to first draft determination, p. 7.

404 Ibid, p. 20.

The second draft rule will result in some changes to the current arrangements for the flows of information and billing. In summary, the information flows under the second draft rule are as follows:

- Consumer electricity use would be measured and recorded at the consumer meter as it is currently.
- The MDP is required to read that meter and send information to the DRSP in instances where a DRSP has been allocated to that NMI. This would be in addition to the information being sent to the FRMP, AEMO and the DNSP.
- The meter data for each NMI would still go into MSATS at AEMO. In MSATS, in accordance with current procedures:
  - a distribution loss factor is applied to each set of NMI data
  - the NMIs associated with each FRMP are summed by transmission node identifier
  - the data is sent to AEMO's energy market management system (EMMS) for settlement and prudentials.
- DRSPs would be able to use the actual metering data for reconciliation purposes (in a similar way to retailers). However, the DRSP would not need to directly use the metering data for settlement.
- AEMO's EMMS will send bills to retailers based on their customers' actual consumption in the wholesale electricity market.
- AEMO will determine baseline methodologies. These methodologies would be used to generate baselines for demand response loads, allowing AEMO to quantify the amount of demand response provided. AEMO will then use this information to separately settle the retailer and the DRSP for the wholesale demand response.

In addition to these information flows, there would also be information provided by the DRSP that will need to be accommodated by AEMO. This information includes:

- **The approved baseline methodology and baseline settings**: these will be used for determining the baseline for the load at that NMI, which will in turn be used for market settlement, discussed in appendix F.
- **The DRSP**: AEMO will record the identity of the DRSP against the NMI. This would facilitate the transfer of metering data to the DRSP from the MDP. It will also facilitate market settlement for wholesale demand response.

Changes to AEMO systems

The second draft rule will require a number of changes to AEMO systems. There are also changes to dispatch procedures to accommodate the dispatch of demand response. This is detailed in appendix D.

The rationale for some of the changes to AEMO's systems is set out in appendix F, which details the settlement model introduced under the second draft rule.

AEMO's submission to the first draft determination highlighted a number of systems changes that would be required to implement the mechanism. This included changes to systems relating to:

- registration
- dispatch
- forecasting
- system operations
- settlements
- prudentials.

Some of these changes are covered in more detail in other appendices. The second draft rule also includes a number of changes from the first draft rule which are designed to reduce the complexity of the changes to AEMO's systems required to implement the mechanism and thereby reduce the associated implementation costs. These changes are highlighted in chapter 5.

The changes to systems resulting from information provision are covered below.

Information provision

As a result of the second draft rule, AEMO's systems for providing information to specific market participants will need to be updated to accommodate a number of changes. These changes include:

- new fields for NMI standing data including:
  - whether a customer has a DRSP and, if so, the identity of the DRSP
  - the selected baseline methodology and baseline settings for the NMI
- allowing DRSPs to retrieve NMI standing data.

AEMO will also need to ensure there is a process for changing the DRSP recorded against a particular NMI (for example, where a customer switches from one DRSP to a different one). The Commission considers this process may include the following elements:

- If a customer is transferring between DRSPs:
  - The incoming DRSP would need to submit an application to classify that load as a wholesale demand response unit.
  - AEMO would undertake an eligibility check. This would include checking whether the NMI for that load is already associated with a different DRSP.
  - If the NMI is already associated with a different DRSP, AEMO would notify the incoming DRSP, and that DRSP would then need to request its customer to terminate its contract with its original DRSP.
  - The original DRSP would then be required to notify AEMO that the relevant NMI is no longer a qualifying load for that DRSP, and the load would then cease to be classified as a wholesale demand response unit for the original DRSP.[405]
  - The incoming DRSP would then be able to classify that load as its wholesale demand response unit.

405 Clauses 2.3.6(k) and (l) of the second draft rule.

    - Once classified, AEMO would record the identity of the incoming DRSP against that NMI in MSATS (visible to the incumbent retailer).
- If a DRSP's contract with a customer terminates (in circumstances where the customer is not transferring to a new DRSP):
    - the DRSP would be required to notify AEMO that the relevant NMI is no longer a qualifying load for that DRSP, and the load would then cease to be classified as a wholesale demand response unit for that DRSP.[406]
    - AEMO would then remove the notification of the DRSP against that NMI in MSATS.

Market settlement systems

The second draft rule introduces a settlement model for wholesale demand response. This would require AEMO to either change its existing market settlement systems or introduce a new, separate system. The settlement system would need to:

- determine the quantity of demand response for the NMIs where demand response was provided
- pay the DRSP and bill the retailer for wholesale demand response, in each case adjusted to account for the reimbursement amount.

New obligations for MDPs

Under the second draft rule, the existing obligations on MDPs would remain, including their obligation to provide metering data to all registered participants with a financial interest in the energy measured by the meter.[407] This would now extend to DRSPs.

Under the second draft rule, MDPs would be required to send consumer metering data to a DRSP when one is allocated to that NMI.[408] DRSPs would need to become accredited with AEMO as B2B e-Hub Participants in order to receive this data. The MDP would need to reference the NMI standing data maintained in MSATS to determine if there is a DRSP and, if so, the identity of the DRSP.

The second draft rule places this obligation on MDPs because the actual meter data is likely to be useful for DRSPs in informing and reconciling settlement. In addition, it is unlikely to place additional burdens on the MDP as they are currently required to send the same meter data to multiple parties.

H.4 Complementary changes

The Commission considers that the supplementary changes detailed in this section will help facilitate greater uptake and transparency of a range of forms of wholesale demand response in the NEM. Many of these measures can be implemented relatively easily and without imposing significant costs on market participants.

The measures which are discussed in this section include:

406 Clauses 2.3.6(k) and (l) of the second draft rule.
407 Clause 7.15.5(c)(1) of the NER.
408 Clause 7.15.5(f)(5) of the second draft rule.

- increasing the utility of AEMO's demand side participation (DSP) portal
- consideration of changes to the AER's Energy Made Easy website to increase the visibility of retail contracts involving spot-price pass-through and demand response
- consideration of the impacts of the administered price cap (APC) on wholesale demand response
- revising the Energy Charter to include a commitment by retailers to facilitate more wholesale demand response.

H.4.1 AEMO's DSP Portal

Background

The Commission made a final rule in 2015 that sought to improve the quality of information on demand side participation in the NEM. Under the final rule, registered participants in the market (including retailers and network businesses) are required to provide information on demand side participation to AEMO, in accordance with the DSPI Guidelines.[409]

This has been implemented through the creation of AEMO's demand-side participation portal.[410]

The data provided through this process is intended to provide greater visibility of demand-side resources that are price sensitive, and so those which are engaging in wholesale demand response, for the purposes of improving AEMO's load forecasts. The information provided to AEMO through the portal should include information in relation to:[411]

- contractual arrangements between a retailer and a customer, in which they agree to the curtailment of non-scheduled load or the provision of unscheduled generation in specified circumstances
- the curtailment of non-scheduled load or the provision of unscheduled generation in respect of the demand for, or price of, electricity.

The information sought by AEMO is relatively detailed and is intended to provide greater transparency regarding the extent of wholesale demand response in the NEM. This information is important in being able to draw conclusions on the efficiency of the system-wide level of demand response.

We understand from informal consultation with stakeholders that further clarity on the reporting requirements applying under the NER and improvements to the functionality of the DSP Portal would assist in ensuring that the information captured is accurate and transparent. Relevant issues highlighted by stakeholders include:

- It is currently not clear whether participants that do not have any demand response arrangements with customers are required to report this to AEMO. This makes it difficult

409 AEMC, *Improving demand side participation information provided to AEMO by registered participants*, final determination, March 2015, available at: https://www.aemc.gov.au/rule-changes/improving-demand-side-participation-information-pr.

410 For more information, see: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/DSPIG/Demand-Side-Participation-Information-Guidelines.pdf.

411 NER clause 3.7D(e)(1).

to determine whether participants that have not reported information to AEMO are in breach of the NER.

- The functionality of the DSP portal can present challenges when seeking to report certain types of demand response in a participant's customer portfolio.[412] The Commission understands that AEMO has sought to rectify some of these issues.
- The types of information AEMO expects to receive could be made clearer in the DSPI Guidelines.
- There was a lack of clarity about how AEMO uses the information submitted to the DSP portal.

Commission's analysis and conclusions

The Commission considers that increasing the transparency and accessibility of the information submitted to the DSP portal would assist in understanding the impact of retailer-led demand response in the wholesale market. Currently, AEMO is not required to publish information regarding the data submitted by market participants to the DSP portal. Further, AEMO is only required to publish general information about the extent to which the data provided to it in the portal informed its development or use of load forecasts. As discussed in section 3, AEMO's most recent report was published in August 2019 and provided estimations of current levels of demand side participation. This report included analysis of the volumes and types of potential demand response capacity that exists in the NEM.

The Commission considers it appropriate that the NER expressly identify particular types of information that should, at a minimum, be included in AEMO's reporting on information submitted to the DSP Portal. This is intended to ensure that this information is captured in AEMO's reports and is transparent to market participants on an ongoing basis.

DRSPs are required to submit detailed information to AEMO when classifying a load as a wholesale demand response unit (see appendix C) and this form of demand response will be scheduled and therefore visible to AEMO. However, as discussed in appendix E, DRSPs are not required under the second draft rule to submit information to AEMO for the purposes of MT PASA. The Commission considers it appropriate for DRSPs to submit information of this nature through the DSP Portal. It would therefore be efficient for AEMO to report on demand response provided by DRSPs[413] at the same time as it reports on the demand side participation information submitted through the DSP portal.[414]

The second draft rule amends the NER to clarify the requirements that apply to the submission of information about demand side participation in the NEM to AEMO by registered participants and how AEMO deals with that information. The Commission acknowledges that

412 For example, the Commission understands that the interaction between the DSP portal and MSATS makes it difficult to accurately submit information about demand response where the relevant demand response arrangement is between a customer and a retailer-related entity that is not itself a registered participant.

413 Under clause 3.10.6 of the second draft rule.

414 Under rule 3.7D(c) of the second draft rule.

AEMO has already started to report on some of the additional demand side information required under the second draft rule.[415]

Changes to demand side participation information reporting requirements

The second draft rule:

- specifies that DRSPs are required to report, using the portal, information on their contractual arrangements for the provision of wholesale demand response, which may include the quantity of wholesale demand response to be provided and the circumstances and location in which it would be provided[416]
- requires entities that do not have any demand side participation information for a period to report that fact to AEMO[417]
- requires entities to report on arrangements for the adjustment of non-scheduled load, including arrangements for increases as well as decreases in consumption (e.g. to incentivise increased consumption during low-price periods).[418]

Under the current framework, the AER has no way of knowing whether a participant that did not submit a report decided not do so because it has no demand response customers, or simply failed to comply with its requirements under the NER. Clarifying that participants are required to submit a report to AEMO even where they have no demand response arrangements with customers will therefore make it easier for the AER to enforce compliance with the reporting requirements.[419]

In addition, the Commission recommends that the requirement for registered participants to report information in accordance with the DSPI guidelines be classified as a civil penalty provision, for improved compliance and enforcement ability.[420]

Changes to how AEMO deals with demand side participation information

The second draft rule:

- increases access to information about wholesale demand response by requiring AEMO to make the following information on wholesale demand response publicly available (without disclosing any confidential information):[421]
  - an analysis of volumes and types of demand response reported through the DSP portal, including an analysis of trends in this information
  - the different types of variable network tariffs which are currently used to facilitate network-led demand response and the proportion of customers on these tariffs

415 See AEMO, *Demand side participation forecast and methodology*, August 2019. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.

416 Rules 3.7D(a) and (e) of the second draft rule.

417 Rule 3.7D(b)(2) of the second draft rule.

418 Rule 3.7D(e) of the second draft rule.

419 Rule 3.7D(b)(2) of the second draft rule.

420 Rule 3.7D(b) of the second draft rule.

421 Rule 3.7D(c) of the second draft rule.

- clarifies that AEMO must distinguish between participant types (retailers, network service providers and DRSPs) when reporting such information.[422]

The second draft rule requires AEMO to publish an annual report each year setting out the information specified above. This is intended to clarify minimum reporting requirements AEMO must meet with respect to information submitted to the DSP Portal. However, this requirement is not intended to limit the types of information AEMO can report in this regard.

Further, expressly requiring AEMO to publish information relating to wholesale demand response procured by retailers, network service providers and DRSPs (based on information submitted to the DSP portal) will ensure that:

- registered participants are provided with guidance and transparency about how the information they submit to the DSP portal is used by AEMO
- the market has guidance on the level of participation in, and effectiveness of, the demand response mechanism
- market participants are able to develop more accurate demand forecasts, potentially leading to more efficient operational and investment decisions.

The Commission also understands that the DSP portal may not currently capture information about certain types of demand response in the NEM due to limitations in the functionality of the portal. Accordingly, the second draft rule requires AEMO to undertake a review of the DSPI Guidelines[423] and the Commission also recommends that AEMO consult with stakeholders to identify changes which can be made to the DSP portal to ensure that participants are able to report all wholesale demand response provided by their customers. AEMO's submission to the first draft determination notes that AEMO "would welcome the opportunity to work directly with stakeholders providing information into the portal to address some of the more operational concerns".[424] The Commission encourages stakeholders who have concerns to reach out to AEMO and discuss these directly.

The amended DSPI Guidelines are to be published by 31 December 2020 in order to allow participants to review the amended Guidelines before commencing their next round of data submissions when the DSP Portal opens on 31 March 2021.

DSP portal and qualifying contracts

The Commission notes that under the current rules for the Retailer Reliability Obligation (RRO), a "demand side participation contract" is only a qualifying contract for the purposes of the RRO if it is also registered in the DSP portal.[425] The first draft rule amended these provisions to provide that a contract for the provision of wholesale demand response under the mechanism may be a qualifying contract even where it is not registered in the DSP Portal, given that in the first draft rule wholesale demand response provided by DRSPs was not reported through the portal.[426] The second draft rule reverses this change, with the result

422 Rule 3.7D(c)(2) of the second draft rule.

423 Clause 11.120.7 of the second draft rule.

424 AEMO, submission to first draft determination, p. 22.

425 NER clause 4A.E.1(a).

426 Clause 4A.E.1(c) of the first draft rule.

that wholesale demand response contracts (as with other demand side participation contracts) may only be qualifying contracts if they are registered in the portal and meet the other relevant criteria.[427]

Other than in the circumstances described in the third last paragraph in appendix h.3.2 above, if a customer initially has a demand response contract with a retailer which is reported in the DSP Portal and counted as a qualifying contract for the RRO, but then engages a DRSP and provides wholesale demand response through the mechanism instead, the retailer will be required to cease reporting that contract as its qualifying contract in its next report to the DSP Portal. The Commission considers this is appropriate as, in these circumstances, the DRSP rather than the retailer will control the customer's demand response.

The interaction between the RRO and the introduction of the mechanism under the second draft rule is discussed further in appendix h.3.2 above.

Reporting by AEMO on DRSP-led wholesale demand response

The second draft rule also requires AEMO to publish an annual report including the following information on DRSP-led wholesale demand response (without disclosing any confidential information):[428]

- the number of registered DRSPs
- the number and capacity of loads classified as wholesale demand response units
- the amount of demand response dispatched in the wholesale market under the wholesale demand response mechanism, as well as the frequency of dispatch
- analysis of the spot price levels at which wholesale demand response was dispatched
- analysis of the impact of wholesale demand response on the procurement and use of market ancillary services
- relevant trends, including year-on-year changes, in the above data over time.

The Commission considers that these changes complement the other reforms required to facilitate the implementation of a wholesale demand response mechanism.

H.4.2 Energy Made Easy website

Background

Energy Made Easy[429] is a price comparison website developed and maintained by the Australian Energy Regulator (AER) in accordance with the NERL[430] and the AER's Retail Pricing Information Guidelines (RPIG).[431] The website is aimed at helping residential and small business consumers compare electricity and gas plans offered by different retailers and find the plan which best suits their consumption behaviour and financial circumstances.

427 Clause 4A.E.1(c) of the second draft rule.

428 Clause 3.10.6(c) of the second draft rule.

429 See www.energymadeeasy.gov.au.

430 NERL section 62.

431 Available at https://www.aer.gov.au/retail-markets/retail-guidelines-reviews/retail-pricing-information-guidelines-2018.

Energy Made Easy may include other information in addition to the prices of standing offer and market offer plans offered by retailers if the AER considers that such additional information would achieve the purpose of a price comparator.[432]

The price comparison tool on the Energy Made Easy website does not currently display spot price pass through contracts offered by retailers in the NEM. There is also no information provided about the nature of demand response products or how consumers may benefit from such products. This deprives consumers of the opportunity to compare such products with other offers that adopt more traditional tariff structures.

Commission's analysis and conclusions

The Commission is aware that there are a number of retailers offering wholesale demand response products (as detailed in chapter 3), but considers that these products may not be readily understandable, or easily found by customers who want to engage in wholesale demand response. The Commission also considers that more of these products will emerge in the near-term given consumer preferences and technology trends.

The Commission considers that it may be desirable for changes to the Energy Made Easy comparison tool to be made such that:

- spot price pass through contracts and other demand response services offered by retailers are represented, and that their cost and competitiveness is accurately portrayed to users of the tool
- retailers provide easy-to-understand information about the risks and requirements involved with retailer-led demand response arrangements, particularly where customers are materially exposed to the wholesale market price.

The Commission considers that such changes would increase the awareness and transparency of retailer-led demand response products among consumers and would allow consumers to make more informed choices when considering such products. Increasing access to information about the risks associated with such products is also important to make sure that consumers understand that consumers bear some (or all) of the wholesale price risk under these products and that they should carefully consider whether this is suitable for their particular circumstances.

Further, broadening the scope of the information retailers are required to submit would allow consumers and retailers to make better informed decisions in relation to the provision of wholesale demand response offers and services (provided this information is publicly available). This may also increase competition for retailer-led demand response products in the NEM, as consumer demand for such products may grow as public awareness of the potential value of demand response increases.

Making this information more accessible will reduce the existing information asymmetry between consumers and retailers which disadvantages consumers seeking to provide wholesale demand response. It is anticipated that this will help empower consumers to realise greater value from their wholesale demand response, thereby creating greater

432 NERL section 62(5).

incentives to provide demand response and helping to expose the efficient level of wholesale demand response in the NEM over time.

The demand response comparison tool could provide an estimate of the potential value a customer on a flat retail tariff may be able to capture by entering into a demand response arrangement with a DRSP (this may take into account, for example, the customer's tariff and usage information, as well as historical market data). This will allow consumers to make more informed choices when considering DRSP demand response contracts.

In its submission to the first draft determination, the AER noted that it was undertaking a major redevelopment of the Energy Made Easy website and the changes described above are beyond the scope of this project. While the AER agreed in principle with the objectives of increasing the awareness and transparency of retailer-led demand response, it also noted that any changes to Energy Made Easy should be informed by consultation and consumer testing, and that the timing for any such changes will depend on available resources and funding in the context of the AER's broader work program.[433] The Commission agrees with the AER's comments and considers that the proposed changes should be progressed at the next available opportunity.

Given that the NERR do not apply in Victoria, the Victorian Government administers its own price comparison website for energy products.[434] The Commission recommends that the Victorian Government consider similar changes to its price comparison website to ensure that Victorian consumers also receive the benefits of the proposed changes.

H.4.3 Relationship between CPT and APC and wholesale demand response

Background

Peak demand events during January 2019 provided insight into how the cumulative price threshold (CPT) and administered price cap (APC) impact on consumers' willingness to provide wholesale demand response.

The CPT imposes a cap on the total market price that can occur over seven consecutive days. The CPT is currently set at $221,100.[435] The CPT seeks to maintain the overall integrity of the NEM by limiting market participants' exposure to sustained high prices which could threaten the financial viability of prudent market participants. The CPT should be set at a level such that prices over the long term incentivise enough new investment in generation so the reliability standard is expected to be met.

If the sum of the spot prices over a seven-day period exceed the CPT, the APC is triggered. The APC is currently set at $300/MWh.[436] The APC also seeks to maintain the overall integrity of the NEM by limiting market participants' financial exposure to sustained high prices, while

433 AER, submission to first draft determination, p. 6.

434 See https://compare.energy.vic.gov.au/.

435 AEMC, *Schedule of Reliability Settings,* February 2020. Available at: https://www.aemc.gov.au/sites/default/files/2020-02/Schedule%20of%20reliability%20settings%20-%20Calculation%202020-21%20financial%20year_0.pdf.

436 AEMC, *Administered Price Cap Schedule*, November 2011. Available at: https://www.aemc.gov.au/sites/default/files/content//Schedule-for-the-Administered-Price-Cap.pdf.

maintaining incentives for participants to supply energy during the period of trading after the CPT is exceeded (this period is known as an "administered price period").

The Reliability Panel (Panel) is responsible for assessing whether the level of the CPT and the APC remain appropriate to support reliability in the NEM as part of its *Reliability standard and settings review* (RSSR)*,* which the NER require to be undertaken at least every four years.[437] The most recent review was completed in April 2018. In its final report, the Panel recommended keeping the current reliability standard and reliability settings unchanged.[438] The reasoning for maintaining the APC at $300/MWh included that this is considered to be sufficient to cover the short run marginal costs of most existing low capacity generators in the NEM. However, it has become evident that this price may not provide a sufficient incentive for many consumers that are capable of providing demand response to do so when needed (as discussed below).

On 25 January 2019, the APC came into effect after a period of prolonged high prices. The Commission understands from informal discussions with stakeholders that when this occurred, it may have led to some customers that had been undertaking wholesale demand response at the time to cease doing so, as prices were not high enough to justify a reduction in load. Instead, some of those customers started to increase their consumption when the APC was triggered.

This was complicated by the fact that at the time, the Reliability and Emergency Reserve Trader (RERT) was being used and AEMO had also instructed involuntary load shedding. The Commission understands that some customers who had previously been providing demand response were requesting RERT contracts from AEMO in order to gain payment above the APC for continuing to provide demand response.

Commission's analysis and conclusions

In light of these events, the Commission considers that it would be useful for the Panel to consider whether the APC remains appropriate, given recent experiences of how the current APC impacts on wholesale demand response during periods of peak demand.

Wholesale demand response currently makes a higher contribution to the demand/supply balance in the NEM, particularly during reliability events, compared to when the APC was set in 2008. The fact that some wholesale demand response providers appeared to stop responding when the APC was triggered in January 2019 meant that the reliability issue occurring at the time could have been exacerbated, leading to either more RERT contracts being used or a higher amount of involuntary load shedding. This behaviour may not have occurred if the APC (or CPT) was set at a higher level. On the other hand, a higher APC would reduce the protection the APC affords to consumers from sustained high prices.

The APC is reviewed by the Panel as part of the RSSR. The next RSSR is currently scheduled for publication in 2022, although the Commission did note in the final determination for the *Enhancement to the RERT* rule change that the Panel may turn its mind to the reliability

437 NER clause 3.9.3A(d).

438 Reliability Panel, *Reliability standard and settings review*, final report, 30 April 2018. Available at: https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018.

standards and settings sooner depending on the outcome of the AER's VCR estimates, which were published in December 2019.

It is worth noting that the RSSR considers the reliability settings together as a package, given that a change to one particular setting may necessitate a change to another. For example, if the market price cap is changed, then it needs to be considered whether or not the cumulative price threshold also needs to be changed. This is why the reliability standards and settings are reviewed comprehensively together. As such, it may be considered challenging or inappropriate to consider the APC on its own.

However, the Commission considers that it is reasonably clear that a liquid wholesale demand response market was not a consideration when the APC was set. Therefore, it may be worth the Panel turning its mind to potential changes in respect of this issue before it undertakes the next RSSR depending on the timing of this review (as discussed further below). Such consideration would include the following issues:

- what theoretical framework should apply to considering changes to the APC in order to better account for wholesale demand response
- what considerations should be taken into account e.g. the change to the automatic price floor
- how may this impact on the contract market (particularly since caps are typically referenced by a price related to the administered price cap)
- how changing the APC may impact on the ability for wholesale demand response to contribute to the reliability of the system.

If this interim review were to occur, this would allow the Panel to be better prepared when it undertakes the next RSSR, particularly given the large number of market changes it will have to take into account. The conclusions from this scoping exercise can be used as an input into the next RSSR. The Commission notes that the ESB has been tasked by the COAG Energy Council with undertaking a review of the reliability standard and providing advice to the Council for consideration and decision by March 2020. The timeframes and approach for the next RSSR will become clearer following the completion of this work by the ESB.

A separate but related issue is the fact that, while parties can claim compensation following the application of an APC, it is not clear that this is well-known. The Commission has published a set of guidelines about how this compensation is determined, which were last reviewed in September 2016.[439] The current objective of the payment of compensation under the NER is to maintain an incentive for: scheduled generators, non-scheduled generators and scheduled network service providers to supply energy; ancillary service providers to supply ancillary services; and market participants with scheduled loads to consume energy during price limit events.[440] While scheduled loads can make a claim if they face a net loss, the consideration of this in the rules and guidelines is if an administered floor price in the region applies, not an administered price cap.[441]

439 AEMC, *Final Amended Compensation Guidelines*, September 2016. Available at: https://www.aemc.gov.au/sites/default/files/content/6bdf3d79-1caa-4508-859b-ca6c5d99c222/Final-Amended-Compensation-Guidelines.PDF.

440 NER clause 3.14.6(c).

The second draft rule makes minor changes to the NER to clarify that DRSPs can claim compensation following the application of an APC, and includes a corresponding requirement on the Commission to review and, if necessary, update the compensation guidelines to reflect the amending rule.[442]

The Commission may also consider undertaking a more holistic review of these guidelines to determine whether changes are necessary to clarify the circumstances in which different parties can claim compensation.

H.4.4 Retailers facilitating more wholesale demand response

The lack of existing demand response products available to consumers and the possible conflicts of interest which may reduce the incentives for vertically-integrated retailers to offer such products are key issues which were raised by the rule change proponents and other stakeholders.

Wholesale demand response can provide a range of services and benefits that contribute to the security and reliability of the NEM, as well as increasing the efficiency of the market and providing consumers with greater choice and control over their energy consumption. The Commission considers that these benefits align with the commitments made by signatories to the Energy Charter, which was launched in early 2019. The Energy Charter is focused on "embedding a customer-centric culture and conduct in energy businesses to create tangible improvements in affordability and service delivery".[443] The Charter identifies principles which signatories should seek to implement as core elements of their culture and the way they conduct their business. A number of these principles are relevant to the provision of demand response products and services to consumers, including that signatories will put customers at the centre of their business and the energy system and will improve the customer experience. Given that retailers that are signatories to the Charter have committed to facilitating customer outcomes which are consistent with these principles, the Commission considers that it is incumbent on such retailers to consider providing greater opportunities for customers to engage in demand response. The Commission would expect that the disclosure and reporting regime applying to Charter signatories will shed light on the extent to which this is occurring.

The Charter states that it will be periodically reviewed and improved to reflect changing expectations and learnings.[444] The first review is planned to follow the publication of the first Accountability Panel Evaluation Report on 30 November 2019.

The Commission noted in its *2019 Retail Energy Competition Review* that the Commission supports the efforts of energy businesses to improve consumer outcomes through the Energy Charter and encourages more widespread adoption of the Energy Charter.[445] The Commission

441 Clause 3.14.6(a)(2) of the NER.

442 Clauses 3.14.6 and 11.120.6(c) of the second draft rule.

443 *The Energy Charter*, January 2019. Available at: https://www.theenergycharter.com.au/publications.

444 Ibid, p. 6.

445 AEMC, 2019 Retail Energy Competition Review, June 2019. Available at: https://www.aemc.gov.au/market-reviews-advice/2019-retail-energy-competition-review.

therefore recommends that DRSPs also sign up to the Energy Charter, given that they will have a direct and ongoing relationship with energy customers.

I SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS

This appendix sets out the issues raised in the stakeholder submissions on the first draft determination for these rule change requests and the Commission's response to each issue. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Table I.1: Summary of issues raised in submissions to first draft determination

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
Administered Price Cap		
EUAA, p. 4.	We agree that the implementation of the APC at $300/MWh might result in a lower level of demand response being bid into the market at a time of high prices and involuntary load shedding. However, a balance needs to be struck between: • the benefits of additional demand response from any rise in the APC, and • whether the rise in the APC will result in any additional generators offers that would offset the need for additional RERT Even if there is additional RERT required and if not available, load shedding, these costs need to be balanced against the large wealth transfer to generators that would result from a rise in the APC.	The Commission agrees that these are the types of considerations the Panel would need to take into account in any review of the interaction between the APC and wholesale demand response. As noted in the second draft determination, the Panel may turn its mind to the reliability standard and settings sooner than 2022 depending on a number of variables, including the outcome of the ESB's advice to the COAG Energy Council on the reliability standard.
Costs and benefits		
IES, p. 3.	We would like to see a survey of large customers indicating the degree of interest in participating in this style of mechanism. Even better, a practical trial should be conducted of this and alternate mechanisms.	Numerous large customers and their representatives, as well as small customer representatives have written in to the Commission throughout this process. In addition, the Commission has heard from meetings and stakeholder workshops that there is a strong interest in participating in the mechanism. Trials are discussed in chapter 3.

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
EnergyAustralia, p. 9.	The AEMC should undertake a cost benefit assessment and the estimated costs should be made public.	In considering any rule change request, including this one, the Commission considers whether the change is in the long-term interests of consumers. The Commission considers that the draft rule is likely to be in the long-term interests of consumers for the reasons set out in chapter 2. The Commission notes that any cost benefit assessment would not robustly or comprehensively quantify the net benefits of the mechanism. It is also difficult to directly attribute incremental costs of implementing a change to the regulatory framework to a particular rule change at a time when there are numerous complementary and concurrent changes underway.
Momentum Energy, p. 5.	The mechanism will impose significant system and administration costs onto AEMO and we suggest that the AEMC should conduct a cost benefit assessment of this change to ensure it justifies the work involved especially as it is only a short term interim solution.	
Snowy Hydro, p. 2.	The Commission should undertake a cost benefit analysis to determine the "net benefit" of the rule change before it is finalised. If the rule change does not pass the cost benefit test, we would welcome a wider review of the available models that could fit into the NEM.	
Meridian Energy/Powershop, p. 2.	There will be limited benefits to the market overall, although individual customers and DRSPs may see some returns over the long term. These benefits are likely to be offset by increased costs, relating to the new settlement regime, implementation of and supporting new systems, additional DRSP margin and the requirement for retailers to manage the changed risk profile of the remaining portfolio.	
Powerpal, p. 3.	We would encourage the commission to seek further data to evaluate and model what level of additional capacity might enter the market as a result of the preferred draft rule change. This could be done by, for example, working with existing Australian demand response providers who may wish to become DRSPs under the mechanism to	

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	understand the types of loads they would seek to obtain the right to curtail in order to offer additional demand response into the market, and then estimating the aggregate curtailable load available in Australia of each load type.	
Directions		
Stanwell, p. 7.	Directions are a valuable tool for AEMO to manage system security, to be used in rare circumstances. It is important that AEMO has the option to direct DRSPs as this may be more cost effective for consumers than directing generators. Stanwell's experience is that AEMO Operators typically consult with the participant before issuing a direction and are receptive to information on any constraints a participant has in responding to a direction. The DRSP could also manage its availability to directions by bidding unavailable.	The Commission has sought to treat DRSPs equivalent to generators under the second draft rule to the extent that it is reasonable and practicable to do so. The Commission considers that the issuing of directions by AEMO is an area where the obligations of DRSPs should reasonably differ from those of generators. Providing wholesale demand response is not the primary purpose of energy consumers, including those participating in the mechanism, and it would be unreasonable to require these customers to reduce their load at any time in response to a direction when this could have significant impacts on their commercial operations. This is discussed further in appendix D.
DSP Portal		
Ausgrid, p. 6.	We believe that the rule change should allow access to DSPI at the NMI level for registered participants with an interest in that NMI, including distributors. As part of the AEMO review of the DSPI Guidelines, a minimum set of DSPI data fields should be determined that are accessible to registered participants, including distributors, for the NMIs in their supply area, without disclosing any confidential commercial information. Including this requirement in cl	The Commission considers that AEMO is best placed to determine the form in which information should be submitted to the DSP Portal, in consultation with participants, given that it is their systems that determine the form in which the information must be provided. AEMO's review of the DSPI Guidelines will be subject to the Rules Consultation Procedures and participants will have the opportunity to provide input to the review through this process.

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	3.7D of the rules would assist distributors to better plan the electricity network for the benefit of all customers.	
Impacts on contracts market		
Delta Electricity (Marsden Jacobs report), p. 18.	Like generators, DRSPs could sell peaking contracts for the purpose of obtaining additional revenue. If this was done, such contracts could be sold to retailers, providing a signal to reduced need for new peaking plant. Given the nature of DR, it would be expected that these would not be equivalent to firm cap contract but may have conditions such as a period of notice, maximum duration, and an option for the DRSP to declare a reduced quantity of capacity support. Such contracts would not be liquid and may have the most value to the retailer that supplies the consumer that would provide the DR.	If a DRSP elects to sell a cap contract to a retailer, it will be up to the DRSP to manage and defend its position under that contract.
Delta Electricity (Marsden Jacobs report), p. 18.	Under the WDRM with the DRSP as a separate party to retailers, there is no recognition of the capacity provided by DR to retailers. This would act to limit long-term market benefits with the result that consumer prices would be higher. This is because the capacity provided by DR does not result in a reduction of the spot price risk to retailers. This means that the contracting requirements of retailers are unchanged despite the demand level being less (by the level of demand response).	While the contracting requirements of retailers would remain unchanged in the short term, over time this would be expected to decrease as customers' baselines are adjusted to account for the provision of demand response. Further, the mechanism will increase competition in the wholesale market, providing a potentially cheaper form of peaking generation which could be expected to reduce price spikes and therefore lead to an overall reduction in wholesale prices (the benefits of which will flow through to consumers).
Delta Electricity (Marsden Jacobs report), p. 21.	Third-party DRSPs are unlikely to be able to sell peaking (i.e. cap) contracts based on the WDRM arrangements. This would be due to the lack of firmness provided by DR. The	If a DRSP elects to sell a cap contract to a retailer, it will be up to the DRSP to manage and defend its position under that contract.

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	lack of firmness would reflect the uncertainty of baselines and the ability of the customer to respond in any interval. It may be that a DRSP that has many relationships to consumers may be able to sell / provide some level of firm capacity.	
Snowy Hydro, p. 2.	Snowy Hydro is concerned that DRSPs could potentially bid strategically, creating risk to market participants by distorting the contract market.	The second draft rule sets out clear and comprehensive obligations on DRSPs in respect of bidding which seek to minimise any distortionary outcomes. This includes making DRSPs subject to the bidding in good faith requirements that apply to generators.
Implementation		
Enel X, p. 13.	The draft rule requires AEMO and the AER to develop and publish a number of guidelines ahead of the commencement date. Enel X is concerned that the rules consultation procedure, if only commenced when necessary to have published these guidelines by the commencement date, will not provide sufficient time for AEMO, the AER and stakeholders to consider the broad and complex range of issues that the guidelines are to cover.	The second draft rule provides that the transitional provisions relating to the development or amendment of guidelines and procedures by AEMO and the AER will commence on 18 June 2020, allowing work on those processes to commence as soon as possible. The key guidelines and procedures are required to be in place by 24 June 2021. The Commission expects that AEMO and the AER will commence these processes in the near-term to ensure sufficient time for consultation with stakeholders.
Enel X, p. 13.	One implementation issue not mentioned in the draft determination is the fact that some retailers will need to amend their contracts to remove clauses that prevent customers from engaging with a third party for the purposes of providing demand response.	The Commission has noted in the second draft determination that the implementation timeframes for the mechanism will allow retailers sufficient time to renegotiate their existing retail contracts if required. The second draft rule does not specify the terms retailers may include in their contracts in relation to participation in the mechanism. The Commission

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
		considers that this is a commercial consideration for retailers.
Information provision		
Infigen, p. 3.	Infigen recommends that both the offered quantity and the settled quantity be made publicly available for each demand response activation (on a DRSP basis per trading interval). This is symmetrical with ability for anyone to calculate generator settlements from publicly available data (i.e., offers & bids, dispatched quantity, and settled quantity for each unit).	The Commission agrees. AEMO is responsible for publishing this data and under the second draft, AEMO would be expected to provide the same information in relation to DRSPs.
Stanwell, p. 7.	In future, to accurately price and assess a new customer, retailers will also require access to the demand response history of the customer (since they will be responsible for it). It is not clear how demand response from an aggregated resource will be able to be allocated to individual loads for future pricing processes.	Consumers will be able to access this information. Prospective retailers will therefore also be able to access this information by engaging with a new customer the retailer is seeking to sign up.
Stanwell, p. 7.	Stanwell suggests that any load participating in the demand response mechanism should also comply with the 42 month notice of closure obligation on generators.	The Commission does not consider this requirement to be appropriate for loads participating in the mechanism. The concepts of closure or retirement do not apply to loads in the same way as generators. It is therefore not clear that any such obligation would be useful or practical. The Commission also notes that DRSPs will be required to comply with other information provision processes that currently apply to generators.
EnergyAustralia, p. 11.	We note that the AEMC has not considered whether 3-year closure notice provisions should be required for aggregated loads exceeding 30MW.	
Enel X, p. 7.	Enel X is concerned that giving retailers visibility of when a customer enters into an agreement with a DRSP will undermine the success of the framework. Specifically, Enel	The Commission considers that it is important that retailers have access to this information in order to adjust their risk management strategies for that customer. The Commission

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	X is concerned that retailers will force or threaten a change in the price, terms or conditions of their retail contract such that the DRSP's offer now looks unattractive to the customer.	also expects that retailers will face competitive pressures to facilitate that customer's desire to participate in demand response.
Enel X, p. 8.	An obligation to notify the relevant retailer when its customer has entered into an agreement with a DRSP may also give the retailer an opportunity to capitalise on the customer's interest in wholesale demand response and offer them a product at a price just below what the DRSP is offering. Again, a retailer that does this would be taking advantage of privileged information it receives as the incumbent in the retail market to hamper competition in the wholesale demand response market.	The Commission acknowledges this as a potential outcome. However, this is not significantly different to a retailer offering a customer a product at a better price than a competing retailer when informed by the customer of the competitor's offer. If a retailer can offer the relevant product at a lower price, this provides an incentive for DRSPs to develop more competitive offerings, which ultimately benefits consumers.
Interaction with other reforms		
ERM Power, p. 2.	ERM Power understands that the AEMC does not have carriage of all this work, nor can it pick and choose which rule changes to investigate. However, we are concerned that the interactions between different rule changes are not being fully explored, or at least not in a way that is clear to market participants. The WDRM draft determination contains only a brief reference to the RRO, while ignoring the wider implications that higher hedging levels may have on retailer costs under the WDRM. Nor has the draft determination included discussion of the potential ramifications of the CoGaTI review and the proposed implementation of generator nodal pricing and financial	The Commission has considered and addressed the interaction between the introduction of the mechanism and the RRO in the second draft determination and the second draft rule. In relation to other regulatory reforms, while the Commission considers the interaction between these reforms as part of its policy development process, the Commission cannot make a rule on the assumption that a separate rule may or may not be made in the future. Following the extension for making a final determination in December 2019, the Commission has improved the design of the mechanism in light of the prospect for a longer term transition to a two-sided market.

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	transmission rights on both contract markets and how wholesale demand response will be settled in the market. These interactions can and should be explored in greater depth and included in the final determination as well as in other market reviews and rule change processes.	
Australian Energy Council, p. 4.	While the more preferable rule proposed by the AEMC has considerable improvements over the original proposal by limiting the changes required to AEMO's and stakeholders' systems, unfortunately its reduced scope also makes it costly and effectively disposable. This is further compounded by the work being conducted by the Energy Security Board, which may result in significant changes to the wholesale market design. On this basis, and in the absence of detailed information on the principles determining baselines, the Energy Council believes that implementation of the proposed rule should be deferred until the effect of other market changes becomes clearer, and the rule can be developed further so that it can be applied to a broader range of customers.	The Commission has considered the interaction between various regulatory reforms as part of its policy development process, as suggested in KPMG's recent framework to consider congruency of wholesale market reforms. The Commission is working closely with the ESB on its post 2025 market design work. The changes to the design of the mechanism under the second draft rule are targeted at significantly reducing the implementation costs for AEMO.
Network impacts		
Energy Networks Australia, p. 1.	If substantial amounts of demand response are switched in a very short period of time in localised areas, for instance a demand response event triggered when pool price hits a certain threshold, then it may cause local network disturbances which will adversely affect the remaining customers.	The Commission agrees that increased visibility of how distributed energy resources interact and impact the distribution network is important. Our grid of the future report encouraged DNSPs to continue to develop business cases for improvement of modelling and monitoring of their LV networks, including the quantification of costs and benefits of

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
		their approaches.
Energy Networks Australia, p. 2.	If the local DNSP has separate DR arrangements with large commercial customers, then there is a possibility of "double-counting" expected DR leading to a shortfall of supply.	If a DNSP has a commercial relationship with a customer for the provision of demand response, it will need to account for the possibility of that customer providing demand response to other parties. This would be the case under the current arrangements if a DNSP and a retailer were to both have a demand response contract with a customer. Under the second draft rule there will be no double counting, as demand response that would have occurred other than through the mechanism (e.g. through a contract with a DNSP) cannot participate in the mechanism.
Energy Queensland, p. 7.	Demand response at the local level is used by DNSPs to respond to local network issues that will be different to broader market demand issues. As a result, it is very unlikely that DNSPs will be able to defer augmentation for capacity and / or voltage control. Therefore, demand response in the wholesale market does not necessarily offset distribution network augmentation and uncontrolled demand response can in fact have an adverse impact at a local network level (particularly in weaker parts of the network).	The Commission agrees that there will not necessarily be a direct correlation between time of value in the wholesale market and in the local network for demand response. The benefits of introducing a wholesale demand response mechanism include a range of aspects, including promoting reliability in the wholesale market. It would also increase the number of consumers participating in demand response which would, in turn, increase the number of customers available to provide demand response to the local DNSP at times when this would be valuable to the DNSP (noting that this demand response could not also be sold through the mechanism).
Energy Queensland, p. 8.	Energy Queensland is of the view that further consideration is required as to the potential for any unintended consequences that the new mechanism may impose on	The Commission considers that AEMO is well-placed to manage any system security impacts associated with wholesale demand response being integrated with central

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	other customers and market participants as well as possible impacts on system stability and strength when the demand response mechanism operates and how these issues will be addressed.	dispatch. The second draft rule includes requirements on DRSPs and processes designed to give AEMO the tools to do so.
Potential demand response capacity		
CS Energy, p. 3.	Contrary to concerns raised by some stakeholders that consumers are unable to undertake demand response due to the absence of offers being made available by retailers, CS Energy's experience is that offers for demand response are not aggressively being taken up by customers.	The Commission has received feedback from large customers (as detailed in the second draft determination) indicating that there is limited competition between retailers for demand response offers to such customers and, where these products are available, these customers have difficulty capturing the reasonable value of their demand response under such arrangements. The mechanism will provide greater opportunities for these customers to provide wholesale demand response and capture the value of doing so.
Powerpal, p. 4.	In the most unfavourable situation where the rule change simply attracts a proportion of preexisting wholesale demand response to the mechanism without adding a material level of additional capacity, the pricing bid by DRSPs for demand response capacity will be immaterial. This is because without additional capacity generators will remain the price setters, likely at or near the market price cap as for recent LOR events. So while reliability may improve marginally (as the demand response capacity would now be dispatchable and therefore more predictable) costs to consumers could be expected to increase as the demand response capacity would now be settled in the	The Commission considers that if existing demand response were to be provided through the mechanism, this would reflect that these customers were being provided greater value for their demand response through a DRSP than they are currently able to obtain. In addition, the mechanism would make the wholesale demand response more transparent and more reliable for the system operator. The demand response settled in the wholesale market would not add additional costs as it is provided in lieu of generation.

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
	market at the spot price.	
Powerpal, p. 3.	Of particular concern is that there appears to be no published estimate of how much latent flexibility there is in large Australian C&I loads such that these loads could potentially be bid into the market as additional capacity, i.e. additional to demand response capacity that is already being made available via alternative mechanisms. Given the criticality of the success of the mechanism to its ability to unlock additional demand response capacity we find it striking that no such analysis has been conducted. The approach of the commission seems to be very much "build it and they will come", which given the additional costs that will be imposed on market participants (and ultimately passed on to consumers) strikes us as carrying a high level of risk.	Under the current arrangements, the level of wholesale demand response in the NEM is opaque and, as such, it is difficult to know if this level is efficient or not. However, the Commission understands from stakeholder meetings and stakeholder workshops that there is a strong interest in participating in the mechanism. The Commission has also designed the mechanism with the intention of reducing the implementation costs and the associated risks of redundant IT infrastructure.
Scheduling		
Delta Electricity (Marsden Jacobs report), p. 19.	Executive summary paragraph 27 states that 'without scheduling, the reliability benefits associated with the mechanism would be reduced.' The paper provides no evidence to support this.	The second draft determination sets out a range of benefits associated with wholesale demand response being scheduled, including: • more efficient price formation in the wholesale market • increased transparency for other market participants, leading to more efficient operational and investment decisions on both the supply and demand side of the market •

STAKEHOLDER	ISSUE	COMMISSION RESPONSE
		• greater certainty of the reliability of wholesale demand response for AEMO.
Energy Queensland, p. 10.	As noted previously, the AEMC has stated that the intent of the rule change is to treat scheduled demand response in a similar manner to scheduled generation in the wholesale market. However, it does not appear that other obligations that currently apply under the NER with respect to embedded generators, for example the requirement for DNSPs to make avoided transmission use of system payments to embedded generators (rule 5.3AA), have been considered by the AEMC in its draft rule determination. Energy Queensland therefore recommends that further clarity is provided in the final rule determination on this and similar matters.	The second draft rule treats DRSPs as equivalent to generators to the extent it is reasonable and practicable to do so. This is particularly important in respect of scheduling and participation in central dispatch to ensure that AEMO can rely on wholesale demand response as a substitute for generation. However, the second draft rule does not seek to replicate every obligation or process relating to generators under the rules for DRSPs.
Settlement		
Delta Electricity (Marsden Jacobs report), p. 6.	An analysis of the potential dynamics of the WDRM found that the arrangements introduce significant uncertainty into the cash flows to the various parties, introduce increased risk to retailers without confidence that DR will be increased, and reduces the relationship of DR capacity to the capacity contract market: • The increased risk to retailers is primarily associated with not receiving the reduced spot purchase costs associated with DR; • The spot purchase reductions obtained by a DRSP are unlikely to be used to hedge capacity sales;	The second draft rule seeks to minimise any risk to the retailer by ensuring that retailers' position remains largely unchanged regardless of whether their customers are participating in the mechanism. The Commission considers that DRSPs will face competitive pressures to offer prospective customers a reasonable portion of the value of their demand response. The second draft rule also includes a framework to ensure that baselines are robust, subject to appropriate accuracy requirements and regularly tested.

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	• The risk of a low take-up of DR is due to the DRSP potentially absorbing a significant portion of the DR value; • Baselines introduce significant cash flow variability risk; and • The retailer and market do not have a reduced contract requirement that would result from DR being supplied via a third-party DRSP. These issues could mean that additional capacity would be required that would not have been otherwise needed, with the flow-on effect of a reduction in the value of DR. This dynamic could also impact the potential transition to a two-sided market.	
Delta Electricity (Marsden Jacobs report), p. 13.	The basis of this payment [from the DRSP to the customer for DR provided] is that the customer is not "seeing" the spot price, and this is needed to provide that signal. As the DRSP would have a business model to capture a proportion of this value, the incentives for the customer to undertake DR would be proportionally reduced.	The Commission considers that DRSPs will face competitive pressures to offer prospective customers a reasonable portion of the value of their demand response. The mechanism provides an additional avenue for consumers to undertake demand response. The Commission expects that consumers will also continue to respond to price signals through other products and programs where they can obtain more value from doing so.
Electricity Exchange, p. 5.	We believe that the socialisation of the cost of the delivered DR among retailers would considerably enhance the level of participation in the mechanism.	The Commission considers the socialisation of the costs produces distorted pricing signals which would lead to inefficient outcomes.
Momentum Energy, p.	We also do not agree with the assumption, put forward at	The example referred to was intended to illustrate one

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2.	the first AEMC workshop to justify retailers' accommodating the DRM that any retail margin lost by retailers during the peak periods, when the DRM will operate, will result in increased consumption in the adjacent off peak periods where the DRM will not be called upon. We do not believe this will always be the case as some businesses may: • Shift production to alternative plants; • Implement peak demand process operational changes specific to the peak periods; • Utilise onsite alternative generation plant during peak periods; or • Simply forgo production in high price periods.	potential outcome of a customer providing wholesale demand response from a retailer's perspective. The Commission agrees that this will not always be the case.
Stanwell, p. 9.	Consideration should be given as to whether a condition of participation in the mechanism is a fixed price retail agreement.	The second draft rule addresses the risk posed to retailers by spot-price exposed customers participating in the mechanism by precluding such customers from doing so in intervals in which they are spot-price exposed.
Enel X, p. 11.	While much has been said about the potential for retailers to under-recover their costs under the reimbursement rate approach, it is important to note that there is also the potential for retailers to receive a windfall gain if the reimbursement rate is too high. The original settlement model, or a requirement for retailers to reveal their true costs, would address this issue. However, we understand the AEMC's reasons for not pursuing such approaches.	The Commission agrees that the reimbursement rate could under-compensate or over-compensate retailers in any given transaction. This will depend on a range of factors, including spot prices over the previous 12 months, the retailer's pricing structure and the customer to which the transaction relates.
Systems changes		

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EnergyAustralia, p. 10.	It is unclear what rights DRSPs will have in regard to a customer's meter data. This data is procured and paid for by retailers, and distribution businesses (depending on the jurisdiction and the customer's meter type). If DRSPs are to interact with Meter Data Providers (MDPs) to obtain data for commercial purposes, this should be supported by a contractual relationship. Should the DRSP require data, they should seek an agreement with the relevant parties, or otherwise install their own metrology device. It is not appropriate for retailers, or distribution businesses, to be charged for any additional metering works that are required for a DRSP to provide its service including providing unscheduled meter reads, metering disputes, any metering investigations or works, and any system change costs associated with implementing the rule such as changes in B2B and B2M. Further, should a customer entering a contract with a DRSP require a meter to be installed, the retailer should be able to refer these costs to the DRSP, rather than being responsible for them. Further, when developing B2B Procedures, AEMO will need to be cognisant of the fact that DRSPs do not have a commercial relationship with retailers, distribution businesses or MDPs.	To the extent that additional metering costs are imposed in relation to the provision of metering services, these costs could be attributed to the customer through the existing retail contract.
EnergyAustralia, p. 10.	It is unclear whether all customers should be required to fund AEMO's development and maintenance costs or whether these costs should fall on the DRSPs (and their customers) who are the direct beneficiaries of the changes. While it is possible that all customers could benefit, this	The Commission considers that all customers will benefit from the increased participation of wholesale demand response in the wholesale market in a transparent, scheduled manner, including through reduced wholesale prices. The Commission therefore considers it appropriate that the implementation

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	outcome is not a certainty and it would be inappropriate for all customers to cross-subsidise those who are benefitting from the changes. The AEMC should recommend AEMO to consider changes in its next fee determination, prior to implementation of the rules, that DRSPs incur a portion of AEMO's costs for metering, B2B and dispatch systems.	costs be funded by all customers. Further, DRSPs will be subject to participant fees under rule 2.11.
Telemetry		
Stanwell, p. 5.	If SCADA can not be used for all scheduled wholesale demand response providers, then Stanwell suggests it at least be enforced, through the Rules, on loads providing demand response greater than 1MW.	The second draft rule allows AEMO to determine the telemetry and communication requirements applying to loads which are sought to be classified as wholesale demand response units. The Commission understands that AEMO will require loads with demand responsive capacity greater than 5 MW to use SCADA for system security reasons. This is discussed in appendix C of the second draft determination. DRSPs are not subject to causer pays under the second draft rule.
Stanwell, p. 4.	In addition to the type 1, 2, 3 or 4 meter plus "appropriate communications and telemetry for the issuing of dispatch instructions", large loads should also provide Supervisory Control and Data Acquisition (SCADA) feeds in order to determine their causer pays factor when dispatched for demand response.	
Stanwell, p. 9.	Retailers pay for, and pass onto customers, the costs associated with metering. Consideration should be given as to whether the DRSP should contribute to these costs, especially if, due to participation in mechanism, a new meter is required.	To the extent that additional metering costs are imposed, these costs could be attributed to the customer through the existing retail contract.
Two-sided market		
Australian Energy Council, p. 2.	In a similar manner to the contract market mitigating the risk of the spot market for generators and retailers, for a	The Commission acknowledges the AEC's comments on this issue. On 14 November 2019, the Commission published a

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	two-sided market to develop properly, an analogous contractual market will need to develop to alleviate the risk for retailers and consumers. In this way the overlay of a pool-exposed demand response market with a contractual market is similar to the private arrangements between FRMPs and Demand Response Aggregators suggested by the Energy Council in its rule change request.	paper on the impacts of digitalisation on the NEM. This paper sets out some thinking on digitalisation and the potential to move to a two-sided market. The COAG Energy Council has flagged consideration of the development of a two-sided market as a priority and has asked the ESB to provide advice on the design of a two-sided market.
ENGIE, p. 4.	First, the Commission could mandate participation of large loads in the market above a designated threshold. Large loads are already by their nature actively involved in managing their energy costs especially in light of the large and challenging price increases they have faced in the past decade.	The Commission encourages stakeholders to provide input on the two-sided market concept through the ESB's 2025 Market Design process. The Commission considers that, at this point in time, there would be value in introducing a wholesale demand response mechanism and that this will provide market participants with opportunities to gain experience with practices and processes that will be useful in a two-sided market. Noting ENGIE's comments, these could form part of the design of a two-sided market.
ENGIE, p. 4.	In this regard, if the Commission has a two-sided market as a future ambition, then there may be simpler, easier changes which could be more quickly adopted and are likely to have larger payoffs for customers as opposed to changing the market to suit a specific third-party business model.	
Major Energy Users, p. 5.	The demand response program is a transitionary tool to reach a two sided market is misplaced. This means that the demand response should be assumed to be an enduring element of the electricity market into the future and that the rules should reflect this reality.	Some aspects of the mechanism will become less effective as the level of demand side participation increases. A two-sided market is a market design that would be robust to more demand response participating. The Commission will have an opportunity to consider the performance of the mechanism review three years after the mechanism commences.

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PIAC, p. 20.	The wholesale demand response mechanism is an essential component of a two-sided market, but a two-sided market is not a replacement for the mechanism. PIAC considers the aspiration for more active and symmetrical participation in the market is a worthy one that is supported by the introduction of a wholesale demand response mechanism. However, we challenge some of the AEMC's views with respect to the idealised market, and consider the two-sided market should not be viewed as an energy-retailer-centric one.	The Commission encourages stakeholders to provide input on the two-sided market concept through the ESB's 2025 Market Design process. This includes views on the roles for market participants, including aggregators and retailers, in a two-sided market.
PIAC, p. 21.	Most consumers want to access low-cost energy from the grid from a retailer, and these other services from another provider, and they do not want to compromise one offer for the sake of another. Anecdotally, a prominent Australian battery services provider has advised PIAC that approximately half of the potential customers they seek to recruit that do not enter into a contract with them, decline because they would have to also enter into a specific retail contract to do so.	The mechanism introduced under the second draft rule would address this issue by allowing consumers to enter into arrangements with DRSPs without requiring the approval or involvement of the consumer's retailer.
PIAC, p. 22.	If the AEMC's belief is that when the optimal amount of DR participation is reached then the mechanism will not be required, PIAC considers the opposite is true: the mechanism that has enabled that participation will need to remain in place in order to sustain the optimal state of the market.	The Commission considers that, over time as a greater proportion of the demand side participates in the market, aspects of the mechanism will become less workable e.g. centrally determined baselines. With large amounts of demand side participation, a two-sided market would likely be a better framework for rewarding demand response and sharing the value with the rest of the market.

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		The Commission considers that participating in the mechanism will provide DRSPs with experience that will be valuable in a future two-sided market.
PIAC, p. 22.	PIAC disagrees with this. There is no way for responding to price signals that requires no type of 'baselining'. Different types of DR just require different parties to carry the risk and determine the value. Baseline accuracy risk, for example, is shared by: • Consumers in a given NEM region, participating DRSPs and participating consumers, when provided via a DRSP • The customers of a given retailer, the retailer themselves and participating consumers, when provided via a retailer • The customer themselves, when responding to spot price signals. Even in the latter case, the customer still has a 'baseline' as they determine what they are forgoing in return for the value provided by DR.	The Commission agrees that demand response typically requires a baseline. A two-sided market would not rely on having these baselines centrally determined to quantify the demand response provided. Instead, it would likely decentralise the determination of baselines.
Demand response resources		
PIAC, p. 15.	The mechanism should build a pool of demand response that can also be used for distribution and transmission network, ancillary services and system security purposes if and when the need arises.	The Commission agrees.
Implementation timing		
CEC, p. 3; EUAA, p. 2; BlueScope Steel, p. 2;	A number of stakeholders considered that the mechanism should be introduced earlier than 1 July 2022 and that	The implementation date of the mechanism under the second draft rule would be 24 October 2021. The changes to the

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Energy Efficiency Council, p. 1; Victorian Greenhouse Alliance, p. 1; Major Energy Users, p. 3; South Australian Government, p. 1; Enel X, p. 13; PIAC, p. 5.	AEMO and the Commission should explore how an earlier implementation could be facilitated.	design of the mechanism which facilitate an earlier implementation date and the benefits associated with this are discussed in chapter 5 of this determination.
AGL Energy, p. 8; Aurora Energy, p. 2; CS Energy, p. 6.	Implementing the mechanism earlier than 1 July 2022 may not allow sufficient time for retailers to adjust their retail contracts with large customers where necessary to account for these customers potentially participating in the mechanism, given that such contracts are typically around two years in length.	The Commission understands based on feedback from stakeholders that, following the implementation of the wholesale demand response mechanism, retailers are likely to contract to cover their exposure up to their baseline level of energy consumption, as this is the amount they will be required to purchase in the wholesale market for customers providing demand response under the mechanism. However, the baseline level of consumption should reflect the amount the customer would have consumed in the absence of providing wholesale demand response. Accordingly, a retailer's exposure in the wholesale market will be approximately the same regardless of whether or not its customer is participating in the wholesale demand response mechanism. Nevertheless, the Commission acknowledges that the implementation of the mechanism may require retailers to make adjustments to their risk management strategies (for example in relation to potential changes to customer demand

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		in the periods before and after the customer provides demand response) and incur administrative costs associated with the renegotiation or replacement of existing contracts. The Commission considers that adopting an adequate transition period prior to the mechanism commencing will assist retailers in managing these changes.
AGL Energy, p. 9.	While the settlement model under the rule seeks to minimise the changes required to retailers' billing systems, retailers will still be required to make changes to a range of systems and processes, including those used for pricing, load forecasting, settlement and reconciliation and interaction with MSATS.	The Commission acknowledges that retailers will be required to make some systems changes to accommodate the introduction of the mechanism. As technologies continue to evolve and the trend of digitalisation increases, retailers will need to adjust their systems and operations to adapt to changes in the market. The mechanism under the second draft rule seeks to capture the benefits of wholesale demand response while reducing the implementation costs for retailers.
EnergyAustralia, p. 12; Stanwell, p. 3; AGL, p. 2; Flow Power, p. 3; Snowy Hydro, p. 2.	Significant resources are already required for participants to implement the changes required to facilitate the commencement of five-minute settlement on 1 July 2021 and global settlement in February 2022.	The Commission agrees and has worked with AEMO to find an implementation date that would allow for implementation at a time that would work alongside the implementation of these other processes. The Commission considers the mechanism as designed limits the impacts on market participants and balances the impacts against benefits of bringing forward the implementation.
Other		
Dr Martin Gill, p. 2.	If DRSPs offer consumer demand response they are likely to make multiple bids. Different levels of consumer incentive payments may mean different consumers are involved.	The settlement equations for wholesale demand response under the second draft rule account for transmission and distribution losses. This was based on feedback in AEMO's

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	Accurate modelling probably requires AEMO to estimate and use different Marginal Loss Factors depending on which DRSP bids are dispatched. This is much more complex than the existing modelling they perform. Marginal Loss Factors ensure traditional generators and demand response from large industrial loads is accurately modelled and fairly rewarded. Until similar levels of confidence are available to consumer offered demand response these bids should be excluded from the generator bid stack.	submission to the first draft determination and is consistent with the principle that DRSPs should be treated as equivalent to generators. The Commission notes that customers participating in the mechanism are expected to be primarily large industrial loads and the existing approach to the calculation of marginal loss factors should be appropriate for those customers.
EnergyAustralia, p. 1.	The proposed changes don't capture the full array of demand response capabilities including behavioural, pre-cooling or delayed starts and network service demand response. However, it does deliver benefits in making this activity visible to AEMO.	The Commission acknowledges that there are a range of different types of demand response (as discussed in chapter 3) and the mechanism is specifically targeted at facilitating the provision of wholesale demand response. The Commission agrees that there are substantial benefits associated with making this demand response scheduled and thereby increasing the transparency of this activity to AEMO and other market participants.
EnergyAustralia, p. 1.	We expect the draft rule will introduce limited additional demand response capability as most loads capable of providing the level of controlled and predictable reduction required for AEMO's dispatch processes would already be providing demand response through their retailer.	Large customers have expressed in submissions to the consultation paper and first draft determination, as well as technical working group meetings and informal discussions, that they have difficulty accessing competitive offers by retailers for demand response products. The Commission considers that providing these customers with an additional avenue to provide wholesale demand response through the mechanism will allow them to better access the benefits of demand response while also increasing the overall capacity of
EnergyAustralia, p. 1.	We maintain our views from our submission to the consultation paper that demand response has great potential to deliver benefits to customers, but that creating a new participant type will increase complexity in the	

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	market and does not clearly result in additional demand response being provided over and above that which is already available, or becoming available, from retailers.	demand response in the NEM. The Commission also considers that DRSPs will face competitive pressures to offer prospective customers a reasonable portion of the value of their demand response.
ENGIE, p. 3.	What is being proposed: • is a highly complex arrangement which creates a further overlay on the operation of the market for a service that can already be provided within the current framework; • will likely have high transaction costs with an expectation the bulk of any financial benefit will go to demand response aggregators and not customers and will need to cover the additional costs of infrastructure to provide the DRM.	
Infigen, p. 1.	We consider that retailers are best placed to manage demand response from customers, as retailers are naturally exposed to the wholesale price and have direct incentives to seek opportunities to reduce load at peak times, where efficient to do so. Infigen actively engages with customers to develop flexible retail contracts that best suit their customer needs, including options that expose them to the wholesale market price.	
Energy Queensland, p. 6.	Demand response is already occurring in the NEM and large customers are able to participate in the wholesale market under the current regulatory framework (i.e. by entering into bilateral off-market contracts with retailers and aggregators) without the need for an additional market participant role and significant process and system changes	

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	that will impose further costs and complexity on the market.	
Snowy Hydro, p. 2.	While shaving load off peak demands may appear intuitively attractive, the consequence of this is that peaking generation will receive a lower return and therefore there will be a lesser incentive to build and maintain new firm generation. When DR is not able to respond, the backup that would otherwise exist may not have been built, or the alternative is the DR must be paid for as well as the peak generation, thus duplicating costs.	The Commission considers that the mechanism will allow wholesale demand response to compete with generation in the wholesale market, particularly during times of peak demand, which will lead to lower wholesale prices (the benefits of which will flow to consumers). To the extent that wholesale demand response is not firm and is therefore not able to respond during this period, this will be reflected in the price signals seen by the market.
Snowy Hydro, p. 3.	Energy only markets are designed in allowing generators to recover capital costs at times of tight demand supply, the idea being that at these times prices will be high. However, the introduction of a demand side market that incentivises Commercial and Industrial customers to bid their energy through the WDRM, reducing peak prices for generators, reduces the time frames for them to recover their capital costs. This comes at a particularly sensitive time when the market is transitioning to renewable generation and the need for base-load generation is critical, we cannot support the WDRM.	
Snowy Hydro, p. 4.	Many I&C contracts are likely to impose financial penalties for DS bidding via a WDRM increasing the risk it won't be used much. Demand side contracts are likely to include penalty provisions that would be applied to customers that switch off during high price periods and bid energy through the WDRM. It is not clear to us what proportion of the	This is a matter for commercial negotiation between retailers and commercial and industrial customers. The Commission expects that the implementation of the mechanism will impose competitive pressures on retailers to facilitate their customers providing wholesale demand response (either through the mechanism or through their retail contract).

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	thousands of I & C contracts would include these penalty provisions. These contracts are confidential, making it impossible for Snowy Hydro to know what and how many of the current I & C contracts have these provisions in place.	
Stanwell, p. 4.	The opportunity for loads to opt in and out of dispatch and thereby avoid certain obligations, may create a perverse incentive for some generators to locate behind the meter and register in this way too.	The approach taken to scheduling of DRSPs under the second draft rule does not allow them to opt in and out of dispatch. DRSPs will be treated in a similar manner to scheduled loads and will receive a dispatch target in every dispatch interval.
ENGIE, p. 2.	There has never been a strong argument as to why business models who wish to engage with the consumers and with the wholesale market should not have to: 1. face the same wholesale market risks as other participants; and 2. face the same licensing and financial obligations as existing retailers and AFSL holders.	The second draft rule seeks to treat DRSPs as equivalent to scheduled loads to the extent that it is practicable to do so. The Commission considers that the second draft rule allocates an appropriate level of wholesale market risk to DRSPs. Requirements relating to the need for an Australian financial services licence are not dealt with under the NER.
Tesla, p. 3.	How will this interact with the AEMO VPP Demonstrations Trial? The AEMO VPP Demonstrations Trial currently limits participation to either market customers, with assets registered as ancillary services load, or to MASPs. We note that the timing of AEMO trial is stated to be 12 months with a discretionary extension. In the event that the trial is extended, the AEMC and AEMO will need to consider how, and if, DRSPs can participate.	The Commission agrees that this will be a matter for consideration if the VPP Demonstrations Trial is extended.
Tesla, pp. 3-4.	Noting the many and varied work-streams underway currently, we would encourage the AEMC to undertake a review within the next 12 months, on optimal market	The Commission notes this suggestion. Market participation categories may be considered as part of the *Integrating energy storage systems into the NEM* rule change.

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	participation categories for DER looking at both controllable load and controllable generation. This work can build on the AEMO VPP Demonstrations Trial work, and the development of a bi-directional resource category under a rule change put forward by AEMO.	
Tesla, p. 3.	How will the baselines interact with DRSPs who also register their assets as ancillary services loads?	The baselines will still be based on actual metered consumption. To the extent that loads are ancillary services loads that provide a response to frequency, this would be reflected in their baselines. However, when determining baseline methodologies, AEMO could consider whether it is appropriate to remove these.